



ENERGY FOCUS REPORT Q3 2026



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Oil and Gas Sector

1. An Analysis of the Amended Nigerian Upstream Petroleum Decommissioning and Abandonment Regulations, 2026

Introduction

In March 2026, the Nigerian Upstream Petroleum Regulatory Commission (“NUPRC” or “the Commission”) replaced the 2023 Nigerian Upstream Petroleum Decommissioning and Abandonment Regulations with a revised framework (the “2026 Regulations”).

Decommissioning had, until recently, been relegated to the margins of upstream regulatory attention, overshadowed by licensing, fiscal terms and production obligations. That position changed significantly as the wave of divestments by International Oil Companies (“IOCs”), the emergence of indigenous operators as the principal owners of increasingly mature oil and gas assets, and heightened environmental, social and governance expectations have collectively brought decommissioning and abandonment obligations to the forefront.

The enactment of the 2026 Regulations has further reinforced this shift by strengthening the regulatory framework governing end-of-field-life obligations, making decommissioning a central consideration in asset acquisitions, financing arrangements, operational planning, and long-term risk management. The 2026 Regulations respond directly to implementation difficulties encountered under the 2023 framework; principally around the timing of Decommissioning and Abandonment (D&A) Plan submission, the establishment and custody of the D&A Fund, and the practical administration of compliance.

This article sets out the most consequential departures from the 2023 regime, and considers the practical implications for operators, joint venture partners, and acquirers in the Nigerian upstream sector. The changes are evolutionary and have real consequences for balance sheets, deals, and project timelines. Below are highlights of the key changes:

1. Decommissioning is now a day-one obligation. A D&A Plan must be approved alongside the Work Programme or Field Development Plan (“FDP”), and that Plan sets the Company's annual funding contributions.
2. Liability follows the asset. When an acquirer buys an interest, it inherits its decommissioning obligations. A change of ownership cannot be utilized to leave those obligations behind unless the Fund and D&A Plan position is dealt with.

3. Non-compliance is expensive. Penalties start at US\$500,000 per year, cannot be recovered as costs, and can lead to a revocation of the licence or lease.

Highlights of Key Changes in the 2026 Regulations

Issue	2023 Regime	2026 Regime
D&A Plan submission	Uniform one-year deadline	Tied to Work Programme (PPL) or FDP (PML) approval; six months for existing holders
Fund establishment	90 days	180 days
Fund custody	Primarily Central Bank of Nigeria	Escrow with qualifying Nigerian or foreign institutions that meet credit-rating thresholds
Downgraded custodian	30 days to move funds	90 days
Local content (NNPC JV/PSC IOCs)	Phased increase to 100% local	Flat minimum of 15% held locally; all other operators must hold 100% in Nigeria
Well suspension limit	3 years	4 years, extendable
Successor liability	Implied	Expressly attaches to transferred interests

Key Deadlines and Timelines

Requirement	Timeline
Operational shut-in without approval	Maximum 1 year
Formal well suspension	Up to 4 years (extendable)
Abandonment after suspension expires	Within 1 month
Emergency suspension plan	Within 30 days of notifying the Commission
Well abandonment approval	60 days after which it is deemed approved
Onshore decommissioning application	At least 12 months before start
Offshore decommissioning application	At least 60 months (5 years) before start
Commission decision on decommissioning	12 months, after which it is deemed approved
Resubmission after rejection	180 days after which the Commission may use the Fund and appoint a third party
Review of Fund contributions	Every 10 years, or sooner if costs or the portfolio change materially

Penalty Exposure

Breach	Penalty
Late D&A Plan	US\$500,000 per year, plus possible revocation
Late Fund establishment	US\$500,000 per year, plus possible revocation
Missed annual contribution	One year's contribution plus the outstanding amount, applied severally by working interest
Starting work without approval	US\$1,000,000

Defaulting JV or PSC partners also risk having their crude entitlement lifted by the Commission, with the proceeds paid into the escrow account. None of these penalties are cost-recoverable.

How the Fund Works

Each licence or lease needs a dedicated, interest-bearing escrow account held in US dollars. The Commission must be a party to the escrow agreement, and the funds are protected from third-party creditors and can only be invested in low-risk instruments. Operators with several assets may consolidate their contributions into one account, provided they meet the PIA's accounting requirements.

If an operator defaults or becomes insolvent, the Commission can draw on the Fund and appoint a contractor to undertake the work. That does not release the operator. Any shortfall is still the operator's responsibility, although it can be recovered as a cost and deducted for tax purposes. Any surplus is returned to the operator.

What This Means for Businesses

M&A and Divestments: Decommissioning liability should now be at the centre of due diligence. Before signing, review the target's approved D&A Plan, whether its Fund is adequate, its escrow arrangements, and its compliance record. Transaction documents should state clearly who bears legacy liabilities, funding shortfalls, and obligations after completion.

Financing: Being allowed to use foreign escrow institutions gives operators more room when structuring financial assurance. Lenders also benefit because the Fund is protected from creditor claims and ring-fenced.

Project planning: Decommissioning costs must be built into development economics from the start. For offshore assets, the five-year lead time means operators need to engage contractors and environmental specialists well before end of field life.

JV and PSC Governance: Because partners are severally liable for Fund obligations and face the risk of having crude lifted, check that the Company's funding, default, and indemnity clauses in Transaction Agreements match the new rules.

Conclusion

The 2026 Regulations represent a measured evolution, rather than a fundamental overhaul, of Nigeria's decommissioning and abandonment regime. By integrating decommissioning planning into the licensing and project development lifecycle, introducing a more practical and commercially flexible financial assurance framework, the Regulations seek to strike a balance between regulatory compliance and operational realities.

For operators, joint venture partners, investors, acquirers and financiers, compliance with the new regime should be viewed as a strategic business priority rather than a procedural obligation. In particular, the six-month transition period for updating existing Decommissioning and Abandonment Plans and aligning Fund arrangements presents an important opportunity to ensure regulatory compliance, manage financial exposure and mitigate transaction and operational risks under the revised framework.

2. Non-Associated Gas (NAG) Fiscal Relief: Commercializing Deepwater Gas under the 2026 Incentives Order

Introduction

On 6 August 2026, President Bola Ahmed Tinubu signed the Deep Offshore Oil and Gas Projects Incentives (Tax Remission) Order 2026. It replaces the prolonged project-by-project negotiation approach which caused severe delays in deepwater offshore projects. With a structured framework, this Order introduces globally competitive fiscal incentives to accelerate deep offshore projects and attract fresh investments into Nigeria's energy sector.

While initial industry commentary on the 2026 Deep Offshore Tax Remission Order has heavily emphasized crude oil, this report focuses on the Order's critical fiscal relief for deepwater non-associated gas (NAG). Non-Associated Gas (NAG) is natural gas produced from a reservoir that contains little to no liquid crude oil, meaning the field is developed specifically to extract gas rather than recovering it as a byproduct of oil production.

Commercializing NAG is inherently more complex and capital-intensive than oil extraction, as its financial viability relies heavily on securing firm offtake agreements, developing costly LNG or pipeline infrastructure, and navigating regulated domestic pricing. To offset these steep structural barriers, the 2026 Order introduces fiscal incentives specifically designed to make these challenging gas investments commercially viable for operators.

The Economics of NAG and the Production Tax Credit Mechanism

Unlike crude oil, non-associated gas (or “pure gas”) is inherently expensive and complex to process. Developing standalone gas fields requires massive upfront capital for specialized subsea infrastructure, processing facilities, and evacuation pipelines. Given that pure gas can be expensive to process compared to oil, the government is using a Production Tax Credit (PTC) to lower the company's tax bill as a direct financial reward for getting that gas to market. By offsetting these high technical costs and lowering the operator's overall tax liability per unit of gas sold, the PTC effectively de-risks the investment and improves the project economics needed to unlock stranded deepwater gas.

Key changes are highlighted below:

- 1. Lean gas is rewarded most.** A Production Tax Credit (PTC) of up to US\$1.00 per mscf applies to low-liquid fields. Liquids-rich fields above 100 bbl/mmscf get no gas PTC at all.
- 2. Terms are fixed and predictable.** Standard credits and a published profit gas scale replace case-by-case negotiation, which makes projects easier to underwrite.

3. The clock is running. Projects that miss FID by 31 December 2029 lose half of their Standard PTC, unless force majeure applies.

Timing alert: The FID deadline of 31 December 2029 is roughly three years away. Given typical deepwater lead times for concept selection, offtake agreements and financing, gas projects hoping to qualify for full benefits need to be moving now.

Standard Production Tax Credit

The credit applies to marketable NAG sold from a qualifying deep offshore development and is tied to that approved development. The rate depends on the field's hydrocarbon liquids (HCL) content, meaning the condensate produced alongside the gas.

Field Category	HCL Content	Credit per mscf Sold	Volume Cap
Low-liquid	30 bbl/mmscf or less	Lower of US\$1.00 or 30% of fiscal gas price	First 5 TCF of cumulative sales
Medium-liquid	30 to 100 bbl/mmscf	Lower of US\$0.50 or 30% of fiscal gas price	First 5 TCF of cumulative sales
High-liquid	Above 100 bbl/mmscf	No gas PTC	Not applicable

Supplementary PTC for Greenfield Projects

A new gas project that is not commercially viable on the Standard PTC alone can apply for additional relief. To qualify, the operator must open its economic model to the Nigeria Revenue Service (NRS) and demonstrate that it genuinely needs the support.

Condition	Detail
Combined cap	Standard and Supplementary PTC together cannot exceed US\$8.00 per barrel of oil equivalent
FID deadline	31 December 2029 for full benefits
Missed deadline	Standard PTC falls to 50% of the applicable rate, unless a force majeure extension is granted
Nigerian content	Project activities must be executed in Nigeria, except for critical-path work or where local execution would cost more than 10% extra

Profit Gas Sharing for Existing PSCs

For existing deep offshore NAG Production Sharing Contracts, the Order sets minimum government shares of profit gas. Profit gas is the gas remaining after the contractor has recovered its costs, and it is split between the government and the contractor. The government's share rises as cumulative production grows over the life of the project.

Cumulative Production	Minimum Government Share
Up to 1 TCF	20%
Over 1 TCF to 3 TCF	35%
Over 3 TCF to 5 TCF	45%
Over 7 TCF	60%, with no upper limit

The open-ended top tier closes a gap in earlier rules, which did not clearly address production above the highest threshold.

Compliance Conditions

Rule	What It Means
No stacking	The credits cannot be combined with production allowances under the Sixth Schedule to the Nigeria Tax Act 2025, or with Associated Gas Framework Agreement (AGFA) incentives
Carry-forward limit	Unused credits can be carried forward for up to four years before they lapse
Ring-fencing	Credits cannot be transferred or refunded outside the approved project
Cost overruns	Spending well above the government's cost benchmark reduces the tax credit by 10%
Nigerian content	Required for access to supplementary benefits, subject to the exceptions noted above

What This Means for Businesses

Portfolio screening: HCL content now decides eligibility and the size of the credit. Lean gas fields gain the most, while liquids-rich fields must rely on condensate economics. Re-rank undeveloped discoveries with this in mind.

Commercial structuring: The credit only applies to gas actually sold, so securing firm offtake and evacuation routes, whether pipeline or LNG, is essential to capturing its value.

Cost discipline: The 10% penalty for overruns makes benchmarking against the government's cost standard a board-level issue, not just a project-control matter.

Tax planning: Because the credits cannot be combined with other allowances, operators should model which regime delivers more value. The four-year carry-forward limit means early-life cash flows need to be strong enough to use the credits before they expire.

Existing PSC holders: The profit gas scale reduces the contractor's share as fields mature. Factor the higher government take above 5 TCF into long-term reserve valuations and development sequencing.

Conclusion

The 2026 Order acts as a direct catalyst for deepwater gas commercialization, transitioning Nigeria's upstream environment towards investment-linked incentives. By offsetting structural processing costs through the PTC mechanism, the government has provided a bankable pathway for unlocking non-associated gas reserves. To fully capitalize on this opportunity, project operators should actively benchmark their specific gas field economics against these provisions, assemble their Nigerian content plans, and evaluate FID timelines ahead of the 2029 deadline.

3. Two Regulators, One Market: What Nigeria's Petroleum Operators Must Know About NMDPRA and FCCPC's 2026 Anti-Competition Regulatory Regime.

Introduction

Nigeria's oil and gas midstream and downstream sector is moving toward oversight by two competition-minded regulators at once. The Nigerian Midstream and Downstream Petroleum Regulatory Authority (“NMDPRA”) has published draft regulations that would create a dedicated competition code for the sector, and it has signed a cooperation agreement with the Federal Competition and Consumer Protection Commission (“FCCPC”). The stated intention is coordination. What operators still need to learn is how the two agencies will divide the work in practice, and that is where the greatest risk sits today. Until the final rules and any case allocation protocol are published, operators should assume that both agencies can act.

From Past to Present

Before 2021, petroleum regulation and general competition law ran on separate tracks. The old Department of Petroleum Resources, the Petroleum Products Pricing Regulatory Agency and the Petroleum Equalization Fund (Management) Board handled licensing, pricing and equalisation. The Petroleum Industry Act 2021 (“PIA”) merged the midstream and downstream functions of these bodies into the NMDPRA. The FCCPC, established under the Federal Competition and Consumer Protection Act 2018 (“FCCPA”), applied general competition law across the economy and was already active against anti-competitive conduct in the natural gas market.

That arrangement is now changing. On August 6, 2026, the NMDPRA published the draft Midstream and Downstream Petroleum Prevention of Anti-Competitive Practices and Behaviour Regulations, 2026 and invited comments within 21 days. It then convened a stakeholder forum in Abuja on September 22. The draft contains 138 regulations across 23 parts. The Authority's Secretary and Legal Adviser has described it as a shift from mainly licensing and technical oversight to actively regulating how market power is exercised. The draft is not yet law, and the Authority has said it will review stakeholder comments before finalising the text.

According to the Authority's public presentation, the draft addresses the following:

- General prohibitions on anti-competitive conduct, including agreements and concerted practices, formal or informal, written or oral, explicit or tacit, that prevent, restrict or distort competition.
- Price-fixing, market-sharing, bid-rigging and coordinated supply restrictions.
- Open and non-discriminatory access to pipelines, depots, terminals and other essential facilities, with disclosure of tariffs, fees and general service conditions.
- Dominance and vertically integrated operators. Dominance itself is not prohibited, but abuse of it is.
- Mergers, changes of control and joint ventures.
- Digital markets, data and algorithmic or AI-based pricing.
- Enforcement powers and remedies.

The Interface: Where the Two Regimes Meet

Press reports of the Authority's presentation indicate that the draft formalises concurrent jurisdiction between the NMDPRA and the FCCPC, including joint reviews of mergers that carry competition and consumer-protection implications. The Memorandum of Understanding (MoU) signed on September 10 supports information sharing, market intelligence and coordinated enforcement, and the NMDPRA's leadership describes the two mandates as complementary. At the same forum, however, the Authority's Legal Adviser cautioned that the overlap with the FCCPC needs careful handling.

The overlap arises at three points: investigating suspected collusion or abuse of dominance, reviewing mergers and acquisitions, and imposing penalties. In each, both agencies can advance a credible claim, and an operator could face parallel processes over the same facts.

The legal structure explains why. The FCCPA is a general statute that applies across sectors and contains provisions governing its relationship with sector regulators. The PIA is later in time and specific to petroleum. Regulations made under the PIA rank below both statutes and cannot override the FCCPA. The NMDPRA code therefore works best as a complement to the FCCPA, and its durability will depend on being read that way. The MoU binds the two agencies administratively. It confers no rights on operators and cannot enlarge or reduce the statutory powers of either agency.

The Synergy: What Coordination Can Deliver

When implemented properly, the arrangement plays to each regulator's strengths. The NMDPRA licenses operators and holds supply, storage and pricing data, and it understands how depots, terminals and pipelines work in practice. The FCCPC brings established investigation procedures, merger review experience and competition economics. A functioning referral protocol could produce faster, better-evidenced cases, and clearer lines of authority would give compliant operators and their financiers more predictable outcomes.

What to Expect Next

The following are our expectations, not settled facts.

- A Revised Regulation. Consultation feedback commonly moves a draft on definitions, thresholds and procedure, so operators with concerns should engage while the Authority is still reviewing submissions.
- A published allocation protocol. Industry pressure and the Authority's own comments make a lead-agency rule for mergers and a case referral mechanism the most likely next step.
- Early enforcement in familiar territory. Price coordination, artificial scarcity and access to essential infrastructure are the likeliest first targets because the draft addresses them most directly.
- Jurisdictional challenge. If the boundary between the two regimes stays vague, a test case before the Competition and Consumer Protection Tribunal or the Federal High Court is plausible, and its outcome would shape the regime for years.
- Compliance as a diligence item. Buyers, lenders and joint venture partners are likely to ask for evidence of competition compliance in midstream and downstream transactions.

What an Oil and Gas Executive Should Know

- Audit key contracts for exclusivity, pricing and access terms that could be read as restrictive or discriminatory.
- Review pricing tools. Check whether any algorithmic or shared-data pricing arrangement could be treated as coordination.
- Plan deals for two agencies. Build extra time and flexibility into conditions precedent and long-stop dates for any acquisition of depots, terminals or pipeline stakes.
- Treat every submission as shared. Assume that what you tell one agency may reach the other and keep disclosures accurate and consistent.

How We Can Help

Regulatory regimes are easiest to shape before they harden. Our energy practice advises operators, investors and financiers on midstream and downstream compliance, transaction structuring across both agencies, regulatory submissions and investigation readiness. To discuss how the 2026 regime affects your business, please contact us through our **LinkedIn:** George Etomi & Partners, **website:** geplaw.com, or **email address:** info@geplaw.com.

Power Sector

GenCo-DisCo Bilateral Contracting: Opportunities, Structural Hurdles, and Default Mitigation

Introduction

For more than a decade, Nigeria's electricity distribution companies (DisCos) bought most of their power from a government-owned intermediary rather than directly from the power plants (generation companies, or GenCos). The Nigerian Electricity Regulatory Commission (NERC) issued the Order on the Transition to Bilateral Trading in the Nigerian Electricity Supply Industry in 2024 (“the Order”), which began the shift to direct GenCo–DisCo contracts.

The idea is simple. A generator gets a committed customer, and a distributor gets a committed supplier. The difficulty is that the intermediary also carried the risk that the DisCos would not pay, and that risk now returns to the DisCos. The regulator has built several protections to manage it, and early examples in Lagos suggest that direct supply can work, particularly for customers who can afford realistic prices for reliable power.

This article explains the background to the Order, the benefits of direct contracting, the obstacles it faces, the safeguards against default, and the lessons from existing arrangements.

Background

The Order comes out of Nigeria's power sector reforms, which began with the breaking up of the Power Holding Company of Nigeria Plc (PHCN). The successor generation and distribution companies were subsequently privatised to improve efficiency and service delivery.

Under the Electric Power Sector Reform Act (EPSRA), NBET was incorporated in 2010 to act as a credible buyer of power. Its purpose was to make sure that GenCos were paid on time, to allow independent power projects attract funding. NERC licensed NBET for ten years, with renewal at NERC's discretion.

Over time, NBET's dominance constituted a problem. It left the Federal Government exposed to financial shortfalls when DisCos did not pay enough. The Electricity Act 2023 responded by directing NERC to guide the industry towards more advanced market stages. It also required NBET to stop signing new agreements to buy and resell electricity and to leave its existing rights and obligations to other licensees. However, the current compliance status remains unknown.

Benefits of the Gen-Co Bilateral Contracting

- i. **Improved Revenue Certainty for GenCos:** A contract with a named buyer at an agreed price or formula gives a generator a fairly steady income over the life of the contract. It no longer has to depend wholly on uncertain spot-market sales; hence it can plan its cash flow and is less exposed to short-term price swings. Long-term PPAs are a widely used form of bilateral contract for exactly this reason, because they share market risks between sellers and buyers.
- ii. **Greater Supply Certainty for DisCos:** A direct contract gives a DisCo greater certainty about how much power will be available, which helps it plan its purchasing, its network operations and its obligations to customers. In Nigeria, direct GenCo–DisCo contracting is treated as part of the move towards a more commercially driven electricity market.
- iii. **Reduction of price risk:** Electricity prices move with fuel costs, demand, water levels for hydro plants, plant availability, and grid limits. A bilateral contract can fix the price or set a formula for it, so that both sides can guard against part of that volatility. Studies of electricity markets treat forward and bilateral contracts as important tools for this purpose.
- iv. **Easier project financing:** Lenders and investors look for predictable future income when assessing infrastructure projects. A sufficiently robust PPA shows that there is a committed market for a plant's output. This matters most for capital-intensive projects, including renewable energy. Research on market restructuring identifies long-term contracts as a way of allocating investment and market risk between generators and buyers.
- v. **Facilitation of New Generation Investment:** Where a GenCo has an identifiable purchaser, it can invest in new capacity with more confidence. This is especially important in a system such as Nigeria's, where a shortage of generation limits supply. Bilateral contracts can form part of a wider market framework in which investment is driven by contractual commitments as well as by competitive prices.

Major Obstacles Impacting Bilateral Contracting

Counterparty credit risk: NBET was created as a creditworthy intermediary precisely because DisCos were not regarded as creditworthy enough to sign bankable PPAs directly with GenCos. Bilateral trading passes that payment risk back to the DisCos. This is a serious concern in a market marked by inadequate revenue, weak billing and collection, tariff shortfalls and accumulated market debt. The risk grows under take-or-pay contracts, which NERC identifies as an objective of the bilateral framework. A DisCo may owe payment even where it has not recovered the cost of that power from its customers.

Transmission and system-operation constraints: A direct contract does not guarantee delivery of the agreed quantity. The power still passes through the national transmission grid and is subject to the System Operator's scheduling instructions and the grid's available capacity. Where the grid is constrained, or the System Operator cannot schedule the full quantity, the DisCo may receive less than it contracted for, even though the GenCo is ready to supply.

Regulatory approval and procurement requirements: A GenCo–DisCo agreement cannot rest on commercial agreement alone. Section 68(3) of the Electricity Act 2023 requires bulk power to be procured through an open, transparent, and competitive process, unless NERC permits or requires another method. The Order also requires affected GenCos to obtain NERC's approval for bilateral transactions. These are additional compliance steps that must be completed before supply can start.

Continued reliance on NBET during the transition: Residual capacity from GenCos covered by the Order that is not traded bilaterally continues to be traded through NBET on an interim take-and-pay basis. Where a DisCo's NBET firm capacity and bilateral contracts together fall below its committed capacity under the July 2024 MYTO Order, the shortfall is supplied through that NBET interim arrangement. Bilateral trading therefore runs alongside the NBET structure, and does not replace it, while the transition is under way.

Default Risk and Mitigation Framework

Default here would mean either a DisCo failing to pay or a GenCo failing to supply. The Order and related NERC instruments provide the following safeguards.

Protection against DisCo non-payment: **Tariff Alignment and Over-Contracting Risk:** For DisCos, the main risk is contracting for more power than its revenue can support. The Order therefore requires firm bilateral capacity to be aligned with the generation cost that the DisCo can recover through its approved end-user tariff. It also provides for monthly tariff reviews to reflect relevant economic changes, so that the tariff remains enough to pay for the contracted energy.

- i. **Priority of Bilateral Energy Payments:** Payments for bilateral energy rank first in the DisCo's revenue waterfall for energy and capacity payments, ahead of NBET firm capacity and NBET's residual take-and-pay energy. Customer revenue is therefore applied to bilateral obligations before lower-ranked payments.
- ii. **Secondary escrow accounts protection:** Under NERC's Secondary Escrow Account framework, revenue from bilateral transactions may be held in a dedicated escrow arrangement instead of being treated only as part of the DisCo's general collections. This gives greater visibility and security over the money available to pay the GenCo, while the DisCo's obligations to the wider market remain in place.

- iii. **Payment security and regulatory sanctions:** NERC continues to impose these duties through later tariff orders. The July 2025 Supplementary MYTO Orders for Eko Electricity Distribution Plc and Ikeja Electric Plc require each DisCo to maintain adequate payment securitisation for its energy offtake and make it liable to penalties if it fails to meet payment obligations to its bilateral counterparties.
- iv. **Protection against GenCo non-supply:** Fuel security and GenCo supply default: Bilateral generation capacity must be backed by take-or-pay Gas Supply Agreements with adequate liquidated damages (pre-agreed compensation) if the gas supplier defaults. This is meant to reduce the risk that a GenCo cannot perform because it lacks fuel. In specified circumstances, the System Operator may instruct Azura Power West Africa Limited to increase generation when another on-grid GenCo cannot meet its obligations.

Case Studies: What has worked so far?

Direct purchasing of power by DisCos is not new in Nigeria, especially in Lagos. Two earlier arrangements are instructive.

i. Ikeja Electric and Egbin Power Plc

Ikeja Electric entered into a strategic alliance with Egbin Power Plc that gives it exclusive access to 100MW of bilateral power, delivered through the national grid. The scheme, known to customers as “Bilateral Power”, began in August 2019 in Magodo Phase 2. It was later extended to other estates on the Ikeja Electric network, including Diamond Estate, Magodo Brooks, Ogudu GRA, Ikeja GRA, Omole Phase I and II, and others.

Customers are promised a minimum of 20 hours of supply a day in return for cost-reflective tariffs. The service also offers round-the-clock payment channels, a dedicated complaints team, 24 hours' notice of planned maintenance, and a key accounts team that resolves issues within service level agreement timelines.

ii. Eko Disco and NDPHC

The Niger Delta Power Holding Company (NDPHC) and Eko Electricity Distribution Company Plc (Eko Disco) signed a bilateral agreement for the sale of up to 300MW from NDPHC's power plants to customers in the Ibeju-Lekki area of Lagos and the Agbara industrial area of Ogun State, within Eko Disco's franchise area. The project is meant to remove commercial and technical inefficiencies and to attract significant investment in transmission, distribution and metering.

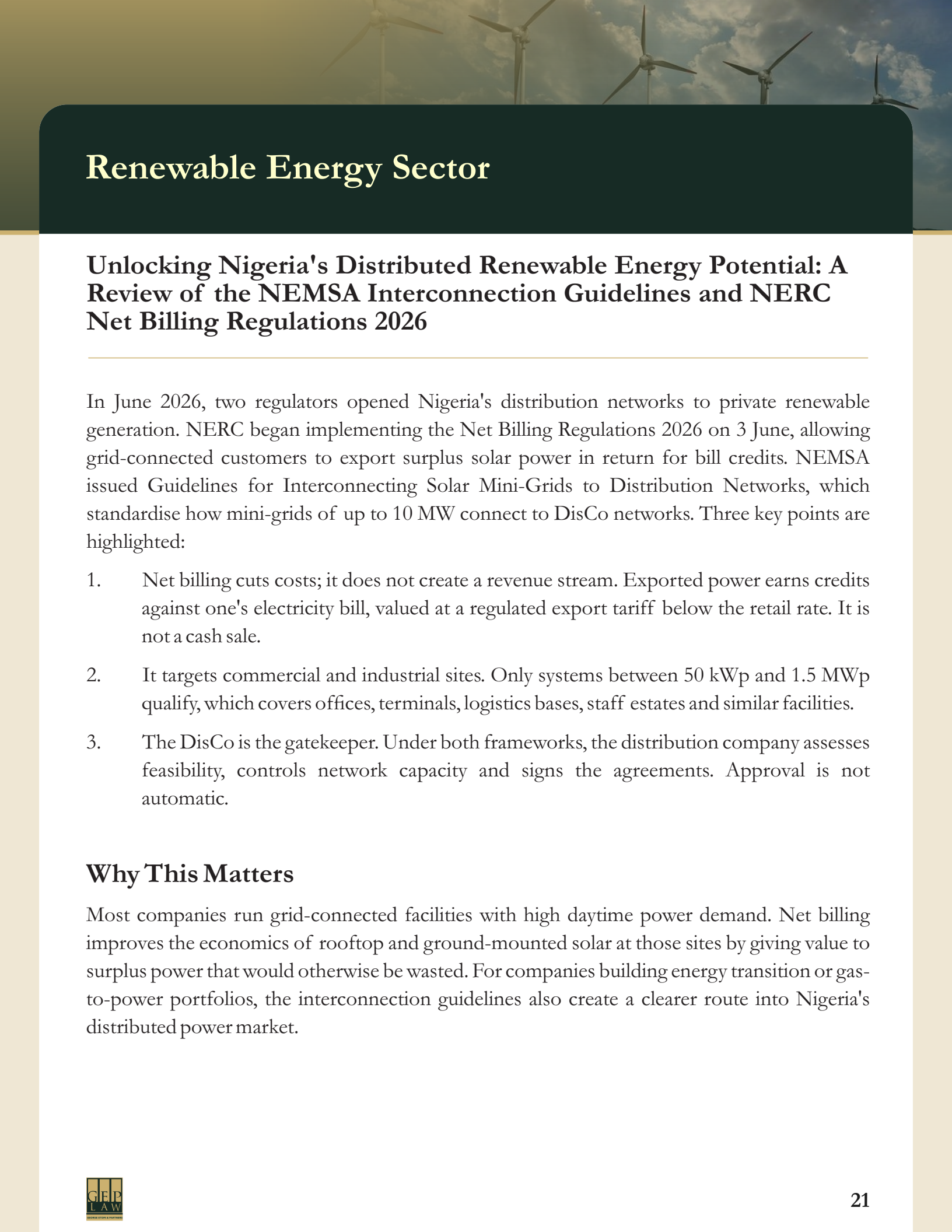
For NDPHC, the arrangement means more power taken from under-used plants and more revenue. For the industry, it should attract investment and improve liquidity, so that more payments are received along the value chain.

Conclusion and Recommendations

Direct contracts are helpful but are not a cure-all. Without a stronger grid, honest metering, effective collection and firm enforcement of contract terms, the sector risks repeating the debt cycles of the past.

The move from a single-buyer system under NBET to direct GenCo–DisCo contracting is the most significant structural change in the industry since privatisation, as it can release stranded generation capacity, improve reliability, and restore financial credibility across the value chain. However, its long-term success depends on fixing deeper problems, particularly limited grid capacity and revenue leakage at the distribution level. To avoid repeating the debt cycles of the NBET era, the following steps are recommended:

- i. Enforceable payment guarantees and properly operated secondary escrow accounts.
- ii. Strict metering, so that customers are billed for what they actually use.
- iii. Bilateral contracts sized to what each DisCo's cost-reflective tariff can realistically support.
- iv. Investment in transmission capacity and clear scheduling rules, so that contracted power can actually be delivered; and
- v. Consistent enforcement of contract terms, penalties and regulatory approvals.



Renewable Energy Sector

Unlocking Nigeria's Distributed Renewable Energy Potential: A Review of the NEMSA Interconnection Guidelines and NERC Net Billing Regulations 2026

In June 2026, two regulators opened Nigeria's distribution networks to private renewable generation. NERC began implementing the Net Billing Regulations 2026 on 3 June, allowing grid-connected customers to export surplus solar power in return for bill credits. NEMSA issued Guidelines for Interconnecting Solar Mini-Grids to Distribution Networks, which standardise how mini-grids of up to 10 MW connect to DisCo networks. Three key points are highlighted:

1. Net billing cuts costs; it does not create a revenue stream. Exported power earns credits against one's electricity bill, valued at a regulated export tariff below the retail rate. It is not a cash sale.
2. It targets commercial and industrial sites. Only systems between 50 kWp and 1.5 MWp qualify, which covers offices, terminals, logistics bases, staff estates and similar facilities.
3. The DisCo is the gatekeeper. Under both frameworks, the distribution company assesses feasibility, controls network capacity and signs the agreements. Approval is not automatic.

Why This Matters

Most companies run grid-connected facilities with high daytime power demand. Net billing improves the economics of rooftop and ground-mounted solar at those sites by giving value to surplus power that would otherwise be wasted. For companies building energy transition or gas-to-power portfolios, the interconnection guidelines also create a clearer route into Nigeria's distributed power market.

Net Billing at a Glance

Feature	What the Regulations Provide
Who qualifies	Customers connected to a licensed DisCo's network, with a renewable system (mainly solar PV) they own, consuming power at the same premises
System size	Minimum 50 kW _p , maximum 1.5 Mwp
Network cap	Total prosumer exports on a network asset cannot exceed 30% of its average load, so an eligible site can still be refused
How exports are valued	Credits at a NERC-approved export tariff, based on the DisCo's avoided cost and capped by reference to the retail tariff
Unused credits	Carried forward to later billing cycles, subject to regulatory conditions
Carbon credits	Retained by the prosumer
Metering	Bidirectional (import/export) net meter supplied by the prosumer; the DisCo reads and reconciles it
Technical standards	Certified engineer; anti-islanding, voltage and frequency protection; single interconnection point; NEMSA inspection
Sale of premises	Rights and credits can transfer to a new owner or occupier, with DisCo approval
Disputes	30 days of negotiation, then referral to NERC for final decision

The Approval Route

1. Apply to your DisCo with a certified single-line diagram, system specifications, proof of occupation and the application fee.
2. The DisCo carries out a technical feasibility assessment and approves or rejects the application.
3. Sign a Net Billing Agreement, which must be executed within five days of approval and sets the export capacity, voltage level and export tariff.
4. Register with NERC as a prosumer.
5. Pay connectivity charges, install the system and net meter, pass NEMSA inspection and complete commissioning with the DisCo.

Mini-Grid Interconnection Guidelines

The NEMSA Guidelines replace ad-hoc, case-by-case approvals for connecting solar mini-grids of up to 10 MW to DisCo networks. NEMSA sets technical standards and certifies installations, NERC issues permits and sets tariff terms, and the DisCo implements the connection. DisCos must publish feeder-level Hosting Capacity Information at least once a year so developers can check available capacity before applying. Approval follows four stages: preliminary screening, permitting (including a tripartite agreement between developer, DisCo and host community), NEMSA inspection, and commissioning.

The Guidelines offer five commercial models, and choosing between them is a strategic decision about revenue, asset ownership and long-term role:

Model	How It Works
Small Power Producer	Developer generates and exports to the network; the DisCo sells to customers
Small Power Distributor	Developer retires its generation and resells DisCo power
Hybrid	Combines generation and resale
Compensation Buy-Out	DisCo buys the mini-grid assets outright
Time-Split Supply	Mini-grid and grid supply customers in agreed time windows

Net Billing vs Mini-Grid Interconnection

	Net Billing	Mini-Grid Interconnection
Best suited to	Cutting energy costs at your own sites	Investing in power supply as a business
Size	50 kWp to 1.5 Mwp	Up to 10 MW per site
Value	Bill credits	Tariff revenue, or a buy-out by the DisCo
Key agreement	Net Billing Agreement with the DisCo	Tripartite agreement with DisCo and community, approved by NERC
Main risk	Export tariff too low to justify the cost	DisCo displacing the developer; tariffs not yet settled

What This Means for Businesses

Facility Energy Costs: Look again at the business case for solar at onshore sites with surplus daytime output. The benefit only applies to grid-connected sites, so off-grid facilities gain nothing unless they connect.

Realistic Economics: Include connection charges, metering, engineering certification, NEMSA inspection and possible grid upgrades in the business financial model. Treat credits as a cost offset, not income.

Portfolio Strategy: Companies diversifying into power should compare the mini-grid models carefully. Some leave the developer as a long-term operator, while others end with the DisCo taking over.

DisCo Exposure: Both frameworks depend on DisCo performance, including timely feasibility reviews, accurate capacity data and reliable settlement. Build approval delays into project schedules.



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