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Petroleum Production Cost in Nigeria: Drivers and Benchmarks

IZUCHUKWU ONUCHE[1], NANJUL JAMES BALI[2]
[1]*Center for Gas, Refining and Petrochemical Engineering, University of Port Harcourt*
[2]*Nigerian Upstream Petroleum Regulatory Commission (NUPRC), Abuja*

Abstract—This study evaluates petroleum production cost per barrel in Nigeria through an integrated assessment of operational, technical, fiscal, and country-specific cost drivers. Owing to the limited availability of publicly accessible and non-proprietary cost data, the study adopts a survey-based methodology, drawing on expert responses obtained from 208 professionals across the Nigerian upstream oil and gas value chain, including regulators, international oil companies, indigenous operators, and academia. Quantitative responses were analysed using descriptive statistical techniques, while qualitative inputs were examined through thematic content analysis. Findings identify drilling and completion expenditure, lifting operations, logistics, statutory obligations, infrastructure, and security as dominant cost determinants. Country-specific factors - particularly crude theft, pipeline vandalism, community relations costs, and import dependence for oilfield equipment significantly differentiate Nigeria from lower-cost global producing regions. Production cost clusters within the $20–40/bbl range, with a weighted benchmark estimate of approximately $30/bbl. This aligns with regulatory and industry-reported cost ranges for Nigerian upstream operations. The study situates Nigeria within the global upstream cost curve as a mid to high cost producing nation, higher than core OPEC producers but competitive relative to frontier offshore basins. Policy implications are framed in the context of the Upstream Petroleum Operations Cost Efficiency Incentives framework, highlighting pathways for cost optimisation, regulatory efficiency, oil infrastructure, security, and technology deployment. The findings provide evidence-based guidance for policymakers, regulators, and investors seeking to enhance cost competitiveness and long-term sustainability of Nigeria's upstream petroleum sector.

Keywords— Petroleum production cost; Upstream economics; Cost drivers; Nigerian factor; Cost benchmarking

I.INTRODUCTION

The long-standing argument that the world will eventually run out of petroleum resources is largely dependent on whether the rate of hydrocarbon depletion exceeds the rate of new discoveries and reserve additions. Beyond the question of resource exhaustion, however, the continued relevance of petroleum remains evident, particularly given its role as a primary feedstock for a wide range of essential products across multiple industries. This perspective contrasts with earlier assertions that the oil industry would lose demand long before hydrocarbon resources are depleted (Adelman, 2002). While such arguments acknowledge the longevity of petroleum resources, they often understate the expanding non-fuel demand for petroleum-derived products, which continues to sustain global relevance.

Nigeria remains one of Africa's most significant hydrocarbon-rich nations. (Rui et al., 2018). According to the Nigerian Upstream Petroleum Regulatory Commission (NUPRC), the country's proven crude oil reserves stood at 36.96 billion barrels as of January 1, 2023, an estimate that closely mirrors the cumulative crude oil production of approximately 37 billion barrels between 1961 and 2021 (NUPRC, 2024; Gbakon et al., 2021). These reserve estimates are subject to periodic upward reviews as new discoveries are made. For instance, the NNPC-Chevron joint venture announced a major oil discovery in the Niger Delta in early 2026, which is expected to contribute to future reserve updates. However, hydrocarbon reserves, irrespective of their magnitude, do not translate into economic value or national income unless they are commercially produced.

The process of converting subsurface hydrocarbon resources into economic value is fundamentally governed by production cost. Crude oil located deep within reservoirs must be developed, lifted, processed, and transported to the surface, all of which incur significant costs. The magnitude and structure of these costs ultimately determine whether reported reserves are economically viable. Consequently, production cost per barrel represents a critical metric in upstream petroleum economics and investment decision-making.

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Production cost per barrel refers to the average expenditure incurred by an operator to extract and produce one barrel of crude oil. It typically comprises exploration, development, drilling, lifting, labour, equipment, logistics, and other operational overheads. These cost components are influenced by a combination of generic factors common across producing regions and field-specific characteristics. In addition, country-specific conditions introduce further variability. As an oil-producing nation, Nigeria exhibits unique operational, regulatory, and infrastructural features (hereafter refers to the Nigerian factor) that may cause its production costs to differ substantially from those of other producing countries. (Okpo et al., 2023).

At the firm level, production economics and operational philosophies further shape cost thresholds. This explains the variation in minimum economic production rates adopted by different operators. For example, while a typical international oil company operating in Nigeria may set a minimum threshold of approximately 100 barrels of oil per day (bopd) per well in swamp or offshore environments, indigenous operators may sustain production at levels as low as 20 bopd or less while remaining commercially viable. Such disparities underscore the influence of corporate cost structures, asset maturity, and risk tolerance on production economics.

Several factors contribute to petroleum production costs in Nigeria, including community-related expenditures, equipment importation costs due to limited domestic manufacturing capacity, environmental management costs, crude oil quality characteristics, and infrastructure security challenges. (Taffamel and Akrawah, 2015). Nigerian crude oils are predominantly light and low Sulphur grades, with API gravities typically ranging between 21° and 45° API, which can positively influence processing economics (Eti et al., 2006). Conversely, oil theft and sabotage have historically contributed to production losses and increased operating expenditures, reflecting persistent security challenges within the oil and gas infrastructure. Although policy reforms such as the Petroleum Industry Act (PIA) 2021 have been associated with reported reductions in oil losses, the quantification of theft- and sabotage-related costs remains contentious due to limited metering infrastructure and inconsistent reporting.

This study aims to identify the key cost drivers in petroleum production in Nigeria and sets a production cost per barrel based on a structured survey instrument that was developed and administered to professionals across the Nigerian oil and gas value chain, particularly in the upstream petroleum operations.

Given the large number of interdependent and volatile parameters influencing petroleum production costs, incorporating all individual cost drivers into a single predictive model may introduce excessive complexity and uncertainty. For this reason, the present study adopts a systems-level approach, treating petroleum production cost as an aggregated construct. The cost framework is therefore simplified into four principal components: exploration cost, development cost, lifting cost, regulatory cost, and additionally the Nigerian-factor cost. This "black-box" representation enables a more tractable and analytically robust examination of petroleum production cost drivers and benchmarking practices in Nigeria.

II.COST DRIVERS AND THE NIGERIAN FACTOR

To enable analytical simplification, the cost drivers can be aggregated into five principal cost categories:

1. Exploration Cost: These are costs incurred in discovering hydrocarbons such as cost of seismic acquisition and processing, geological and geophysical studies, exploration drilling, wildcat wells, and reservoir characterization technology. Key drivers in this category include depth, reservoir type, technology, terrain.
2. Development Cost: are those costs required to bring discoveries to production, which include cost of development drilling, well completions, sand control, subsea systems, production platforms/FPSOs and infrastructure installation. The key drivers are reservoir consolidation, depth, logistics, reservoir pressure.
3. Lifting (Operating) Cost: These are the day-to-day production expenses such as cost of artificial lift, power and fuel, water handling, maintenance, workovers and production chemicals. Water cut, depletion, drive mechanism, sulphur content, and API are major cost drivers in this category.
4. Regulatory Cost: are those Government-imposed financial obligations including royalties, petroleum profit tax, licensing fees, environmental compliance,

host community funds. Royalties, taxes, and production sharing terms influence net production cost and project economics (Tordo et al., 2010).

5. Nigerian-Factor Cost: This category captures peculiar socio-economic and geopolitical cost escalators unique to Nigeria's operating environment. They include country-specific cost burdens such as security expenditure, theft and sabotage losses, community relations cost, equipment importation, logistics constraints, local content compliance, and infrastructure deficits. Availability of oil infrastructure creates easy access to pipelines, export terminals, and processing facilities which reduces evacuation and processing costs; while local content compliance may increase short-term cost but build long-term capacity.

Although the determinants of the production cost per barrel in oil and gas industry are numerous and dynamically complex, the following are the key cost drivers (in no particular order):

Reservoir depth and Pressure: Reservoir depth is a primary determinant of drilling and development cost. Deeper reservoirs require longer drilling time, higher-grade drilling fluids, increased casing design complexity, and high-pressure/high-temperature (HPHT) equipment. Deep wells also increase rig day rates and fuel consumption. For example, ultra-deepwater wells in the Gulf of Mexico or offshore Nigeria can cost several hundred million dollars per well due to water depth and subsurface complexity (Kaiser and Pulsipher, 2007). In contrast, shallow onshore wells are significantly cheaper to drill and complete. High reservoir pressure supports natural flow, reducing lifting costs. Low-pressure reservoirs require artificial lift systems such as gas lift, ESPs, or rod pumps, increasing CAPEX and OPEX (Brown, 1984).

API Gravity and Water Cut: API gravity determines crude oil density and flow characteristics. Light crudes (high API) flow more easily and require less artificial lifting and processing, thereby reducing lifting and refining costs. Nigerian crudes are generally light (21° - 45° API), making them attractive in global markets and relatively cheaper to process (Eti et al., 2006). Heavy oils, conversely, require thermal recovery, diluents, or upgrading, increasing production cost (Speight, 2014). Water cut refers to the percentage of water produced with hydrocarbons. As reservoirs mature, water cut increases, raising separation, treatment, reinjection, and disposal costs. High water cut fields require additional facilities such as separators, hydrocyclones, and produced water reinjection systems, significantly increasing operating expenditure (OPEX) (Ahmed, 2010).

Depletion Rate: Reservoir depletion reduces natural pressure support, leading to declining production rates and higher unit lifting costs. As depletion progresses, operators must introduce secondary or tertiary recovery methods such as water flooding or gas injection, increasing operational costs (Dake, 2001).

Extent of Reservoir Rock Consolidation: Unconsolidated formations (e.g., Niger Delta sands) produce sand along with hydrocarbons, necessitating sand control measures such as gravel packing, frac packs, or screens. These interventions increase completion and maintenance costs (Suman et al., 1983).

Field Terrain and Drive Mechanism: The cost of production also depends on whether the oilfield is onshore, offshore or deepwater. The terrain significantly impacts cost: While onshore fields generally incur lowest cost as compared to swamp/shallow offshore fields, deepwater fields incur the highest cost. Deepwater developments require subsea systems, FPSOs, and complex logistics, often exceeding \$15 - \$25/bbl in lifting cost alone (Kaiser and Yu, 2010). Drive mechanisms determine energy availability for hydrocarbon to flow from the reservoir through the wellbore to the surface. Reservoirs with strong natural drive require fewer artificial lift interventions (Ahmed, 2010). There are number of drives mechanism such as solution gas drive, water drive, gas cap drive and rock compression drive. A combination of these can drive a reservoir. Solution gas drive declines rapidly and requires higher cost later to sustain reservoir pressure. Water drive maintains stable production and hence lower lifting cost but requires extra professional handling and monitoring to avoid early water breakthrough. Gas cap maintains moderate cost profile.

Technology Deployment: Advanced technologies such as 4D seismic, intelligent completions, digital oilfields, and enhanced oil recovery (EOR) improve recovery but increase upfront costs. However, they may reduce long-term unit costs through efficiency gains (Lake et al., 2014). If the technology is readily available in the country then it would mean less cost as against when the technology has to be sourced abroad.

Sulphur Content: High sulphur (sour) crudes require corrosion-resistant facilities, desulfurization, and environmental safeguards, increasing processing and handling costs. Sweet crudes like many Nigerian blends incur lower treatment costs (Speight, 2014).

Reservoir Type and Production Method: Tight reservoirs have low permeability and require hydraulic fracturing and horizontal drilling. These technologies significantly increase development cost compared to conventional reservoirs (Holditch, 2006). Natural flowing wells have minimal lifting cost. Artificial lift systems introduce equipment, power consumption, maintenance, and workover costs (Brown, 1984).

Logistics and Security: Logistics costs include transportation of personnel, equipment, drilling materials, and crude evacuation. Remote swamp and offshore locations require helicopters, marine vessels, and specialized supply chains, increasing cost per barrel (Kaiser and Pulsipher, 2007). Security expenditure covers surveillance, escorts, facility protection, and community relations. In politically volatile regions, this becomes a significant OPEX component.

Theft and Sabotage: Pipeline vandalism and crude theft result in production losses, deferred production, repair costs, and environmental remediation expenses. Nigeria has recorded substantial losses from such incidents (Katsouris and Sayne, 2013).

Other critical determinants include field maturity and oil price. Brownfields often have higher maintenance costs but lower exploration cost compared to greenfields. Price volatility affects cost optimization strategies and investment thresholds.

III.METHODOLOGY

A structured survey instrument was developed and administered to professionals across the Nigerian oil and gas value chain, with particular emphasis on upstream petroleum operations. Due to the extremely limited availability of reliable, publicly accessible, and non-proprietary petroleum production cost data in Nigeria, this study primarily relies on expert-elicited information obtained through this survey. A total of two hundred and eight (208) valid responses were received and analysed. Respondents were drawn, under strict anonymity, from key stakeholder groups including regulatory institutions, international oil companies, indigenous oil companies, and academia. The diversity and professional depth of the respondent pool provide a robust basis for capturing industry-wide perspectives on petroleum production cost, while the anonymity of responses encourages candid disclosure on cost drivers and benchmarking practices in Nigeria.

The minimum required sample size was estimated using the standard normal approximation:

$$n = \frac{Z^2 p(1-p)}{e^2} \qquad 1$$

Where Z-score = 1.96 corresponds to a 95 % confidence level, p = 0.5 represents maximum population variability, and e = 0.07 denotes the margin of error. This yields a minimum required sample size of approximately 196 respondents. The study obtained 208 valid responses, thereby exceeding the minimum requirement for statistical validity and providing adequate power for industry-level inference. (Krejcie & Morgan, 1970)

Closed-ended questionnaire items were analysed using descriptive statistical tools such as frequency distributions, percentages, and weighted means. Open-ended responses were analysed using thematic content analysis, whereby recurring cost drivers and operational challenges were identified, coded, and grouped into dominant thematic categories.

IV.RESULTS AND DISCUSSION

4.1 Respondents' Years of Experience

The respondent pool is dominated by mid to senior level professionals, indicating that the survey reflects experienced, decision relevant perspectives rather than entry level opinions. This strengthens the reliability of the cost benchmark and the policy implications derived from the findings. Figure 1 below shows the number of respondents and their years of experience.

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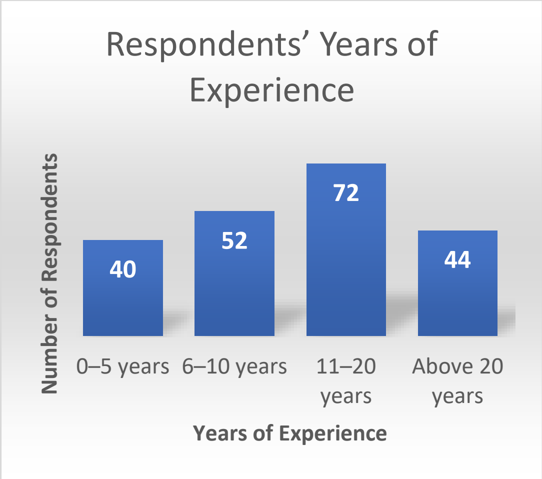

Figure 1: Respondents' Years of Experience

4.2 Stakeholder Representation by Job Category

The respondents span diverse technical and managerial roles including drilling engineers, production engineers, reservoir engineers, project managers, operations personnel, commercial analysts, regulators, and academia drawn from international oil companies (IOCs), indigenous oil companies, service providers, and regulatory bodies. Although more respondents were recorded from regulators and indigenous oil companies, a good percentage also came from NNPC LTD which partners with many oil companies in Nigeria. This multidisciplinary representation enhances the reliability of the perception-based cost evaluation, given that petroleum production cost is influenced by both subsurface and surface operational decisions. Figure 2 shows the respondents versus their categories.

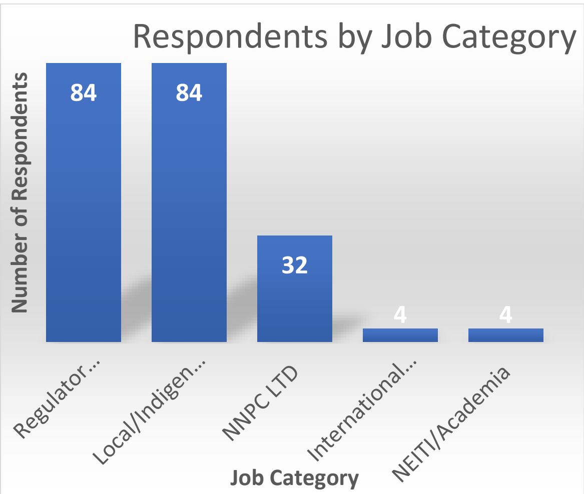

Figure 2: Respondents by Job Category

4.3 Ranking of Primary Cost Drivers in Nigerian Production Systems (From Closed-End Responses)

Respondents ranked major cost components using a five-point Likert scale (1 = No Influence; 5 = Very High Influence). Aggregated responses reveal a clear hierarchy of cost drivers.

4.3.1 High-Impact Cost Drivers

The following factors recorded consistently high influence rankings: drilling and completion operations; production (lifting) and processing facilities; transportation and crude evacuation; health, safety, environment (HSE) and security; statutory obligations; and oil theft and infrastructure vandalism.

Drilling and completion costs remain capital intensive due to rig rates, casing design, mud systems, logging services, and well complexity. Terrain emerged as a top drilling cost determinant. Deepwater wells require floating rigs, subsea completions and specialized riser systems This results in drilling costs several multiples higher than onshore wells. NUPRC had in its annual report stated that the average unit development cost for the approved Field Development Plans (FDPs) on terrain basis in 2023 are $4.16 for onshore, $4.20 for offshore and deepwater as $9.93.

However, uniquely Nigerian cost escalators particularly oil theft and pipeline vandalism ranked comparably high, reflecting their material impact on deferred production, repair expenditure, and surveillance costs.

Highly ranked lifting cost drivers include maintenance of production facilities; energy and fuel for power generation, logistics and material transportation, HSE operations and production losses from theft. Pipeline downtime and facility maintenance also contribute to deferred production and cost escalation. Transportation costs were also highly ranked due to Nigeria's heavy reliance on pipelines, barging, and trucking amid frequent evacuation disruptions.

Regulatory Compliance such as licensing processes, environmental audits, and operational reporting requirements introduce administrative cost layers and project delays. Statutory obligations such as royalties, petroleum taxes, concession rentals, and

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signature bonuses were ranked among the highest external cost drivers. These fiscal instruments directly affect project breakeven thresholds. Host community costs like corporate social responsibility projects, and compensation payments represent institutionalized expenditure under Nigeria's social license to operate framework.

4.3.2 Moderate-Impact Drivers

Moderately ranked factors include: labour cost; capital infrastructure expenditure; and enhanced oil recovery (EOR) deployment. While labour costs are significant, they are less dominant relative to security and logistics. EOR ranked moderate largely due to its limited application across Nigerian assets, where many fields are still in primary or secondary recovery phases.

4.4 Dominant Cost drivers from Open-Ended Responses

Qualitative responses were analysed thematically to identify dominant cost determinants and policy concerns. Security of assets, technological modernization, regulatory stability, and cost optimization emerged as the most critical issues. The findings suggest that policy interventions should prioritize infrastructure, security, promote digital oilfield technologies, streamline regulatory processes, and incentivize cost-efficient operations without compromising health, safety, and environmental standards. Stakeholders noted that cost optimisation, oil infrastructure and security are critical determinants of cost and sector competitiveness. The findings suggest that policy interventions should prioritize infrastructure, security, promote digital oilfield technologies, streamline regulatory processes, and incentivize cost-efficient operations without compromising health, safety, and environmental standards. Stakeholders noted that cost optimisation, oil infrastructure and security are critical determinants of cost and sector competitiveness. Figure 3 shows the frequency of mentions of these cost drivers.

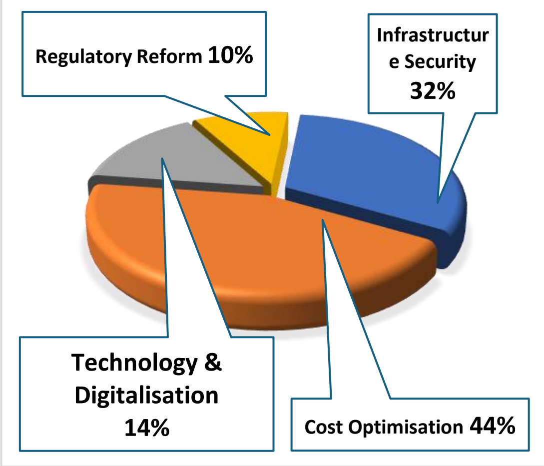

Figure 3: Frequency of Mentions Key Cost Drivers.

4.5 Oil Production Cost Benchmarks

Findings indicate that respondents are familiar with crude oil production cost benchmarks in Nigeria. Most respondents reported moderate to very high awareness of per-barrel production cost estimates. This suggests that the dataset reflects informed professional judgment rather than speculative opinion.

From the questionnaire responses, the perceived average cost of crude oil production in Nigeria clusters within three dominant bands summarized in Table 1 below:

Table 1: Summary of Dominant Cost Bands

Cost	Terrain Type/Band
$10 - $20 per barrel	Mature onshore / swamp assets;
$40+ per barrel	Deepwater / high-security terrains;
$20 - $40 per barrel	Most frequently selected range

The average cost of crude oil production in Nigeria ranges between $10 and $40 per barrel, depending on terrain, security exposure, and infrastructure availability. The modal response category was $20 - 40/bbl. Using midpoint approximation for categorical ranges, the weighted central estimate converges around $30/bbl, which is adopted in this study as the indicative industry cost benchmark.

This perception aligns with publicly available industry benchmarks, where Nigerian lifting costs vary significantly by terrain, security exposure, and infrastructure availability. Nigeria's upstream production cost has been reported by the Nigerian

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Upstream Petroleum Regulatory Commission (NUPRC) to range between \$25 and \$40 per barrel, placing the country among high-cost oil-producing nations. (NUPRC, 2024)

Table 2 summarizes that the production cost per barrel in Nigeria is higher than low-cost OPEC producers but lower than frontier deepwater provinces.

Table 2: Nigerian Oil Production Cost vs Global Benchmarks

Region	Cost (\$/bbl)
Middle East	5 – 10
US Shale	35 – 50
North Sea	30 – 50
Nigeria	~30

(Benin, 2020).

V.CONCLUSION

This study provides a comprehensive evaluation of petroleum production cost per barrel in Nigeria through an integrated survey-based and analytical framework. By leveraging expert elicitation across regulatory, operational, and technical domains, the research addresses the longstanding data opacity surrounding upstream cost structures in Nigeria.

Findings confirm that petroleum production cost in Nigeria is shaped by a complex interaction of subsurface conditions, operational requirements, fiscal regimes, and country-specific socio-economic factors. Drilling and development expenditure, lifting operations, logistics, and statutory obligations constitute core cost components, while security challenges, infrastructure deficits, and equipment import dependence represent uniquely Nigerian cost factors.

Benchmark analysis indicates that Nigeria's production cost clusters within the \$20–40/bbl range, with an indicative weighted average of approximately \$30/bbl. This positions Nigeria above low-cost Middle Eastern producers but within competitive range relative to offshore and mature basin developments such as the North Sea and US shale plays.

The study underscores that cost competitiveness in Nigeria is not solely a function of geology or reservoir performance but is significantly influenced by governance quality, infrastructure security, regulatory efficiency, and technology adoption. Consequently, sustainable cost reduction requires coordinated policy, fiscal, and operational reforms rather than isolated technical interventions.

In aligning with national cost-efficiency policy frameworks, the research provides actionable insights for regulators, investors, and operators seeking to enhance upstream project viability, attract capital investment, and ensure long-term sustainability of Nigeria's petroleum resources within an evolving global energy landscape.

VI.RECOMMENDATIONS

Strategic cost optimisation in Nigeria's upstream petroleum sector requires an integrated policy and operational approach. Priority interventions include strengthening oil and gas infrastructure security through advanced surveillance technologies and community-based protection frameworks to curb theft and vandalism; streamlining regulatory approval processes via digitalisation and single-window compliance systems to reduce project delays; and implementing targeted fiscal incentives to improve investment viability in high-cost and marginal fields. Additionally, expanding local content capacity in oilfield manufacturing and services will reduce import dependence and foreign exchange exposure, while accelerated deployment of digital oilfield technologies and predictive maintenance systems can enhance operational efficiency. Finally, promoting shared production and evacuation infrastructure among operators will minimise capital duplication and lower unit development and lifting costs, thereby improving Nigeria's global cost competitiveness.

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