

Nigeria's Deep Offshore Investment Reset: What the 2026 Tax Remission Order Means for Investors

Regulatory Update

Introduction

Nigeria's fiscal framework for deep offshore petroleum projects has received a new layer of investment incentives with the Deep Offshore Oil and Gas Projects Incentives (Tax Remission) Order, 2026 (the "Order")¹. The President made the Order 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"). The Order introduces production-linked tax remission incentives for qualifying deep offshore crude oil and non-associated gas developments.²

The Order operates within the wider petroleum and tax framework established by the PIA and the Nigeria Tax Act 2025 ("NTA"). Among other things, the PIA requires the Minister of Petroleum to promote an enabling environment for investment in the Nigerian petroleum industry and imposes a corresponding objective on the Nigerian Upstream Petroleum Regulatory Commission ("NUPRC") to promote an enabling environment for investment in upstream petroleum operations. The NTA also contains specific provisions for deep offshore and inland basin production sharing contracts ("PSCs") that are yet to convert under the PIA or have been renegotiated in accordance with it.³

Against this backdrop, the Order introduces three (3) principal incentives, namely the Standard Production Tax Credit ("Standard PTC"), the Supplementary Production Tax Credit ("Supplementary PTC") and the Profit Oil Reset, while separately prescribing a profit gas sharing formula for existing non-associated gas deep offshore PSCs.⁴

In this context, a Production Tax Credit ("PTC") is a production-linked tax-remission incentive calculated with reference to qualifying oil or gas production. For investors, however, the headline value of the incentives tells only part of the story, as the actual benefit depends on whether a project qualifies. The requisite conditions include when its Final Investment Decision ("FID") is taken,⁵ how the project is structured and executed,⁶ its technical costs⁷ and whether the applicable conditions continue to be satisfied. FID, in practical terms, is the point at which the relevant project participants formally and irreversibly commit to fund and develop the project and engage construction contractors to begin its implementation.⁸ Accordingly, the more useful question for investors is not simply what incentives the Order provides, but how a qualifying project can obtain, utilise and preserve them.

Aug 6, 2026

Order date

Effective from 28 February 2024.

3+1

Principal incentives

Standard PTC, Supplementary PTC and Profit Oil Reset, plus a profit-gas formula.

2029

FID deadline

Qualifying projects must reach FID by 31 December 2029.

The Standard PTC: The First Layer of the Incentive

The Standard PTC applies to qualifying developments under both existing and future deep offshore leases, although the applicable conditions vary by lease category. For an existing lease, FID must be taken between the effective date of the Order and December 31, 2029. Where that deadline is missed, and no *force majeure* extension is granted, the Standard PTC is reduced to 50% of the otherwise applicable rate, provided the project satisfies the remaining eligibility requirements.⁹

For crude oil developments with producible reserves not exceeding 400 million barrels of crude oil equivalent, the Standard PTC is \$3 per barrel or 20% of the fiscal oil price, whichever is lower, up to a cumulative production of 150 million barrels. Where producible reserves exceed 400 million barrels of crude oil equivalent, the applicable credit increases to \$4.50 per barrel or 20% of the fiscal oil price, whichever is lower, up to cumulative production of 500 million barrels.¹⁰ Future leases and leases derived from licences awarded after the effective date are to receive an additional \$1 per barrel, subject to the applicable production threshold.¹¹ However, where the fiscal oil price falls below \$50 per barrel in any month, the applicable oil credit for that month is reduced to 50%.¹²

A separate Standard PTC applies to qualifying non-associated gas developments. Where the Hydrocarbon Liquids ("HCL") content does not exceed 30 barrels per million standard cubic feet, the credit is \$1 per thousand standard cubic feet of gas sold or 30% of the fiscal gas price, whichever is lower, up to a cumulative volume of 5 TCF. Where the HCL content exceeds 30 but does not exceed 100 barrels per million standard cubic feet, the applicable rate is \$0.50 per thousand standard cubic feet or 30% of the fiscal gas price, whichever is lower, again up to a cumulative volume of 5 TCF.¹³ Once the HCL content exceeds 100 barrels per million standard cubic feet, however, the Standard PTC shall not apply.¹⁴

In addition, for existing non-associated gas deep offshore PSCs where a Concessionaire represents the Federation, the Order prescribes minimum Government profit gas allocations ranging from 20% for volumes up to 1 TCF to 60% for volumes exceeding 7 TCF, with intermediate allocation bands applying between those thresholds.¹⁵ Importantly, the crude-oil Standard PTC is project-specific, as it is calculated only on crude oil produced and sold from the approved development and cannot be applied to production from another field, lease, asset, project or contract area.¹⁶

Careful attention must also be paid to the Order's timing provisions because it distinguishes between its effective date and commencement date. Although the Order was made on August 6, 2026, it defines February 28, 2024, as its "Effective date", with paragraphs 1–5 and 12–15, which deal with the Standard PTC, the gas profit sharing formula and the calculation and application of tax credits, deemed to have taken effect from that Effective date. By contrast, paragraphs 6–11 and 16, which principally deal with the Supplementary PTC and Profit Oil Reset, take effect from the "Commencement Date", being the date on which the Order was signed.¹⁷

The Order further provides that the essence of the Standard PTC is to incentivise deep offshore investment and exclusively benefit parties to a PSC that directly fund developments leading to production.¹⁸ Consequently, investors should assess the incentive at the level of each qualifying project rather than assume that the benefit can be spread across an upstream portfolio.

Made pursuant to · Operates within

The Order rests on three statutory anchors

Section 3(1)(e), PIA 2021

Presidential authority to issue production-linked incentives for deep offshore projects.

Section 79(2)(g), PIA 2021

Field development plans must include an approved Nigerian content plan under the NOGICD Act.

Section 77(1), NTAA 2025

Power to grant tax remission by Order, anchoring the credits in the tax administration regime.

Section 101, NTA 2025

Part III of Chapter Three applies to deep offshore and inland basin PSCs yet to convert under the PIA.

Supplementary PTC and Profit Oil Reset

Standard Production Tax Credit

Beyond the Standard PTC, the Order provides an additional layer of relief through the Supplementary PTC, although this benefit is not automatic. The Nigeria Revenue Service ("NRS") determines the applicable amount on a case-by-case basis, having regard to the economic profile of the relevant project development. Importantly, the Order requires the NRS, within 45 days of its commencement date, to develop and publish guidelines setting out the criteria and methodology for determining the applicable level of Supplementary PTC, and to adhere to those guidelines when making its determination.¹⁹ This should provide investors with a more transparent basis for assessing how the Supplementary PTC may apply to the economics of a proposed development.

Profit Oil Reset

The Profit Oil Reset provides a further incentive for qualifying deep offshore leases operating under PSCs, particularly where existing production in the same contract area has already moved further up the applicable profit oil sliding scale. In practical terms, the mechanism allows the eligible new development to restart its profit-sharing calculation at a 70:30 contractor – government ratio, provided the applicable conditions are satisfied, notwithstanding that production elsewhere in the same contract area may already have graduated to a higher step. The reset applies only to the approved development, which must also be ring-fenced for cost recovery and tax purposes.²¹

Supplementary Production Tax Credit

The value of the Supplementary PTC is also subject to prescribed limits. The combined Standard and Supplementary PTC cannot exceed \$11.50 per barrel for an oil development or \$8 per barrel of oil equivalent for a non-associated gas development. Furthermore, for the Supplementary PTC to apply to a future lease or a lease awarded on a licence issued after the effective date, the relevant project development must reach production within seven years from the date the lease was awarded.²⁰

Profit Gas Sharing Formula

This mechanism should be understood alongside the NTA. Section 101 of the NTA applies Part III of Chapter Three to deep offshore and inland basin PSCs that are yet to convert under the PIA or have been renegotiated in accordance with it. Within that framework, section 110 provides that profit oil is the balance of available crude oil after deducting royalty oil, tax oil and cost oil, and is allocated to the parties in accordance with the terms of the PSC.²² Once a Profit Oil Reset is approved, the Concessionaire and Contractor must execute an addendum to the relevant PSC within 30 days and submit a copy to the NRS, NUPRC and the Office of the President within 14 days of execution.²³

Combined Standard plus Supplementary PTC caps

Oil development

\$11.50/bbl

Combined credit ceiling

Maximum combined Standard and Supplementary PTC for an oil development, irrespective of tier.

Non-associated gas

\$8/boe

Combined credit ceiling

Maximum combined Standard and Supplementary PTC for a non-associated gas development, expressed per barrel of oil equivalent.

Who Qualifies? Greenfield Status, FID and Nigerian

The additional incentives are deliberately targeted at qualifying new developments. To access Supplementary PTC, an application must relate to a crude oil or non-associated gas project development within a deep offshore lease, and the development must be greenfield, with FID not yet taken as at the commencement date of the Order. FID must subsequently be taken on or before December 31, 2029, subject to the prescribed force majeure mechanism. For the Profit Oil Reset, these requirements also apply, but the relevant PSC profit oil sliding scale must additionally have progressed beyond the 70:30 contractor – government ratio.²⁴

Profit-sharing on a reset development



The reset applies only to the approved development, which must also be **ring-fenced for cost recovery and tax purposes**. This mechanism works alongside section 110 of the NTA, which provides that profit oil is the balance of available crude oil after deducting royalty oil, tax oil and cost oil and is allocated to the parties in accordance with the terms of the PSC.

Against this eligibility framework, the Order’s definition of “project development” becomes particularly important. It covers activities aimed solely at developing an undeveloped crude oil or non-associated gas field, or a group of greenfields, pursuant to an approved field development plan. At the same time, it expressly excludes infill drilling, workovers, recompletion, debottlenecking, routine facilities upgrades, enhanced recovery from an existing producing field and other brownfield optimisation activities.²⁵ This distinction means that the enhanced incentives are directed at qualifying new developments rather than the routine optimisation of existing producing assets.

Approval of the Supplementary PTC or Profit Oil Reset is also not sufficient, on its own, to enjoy the benefit. Project-development activities must generally be performed in Nigeria, although the Order creates exceptions for activities on the critical path, such as long-lead items that significantly affect the project timeline, and activities that are 10% more expensive to execute in Nigeria after the full associated costs are taken into account. Even where work is carried out outside Nigeria under these exceptions, it must comply with a Nigerian Content Plan approved by the Nigerian Content Development and Monitoring Board (“NCDMB”).²⁶

This requirement is consistent with the wider upstream framework. *Section 79(2)(g) of the PIA* requires a field development plan to include an approved Nigerian content plan pursuant to the Nigerian Oil and Gas Industry Content Development Act 2010 (“NOGICD Act”). Section 7 of the NOGICD Act requires an operator, in bidding for any licence, permit or interest and before carrying out any project in the Nigerian oil and gas industry, to submit a Nigerian Content Plan demonstrating compliance with the Act. Accordingly, Nigerian-content planning should form part of the project-development strategy from an early stage, rather than being treated as a separate procurement consideration after the principal investment decisions have been made.

In short · supplementary layer

Project-specific by design

The enhanced incentives are directed at qualifying **new developments** rather than the routine optimisation of existing producing assets — eligibility must be considered alongside the broader project-development schedule, not merely at the filing stage.

In short · local content

Plan at project inception

Nigerian-content planning should form part of the project-development strategy **from an early stage**, rather than being treated as a separate procurement consideration after the principal investment decisions have been made.

Cost Discipline, Disclosure and Protecting the Benefit

In addition to satisfying the eligibility requirements, applicants for the enhanced incentives must provide detailed information concerning the economics of the proposed development. An application for the Supplementary PTC or Profit Oil Reset must therefore be accompanied by a full open-book economic model setting out the relevant cost, price, production and fiscal assumptions. The NRS must, within 45 days of receiving a complete application, consider it in consultation with the Federal Ministry of Finance and relevant institutions and issue a formal approval or refusal within that period.

Cost performance can also directly affect the value of the incentive available to a qualifying project. Where the unit technical cost of a development exceeds benchmarked cost levels determined in accordance with regulations made by NUPRC, the tax credits granted under the Order are reduced by 10%. This requirement connects with NUPRC's wider commercial regulatory role under the PIA, which includes developing cost studies and benchmarks for the evaluation of upstream petroleum operations. For investors, the implication is that project economics and cost discipline are not merely commercial considerations but can also affect the amount of fiscal relief ultimately available.

The Order further restricts how the credits may be used. Tax credits accruing under the Order cannot be combined with production allowance incentives under the Sixth Schedule to the NTA or incentives under the Associated Gas Framework Agreement. Where a tax-credit surplus arises, it may be carried forward for a maximum of four years, but it cannot be refunded, transferred, assigned, sold or converted to cash and cannot be set off against liabilities other than the tax liability arising from the qualifying project development approved under the Order.²⁹

These restrictions mean that the headline value of a tax credit and the amount a project is ultimately able to utilise may not always be the same. Accordingly, investors should model the incentives alongside the project's expected tax position, applicable production profile and the four-year carry-forward limitation, rather than assessing the nominal credit in isolation.

The Supplementary PTC is also subject to an express clawback mechanism, which places considerable importance on the accuracy of information supplied to the NRS and continued compliance with the conditions of approval. Where the NRS determines that an applicant obtained, utilised or benefited from the incentive through a false statement, misrepresentation, omission, concealment, incorrect data, artificial arrangement, prohibited tax avoidance arrangement, breach of an approval condition or failure to satisfy an eligibility requirement, it may withdraw the approval, recompute the tax payable, recover the wrongly utilised benefit and impose applicable penalties and interest.³⁰

45d

Clawback — protected accuracy threshold

A 45-day window in which consent can be reconsidered

Where the NRS determines that an applicant obtained, utilised or benefited from the incentive through a false statement, misrepresentation, omission, concealment, incorrect data, an artificial arrangement, a prohibited tax-avoidance arrangement, breach of an approval condition, or failure to satisfy an eligibility requirement, it may withdraw the approval, recompute the tax payable, and recover the wrongly utilised benefit, together with applicable penalties and interest.

What Investors Should Do Now

For investors with undeveloped deep offshore assets, the first step should be an asset-by-asset eligibility assessment. Each proposed development should be reviewed against the relevant lease category, greenfield status, FID position, applicable reserve or HCL thresholds and, where relevant, the position of the profit oil sliding scale under the existing PSC. This assessment should help investors determine whether a project may qualify for the Standard PTC alone or may also be eligible for the Supplementary PTC or Profit Oil Reset.

Project timelines should then be tested against the December 31, 2029, FID deadline, while investors seeking the Supplementary PTC for future leases should additionally account for the requirement that the relevant development reach production within seven (7) years of the grant of the lease. The significance of these timelines means that eligibility should be considered alongside the broader project-development schedule rather than only when an incentive application is ready to be filed.

The available incentives should also be incorporated into the project's financial and contractual analysis, taking into account the applicable production ceilings, oil-price adjustment, technical-cost reduction, restriction on combining specified incentives and the four-year limit on carrying forward surplus credits. For PSC projects, this analysis should also consider the potential value of a Profit Oil Reset and the contractual steps required to give an approved reset effect.

Equally, the economic model, Nigerian Content Plan, PSC documentation and tax records should be aligned so that they present a consistent basis for the incentive claimed. This is particularly important because the Order requires detailed economic disclosure at the application stage and permits clawback where the benefit is obtained or utilised on the basis of inaccurate information or a breach of the applicable conditions.

Compliance also continues after approval. The Order requires tax credits to be computed monthly based on crude oil production or gas sold from the approved project after production commences, with the credits reconciled annually as part of the applicant's tax incentive returns and annual tax returns. The available tax benefit must also be considered alongside the minimum effective tax rate prescribed under section 57 of the NTA. Where an in-scope company's effective tax rate falls below 15%, the company must pay additional tax sufficient to bring its effective tax rate to 15%. This requirement applies to a company that is a constituent entity of a multinational enterprise group with aggregate group turnover of at least £750 million or its equivalent, and to any other company with aggregate turnover of at least ~~N~~50 billion in the financial year.³¹ Section 27 of the NTAA also requires taxable persons enjoying tax incentives to submit Annual Tax Incentives Returns in addition to their annual tax returns.³² Obtaining the incentive is therefore only the beginning of the process, while preserving and fully utilising it requires continuing attention to the conditions governing the benefit.

Bottom line for the PSC track

Treat eligibility and compliance as a single investment thesis

For PSC projects, the analysis should also consider the potential value of a Profit Oil Reset and the contractual steps — **30 days** to execute the PSC addendum and **14 days** to file with NRS, NUPRC and the Office of the President — required to give an approved reset effect.

Conclusion

The 2026 Order creates a structured incentive regime for qualifying Nigerian deep offshore projects through the Standard PTC, Supplementary PTC and Profit Oil Reset. However, the benefits are deliberately project-specific and conditional, with FID timing, greenfield status, Nigerian content, technical costs, economic disclosure, PSC structure and continuing tax compliance all influencing whether an incentive can be obtained, fully utilised and retained.

For oil and gas investors, the Order should therefore be considered at the project-planning stage rather than after the principal development decisions have already been made. Aligning project economics, contractual arrangements, Nigerian-content strategy and tax compliance with the applicable requirements will be central to capturing the available value while reducing the risk of reduction, lapse or clawback.

Ultimately, Nigeria's new deep offshore incentives create an opportunity which aims to unlock global deepwater capital, but access to that opportunity is not automatic. Investors that identify qualifying projects early and build the requirements of the Order into their development strategy from FID through production will be better positioned to capture and preserve the available benefits.

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Closing observation

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Endnotes

1. Deep Offshore Oil and Gas Projects Incentives (Tax Remission) Order 2026, SI No 37 of 2026 ('Deep Offshore Order 2026').
2. Deep Offshore Order 2026, preamble; Petroleum Industry Act 2021, s 3(1)(e); Nigeria Tax Administration Act 2025, s 77(1).
3. Petroleum Industry Act 2021, ss 3(1)(e), 6(h); Nigeria Tax Act 2025, s 101.
4. Deep Offshore Order, 2026, paras 1–3 (Standard PTC), para 4 (profit gas sharing formula), para 6 (Supplementary PTC) and para 7 (Profit Oil Reset).
5. Deep Offshore Order 2026, paragraph 1(1)(a)
6. *ibid*, paragraph 9.
7. *ibid*, paragraph 13.
8. *ibid*, paragraph 19.
9. *ibid*, paragraph 1(1), (3).
10. *ibid*, paragraph 2 (1).
11. *ibid*, paragraph 2 (2).
12. *ibid*, paragraph 2 (3).
13. *ibid*, paragraph 3 (1)(a)(b).
14. *ibid*, paragraph 3 (2).
15. *ibid*, paragraph 4.
16. *Ibid*, paragraph 2 (4).
17. Deep Offshore Order 2026, paras 17–19. The Order distinguishes between its "Effective date" and "Commencement Date". The "Effective date" is 28 February 2024, while the "Commencement Date" is the date on which the Order was signed, being 6 August 2026. Paragraphs 1–5 and 12–15 are deemed to have come into effect from the Effective date, while paragraphs 6–11 and 16 take effect from the Commencement Date.
18. *Ibid*, paragraph 5.
19. *Ibid*, paras 6(1)–(2), 10(2)(b), (4).
20. *Ibid*, para 6(2)(a), (c)(ii).
21. *ibid*, paragraphs 7(1)–(3) and 8(2).
22. Nigeria Tax Act 2025, ss 101, 110.
23. Deep Offshore Order 2026, para 7(4).
24. Deep Offshore Order 2026, paragraph 8(1) (2).
25. *ibid*, paragraph 19 (1), defining "project development" as "a project comprising activities solely aimed at developing a greenfield crude oil or non-associated gas field (undeveloped field) or group of greenfields within a single or multiple oil mining leases, pursuant to an approved field development plan and does not include infill drilling, workover, recompletion, debottlenecking, routine facilities upgrade, enhanced recovery from an existing producing field, or any other brownfield optimisation activity".
26. *ibid*, paragraph 9.
27. *ibid*, paragraph 10(1) - (3).
28. *ibid*, paragraph 13; Petroleum Industry Act 2021, s 8(b).
29. *ibid*, paragraphs 14 - 15.
30. *ibid*, paragraph 11.
31. Nigeria Tax Act 2025, s 57(1)–(2).
32. Nigeria Tax Administration Act 2025, s 27(1).



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