
African
Energy
Chamber
The State
of African
Energy
2027 Outlook
Report
S&P Global
Energy


African Energy Chamber



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2027 Outlook Report

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Foreword

Dear Colleagues,

In 2026, the world learned once again that energy is not theory, but logistics, leverage, and national security. The conflict tied to Iran and the resulting strain on the Strait of Hormuz exposed how quickly a single chokepoint can rattle crude flows, LNG cargoes, refined products, shipping schedules, and insurance costs. When a passage that normally carries roughly a quarter of the world's seaborne oil trade and nearly a fifth of global LNG trade is disrupted, the shock is immediate and undeniable. That reality reminded every government, every investor, and every operator of a simple truth: energy security is built on supply, infrastructure, and execution not slogans.

Africa enters 2027 from a position of strength and responsibility. Across the continent, hydrocarbon production is expected to reach roughly 11 MMboe/d, underscoring the scale of Africa's upstream potential and the importance of converting resources into reliable supply. This is not an abstract ambition. It reflects real progress in field development, refinery expansion, pipeline construction, and the commercial discipline required to move hydrocarbons from the ground to the market. In an uncertain world, Africa's ability to produce, process, and export oil and gas is not merely an economic advantage it is a strategic asset.

The case for African gas has never been clearer. LNG disruptions in 2026 reinforced the need for new supply, and major African projects such as Rovuma LNG and Mozambique LNG remain central to the continent's long-term role in global energy security. Gas is not a talking point. It is feedstock for industry, fuel for power generation, and a practical bridge that helps African economies industrialize while expanding access to electricity. Where governments support stable fiscal terms, bankable contracts, and timely permitting, gas can anchor growth, strengthen grids, and improve public revenues.



That same realism must guide the power sector. Africa's energy challenge is not whether to choose oil, gas, power, or renewables as if they were competing camps. The real task is to build an integrated system that can serve more than 1.4 billion people today and far more tomorrow. More than 26 African countries are projected to at least double their populations between 2017 and 2050, and that growth will drive demand for electricity, transport fuel, fertilizers, industrial heat, and digital infrastructure. Data centers, urbanization, and manufacturing expansion are not future possibilities they are near-term load growth. And load growth requires dependable generation, transmission, fuel supply, and investment-grade policy.

That is why an "all-of-the-above" energy strategy remains the only serious path forward. Oil revenues can finance roads, ports, schools, hospitals, refineries, and pipelines. Gas can stabilize baseload power and support industrialization. Renewables can and should grow, especially where solar, wind, and geothermal resources are strongest, but they must be integrated through grids, storage, and market reforms that make them dispatchable and bankable. The conversation should never be framed as fossil fuels versus development. In Africa, fossil fuels and new energies are part of development, and in many countries they remain the fastest, most reliable way to expand access, create jobs, and strengthen fiscal capacity.

That is also why Africa must resist regulatory overreach that tries to govern African development from outside African borders. Some European frameworks increasingly seek to impose compliance burdens on producers and projects well beyond the EU's own territory. Heavy-handed rules especially supply-chain and due-diligence mandates such as the EU's Corporate Sustainability Due Diligence Directive (CS3D)—risk making oil and natural gas harder to secure by adding cost, complexity, and delay to already challenging investment environments. These policies do not simply add paperwork. They can slow contracting, complicate traceability across long supply chains, and raise the risk premium on projects that the world needs to move forward. In the end, that hurts African producers, African consumers, and Europe's own long-term energy reliability.

Let us be plain about the matter: energy security is not served by bureaucratic red tape. It is served by stable partnerships, clear rules, open investment channels, and the freedom to build. African leaders should not accept a model in which distant regulators with radical climate change ideologies dictate operational outcomes for African resources while African countries still struggle to electrify homes, power factories, and refine their own crude. The continent needs pro-growth policy, pro-infrastructure policy, and pro-investment policy—policy that welcomes capital, de-risks projects, and rewards execution.

Critical minerals add another layer of opportunity, but only if Africa moves beyond extraction alone. Value is created when minerals are processed, refined, and integrated into regional industrial systems powered by reliable energy and supported by transport corridors, ports, and modern grids. That means the same lesson applies across the sector: build the infrastructure, support the projects, and the value will follow.

This State of African Energy 2027 Outlook is therefore more than a report. It is a statement of purpose. It reflects a continent that is no longer asking permission to develop its resources. It reflects African governments and companies that understand the relationship between energy and prosperity. It reflects a simple and enduring principle: energy poverty is not a strategy, and deprivation is not development.

Africa stands at a decisive crossroads. One path is built on realism, investment, infrastructure, and energy abundance. The other is defined by delay, dependency, and policy choices that too often place ideology above human need. Africa should choose the path that delivers power, industry, revenue, and opportunity. It should choose the path that secures energy on African terms.

That is the spirit of this Outlook: bold, factual, and unapologetically committed to the proposition that Africa's oil, gas, and power future must be built by Africans, for Africans, and in partnership with the world on fair, practical, and investment-ready terms.

Sincerely,

NJ Ayuk
Executive Chairman,
African Energy Chamber

Executive summary

The State of African Energy 2027 Outlook Report presents a dynamic sector undergoing major expansion resulting from the blockages in the Strait of Hormuz, renewed investment, and increasing infrastructure projects to support refineries and pipeline development. With growing demand for refined products and natural gas, a rapidly expanding renewable power market, and a geopolitical rush to gain access to strategic critical minerals, Africa's energy sector is in a period of new growth and integration into global markets.

Just Energy Transition:

A just energy transition that recognizes localized African contexts begins with energy access. Unique to other regions, energy consumption reduction is not a main priority, but rather expanding affordable, reliable and modern energy services across the continent. Energy security lies at the forefront of this transition and to achieve this, the continent must prioritize affordable fuels, adaptive infrastructure, and reliable power systems to improve living standards and institutional capacities. Local conditions must be acknowledged as African countries are home to diverse landscapes, industrial structures, and governments that ultimately guide the strategy for transition pathways.

Upstream:

Marked by a cautious renewal of new investments, upstream markets have been leveraging this new attention to offset declines in output. This decline is largely attributed to established producers like Algeria and Nigeria who have maturing fields with aging infrastructure and now face increased competition from emerging investment hotspots such as Namibia and Côte d'Ivoire. Hydrocarbon production is expected to reach roughly 11 MMboe/d in 2027 and expand to 12.5 MMboe/d by 2030. Exploration on the continent has witnessed a rising trend towards deep-water prospects, largely across immature and frontier basins. Upstream ownership is at a crossroads between the consolidation of mature assets and strategic positioning for future growth opportunities.

Oil Markets – Midstream and downstream:

Prolonged disrupted operations of the Strait of Hormuz have led to growing tensions surrounding Africa's growing import dependency and heightened concerns over supply-side product affordability. With varying levels of interaction with Middle Eastern markets, African industries and policy makers have been taking diversified approaches to ensure market growth and continuity. Policies have been adapted across the region to tackle issues such as the regulation of fuel prices and introduction of strategic fuel reserves to support long-term solutions. Economic and population growth prove to be conducive to refined product demand growth in the long run as Africa's economy is projected to expand the fastest in comparison to other regions of the world. Currently, the continent represents less than 5% of global oil-product demand, despite hosting 18% of the global population. Infrastructure projects are paramount to unlock this growth as cross-border connectivity and transport are long-standing issues hindering the potential of oil markets, among other energy sectors.

Gas and LNG:

Transformation has been at the core of this sector as increasing attention is placed on Africa's positioning with the global gas value chain. The continent stands as a major exporter and a rising importer, while also leveraging domestic gas resources for domestic consumption. As it stands, Africa contains more than 550 Tcf of known gas resources and supplied 9% of global LNG resources in 2025, expecting further growth in the coming years. LNG suppliers can play a strategic role in balancing current market dislocations that arose from conflicts across the Middle East. A major sectoral expansion is the monetization of gas as it proliferates beyond exports. Due to population growth and increasing energy demand, gas

is being increasingly viewed as a tool to sustain this development and further drive economic value beyond extraction and export.

Power and Renewables Outlook:

With rapid population growth, urbanization, and digitalization, the power sector is a major point of contention, particularly for the nearly 565 million people on the continent lacking access to power. Challenges revolve around generation capacity and increased investment for scalable electrification projects to ensure improved quality of life and economic development. Average annual electricity consumption in Sub-Saharan Africa lies around 377 kWh, compared to the global average of around 3,600 kWh per capita. Renewable energies are increasingly dominating narratives as Africa contains some of the strongest wind, solar, hydro, and geothermal resources. Private sector support and more favorable procurement frameworks have uplifted these projects and allowed for a diversification of Africa's energy generation mix.

Critical Minerals Outlook:

Rising in strategic importance for the global economy as governments, manufacturers, and corporations compete for reliable supplies of critical minerals, this sector is particularly important for Africa as it hosts some of the largest endowments of minerals like cooper, cobalt, and lithium. These interests are gaining geopolitical attention on a global stage with China's long-standing mining investments across the continent, whereas the United States, Europe and numerous middle powers like India and Japan increasingly forming partnerships to expand investment opportunities throughout Africa. The continent lies with a critical moment where increasing industrial capacity will allow nations to gain more control over their own resources, reap immense economic benefits, and act as a prominent leader in global supply chains.







Chapter 01

1.0 The Macro Picture

Macroeconomic overview: Africa 2026-2027

Macroeconomic trends in Africa have been adversely affected by the US/Israel-Iran war. Once again, the conflict has exposed the global economy, including Africa, to heightened vulnerabilities stemming from rising prices and supply chain disruptions, slowing economic growth. Efforts to diversify and strengthen energy supply, and to develop AI technology and defence capabilities have created both downside risks and emerging opportunities for Africa.

The ongoing disruptions to trade through the Strait of Hormuz have created a major chokepoint in trade between Gulf Cooperation Council (GCC) countries and global markets, affecting the movement of key commodities including liquefied natural gas (LNG), crude oil, refined petroleum products, urea, ammonia, sulphur and other goods.

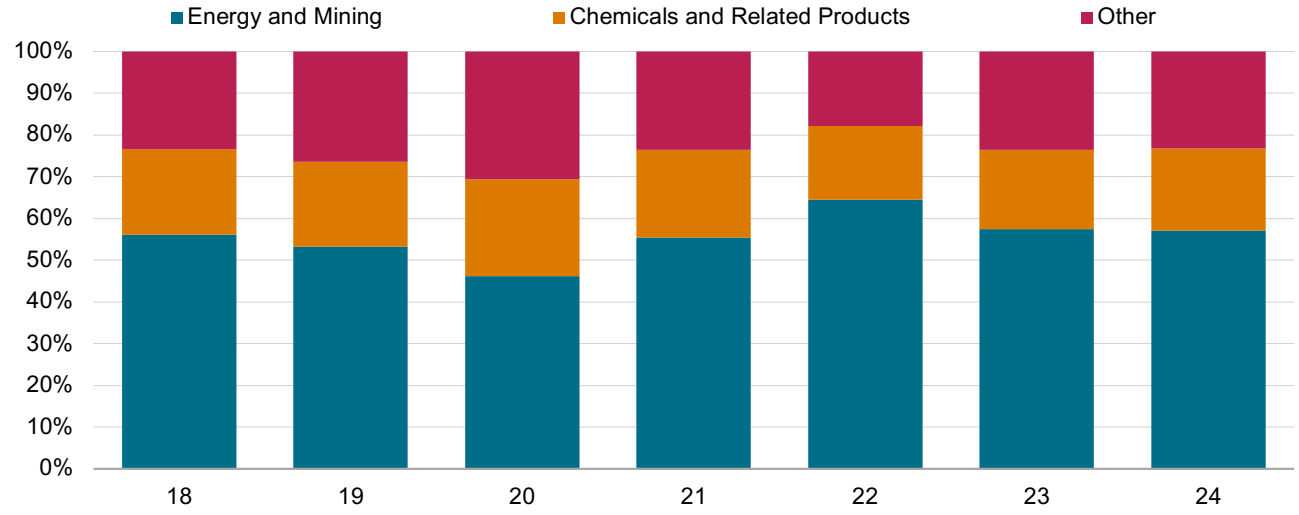
Fortunately for Africa, the relatively small share of trade between the GCC countries and the region, has left the disruption to overall African trade relatively contained, with an uneven impact depending on sector. S&P Global Market Intelligence data show that around 6%–8% of Africa's total exports are destined for GCC countries, consisting primarily of iron ore and related products and precious metals such as gold.

Imports from GCC countries account for roughly 8%–10% of Africa's total imports and consist mainly of crude oil, refined petroleum products, and plastics in primary form.

Delays to refined fuel imports and higher prices have weakened economic activity, with demand for refined fuel having been lowered by persistently high retail prices. Some African countries have introduced measures to ease the burden on consumers and additional refined fuel capacity has been brought online at the Dangote refined fuel plant in Nigeria but pump prices have increased by double-digit rates in most countries. Economic activity has been further constrained by physical product shortages in several markets, including Madagascar, Zambia, Mozambique, and the Democratic Republic of Congo.

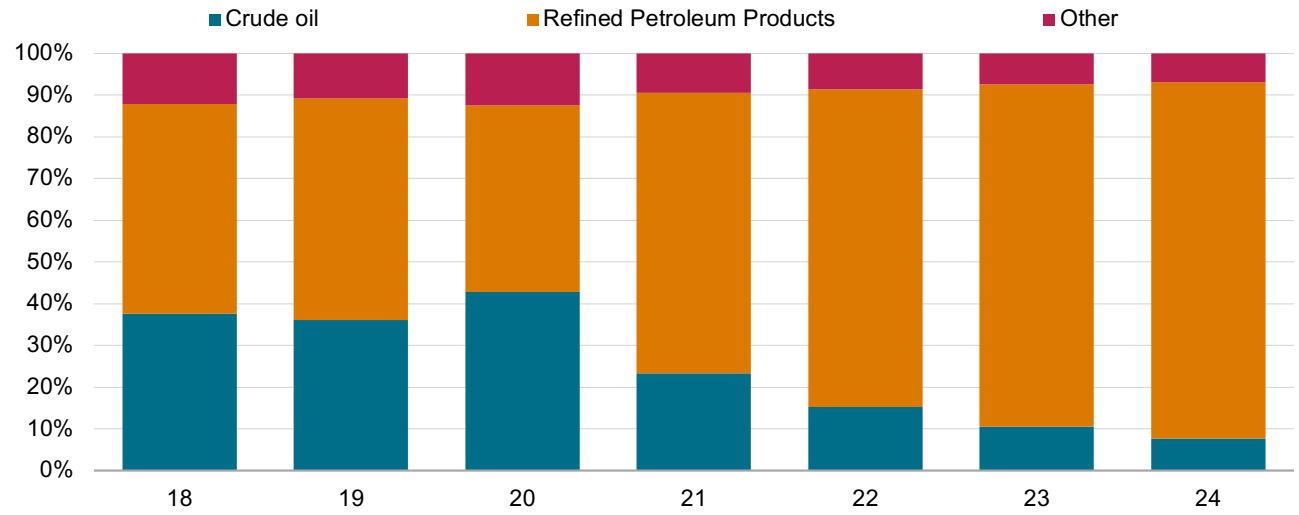
In response, monetary policy across Africa has become more divergent in 2026. South Africa and Rwanda have tightened policy in response to renewed inflation pressures, while other countries, including Angola and Zambia, have continued easing cycles, with energy price pressures being offset by lower food prices and resilient exchange rates.

GCC exports to Africa concentrated in energy and chemical products (% Composition)



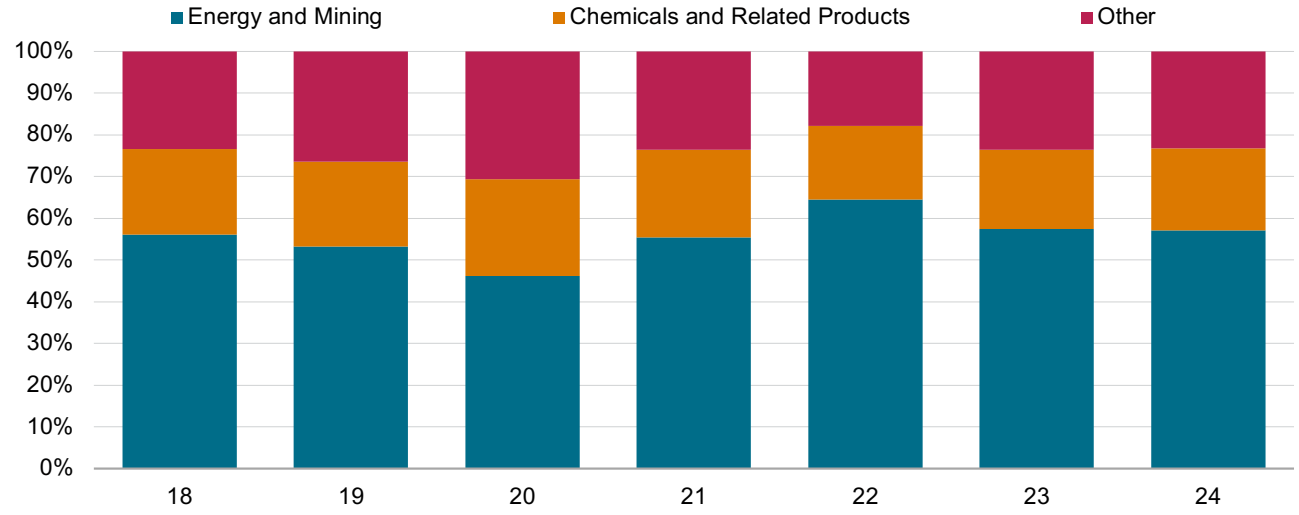
As of August 18, 2026.
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GCC energy and mining exports to Africa concentrated in crude oil and refined products (% Composition)



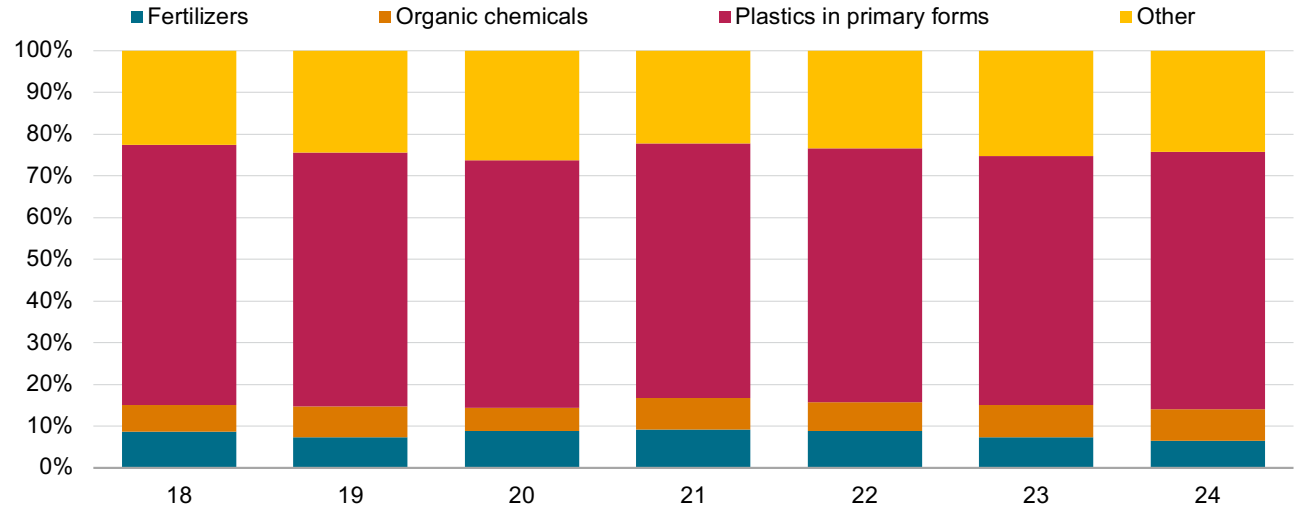
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GCC exports to Africa concentrated in energy and chemical products (% Composition)



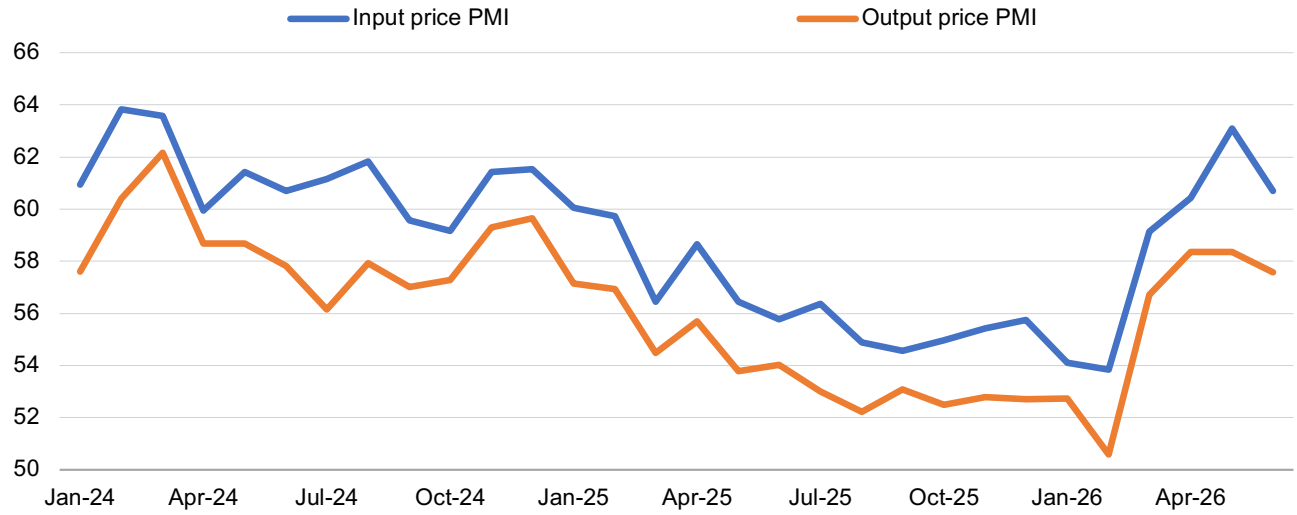
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GCC chemical exports to Africa concentrated in fertilizers and plastics in primary forms (%



As of August 18, 2026.
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Sub-Saharan Africa: Input and output PMIs (Index 50=neutral)



As of August 18 2026.
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The agricultural sector has the potential to worsen cost of living pressures and pressure on real disposable income, which are likely to soften household spending in Africa during 2026-7. Food prices are likely to increase in 2027 to reflect disruptions to agricultural production caused by El Niño conditions and higher fertilizer prices.

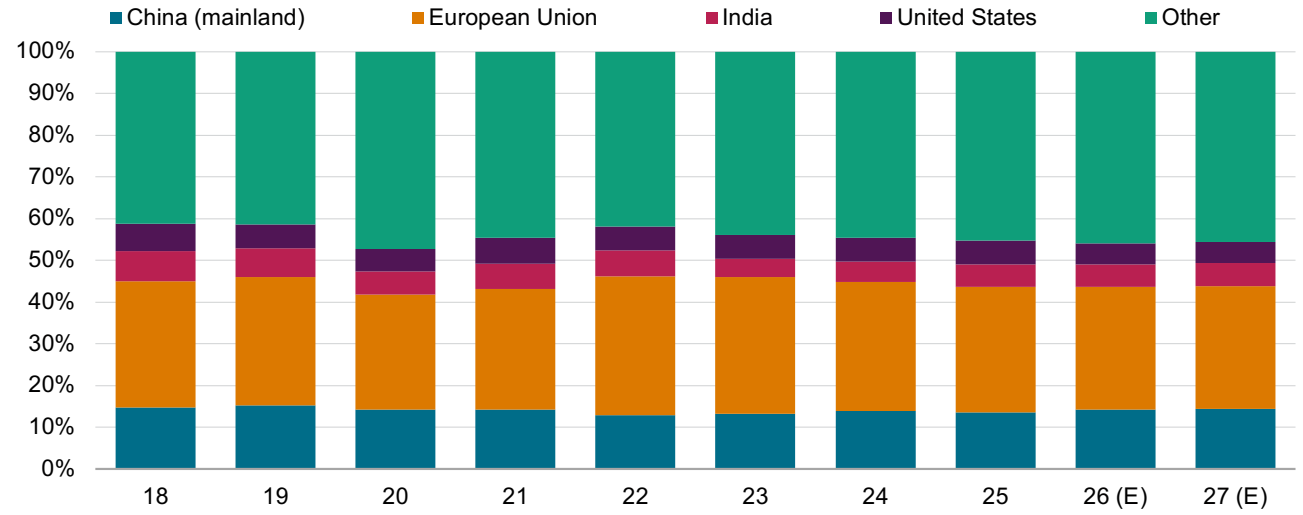
Buffers from natural resource development continue to limit downside pressures on Africa's overall growth. Global demand for critical minerals and rare earth elements used in renewable energy, defence, and AI-related technologies will continue to support mining investment across the continent, including in the Democratic Republic of the Congo's cobalt and copper sectors, Guinea's bauxite and iron ore sectors, lithium projects in Zimbabwe, Mali, and Namibia, manganese, platinum-group metals (PGMs), helium in South Africa, and graphite in Mozambique and Madagascar. In several cases, mining investment is driving major infrastructure expansion programmes, such as the Lobito Corridor connecting the copper belts of the DRC and Zambia to Angola's Atlantic coast, and the Trans-Guinean railway linking the Simandou iron ore project to the Port of Morébaya in Guinea.

Lasting interruption of oil exports by GCC countries would increase the risk that substantial GCC investment, notably from Saudi Arabia and the United Arab Emirates (UAE), would be tapered. Continued access to GCC investment remains important for Africa's development trajectory. Saudi Arabia and the UAE have been actively investing in port expansion projects across Africa to expand capacity and strengthen trade connectivity. Additionally, in July 2026, ADNOC Distribution acquired Shell Downstream South Africa for approximately US$1 billion, gaining ownership of around 580 fuel stations, as well as related wholesale, aviation, and lubricants operations in the country. The UAE currently has the largest direct mining footprint in Sub-Saharan Africa, particularly in copper assets in Zambia and the DRC, while Saudi Arabia is increasingly pursuing copper, lithium, cobalt, and rare-earth supplies through equity stakes, partnerships, and long-term offtake agreements as part of its Vision 2030 agenda and critical-minerals security objectives.

Geopolitical positioning is also reinforcing Africa's importance as a trade partner going forward, encouraging mainland China and European countries to increase their access to Africa's growing market and benefit from the African Continental Free Trade Area (AfCFTA), its rising population and relatively strong economic development prospects. China (mainland)'s China–Africa Economic Partnership for Shared Development (CAEPSD), backed by China's zero-tariff treatment for imports from African countries, is likely to deepen trade ties and encourage export-oriented mainland Chinese investment across the continent. China (mainland) became Africa's largest importing partner in 2025, and trade between the two is expected to deepen further in the coming years.

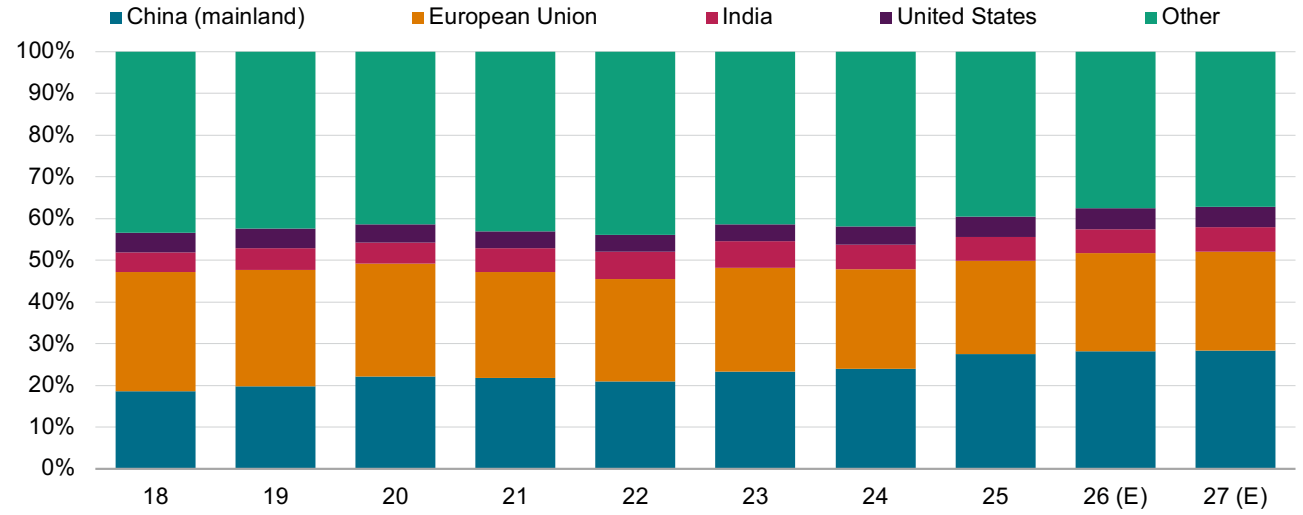
The European Union remains Africa's largest exporting partner. Africa's exports to Europe are dominated by oil and gas, minerals and metals (including copper, cobalt, gold, platinum, manganese and graphite), and agricultural products such as cocoa, coffee, tea, citrus and wine. Manufactured exports to Europe, particularly vehicles, textiles and chemicals, are becoming increasingly important in Morocco, Tunisia, Egypt and South Africa. Like the United States, Europe is increasingly expanding its investment into the mining sector, particularly in the copper belt . Efforts to increase energy security and diversify supply sources provide scope for expanded European energy imports from West and North African partners

European Union remains Africa's largest exporting partner (% composition)



As of August 18, 2026.
Source: S&P Global Market Intelligence.
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China (mainland) became Africa's largest importing partner in 2025 (% composition)



As of August 18, 2026.
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Overall, S&P Global Market Intelligence forecasts an overall growth rate for Africa of 3.9% in 2026-2027, down from 4.4% in 2025. This forecast remains subject to several adverse risks, which would lower it further. These include the threat of reduced access to global financial markets, combined with higher global interest rates, rising insecurity in the Sahel region and continuing upward pressure on energy costs as reserve stocks decline. Counterbalancing this, investment in Artificial Intelligence (AI) offers potential for significant growth in Sub-Saharan Africa, although the scale of potential gains will depend on governments' ability to overcome the infrastructure gaps in water and electricity, skills deficits, and institutional constraints that currently limit adoption. However, slow or low AI adoption would be damaging, likely widening Africa's productivity/technology-gap with the US, Europe and APAC.





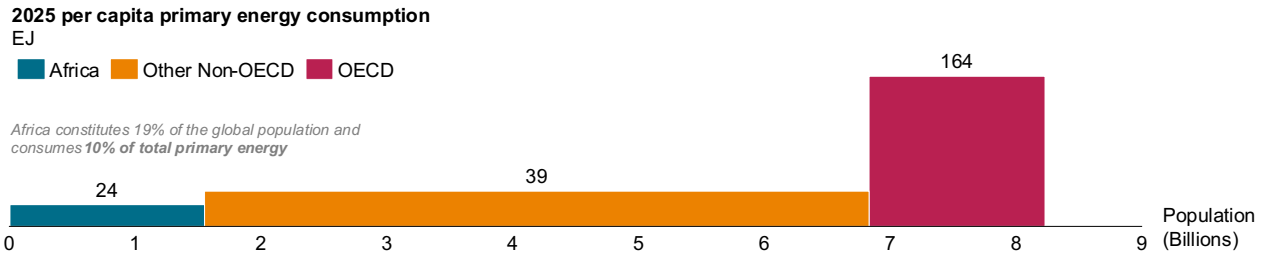


Chapter 02

2.0 Just Energy Transition Begins with Energy Access

For Africa, a just energy transition starts with energy access. The continent's immediate challenge is not reducing energy consumption, but expanding reliable, affordable and modern energy services to support development. Hundreds of millions of people still lack electricity, while many more rely on traditional biomass for cooking. Low per capita energy use continues to constrain productivity, industrialization and living standards. As seen in Figure 1, Africa's energy consumption falls well below the rest of the world (in aggregate).

Figure 1. Population and Energy Consumption per Capita of Africa and Rest of World

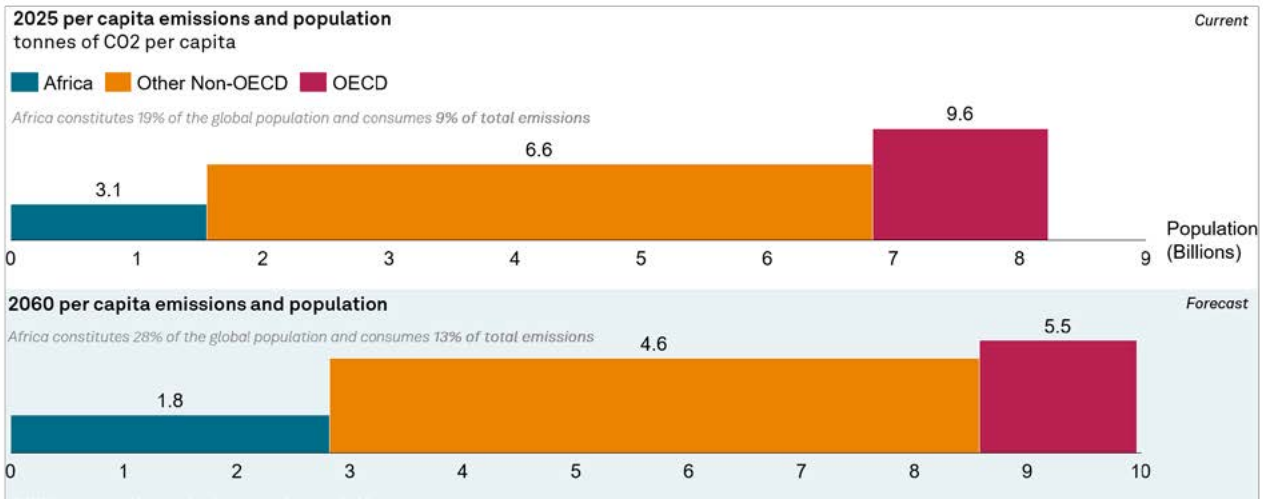


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This development challenge sits alongside a very small emissions footprint. Africa currently accounts for only around 5% of global energy-related emissions despite representing about 19% of the world's population, with per capita energy-related emissions far below the global average. As seen in Figure 2, even as Africa's total emissions rise with population and economic growth, its share of global emissions is expected to remain modest relative to its demographic weight.

Figure 2. Population and Emissions per Capita of Africa and Rest of World



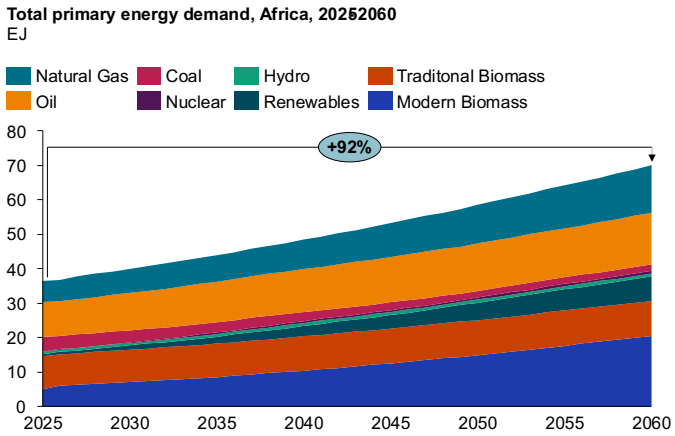
Energy Addition Will Require an "All Fuels" Approach

Unlike mature economies, where transition often means substituting lower-carbon energy for existing fossil fuel demand, Africa's transition will be driven mainly by energy addition. Population growth, urbanization and industrial expansion will require much larger energy systems, supported by renewables, hydro, natural gas, petroleum products, storage, transmission, distributed systems, regional trade and, in some markets, nuclear power. As seen in Figure 3, energy demand is forecast to increase by 92% between 2026 and 2060, with all fuels continuing to co-exist.

This does not imply that every fuel will play the same role in every market. Rather, different fuels and technologies will be needed to meet different requirements: variable renewables can expand low-cost supply where resources are strong; gas and liquid fuels can support dispatchability, industrial heat and system resilience; hydro and geothermal can provide firm low-carbon power where resources allow; and grids, storage and regional interconnections will be critical to integrating supply across wider systems.

The objective should not be fuel exclusion, but the creation of energy systems that are larger, more reliable, more affordable and progressively lower in emissions intensity.

Figure 3: Total Primary Energy Demand, Africa, 2026 - 2060



A Transition Built on Energy Security

Energy security must remain central. Reliable power systems, affordable fuels and resilient infrastructure are essential to investment, industrial output and improvements in living standards. For sectors such as mining, manufacturing, logistics and data infrastructure, the availability of dependable energy can be as important as its cost.

There Is No Single African Transition Pathway

There is no single African transition pathway. Countries differ widely in resource endowments, infrastructure, industrial structure, affordability constraints and institutional capacity, so transition strategies will need to reflect local conditions rather than imported models. A gas-rich producer with underutilized domestic supply, a hydro-based power system exposed to drought risk, a coal-dependent industrial economy, a mineral-rich country seeking to move into processing, and a small import-dependent market will each face different choices and trade-offs.

This also means that the balance between access, affordability, reliability, industrial development and emissions reduction will vary by market. In some countries, the priority will be expanding grid-connected power and reducing outages; in others it will be replacing traditional biomass, developing domestic gas-to-power, scaling renewables, improving refining and product logistics, reducing flaring and methane emissions, or building the infrastructure needed for mining and minerals processing. The common requirement is not a single prescribed fuel mix, but a practical pathway that increases useful energy supply while steadily reducing emissions intensity where viable.

Concluding Remarks

The rest of this report considers how upstream, downstream, gas and LNG, power and critical minerals each contribute to that broader agenda: expanding energy supply, strengthening security, enabling industrial development, reducing avoidable emissions such as flaring and methane, and supporting a more resilient development pathway.



Chapter 03



3.0 Strategic Narrative

Resource Opportunity Meets Execution Reality

Africa's upstream sector is entering a new investment cycle driven by a combination of growing energy demand, renewed resource security concerns and the emergence of several high-potential exploration and development hubs. Hydrocarbon production is expected to reach approximately 11 MMboe/d in 2027 (production revisions have resulted in a slightly reduced 2027 forecast), rising to around 12.5 MMboe/d by 2030 (FID rationalisation has resulted in a lower 2030 production outlook than anticipated in 2026) as a new generation of oil and gas projects comes online. While established producers such as Algeria, Nigeria, Angola, Libya and Egypt will continue to account for the majority of regional output, the centre of growth is gradually shifting towards emerging producers including Namibia, Mozambique, Uganda and Côte d'Ivoire, where major discoveries, new export infrastructure and improving investment frameworks are attracting international capital.

Conflicts in Russia and the Middle East have highlighted the need for a diversified supply base. These conflicts have forced a rationalisation of the historical African risk premium. This eroding risk premium has resulted in renewed momentum to drive developments forward and has added to the already established GIOC trend of focusing exploration efforts on African deepwater immature and frontier opportunities.

The continent's resource base remains globally significant and increasingly competitive. A renewed exploration focus on frontier and immature basins along the Atlantic Margin and the Eastern Mediterranean has generated strong industry interest, supported by attractive fiscal terms, greater access to acreage and the potential for large-scale discoveries capable of materially moving company portfolios. At the same time, national oil companies, indigenous operators and regional champions are taking on a larger role in asset ownership as international operators concentrate capital on selective deepwater, gas and large-scale development opportunities. This combination of frontier exploration, portfolio repositioning and growing local participation is reshaping the African upstream landscape and creating new pathways for investment and partnership.

Investment momentum is expected to remain strong throughout the decade. Global upstream capital spending is forecast to exceed $500 billion annually, with Africa attracting approximately $40 billion of annual investment through a combination of deepwater oil developments, LNG projects and infrastructure-led gas opportunities. The largest share of capital will be directed towards Mozambique, Nigeria, Angola, Libya and Côte d'Ivoire, while new project sanctions in Uganda, Kenya and Namibia are expected to further diversify the continent's production base. However, resource potential alone will not guarantee success. The ability to convert discoveries into production increasingly depends on access to financing, infrastructure readiness, commercialisation pathways and effective project execution.

As global upstream capital becomes more selective, aboveground factors emerge as the key differentiator between success and delay. Many African governments have responded by introducing more competitive fiscal terms, streamlined licensing approaches and targeted incentives aimed at accelerating exploration and development. Angola, Algeria, Nigeria and Libya have all introduced reforms designed to improve project economics and attract investment, while frontier jurisdictions increasingly use technical evaluation agreements and flexible pre-exploration frameworks to secure early operator engagement. Nevertheless, regulatory uncertainty, security challenges, local-content requirements, access to export infrastructure and evolving political dynamics continue to influence investor sentiment across several markets.

The central challenge for Africa's upstream sector is therefore shifting from resource discovery to resource delivery. The continent possesses a substantial undeveloped resource base and an increasingly attractive portfolio of exploration opportunities, yet the value of these resources will ultimately depend on the ability of governments, operators and investors to translate geological success into bankable projects, competitive developments and reliable routes to market. Countries that combine resource potential with fiscal stability, effective governance, access to capital and credible commercialization pathways will be best positioned to capture the next wave of investment and establish themselves as the continent's leading growth engines through 2030 and beyond.

3.1 Reserves & Production Outlook

3.1.1 Exploration and Development in Africa

Africa's upstream sector is in a phase of cautious resurgence, as mature crude producers harness new investment to offset output declines, and new E&P venues emerge as growth hotspots. Gas developments in both frontier and more mature hydrocarbon host countries will also add to output growth. Established producers, such as Algeria, Nigeria, Libya, Egypt, and Angola, dominate output but face challenges from aging infrastructure, maturing fields and competition from emerging investment hotspots such as Côte d'Ivoire and Namibia, which are attracting new investment due to recent discoveries or the hope of significant upside. The focus on frontiers and emerging basins has been accelerated in part due to attractive terms relative to more mature producing provinces and due to high prospectivity.

While there has been an overall increase in production within the continent, certain countries face the risk of stranding substantial assets due to technical constraints that outweigh the economic viability of these resources. In these cases, a pragmatic approach to terms and strong messaging related to fiscal stability is critical in shaping investment decisions.

In recent years, exploration has seen a growing trend toward targeting increasingly deep-water prospects, with explorers chasing large and giant prospects typically found in immature and frontier basins. These frontier regions have successfully attracted exploration capital with competitive terms and a willingness to share data. IOC positioning, particularly along the Atlantic margin and within frontier and immature basins, highlights a shifting focus towards basins with the potential for "needle-moving discoveries" and underscores the importance of attractive terms in frontier basins, even if those basins are located in countries with a long history of hydrocarbon production.

The Eastern Mediterranean

The Eastern Mediterranean remains one of the most important gas-producing regions globally. While Egypt remains the region's main gas market and LNG hub, the development of Cypriot and Israeli resources is expected to play an increasingly important role in shaping regional gas balances and export opportunities. The region's outlook will depend not only on new discoveries, but also on the ability to commercialize resources through cross-border infrastructure and gas trade. Existing pipelines and LNG facilities provide a foundation for regional integration, but further investments in transportation and processing infrastructure will be required to unlock additional volumes and support long-term growth. Exploration activity continues to highlight significant upside potential, particularly in frontier areas such as the Herodotus Basin offshore Egypt and Cyprus. However, infrastructure timing, pricing, regulatory frameworks and geopolitical developments will remain key factors influencing the pace of future investment and production growth across the Eastern Mediterranean.

Onshore North Africa

Onshore North Africa remains one of Africa's most important hydrocarbon regions, anchored by Algeria, Libya and Egypt, which account for most of the region's oil and gas production and resource base. While Algeria continues to focus on sustaining gas output and monetizing new developments, Libya is pursuing incremental production growth through field rehabilitation, brownfield optimization and renewed licensing activity. Egypt remains a key regional gas producer despite declining domestic gas output, efforts are focused on accelerating exploration, improving fiscal terms and advancing new developments in both the Western Desert and adjacent Mediterranean assets.

Elsewhere, Tunisia and Morocco offer smaller but strategically important growth opportunities. Tunisia continues to promote exploration and development to slow production declines and reduce import dependence, while Morocco is emerging as a regional gas growth story.

Onshore Central Africa

The Chad-Niger-Sudan-South Sudan corridor represents one of Africa's smaller but strategically important onshore hydrocarbon belts, with a combined crude oil production exceeding 400,000 b/d.

The corridor is significant not only for its upstream resource potential but also for establishing two major export routes connecting local production to international markets: in West Africa, crude oil from Niger is exported via the Niger-Benin pipeline to the Atlantic coast, while Chadian production flows through the Chad-Cameroon pipeline to the terminal at Kribi, providing direct access to global crude markets.

Overall, the corridor's future will be shaped less by subsurface potential than by above-ground risks, making Niger the clearest growth market and Sudan-South Sudan the most challenged opportunity.

The Atlantic Margin

Discoveries offshore Côte d'Ivoire and Namibia, as well as in

Morocco, have reinvigorated interest in deepwater acreage along the African Atlantic margin. High-impact drilling has taken place in São Tomé and Príncipe (Douala Deep Sea Basin) and will continue in late 2026 and into 2027 within the Angolan portion of the Namibe Basin and Namibia's Walvis Sub-basin. Positioning by the large IOCs within the ultra-deepwater portions of several West Africa frontier and emerging basins suggests a prolonged focus on large Jurassic-Cretaceous-aged fans within the more frontier areas (please see High impact exploration for more on Namibia, Côte d'Ivoire, Sao Tome and Principe, Angola, South Africa, Somalia and Zimbabwe).

Emerging areas of exploration focus

Africa's frontier and immature basins have hosted several IOC entries since 2024. IOCs have captured acreage under very attractive terms, often during technical evaluation area (TEA) or similar agreements. This trend is seemingly accelerating, fuelled by geopolitical instability in the Middle East.

Morocco

Murphy's entry into the Gharb Deep Offshore license highlights growing interest in the country's underexplored Atlantic margin and supports ONHYM's strategy of attracting experienced international operators.

Guinea

Eni has built a substantial technical evaluation footprint, taking 15 blocks covering approximately 49,100 square kilometers across the Senegal-Mauritania-Guinea-Bissau-Conakry Basin (M.S.G.B.C. Basin) and the Sierra Leone Basin. This position gives ENI exposure to a broad segment of the northern Atlantic margin, extending across both underexplored and regionally prospective plays.

Sierra Leone and Liberia

Further south along the Equatorial Atlantic Basin—which is bounded to the north by the Saint Paul transform system and to the south by the Romanche transform system—activity is concentrated in Sierra Leone, specifically in the Sierra Leone Basin. Here, both Eni and Shell have secured acreage under technical evaluation terms. Eni holds five blocks covering about 6,800 square kilometers, while Shell has built a larger position with 19 blocks totaling roughly 20,600 square kilometers. Collectively, these awards indicate rising industry interest in revisiting Sierra Leone's offshore potential following earlier basin exploration efforts.

Equatorial Guinea and Gabon

In the central segment of the South Atlantic central evaporitic/salt basin province (also known as the Interior Margin/Salt Basins), situated between the Romanche zone and the Rio Grande Fracture Zone, momentum has increased markedly in Equatorial Guinea and Gabon.

In Equatorial Guinea, Eni and Chevron have built sizable technical evaluation portfolios after winning six and five reconnaissance blocks, respectively. Eni holds acreage totaling about 12,000 square kilometers, concentrated mainly in the frontier Gabon–Douala Deep Sea Basin, where an Upper Cretaceous play was discovered in 2022 following Kosmo's Jaca new-field wildcat. Chevron controls roughly 6,500 square kilometers around Bioko Island, with interests spanning the Niger Delta, the Gabon–Douala Deep Sea Basin, and the Douala Basin. Any gas discovery made in the area could be brought to market quickly, supported by the EGLNG facilities operated by Chevron, which rely primarily on supply from the Alba and Alen fields and, over the medium term, from Aseng and Yoyo–Yolanda.

Gabon has attracted substantial attention from major operators, with BP, Shell, and ExxonMobil all securing sizeable TEA positions. BP has taken 10 blocks covering roughly 27,100 square kilometers in the Gabon Coastal Basin. Shell's position is broader, comprising 14 blocks and approximately 38,600 square kilometers across the Gabon Coastal Basin, the Gabon Douala Deep Sea Basin, the Lower Congo Basin, and the Congo Fan. ExxonMobil holds the largest TEA footprint in the country, with 20 blocks covering around 53,300 square kilometers across the Gabon-Douala Deep Sea Basin, the Lower Congo Basin, and the Congo Fan.

Overall, these agreements reflect a strategic push by interna

3.1.2 Hydrocarbon production outlook

Africa's hydrocarbon production is expected to reach about 11 million barrels of oil equivalent per day (MMboe/d) in 2027. New project start-ups are projected to lift continental output to approximately 12.5 MMboe/d by 2030, with North Africa accounting for around 45% of total production and Sub-Saharan Africa supplying the remainder. Sub-Saharan Africa's production share is expected to exceed earlier forecasts by the end of the decade and into the early 2030s, supported by final investment decisions (FIDs) on major Mozambique LNG developments in 2025 and 2026 and a growing pipeline of Namibian projects that are nearing FID in 2027 and 2028.

The continent's upstream base remains highly concentrated. Algeria is expected to be Africa's largest producer when both oil and gas are included, closely followed by Nigeria, with each contributing around 2.5 MMboe/d. Libya, Angola and Egypt are each expected to produce more than 1 MMboe/d. Together, these five countries represent roughly 80% of Africa's hydrocarbon output, underscoring the continued importance of mature producing areas.

At the same time, emerging producers such as Uganda, Mozambique, Namibia and Côte d'Ivoire are set to play a larger

role as new projects come onstream. Delivering this growth will depend on sustained investment, timely project sanctioning and the technical and operational capacity required to develop higher-risk and more complex reservoirs.

Spotlight on the top-producing countries

Angola

Angola, one of Africa's long-standing oil producers and a member of the continent's "big five," has experienced a steep production decline since peaking near 2.0 MMbbl/d in 2008. Output is expected to average just above 1.0 MMbbl/d in 2026 before falling below that level in 2027, reflecting the natural decline of the country's mature, offshore-dominated asset base.

The "big five" operators still account for nearly 70% of national production, but sustaining output above 1.0 MMbbl/d will become increasingly difficult without new large-scale discoveries. Developments such as Agogo and Kaminho will provide near-term support and help slow the rate of decline, but they are unlikely to fully offset losses from aging fields without additional project sanctions and investment.

In response, Angola has adopted a pragmatic investment strategy. Incremental fiscal terms introduced in late 2024 were designed to incentivise further investment in mature assets, while the longer-term focus has shifted to frontier exploration in the Namibe Basin and the ultra-deepwater Congo Fan. Enhanced fiscal competitiveness has brought Angolan frontier acreage broadly in line with other emerging frontier plays, driving renewed IOC interest, significant acreage awards, and a series of high-impact exploration campaigns, including Ondjaba, Quitexe, Arcturus, and the upcoming Merengue-1 well.

Algeria

Algeria is a mature oil and gas producer with growth potential, particularly in gas. Production is concentrated in the country's southern onshore basins, with Sonatrach dominating the sector, accounting for roughly 75% of liquids production and more than 80% of gas output.

In 2025, 17 hydrocarbon discoveries were reported, although most are understood to be modest in size. Sonatrach and Eni were the most active explorers. Total hydrocarbon production averaged approximately 3.0 MMboe/d, comprising more gas than liquids, with crude oil output near 0.93 MMbbl/d. In 2026, oil production is expected to remain broadly stable at around 1.0 MMbbl/d, while gas production is forecast at approximately 10 Bcf/d.

Several gas gathering and infrastructure projects are underway, often incorporating decarbonisation initiatives such as photovoltaic power installations at Eni's Bir Rebaa North complex. New developments, including Tin Fouye Tabankort Sud and In Amenas II, are scheduled to start up in 2026. While these projects will support incremental gas supply, they are unlikely to materially alter Algeria's production trajectory, with total hydrocarbon output expected to remain broadly flat at around 3.0 MMboe/d over the next five years.

The government is targeting higher hydrocarbon production to underpin economic growth and diversification efforts, with an ambition to increase gas production capacity to 200 Bcm/y within five years, including 100 Bcm/y available for export.

Nigeria

Nigeria remains one of Africa's largest upstream producers, with average output of around 2.3 MMboe/d – sold volumes – over the past five years. The sector is undergoing a significant transition, driven by improving production performance, a shift in operator roles, growing deepwater investment, and a stronger focus on gas commercialization.

Onshore production improved through 2024 and into 2025, supported by enhanced security measures aimed at reducing pipeline theft and vandalism. By July 2026, crude oil and condensate output had reached more than 1.8 MMbbl/d, showing progress toward the government's target of at least 2.1 MMbbl/d by the end of 2026. In the longer term, Nigeria aims to raise oil production to 3 MMbbl/d by 2030, although this will depend on the delivery of major projects and continued improvements in security and infrastructure reliability.

A major structural change has taken place in the Niger Delta in the last few years. International oil companies shifted their focus away from mature and higher-risk onshore assets toward deepwater and gas projects. At the same time, indigenous operators such as Renaissance Africa Energy, Seplat Energy and Oando have taken a larger role in onshore and shallow-water production. This transition is reshaping the operating landscape and creating a clearer division between domestic-led onshore activity and IOC-led offshore development. This has also complicated the competitive landscape, increased pressure on players to develop their projects and reduced potential economies of scale.

Deepwater projects are central to Nigeria's medium- and long-term liquids outlook. Shell's Bonga North project, which reached final investment decision in 2024, is ex-

pected to deliver peak production of around 110,000 bbl/d toward the end of the decade. Other major offshore development (or redevelopment) projects include TotalEnergies-operated Preowei and Ntokon, Oriental's Okwok, ExxonMobil's Usan, Eni's Zabazaba and Etan, and Shell's Bonga Southwest. All could provide additional production growth, particularly after 2030.

Gas is becoming an increasingly important part of Nigeria's upstream strategy. The government is seeking to expand domestic gas supply, support industrial demand and increase LNG exports. Key projects include ANOH gas development by Seplat and Renaissance, expected to reach peak output of around 595 MMcf/d, TotalEnergies' Ubeta project, which will supply Nigeria LNG, and the proposed Yoho-linked floating LNG project. These developments are aligned with national targets to raise gas production – gross production – from 7.8 Bcf/d to 10 Bcf/d by 2027 and 12 Bcf/d by 2030, as well as the need for additional feed gas for Nigeria LNG Train 7.

The investment and regulatory environment is also evolving. The implementation of the Petroleum Industry Act (PIA) continues to reorganize licensing, acreage conversion and regulatory processes. The 2025 Licensing Round was designed to attract new capital through more competitive terms, including lower signature bonuses and targeted incentives for deepwater and non-associated gas projects. Additional fiscal incentives have also been introduced to support both existing assets and new developments.

Despite these positive trends, Nigeria's upstream sector still faces major challenges. Oil theft, sabotage, infrastructure constraints, underinvestment and natural field decline continue to limit production growth. Achieving the country's 2026 and 2030 production targets will depend on maintaining security gains, attracting sufficient investment, accelerating project execution and ensuring that both oil and gas developments move forward on schedule.

Egypt

Egypt remains one of Africa's important gas producers, although production has declined since its 2021 peak, increasing reliance on LNG imports and imported Israeli gas. Gas production fell to around 4.2 Bcf/d in mid-2026, while oil output remained relatively stable at approximately 450,000 b/d. The country continues to pursue a strategy focused on short-cycle gas developments, frontier exploration and improved investment terms to reverse decline rates and strengthen domestic energy security.

New projects are expected to support supply growth, including WDDM Phase 12A and Arcius Energy's Harmattan development, each targeting around 150 MMscf/d, alongside the continued expansion of the Kamose field offshore North Sinai. Operators including Shell, Eni, Harbour Energy and Cheiron continue to invest across the Nile Delta, offshore Mediterranean and Western Desert as Egypt seeks to stabilise hydrocarbon production.

Libya

Libya's upstream sector showed a mix of operational gains and persistent structural constraints during 2026. Crude production briefly reached a post-2013 high of almost 1.44 MMb/d in June, although sustainable output is generally estimated at 1.2-1.35 MMb/d due to funding, infrastructure and political constraints.

Field rehabilitation and brownfield optimization remain the primary drivers of growth.

Several discoveries and development projects also progressed during the year. OMV and NOC declared the Essar discovery in the Sirte Basin commercially viable, with estimated reserves of around 195 MMbbl. In the Ghadames Basin, Sirte Oil reported strong test results from NC216 and continued development of Hamada North, one of Libya's most important undeveloped oil assets.

On the gas side, operators remain focused on maintaining domestic supply and reducing flaring. Eni brought the Sabratha Compression Project online at Bahr Essalam, supporting production from Libya's largest gas field, while the Bouri Gas Utilization Project continued to advance toward startup. Together, these projects are expected to improve gas recovery, reduce flaring and strengthen supplies to both the domestic market and the GreenStream export system, currently at around 10% of its capacity.

Spotlight on countries gathering momentum

Côte d'Ivoire

In 2025, Côte d'Ivoire reached several oil production milestones, building on 2024, when the first full year from Baleine Phase 1 increased output by over 50% year over year. 2025 marked the first full year of production from Baleine Phase 2, which began in December 2024. One month later, Eni reported that Baleine was performing above expectations and that the Phase 2 facilities were already surface-constrained. By July 2025, production from both Baleine phases exceeded 62,000 bopd, supplying around 90% of Côte d'Ivoire's output in 2025. The increase was partly offset by Baobab's shutdown which produced about 15,500 bopd in 2024. Pro-

duction ended in January 2025, when its FPSO was sent to Dubai for refurbishment, deferring around 5.2 million barrels. The FPSO returned in April 2026, and four wells were restarted. A seven-well campaign is planned for later in 2026-2027 to raise output from block CI-40. The main upside remains Baleine Phase 3, with Eni taking the FID in

May 2026 and the potential to more than double current national production.

Mozambique

The country's production outlook is shaped by the expansion of large-scale LNG projects in the Rovuma Basin. The country currently produces from four fields: the onshore Pande, Temane, and Inhassoro fields, operated by Sasol, and the offshore Coral field, operated by Eni. In the coming years, four major LNG projects in the Rovuma Basin are expected to begin operations: Eni's Coral Norte FLNG (2028), TotalEnergies' Mozambique LNG (2029), ExxonMobil's Rovuma LNG (early 2030s), and Eni's third FLNG unit, anticipated to be commissioned in 2031. Once these developments come online, Mozambique is expected to emerge as one of Africa's most significant gas producers and LNG exporters, with production increasingly oriented toward international markets.

Spotlight on the next producing countries

Uganda

Uganda's production outlook is anchored by the start-up of the Lake Albert developments. First oil is expected in late 2026 from the Tilenga project, operated by TotalEnergies, and the Kingfisher project, operated by CNOOC. Development drilling and associated infrastructure work are progressing, including the East African Crude Oil Pipeline (EACOP). Once operational, these projects are expected to establish Uganda as a meaningful contributor to Africa's upstream production growth.

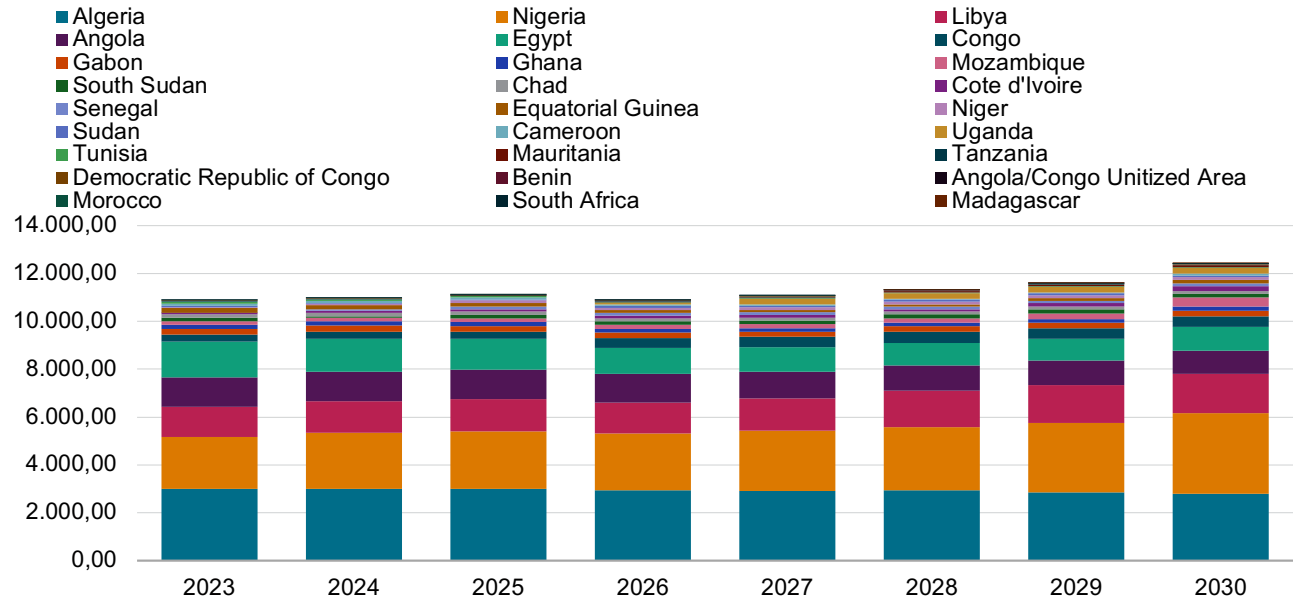
Kenya

Kenya's production outlook remains tied to the development of the Lokichar discoveries. Phase 1 production is expected to reach around 20 Mbbl/d, with output potentially increasing to approximately 50 Mbbl/d by 2032 as additional fields are brought online. Project timing and ramp-up remain closely linked to the availability of export infrastructure and logistics solutions.

Namibia

Namibia is expected to emerge as a major new oil producer over the next decade. First oil from TotalEnergies' Venus development is anticipated in 2030/31, with a capacity of around 150 Mbbl/d (delays related to FID suggest a 2031 start-up – this is contributing to the downward revision for the African 2030 production outlook). The Mopane development is expected to follow approximately two years later, adding a further 170 Mbbl/d. On this basis, Namibia could be producing more than 300 Mbbl/d by the mid-2030s. If the Rhino/Azule development proceeds on a similar timeline, with capacity of around 100 Mbbl/d, production could approach 400 Mbbl/d during the same period.

Africa production outlook (Mboe/d)



As of August, 2026.
Source: Upstream Content, a product of S&P Global Energy.
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3.1.3 Rig market perspective

West Africa continues to be one of the three core global deepwater markets alongside Brazil and the US Gulf of Mexico - these currently account for 79.8% of working drillships. Modern 6th and 7th generation drillships remain in strong demand in the region, particularly for developments offshore Angola, Nigeria, Côte d'Ivoire and Namibia.

The most recent demand forecast shows drillship demand is expected to average 10 units over 2026, 12 over 2027 and 13 over 2028. Average marketed surplus over the period is expected to be 5 units over 2026 and 4 over both 2027 and 2028.

All eyes in the global ultra-deepwater sector are on West Africa, where a number of contract awards are pending that will shape the next phase of rig availability. The table below shows the most significant of these requirements, which are either at tender, pre-tender or probable status in Petrodata Rigs' open demand records.

As seen from the table the tender process is well advanced in a number of these programs and award decisions can be expected very soon for Chevron Nigeria's program, from some of the TotalEnergies' requirements in Nigeria and Namibia, and from Shell Namibia. The work on offer to contractors is a healthy mix of long-term developments, exploration and appraisal work following significant finds in recent years.

Such is the level of demand in West Africa and the lack of availability in the current fleet that a number of inward mobilizations are likely. Two units are already confirmed to enter the region for agreed programs. Stena Forth will mobilize from Egypt to Namibia later in third quarter 2026 for one well off Namibia with Chevron — this places the unit well for further work for some of the outstanding work in West Africa. Also, later this quarter Saipem's Santorini will mobilize from Israel to Cote d'Ivoire to undertake Eni's 630 days plus options development drilling program at Baleine Phase 3.

Significant floater requirements

Operator	Description	Country	Location	Start	Days	Rig selection
TotalEnergies	3 wells + 9 x 1-well options	Nigeria	PPL 2001, OPL 257, PML 2/3/4	Oct-2026	130	Award pending
Shell	2 wells	Namibia	Merlin	Oct-2026	90	Award pending
Chevron	2 years + 1-year option	Nigeria	Agbami, OML 127/128	Nov-2026	730	Completed
Heritage	1 well + 1 well option	Ghana	Edinam	Nov-2026	45	Award pending
TotalEnergies	2 wells + 1-well option	Namibia	Mopane Extension/ Quiver/Sobreiro	Nov-2026	300	Award pending
Murphy	3-5 wells	Cote d'Ivoire	Bubale	Apr-2027	250	Tender expected
Tullow Oil	5 wells + 5 x 1-well options	Ghana	TEN/Jubilee	May-2027	300	Award pending
Azule Energy	5 wells + 2 option wells	Angola	Blocks 31, 31/21, 18 and 15/06	Sep-2027	90	Tender expected
Eni	22 wells	Nigeria	Zabazaba, PML 103	Dec-2027	730	Tender expected
TotalEnergies	18 wells + 21 P&A wells as options	Namibia	Venus	Dec-2027	830	Award pending
TotalEnergies	18 wells + 21 P&A wells as options	Namibia	Venus	Feb-2028	830	Award pending

Data from CERA Upstream Solutions. Compiled Aug. 20, 2026.

Source: S&P Global Energy.

Although there are idle drillships in the Canary Islands that would be theoretically well-placed to pick up work in West Africa, these need reactivation (Valaris DS-11, DS-13 and DS-14) or likely to pick up other contracts (Noble Globetrotter I and West Carina).

Four marketed units are also due to leave West Africa in the coming months for contracts elsewhere. Stena DrillMAX is in the Canary Islands and could undertake work in West Africa before mobilizing to the Mediterranean in early 2027 for commitments. Noble Venturer will mobilize from Ghana to the US Gulf in 2027 after completing operations with Tullow Oil — hence Tullow's need for a replacement unit to carry on the development work at the Jubilee project from mid-2027.

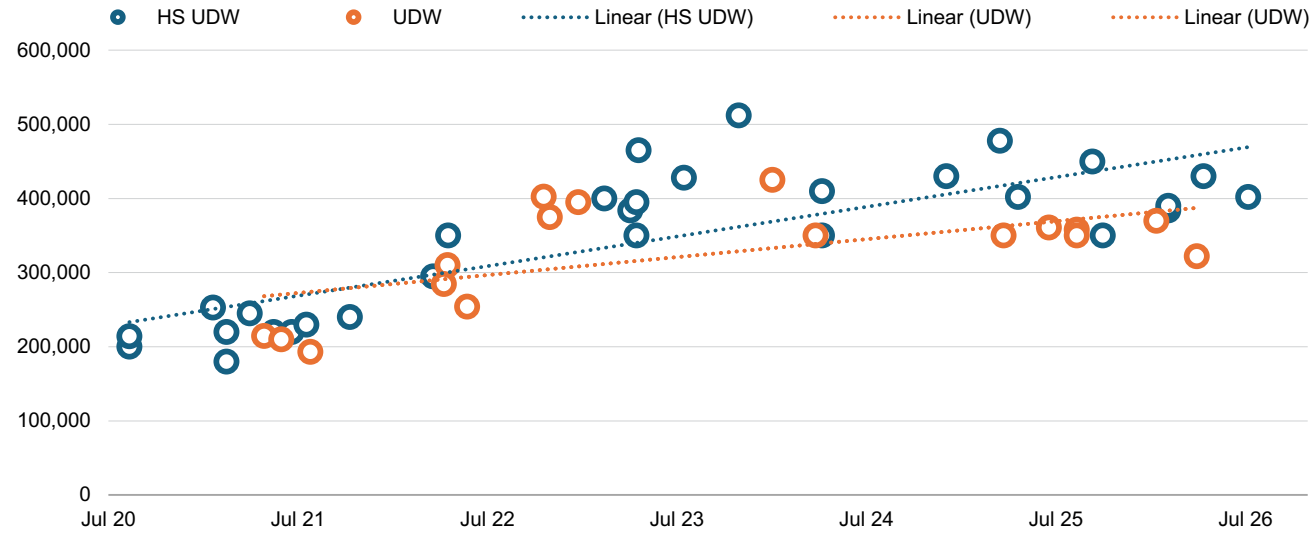
Deepwater Skyros will leave Cote d'Ivoire around fourth quarter 2026 to mobilize firstly to Singapore before commencing work with Chevron Australia in second quarter 2027. In addition, Saipem 12000 — currently with Azule Energy off Angola — will mobilize to Mozambique in late 2026 to start Eni's Coral North development work. This positions the rig well for other LNG-focused projects off Mozambique from the likes of TotalEnergies and ExxonMobil.

So, with an incumbent fleet that is already heavily committed and the likelihood of extensions with some current operators, the indications are that another three high-specification ultra-deepwater drillships could be on their way to West Africa to fill some of the requirements above. Particularly as areas such as the US Gulf are forecast to see a slight drop in demand in late 2026/early 2027, providing some availability opportunities.

The chart below shows rates for new mutual fixtures for both ultra-deepwater and high-specification ultra-deepwater floaters in West Africa since early 2020. The trend for both categories has been increasing, and it will be interesting to see if in the next batch of contract awards operators are still able to keep charter rates around the $400,000 mark or if the market has tightened globally to an extent that material changes to prices become a reality.

Demand in the jackup market remains steady but with adequate rig supply bordering on over-supply. The most recent demand forecast shows demand is expected to average 17 units over 2026, 17 over 2027 and 15 over 2028. Average marketed surplus over the period is expected to be 5 units over 2026 and 4 over 2027 and 6 over 2028. Nigeria remains the dominant source of demand, with Angola/Cabinda a distant second

West Africa fixture day rates for UDW and HS-UDW drillships 2020-26 ($)



Date from CERA Upstream Solutions. Compiled Aug. 20, 2026.
Source: S&P Global Energy.
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3.1.4 A view on recoverable reserves

Africa retains a substantial remaining hydrocarbon resource base of at least 161 billion boe, with approximately one-third located in North Africa. Remaining resources are concentrated within a relatively small number of countries and operator portfolios, underscoring both the scale of the opportunity and the concentration of future development activity.

Nigeria holds the largest remaining recoverable resource base, with more than 40 billion boe, followed by Algeria with approximately 27 billion boe. Other major resource holders include Libya, Angola and Egypt. Significant gas discoveries in Mozambique and recent exploration successes in Namibia have elevated both countries into the top tier of African resource holders. Mozambique's position reflects the scale of the offshore gas discoveries made over the past 15 years. However, only one LNG project is currently in production. Namibia's rise has been driven by a series of major offshore discoveries in the Orange Sub-basin since 2022, with first oil expected in 2030/2031.

The African resource base is broadly balanced between liquids and natural gas, although its distribution varies by region. The current perception is that East Africa's exploration potential is gas-focused due to the existing discoveries within the Rovuma Basin. West and Southern Africa have proven to offer a more balanced mix of oil and gas opportunities, supported by Nigeria, Angola, Gabon, Côte d'Ivoire, Congo, and Equatorial Guinea, as well as emerging developments in Namibia.

Around 70 billion boe of remaining recoverable resources are associated with producing assets, benefiting from existing infrastructure and established commercial pathways. A significant volume of the remainder (91 Bboe) is concentrated in undeveloped discoveries, particularly in Namibia, Mozambique, Tanzania, Uganda and Kenya, where commercialization will require investment in infrastructure, export routes and market access.

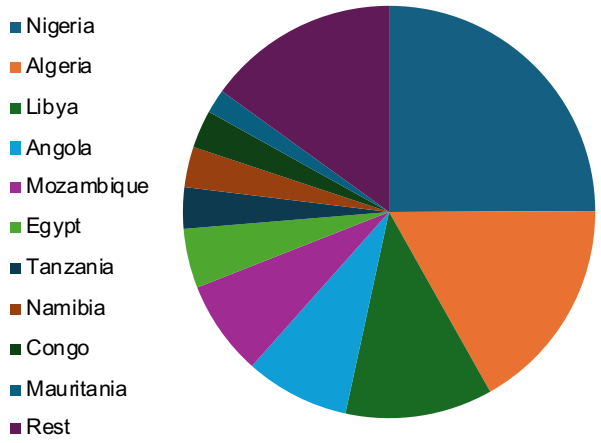
Among the international oil companies, TotalEnergies holds the largest remaining recoverable resource position in Africa, closely followed by ENI, with Chevron, Shell and ExxonMobil completing the top five. TotalEnergies' position is underpinned by its exposure to the large gas discoveries in Mozambique, the emerging offshore province in Namibia, and major East African developments. ENI's leading role is supported by its extensive position in Algeria, recent significant discoveries offshore Côte d'Ivoire, its operatorship of the Coral FLNG project in Mozambique, and its involvement in Azule Energy in Angola, one of the country's largest upstream operators.

A critical distinction within Africa's remaining resource base lies between volumes with clear commercialization pathways and those facing infrastructure, market, technical or above-ground constraints. Resources located near existing infrastructure and export routes typically have a higher likelihood of progressing into reserves and production. In contrast, many undeveloped discoveries, particularly gas resources, remain dependent on the development of markets, transportation infrastructure and supportive commercial frameworks.

While gas represents an increasing share of Africa's remaining resource opportunity, its commercialization is inherently more complex than that of oil. Successful gas developments require sufficient domestic or regional demand, access to pipeline markets or LNG export capacity, long-term sales agreements and significant investment in gathering, processing and transportation infrastructure. In addition, growing global LNG supply and increasing competition among exporting regions may constrain market opportunities for some African projects. As a result, gas developments generally face longer lead times, higher capital requirements and greater execution risk than comparable oil projects.

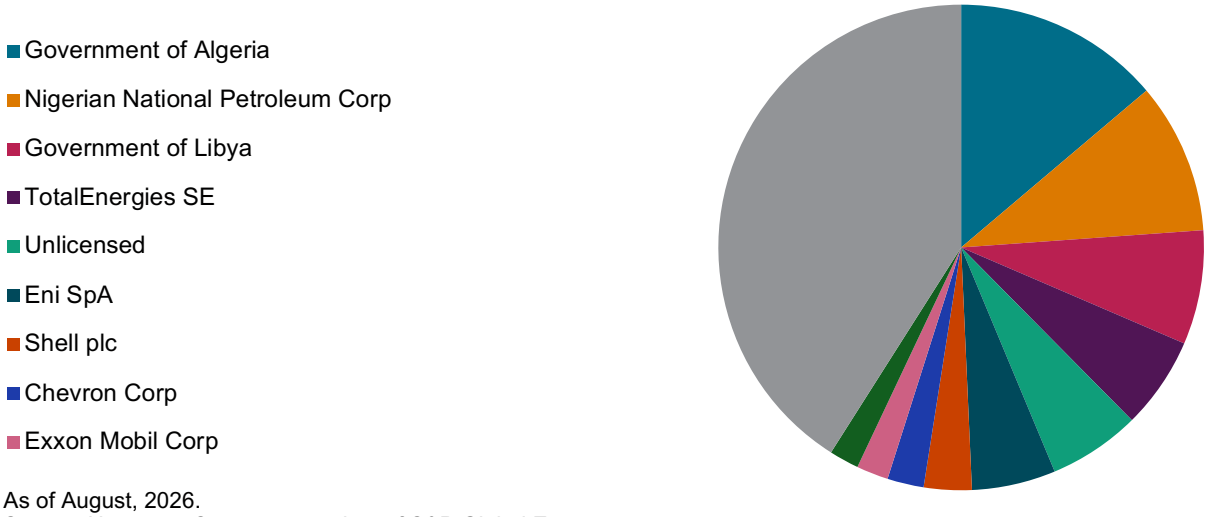
Overall, Africa's remaining recoverable resource base remains globally significant and offers substantial long-term growth potential. However, future value creation will depend less on resource scale alone and more on the ability to secure market access, develop competitive projects and overcome infrastructure, technical and above-ground constraints. The most attractive opportunities are therefore likely to emerge where large resource concentrations are supported by credible commercialization pathways, competitive development concepts and favorable investment conditions.

Africa Recoverable Resources (MMboe)



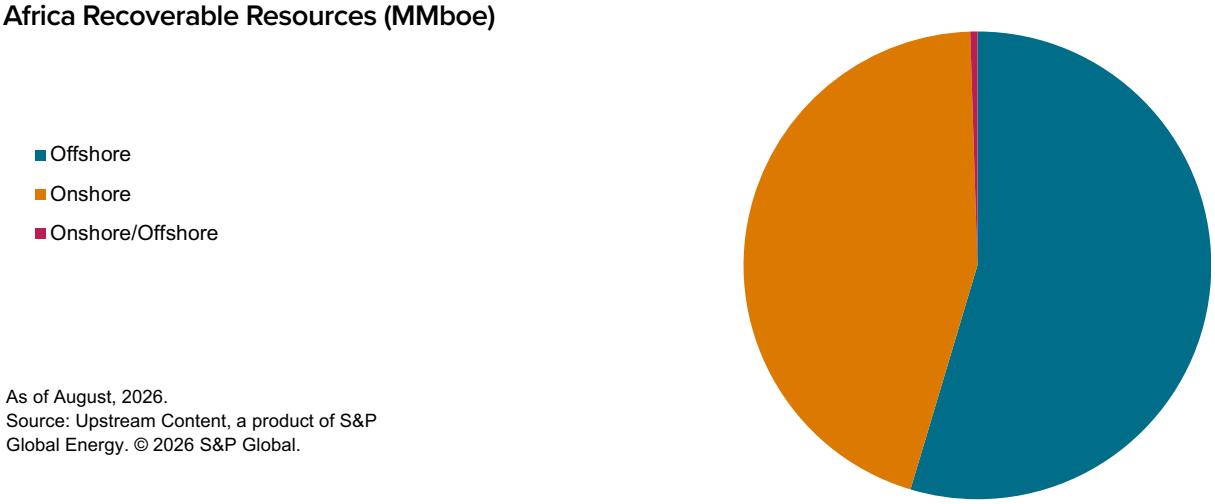
As of August, 2026.
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Africa Recoverable Resources (MMboe)



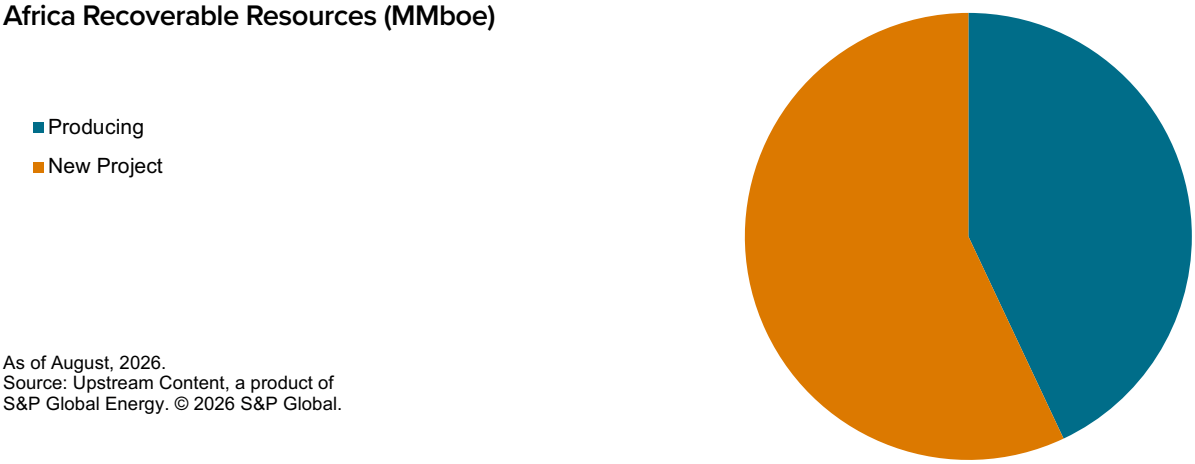
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Africa Recoverable Resources (MMboe)



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Africa Recoverable Resources (MMboe)



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3.2 Opportunities and investment competitiveness

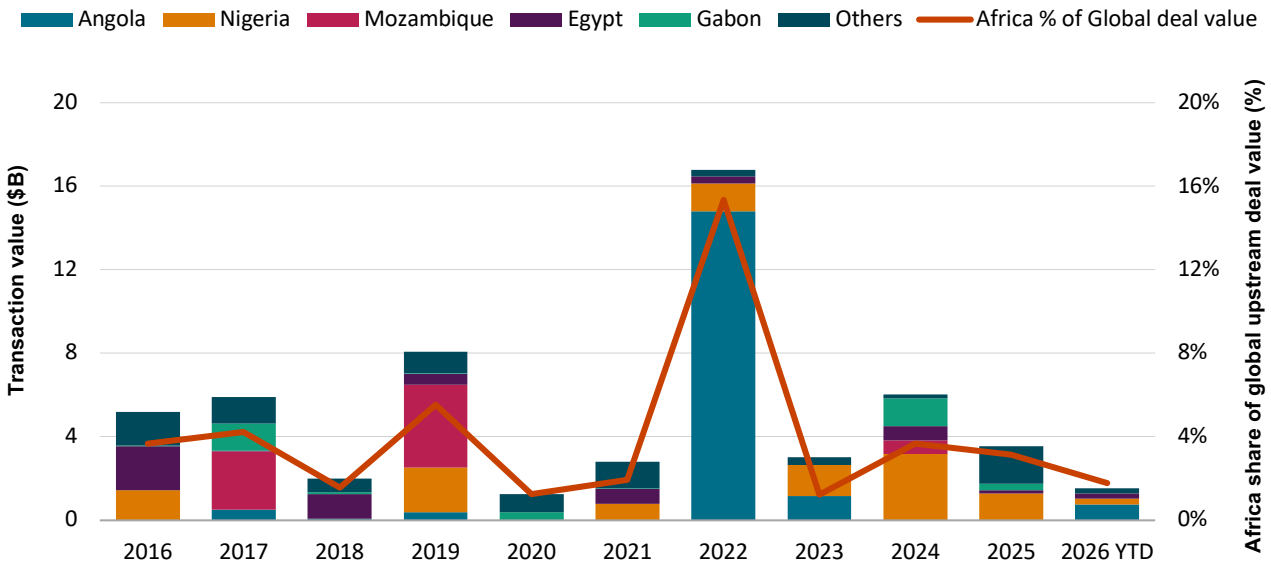
3.2.1. M&A transactions

Ownership is shifting toward selective growth and regional consolidation

African upstream ownership is diverging between mature asset consolidation and positioning around future growth opportunities. International operators are concentrating capital around core deepwater, gas and development-stage positions, while regional operators, indigenous companies and regional NOCs are expanding across producing assets with visible cash flow and established operating footprints.

Recent transaction activity points to a clear preference for assets that combine production, reserves visibility and a route to commercialization. Producing and development-stage assets continue to account for the lion's share of disclosed transaction value, while exploration-led positions are drawing capital through selective acreage entry and partnership-led structures rather than large outright acquisitions.

Africa upstream transaction value



West Africa remains the dominant sub-region of disclosed African upstream M&A value, accounting for two-thirds of transaction value in the last 10 years. Deal activity has been concentrated in Côte d'Ivoire, Nigeria, Angola and Gabon, although each market is attracting capital for different reasons. Côte d'Ivoire has gained prominence through development-led investment, Nigeria and Angola continue to generate activity from producing asset transfers and portfolio high-grading, while Gabon has seen greater state participation in asset ownership.

North Africa is becoming more relevant as licensing activity, gas-linked assets and brownfield redevelopment move back into the transaction discussion. Algeria and Libya have reopened acreage after long periods of limited access, while Egypt continues to combine infrastructure-led gas development with higher-impact Mediterranean exploration. In East Africa, Mozambique remains the sub-region's main transaction value driver, supported by LNG-linked gas developments and renewed project execution by major operators.

Regional operators are reshaping Africa's mature asset landscape

Portfolio rationalization by large international operators continues to create acquisition opportunities across Africa's mature producing basins. Regional independents, indigenous operators and NOCs have become more important buyers, particularly where assets offer production, reserves, operating history and greater control over future development activity.

Nigeria remains the clearest example of localisation in upstream ownership. Mature onshore and shallow-water assets have steadily moved from international operators to domestic and regional buyers, with acquisitions involving Renaissance, Seplat Energy, Heirs Energies, Chappal Energies and NNPC highlighting the shift toward African-led ownership of producing assets. Beyond reserve additions, these transactions provide access to infrastructure, gas value chains and established operating positions, supporting the emergence of larger regional upstream platforms.

At the same time, recent reforms aimed at improving deepwater project economics could broaden Nigeria's transaction landscape beyond mature asset consolidation. Greater fiscal clarity and a more standardized framework for offshore developments may improve the competitiveness of undeveloped deepwater resources, supporting future partner entry, project financing and portfolio transactions around development-stage assets.

Angola presents a different transaction profile. Mature offshore assets continue to attract buyers focused on field-life extension and incremental production, while the country is also drawing renewed interest in deepwater and ultra-deepwater acreage. This gives Angola one of the broader M&A opportunity sets in Africa, spanning both near-term producing assets and longer-cycle exploration-led growth positions.

Gabon reflects a stronger state-backed consolidation angle. Gabon Oil Company's acquisition of Tullow's assets strengthens national ownership of producing resources and increases domestic participation in future cash flow. Similar approaches are becoming more visible across parts of Africa as governments seek a more active role in upstream portfolio management and resource development.

Côte d'Ivoire highlights a different form of portfolio repositioning. Recent activity has focused less on mature asset transfers and more on development-stage projects, where new capital can accelerate execution while operators retain exposure to future growth. As more African discoveries move toward development, similar partner-led transactions could become a larger share of regional M&A activity.

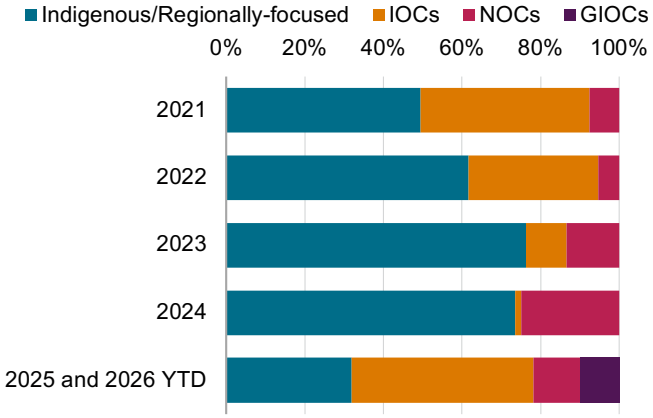
Is global capital returning to selected African basins?

Recent transactions and licensing activity points to a selective return of global capital rather than a broad retreat from Africa. International operators are becoming increasingly selective in Africa, concentrating capital into fewer positions with larger resource potential, stronger gas exposure and clearer long-term reserve replacement value.

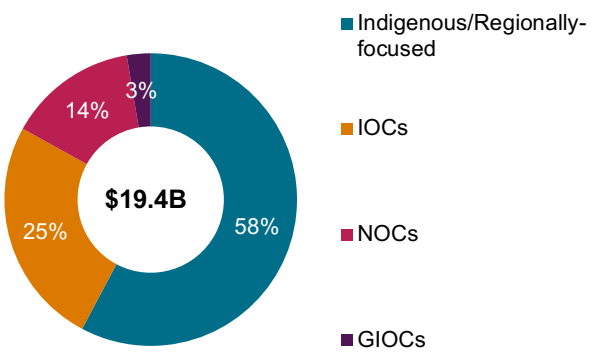
Algeria and Libya are the clearest examples. Algeria's latest licensing round attracted participation from Eni, TotalEnergies, Sinopec and QatarEnergy, while Libya's first bid round since 2007 secured commitments from Chevron, Eni, QatarEnergy and Repsol. The participation of both global majors and international NOCs in acreage that had been largely unavailable for years points to renewed competition for African exploration access where governments improve commercial terms and reopen material acreage.

The re-entry theme extends beyond North Africa. Shell has re-established positions in offshore Gabon and Angola, while ExxonMobil, Chevron and other international oper-

Segmentation of buyers



Total Segmentation of buyers during 2021-2026 YTD



ators have expanded activity across selected deepwater and frontier opportunities. Much of this capital is being directed toward basin entry, appraisal programmes and emerging hydrocarbon provinces rather than mature producing asset acquisitions.

Licensing awards and frontier acreage are becoming an important source of future transaction activity. These positions often begin as acreage entry or technical evaluation, but can later generate farm-downs, partner entries, carried funding and portfolio realignment as assets move toward appraisal and development. A larger share of future African M&A could therefore originate from newly opened acreage and emerging resource plays rather than traditional producing asset transfers.

Capital access is emerging as the new transaction filter
Capital availability is becoming a larger determinant of African upstream transaction activity. Asset availability remains strong, but many buyers face constraints around acquisition funding, development obligations and country risk. This is increasing the importance of transaction structures and alternative sources of capital.

Commodity traders are becoming more visible in upstream financing through acquisition funding, prepayment arrangements and direct equity participation. The Vitol-Eni transaction illustrates how traders are moving beyond traditional offtake relationships to secure long-term supply exposure and participate directly in development-stage assets. For operators, these structures provide another source of funding while preserving flexibility around portfolio decisions.

Farm-ins, carried interests and phased capital commitments are also becoming more common across frontier and development-stage assets. Operators are increasingly introducing partners to share appraisal costs, fund development obligations and manage project risk rather than transferring ownership through outright sales. Namibia's ownership restructuring around the Mopane discovery highlights how equity adjustments and carried funding can reduce capital exposure while preserving upside ahead of major development decisions.

Similar structures are likely to become relevant across Angola, Gabon, Liberia, Morocco and other Atlantic Margin opportunities, where resource potential is significant but capital requirements remain substantial. In many cases, the transaction challenge is not access to acreage, but access to development capital.

Traders, strategic investors, farm-in partners and well-capitalized NOCs are becoming more important participants in this environment. Their involvement creates additional funding options for operators and alternative routes for ownership change across both producing and development-stage assets.

Outlook: Where ownership could move next

Africa's next upstream M&A cycle is likely to be shaped less by broad portfolio exits and more by the need to fund assets progressing from acreage capture, discovery and appraisal toward commercial development.

Mature producing assets will remain part of the opportunity set, particularly where regional operators and NOCs can build scale around established producing portfolios. However, the more strategic ownership shifts are likely to emerge in assets that require capital, technical partners or commercial structuring before development. Algeria and Libya have reopened material acreage after long periods of limited access, Namibia continues to move from discovery toward development planning, and the Atlantic Margin remains an important source of frontier exposure.

Capital is moving toward assets with clearer routes to monetisation. Gas resources linked to LNG, domestic demand, existing processing infrastructure or export systems should attract stronger competition than standalone discoveries requiring new infrastructure. This is particularly relevant for North Africa, West Africa and selected LNG-linked markets, where infrastructure access and commercial offtake can materially improve transaction quality.

The competitive landscape is widening beyond traditional E&P buyers. Regional operators and NOCs remain natural buyers of producing assets, while global majors are focusing on selective deepwater, gas and exploration-led positions. Traders, infrastructure-linked investors and strategic capital providers are becoming more relevant where development funding is the main constraint.

The strongest opportunities for E&P companies are likely to sit in three areas: infrastructure-backed producing assets, gas-linked resources with visible commercialisation routes and frontier or recently licensed acreage where early entry can secure exposure before competition broadens. The next phase of African upstream M&A is likely to be defined less by access to assets and more by access to capital, commercialisation pathways and development partners, particularly across gas developments, frontier acreage and recently reopened basins.

3.2.2. Ongoing and planned licensing rounds

Africa's licensing landscape has shifted significantly since 2024, as host countries adapt to renewed upstream investor interest.

Major IOCs have turned their strategic focus from energy transition to resource security and diversity, and are refilling their exploration hoppers with frontier acreage in search of material liquids discoveries.

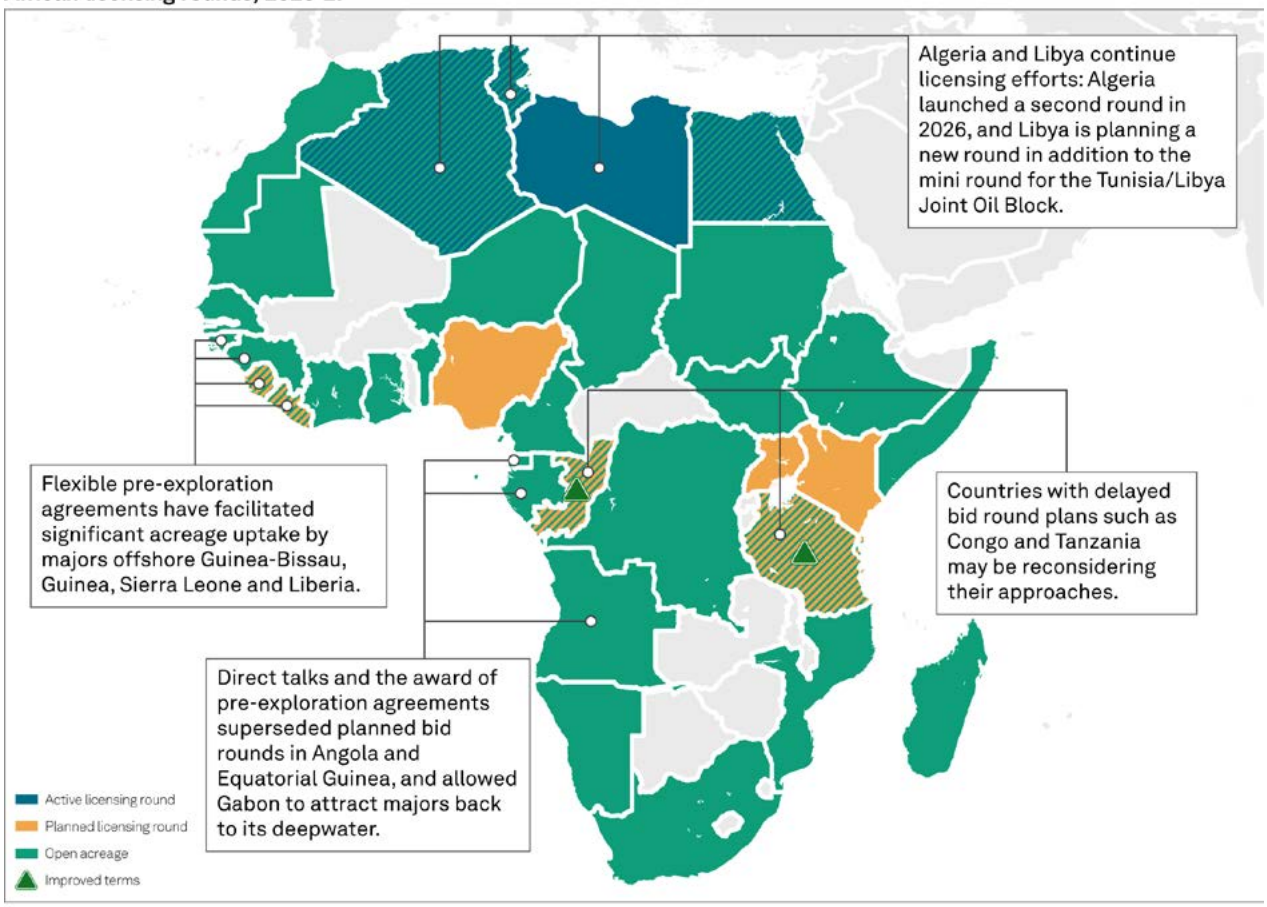
In 2025, two-thirds of the deepwater acreage captured globally was in Africa. The Atlantic Margin play was the focus, with IOCs allocating over 200,000 sq km in the area in 2025, up from 30,000 sq km in 2024.

Most of this new acreage has been offered via MoUs, TEAs and reconnaissance permits along West Africa's Atlantic Margin, as host countries move to harness renewed IOC interest by offering improved contractual flexibility and quicker access to below-ground, technology-driven pre-drill risk assessment.

That said, some countries have persevered with bid rounds, albeit with mixed success. Nigeria has maintained a high pace of licensing rounds since 2022, with two rounds completed and a new round planned for 2026. The authorities announced the awards from its 2025 licensing round in July 2026: a total of 37 blocks across deepwater, shallow and onshore frontier acreage were awarded predominantly to Nigerian companies, with Chevron receiving the only deepwater block, as the only IOC awarded a block. São Tomé and Príncipe, meanwhile, launched a fast-track bid round in mid-2026 but rejected all proposals for the blocks on offer, citing a lack of potential new investors for its competitive landscape.

In North Africa, bid rounds still play an important role for major producers, with Egypt actively seeking investment with a new round alongside tenders from Algeria and Libya.

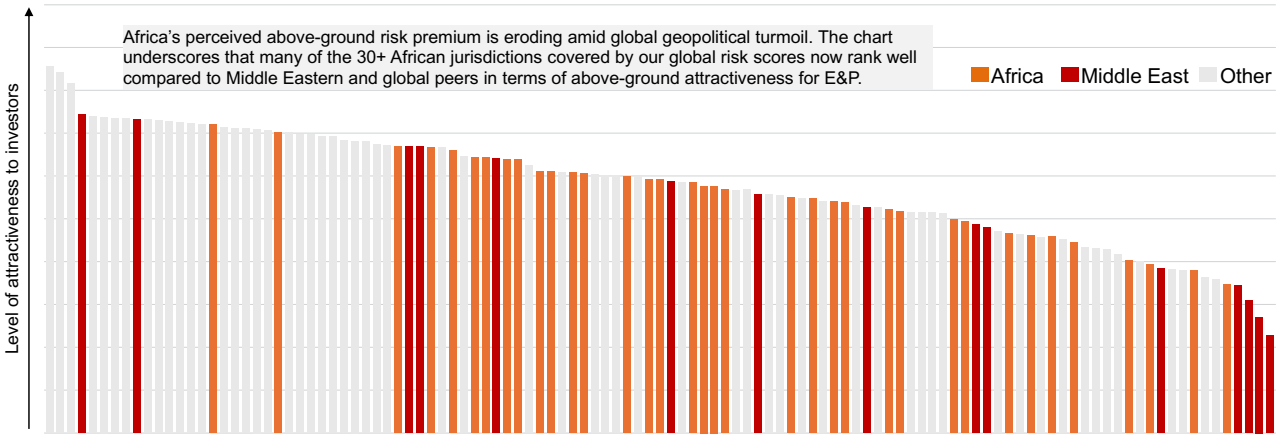
African licensing rounds, 2026-27



Data compiled Aug. 12, 2026.
Sources: S&P Global Energy; 263828-01.
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3.2.3 E&P Above-ground Attractiveness

Oil and Gas Risk scores: Benchmarking African countries against Middle Eastern and global peers



As of August, 2026.
Source: S&P Global Energy.
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Competition for E&P capital is rising as African countries seek to capture intensifying IOC interest. Above-ground attractiveness will be a principal host country differentiator amid global geopolitical turmoil, and Africa's perceived relative investment risk premium is reducing as other regions face instability and policy volatility.

At the same time, major IOCs are restocking their exploration acreage portfolios, prioritizing frontier areas along the Atlantic Margin that could yield material liquids discoveries producing lower-cost, quicker-to-market "advantaged" barrels.

Key above-ground trends to watch:

Pre-contract agreements dominate frontier licensing: Ease of access is a strategic focus across Africa, with pre-contract agreements increasingly favored over bid rounds. These agreements better address investor concerns about the longer timelines, high costs and lower success rates of deepwater exploration than lengthier, admin-heavy bid rounds.

The pre-exploration agreements have allowed frontier countries such as Sierra Leone and Guinea to attract major investors such as Eni and Shell for the first time, while mature producers with frontier areas (such as Angola and Gabon) have also used them to tempt majors back (such as Shell, ExxonMobil and BP).

Pre-exploration agreements have usurped bid rounds in some cases, with Equatorial Guinea and Angola recently cancelling or scaling back planned deepwater tenders after prime acreage was allocated via preliminary agreements instead.

To capture IOC interest, most African countries are offering more attractive fiscal and contractual terms: Mature producers are pushing for more comprehensive investor-friendly reforms via hydrocarbon code revisions, including resource and terrain specific terms and incentives. Frontiers — and mature producers with frontier areas — are offering enhanced flexibility and reduced signature bonuses.

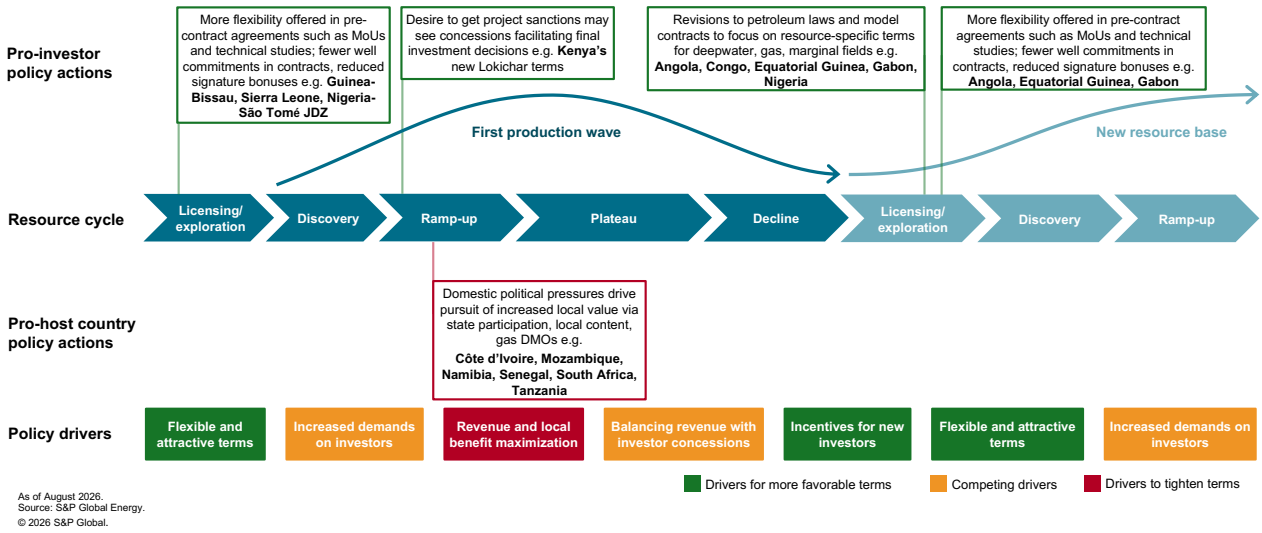
Emerging producers buck the trend of easing terms: By contrast, Africa's emerging producers are bucking the trend of easing terms, seeking instead to maximize revenue gains and economic development. Emerging producers occupy a key inflection point in the resource curve, as governments often reappraise E&P policies and contractual approaches to fully harness benefits derived from the sector as production approaches and ramps up.

In 2027, new local content laws, enhanced state participation and extended domestic market obligations (particularly for gas) will come to the fore in countries such as Mozambique, Namibia, Senegal and South Africa, posing commercial, compliance and contract sanctity risks to foreign investors.

Government decision-making remains critical for E&P: Government decision-making will heavily influence upcoming major E&P project progress. Key operator decisions on global-scale developments, such as Rovuma LNG (Mozambique), Tanzania LNG and Venus (Namibia), will be significantly influenced by security, contractual and regulatory choices made by host governments.

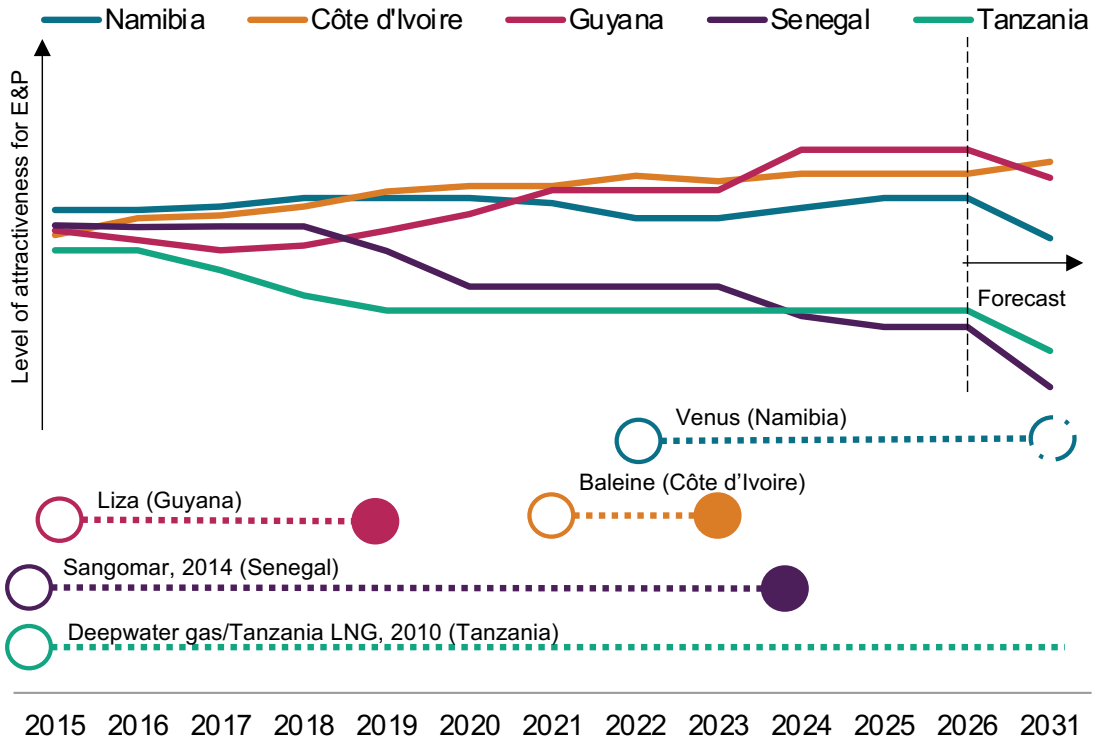
Amid institutional, regulatory and contractual changes, TotalEnergies' sanctioning of Venus will be particularly closely watched as an endorsement of Namibia's hydrocarbon sector governance, and as a signpost for unlocking the Orange Sub-basin's vast production potential. Namibian authorities are eager to avoid the above-ground hurdles that have delayed other major African deepwater projects (see chart).

Resource curve defines host country terms: Emerging producers seek enhanced benefits while mature host governments offer pragmatic incentives



As of August 2026.
Source: S&P Global Energy.
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Oil & Gas Risk: Evolution of scores for Hydrocarbon Sector Operations for Namibia and deep offshore peers



As of September 2026.

The risk factor category Hydrocarbon Sector Operations include: Sanctity of Contract, Regulatory Burden, Civil Society Risk, Corruption, Rule of Law.

The discoveries noted are the first significant projects for the respective host countries.

Source: S&P Global Energy.

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Discovery
First production
Expected first production

Case studies:

Angola: Incentives drive more upstream investment

Angola's expanding, region-leading suite of fiscal incentives continues to drive new upstream investment, by promoting development of discovered but undeveloped reserves (marginal, mature and gas fields) and to facilitate the discovery of additional resources close to existing infrastructure.

The 2018 marginal field terms were particularly significant, as their broad applicability made them a de facto tax cut for deepwater oil. The 2024 Incremental Production decree, meanwhile, was a vital investment facilitator at Angola's maturing fields; S&P Global Vantage analysis shows that approximately 50% of Angola's production now comes from assets with 80% of the recoverable volumes already produced, and eight of Angola's 10 largest fields have produced at least 70% of their recoverable volumes.

Aside from incentives for existing resources and production areas, contractual terms for frontier E&P in the Namibe and Kwanza Basins have also been made more competitive. Recent frontier contracts and evaluation agreements signed with ExxonMobil, Shell and TotalEnergies underscore the effectiveness of reforms in bolstering commerciality as IOCs extend the Atlantic Margin play in search of material liquids discoveries.

Angola: Selected key legal and fiscal reforms

Decrees 211/15 and 5/18: Exploration activities inside existing development areas
- Facilitated near-field exploration and improved cost recovery at key hubs such as Blocks 14 and 17. Improved 2018 terms led to discoveries such as Bavuca South and Likembe in ExxonMobil's Block 15.

Decrees 2/16 and 6/18: Marginal field terms
- Expanded 2016 incentives; reduced tax rates and improved cost recovery; broad applicability (reserves/IRR) for most new deepwater projects; applied to TE's Kaminho and Chissonga and Azule's PAJ, among others.

Decree 7/18: Natural Gas Framework Law
- Conferred ownership of gas resources to foreign investors; reduced tax and royalty rates and boosted cost recovery; applied to Blocks 0, 1, 2, 3 and 15/14 for ALNG backfill and a possible new FLNG project in Block 24.

Decree 49/19: Established ANPG as new standalone regulator
- Removed regulatory and concessionaire duties from Sonangol.

Decrees 52/19 and 249/21: Licensing rounds strategy 2019-2025 and permanent offer system
- Established a hybrid licensing strategy; 41 blocks awarded of 55 offered.

Decree 8/24: Incremental Production
- Reduced taxes and higher cost recovery for mature fields; applied to TE's Block 17 and ExxonMobil's Block 15; Equinor also considering new projects.

Additional actions:
Ad-hoc PSC renegotiations; Gas Master Plan (GMP)
- Multiple PSCs for maturing fields revised; frontier contracts in Kwanza and Namibe Basins made more attractive; GMP to boost monetization.

As of August 2026
IRR = Internal rate of return; TE = TotalEnergies; ALNG = Angola LNG; ANPG = National Oil and Gas Agency (Agência Nacional de Petróleos e Gás); FLNG = floating LNG; PSC = Production sharing contract.
Source: S&P Global Energy.
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Domestic and international power dynamics will shape Africa's E&P investment landscape: More turbulent and unpredictable global geopolitics will increasingly affect Africa, as countries seek to balance commercial and political relations with China, Russia, the US and Middle Eastern governments. Global fragmentation calls for intergovernmental collaboration on E&P, infrastructure, regulation and financing, to insulate Africa from international volatility. But tangible delivery beyond rhetoric remains a challenge, with ambitious cooperative initiatives and projects such as the African Energy Bank, the African Petroleum Regulators Forum (AFRIPERF) and the African Atlantic Gas Pipeline (AAGP) likely to be closely watched as signposts for cross-border success.

Gabon: TEAs refresh flagging sector as IOCs return

Gabon has recently reversed a trend of upstream investor disinterest in its underexplored, high-potential deep offshore, by tempting back major IOCs that had largely exited the country amid declining production

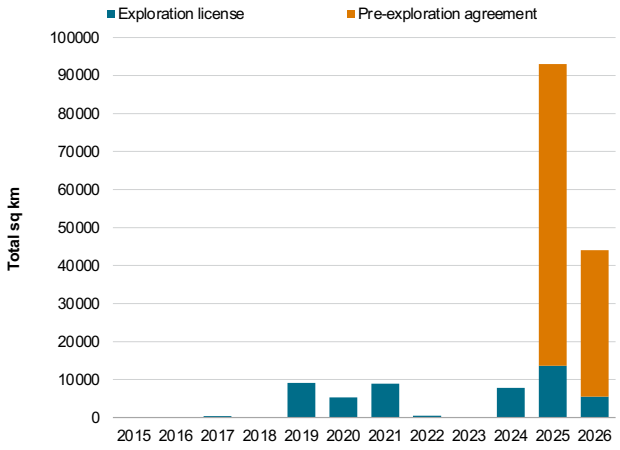
Successive deepwater bid rounds in 2015 and 2018 failed to draw investor interest; none of the five blocks offered in 2015 were awarded and the 2018 round awarded two blocks from 35 offered. A revised 2019 Petroleum Code did improve interest in shallower areas, but terms were not sufficiently attractive to capture frontier deepwater interest.

Gabon's decision to offer deepwater Technical Evaluation Agreements (TEAs) from 2025, combined with the promise of further improved terms in a revised Petroleum Code, dramatically boosted investor engagement amid revived interest in the broader Atlantic Margin play.

In October 2025, BP was awarded a TEA for 10 blocks in the North Gabon Sub-basin, while ExxonMobil received 15 blocks in an area straddling the South Gabon Sub-basin and the Lower Congo Basin. In June 2026 Shell signed a TEA for 8 deepwater blocks in the Gabon Coastal Basin.

The TEAs offered the IOCs preferential access to the acreage should they solidify their interest, with authorities expecting firm related production sharing contracts to be signed in the second half of 2026. The updated Petroleum Code has not yet been passed but should TEA signatories sign contracts they are likely to benefit from tailored deepwater fiscal terms, reduced state participation and the removal of signature bonuses.

Gabon: Recent TEAs significantly boost acreage capture



Data compiled August 2026.
Data from CERA Upstream Solutions.
Source: S&P Global Energy.
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Mozambique: New laws toughen E&P investment environment

In June 2026, Mozambique has passed an updated petroleum law and a first stand-alone local content law. The petroleum law stipulates a minimum state equity share of 15%, while mandating domestic hydrocarbon supply. The local content law mandates training and employment of Mozambicans and prioritizes Mozambican suppliers and products, while establishing a central Local Content Authority to enforce regulations.

The applicability of both laws to existing contracts and projects is uncertain. A strong stabilization clause in the 2014 LNG Decree Law appears to protect existing projects from certain legal changes, while the new Petroleum Law also appears to protect existing contractual rights — but with exceptions. The new Local Content Law, meanwhile, appears intended to supplement current regulations, which could increase the regulatory burden on ongoing and planned projects and/or spark disputes if the government seeks to fully impose it on existing contracts.

The new laws will boost domestic benefits from the hydrocarbon sector but will also likely increase costs, compliance burden and regulatory uncertainty for foreign E&P companies undertaking new projects. The laws may also impact existing and planned LNG projects, depending on the degree of retroactivity, which may be clarified by pending implementing legislation. Even if they are retroactive, the laws are unlikely to materially undermine LNG project economics or significantly slow development timelines for existing projects.

Namibia: Investment uncertainty lingers amid institutional and legislative changes

Namibia's government is progressing multiple strands of new and updated legislation intended to revise and solidify the country's regulatory and investment frameworks ahead of rapid projected E&P sector growth, which could propel the country from non-producer now to 400,000 b/d by 2035.

However, delays to the passage of the Petroleum Amendment Bill raise the risk of knock-on delays to key approvals for upstream projects. The bill has been slowed amid parliamentary debates over controversial plans to centralize decision-making under presidential oversight with the new Upstream Petroleum Unit (UPU). The UPU is intended to streamline decision-making and expedite projects, but its implementation before parliamentary approval could have the opposite effect. More positively, implementation of a new local content law is nearing, with Namibia's cabinet approving the policy in mid-August 2026. This will boost local participation and benefits but will also increase the regulatory burden on foreign investors.

More broadly, legislative and regulatory updates are sustaining uncertainty for existing and potential E&P investors at a critical time, with key issues such as licensing processes, M&A approvals, local content guidelines, fiscal stabilization clauses, access to arbitration, company ownership rules and foreign exchange limits all in flux.

Nigeria: Post-PIA investment drive brings results

Following the enactment of the long-awaited Petroleum Industry Act (PIA) in 2021, Nigeria has offered additional E&P incentives through executive orders since early 2024, to support ambitious output targets of 3 million b/d and 10 Bcf/d by 2030. Three significant projects have since reached final investment decisions, with the 110,000-b/d deepwater Bonga North project the most critical of those sanctioned in terms of long-term production impact.

While the additional incentives contributed to improving project economics, their sanctioning is likely also the outcome of a combination of additional factors: a more structured hydrocarbon sector framework, a more investor-attuned administration, as well as changing company strategies amid a global shift from energy transition to energy addition.

Notably, two out of the three sanctioned projects will produce non-associated gas, and are set to supply feedstock to the Nigeria LNG plant, underlining that LNG exports remain the more attractive option for operators ahead of domestic supply. The PIA introduced a more transparent domestic gas price structure, but prices remain at the same level as in the 2010s, undermining the government's ambition for greater domestic use of natural gas.

In parallel with incentives, the government's push toward unlocking increased production and new projects has contributed to settling long-running disputes over contractual terms and corruption allegations, and paving the way for renewal of key licenses, such as the Bonga development, Agbami and Egina in 2021/22, and OPL 245 with the Etan/Zabazaba fields in 2026.

Illustrating gathering momentum amid the government's sustained engagement efforts, Shell's FID on the long-delayed $20 billion, 150,000-b/d Bonga Southwest Aparo (BSWA) project also now appears imminent following settlement of contractual disputes and the introduction of new fiscal incentives in 2026, including an enhanced production tax credit.

Nigeria: Selected key legal and fiscal reforms

August 2021: The Petroleum Industry Act (PIA) is enacted
- Streamlined the hydrocarbon sector framework; created new upstream regulator; restructured the NOC; eased royalty terms for deepwater and gas

February 2024: President Tinubu issued upstream Executive Orders
- Introduced tax credits for non-associated gas for onshore and shallow water greenfield developments; directed streamlining of the contracting process to reduce the contracting cycle to six months. The order also directed the formulation of deepwater incentives for crude and NAG.
→ Contributed to FID on the Ubeta (2024) and HI (2025) onshore/shallow water NAG projects, and the Bonga North (2024) deepwater oil project.

May 2024: NUPRC introduced revised licensing round terms
- Signature bonus structure setting maximum levels, with separate amounts for onshore/shallow water and deepwater.

October 2024: Ministry of Finance issued Notice (based on the February Executive Order) on deepwater tax credits

May 2025: President Tinubu issued Executive Order on tax credits for operating cost efficiencies

August 2026: President Tinubu issued Executive Order on production tax credits for deepwater projects
- The incentives apply to greenfield oil and NAG projects. Eligible projects (if FID is taken before Dec. 31, 2029) include: Bonga Southwest Aparo, Owowo, Zabazaba/Etan, Preowei

Additional and pending actions
- Implementation of NNPCL's 2026 Gas Master Plan.

As of August 2026.
FID = final investment decision; NAG = non-associated gas; NNPCL = Nigerian National Petroleum Company Limited; NOC = national oil company; NUPRC = Nigerian Upstream Petroleum Regulatory Commission.
Source: S&P Global Energy.
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3.3 Major project outlook and cost environment

3.3.1 African Frontier Basins Outlook

Since the start of 2021, 47 wells in Africa have been tagged as High Impact Wells (HIWs). A HIW is defined as a well that may have a significant commercial or geological impact on a global scale.

To qualify as a HIW, a well must:

- target potential recoverable resources in excess of 250 MMboe, or
- serve as a play/basin opener, or
- or meet another specific criterion, such as being part of an unconventional evaluation.

Of these, 18 have resulted in discoveries — a technical success ratio of almost 40%. The bulk of these discoveries have been in the Namibian portion of the Orange Sub-basin, which skews the results positively. Considering high-impact exploration in Africa, excluding Namibia, the success ratio falls to 25%. Conversely, when looking only at the Namibian portion of the Orange Sub-basin, the technical success ratio exceeds 70%. For this reason, exploration excitement shifts to frontier–immature basins once initial discoveries are made. In a frontier basin or frontier plays within a more mature basin, the geological risk, or at least its perception of that risk is significantly reduced after the initial discoveries are made. This inevitably leads to a flood of interest and a significant uptick in exploration activity. While this phenomenon is common, those entering a basin or targeting a new play have a significant competitive advantage and stand to benefit from holding sweet-spot acreage, especially if the entry strategy includes a large acreage position. These early movers likely also benefit from better fiscal terms than those granted to entrants after discoveries have been made.

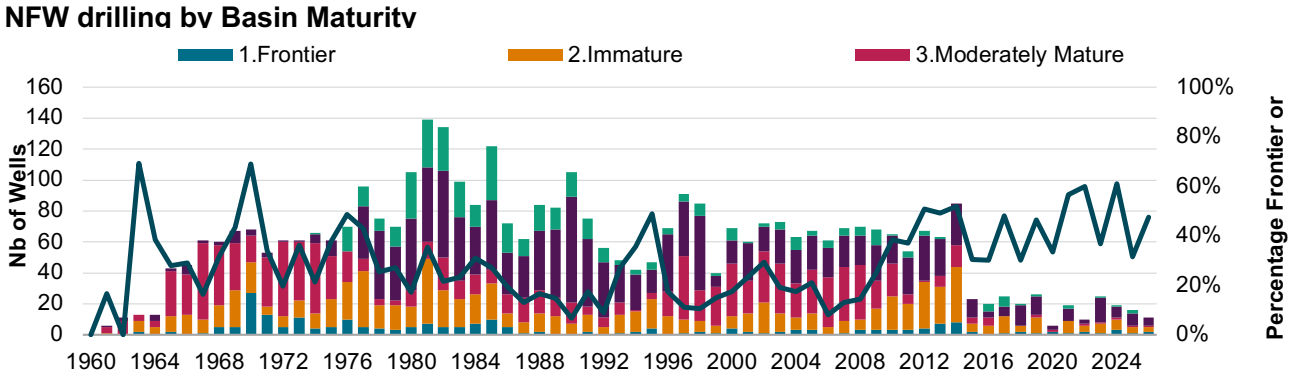
It is against this backdrop that the 11.7 Bboe discovered between 2021 and August 2026 highlights the significance of frontier and immature basins. Of this, some 8.3 Bboe resulted from high-impact exploration within frontier or immature basins. The largest contributors are the Namibian portion of the Orange Sub-basin and the Côte d'Ivoire portion of the Côte d'Ivoire–Tano Basin (both provinces yielded additional discoveries in 2026, adding some 500 MMboe of recoverable resources).

It is Africa's frontiers that are driving resource additions and that's the reason the continent is drawing so much attention from explorers. Africa continues to offer up new frontiers, all of which may draw exploration capital. Places to keep an eye on are the ultra-deep-water portion of the Congo Fan in Angola, the Gabon–Douala Deep Sea Basin offshore Equatorial Guinea and São Tomé and Príncipe, the Namibe Basin in Namibia and Angola, the M.S.G.B.C. Basin (Senegal-Mauritania-Guinea-Bissau-Conakry), the Herodotus Basin offshore Egypt, the offshore portion of the Sirte Basin and the Somali Basin.

There have been high-profile disappointments like Eni and BP's Matsola-1, but the well confirmed elements of a working petroleum system and provided valuable calibration data for follow-on prospects across Libya's underexplored deepwater Sirte Basin. Offshore São Tomé and Príncipe, Shell drilled the Falcao-1X well four years after Jaca-1X established the existence of a working petroleum system in the frontier Gabon–Douala Deep Sea Basin. However, this second probe did not confirm the presence of hydrocarbons west of Jaca-1X.

Others that have already played host to exploration cycles may present significant opportunities in a similar fashion to the Côte d'Ivoire–Tano Basin. One example is the M.S.G.B.C. Basin, where over 9.5 Bboe was discovered between 2014 and 2019, but is still viewed as immature in terms of exploration.

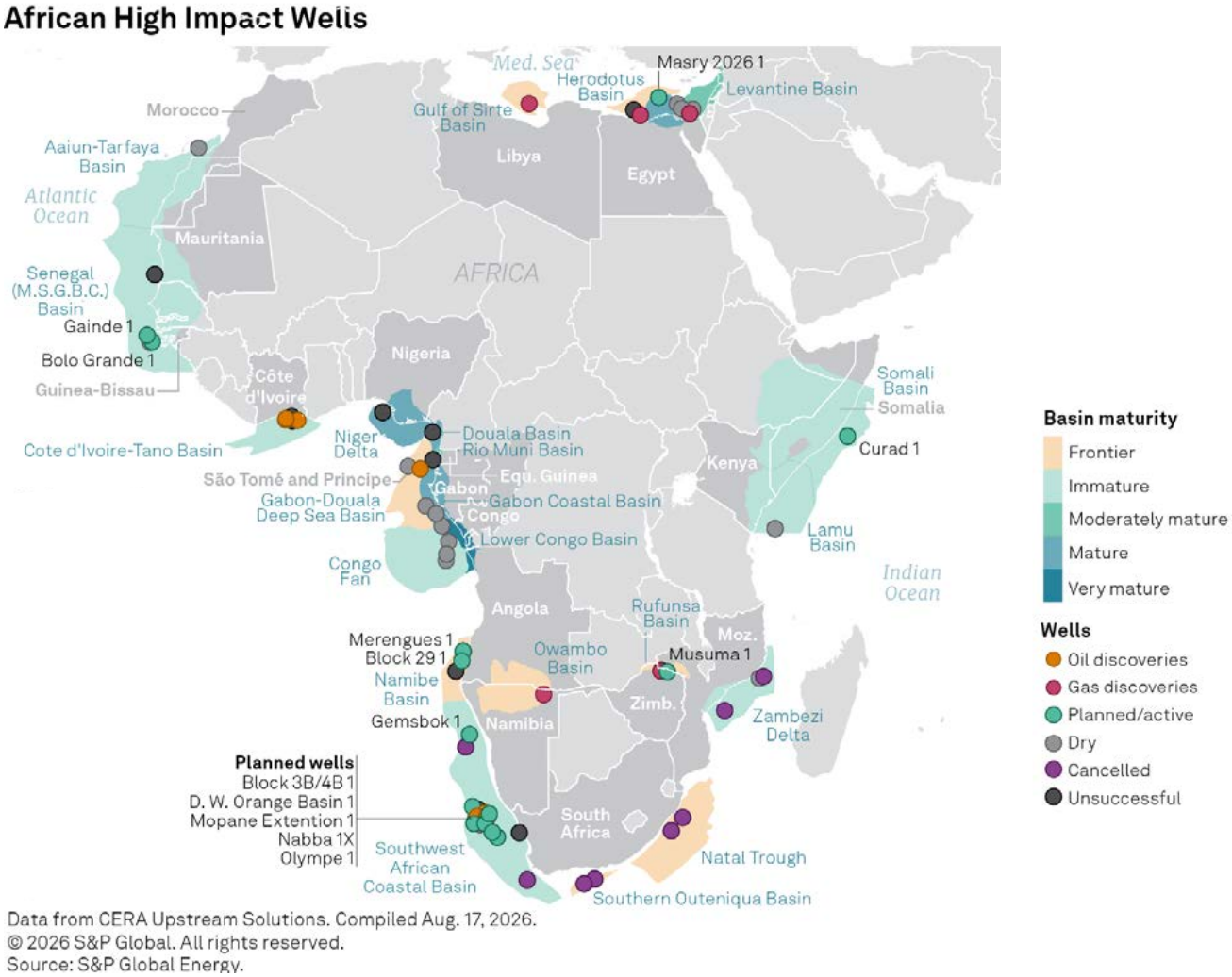
Offshore exploration drilling trends in Africa



Data compiled August 2026 .
Source: S&P Global Energy
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The shift to frontier and immature basins, underway since 2008, was briefly interrupted by the 2014/2015 oil price crash but has since resumed.

Exploration hotspots



Data from CERA Upstream Solutions. Compiled Aug. 17, 2026.
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Source: S&P Global Energy.

Spotlight on high-impact exploration

Namibia

Perhaps the most prominent high-impact exploration location in Africa since 2021 is the Namibian portion of the Orange Sub-basin. In less than five years, just over 6.3 Bboe have been discovered. TotalEnergies, Shell, Galp and Rhino Resources have all been successful. However, there are challenges. TotalEnergies has raised concerns related to reservoir quality and higher-than-expected gas-to-oil ratios but ultimately, the company is expected to move forward with the Venus development. TotalEnergies the new operator of PEL 83 and intern the Mopane complex will conduct an extensive appraisal and exploration campaign aimed at tightening up resource numbers and progressing towards a final investment decision. Shell has also released positive new after the completion of the Merlin 1X well describing it as its most its most promising subsurface result to date within the license. Rhino Resources and its partner, Azule Energy, have also recorded further success at the Volans discovery.

As of early September 2026, two high-impact wells are expected to be spudded before the end of the year. TotalEnergies is expected to drill the Mopane Extension 1 located within Blocks 2813A, 2814B (PEL 83), the well will test and extend to the east of the Mopane complex. The other well to be drilled in 2026 will be the Chevron-operated Nabba 1X within Block 2813B (PEL 90). Equinor has farmed into the block and is therefore expected to participate in the well. This will be Chevron's second well in the block, following the unsuccessful Kapana well drilled in late 2024. While both wells are considered high impact, Nabba-1X is likely to attract greater attention.

Beyond that, 2027 is set to host to Chevron's Walvis Sub-basin well targeting the Gemsbok prospect Block 2112B and Block 2212A (PEL 82). The well is highly impactful for several reasons, including the targeted resource. But perhaps the most important reason is that it has the potential to establish the first commercial discovery within the basin. The 2013 Wingat-1 well resulted in a technical discovery and hence was the basin-opening discovery; however, it was non-commercial. That said it proved a working petroleum system. All eyes will be on this well, which has particular significance for BP. BP picked up 3 blocks that flank PEL 82, a discovery by Chevron would go a long way to validating the acreage position.

South Africa

In 2027, exploration activity is expected to move south toward the Orange Sub-basin's high-potential deep- and ultra-deep-water prospectivity shared by Namibia and South Africa, where South Africa's portion, largely untested, has been substantially de-risked by discoveries to the north and, together with South Africa's favorable fiscal regime, has in the past driven strong interest in acquiring acreage across the country.

TotalEnergies' high-impact well in Block 3B/4B is now expected in 2027, as there has been no further update supporting a 2026 spud date. Any well drilled in the block would qualify as high impact, particularly if located in water depths exceeding 1,500 m and targeting more than 250 MMbo. If, as assumed, both Fan SA and BushBaby are tested with a single well, the targeted volume could be in the region of 670 MMbo. This well could also represent the first deepwater test of the Orange Sub-basin within South African waters.

TotalEnergies is also progressing another potential high-impact well campaign in its DWOB block, located 211 km offshore from Saldanha Bay, with water depths ranging from 500 m to 3,900 m, that should occur later in the decade. The company's area of interest for oil and gas exploration covers approximately 15,000 sq km.

Shell's high-impact well in the NCUD block, also known as 274ER, is now considered most likely to occur no earlier than 2027. The specific drilling targets have not yet been disclosed. However, regional context indicates that discoveries in Namibia to date have been made in the Lower Cretaceous Albian and the Upper Cretaceous Cenomanian to Turonian intervals.

Angola

Angola's pragmatic approach to contractual flexibility and fiscal incentives has yielded results. The return of Shell and its commitment to spend a billion dollars on exploration in the country are a testament to the flexible and inviting environment.

The most recent high-impact well was the Quitexe 1 well drilled by Azule within the ultra-deep-water Block 47. The well was unsuccessful; however, its drilling is understood to be related to the attractive terms that Azule negotiated for blocks 46 and 47. Chevron is likely to be next to test the ultra-deepwater portion of the Congo Fan within blocks 49 and 50 – once confirmed, this well will also be designated high impact. It will be drilled within a similar ultra-deep-water environment between 100 and 200 km south of the Quitexe 1 well. A commercial discovery could open the floodgates for exploration over more than 30,000 sq km.

Further south within the Namibe Basin, near-term high-impact exploration is expected from Azule Energy within Block 28 where Azule is expected to spud the Merengues 1 well. The primary target is assumed to be Albian shelf-edge carbonate build-ups, while a secondary target could be Cenozoic turbidites/fans. The well will be the fourth well drilled within the basin and the second within Angolan waters. It follows Exxon's Arcturus 1 well, which did not result in a commercial discovery but may have intersected source rock.

TotalEnergies may also drill in this basin, but its plans seem less certain than Azule's. TotalEnergies is understood to have selected the prospect but very little is known about the well. The planned location is believed to be at the shelf edge in water approximately 1,000 m deep.

Côte d'Ivoire

Côte d'Ivoire has seen a strong run of recent exploration and development success, reinforcing its position as one of West Africa's more dynamic upstream growth areas. Eni's February 2026 Calao South discovery at Murene South-1X in Block CI-501, located 8 km southwest of the 2024 Murene-1X Calao discovery, is a notable addition. The find, made in high-quality Cenomanian sandstones, confirms the wider Calao channel complex and positions it as the country's second-largest hydrocarbon accumulation after Baleine, with estimated volumes of up to 5.0 Tcf of gas and 450 million barrels of condensate, or approximately 1.4 billion barrels of oil equivalent.

Murphy Oil also added momentum with its June 2026 Bubale-1X discovery in Block CI-709. It has a broad gross resource estimate of 340–850 million barrels of oil equivalent, and oil was encountered in both the Turonian and Cenomanian objectives, supporting the block's commercial potential despite earlier Civette and Caracal wells being plugged and abandoned after hydrocarbon shows.

M.S.G.B.C. Basin

The 900,000 sq km basin covers offshore acreage both on and offshore from Mauritania in the north to Guinea Conakry in the south. Over 9.5 Bboe were discovered between 2014 and 2019 in four clusters: GBA (Greater Bir Allah), GTA (Greater Tortue Ahmeyim), Sangomar and Yakaar-Teranga. There were also notable failures, such as Requin Tigre, a large basin floor fan prospect drilled by Kosmos in 2017. This dampened exploration excitement, with some super majors (ExxonMobil, Shell and TotalEnergies) deciding to exit the basin and relinquishing their acreage positions.

Others, including Woodside Energy Group Ltd., Kosmos Energy Ltd. and BP Plc, shifted their focus to field development rather than further exploration. For Woodside, that meant Sangomar; for Kosmos and BP, Greater Tortue Ahmeyim.

Until mid-2025, there were no active exploration projects in the MSGBC Basin. The failures of Shell (Panna Cotta well in Mauritania in 2023) and Apus Energy (Atum 1 well in Guinea Bissau in 2024) have impeded interest revival in the basin. That said, the basin is still viewed as immature and heavily underexplored.

A trend reversal started in October 2025 when Chevron was awarded two blocks in Guinea Bissau. This continued in 2026 with Eni being awarded a reconnaissance permit in Guinea and an exploration block in Gambia.

It is also worth noting that the pace of resource additions in the basin between 2014 and 2019 was comparable with that seen in Guyana and with what Namibia has achieved since 2022. The MSGBC Basin therefore appears to retain substantial exploration potential.

Mozambique

The frontier Zambezi Delta is the last great African delta that has yet to produce hydrocarbons. It covers almost 240,000 sq km and hosts only 13 wells — seven onshore and six offshore.

In 2023, Eni drilled the deep-water Raia 1 high-impact exploration well — the first deep-water well in the basin. The well is said to have targeted a prospect potentially holding some 600 Mmbo in Eocene deep marine clastics of the Cheringoma Formation. The well is believed to have been unsuccessful, and the Aquadrill West Capella drillship plugged and abandoned it without conducting testing operations.

Still, the Zambezi Delta remains one of Africa's top frontier basins. In early 2026, five blocks awarded to CNOOC under the sixth licensing round became effective, with two parallel 3D seismic surveys planned. GeoPartner will also launch a 14,000 sq km 3D seismic survey in the delta before year-end.

Somalia

2026 marks a major turning point in hydrocarbon exploration in Somalia. Turkish company TPAO completed the acquisition of nearly 5,000 sq km of 3D seismic data across its three offshore blocks in June 2025 and spudded the high-impact Curad 1 well in June this year. The well has a PTD of approximately 7,500 m (WD approximately 3,500 m), with drilling operations expected to be completed toward the end of this year or in early 2027. It has been 40 years since any offshore drilling took place in Somalia.

Seismic interpretation has been used to build a working prospect model that points to proposed plays in the Mid Somalia High sub-basin, with clastic and carbonate reservoirs of Triassic to Early Cretaceous age and a Lower Jurassic syn-rift shale source. The analysis typically assumes oil as the primary target.

Libya

One of the oldest and most mature hydrocarbon-producing nations in Africa, Libya still plays host to frontier offshore acreage. BP and Eni spudded the high-impact Matsola 1 ultra-deep-water well targeting gas, found non-commercial.

Success at Matsola 1 would have opened the deep and ultra-deep-water portion of the Sirte Basin to further exploration and derisk the Gulf of Sirte Basin.

In any case, the failure of Matsola-1 does not materially alter the long-term exploration thesis for offshore Libya. Rather, it highlights the challenge of finding accumulations of sufficient scale to justify development in a technically demanding and politically complex environment. Recent offshore licensing awards to Eni, QatarEnergy and Repsol suggest that industry appetite for frontier exploration remains intact despite the setback.

Beyond the Sirte Basin, the Pelagian Basin continues to offer exploration and development opportunities. The relaunch of the Tunisia-Libya Joint Oil licensing round for the Zarat area highlights continuing interest in offshore gas and condensate resources, although commercialization challenges linked to high CO2 concentrations and cross-border unitization remain significant.

Egypt

As Africa's oldest commercial hydrocarbon-producing country, Egypt still holds frontier potential. This was proven in early 2025 by Exxon's crucial discovery of gas with the Nefertari 1 new-field wildcat in the frontier Herodotus Basin–North Marakia offshore block. Egypt is a country where the demand for gas far exceeds internal production capacity and, thus, almost any gas discovery has an obvious market. Geopolitical events also have a significant impact, as was evident from the recent uncertainties in the Middle East.

The Nefertari 1 discovery, which could be in the range of 2 to 3 Tcf, is facing challenges with commerciality, even though it represents a promising play. This basin opener was the first well of a three-well exploration campaign by ExxonMobil in the East Mediterranean. The highly anticipated Elektra 1 well in Cyprus's Block 05 was drilled in early 2025 and abandoned as a non-commercial gas discovery. The third well, Pegasus 1, was spud in late May within the Cypriot Block 10 with reports of a significant gas find.

The Herodotus Basin covers over 78,000 sq km and thus far has been tested five times, resulting in two discoveries — a technical success rate of 40%. The basin will likely continue to attract exploration attention on both the Egyptian and Cypriot sides of the boundary.

The basin continued to mature during 2026 as Shell's Velox-1X well confirmed a hydrocarbon charge and the presence of a working petroleum system in the southern part of the basin.

The Egyptian Red Sea also warrants attention as one of Africa's last truly frontier basins. Despite its proximity to the prolific Gulf of Suez petroleum system, the basin remains lightly explored and could offer significant upside for companies willing to pursue high-risk, early-entry exploration opportunities.

Zimbabwe

Invictus Energy Ltd. is expected to spud Musuma 1 by the end of 2026 as its third exploration well in the Cabora Bassa Project in the Rufunsa Basin. The well will be drilled outside the Mukuyu gas-condensate discovery area and will target a clastic play in the Mid- to Upper Jurassic Dande Formation. It is designed as a straightforward vertical well with a planned total depth of about 1,500 meters.

The Musuma prospect was selected based on direct hydrocarbon indicators in seismic data, including updip brightening and a consistent flat spot observed in the Mid- to Upper Jurassic Dande Formation across multiple seismic lines and survey vintages in the EPO 1848 license area. It is one of eight targets identified from the CB23 Seismic Survey acquired by the company. If drilling at Musuma is successful, it could add to the resource potential alongside the Mukuyu 2 gas discovery made in two gas-condensate reservoirs in the Lower Triassic Lower and Upper Angwa formations. A new discovery would provide additional options for Mukuyu and help establish a foundation for full-field development in the Cabora Bassa Basin in line with Invictus' early gas monetization strategy.

São Tomé and Príncipe

Despite Shell's recent unsuccessful Falcao-1X well, the Gabon–Douala Deep Sea Basin remains a prospective area to monitor. Falcao-1X was only the second exploration probe after Galp's Jaca-1X, which confirmed the presence of hydrocarbons in the Upper Cretaceous clastic series extending in the eastern part of the basin.

3.3.2 Key near- to medium-term African hydrocarbon projects (2027–2028)

Africa's medium-term production outlook is concentrated in a small set of sanctioned projects scheduled to start up in 2027 and 2028, with the highest strategic relevance clustered in Uganda, Libya, Kenya, Nigeria, Algeria, Angola and Mozambique. These projects are less about standalone profitability and more about whether credible execution and infrastructure linkages translate into timely volumes at scale.

The core 2026–2027 project set includes Lake Albert (Uganda), Lokichar (Kenya), Bonga North (Nigeria), Tin Fouye Tabankort Sud (Algeria), and NC041 A & E and Bouri (Libya). In 2028, Kaminho (Angola) and Coral Norte FLNG (Mozambique) are expected to drive the next step-up in Africa's sanctioned LNG and deepwater gas/condensate supply.

Project maturity and strategic importance

Lake Albert is a large Western Uganda onshore oil development comprising Tilenga and Kingfisher CPFs (plus Kaiso Tonya), targeting ~230,000 bo/d processing capacity across multiple hubs and fields. Its commercial viability and timing are highly dependent on the 1,400 km EACOP export pipeline to Tanga; without EACOP, upstream production lacks a scalable route to international markets, making pipeline sanctioning and readiness central to field start-up. Construction of the pipeline and startup were expected in October 2026; however, it seems likely that sustained production will commence in the first half of 2027.

Bonga North is a deepwater oil development in Nigeria (OML 118) that targets >300 million boe of recoverable resources and peak production of ~110,000 bo/d. Following its December 2024 FID, it is designed as a subsea tie-back to the existing Shell-operated Bonga Main FPSO, implying dependence on FPSO capacity availability and modifications to sustain hub throughput. First production is targeted for the late 2027 window, with crude export by shuttle and gas routed via existing export infrastructure.

Lokichar Trough in Kenya (Blocks 10BB and 13T) covers ten discoveries and is structured into two phases under a revised FDP. Phase 1 is planned at 20,000 b/d (20,000 b/d from initial field pairs), supported by a CPF, water injection and major crude evacuation logistics from Turkana to the coast. A key development change is the scrapping of the Lokichar–Lamu pipeline plan: Phase 1 is intended to move crude by road to Mombasa, while Phase 2 would require a shift to rail—making logistics execution and timing decisive for the December 2026 first-oil window.

In Libya, NC041 A & E Structures is an infrastructure-led offshore gas development (PSC to 2050) covering seven fields. Development is based on fixed offshore processing/wellhead facilities, subsea clusters and multiphase pipelines feeding the Sabratha platform and onward supply to the onshore Mellitah complex; LNG export then routes via GreenStream to Italy.

In Algeria, Tin Fouye Tabankort Sud is an onshore gas development spanning six fields, supported by gas marketing and sanctioned by the Algerian government. It has taken FID, with first production expected in 2027 and resources estimated at >100 million boe.

Angola's Kaminho and Mozambique's Coral Norte FLNG represent the most consequential 2028 projects. Kaminho is the first deepwater condensate development in the Kwanza Basin (Block 20/11) sanctioned in May 2024, featuring a converted FPSO tied to subsea infrastructure. Importantly, the development's first stage is focused on condensate monetization. Initially, gas will be reinjected.

Coral Norte FLNG is Mozambique's next project to come onstream in addition to Coral Sul (2022 startup), designed as a near "blueprint" duplication using a second turret-moored FLNG vessel. FID for Coral Norte was taken on 3 October 2025, and start-up is targeted for 2028, with production supported by ultra-deepwater subsea wells, onboard liquefaction capacity of ~3.4–3.5 mtpa LNG, and international offtake arrangements. Gas/condensate integration is central to project economics, including domestic gas/condensate allocations alongside LNG sales.

Country	Project	Operator	Expected Start Date	Expected Production Rate
Uganda	Lake Albert (Tilenga & Kingfisher)	TotalEnergies (Tilenga); CNOOC (Kingfisher)	Late 2026/H1 2027	~230 Mbbls/d
Nigeria	Bonga North	Shell	late 2027	~110 Mbbls/d
Kenya	Lokichar Trough (Phase 1)	Gulf Energy	December 2026	~20 Mbbls/d
Libya	NC041 A & E Structures	Mellitah Oil and Gas BV	2027	~450 MMscf/d
Algeria	Tin Fouye Tabankort Sud	Groupement TFT	2027	~100 MMscf/d
Angola	Kaminho	TotalEnergies	2028	~55 Mbbls/d
Mozambique	Coral Norte FLNG	Eni Spa	2028	~3.4-3.5 mtpa LNG

Schedule and execution risks

Schedule risk is the most immediate threat to the 2027–2028 sanctioned set, with pressure points concentrated in drilling performance, long-lead equipment delivery, offshore installation windows, subsea procurement, and floating facility readiness and commissioning. Deepwater and floating LNG projects (including Bonga North, Kaminho and Coral FLNG) carry elevated exposure to offshore construction performance, contractor availability and cost escalation; any slippage in major vessel or subsea integration milestones could extend start-up beyond current schedules.

Onshore oil projects such as Lake Albert and Lokichar face a different execution profile: while upstream scopes may be more controllable, the overall schedule is increasingly governed by midstream readiness—roads, pipelines, export infrastructure, land access, and community/government coordination. For these projects, export logistics and enabling infrastructure are as schedule-defining as field development itself.

3.3.3 E&P Capital Spending 2027–2030

Market Overview

Upstream CAPEX across the selected African markets is expected to rise by approximately 40% in 2027 and 2028 compared with the preceding years, reaching levels close to $50 billion. More than 80% of this spending is expected to be concentrated in Mozambique, Nigeria, Angola, Libya and Côte d'Ivoire, driven by recently sanctioned projects scheduled to start up over the next four to five years.

The remaining capital is largely allocated to infill drilling, smaller tie-back developments and brownfield activity aimed at maintaining production levels and extending the producing and economic life of existing production hubs. By 2029, the portfolio begins to move beyond its absolute peak, although spending remains elevated.

Company-Level Spending

At the company level, Eni is expected to be among the largest spenders, reflecting its exposure to several major developments. These include its involvement in the Mozambique Rovuma venture, the Coral FLNG project, Baleine Phase 3 in Côte d'Ivoire, the NC041 A&E Structures project in Libya, Block 31 in Angola through Azule Energy, the Eni-BP joint venture, and the Bonga North development in Nigeria.

TotalEnergies is also expected to remain a major capital contributor through its participation in the Kaminho development in Angola, the Lake Albert development in Uganda, the NC98 block in Libya, the Tin Fouye Tabankort Sud development in Algeria and several projects in Nigeria.

Regional Outlook

Mozambique remains the largest capital destination over the 2027–2029 period, with spending of around $60 billion. This is primarily linked to the sanctioned Coral Phase 2 project and Rovuma LNG, which ExxonMobil has indicated is expected to reach FID before the end of 2026. The scale of spending highlights the continued importance of LNG and offshore gas developments, which are expected to absorb substantial capital even after the 2027 peak.

Nigeria remains the second-largest market, with spending of around $10 billion. This is only slightly below its 2028 peak, suggesting a sustained investment plateau supported by deepwater oil and gas-led developments.

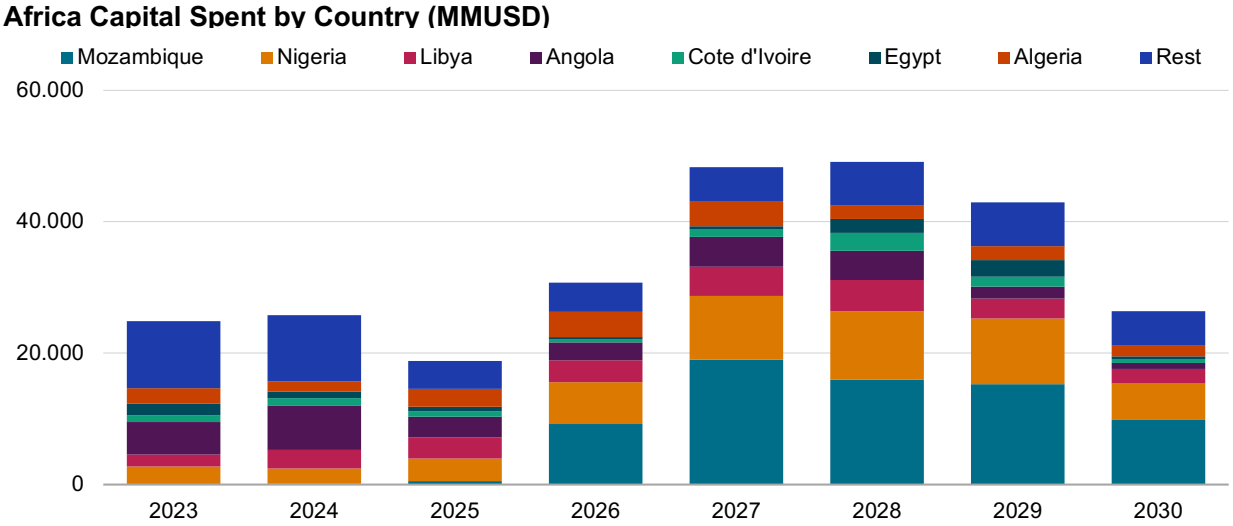
Angola's spending is expected to remain in the range of $4 billion to $5 billion during 2027–2028 before falling sharply thereafter. This indicates that Angola's offshore investment wave is expected to taper more quickly than those of Mozambique or Nigeria.

Algeria remains relatively stable at around $2 billion, supported by its onshore gas developments and mature-basin investment model. Côte d'Ivoire, Uganda, Ghana and Senegal remain on a lower capital trajectory, reflecting a shift from large-scale development and pipeline construction toward production operations. However, offshore production momentum continues through projects such as Baleine and other phased developments.

Post-Peak Transition

Overall, 2027–2028 represents the high-water mark for development CAPEX across the selected African markets. The period is led by Mozambique and Nigeria, supported by Angola, Algeria and Côte d'Ivoire, while Uganda and Kenya play smaller, more specialized roles.

From 2029 onward, the investment cycle begins to transition from major greenfield construction toward ramp-up activity, production optimization, infill drilling, maintenance and broader brownfield investment. This marks a shift from large-scale project execution to sustaining output and maximizing returns from assets brought onstream during the preceding investment wave.



As of August, 2026.
Source: Upstream Content, a product of S&P Global Energy.
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3.3.4. Supply chain dynamics

Upstream capex spending in Africa
Upstream capital expenditure (capex) in Africa has been volatile. Historically, upstream capex growth in Africa has lagged the global trend, but the region is now catching up. Over the past decade, upstream spending in Africa has increased by nearly 50%, broadly in line with global upstream spending growth. The momentum has clearly shifted in Africa's favor.

S&P Global forecasts 44% growth in African upstream capex between 2026 and 2030, compared with 25% globally. Offshore capex is expected to grow steadily, increasing from $16 billion in 2026 to $20.8 billion by 2030. This growth reflects a renewed focus on developing offshore resources in the region, although the political environment remains challenging in several African countries.

Cost
Most of the equipment required for E&P activities is sourced through a global supply chain, although there are some exceptions. Costs can therefore be divided into three broad categories:

- Global cost drivers
- Local cost drivers
- Day rates

Segments influenced by global cost drivers typically have limited local-content requirements. Africa's industrial base remains relatively small, with most facilities focused on maintenance and service activities. As a result, projects in Africa procure products and services from the same suppliers and manufacturing facilities that serve operators worldwide, including FPSOs built in Asia, subsea equipment manufactured in Asia or Brazil, and turbines supplied from Europe or North America. Pricing for these products is generally not Africa-specific, apart from transportation and logistics costs.

Local cost drivers have a significant influence on segments with stringent local-content requirements. These are typically more labor-intensive projects, such as LNG facilities, onshore production facilities, and refineries.

The vessel and rig markets are driven by day rates, which are influenced by the global supply-demand balance, as well as transit times and associated costs.

S&P Global expects costs to increase by 10% for onshore projects and 14% for offshore projects between 2026 and 2030. S&P Global also forecasts salary levels for construction and manufacturing workers in Africa, measured in U.S. dollars, to increase by 21% and 27%, respectively, over the same period. This growth is similar to Asia and slightly higher than Europe, while North America is expected to see an increase of 12% to 13%.

Heavy-lift vessel rates entered 2026 on a firmer footing, with average day rates rising in the first quarter. This increase was driven mainly by African and South American markets, while Asia-Pacific, despite being a key heavy-lift region, recorded a decline in average rates during the same period.

Engineering services

Engineering demand
Demand for engineering services associated with African projects is expected to remain robust over the next two to three years, driven primarily by onshore LNG liquefaction and onshore production facilities. Offshore and subsea developments are expected to contribute significantly to demand toward the end of the decade. Recent project sanctions include Phase 3 of the Baleine development offshore Côte d'Ivoire and, potentially, Rovuma LNG Phase 1 in Mozambique.

Engineering supply
As with most projects in Africa, engineering work* for these developments will largely be carried out overseas. Tier-1 and boutique engineering contractors have invested in developing capacity through joint ventures. Ongoing initiatives include efforts by DORIS Engineering S.A.S., Hanwha Ocean Co., Ltd., and Windhoek Consulting Engineers (Pty) Ltd. (WCE) in Namibia to upskill local personnel for subsea and FPSO engineering workstreams. However, the local talent pool remains limited and is unlikely to support substantial volumes of engineering work.

Nigeria has the most prescriptive local-content requirements, while other African countries** generally require only broad commitments to local supply-chain development. Under the Nigerian Oil and Gas Industry Content Development Act (NOGICD) 2010, 50% to 90% of engineering hours must be performed by Nigerians, depending on the type of structure or facility. Non-compliance may result in blacklisting or other sanctions.

Engineering cost
Engineering costs in Africa, as measured by salary levels, are expected to increase by 23% in 2026. This sharp increase is driven by higher energy costs, although employers are unlikely to adjust wages sufficiently to fully offset inflation.

Annual cost growth beyond 2026 is expected to remain in the single digits as oil prices stabilize.

*Engineering work comprises front-end engineering design (FEED), detailed engineering, and engineering project management.

**Nigeria, Mozambique, Namibia and Angola*

Onshore Rigs

Onshore rig demand
Africa's onshore rig demand decreased by 2% in 2025 due to lower drilling activity in North Africa, where most regional onshore drilling occurs, particularly in Algeria, Egypt, and Libya. Each country faces distinct challenges.

Algeria continues to announce plans to increase production but has consistently struggled to meet its targets. After years of natural gas surplus, Egypt has become increasingly reliant on imports, and much of the activity aimed at increasing gas production is expected to come from offshore developments. In Libya, political instability remains a persistent challenge despite relatively regular licensing rounds.

In 2026, rig demand is projected to increase by 4%.

Positive exploration trends are emerging across the region. In February 2026, Petrosen SA of Senegal announced a $100 million onshore exploration campaign, the first in decades, with the company aiming to make a discovery by the end of 2026. In January 2026, Nigeria reduced signature bonuses and sign-on fees for new awards to attract additional investment. The country expects to hold annual licensing rounds beginning in 2026. Reconnaissance Energy Africa Ltd. completed its second exploration well in Namibia's Damara Fold Belt in November 2025.

Onshore rig supply:
Africa produces most of its oil and gas from offshore operations, meaning that onshore rig supply is relatively limited compared with other regions and accounts for approximately 4% of global rig capacity. Egypt and Algeria account for more than 70% of Africa's onshore rig fleet.

Drilling activity in Egypt is concentrated in the onshore Western Desert. Rigs in Egypt are heavily concentrated among local contractors with high-specification capabilities. The largest international supplier is China-based Zhongman Petroleum and Natural Gas Group Corp. Ltd.

Algeria remains highly reliant on national contractors but has a moderately larger group of international contractors than Egypt, with Nabors Industries Ltd. being the largest. Rig utilization in Africa remains tight, exceeding 85% over the past several years, according to the 2025 NOV Rig Census. By comparison, the gross number of rigs recorded in the region suggests a surplus of capacity relative to reported demand.

Onshore rig costs:
Reliable data on actual day rates in the region is limited, and rates are likely to vary significantly by country. Recent Middle Eastern day rates may serve as a useful proxy for certain North African markets. In Oman, rates for top-performing rigs can reach approximately $60,000 per day. In Qatar, a mature market, rates are unlikely to exceed $30,000 per day and are more likely to average around $25,000 per day. Chinese suppliers often reduce pricing to gain market share, which generally benefits operators when they are active in a region.

UCCS trend for African onshore rig costs:

2026	2027	2028	2029	2030
8%	10%	5%	3%	5%

These are nominal rates and Africa is heavily influenced by inflation.

Fabrication

Fabrication demand
Over the past two decades, Africa has experienced significant changes in the profile of its offshore EPC projects. From 2005 to 2015, deepwater developments in West Africa dominated the region's offshore activity. This decade-long expansion culminated in the award of the Egina FPSO in 2013. However, the 2014 oil price collapse, the resulting downturn in the oil and gas sector, and broader challenges across Africa hindered progress on large deepwater projects.

Smaller fixed platforms, FPSO and MOPU conversions, and brownfield modification projects became the dominant areas of activity until around 2022, when major projects began returning to the region, led by East Africa. LNG and FLNG developments, including Coral and Mozambique LNG, were key drivers of this recovery.

This resurgence is being driven by a shift toward higher-value, more complex offshore developments. Activity is also moving from emerging markets in East Africa back toward established West African plays. LNG developments such as ExxonMobil's Rovuma LNG continue to support activity in East Africa. This trend is already evident, with operators ordering two newbuild FPSOs during the first half of 2026:

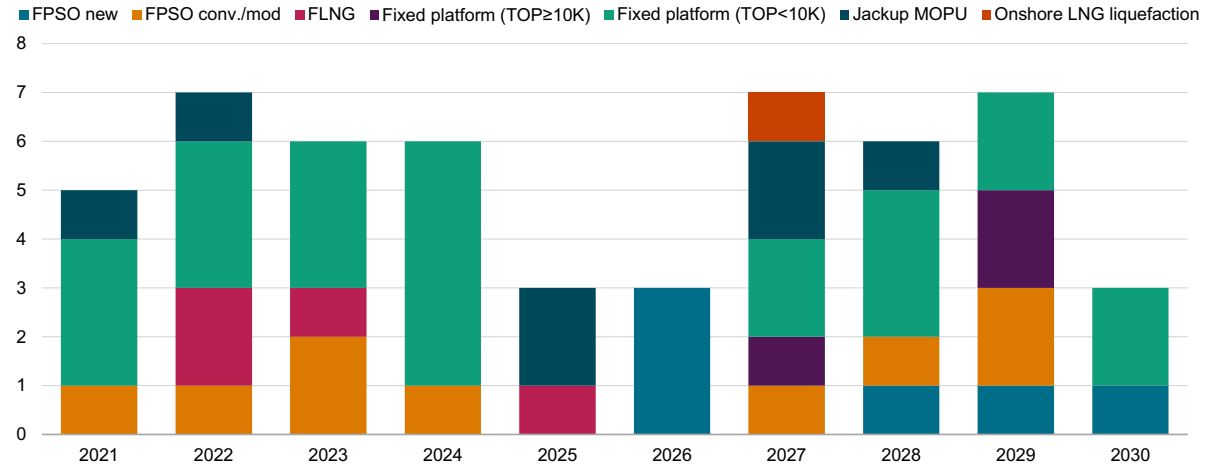
Greater PAJ in Angola and Baleine Phase 3 in Côte d'Ivoire.

Looking ahead, the next five years will be shaped by several key drivers. Major discoveries in Namibia and Nigeria are expected to be developed through newbuild FPSOs, including TotalEnergies' Venus FPSO, and fixed-platform developments. Occasional FLNG projects, such as Tortue FLNG, may also proceed to development. This evolution highlights the resilience of Africa's offshore sector as it once again transitions toward the sophisticated deepwater developments that characterized the region prior to 2014.

A critical aspect of Africa's fabrication market is its heavy reliance on Asian shipyard capacity. While African yards are often involved in fabricating smaller structures, such as wellhead platforms and simple modules or components, to satisfy local-content requirements, they generally lack the capability to execute more complex scopes of work. The fabrication of newbuild FPSOs, large fixed platforms, and large-scale onshore LNG modules is therefore typically outsourced to established Asian shipyards.

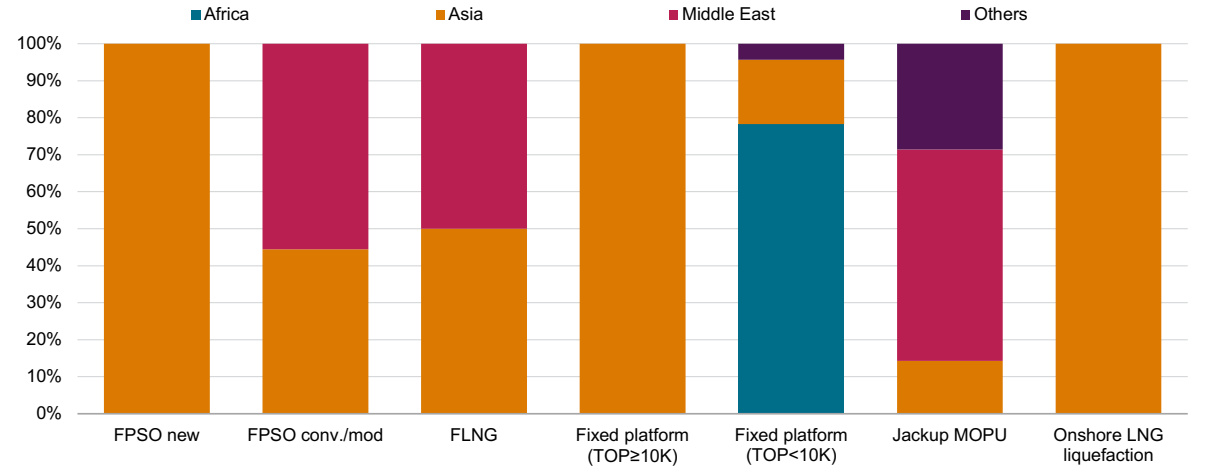
This Africa-Asia partnership will remain critically important, not only for the successful development of offshore projects but also for the industrial development of host countries. A notable example is the SHI-MCI joint venture yard in Nigeria between Samsung Heavy Industries and local partner MCI. Initially established to support the Egina FPSO, the facility has evolved into a thriving ship-repair yard and is well positioned to maximize local content participation in future Nigerian FPSO developments.

Africa project awards



As of Aug. 13, 2026.
Source: S&P Global Energy.
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Africa projects key execution location



As of August. 13 2026
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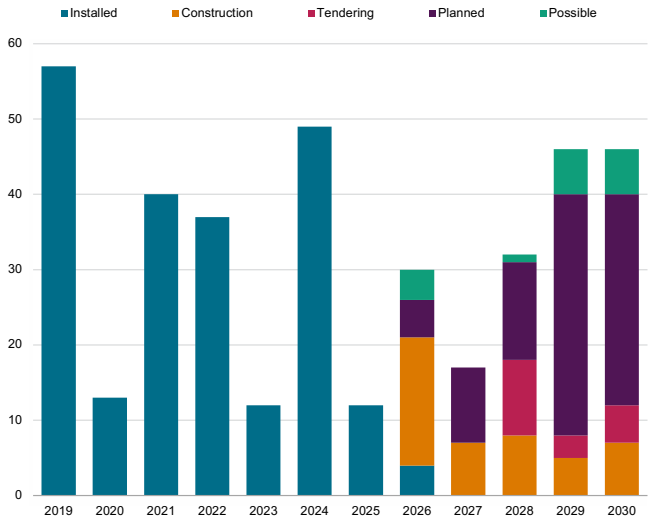
Subsea Equipment:

Subsea equipment demand

Africa represents one of the most attractive long-term opportunities in the global oil and gas industry, supported by extensive undeveloped resources and improving investment conditions. Subsea activity is expected to outperform market expectations during the 2026-2030 period, supported by new developments offshore Angola and in Nigeria's Niger Delta region. Emerging markets such as Namibia and East Africa, particularly Mozambique, also have multiple projects progressing, led by operators including Eni and TotalEnergies.

Following political reforms and fiscal incentives, Shell is expected to take a final investment decision (FID) on the Bonga South West Aparo project in Nigeria by the second quarter of 2027. ExxonMobil is expected to follow with the development of its Owowo deepwater project, originally discovered in 2012.

Subsea Equipment demand: Africa



Subsea equipment supply

All major subsea equipment suppliers maintain operations in Africa, primarily in the form of service facilities and regional offices. Equipment assembly generally takes place in manufacturing facilities outside Africa that serve global markets. S&P Global estimates global subsea production capacity at 350 to 400 subsea trees per year. Global demand is expected to remain close to 250 subsea trees annually throughout the forecast period.

Both OneSubsea and Baker Hughes secured major contract awards in Africa during 2026. However, subsea tree suppliers currently have available manufacturing capacity.

Local content:

Baker Hughes maintains a subsea manufacturing and service footprint in Africa through facilities in Angola, Nigeria and Algeria. The company's operations include subsea plants in Calabar and Onne, Nigeria, a multiproduct facility in Luanda, Angola, and a manufacturing joint venture with Sonatrach in Arzew, Algeria. These facilities support activities including subsea tree assembly and testing, subsea production equipment servicing, wellhead and valve manufacturing, and turbomachinery overhaul. The African footprint provides local assembly, testing, manufacturing and aftermarket support capabilities for offshore developments across the region.

TechnipFMC maintains one of the largest subsea infrastructure footprints in Africa, primarily centred in Angola and Nigeria. The company's facilities include the Dande spoolbase, the Lobito umbilical plant, construction and engineering operations in Lobito, and service and engineering support facilities in Port Harcourt. TechnipFMC has identified Angola as a strategic hub for delivering subsea developments across Africa, supported by local engineering, manufacturing and project execution capabilities. The company's integrated engineering, procurement, construction and installation (iEPCI) model combines subsea production systems with SURF capabilities under a single project structure.

OneSubsea the subsea joint venture comprising SLB's and Aker Solutions' subsea businesses together with a strategic partnership with Subsea7, remains an important competitor in African deepwater markets. The company provides subsea production systems, processing technologies, compression solutions and lifecycle services for offshore developments. Together with TechnipFMC and Baker Hughes, OneSubsea competes for major subsea equipment and development contracts across Angola, Nigeria and other offshore basins in West Africa.

Supplier	Base	Location	Description
Baker Hughes	Subsea plant	Calabar, Nigeria	Multiproduct manufacturing facility supporting local-content requirements; operational since Q4 2018.
Baker Hughes	Subsea plant	Onne, Nigeria	Service, maintenance and limited manufacturing capacity for subsea production equipment; operational since 2013.
Baker Hughes	Multimodal / Multiproduct facility	Luanda, Angola	Regional hub supporting subsea tree assembly and testing, subsea infrastructure manufacturing, turbomachinery overhaul, drilling and intervention services, wireline services and maintenance support for upstream, LNG and downstream facilities; inaugurated in 2019
Baker Hughes	Multiproduct plant (JV)	Arzew, Algeria	Joint venture with Sonatrach; Baker Hughes owns 51%. Manufactures, assembles and services wellheads, subsea trees, blowout preventers and valves.
TechnipFMC	Spoolbase	Dande, Angola	Major flexible pipe and SURF facility. Originally commissioned in 2006 with pipe stalk fabrication, automatic welding, pipe-in-pipe and plastic liner capabilities.
TechnipFMC	Umbilical plant	Lobito, Angola	Manufactures stainless-steel umbilicals for offshore developments.
TechnipFMC	Construction yard	Lobito, Angola	Joint venture with Sonangol EP; provides engineering support, fabrication, feasibility studies and project execution services.
TechnipFMC	Service and engineering base	Port Harcourt, Nigeria	Oilfield and subsea support base including engineering and technical support services.
TechnipFMC	Operational hub (Sonils Base)	Luanda, Angola	Major engineering, manufacturing, project management and execution centre supporting Angola and wider African subsea developments.
OneSubsea	Subsea systems and services hub	Angola	Supports subsea production systems, processing systems, compression systems and lifecycle services for offshore developments. Public disclosures are less specific regarding manufacturing locations.
Subsea7	Fabrication and logistics yard	Lobito, Angola	Major offshore support, fabrication and logistics base supporting Angolan and regional subsea projects.

SURF

SURF demand

Africa's SURF outlook is strengthening over the 2026-2031 period, supported by ongoing deepwater developments in West Africa and emerging offshore activity in Southwest Africa. Demand is being driven by a combination of field-life extension projects, new developments, gas monetization initiatives, and a growing pipeline of projects progressing through planning, tendering, and pre-development phases.

The current demand profile reflects a balance between near-term project execution and longer-term development opportunities. Angola continues to generate significant SURF requirements through brownfield and field-life extension activity, while Nigeria is supported by new subsea tieback developments. Together, these markets remain the primary sources of near-term SURF demand in the region.

A key demand driver is the Girassol Life Extension Project offshore Angola, where TechnipFMC has been contracted to supply and install flexible pipe systems that will replace existing rigid pipe bundles and extend the productive life of the field.

Looking ahead, Namibia is expected to become one of the region's most important sources of future SURF demand. Major developments in the Orange Basin, particularly the Venus and Kudu projects, are expected to require extensive subsea infrastructure as they progress toward execution. Continued exploration success by operators including TotalEnergies, Galp, Rhino Resources, and Chevron is further strengthening the country's long-term offshore outlook. The Venus development, which is expected to include up to 40 subsea wells tied back to an FPSO, is among the largest offshore projects currently advancing in Africa.

Additional demand is being generated by gas monetization developments, including the Aseng Gas Monetization Project offshore Equatorial Guinea, where Subsea7 has been contracted to install new flowlines and umbilicals connecting the Aseng field to the Alen platform.

Overall, Africa's SURF market is evolving from one driven primarily by established offshore regions toward a broader growth story that includes Namibia's emerging deepwater sector, supporting long-term demand for subsea infrastructure across the continent.

SURF Supply

Africa's SURF supply capabilities are concentrated in West Africa, particularly in Angola and Nigeria, where major international suppliers have established manufacturing, fabrication, engineering, and logistics facilities to support offshore developments.

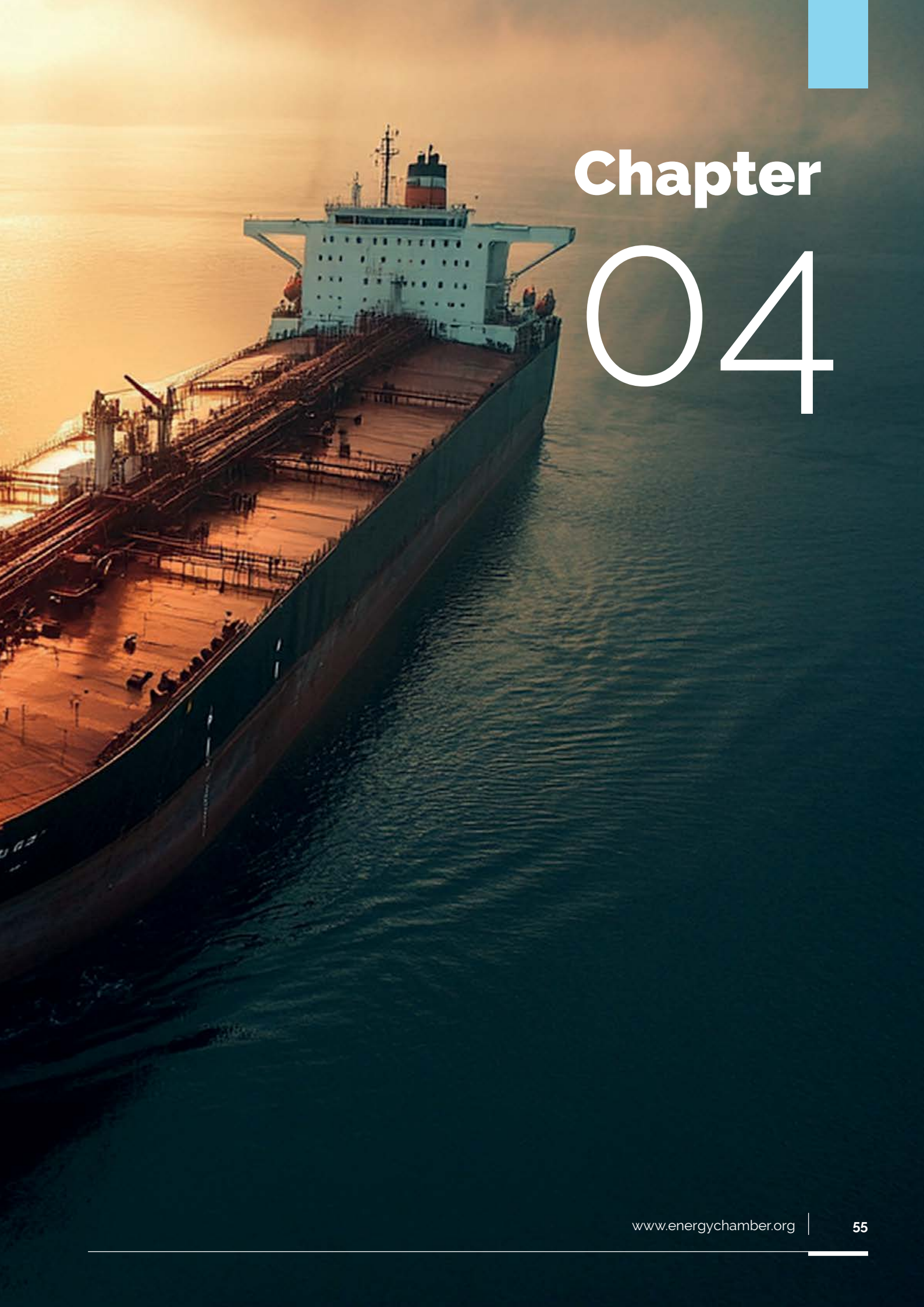
TechnipFMC maintains the most extensive regional SURF infrastructure footprint. Its Dande spoolbase in Angola serves as a major flexible pipe and SURF facility, providing pipe stalk fabrication, automated welding, pipe-in-pipe, and plastic-liner capabilities. The company also operates a dedicated umbilical manufacturing facility in Lobito, producing stainless-steel subsea umbilicals for offshore developments. Additional support is provided through the Lobito construction yard, the Sonils operational hub in Luanda, and an engineering and technical-support base in Port Harcourt, Nigeria.

Baker Hughes has established a broad subsea manufacturing and service network across the continent. Facilities in Calabar and Onne support subsea production-equipment manufacturing, assembly, maintenance, and service activities. In Angola, the company's Luanda facility functions as a regional hub supporting subsea tree assembly and testing, subsea infrastructure manufacturing, drilling and intervention services, and maintenance operations. Baker Hughes also operates a joint-venture manufacturing facility in Arzew, Algeria, producing subsea trees, wellheads, blowout preventers, and valves.

Additional regional capabilities are provided by OneSubsea and Subsea7. OneSubsea maintains a subsea systems and services presence in Angola, supporting subsea production, processing, compression, and lifecycle-service activities. Subsea7 operates a fabrication and logistics yard in Lobito that supports offshore construction, fabrication, and logistics for projects throughout Angola and the broader West African region.

Overall, Africa's SURF supply chain is anchored by a mature supplier ecosystem centered on Angola and Nigeria. The combination of flexible-pipe manufacturing, umbilical production, fabrication yards, engineering centers, assembly facilities, and logistics bases provides a strong platform to support both ongoing developments in West Africa and future large-scale projects offshore Namibia.





Chapter 04

4. Oil markets - Midstream and downstream outlook

Sector Narrative: The emergence of a more resilient African refining and trading system

Recent developments in the Middle East have increased concerns over Africa's growing import dependency and possible impact of the supply disruption on product affordability. While different markets across Africa have varying degrees of exposure to supply from the Middle East, supply chain resilience, price stability and the shift from imported products towards more diversified African refining and trade systems have understandably become the key focus area for the industry and policy makers.

Moreover, Africa's oil product markets are facing two major pressure points that converged at once: disrupted Middle East routes and a deepening Russian refining crisis. Africa, alongside Europe and Latin America, is among the import-dependent regions that is experiencing the biggest pinch from the tightening diesel market.

Policy responses to these crises have varied across the region, ranging from increased regulation of fuel prices, targeted subsidies, energy-saving measures and centralised fuel imports to more long-term proposals such as introduction of strategic fuel reserves and increasing support for new refining projects.

While supply disruptions and high price environment have exposed Africa's import vulnerabilities and short-term pressures to fuel demand; long-term demand fundamentals for the region remain bullish:

- Robust population and economic growth will support African refined product demand growth over the long term. Africa's economy is projected to grow at the fastest among world regions and significantly above the global average
- Africa's light-duty vehicle fleet and personal mobility are forecast to experience strong growth driven by expansion of the middle class and rising income levels.
- Expanding economy will also result in increased demand from commercial transport trucking, especially for the continent's 17 landlocked markets.
- Refinery production has expanded over the last two years, largely as a result of ramp-up of utilisation of Dangote refinery and support from high margin environment. This has reversed a downward trend in Africa's refinery supply that has experienced several shutdowns and low utilisation rates.
- New refinery projects have been announced for the region, including expansion of existing Dangote refinery as well as announcement of a potential 700,000 b/d refinery in Lamu, Kenya. Other projects regarded as firm or likely include Cabinda refinery in Angola with potential for further expansion and Uganda's Hoima refinery.
- While acknowledging the importance of the energy transition, governments across the region have stressed their intent to prioritize energy security and affordability in view of reaching their development goals.

On a global level, our base case outlook assumes Middle Eastern oil exports to rise over time; however, supply is expected to remain below prewar levels. Production growth in other regions cannot offset the loss of supply. We expect a crude supply deficit in the fourth quarter of 2026 and only a modest surplus in 2027. Consequently, crude inventories are likely to remain low keeping oil prices supported even as demand growth remains muted.

4.1. Oil Demand Outlook

Oil demand in many mature economies around the world has already peaked or is expected to peak in the next few years. In contrast, Africa's oil demand is expected to experience significant growth to 2050 and beyond, supported by population growth and robust economic activity.

Population will increase by ~0.9 billion by 2050, resulting in increased demand for oil products and extending peak demand well beyond our forecast period.

Similarly, Africa's GDP is projected to increase by a robust compound annual growth rate of 3.9% between 2026 and 2050 - the fastest among world regions and significantly above the global average of 2.4%.

In 2025, the continent accounted for less than 5% of global oil product demand and approximately 3.2% of the world's GDP, despite representing 18% of the world's population.

Figure 1. Africa Population

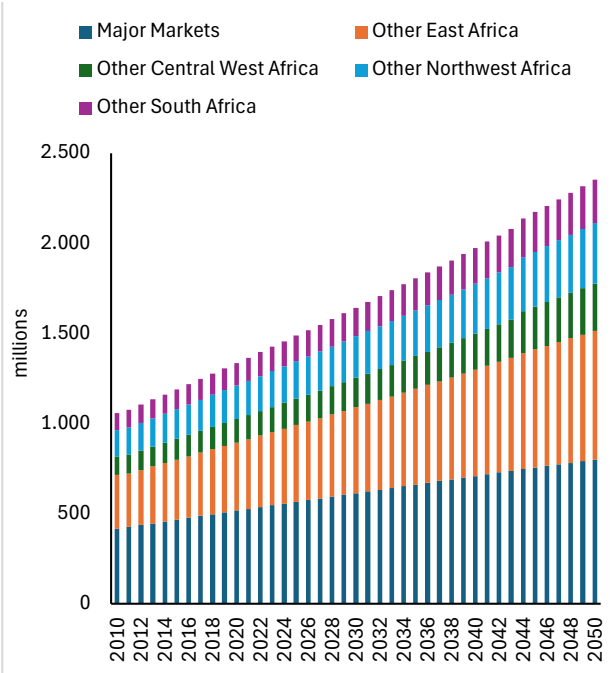
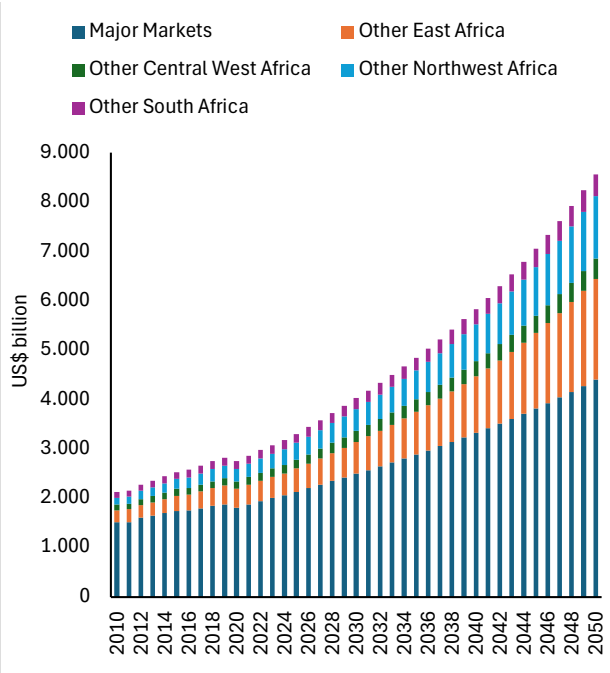


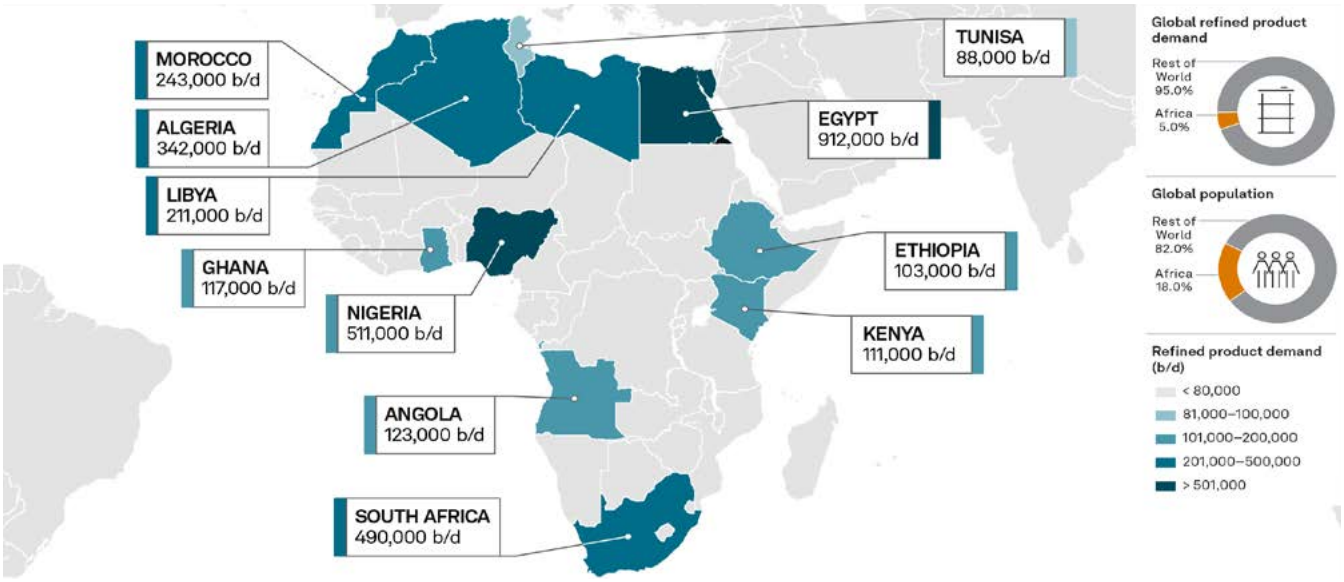
Figure 2. Africa GDP



Source: S&P Global Energy

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Figure 3. Africa Demand for Refined Products (2025)



Source: S&P Global Energy

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Increased economic activity is expected to drive commercial transport requirements and industrial demand, while expanding population and growing income levels are expected to support rising car ownership rates and personal mobility.

Figure 4. Africa Oil Product Demand

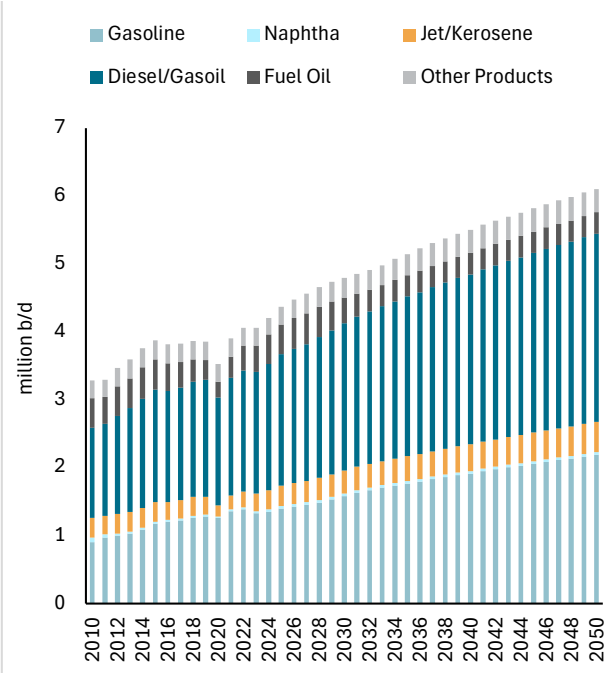
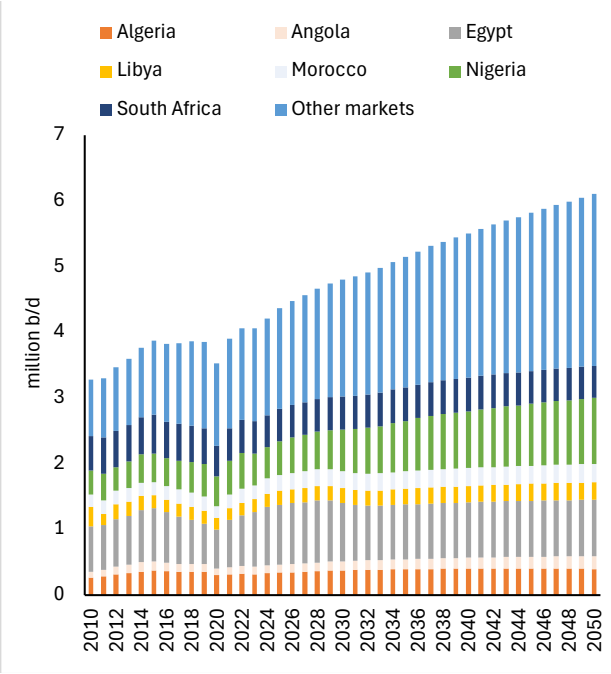


Figure 5. Africa Oil Product Demand by Country



Source: S&P Global Energy

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Africa is expected to be the main driver of global **gasoline** demand growth over the long term, partially offsetting declines in OECD markets and China. Gasoline consumption in Africa is projected to grow by nearly 0.8 million b/d from current levels to reach nearly 2.2 million b/d in 2050. Long-term demand growth will be primarily driven by Nigeria, the continent's largest gasoline market, while smaller, less developed markets will also make strong contributions to regional demand growth through to 2050.

Excluding Nigeria and, to a much lesser degree, Egypt, gasoline demand in Africa's main markets—namely Algeria, Morocco, and South Africa—is expected to either slowly decline or plateau over the long term. In these markets, vehicle fuel economy gains and the penetration of alternative vehicles in the long-term will contribute to suppressing gasoline demand.

Africa's **diesel/gasoil** demand in the continent is expected to grow by 43% by 2050, reaching just below 2.8 million b/d. Along with private and commercial road transport, gasoil demand will be supported by heightened activity in the extractive sectors, as investments in critical minerals for the energy transition, such as lithium, cobalt, and nickel, pick up. Mineral resource-rich countries in Central and Southern Africa, notably Angola, the Democratic Republic of Congo, Zambia, and Zimbabwe, are projected to be significant drivers of regional gasoil demand growth.

Jet fuel and kerosene demand in Africa is projected to expand by 50% from current levels by 2050, reaching 444 thousand b/d. Population expansion, a growing middle class, and increased cross-border business activity in the region will drive growth in both passenger travel and freight. Additionally, investments in infrastructure, such as Ethiopia's mega airport project 40 km southeast of Addis Ababa, along with efforts to enhance regional connectivity, such as the African Continental Free Trade Area (AfCFTA), are expected to facilitate increased air travel.

Africa accounts for only a small fraction of global **naphtha** demand, primarily due to the lack of large-scale petrochemical industries across the continent. Home to one of Africa's most developed petrochemical industries, Egypt accounts for two-thirds of Africa's overall naphtha consumption, at 25,000 b/d in 2025. The country is currently in discussion with China National Chemical Engineering Co. Ltd. (CNCEC) regarding the Red Sea Petrochemicals Complex project in Ain Sokhna. While the project is currently assessed as speculative, it would represent a significant upside for regional naphtha demand if materialized.

Residual fuel oil is the only product for which demand is forecasted to decline over the long term; the product's share in Africa's demand mix will decrease from 10% in 2025 to around 5% by 2050, as all major user segments, including bunkering and power generation, progressively switch to comparatively cleaner fuels.

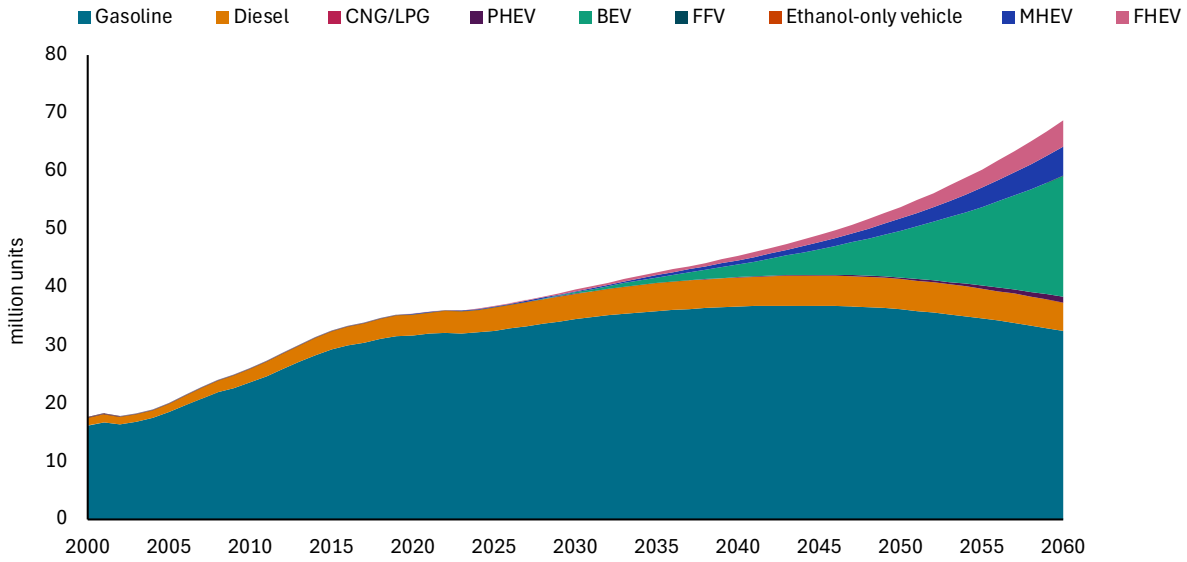
4.2.Light Vehicle Fleet Outlook

Africa's light-duty vehicle fleet is expected to grow from 37 million in 2025 to 54 million by 2050 and 69 million by 2060, driven by population growth and the expansion of the middle class. Internal Combustion Engine (ICE) vehicles will continue to dominate for the foreseeable future, but alternative vehicle adoption is expected to accelerate from the mid-2040s onward.

Alternative vehicles are projected to account for 46% of Africa's total vehicle fleet by 2060, compared with less than 0.5% as of 2025. Nevertheless, alternative vehicle penetration in Africa will remain below that of other regions: North America (89%), Latin America (75%), Europe (74%), and Asia Pacific (79%).

Gas-rich countries such as Algeria, Egypt, and Nigeria have launched ambitious CNG and LPG vehicle conversion projects in recent years. However, high conversion costs and limited infrastructure, particularly refuelling stations for converted vehicles, will pose challenges to mainstream adoption.

Figure 6. Africa Light Duty Vehicle (LDV) Fleet



Source: S&P Global Energy

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Abbreviations: CNG/LPG = compressed natural gas/ LPG; PHEV = Plug-in Hybrid Electric vehicle; BEV = battery electric vehicle; FFV = Flex-fuel vehicle; MHEV = Mild hybrid electric vehicle; FHEV = Full hybrid electric vehicle

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Gas-rich countries such as Algeria, Egypt, and Nigeria have launched ambitious CNG and LPG vehicle conversion projects in recent years. However, high conversion costs and limited infrastructure, particularly refuelling stations for converted vehicles, will pose challenges to mainstream adoption.

4.3. LPG Demand Outlook

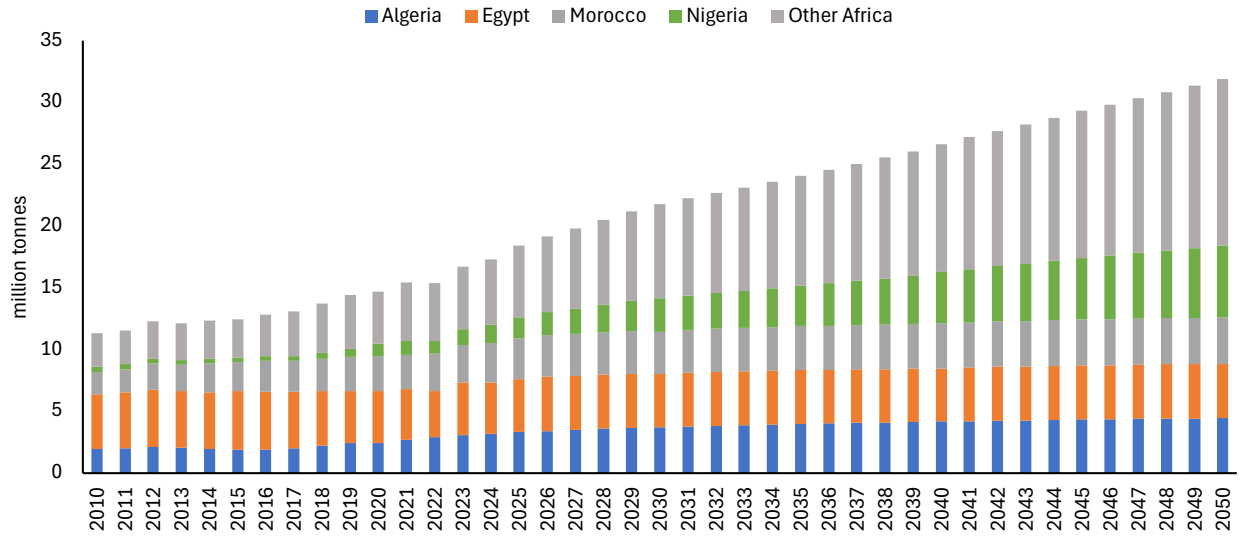
Today, nearly 2.5 billion people (one-third of the global population) are without access to clean cooking solutions, including over 900 million in Africa. In remote villages and low-income urban areas, many families use traditional biomass fuels such as coal, paraffin, wood and dung, which emit toxic fumes and contribute to climate emissions and deforestation.

To improve this situation, LPG is identified as the most abundant and cleanest available option for many African households. Its ease of transport and storage makes it a practical choice, especially in regions where infrastructure for electricity and solar power is still underdeveloped. As an example, switching to LPG from firewood as a cooking fuel leads to many benefits of each African household, e.g.:

- Reducing indoor air pollution from particulate matter by 98% – significantly decreasing the number of premature deaths and health conditions caused by household air pollutants.
- Saving 1.2 million hectares of forest per year – equivalent to nearly one-quarter of current global deforestation.
- Decreasing emissions of black carbon (or soot), a powerful greenhouse gas (GHG), by 117 million tonnes of CO2 equivalent per year – nearly offsetting Nigeria's annual CO2 emissions.
- Decreasing 279 million tonnes of CO2 per year – roughly equivalent to the annual emissions from mid-sized countries such as Taiwan and Malaysia.

Implementing the switch from firewood to LPG presents both challenges and opportunities for Africa, requiring the development of regulatory frameworks, consumer financing plans, and the construction of necessary infrastructure. These efforts could result in significant increases in LPG consumption across the continent.

Figure 7. Africa LPG Demand



Source: S&P Global Energy

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The Strait of Hormuz disruption has had an impact on global LPG markets, raising questions on both affordability and competitiveness of residential use of LPG in Africa. Supply constraints have raised delivered LPG costs through higher benchmark prices, freight and risk premiums, especially in import-dependent markets. Household demand response may potentially appear first through lower refill frequency and greater fuel stacking, rather than any immediate switching away from LPG. However, the response is largely dependent on subsidy structures in individual markets, capability of governments to absorb additional costs and availability of competing fuels. While the current situation is not likely to create any widespread physical supply shortages, impact on affordability will determine consistency of LPG demand.

4.4. Refinery Projects in Africa

Africa accounts for roughly 3% of the world's total refining capacity at just under 3 million b/d as of 2026, with most of the capacity concentrated in just four countries. Algeria, Egypt, Nigeria, and South Africa collectively make nearly 80% of the continent's total refining capacity.

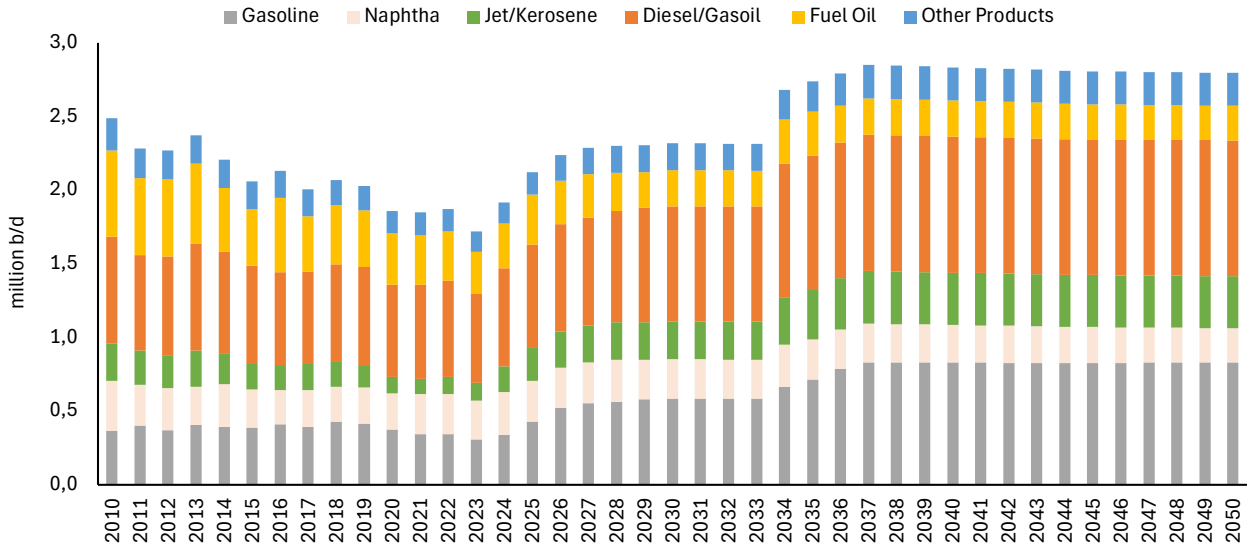
Before 2024, refining capacity and supply in the region had been on a downward trend due to several shutdowns. Over the last few years, closures of refining capacity in South Africa, led to the loss of nearly 300,000 b/d of capacity.

However, regional refining capacity was significantly boosted in 2024 with the commissioning of the 617,500 b/d Dangote refinery in Nigeria, by far the continent's largest plant. Since then, the refinery has ramped up operations to full capacity and is now supplying domestic, regional, and international markets. Additionally, the launch of Ghana's greenfield 40,000 b/d Sentuo refinery and the completion of expansion works at Egypt's Midor Amiriyah refinery (which increased the facility's capacity from 100,000 b/d to 160,000 b/d), have further strengthened the region's refining landscape.

In 2025, African refineries produced over 2.1 million b/d of refined products, an 11% increase over 2024 volumes, mainly due to additional supply from the Dangote refinery. Additionally, due to high margin environment driven by the current supply disruption, refinery utilisation rates are expected to be particularly strong. Crude discharges at Lekki and sourcing of additional regional crude point to relatively high operating rates at Dangote.

Over the long-term, Africa's refinery utilization rate is projected to average around 83%, while crude and condensate runs will sit just below 3 million b/d.

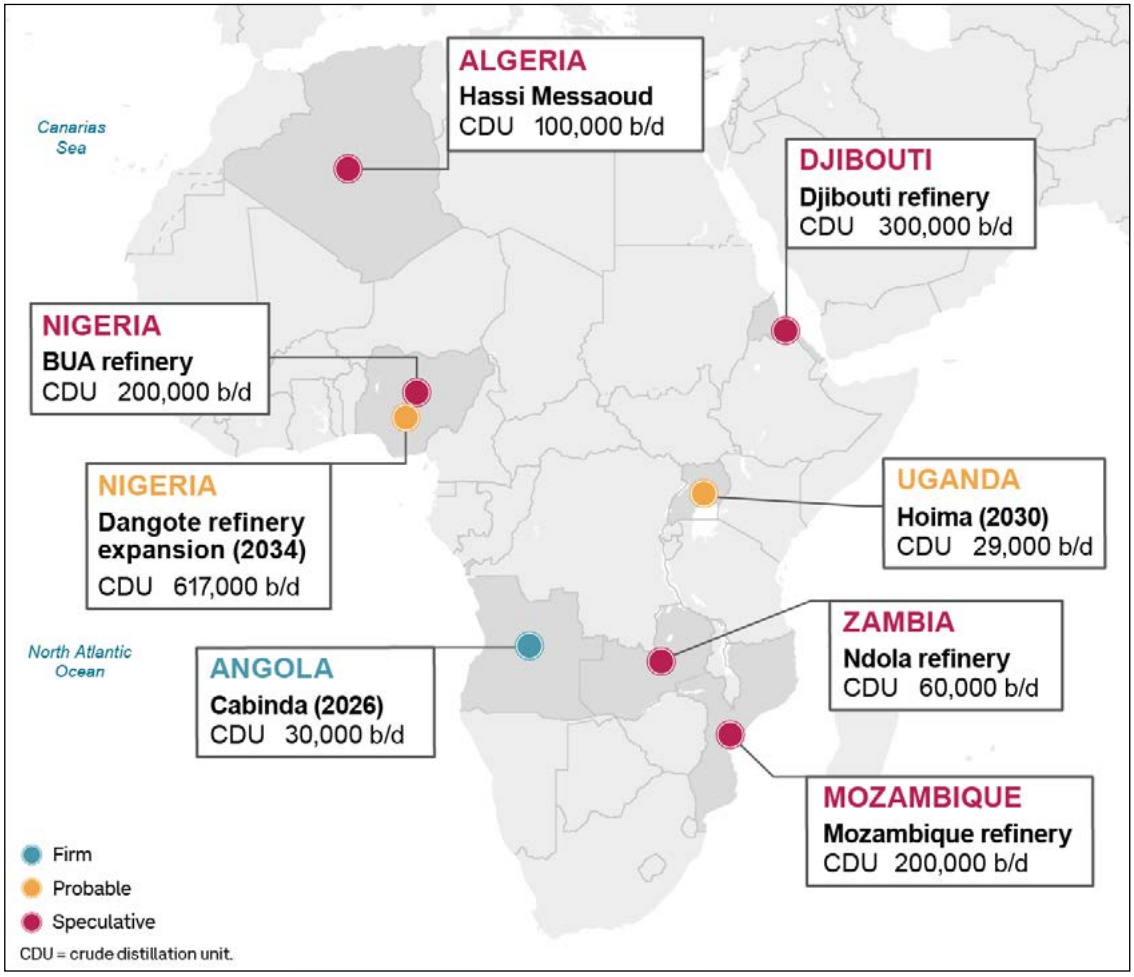
Figure 8. Africa Refinery Production



Source: S&P Global Energy

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Figure 9. Announced Africa Refinery Projects



Source: S&P Global Energy

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We expect Africa's refining capacity to receive a significant boost in the mid-2030s due to the planned Dangote II expansion project, which will bring roughly 617,000 b/d of additional capacity, taking the region's total capacity above 3.5 million b/d.

Apart from Dangote's expansion, we expect only a handful of refinery projects to materialize in the short to medium term. Limited funding opportunities and competition from imports will be the main impediments to further refinery project development.

Cabinda refinery is the only greenfield refinery project expected to come online in Africa in the near-term. Following some delays, the project's first phase, which includes the commissioning of a 30,000 b/d crude distillation unit, is scheduled to begin operations by end-2026. Phases 2 and 3 of the project aim to add an additional 30,000 b/d of capacity to the plant. However, at this stage, these expansion phases are considered speculative.

Another likely greenfield project is Uganda's Hoima refinery. The project aims to secure local added value in the context of the start of domestic crude production at the country's Lake Albert fields, which is slated to commence in the second half of 2026. The project's first phase, with a capacity of 29,000 b/d out of a planned total of 60,000 b/d, is not expected to be completed before 2030 at the earliest.

Dangote Industries has also recently proposed a large scale 700,000 b/d refinery in Lamu, Kenya, which could reshape East Africa's fuels market, shifting the region away from import dependence. Dangote's delivery of the Lekki refinery demonstrates an ability to execute complex, capital-intensive projects, potentially improving the likelihood that East Africa can establish a commercially viable refining centre that supports the region's long-term energy security objectives. However, the project remains at an early stage of development. Key aspects of financing, execution and commercial structure all remain to be defined as the project progresses.

Numerous projects have also been announced in various countries but seem unlikely to materialize, notably due to a lack of concrete financing solutions. Considering the growing reluctance from international financiers to back fossil fuel projects, future financing will likely need to be sourced domestically or from partners in the Middle East and Asia.

Against that backdrop, the African Energy Bank, a partnership between Afreximbank and the African Petroleum Producers Organization, is slated to commence operations in July 2026 and could help close some financing gaps.

For a refinery project to be viable, it either needs to be economically attractive or receive significant state support, justified based on domestic refined product supply security, and/or dovetail into the narrative of supporting the domestic economy, or ideally all of these. To be economically attractive, it is almost certain that a new refinery project needs to be located in proximity to crude producing assets and refined product demand centres. If this is the case, then the economics of the refinery construction and operations are supported by savings that would occur from no longer having to transport locally produced crude oil to distant markets and no longer having to transport refined products from distant markets to meet domestic demand.

Notable large-scale projects that have been announced include a 300,000 b/d plant in Djibouti, and a 200,000 b/d plant in Mozambique's Vilankulo district. However, these projects remain highly speculative at this stage.

4.5.Refined products trade balance

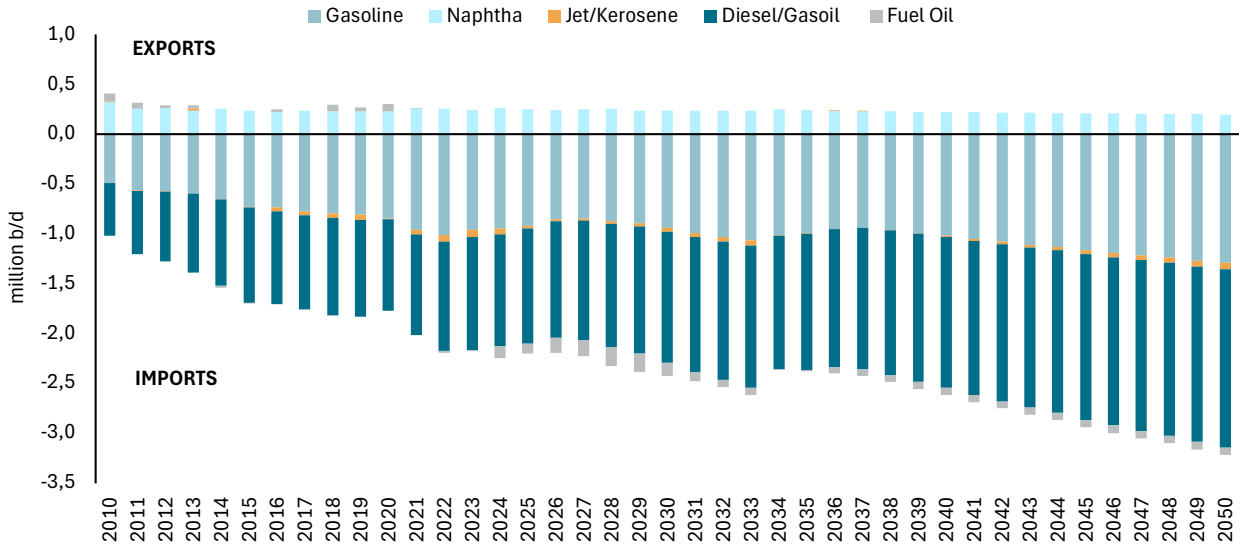
Apart from naphtha, Africa will remain short on all major products through to 2050 and will therefore continue to rely on imports from other regions to make up the shortfall.

The Dangote refinery's ramp-up to full capacity and high utilization rates combined with Angola's Cabinda refinery, constrain refined product import growth in the short term.

While the expected expansion of the Dangote II refinery to 1.3 million b/d will put a dent in net imports in the mid-2030s, import flows are nevertheless projected to grow strongly out to 2050, driven by robust demand growth and limited capacity additions.

Gasoil net imports are projected to amount to 1.8 million b/d by 2050, while gasoline net imports are expected to reach nearly 1.3 million b/d in the same period.

Figure 10. Africa Oil Product Net Trade



Source: S&P Global Energy

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Gasoline imports will remain structurally dependent on European supply over the long term; however, East African markets are expected to be primarily supplied from the Middle East, once flows through the Strait of Hormuz are restored. Supply from India's export refineries and supply from Singapore's trading and storage hub are also expected to be a primary source of gasoline for East African markets.

Diesel/Gasoil supply is also expected to be dependent on Middle Eastern surpluses with additional volumes sourced from Asia Pacific to Eastern and Southern parts of Africa. However, Europe, which has traditionally been a net importer of distillates is expected to switch to a net exporter in the long-term due to declining domestic demand. This is expected to increase availability of diesel/gasoil volumes for export into African markets.

4.6.Challenges and opportunities in Africa's oil trade

Many African countries, especially in West and North Africa, are rich in crude oil reserves and continue to export substantial volumes to international markets. However, despite being crude oil producers, most African countries lack sufficient refining capacity, which forces them to import refined products.

This paradox has led to a busy trading flow, with tankers constantly shipping crude oil out of the continent and refined products into the continent. This makes Africa a hub in global oil shipping routes. The trading ecosystem includes international oil companies, NOCs, commodity traders and shipping firms.

However, several elements of this are not efficient:

- Instead of capturing value through refining, storage and downstream infrastructure, African nations often export low-value crude oil and import high-value refined products, losing out on job creation, skills development and industrial growth. There is also little regional integration in oil trade; most countries trade with Europe or Asia instead of their neighbours, missing out on building a more resilient intra-African energy market, although the African Continental Free Trade Area (AfCFTA) may improve this situation.
- Also, importing refined products is more expensive than refining domestically and product supply needs to be priced on an import parity basis. African countries pay a premium for transport, insurance and intermediary fees and markups.
- Heavy reliance on imports puts additional pressure on local currencies, as physical deliveries are priced in USD, contributing to economic challenges.
- Dependence on imports for refined products exposes countries to global supply disruptions, such as the ongoing constraint of product flow through the Strait of Hormuz.

- Also, while Africa's oil trading markets are dynamic, these are not yet efficient, owing to structural imbalances, infrastructure gaps and dependency on external players.

Addressing these inefficiencies could unlock significant economic and strategic benefits for the continent. Also, investment in refining capacities, such as Dangote in Nigeria or government-led upgrades in Angola and Egypt, can gradually reverse the trade imbalance. In addition, policy reforms, better regulations and regional cooperation are needed to make African oil markets more efficient, self-reliant and inclusive. Finally, energy transition plans and growing interest in renewables may also reshape how Africa approaches energy security and the oil trade over the next two decades.

4.7. Infrastructure and investment considerations

Regional infrastructure has struggled to handle existing product flows. In East Africa, for e.g., shippers at Beira, Dar es Salaam and Mombasa — the key entry ports for refined products — are experiencing significant demurrage, often stretching beyond 20 or 30 days. Onshore, the situation is challenging as well. Pipeline systems linking Beira in Mozambique to Harare in Zimbabwe, Dar es Salaam in Tanzania to Indeni in Zambia, and Mombasa on the Kenyan coast to Eldoret in western Kenya are all constrained, resulting in significant product volumes to be moved inland along these corridors by road. There are proposed projects to expand pipeline capacities, which would be instrumental for petroleum products supply and distribution, as demand continues to grow.

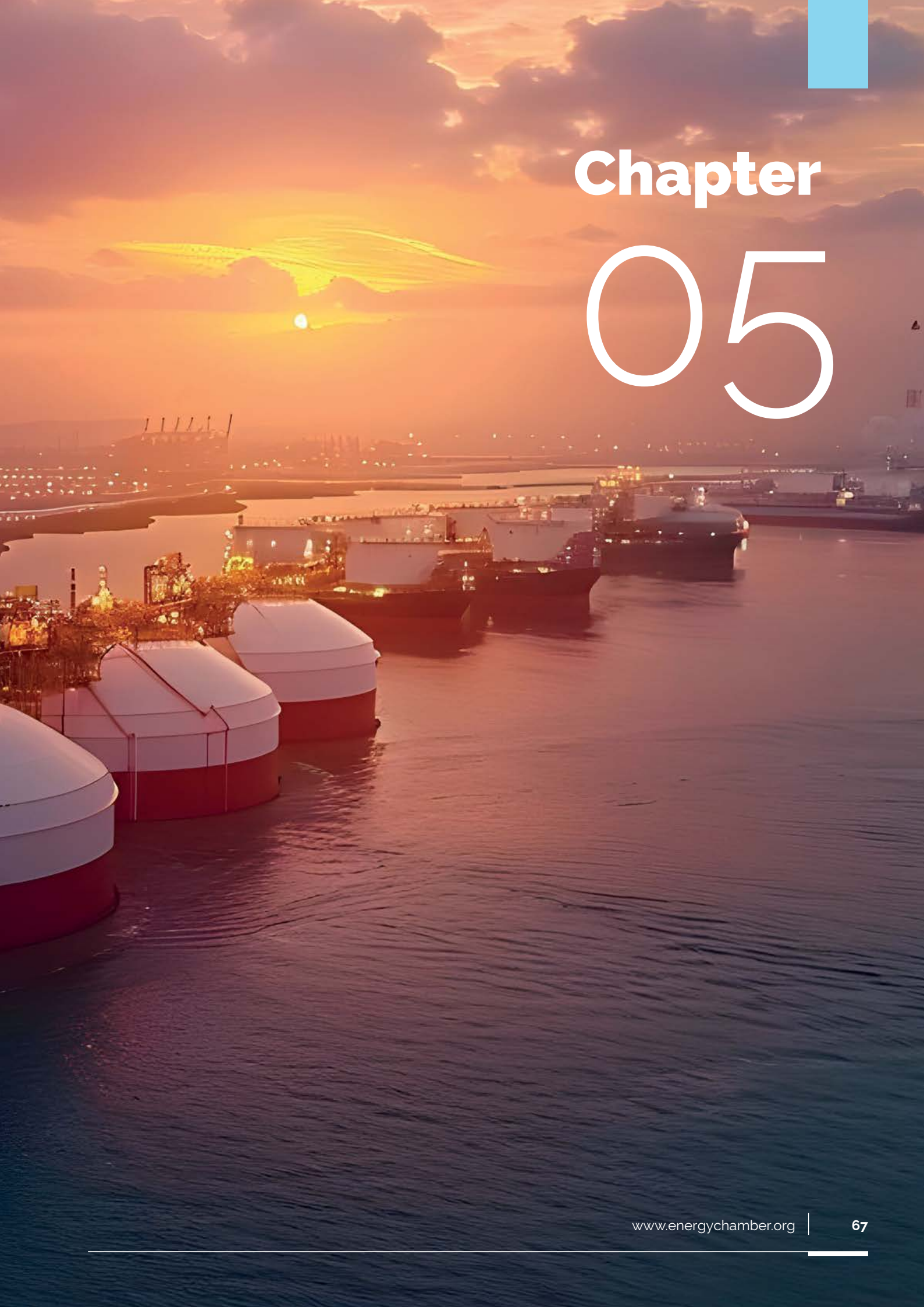
The importance of infrastructure projects should not be underestimated. Infrastructure development serves as the backbone of economic transformation, and Africa's growth potential remains significantly constrained by critical gaps in cross-border connectivity, particularly in energy, transportation, and storage systems. The continent's, unfortunately often somewhat fragmented, approach to infrastructure investment has resulted in isolated national projects that fail to capture the economies of scale and network effects essential for supporting growth. When African nations collaborate on regional infrastructure initiatives, they unlock transformative growth opportunities that individual countries cannot achieve alone. The African Continental Free Trade Area (AfCFTA) has already demonstrated the economic potential of regional integration, and extending this collaborative spirit to infrastructure development could catalyse industrial growth, reduce operational costs, and attract foreign investment. By harmonizing regulatory frameworks, pooling financial resources, and prioritizing projects with regional impact, African governments can transform infrastructure from a barrier into a catalyst for continental prosperity.

The current disruption of flows from the Strait of Hormuz and at the same time reduced diesel/gasoil supply from Russia has exposed some of the import vulnerabilities and limited stock reserves across African markets. In response to the supply disruption, many countries have taken further steps to increase supply security and manage potential supply shortages, for example:

- Tanzania has moved to centralize bulk procurement of refined products;
- Uganda and Namibia are increasing the state entity's role in fuel procurement;
- Rwanda has signed deals to enhance fuel supply security by expanding access to the Central Corridor through Tanzania's Port of Tanga and the Northern Corridor through Kenya;
- Mozambique created a state-owned fuel procurement company to centralize and oversee fuel imports.

Going forward, pressure on supply chains and the need to enhance supply security will increase, as net import requirement for refined products increases to 3.0 million b/d in 2050 from 1.9 million b/d in 2025. It is projected that the downstream infrastructure investment requirement to support this increase is in excess of $20 billion. This underscores the growing need for coordinated investments in African ports, import terminals, pipelines, storage for distribution, and roads and trucks to execute the distribution.





Chapter 05

5. Gas and LNG Outlook – Africa Gas and LNG Export Opportunities

Strategic Positioning and Export Growth

2026 is proving to be another critical year for global gas and LNG markets and brought more focused attention to Africa's future as a growing consumer and exporter of natural gas. As a producer Africa offers diversity and competitive molecules to support value chain security, whilst Africa is also emerging as a key growth market. Case studies provide a deeper dive on timely issues and gas monetization opportunities in Mozambique and South Africa and a case study of synergies between the existing resource base and infrastructure and new gas developments and monetization opportunities in Libya.

Narrative: Africa's Gas Ascendancy - From Resource Abundance to Economic Transformation

Africa is at the center of one of the most consequential shifts in global energy: the emergence of Africa as a structurally important supplier and consumer of natural gas. The continent holds resources that would be transformational anywhere in the world and Africa is now structurally positioned as a long-term pillar of global supply, while the strategic logic is pulling decisively toward domestic deployment as the primary engine of industrialisation, power generation, and economic development. The central insight is that converting this resource endowment into lasting transformation is not a question of reserves or demand, it is a question of regulatory and commercial architecture.

Strategic Positioning and Export Growth

2026 is proving to be a critical year for African gas. With more than 550 Tcf of undeveloped recoverable gas volumes, Africa is uniquely placed to supply global markets seeking diversification while deploying gas as a catalyst for industrialization, power generation, and economic development. Supplying 9% of global LNG in 2025, Africa's geography offers a supply corridor that bypasses the Strait of Hormuz, an advantage amplified by the Hormuz closure, which removed 17% of global LNG supply from Qatari and Emirati producers. By 2030, 13 MMtpa of additional liquefaction capacity is forecast to come online, with pre-FID projects capable of contributing over 60 MMtpa over the next 25 years. Currently Africa has almost 45 MMtpa of floating LNG (FLNG) either operating, under construction or close to FID, showing that African LNG is not simply a beneficiary of current disruption; it is structurally positioned as a long-term pillar of global gas supply and innovation.

Domestic Transformation: Power, Industry, Anchor Demand and Aggregators

Although exports will remain important, the strategic logic is now pulling governments toward domestic markets for structural rather than incidental reasons. Export revenues provide state income but do little to directly address electricity deficits, fuel import costs and volatility, or industrial competitiveness. Gas deployed domestically does all three, while generating In Country Value through investment, localization and job creation.

This explains why at least 13 Sub-Saharan African countries now have explicit policies promoting domestic gas use, and why gas-fired generation is forecast to grow 40% to 2040. Beyond power, gas is a critical industrial feedstock, underpinning fertilizer, methanol, and petrochemical value

chains that transform an associated gas resource into an engine of economic development. Domestic Market Obligations attached to LNG projects are channeling gas into local markets, creating the anchor offtakers that underpin both upstream and infrastructure investment.

Realizing this potential at scale requires demand aggregators - entities that consolidate dispersed, individually uneconomic buyers into a single credible offtake commitment large enough to support project financing. Gas infrastructure requires long-term contracts before it can be financed, yet those contracts cannot be signed without infrastructure; no single small buyer can bridge this gap alone. Where aggregation mechanisms resolve it, as Nigeria's Decade of Gas and Angola's Soyo hub each demonstrate, investment follows.

Import Infrastructure, Regional Pipelines, and Energy Transition

For countries lacking large domestic resources, a wave of new global liquefaction capacity is expected to keep LNG prices low for much of the next decade, opening a timely window for import infrastructure investment. Senegal became Sub-Saharan Africa's first LNG importer in 2025, and South Africa, Kenya, Morocco, Côte d'Ivoire, and Ghana are all advancing regasification activity. Global LNG players with long portfolio positions are increasingly seeking new demand centers, with Africa emerging as a key destination.

Regional co-operation can support the development of African gas pipeline value chains. Three major pipeline corridors further expand the regional energy landscape: the African Atlantic Gas Pipeline connecting Nigerian gas through West Africa to Morocco and Spain; the Trans-Saharan Gas Pipeline via Niger to Algeria; and the Nigeria-Libya Pipeline linking to Italy via existing Mediterranean infrastructure. These corridors would deepen regional energy integration and extend gas access to economies currently consuming none.

The primary consideration for large-scale investment across Africa is rarely a shortage of demand. It is, rather, the commercial and regulatory architecture needed to unlock that demand. South Africa's Gas Master Plan, Nigeria's evolving domestic gas pricing and supply framework, and Angola's structured approach to industrial development at Soyo each reflect an emerging understanding that regulatory design is not a secondary consideration but the foundational enabler of gas sector growth. Countries that establish clear commercialization pathways, credible pricing frameworks, and well-structured aggregation mechanisms will be best placed to convert Africa's extraordinary resource endowment into lasting economic transformation.

5.1. Positioning Gas and LNG in Africa in a Global Context

Africa lies at a trijunction within the global gas market: a long-time major exporter, an emerging domestic market seeking to leverage large gas reserves, and a growing LNG importer too.

Firstly, with significant gas reserves (>550 Tcf), Africa is a net contributor to the global gas market through both LNG and pipeline exports. In North Africa, the historical center of African gas production with for roughly two-thirds of continental output, Algeria and Libya have long benefited from their pipeline export relationships with Europe. Looking ahead, Africa is poised to increase its contribution to global gas supply, particularly Sub-Saharan Africa, which has over 400 Tcf remaining recoverable resources, 70% of the continent's total.

Africa supplied 9% of the global market in 2025, playing a geographical swing role due to its position between the European and Asian markets, This is role is further advanced by avoiding geopolitical and physical chokepoints such as the Straits of Hormuz and the concentration risk identified in the on the US Gulf Coast. This is particularly evident in West Africa, where LNG exports were split roughly evenly between European and Asian buyers. African exports (either through LNG or pipeline volumes) provide buyers with alternative and geographically diversified supply sources, a value proposition that has been reinforced by the two gas market disruptions witnessed over the past five years. Furthermore, with US Henry Hub prices expected to rise over the longer term, African gas volumes are likely to become increasingly competitive, strengthening the continent's position within global gas markets.

Monetization of the gas, however, is expected to pivot beyond exports only. With rapidly growing populations and forecast growth in primary energy demand driven by industrialization, electrification and potential AI-driven ambitions, gas is increasingly recognized as a tool to accelerate development. Gas' versatile role in industry and power generation can be leveraged to drive economic value beyond extraction and export. Governments see significant value in the potential for gas intensive industry, stable power grids, domestic use and transportation, reducing imports of costly fuels priced at international levels. These activities can create greater In Country Value (ICV) through investment, job creation and the development of further economic value chains.

In addition, the impacts of the Straits of Hormuz closure have been felt globally across different commodities, not just oil and gas. This has highlighted the importance of localizing and diversifying value chains for fertilizer, industrial gases, chemical feedstocks etc. This creates opportunities for African countries, rich in natural resources, to provide secure, reliable value chains domestically and regionally through the development these gas intensive industries.

Gas already makes up an important part of the domestic energy mix and economies of North Africa and, increasingly the West African Margin (Nigeria to Côte d'Ivoire) – growth that was driven primarily by domestic resource exploration. Sub-Saharan Africa is expected to be a major focal point for future gas consumption growth from both domestic and imported sections. The power sector is the focus to improve energy security through cleaner, lower cost dispatchable power in co-ordination with renewables to meet growing electricity demand. However, other sectors such mining, industry and transport are gaining traction as future sources of demand. Some governments are promoting these developments through Gas Master Plans and revamps of relevant policy documents as a starting base for nascent gas value chains.

African countries with gas resources can leverage domestic production to support these objectives, following the path taken by other gas-producing economies. As a result, incentivising upstream and midstream development has become a central theme in discussions around domestic gas utilisation. Resource nationalism is also becoming increasingly prominent, even in markets historically focused on exports, as domestic gas supply can reduce exposure to imported fuel costs, foreign exchange constraints, credit risks and supply chain disruptions. However, there is also a realisation that co-ordination between countries on infrastructure and pooling of demand can help maximise economic value on a regional basis.

However, there is also an opportunity for increased LNG imports that would go hand in hand with gas value chain development. 2025 already saw the recommencement of LNG imports into Sub-Saharan Africa through Senegal's gas-to-power project in Dakar. The global gas market is expected to move towards surplus at the end of this decade following a boom in the LNG supply growth from the US and other emerging exporters, including African projects, following the curtailment of Russian exports to Europe but also the recognition that natural and LNG will play a key role in the forecast rapid increase in energy demand globally.

This wave of new supply is expected to keep S&P Global's European and Northeast Asian gas price benchmarks at competitive levels for much of the next decade. As supply grows and prices fall, the next two to three years could provide a significant opportunity for LNG import infrastructure investment. Global LNG players with long portfolio positions are increasingly seeking new demand centers to place volumes, with Africa emerging as a key destination. Countries such as South Africa, Kenya, Morocco, Côte d'Ivoire and Ghana are already attracting activity around LNG import infrastructure. Beyond improving access to gas supply, these developments could help catalyze investment across the midstream segment, helping address infrastructure gaps that have long constrained broader gas market development in Africa.

In terms of tangible gas investment, Africa should not be seen as a single unit but as 54 individual countries with different interdependencies and synergies with each other. Each country provides unique opportunities on the 'trijunction' of the gas value chain which requires unique tailored to market solutions, from both governments and the private sector. Gas expansion is already progressing in numerous countries with first-mover projects across all aspects of the value chain. Record levels of commercial activity are observed for dedicated gas production projects, pipeline development, LNG exports and imports projects, plans for gas-fired power assets, as well as fertilizer and trucked LNG use. This activity will support economic development and energy access whilst also providing a long-term monetization route for more than 550 Tcf of undeveloped recoverable gas volumes.

5.2.Gas market development: opportunities and challenges

Whether consumed domestically or exported via pipelines and LNG, natural gas has the potential to fundamentally transform economies. By meeting the surging energy demands driven by electrification, urbanization, and industrialization, gas serves as a highly scalable catalyst for development.

Beyond expanding energy access, domestic gas resources generate vital export revenues while shielding economies from the volatility of imported fuels. Crucially, a reliable and affordable gas supply drives in-country value (ICV). It stimulates local value chains, attracts industrial investment, creates jobs, and fuels the growth of downstream industries across the transportation and power sectors.

Gas also plays an essential role in the energy transition, allowing nations to balance economic ambitions with climate commitments. As a lower-carbon alternative to coal, oil, and traditional biomass, it serves as a vital bridge fuel while renewable capacity expands. Furthermore, capturing and monetizing associated gas that would otherwise be flared during oil production simultaneously improves resource efficiency and reduces emissions.

While the monetization of these resources in Africa has historically focused on exports, this paradigm is shifting. Particularly in Sub-Saharan Africa, the next major frontier lies in developing the gas value chain to fuel domestic markets and power local economic expansion.

5.2.1. Exports via LNG or pipeline - Opportunities amid the Middle East War

International LNG demand is already a key driver of African gas development. Africa accounted for 9% of global LNG supply in 2025, with exports providing a valuable source of revenue through fiscal receipts, royalties and taxes. In oil-producing markets, LNG development can also monetize associated gas that would otherwise be flared or vented, improving the emissions intensity of upstream operations. LNG remains an attractive monetization pathway given access to international gas prices, which are often significantly higher than regulated domestic gas prices. North Africa has long underpinned Africa's export position through LNG and pipeline sales to Europe, while new projects in Sub-Saharan Africa are expanding the continent's role in global gas supply.

Since 2022, shifting global gas dynamics, including the loss of Russian pipeline gas to Europe and rising Asian demand, have accelerated investment in African LNG. African LNG exports are already set to grow through existing expansions, debottlenecks, and recently sanctioned projects, increasing opportunities for interested buyers to sign offtake contracts. By 2030, we forecast 13 MMtpa of additional African liquefaction capacity to come online (Figure 1 TK). Nigeria LNG (NLNG) alone is expected to add 7.6 MMtpa through an additional train and debottlenecking of Trains 1-6 by mid-2027. In Nigeria, key blueprint projects Key gas projects have progressed to FID (Ubeta, Bonga North, and HI projects) dedicated to providing feedgas to NLNG that advanced specifically because of the new government regulations within Decade of Gas initiative (2021–2030).

Africa's medium-term export volume growth makes a noteworthy contribution to the ongoing major expansion in global LNG supply – beyond Nigeria, with Senegal-Mauritania's cross-border Greater Tortue FLNG project commissioning in 2025 and already operating at high utilization, and Congo's FLNG commissioning in spring

2026. Additionally, we forecast Mozambique to rapidly grow to become the largest LNG exporter out of the continent by 2033. In October 2025, Eni took an FID on its second FLNG unit to be deployed in the Coral field, with first volumes forecast for 2029. TotalEnergies' 13 MMtpa onshore Mozambique LNG project has resumed construction following the October 2025 end to a four-year force majeure triggered by an Islamist insurgency in the country. Although FID is yet to be taken, ExxonMobil's 18 MMtpa Rovuma LNG project to reach FID by end of 2027, with first volumes forecasted in 2032. The project shares a construction site with Mozambique LNG, and the improvement in regional security conditions has materially strengthened its outlook.

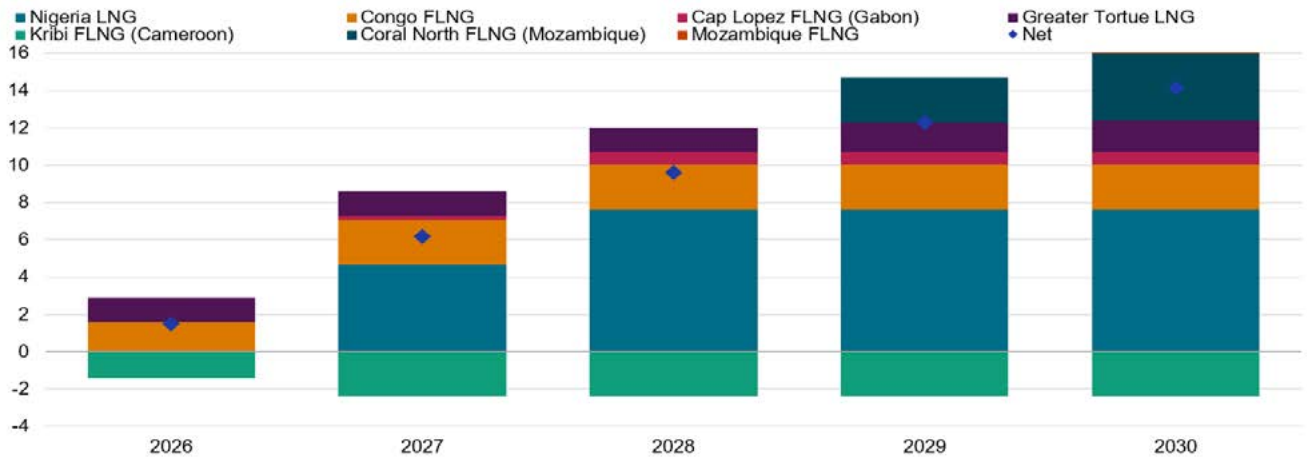
The war in the Middle East, which resulted in the abrupt loss of nearly all supply from Qatari and Emirati liquefaction projects (17% of global LNG supply) due to the closure of the Strait of Hormuz, has however placed African LNG volumes under renewed attention – especially as alternate volumes providing diversity of supply in strategies hedging against the concentration of volumes in the US Gulf Coast, Persian Gulf and Australia.

The immediate short-term response from Africa was limited as most African liquefaction plants already running at or above nameplate at the war's onset. However, growing output in the works prior to the war is playing a role in mitigating the market impact of the war. 6 MMt in year-over-year growth is expected from the continent in 2026. Nigeria accounts for most of this growth due to recent improvement in utilization and lifting deliveries by a third. Most of the response from African exporters was commercial, with liquefaction projects in Nigeria, Angola, and Equatorial Guinea optimizing spring cargoes to chase spreads between Asian and European buyers.

In the longer term, the current gas crisis, the second the previous 5 years, once again underscored the need for buyers to diversify supply risk. Prolonged disruption in the Strait of Hormuz could also affect the construction timelines of Qatar's and the UAE's expansion projects and the two damaged trains, are expected to remain offline for the remainder of this decade thus buyers and portfolio players are looking towards alternative source – and African volumes can be attractive. West African LNG volumes sit between the Atlantic and Pacific basins, letting sellers arbitrage Europe Asia spreads, while East African projects offer Asian buyers a non-Hormuz route with competitive distances.

Crucially, African volumes also help buyers hedge a sec-

Figure 1. African LNG exporters – Near-term supply buildout (MMtpa)



Source: S&P Global Energy

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ond concentration risk the mindset paper flags, over-reliance on US Gulf Coast supply, with its hurricane and trade-policy exposure, giving African LNG a genuine "risk discount" appeal. Equity-marketed volumes would further spread offtake risk across partner portfolios, giving those players supply that is unexposed to US or Persian Gulf geographic risk. African projects fed by associated gas or large-scale non-associated resources carry lower short-run marginal costs than many US projects, which strengthens their netbacks to both basins and gives them room to compete on pricing flexibility as buyers seek indexation variety.

Looking ahead, this region is further expected to drive significant growth in supply, with X% growth in supply expected in the next 25 years. Beyond Rovuma LNG, multiple pre-FID projects are in talks in existing exporters such as in Nigeria (with two potential FLNGs and further expansion of the existing plant), Angola (expansions of existing plants and new trains), Mozambique (a third FLNG), Senegal and Mauritania (expansion of current project). Further projects are being conceived in new entrants such as Tanzania. In total, pre-FID projects could contribute to over 60 MMt of supply in the next 25 years. For scale, Qatar's and the UAE's expansion projects, North Field East, North Field South, North Field West and Ruwais LNG, together represent around 74 MMtpa of under construction capacity; illustrating how Africa could underpin the next expansion phase in the LNG market.

Liquefaction projects as catalysts for domestic gas market expansion

LNG liquefaction projects can also provide an avenue for governments to negotiate domestic gas allocations and the development of infrastructure which would facilitate domestic gas market expansion with IOC and NOC developers. LNG projects in Nigeria, Senegal-Mauritania, and Angola provide anchors for gas development, allowing a portion of supply into local markets. Where these obligations remain modest, they are generally compatible with project sanctioning and can provide an effective means of stimulating domestic gas demand as gas processing infrastructure and means of delivery often exist. In this way, export projects can act as a catalyst for broader gas market development by securing domestic supply and supporting the build-out of enabling infrastructure. Whilst Nigeria was the first mover in Sub-Shahram Africa, this has also been seen most recently in Angola and Senegal where development of LNG projects with agreed on DMOs induced the development of gas consuming assets. The under-construction Gandon gas-fired power station in St Louis will utilize the gas from the DMO of Greater Tortue project, with the pipeline to link the offshore facility to the powerplant currently under construction. Angola meanwhile has seen the development of a gas consumption 'hub' surrounding the onshore Angola LNG site in Soyo. There is already the existing 750 MW Soyo power plant sourcing gas from Angola LNG, with further plans for phase 2 expansion. Additionally, there is advanced plans for a 3800 metric tonne per day ammonia plant at site, also off taking gas from the LNG plant.

FLNG could provide additional upside to African LNG

Floating LNG could provide additional upside to African LNG export volumes. Africa has emerged as the world's leading region for FLNG development, hosting four existing projects that together account for nearly 60% of global floating liquefaction capacity. Floating projects offer multiple advantages, ranging from enhanced security given distance from onshore conflict – as evidenced by Mozambique – to their redeploy able nature, which allows assets to be relocated in the event of political instability or natural disaster. Above all, FLNG projects stand out for their operational flexibility, and as technology matures and scales globally, costs have also trended downward. As such, new floating projects could see increased momentum across the continent if interest in new African projects grows due to the war in the Middle East.

Pipeline developments

Crucially, LNG is not the only route to monetising Africa's gas resources. Cross-border pipelines offer a parallel export pathway, with the added advantage of stimulating demand along their routes. By traversing multiple countries, these projects can enable transit markets that currently consume little or no gas to connect directly to the network, supporting domestic gas use and market development alongside exports.

Three pipeline projects are currently under consideration to transport Nigerian gas to North Africa and onward to Europe (Figure 2): a western route running along the Atlantic coast to Morocco, and two northbound alternatives via Libya (the Nigeria-Libya Pipeline) and Algeria (the Trans-Saharan Gas Pipeline). Excluding Russia and the United States, all three would rank among the longest gas pipelines ever proposed.

The African Atlantic Gas Pipeline AAGP is a proposed extension of the existing West African Gas Pipeline (WAGP), which has transported Nigerian gas to Benin, Togo and Ghana since 2010, primarily for power generation. Joint-

ly developed by Nigeria's National Petroleum Company Limited (NNPC) and Morocco's National Office of Hydrocarbons and Mines (ONHYM), the project took a significant step forward with the signing of an Intergovernmental Agreement (IGA) under the auspices of ECOWAS in 2026. By building on existing regional infrastructure, the project demonstrates how pipeline networks can progressively expand the pool of gas-consuming markets. The AAGP could pass through 11 transit countries and ultimately connect to Spain via the Maghreb-Europe Gas Pipeline, allowing participating countries to access gas for power generation, industrial use and broader economic development. At 5,925 km, it is the longest of the proposed export corridors and would run predominantly offshore before making landfall in Morocco.

The project is designed to serve multiple objectives simultaneously. Beyond strengthening regional energy security in West Africa and Morocco, it could support industrialisation and electricity generation across participating markets while establishing a new export corridor to Europe. In doing so, it would deepen regional energy integration, strengthen cooperation among ECOWAS members and attract investment into associated energy infrastructure.

Two alternative corridors would transport gas northwards rather than westwards. The Trans-Saharan Gas Pipeline would traverse Nigeria, Niger and Algeria over 2,865 km and gained renewed political support in July 2022 when the three governments signed a memorandum of understanding. The second option, the Nigeria-Libya Pipeline, would ultimately connect to Italy through the existing GreenStream infrastructure. Public reports suggest discussions between Lagos and Tripoli have resumed, with both sides exchanging technical data and revisiting earlier feasibility work.

Regardless of the route chosen, the commercial and political challenges are substantial. All three projects carry estimated costs of between $10 billion and $25 billion, while the NMGP would require alignment across a lengthy chain of transit states, each balancing regional ambitions against domestic priorities. More fundamentally, pipelines of this scale require a large and reliable resource base to underpin long-term supply commitments. In Nigeria's case, LNG remains the dominant export monetisation route for new upstream supply development, and further expansion of NLNG is likely to be prioritised before any long-distance export pipeline becomes commercially viable. As a rule, LNG tends to become the more economic export option beyond a certain distance, particularly for offshore routes particularly when speed of development is considered. The viability of these pipeline ambitions will therefore ultimately depend on how they compete with alternative LNG development pathways.

5.2.2. Domestic gas consumption

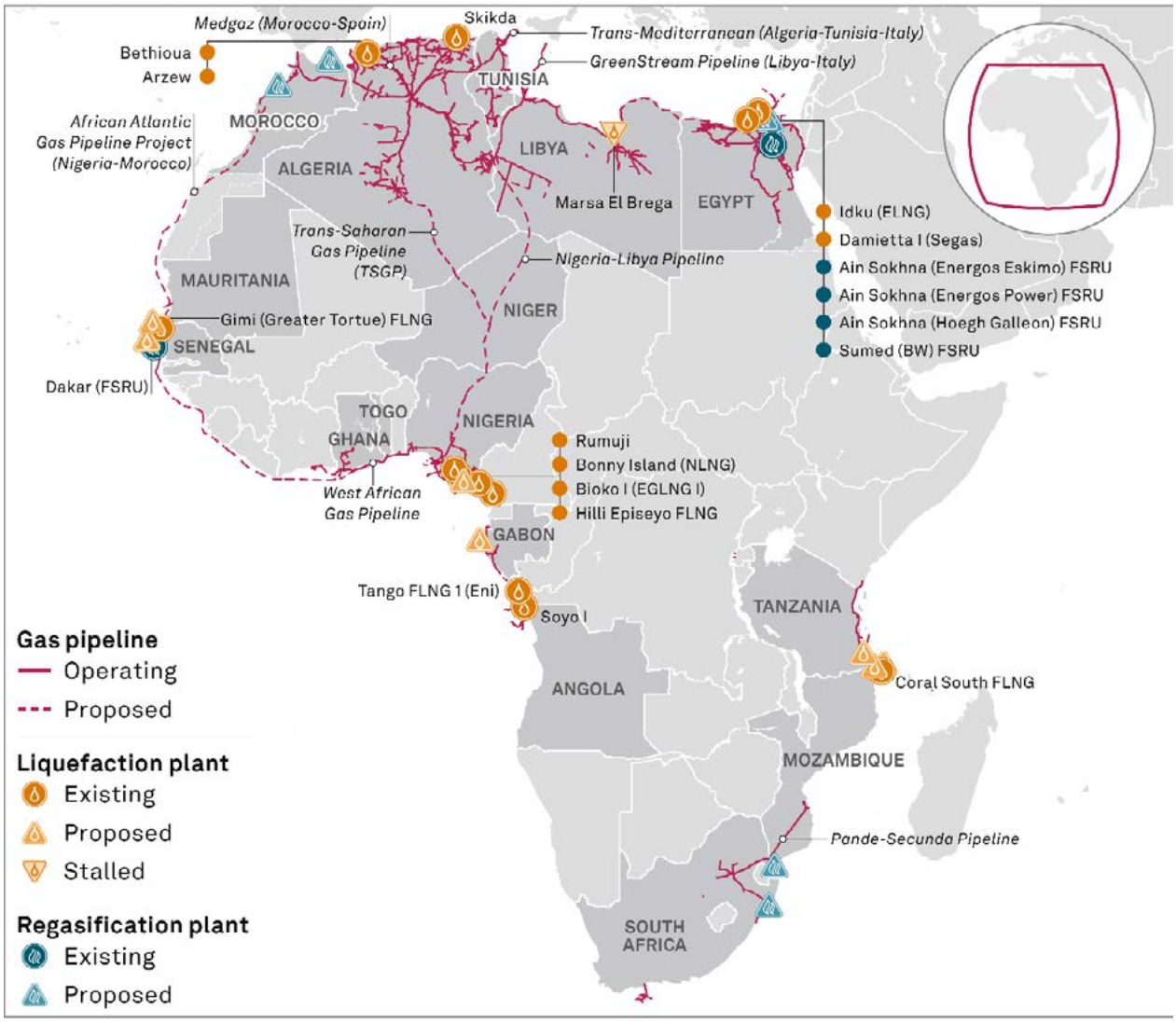
Domestic gas consumption is already at high levels in Egypt, Algeria, and Libya. The major growth opportunity now lies in Sub-Saharan Africa. At least 13 Sub-Saharan African countries have explicit government policies, master plans, laws or strategies promoting domestic natural gas use, with gas-to-power featuring across all of them and most also targeting industrial uses such as fertilizer, petrochemicals, methanol, cement, steel and industrial heat.

Currently, gas in Africa is primarily consumed for generating power. Rapidly growing populations and rising living standards will require significant expansion of electricity supply, while per capita power consumption remains well below the global average. The expansion of domestic gas markets through the power sector is likely to remain one of the most important growth opportunities for African gas demand over the coming decade and thus gas monetization. Gas-to-power offers an opportunity to improve energy access by both increasing flexible and base-load electricity generation. Gas can displace oil-fired generation and replace aging, inefficient coal capacity, particularly across Southern Africa, while complementing renewables, especially as increasingly unreliable weather patterns place strains on countries depending heavily on hydropower.

Gas-fired generation is already the main source of power generation in North Africa. The previous ten years saw a rise in gas-fired generation from North Africa, but increasingly from Nigeria, and the Western African margin (Figure 3). This growth is expected to continue with gas-fired generation is growing by 40% to 2040, solely led by Sub-Saharan Africa.

Nigeria hosts the most institutionalized domestic-gas policy stack in Sub-Saharan Africa and this has resulted in on-grid gas-fired capacity roll out in the past decade. The recent wave of gas-to-power capacity developments across Sub-Saharan Africa demonstrates that this growth is underway, with gas-fired capacity build-outs and project sanctioning at record levels. Countries including South Africa, Senegal, Mauritania, Angola, Ghana, Tanzania and Mozambique have either announced new gas-to-power ambitions or plans to expand existing capacity. The pace of growth will

Figure 43. African gas and LNG infrastructure



Source: S&P Global Energy; Upstream Content

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Major regional African pipeline projects

	Pipeline	Transit Route	Distance (km)	Estimated Cost ($ Bn)
1-	African Atlantic Gas Pipeline (AAGP)	WAGP -> Côte d'Ivoire -> Liberia -> Sierra Leone -> Guinea -> Guinea-Bissau -> Gambia -> Senegal -> Mauritania -> Morocco	5,925	$25 billion
2-	Nigeria-Libya Pipeline	Nigeria -> Niger -> Libya	2,210	$7-13 billion
3-	Trans-Saharan Gas Pipeline	Nigeria -> Niger -> Algeria	2,865	$10-16 billion

Source: S&P Global Energy

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vary by market, depending on factors such as the age and scale of existing coal and oil-fired fleets, renewable energy penetration, rising electricity demand and the condition of transmission infrastructure. Stronger grid networks could also unlock wider gas-to-wire opportunities, including power exports through regional power pools.

Senegal, albeit a small market, has made significant strides in developing its domestic gas value chain alongside its LNG export capabilities in recent years. Since 2024, Senegal has commissioned or advanced several gas-to-power projects focusing on new capacity or converting oil-fired generation to duel-fueled capacity. Examples include the 335 MW Karpowership LNG-to-power facility, the 366 MW Cap des Biches combined-cycle plant, and the 255 MW Gandon gas-fired power station, the first in the North of country, supplied by the DMO for Senegal/Mauritania's GTA FLNG project.

In West Africa, Ghana, utilizing both regional imports from the WAGP and domestic resources, is expanding gas-fired capacity by commissioning the 200 MW Bridge Power project and advancing the 350 MW Aksa Kumasi combined-cycle plant. Meanwhile, Côte d'Ivoire, which relies solely on domestic resources, continues to expand efficient gas-fired generation through the Atinkou combined-cycle project. First-mover projects are also being developed in Mauritania. Increasing domestic production in resource-rich countries and strengthening regional connectivity, either via gas pipeline or wires, could unlock growth in power demand in this region.

At the same time, larger opportunities are emerging in markets such as South Africa (See 4.1.3) where major gas to power demand is developing in order to transition its baseload power from aging coal to gas and support increasing energy demand. Because the country lacks large-scale domestic gas resources, this massive new energy requirement creates an airtight commercial case for LNG imports. By serving as high-volume anchor demand, the power sector provides the financial certainty needed to underwrite capital-intensive infrastructure.

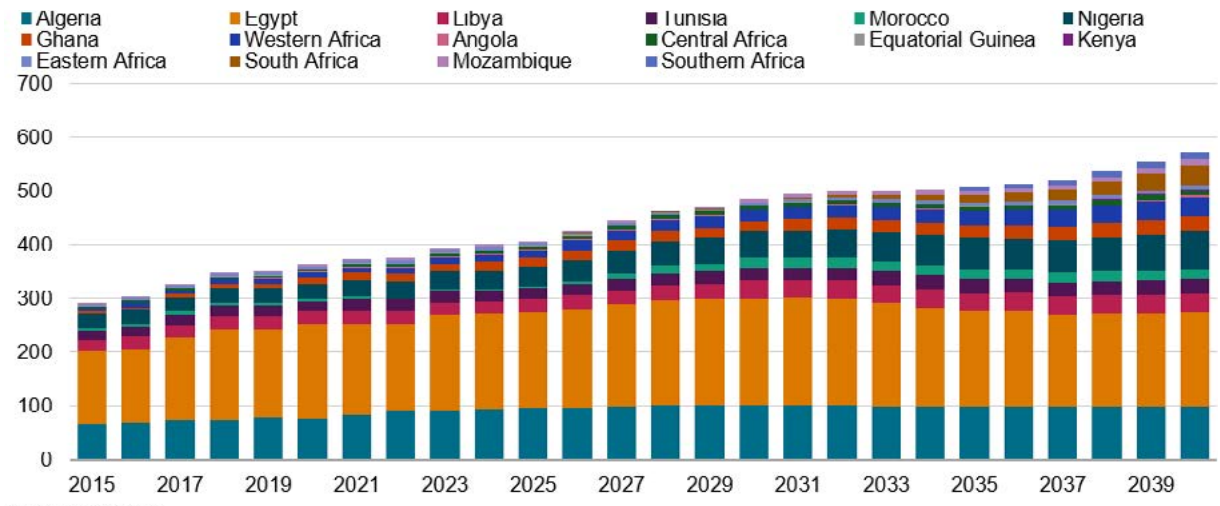
Gas demand sources beyond power

Beyond power generation, gas has a broad industrial role to play across African economies. In energy-intensive industries and mining, it can displace costly and higher-emitting diesel and heavy fuel oil to provide reliable process heat and captive power for smelters, cement kilns, steel plants and remote extraction sites, improving both competitiveness and reliability of supply. Just as importantly, gas serves as a feedstock rather than merely a fuel: it is the primary input for nitrogen-based fertilizers via ammonia and urea, offering a route to strengthen food security and reduce import dependence, as well as the basis for methanol production, which underpins a wide range of petrochemical and downstream manufacturing value chains.

Nigeria illustrates the potential well, hosting large gas-fed fertilizer and petrochemical complexes such as the Dangote and Indorama Eleme plants, while Egypt and Algeria have built substantial fertilizer, methanol and petrochemical sectors on the back of domestic gas, and South Africa's Sasol has long converted gas and coal into fuels and chemicals.

Mining hubs point to a similar opportunity: Mozambique's aluminum smelter at Mozal and Ghana's mineral-processing and industrial loads are natural candidates for gas-to-power, while gas-fired generation is increasingly considered to displace diesel and heavy fuel oil at mine sites across West and Southern Africa. Together with use in power, these in-

Figure 3. Historical and forecasted African power generation from natural gas by country (TWh)



As of August. 2026.
Source: S&P Global Energy.
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dustrial and feedstock applications can catalyze significant investment across the value chain, seeding the kind of broad-based demand that makes upstream and infrastructure projects commercially viable.

Challenges

Africa's gas endowment is substantial, but resource abundance alone does not deliver projects. International majors frequently exit discoveries where the four success factors fail to align: favorable upstream economics, reliable downstream offtake, infrastructure linking supply to demand, and supportive government and regulatory frameworks. Bridging that gap increasingly depends on building anchor demand, the large, creditworthy, baseload consumers around which entire value chains and industries can be developed.

The upstream shift raises the stakes. As the supply center of gravity moves from North Africa to sub-Saharan Africa, the resource base is turning drier. Over half of gas produced today is associated, carrying low or zero break-even costs that have underpinned expansion in Nigeria and Angola. Non-associated gas, more expensive standalone but decoupled from oil rates, re-injection needs and crude price swings, will supply a growing share. Because it is not cross subsidized by oil, sanctioning it hinges on credible monetization models and market structures.

In Angola and Senegal-Mauritania, near-term opportunities remain tied to LNG export projects and their domestic market obligations; where integrated projects stall on unfavorable terms, nations must source domestic supply through standalone domestic projects. Where domestic supply is difficult or far away from demand sources, imports are an option, but they come with their own challenges: establishing LNG import capacity requires significant upfront investment in regasification terminals, storage and connecting infrastructure, exposes buyers to volatile global prices and foreign-exchange risk, and depends on the same creditworthy anchor demand needed to justify domestic supply.

The midstream faces a chicken-and-egg paradox: infrastructure will not be financed without demand certainty, yet demand cannot grow without infrastructure. This is where the anchor-demand model becomes decisive: power generation, fertilizer, methanol, mining and industrial clusters that provide the predictable, long-term offtake pipelines and processing require long-term contracts with creditworthy offtakers and transparent pricing de-risk investment across the chain.

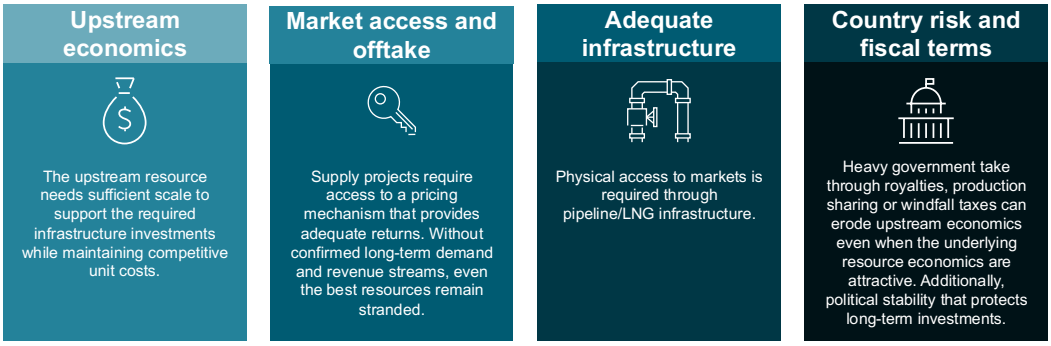
Government's role is to aggregate, not just regulate. Domestic base prices signal a project's ability to break even on the local market, but the tension is real: regulated prices usually sit well below export netbacks. Prices low enough to stimulate demand can be too low to underpin upstream development and infrastructure, creating a cyclical bottleneck. Development of demand aggregators, pooling fragmented buyers into bankable, anchor-scale offtake, government can resolve this, giving suppliers volume certainty while extending affordable gas to smaller consumers.

Private capital enters where the offering fits the market. When a firm anchor offtaker, like mining or power, can be established other entry barriers fall quickly. These include modular, right-sized and tailored solutions such as virtual pipelines, small-scale LNG, distributed power and mini-grids let private investors serve demand incrementally without waiting for full trunkline build-out, seeding the very demand that later justifies larger infrastructure.

Ultimately, each nation must calibrate two balances: between export revenue and domestic ambitions, and between liberalizing the gas market and retaining the regulatory oversight needed to guide market development, protect national interests and achieve long-term strategic goals.

The productive gas capacity shows a lot of gas is available: What factors are necessary for successful supply project execution?

The interplay between these four factors is particularly important. Many assets in sub -Saharan Africa have strong resource bases , which produce optimistic productive capacity outlooks, but IOCs often exit discoveries due to a lack of integration of the followin g four elements, which are essential for project success:



5.3. South Africa and Mozambique gas markets – Lessons from the first large-scale LNG import project in Sub-Saharan Africa

This subsection focuses on South Africa and Mozambique gas markets, historical ties between producing assets in Mozambique and demand centres in South Africa, potential for expanding these ties and imports from emerging upstream projects and downstream infrastructure.

South Africa historically has been in unique position in its 'trijunction' within the gas landscape. South Africa is at a critical juncture in its energy landscape. Substantial economic activity has centred on gas use in industry, specifically gas to liquids but small-scale commercial and industrial use as well. The extent of its gas use remains in the Eastern provinces only due to the gas supply source. Historically, the country's industrial gas demand has been met by pipeline imports from onshore fields in Mozambique. However, these legacy fields face natural decline.

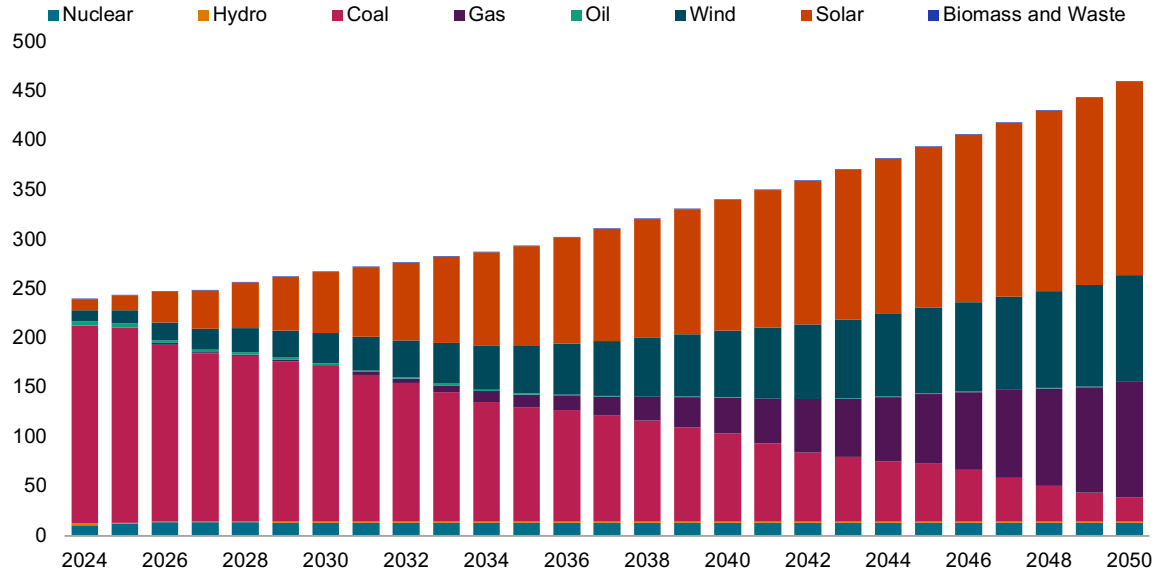
Today, South Africa is at a critical hinge point. Rising energy demand and ageing coal fleet has resulted in gas being the chosen solution for the country's future energy needs. This is colliding with the natural decline of those legacy Mozambican fields, creating a material regional supply transition. South Africa must now consider completely different means of securing supply to fuel its economic strategies.

While South Africa and neighbouring Namibia boast promising offshore discoveries (such as the Orange Basin), the timeline, infrastructure costs, and commercialization challenges of these domestic resources mean they cannot resolve the immediate energy crisis. Consequently, LNG has emerged as the definitive bridge. Projected to account for two-thirds of South Africa's gas supply by 2050, LNG offers the flexibility and speed to market necessary to replace dwindling pipeline volumes and capitalize on a global LNG market expected to become highly competitive in the 2030s.

5.3.1. Anchor demand: Gas-to-Power as the enabler for a new LNG import market

The financial viability of new LNG infrastructure hinges on bankable anchor demand. For South Africa, this demand is unequivocally driven by the power sector. The national Gas Master Plan drafted in 2024 defines gas as 'a key component to the future of South Africa's energy mix'. The national power utility, Eskom, is slated to begin decommissioning its legacy coal-fired plants between 2028 and 2029. To balance the grid and support a growing share of renewables, large-scale gas-to-power generation is essential. Significant gas to power generation is expected in early 2030s with gas-to-power capacities additions displacing coal-fired power generation fleet and balancing the rising share of renewables (Figure 45).

Figure 45. South Africa power generation mix and outlook (TWh)



Source: S&P Global Energy

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This structural shift provides the massive, predictable baseload demand required to underwrite billion-dollar import terminals.

5.3.2. The First LNG import mover: Zululand Energy Terminal

The ZET in Richards Bay is paving the way for Sub-Saharan Africa's LNG import market. Developed by Vopak in a joint venture with the Transnet Authority, the project exemplifies a highly tailored-to-market approach that leverages public-private synergy. Transnet's involvement is particularly strategic; because it already operates the existing Lilly pipeline connected to Richards Bay, this partnership lays the groundwork for utilizing reverse flows to distribute regasified LNG to other parts of the eastern provinces. By maximizing existing infrastructure rather than starting entirely from scratch, ZET demonstrates unprecedented cooperation along the entire energy value chain.

A critical milestone in de-risking the project is the establishment of commercial bankability through robust anchor demand. ZET and Eskom recently signed an HOA establishing a long-term strategic framework, officially granting Eskom to be one of the "foundation customers". This partnership directly underpins Eskom's planned 3,000 MW gas-to-power program. While the power utility anchors the demand, complemented by Exxon as the second foundation customer, they will both utilise the terminal capacity to market their own LNG supply. By following an open-season process for the foundation customers selection, the terminal retains an open-access model. Capacity bookings and offtake still remain available for third-party gas suppliers and independent offtakers for the uncommitted capacity included in the design.

To further align with the gradual ramp-up of domestic gas-to-power capacity, the project utilizes a pragmatic, phased development blueprint. Phase 1 centers on deploying an FSU coupled with onshore regasification, yielding an initial 3 MMtpa of import capacity. As gas-to-power projects evolve, Phase 2 will introduce capacity upgrades to 4.5 MMtpa and replace the FSU with an onshore storage of 220,000 m^3. The expansions culminate in a Phase 3 expansion that will then double the terminal's capacity to 9 MMtpa and onshore storage to 440,000 m^3.

The terminal is rapidly maturing toward execution. Pre-FEED designs and layouts are complete, and environmental assessments are currently being finalized. Supported by the South African government, the project's debt financing strategy is set, with Expressions of Interest flowing in and discussions with local banks advancing positively. Ultimately, this momentum paves the way for an FID synchronized with the Power Plant FIDs in the coming years.



5.3.3 Lessons learned for Sub-Saharan Africa

The ZET highlights that the primary hurdle for large-scale LNG in emerging African markets is not a lack of demand, but commercial bankability. By securing robust foundation demand, partnering with global majors, maximizing existing regional infrastructure, and adopting a tailored, phased approach, the ZET project effectively de-risks the investment. As the first of its kind, it sets the benchmark for future regasification developments across East and West Africa.

5.3.4 Mozambique case study

Mozambique historically was the main gas supplier to South Africa and will continue to play that role, including future LNG supplies, when the LNG export, regasification terminal and infrastructure are ready.

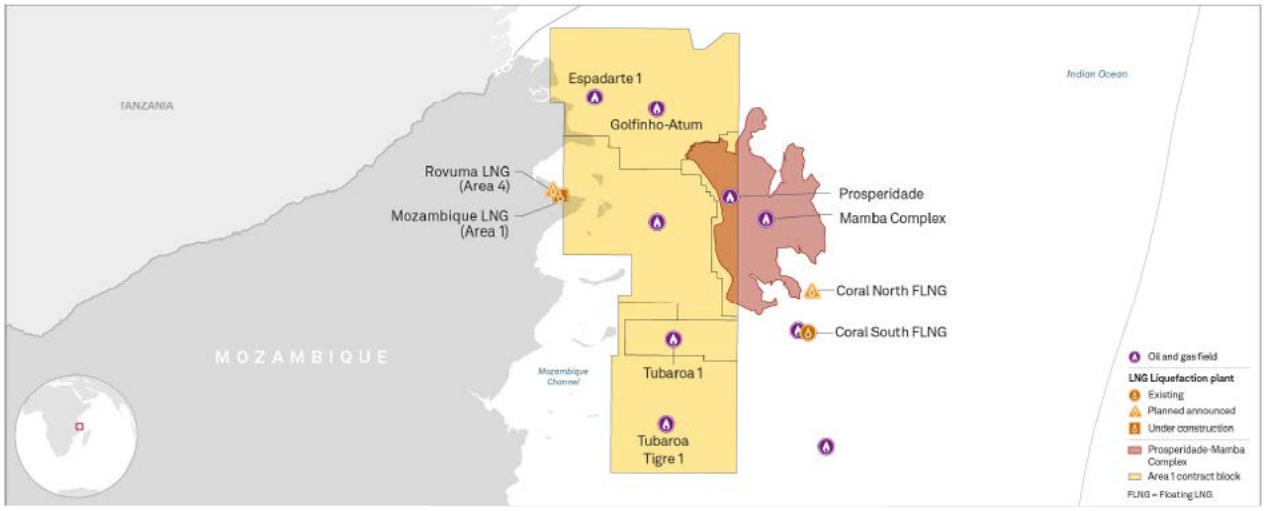
Mozambique has a number of new FLNG and onshore LNG opportunities at various stages of planning and completion. Eni operates Coral South FLNG since 2022 with 3.4 MMtpa capacity and is planning the Coral North FLNG (3.6 MMtpa) with announced operations start in 2028.

TotalEnergies planned the Mozambique LNG (Area 1) project in 2019 and experienced safety issues at the start of its construction that led to a force majeure which was kept for a prolonged period of time until November 2025. The project estimated to cost approximately $20.5 billion, it is located in the Afungi Peninsula, Cabo Delgado Province. By the end of 2020 the construction was completed at about 20% and with force majeure now lifted and construction resuming, the partners expect to start operations in 2029. Its planned capacity was increased up to 13.12 MMtpa.

Recoverable gas resources in Area 1 are estimated at 71 Tcf in total and eventually there is an opportunity for further project expansion. The feedgas for Mozambique LNG is expected to from Golfinho-Atum complex, entirely located within Area 1 (Figure 10). Additional gas resources of 24 Tcf come from Prosperidade field that extends to Area 4 and it will be developed under unitization agreement with Area 4 partners.

Interest in the Area 1 licenses is held by TotalEnergies (26.5%), Mitsui (20%), ONGC (16%), ENH (15%), Bharat Petro Resources (10%), PTTEP (8.5%) and Beas Rovuma Energy (4%).

Figure 10. Mozambique LNG projects map – Key fields and infrastructure



TotalEnergies plan to install low-emission gas turbines, waste heat recovery unit and solar park, thus reducing the average project emissions down to 25 kgCO2/boe, which is expected to be 35% lower than average emission intensity at similar LNG installations globally.

Projects benefits from the signed LNG offtake agreements, namely with PTT of Thailand (2.6 MMtpa for a 20-year period), Tohoku Electric Power (0.28 MMtpa), EDF (1.2 MMtpa for a 15-year period), CNOOC (1.5 MMtpa for a 13-year period), Tokyo Gas and Centrica (2.6 MMtpa for both), and Shell (2 MMtpa). The project is also expected to fulfil certain obligations for gas supplies to the domestic market, as Mozambique views LNG projects as an opportunity to develop the gas industry in the country.

Back in 2014 the government approved legislation providing legal and contractual clarity for future LNG projects development. The new mining and petroleum laws introduced recently in 2026 update the legislation from 2014 aiming to increase the in-country benefits from the mining and oil and gas industries. Among other updates, the new petroleum law imposes stricter use of local content, increased use of local goods, service and labor, and technology and knowledge transfer.

The domestic obligations remain part of the discussion, as precedents have been created by allowing the new Coral North FLNG project to supply a lower share of produced gas volumes to domestic market in the near-term, while still suggesting that 25% of gas output should be supplied locally on average along the field life, as the domestic downstream projects may face delays.

The negotiations over the domestic market obligations of both Mozambique LNG and Rovuma LNG projects are ongoing, given the scale of the future output and likelihood that the domestic consumers, aggregators and midstream connections would be ready to utilize new volumes.

Under the new petroleum law, the project partners may be obliged to free carry ENH up to their participating interest of 40% and until the start of the project, meaning that there will be no repayment of carried costs, which may significantly reduce the expected returns on future developments. These terms require clarification on how these changes will be implemented in practice in upcoming regulations and in the future model contracts.

Uncertainty remains on whether the new regulation will be affecting the new projects only, as the dispute over the cost recovery during the force majeure period at Mozambique LNG continue. At the same time the 2014 LNG Decree and its stabilization clauses clearly protect Mozambique LNG from new legal changes. And in case of any new possible force majeure situations the new regulation also ensures that the project participants potentially won't be able to recover additional costs.

5.4. Identifying synergies between natural gas resource base, existing infrastructure and new development opportunities – Case study of Libya

Libya possesses some of the most highly competitive gas resources and upside potential in Africa with some of the most varied and near term monetization opportunities. The country expects to double its sales of gas production by 2030 with substantial upside achievable from further development and exploration. As a result, gas exports to Italy from Libya are also expected to increase after a prolonged decline. Libya lacked exploration effort and investment, particularly in deep offshore, during the period of time when in other partis in Africa and globally offshore deep-water exploration was booming.

The case of Libya illustrates the advantages of developing new resources alongside the existing infrastructure, readily available for oil and gas exploitation. At the same time various parts of infrastructure require upgrade and rehabilitation along established gas transportation lines and functioning gas hubs, such as Wafa gas plant and Mellitah Gas Complex. The GreenStream pipeline, commissioned in 2004, currently operates at a limited capacity but is able to export at least 1.1 Bcf/d to Italy and doesn't require any extensive upgrade, unless Libya's export potential growth becomes significant in short to medium term.

To support its production targets and support newer investments, Libya made improvements to regulatory framework and improved fiscal terms for foreign investors. After revising the fiscal terms Libya held its first licensing round in 18 years, resulting in new exploration license blocks awards in both onshore and offshore areas. Libya's National Oil Corporation (NOC) is actively seeking partners by offering the foreign investors stakes in ongoing and planned gas upstream and infrastructure projects.

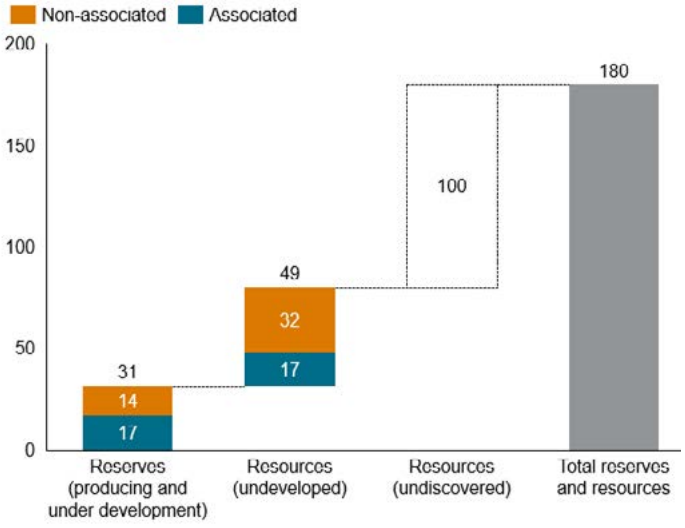
5.4.1. Gas resource potential and investment opportunities in Libya

Libya's remaining gas resources are estimated at 80 Tcf with further upside from yet-to-find and unconventionals. The remaining gas resource potential in Libya represents additional identified gas volumes of up to 70 Tcf with further exploration potential estimated between 65 and 100 Tcf of recoverable natural gas (Figure 11).

Libya's expected recoverable resources include gas volumes of around 10 Tcf with costs of less than $1.50/Mcf, which is highly competitive in regional markets. New offshore developments, including Structures A and E, planned as tiebacks to the existing Bahr Essalam platform and infrastructure in offshore area of Mellitah, and dry gas development in offshore Sirte, named Arous El Bahar, breakeven at a higher gas cost at more than $3/Mcf, which is still competitive for deep offshore.

Priorities are given to quick wins, such as debottlenecking, tiebacks, flaring reduction and existing developments rehabilitation and optimisation. Near-field, hub-based and brownfield investments provide quick wins and at the same time incentivize larger investments.

Figure 11. Libya's Gas Reserves and Resources (Tcf)



Source: S&P Global Energy

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5.4.2.Existing infrastructure benefits and future expansion requirements

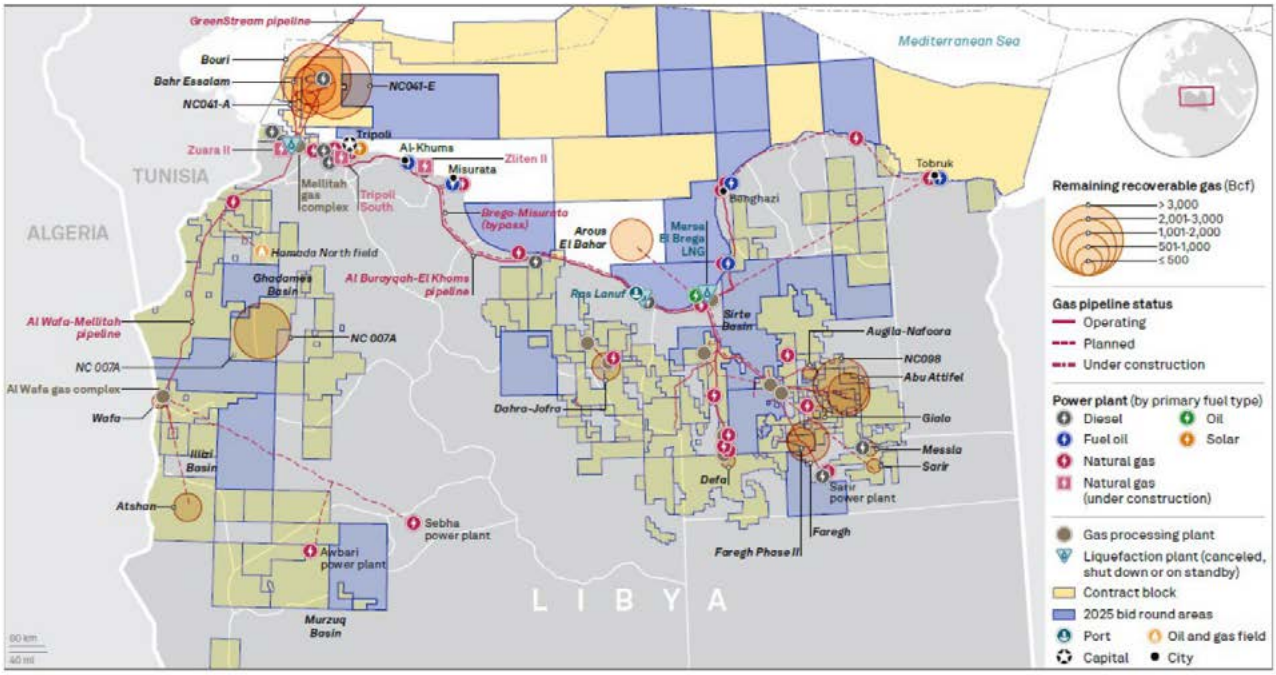
It is expected that northwest offshore Mellitah will remain the key producing area to satisfy the domestic gas demand along the western branch of the coastal pipeline, including Tripoli, Al Khums and Misratah. The new developments in Ghadames and Murzuq basins, such as oil and gas fields in block NC7 and Atshan field development in block NC210 will contribute to maintain the utilisation of Al Wafa complex and gas exports via GreenStream, as well as to supply gas to gas-to-power projects (Awbari and Sebha power plants).

Associated gas from the oil assets in Sirte basin will continue to satisfy the domestic demand in the Eastern part of the country, including Benghazi and industrial complexes in Ras Lanuf and Marsa El Brega areas with additional potential expected in Intisar (103D), block NC98, Gialo area, Faregh and Jofra gas blowdowns.

To evacuate and commercialize the associated gas from oil assets in Sirte basin the gas processing capacities and pipelines network was developed in 1980s-late 1990s. Existing infrastructure provides a material advantage for gas monetization, both for domestic consumption and for exports. Further expected growth in oil production and, therefore, the growing output of associated gas requires expansion of the processing and transportation capacities as well as the upgrade of the existing trunklines, including the major coastal pipeline, linking El Brega gas hub in Sirte with Al Khums and Tripoli.

In S&P estimate, additional processing capacities, including new gas plants at Intisar and Waha areas in Sirte, as well as new gas treatment facilities needed for new developments in southwest of Libya (Atshan and NC7) will require an investment between 1.5 and 2 billion US dollars. New coastal pipeline that will debottleneck the gas output from Sirte to the demand centers along the western part of the coast will require additional 1 – 1.5 billion US dollars and new pipelines to gather and transport gas to the northeastern areas, including Tobruk, another billion US dollars.

Figure 20. Libya's key assets and gas infrastructure map



Source: S&P Global Energy

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If we analyze the key demand centers and sectors in Libya, it becomes obvious that the power generation is Libya's largest gas consumers, accounting for 83% of total domestic gas demand. The sector is run by the General Electricity Company of Libya (GECOL), a state-owned vertically integrated utility established in 1984. In the absence of an independent regulatory authority, GECOL sets its own regulations and tariffs and reports directly to the General Assembly and the Presidency Council.

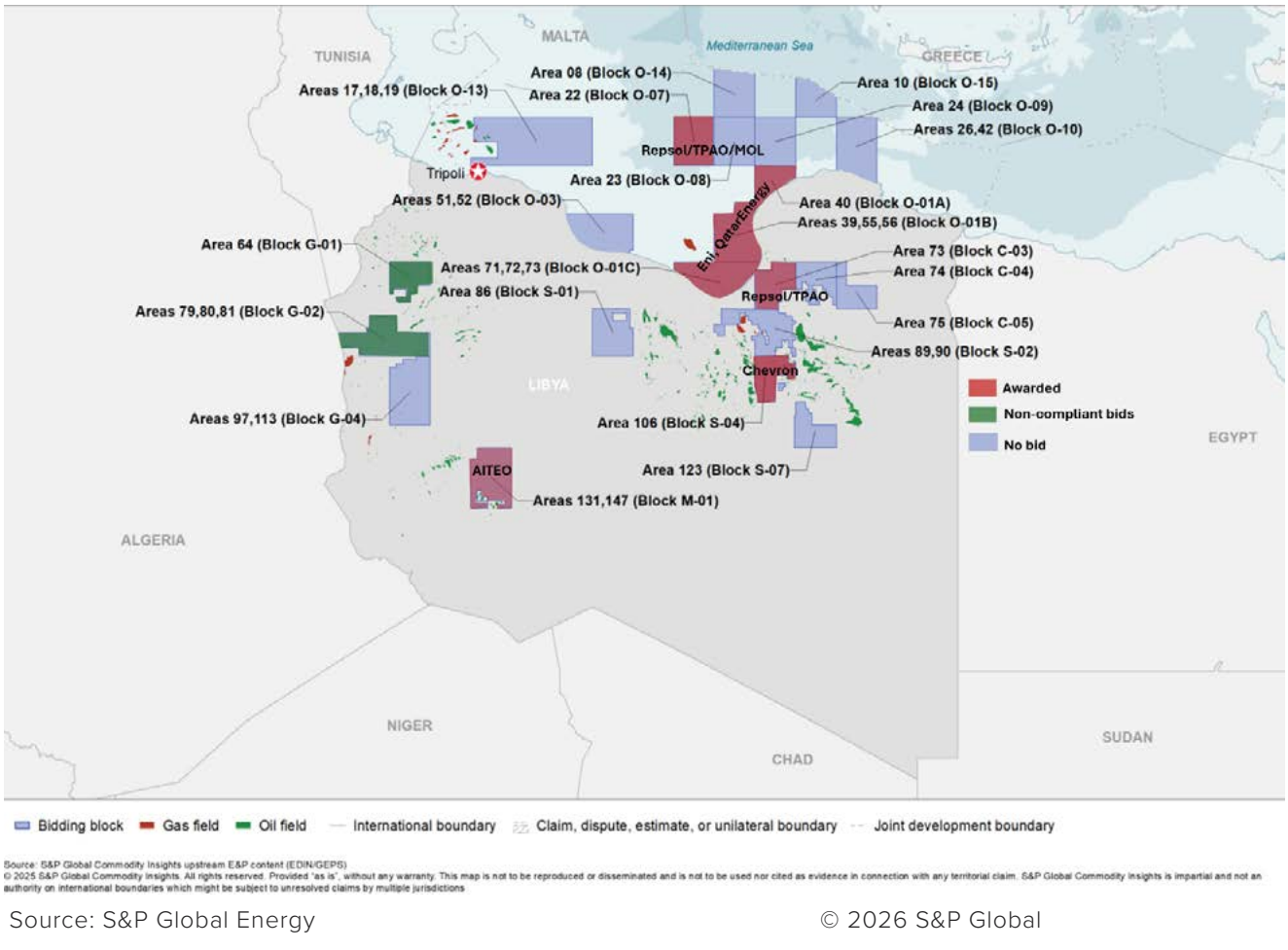
The industrial sector represents the second largest source of domestic gas demand. Key consumers include plants that produce fertilizers, iron and steel, petrochemicals, and cement, most of which are located along the coastal cities of Brega, Misurata and Ras Lanuf, underlying the need for the upgrade of the coastal pipeline as a strategic project for the country.

In total, in S&P estimate the upstream, midstream and downstream power and industrial sectors will require up to 20 billion US dollar investment in near to mid-term with further projects expansions in gas and power sector in long-term (between 2035 and 2050) requiring another $25 billion. Some of the gas network rehabilitation and expansion needs require immediate attention and interest from a variety of stakeholders. These spendings require accurate prioritization and a consistent development and investment programme. The foreign investment appetite remains closely related to contractual and operating stability and clear and transparent regulatory and market mechanisms.

5.4.3. Gas sector regulatory reforms and initiatives

In February 2026, the National Oil Corporation (NOC) announced the winners of the 2025 bid round were Eni, QatarEnergy; Chevron; Repsol, TPOC, MOL; and Nigeria's AITEO (Figure 13).

Figure 13. Libya's 2025 Bid Round Results Map



Source: S&P Global Commodity Insights upstream E&P content (EDIN/GEPS)
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All remaining blocks received a single bid or none at all, resulting in uncontested awards across the rest of the round. With fiscal contract terms significantly improved prior to the bid round, relatively few blocks have been awarded, reflecting remaining operators concerns.

Offshore winners (Eni/QatarEnergy and Repsol/TPAO/MOL) proposed very large 3D seismic programs, reflecting early-stage de-risking of gas-prone deep-water acreage. Onshore winners (Chevron, Repsol/TPAO, and AITEO) submitted leaner 2D and moderate 3D programs, signaling a cautious, phased approach in more geologically mature basins.

The possible reasons why relatively few license selected were the following:

1. Political risk (still divided government and instability)
2. While fiscal terms improved, other regulatory issues persist (force majeure, control definition, lack of clarity on gas monetization)
3. Lots of investors were disqualified, meaning that bid round focus was mainly on big operators; but many of the licenses with small complex discoveries without large exploration structures were not favored by majors.
4. Expectation of new licensing round announcement with better terms to follow in late 2026.

A series of MoUs have been signed for geological and geophysical survey and technico-economic feasibility studies in onshore and offshore areas with Shell, Exxon, TPAO. ConocoPhillips and TotalEnergies agreed to expand Waha Oil assets development further and bp to redevelop Sarir and Messla oil fields in Sirte.

New licensing round is expected in late 2026, combining marginal fields with unlicensed areas, with foreseen further contract improvements. But most importantly, Libya considers a phased approach for its gas market regulatory framework, that is expected to clarify the domestic gas market terms and make the existing gas commercialization options commercially viable for upstream operators. In the short-term the National Oil Corporation (NOC) may well retain the role of the key gas offtaker and major investor. Currently, the NOC fulfils the function of gas regulator, its responsibilities as gas supplier, differentiation of its commercial and regulatory roles are yet to be fully clarified.

At present there is no third-party access established for gas exports or domestic market. An experimental third-party access for liberalised domestic consumers and export capacities may be considered in long-term.

Libyan end-user gas price is the lowest amongst regional and global domestic gas price benchmarks and reflects the subsidized approach to utility pricing in general (Figure 13). The subsidy formalization process is ongoing and reform plan, including the sector pricing, formation of the gas aggregator, is under development.

It is expected that the subsidy policy on gas prices may be reviewed with explicit and transparent formulation of methodology with following gradual implementation of production cost based pricing and linkage to international oil and gas price benchmarks. Gas prices ideally should reflect at least the average cost of production with possible cross subsidies between sectors.

Tariffs for using the new infrastructure should be ideally cost-reflective as well, either explicitly in case of allowed third-party access or implicitly in a regulated prices environment.

Libya is positioned to leverage favorable markets, regulatory progress and low-cost resource for a gas industry revival to secure power and optimize available export and domestic gas monetization options:

1. Power oil-to-gas switching and new power generation capacities are initial focus and aligned with Libya's National Energy Strategy and are highly attractive ($12 - $18/MMBtu netbacks); some 14 GW of gas-fired net capacity additions meet Libya's growing domestic power demand needs.

2. Underutilized fertilizer, methanol and cement plants are low capital intensive and attractive ($6-$12/MMBtu netbacks) and new DRI steel plant delivers c.$5/MMBtu netbacks, investment and jobs.

From both the upstream resource potential and domestic and export gas monetization opportunities perspectives, Libya is in a highly competitive position to develop and expand its core industry sectors, satisfy growing domestic needs in power in combination with renewables and incentivize further economic development. And as many times in the past a lot depends on the way the new phase of investments and rehabilitation plans and programmes are developed, managed and monitored.





Chapter 06

6. Power and renewables outlook

Narrative: Delivering Reliable, Affordable and Inclusive Electricity Growth

Africa's power sector is entering a period of significant transformation. Rapid population growth, urbanisation, industrialisation and digitalisation are driving sustained electricity demand growth, while nearly 600 million people still lack access to power. The continent's challenge is not simply to add generation capacity, but to convert investment into reliable, affordable and scalable electricity access that supports economic development and improves quality of life.

The outlook is increasingly being shaped by renewable energy. Africa possesses some of the world's strongest solar, wind, hydro and geothermal resources, while falling technology costs have made renewables the most competitive source of new power generation in many markets. Solar PV and wind are expected to account for most future capacity additions, supported by growing private-sector participation and improving procurement frameworks.

However, renewable expansion alone will not be sufficient to meet Africa's power ambitions. Many countries continue to face power shortages and require a balanced generation mix that combines low-cost renewables with dispatchable resources capable of maintaining system reliability. In this context, natural gas is increasingly being recognised as an important enabler of the energy transition, providing flexible generation that can support higher renewable penetration while displacing more carbon-intensive coal and oil-fired power.
Meeting Africa's future power needs will require unprecedented investment across generation, transmission and distribution networks. While governments and development finance institutions remain critical in supporting electrification and reducing project risk, the scale of funding required far exceeds available public capital. Mobilising private investment through independent power projects, independent transmission projects, public-private partnerships and bankable offtake arrangements will therefore be essential.

Alongside investment, power sector reform is emerging as one of the most important drivers of growth. Across the continent, governments are pursuing measures to improve utility financial sustainability, strengthen regulation, expand competition and attract private participation. Although progress remains uneven, these reforms are increasingly helping to unlock investment, improve reliability and create more sustainable and investable power sectors.

Ultimately, Africa's power sector represents one of the world's largest long-term infrastructure and energy investment opportunities. The continent's success will depend on its ability to combine abundant energy resources, supportive policy frameworks, market reforms and private capital to deliver reliable, affordable and sustainable electricity for households, businesses and industry.

6.1. Access to electricity

6.1.1. The state of Africa's electrification rate

Access to electricity is a vital condition for economic development, social progress, and improved quality of life. For this reason, it forms a central component of the United Nations Sustainable Development Goals (SDGs), particularly Goal 7, which seeks to ensure universal access to affordable, reliable, sustainable, and modern energy by 2030.

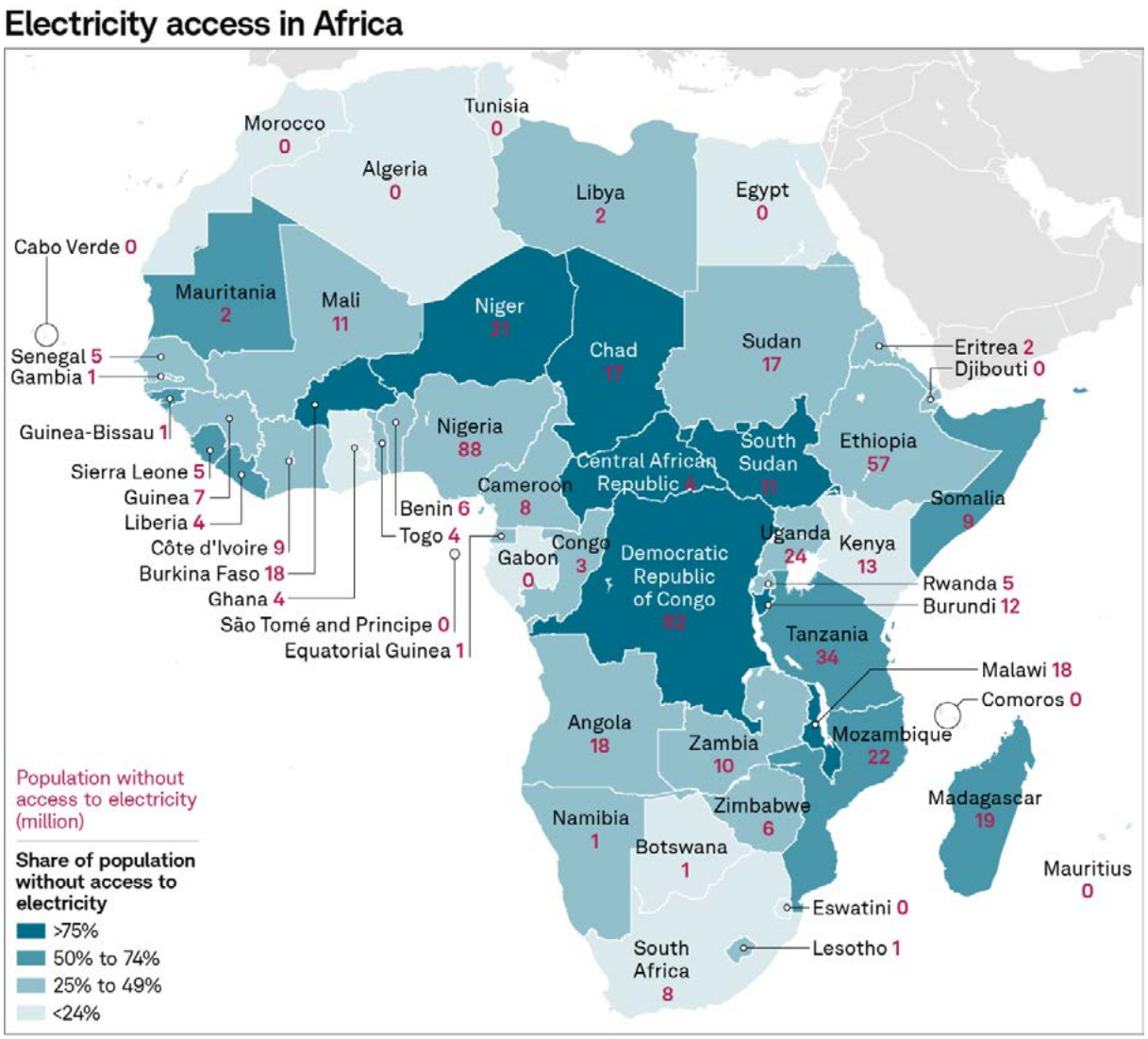
Significant progress has been made globally, with electricity access increasing from 84% in 2010 to approximately 92% in 2024. However, progress has been uneven, with Sub-Saharan Africa remaining the world's largest electrification challenge, where access rates reached only 53% in 2024.

Around 565 million people in Africa lack access to electricity, a large proportion of this population is concentrated in a small number of countries, particularly the Democratic Republic of Congo, Nigeria, and Ethiopia. As a result, average annual electricity consumption in Africa remains around 377 kWh per capita, significantly below the global average of approximately 3,600 kWh per capita.

Considerable differences exist across the continent. North African countries have largely achieved universal electricity access, while Southern Africa registers some of the highest electrification rates in Sub-Saharan Africa. In contrast, several countries in Central, East and West Africa continue to face significant access challenges, with Burundi, the Central African Republic, South Sudan, Niger and Chad among the least electrified countries on the continent.

The pace of electrification progress in Africa also reveals a significant disparity between urban and rural areas. While electricity access has increased rapidly in many urban centres, rural electrification continues to lag as population growth often outpaces infrastructure expansion and low density makes grid expansion costly. This uneven distribution reflects the higher cost and complexity of extending power networks to sparsely populated areas, making rural electrification one of the continent's most persistent development challenges.

Figure 1. Electrification rate



Data compiled Jan. 27, 2026.
Sources: World Bank; S&P Global Energy: 262539-01.

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6.1.2 Challenges to achieving universal and meaningful electricity access

Achieving universal and reliable electricity access in Africa remains challenging due to a combination of infrastructure, financial and institutional barriers. Key challenges include:

- **Infrastructure Deficits and Network Expansion:** Large portions of the continent remain underserved by transmission and distribution infrastructure. Extending networks to rural and remote communities requires significant capital investment due to vast geographical distances common in Africa. Additionally, ageing infrastructure and capacity constraints continue to limit the availability and quality of electricity supply. Across Sub-Saharan Africa, transmission losses average roughly 10% due to poor infrastructure, compared to 6% globally and 2% in advanced markets. The scale of infrastructure investment required remains one of the largest barriers to expanding access across the continent.
- **Utility Financial Sustainability and Cost Recovery:** Many African utilities face financial challenges due to technical and commercial losses, low revenue collection rates, and tariffs that often do not fully recover costs. Weak utility balance sheets can constrain investment in network expansion, maintenance and service improvements, ultimately slowing progress toward broader electrification.
- **Reliability and Quality of Supply:** Connection to the grid does not necessarily guarantee reliable electricity. Frequent outages and supply interruptions remain common in many markets.
- **Policy and Regulatory Frameworks:** Clear and stable regulatory frameworks are critical for attracting investment in generation, transmission and distribution infrastructure. Delays in tariff reform, regulatory uncertainty and administrative bottlenecks can discourage investment and hinder electrification efforts.

6.1.3 The role of distributed generation and microgrids in electricity access

Distributed generation, mini-grids and stand-alone power systems are becoming increasingly important components of Africa's electrification strategy. For many rural and remote communities, decentralised solutions can often be deployed faster and more cost-effectively than extending the conventional grid, making them a critical tool for accelerating electricity access. At the same time, households, businesses and industrial consumers are increasingly investing in distributed generation to improve reliability and reduce exposure to grid outages and rising electricity costs.

South Africa exemplifies the scale of this trend, where persistent load shedding and rising electricity tariffs drove a rapid increase in private sector investment. Although the load shedding crisis has been largely resolved in the past year, registered embedded generation capacity reaching a record 10.5 GW by 2024.

In Nigeria, unreliable grid supply has similarly encouraged widespread adoption of self-generation, while government and development finance institutions continue to expand support for mini-grids and other distributed energy solutions to help address the country's significant electricity access deficit. The International Finance Corporation (IFC) and Norfund, a Norwegian development finance institution, recently supported the rollout of 315 solar-hybrid mini-grid sites in Nigeria, expected to connect approximately 500,000 households and businesses and provide power to around 2.9 million people. This is one of the largest recent distributed energy programmes on the continent. As a result, distributed energy is increasingly serving both as a means of expanding electricity access and as a complement to traditional grid infrastructure across the continent.

Kenya provides a notable example of how distributed energy can complement conventional grid expansion. The deployment of mini-grids and off-grid solar systems, in conjunction with the Last Mile Connectivity Project (LMCP), has helped extend electricity access to remote communities, contributing to an increase in the country's electrification rate from around 35% in 2014 to 77% in 2024, making Kenya one of Sub-Saharan Africa's electrification success stories.

6.1.4 Electrification investment opportunities in Sub-Saharan Africa

Achieving universal electrification in Sub-Saharan Africa represents one of the largest infrastructure investment opportunities globally. In 2022, the International Energy Agency estimates that more than $30 billion per year of investment would be required to achieve universal electricity access by 2030, compared with current annual investment levels of only a few billion dollars. This substantial financing gap highlights the need to mobilise capital from a broad range of sources, including governments, development finance institutions and private investors. While public funding and concessional finance will remain critical, they are unlikely to be sufficient on their own to meet the scale of investment required.

Development finance institutions continue to play a leading role in supporting electrification across the continent. The African Development Bank, World Bank Group and other international partners have committed significant capital towards grid expansion, rural electrification, mini-grids and off-grid energy solutions. For example, the African Development Bank (AfDB) has committed over $1.1 billion in financing for rural electrification in Nigeria alone, including direct funding for microgrids and grid extension, while the World Bank Group (WBG) is supporting mini-grid deployment through a $750 million Nigeria Distributed Access through Renewable Energy Scale-up (DARES) initiative expected to reach more than 16 million people. Another key initiative is Mission 300, launched in April 2024 by the World Bank and AfDB and backed by 30 countries utilizing specialized National Energy Compacts. It aims to connect 300 million Africans to clean electricity by 2030. This initiative has already connected 50 million people, with 100 million more in the pipeline by combining grid expansion with solar mini-grids.

Importantly, the role of development finance institutions extends beyond simply providing capital. By taking on risks that commercial lenders are often unwilling to accept, providing concessional and blended finance structures, and supporting project preparation and regulatory reform, they help establish the foundation for future private sector investment. These programmes are therefore critical not only for expanding electricity access, but also for creating a pipeline of bankable infrastructure projects capable of attracting larger pools of commercial capital over time.

To bridge the remaining financing gap, governments are increasingly exploring mechanisms that can attract greater private sector participation. In the transmission sector, Independent Transmission Projects (ITPs) are emerging as a particularly important model. By allowing private developers to finance, construct and operate transmission infrastructure under long-term contractual arrangements, ITPs can accelerate grid expansion while reducing pressure on sovereign balance sheets. Examples such as Uganda's Amari Grid Project, Mozambique's LTEC project and South Africa's national ITP programme demonstrate the growing role of private capital in unlocking investment in critical network infrastructure.

6.2. Power demand and supply outlook in Africa

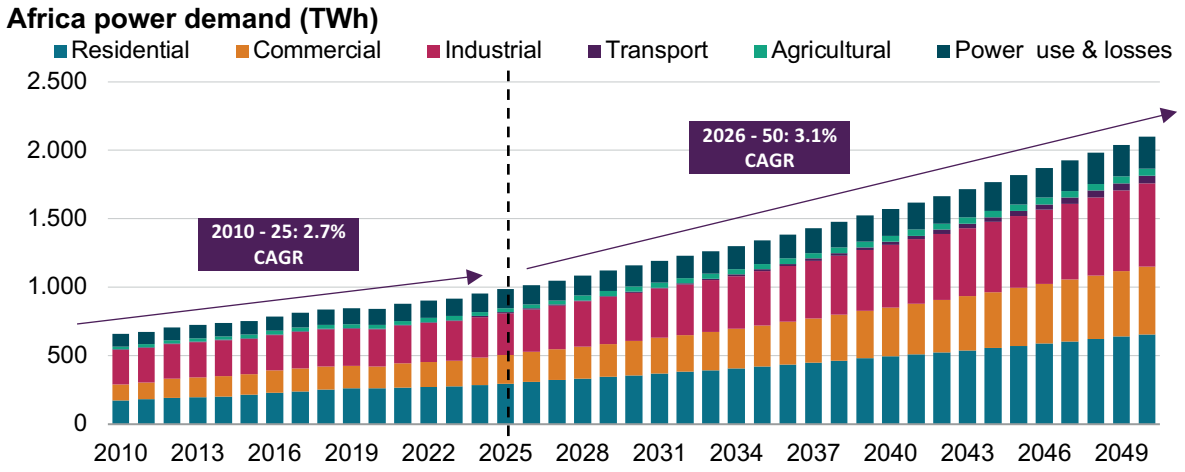
6.2.1 Africa power demand outlook

Africa's total power demand is projected to be 1,070 TWh by 2026, excluding off-grid systems. Demand is expected to grow at a Compounded Annual Growth Rate (CAGR) of 3.2% from 2026 to 2050, ultimately reaching 2,310 TWh by 2050. Africa's power consumption per capita is projected to remain low, owing to inadequate infrastructure, limited electricity access in rural areas, high power costs, and rapid population growth that outstrips improvements in power generation and distribution. In 2024, the average usage in Sub-Saharan Africa was only 377 kWh per person annually, significantly lower than the global average of over 3,500 kWh. Demand in the whole African continent is projected to reach just 960 kWh per capita by 2050, raising concerns about the continent's future well-being and quality of life.

Economic development in the industrial and commercial sectors is expected to be the major driver of power demand in Africa. As countries industrialize and diversify their economies, the need for electricity to support manufacturing, services, and infrastructure projects will grow. The

industrial sector accounts for 30% of Africa's total power consumption, with the residential sector 28% and the commercial sector 20%. Despite its high share in GDP, the agriculture sector is one of the least power-consuming industries. The adoption of Electric Vehicles (EVs) is expected to have a minimal short-term impact owing to several challenges faced by various African countries, including power shortages, high electricity costs, a lack of EV charging points, the high initial cost of EVs and limited government incentives.

Figure 45. Power demand in Africa

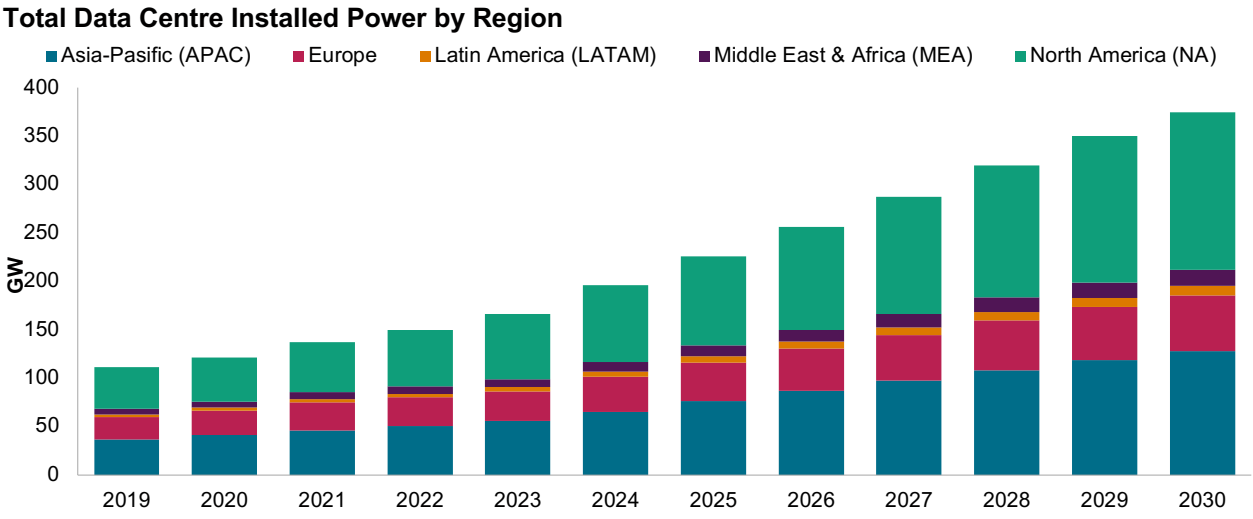


Data compiled June 30, 2026.
Source: S&P Global Energy
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6.2.2. Impact of data centres on power demand

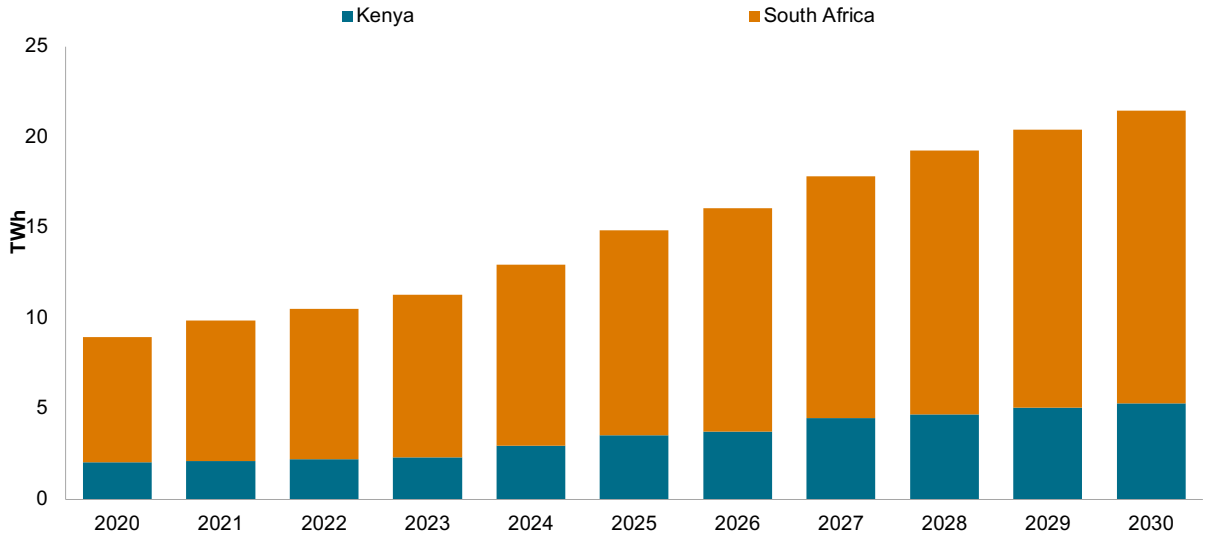
Global data centre power capacity is forecast to increase from 133 GW in 2024 to 335 GW by 2030, driven by rapid growth in cloud computing, artificial intelligence, digital services and enterprise data storage. While growth is expected across all regions, Africa remains a relatively small participant in the global market. The Middle East and Africa region is projected to increase data centre power capacity from 7 GW in 2024 to 12 GW by 2030, although its share of global capacity is expected to remain modest compared with more mature markets.

Figure 2. Total region-wise installed power at datacentres



Data compiled July. 08, 2025.
Source: S&P Global Market Intelligence, 451 Data Centre Knowledge Base 2024
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Figure 2. Total region-wise installed power at datacentres



As of July 2025
Source: S&P Global Market Intelligence, 451 Data Centre Knowledge Base 2024 © 2026 S&P Global

As Africa's digital economy expands, data centres are becoming increasingly important electricity consumers. Unlike many traditional loads, data centres require large volumes of continuous, high-quality power, making them potential anchor customers for new power generation, transmission and grid infrastructure investments. Well-structured data centre demand can improve the bankability of power projects through long-term commercial agreements and support investment in electricity infrastructure that may also benefit surrounding consumers.

However, the pace of data centre growth in Africa is increasingly being determined by power sector constraints rather than demand for digital services. Recent industry analysis identifies power availability as one of the primary barriers to expansion, with many markets facing generation shortfalls, transmission bottlenecks, connection delays and grid reliability challenges. As a result, developers are increasingly evaluating captive generation, renewable-plus-storage solutions and extensive backup systems. Beyond power, sector growth is also influenced by fibre connectivity, data governance frameworks, skilled labour availability and regulatory certainty.

The extent to which data centres contribute to electricity demand will ultimately depend on the ability of national power systems to accommodate large and concentrated loads. Reliable generation capacity, transmission infrastructure and timely grid connections are therefore becoming increasingly important determinants of future data centre investment. Markets that successfully address these constraints are likely to be better positioned to capture the economic benefits associated with artificial intelligence, cloud computing and digitalisation, while simultaneously creating new opportunities for investment across the power sector.

South Africa remains the largest market

South Africa is expected to remain Africa's largest data centre market, with electricity consumption projected to increase from 10 TWh in 2024 to 16.1 TWh in 2030, representing a CAGR of approximately 8.27%. Growth is increasingly being driven by cloud migration, wholesale colocation capacity and larger-scale artificial intelligence related deployments. As data-centre loads become more concentrated, the availability of reliable generation, transmission and grid connection capacity will become an increasingly important determinant of future expansion.

Kenya: Growth Supported by Cloud Demand and Digitalisation

Kenya is expected to remain one of Africa's fastest-growing data-centre markets, with electricity consumption projected to increase from 3 TWh in 2024 to 5.3 TWh in 2030, equivalent to a CAGR of approximately 9.95%. Supported by growing digitalisation, improving connectivity infrastructure and initiatives such as Konza Technopolis, Kenya is strengthening its position as a regional hub for cloud and digital services. However, future growth will depend on the ability of the power system to provide reliable electricity and adequate transmission capacity to support large new loads.

6.2.3 Africa power installed capacity outlook

Africa's power supply landscape is characterised by a diverse mix of power supply technologies, each playing a crucial role in meeting the continent's growing power demand. Africa has an estimated installed capacity of 347 GW in 2026, with fossil fuels still dominating the capacity mix. Natural gas is projected to account for 35% of the installed capacity mix by 2026, followed by oil at 16% and coal at 14%. By 2030, installed capacities are projected to grow significantly across key economies to support regional demand, with South Africa's capacity projected to reach 94 GW (up from 76 GW in 2026), Angola's rising to 10 GW (up from 7 GW in 2026), and Mozambique's capacity growing to 3 GW (up from less than 1GW in 2026).

In addition to this growth, the African electricity sector is witnessing a significant shift towards more sustainable sources. Africa possesses immense renewable energy potential across solar, wind, hydro, and geothermal sources Africa has vast solar energy potential, receiving 2,000–3,000 kWh/m^2/year of solar irradiation, yet only a small portion is utilized. It is estimated by the International Renewable Energy Agency (IRENA) that wind power could provide around 1,300 GW, especially in North, East, and Southern Africa where wind speeds are favourable. The continent is also estimated to hold about 1,100 GW of hydropower potential, with only 11% currently developed. While geothermal resources in the East African Rift are estimated to be capable of providing 15–20 GW. While the scale of the continent's solar, wind, hydro, and geothermal resources are distributed unevenly across regions, their complementary nature creates a diversified renewable energy base that could be a significant opportunity through greater regional interconnection and power market integration.

Hydropower currently contributes around 17% of Africa's installed generation capacity. Harnessing the continent's abundant water resources, hydropower remains a key renewable energy source and provides a significant share of electricity generation in countries such as Ethiopia, Lesotho, Mozambique, the DRC and Zambia. However, its share of the capacity mix is projected to decline to around 10% by 2050 as solar PV and other renewable technologies are deployed at a faster pace. While hydropower provides valuable low-carbon and dispatchable generation, increasing concerns remain around its exposure to hydrological variability and climate-related weather events. Recent droughts in Southern Africa, particularly in Zambia where reduced water levels materially constrained hydropower output and electricity supply, have highlighted the risks associated with overreliance on a single resource and reinforced the importance of maintaining a diversified generation mix.

Solar and wind are rapidly expanding across Africa, supported by declining technology costs, abundant resource availability and financing structures that are increasingly capable of attracting private investment. Together, these technologies currently account for around 11% of installed capacity and are projected to increase to 25% by 2030 and over 50% by 2050. Their scalability, relatively short development timelines and compatibility with IPP and long-term offtake arrangements have made them the preferred technologies for new power generation investment across much of the continent.

Other renewable technologies also offer significant potential. Geothermal resources in East African countries such as Kenya, Ethiopia and Tanzania could provide reliable dispatchable renewable power. However, development has been constrained by high upfront exploration costs, drilling risks and long project development timelines, with Kenya being the only market so far where geothermal is a key source of generation. Biomass and waste-to-energy projects may also contribute to localized power supply and waste management objectives, although deployment remains limited relative to solar and wind.

Figure 4. Installed capacity in Africa

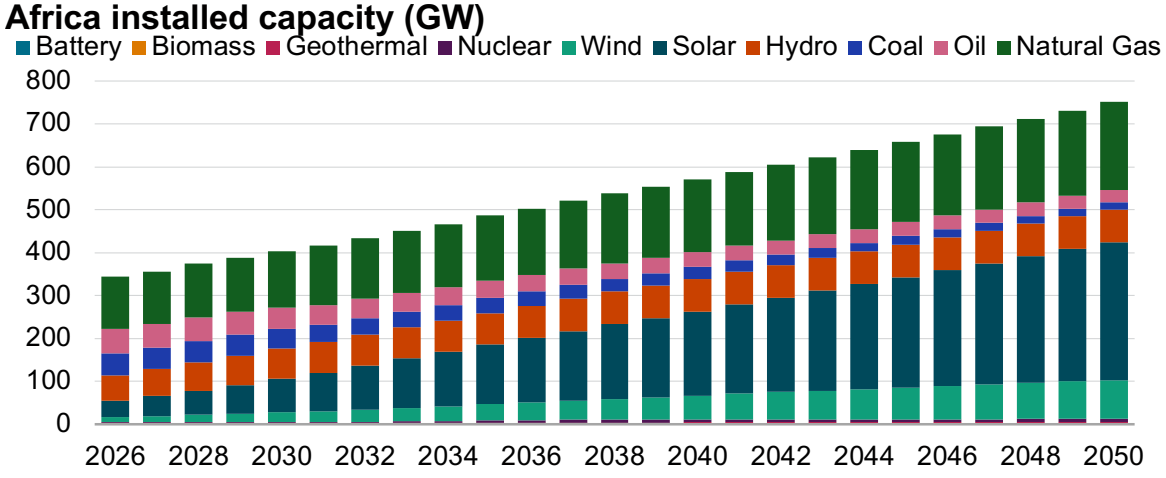
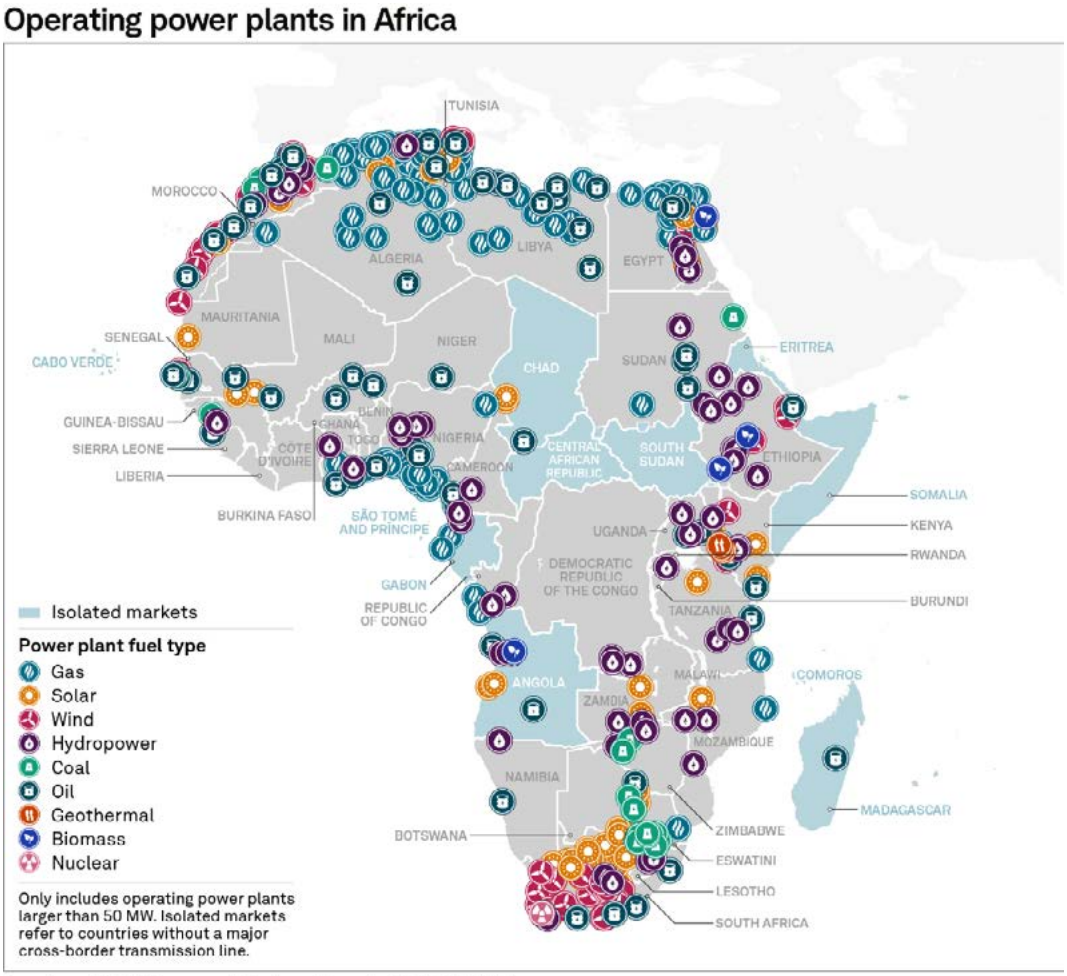
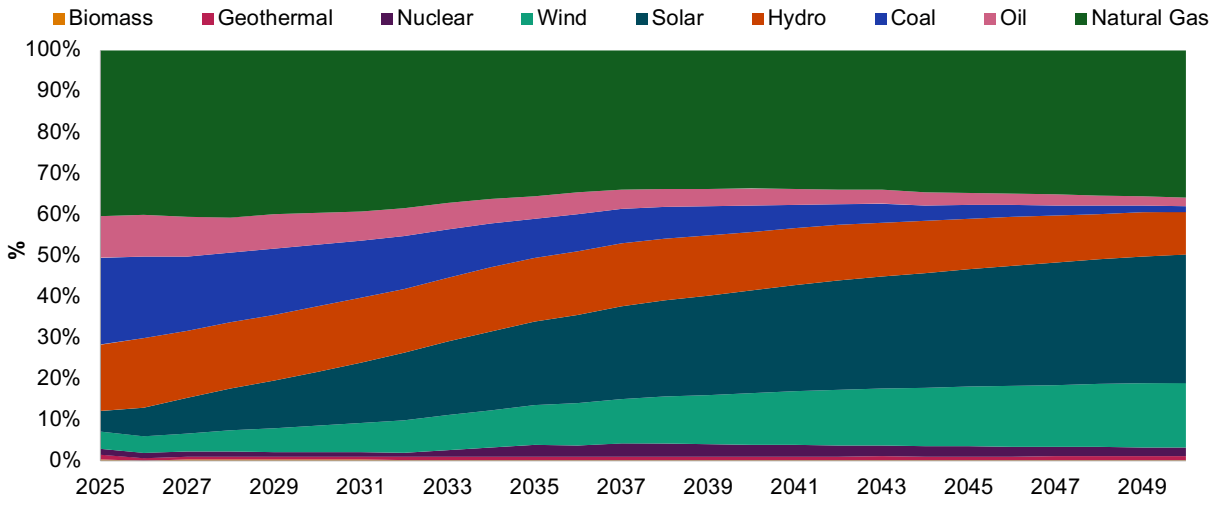


Figure 5. Operating power plants in Africa



Data from CERA Upstream Solutions. Compiled July 28, 2026.
Source: S&P Global Energy: 263654-02.
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Figure 6. Power generation by fuel (%)



Data compiled June. 30, 2026.
Source: S&P Global Energy
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6.2.4 Contribution of natural gas to Africa's power system

Solar PV and wind remain the lowest-cost and fastest-to-deploy sources of new power generation globally, making them the natural foundation of future electricity systems. However, their variable output requires flexible, dispatchable generation to ensure reliability and meet demand when renewable resources are unavailable. In this context, natural gas, particularly highly efficient combined-cycle gas turbines (CCGTs), represents the most practical complement to renewable energy, offering a compelling combination of dispatchability, affordability and lower emissions than coal or oil-fired generation. As many African countries continue to face significant power shortages, a balanced generation mix built around low-cost renewables and flexible gas-fired capacity can expand electricity access, reduce emissions, and enhance grid stability. The ability of gas plants to ramp quickly in response to fluctuations in renewable generation and demand makes them a critical enabler of higher renewable penetration while maintaining a secure and reliable power supply.

While several African countries possess significant indigenous natural gas resources, many do not, creating an uneven geographical distribution of fuel supply across the continent. Addressing this imbalance will require greater regional integration, not only through interconnected electricity transmission networks but also through the development of supporting gas infrastructure. This may include cross-border gas pipelines, LNG import and regasification facilities, and virtual pipeline solutions such as compressed or liquefied gas transported by road, rail or sea. Enhanced regional power pools can then enable countries with access to domestic gas resources or imported LNG to supply flexible gas-fired generation to neighboring markets, helping to improve energy security, expand electricity access, optimise infrastructure investment and support higher levels of renewable energy penetration across the region.

Natural gas currently constitutes 40% of electricity generation across the continent. While natural gas generation is projected to expand to around 830 TWh by 2050, its share in the overall generation mix is expected to remain relatively stable at approximately 36%.

With global gas markets and supply chains come inherent risks that exposes power markets reliant on gas imports to global risks. Recent geopolitical events and domestic resource constraints highlight the deep vulnerability of gas-heavy grids to fuel supply shocks. Egypt's power plant fleet is overwhelmingly reliant on natural gas, with gas acting as the primary fuel for about 80% of installed capacity and accounting for about 70% of electricity generation as of 2025. Following Iran's retaliation on February 28, 2026, Israel shut down the Leviathan and Karish gas fields, suspending pipeline gas exports of over 1 Bcf/d (9 Bcm/year) to Egypt and Jordan. This removed 25% of the gas feedstock for Egypt's power generation. Egypt responded by tapping the LNG spot market, requiring 9 additional LNG cargoes per month, and expanded its FSRU capacity during 2025 to increase regasification flexibility. However, soaring LNG spot prices (with TTF surging to over $15/mmBtu in early March 2026) and import costs have heavily increased the state's fiscal subsidy burden. This illustrates the importance of countries exploring diversified power sources as far as possible.

In countries that are heavily reliant on coal for baseload power, particularly South Africa and Morocco, the imperative to reduce emissions in line with Nationally Determined Contributions has prompted plans to phase out coal power. This transition is expected to result in a significant decline in coal-generated electricity in Africa, from 212 TWh in 2026 to just 33 TWh by 2050. It is anticipated that gas generation and renewables together will have to step in to fill this gap. A similar trend is observed in nations that predominantly depend on oil for baseload power, such as Nigeria, Angola, and Senegal.

The strategic role of natural gas in supporting renewable energy integration, improving grid reliability and displacing more carbon-intensive fuels is increasingly being recognised across Africa. A number of countries have already begun implementing policies, infrastructure plans and power sector reforms to support gas-to-power development, as illustrated in the table below. However, these examples represent only a small subset of African markets. While several countries are actively advancing gas-to-power initiatives, the majority of the continent has yet to establish the policy frameworks, infrastructure and investment pipelines required to unlock the full potential of gas in the energy transition. The table therefore highlights not only the progress being made by early movers, but also the significant opportunity that remains across the broader African market.

Despite its strategic role in supporting reliable and lower-emission power systems, the deployment of gas-to-power projects in Africa remains challenging. Success requires the coordinated development of the entire gas-to-power value chain, including upstream gas supply, transportation and import infrastructure, power generation assets, transmission networks, and creditworthy power offtake arrangements. In many African markets, these elements are still at varying stages of development, while regulatory uncertainty, financing constraints, and limited institutional experience with integrated gas-to-power planning can further delay investment decisions. As highlighted by the relatively small number of

Table 1. Selected countries that have stated gas-to-power ambitions

Country	Current gas-to-power	Future gas-to-power ambitions	Coal retirement	Oil replacement	Potential origin of gas supply
Nigeria	✓	The gas master plan has gas-to-power as a central pillar	✗	✓	Current and contingent domestic sources
South Africa	✗	The gas utilisation master plan strongly emphasises the importance of converting gas into power	✓	✓	LNG imports directly into South Africa or via Mozambique; domestic sources are small and require infrastructure
Senegal	✓	The gas-to-power strategy is specifically designed around converting gas resources into electricity generation capacity, with the aim of having 3 GW of gas-to-power installed capacity by 2050	✓	✓	Domestic sources contingent on the development of LNG-integrated projects and the development of gas infrastructure to onshore projects; LNG is currently being imported for power
Ghana	✓	The gas master plan emphasises gas-fired power generation for energy security	✗	✓	Pipeline imports from Nigeria; LNG imports or contingent domestic resources are future options
Tanzania	✓	The natural gas utilisation master plan includes important provisions for generating electricity with natural gas	✗	✗	Contingent domestic sources
Mozambique	✓	The natural gas master plan includes substantial gas-to-power components	✗	✗	Present and contingent domestic sources
Angola	✓	The finalised gas master plan has ambitions for new gas assets and oil-to-gas switching	✗	✓	Present and contingent domestic sources

Source: S&P Global Commodity Insights

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countries with established gas-to-power frameworks, unlocking the sector's potential will require not only investment in infrastructure, but also stronger policy coordination, market development, and regional cooperation. Addressing these barriers will be critical to enabling natural gas to effectively complement renewable energy growth, improve energy security, and support long-term economic development across the continent.

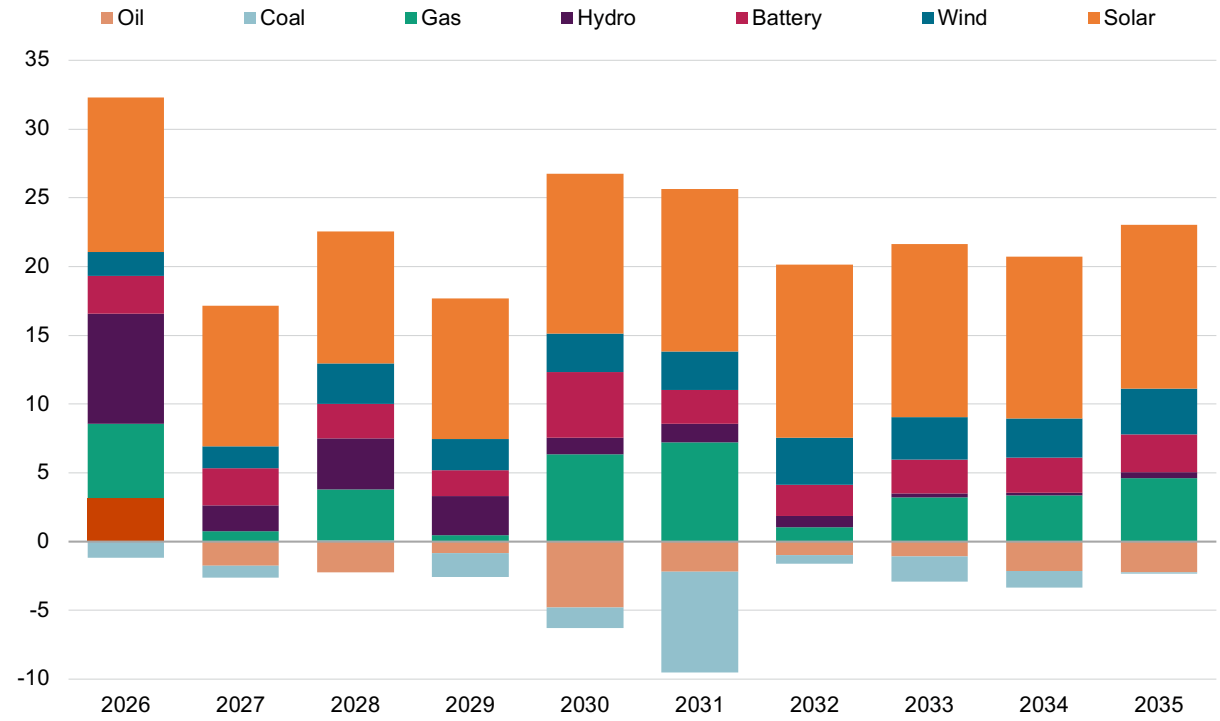
6.2.5 Unlocking Africa's wind and solar potential

The share of coal-fired and oil -based power generation has been steadily declining in Africa over the past few years. In contrast, the share of renewables has increased as national governments and companies actively seek cheaper and less carbon-intensive power sources. The current roughly 7% generation contribution of solar and wind sources to the electricity mix is projected to increase to 47% by 2050. Overall renewables, incorporating hydro, geothermal, and biomass, are projected to provide 58% by 2050.

The continued growth of renewable energy in Africa is being driven by sustained reductions in technology costs and declining Levelized Costs of Electricity (LCOE) globally. Africa's renewable energy economics are further strengthened by its world-class solar and wind resources, which enable high asset utilisation, as well as generally favourable land and construction costs in many markets. As a result, utility-scale renewable projects in Africa are increasingly among the most cost-competitive sources of new power generation globally. For 2025, the LCOE of utility-scale solar PV projects ranged from $28 to $66/MWh, and onshore wind ranging between $31 and $78 per MWh, comparing favourably with many developed markets. While much of this cost decline reflects global improvements in renewable energy technologies and international supply chains, leading African markets such as South Africa and Kenya have also benefited from the gradual maturation of local renewable energy ecosystems, including, among other factors, improvements in project development capabilities, construction expertise, logistics, operations and maintenance, and supporting supply chains.

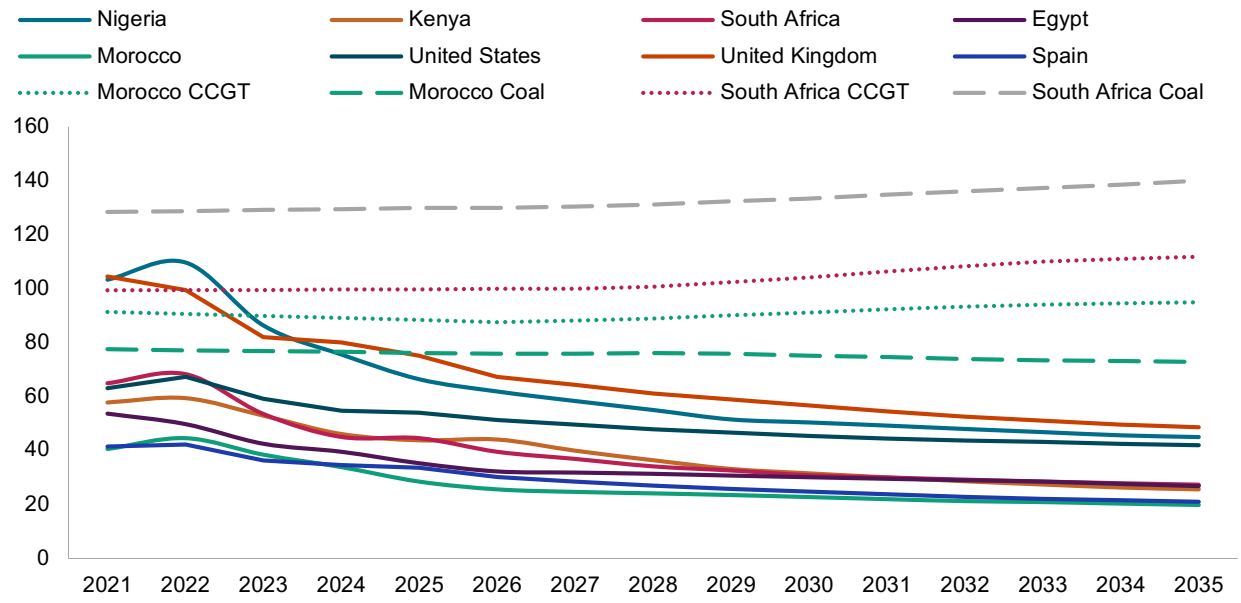
In contrast to declining renewables cost, the economics of thermal generation remain exposed to fuel price volatility, carbon pricing mechanisms, environmental compliance costs and increasingly constrained financing conditions, contributing to a gradual increase in projected coal- and gas-fired LCOEs. While the long-term cost trajectory clearly favours renewables, power system planning cannot be based on cost alone. The variable nature of solar and wind generation necessitates complementary dispatchable capacity, which may include battery storage, hydropower, natural gas and other flexible technologies depending on local resource availability and system requirements. The optimal generation mix will therefore vary by country, reflecting differences in resource endowment, energy security priorities and decarbonisation objectives.

Figure 7. Power capacity additions in Africa by energy type (GW)



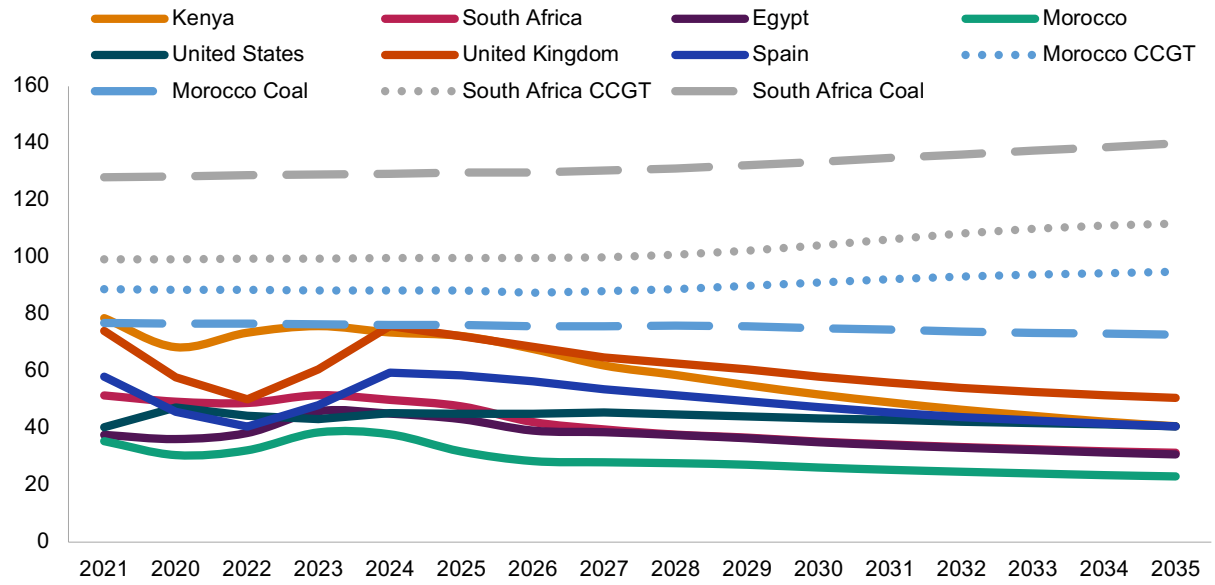
A negative figure indicates net retirements.
Source: S&P Global [Division].
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Figure 8. Solar PV LCOE against Fossil Fuel Benchmarks (USD/MWh)



Data compiled Feb 9, 2026.
Source: S&P Global Energy
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Figure 53. Onshore wind LCOE against Fossil Fuel Benchmarks (USD/MWh)

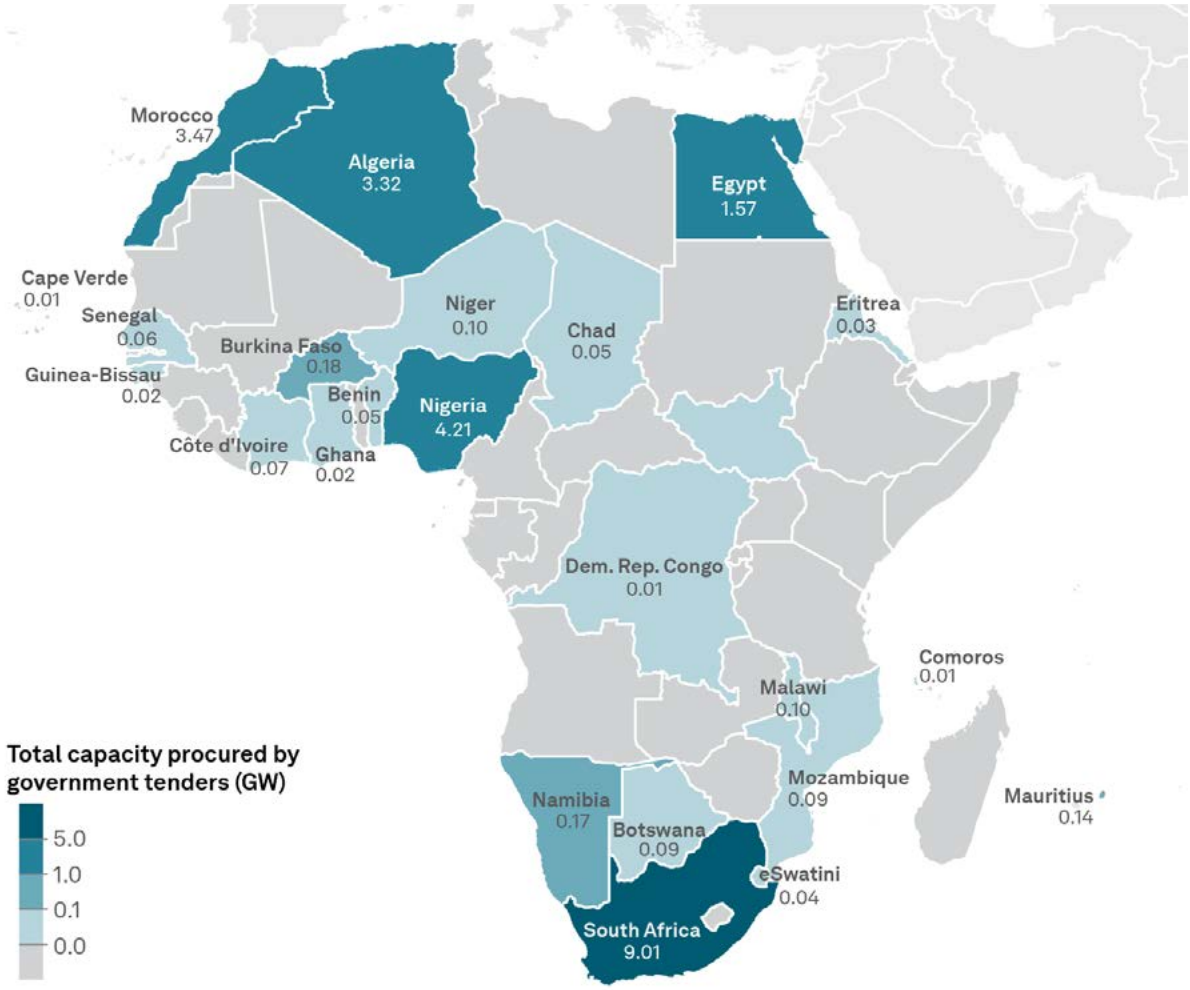


Data compile Feb 9 2026
Source: S&P Global Energy
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Africa has made significant strides in renewable power procurement over the past decade. By the end of 2025, the continent had auctioned over 25 GW of renewable energy capacity, primarily from solar and wind sources. These initiatives have been bolstered by supportive policies aimed at fostering investment and encouraging the development of infrastructure necessary for renewable energy projects. National governments across Africa have implemented various measures, including competitive tendering processes, feed-in tariffs, and power purchase agreements, to attract domestic and international investors. This policy support has been crucial in reducing the cost of renewable energy and increasing its share in the power mix. Notable market leaders such as South Africa, Morocco, and Egypt have successfully developed large-scale renewable projects, showcasing the potential of public-private partnerships (PPPs) and innovative financing models.

Private offtake through power purchase agreements (PPAs) is rapidly gaining traction as an alternative to government procurement in Africa, with over 16 GW of capacity secured via private deals, with almost 5GW in 2025 alone. This shift is largely driven by the private sector's need for energy security, cost predictability, and the ability to meet environmental, social, and governance targets. Private offtake arrangements offer more flexibility, faster timelines, and reduced exposure to regulatory delays against government-led tenders, making them attractive in markets. Conversely, public procurement processes can be slow or uncertain. South Africa, Morocco, and more recently Egypt are leading in private offtake for renewable energy, accounting for most privately negotiated PPAs in Africa. These countries have established clear policy frameworks, streamlined regulatory processes, and provided strong investment incentives, making them attractive markets for private sector participation. Their proactive approach has enabled faster project development and greater investor confidence.

Figure 54. Renewable energy capacity procured through competitive tenders in Africa



6.2.6 Africa's renewables investment outlook

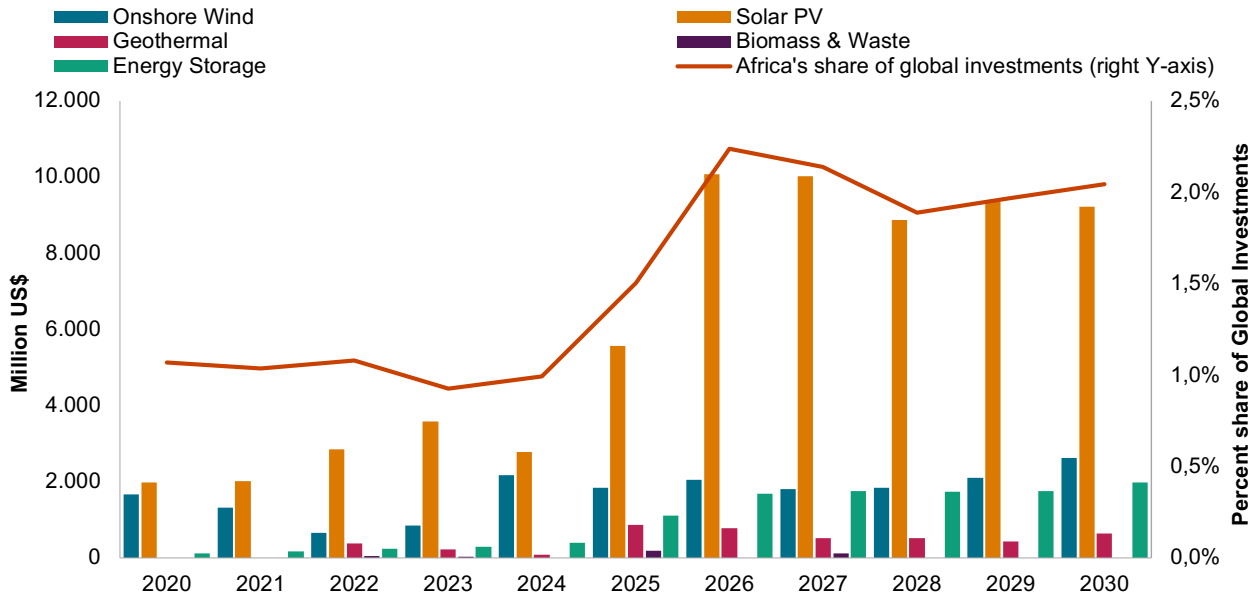
Despite its vast renewable energy potential and growing need for new electricity supply, Africa continues to attract only a small share of global clean energy investment. This investment gap is particularly striking given that Africa is the world's second most populous continent and home to some of the fastest-growing electricity demand.

Between 2020 and 2025, Africa invested $34 billion in clean power technologies, with 52% directed towards solar power and 25% towards onshore wind. Despite this investment, Africa's share of global investments is projected to be just 1.5% in 2025. From 2026 to 2030, Africa is projected to invest $70 billion, raising its share of global investments to around 2%. The increasing share is positive news; however, it remains marginal compared with the rest of the world.

Although Africa has made progress in power-related investment, it lags behind other regions due to the perception of high risks associated with investing in African energy markets. These markets are often characterised by political instability, regulatory uncertainties, and inadequate infrastructure. Investors are concerned about the potential for policy changes, corruption, and bureaucratic hurdles that can delay projects and increase costs. The lack of a robust financial ecosystem, including limited access to capital and high interest rates, further deters investment in power technologies.

To accelerate renewable energy investment, African nations need to address several structural and financial barriers that have slowed progress. Key priorities include strengthening political and regulatory stability, essential for building investor confidence and reducing perceived risks. Establishing clear, long-term policy frameworks and transparent regulatory processes can help attract both domestic and international capital.

Figure 9. Africa renewables investment outlook



Data compiled June 30, 2026.
Source: S&P Global Energy
© 2026 S&P Global.

6.2.7 Emerging nuclear policy

The 1.86 GW Koeberg nuclear power plant in South Africa is currently the only operational nuclear power plant in Africa. In 2024, South Africa's National Nuclear Regulator (NNR) granted a 20-year long-term operation license extension for Koeberg Unit 1, extending its operational life to 2044.

Nuclear offers a unique advantage, it delivers stable baseload power, crucial for replacing fossil fuel generation and for stabilising grids that increasingly depend on intermittent renewable sources. However, The LCOE for traditional nuclear remains high, projected to stay flat over the period, reaching a regional average of around $170/MWh. It is projected to stay high through 2050 compared with solar PV ($20–34/MWh) and onshore wind ($24–48/MWh) which are expected to decline further. This makes nuclear less competitive in Africa, where energy affordability is critical. The large capital requirements of nuclear projects often necessitate substantial foreign financing, exposing projects to sovereign risk, regulatory uncertainty and higher financing costs. As a result, nuclear can be less economically attractive than solar and wind, which offer lower upfront costs, faster deployment and greater scalability.

Amid renewed global interest in nuclear power as a reliable low-carbon generation source, around 13 African countries are progressing through the IAEA's Milestones Approach for the development of nuclear power programmes. Egypt is the clear front-runner, with the 4.8 GW El Dabaa Nuclear Power Plant currently under construction and the first of four VVER-1200 units expected to enter commercial operation around 2028. While the project represents a significant milestone for nuclear development on the continent, its substantial capital requirements and reliance on foreign financing highlight the economic challenges associated with deploying nuclear technology in emerging markets. In particular, the project's economics remain exposed to exchange rate movements and sovereign financing risks, given the large share of costs denominated in foreign currency.

Beyond its capital intensity, El Dabaa also illustrates the strategic dependencies often associated with nuclear developments, with project financing, reactor technology, fuel supply, and operational support largely provided by Russia's Rosatom and associated state institutions. This concentration of external support introduces an additional layer of geopolitical and financing risk relative to more modular generation technologies.

South Africa continues to view nuclear power as an important component of its long-term energy mix and has maintained plans to procure additional nuclear capacity. However, previous procurement initiatives have faced delays due to legal challenges, public participation requirements and concerns regarding procurement transparency, resulting in several processes being reviewed and restarted. Nevertheless, the recently approved Integrated Resource Plan (IRP 2025) reaffirms the country's commitment to nuclear power, providing for 5.2 GW of new nuclear capacity by 2039 as part of a broader strategy to diversify the generation mix and support long-term energy security. While countries such as Ghana and Kenya have established nuclear development programmes and articulated long-term deployment ambitions, they remain at a comparatively early stage of development and face many of the regulatory, financing, skills and infrastructure challenges associated with establishing a new nuclear industry.

Improving policy certainty, strengthening regulatory institutions, enhancing utility creditworthiness and establishing transparent long-term procurement frameworks will be critical to lowering financing costs and improving the investment case for nuclear power across Africa.

Small Modular Reactors (SMRs) are increasingly being evaluated as an alternative to conventional nuclear power in Africa. Their smaller unit sizes, modular construction approach and lower upfront capital requirements can make them more suitable for countries with smaller electricity systems or for supplying large industrial and mining operations. While SMRs may improve project financeability by reducing the size of individual investments and allowing capacity to be added incrementally, they are not necessarily expected to produce cheaper electricity than large-scale nuclear plants, particularly during the early stages of commercial deployment. Nevertheless, their flexibility and reduced project execution risk have resulted in growing interest from policymakers across the continent.

Ghana and Kenya are widely regarded as among the most advanced African countries exploring SMR deployment, having established dedicated nuclear development programmes, engaged with prospective technology providers, and worked closely with the IAEA to strengthen the regulatory and institutional frameworks required for future nuclear projects. Although commercial deployment remains some years away, both countries have made meaningful progress in establishing the foundations required to evaluate future SMR investments.

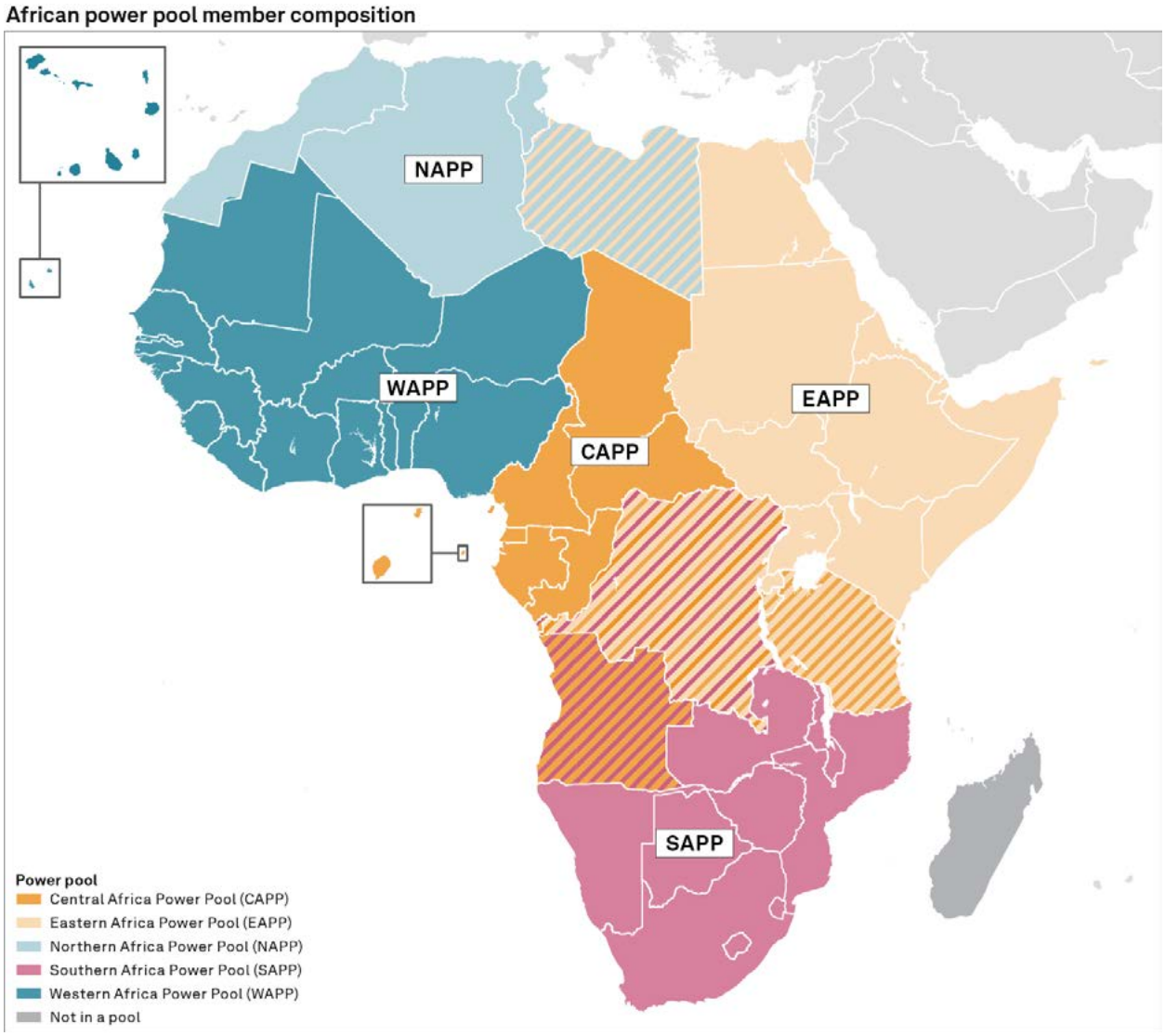
6.3. Regional integration through power pools can support the continent's power ambitions

Regional electricity integration has the potential to address several of Africa's power sector challenges by improving system reliability, diversifying supply sources, and creating larger markets for new generation projects. This can reduce investment risk and support more efficient utilisation of generation resources across national borders. However, these benefits depend on adequate transmission infrastructure, aligned regulatory frameworks, and effective market design.

6.3.1 Insights into Africa's power pools

Five regional power pools have been established across the continent. These power pools are collaborative frameworks that enable neighbouring countries to interconnect their electricity grids, share resources and coordinate energy policies.

Figure 10: Regional power pools in Africa



The Southern African power Pool (SAPP) stands out as the most advanced and successful. SAPP's achievements are rooted in its robust institutional framework, high degree of grid interconnection and a transparent, competitive electricity market that has enabled efficient trading and resource optimisation.

The West African Power Pool (WAPP) has made notable progress, particularly in expanding cross-border interconnections and increasing electricity trade. However, WAPP's market is still maturing, and its growth is hampered by incomplete grid links, regulatory fragmentation and persistent financial challenges such as payment arrears.

The Eastern Africa Power Pool (EAPP) is also making strides, with several large-scale interconnection projects underway. Yet, its development is slowed by political and regulatory fragmentation, infrastructure gaps and occasional security tensions among member states.

The Central African Power Pool (CAPP) remains the least developed, with minimal cross-border trade and limited infrastructure. Political instability, weak governance and a lack of investment have all contributed to its slow progress.
The North African Power Pool (NAPP) boasts some of the continent's most advanced infrastructure, but regional electricity trade is limited since most countries prefer bilateral agreements and focus more on integration with European markets than with sub-Saharan Africa.

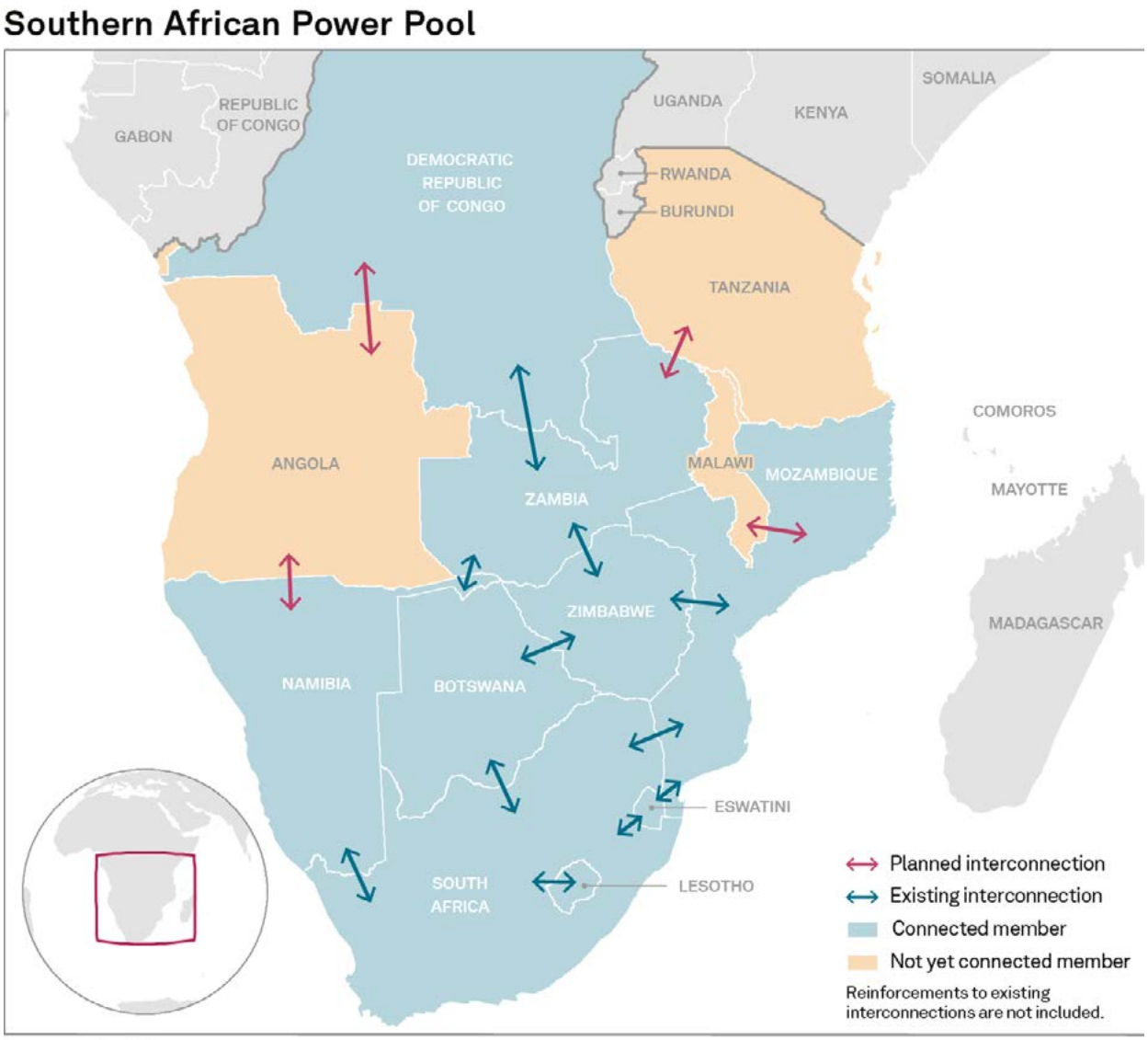
Efforts to integrate these regional pools into a single, continent-wide electricity market are also gaining momentum. Spearheaded by the African Union, the African Single Electricity Market aims to establish the world's largest integrated electricity market by geographic coverage, spanning 55 countries and more than 1.3 billion people, while harmonising technical standards, regulatory frameworks and infrastructure planning across regions. However, this vision faces significant barriers, including geographical distances, technical incompatibilities, the vast infrastructure needed, political fragmentation and differing national interests.

SAPP power pool overview
Created in 1995, the SAPP has 12 members and is the most advanced and liquid power pool on the continent. SAPP operates a multi-segment physical market, including bilateral agreements, a Day-Ahead Market (DAM), an Intra-Day Market (IDM), and Forward Physical Markets. Bilateral agreements continue to dominate, accounting for 80% of SAPP trading volumes, representing 7.2 TWh of electricity traded between January and October 2025, compared to almost 1 TWh cleared across competitive DAM/IDM exchanges over the same period. This low exchange liquidity is reflected in a regional churn factor of less than 1%, meaning that exchange-traded volumes account for less than 1% of total electricity consumption. By comparison, mature European day-ahead electricity markets typically exhibit churn factors ranging from approximately 24% to more than 100%.

Transmission congestion, network bottlenecks, and unplanned line outages remain key barriers to greater power trading within SAPP. In November 2025, 152.5 GWh of potentially tradable electricity went uncleared in SAPP's competitive markets due solely to transmission constraints. To address these limitations, SAPP's master plan prioritises a number of strategic transmission projects aimed at integrating currently weakly connected or unconnected members, strengthening cross-border transfer capability, and alleviating congestion along key regional corridors. These projects include:

- **Zambia-Tanzania-Kenya Line:** A 400-kV/330-kV line connecting Tanzania and Zambia, physically linking the SAPP and EAPP. Initial capacity is 400 MW, with full operational status scheduled for 2028.
- **Angola-Namibia Interconnector:** A 366-km, 400-kV line advancing past feasibility stages to tie Angola to the SAPP and integrate the proposed 600 MW Baynes cross-border hydropower project.
- **ZIZABONA Corridor:** A 400/330-kV route linking Zimbabwe, Zambia, Botswana, and Namibia to bypass central SAPP bottlenecks.
- **Mozambique-Malawi:** A 218-km, 400-kV line designed to connect Malawi to the SAPP grid, currently nearing completion.

Figure 11: The Southern African Power Pool



Data compiled Feb. 3, 2026.
Source: S&P Global Energy: 262627-01.

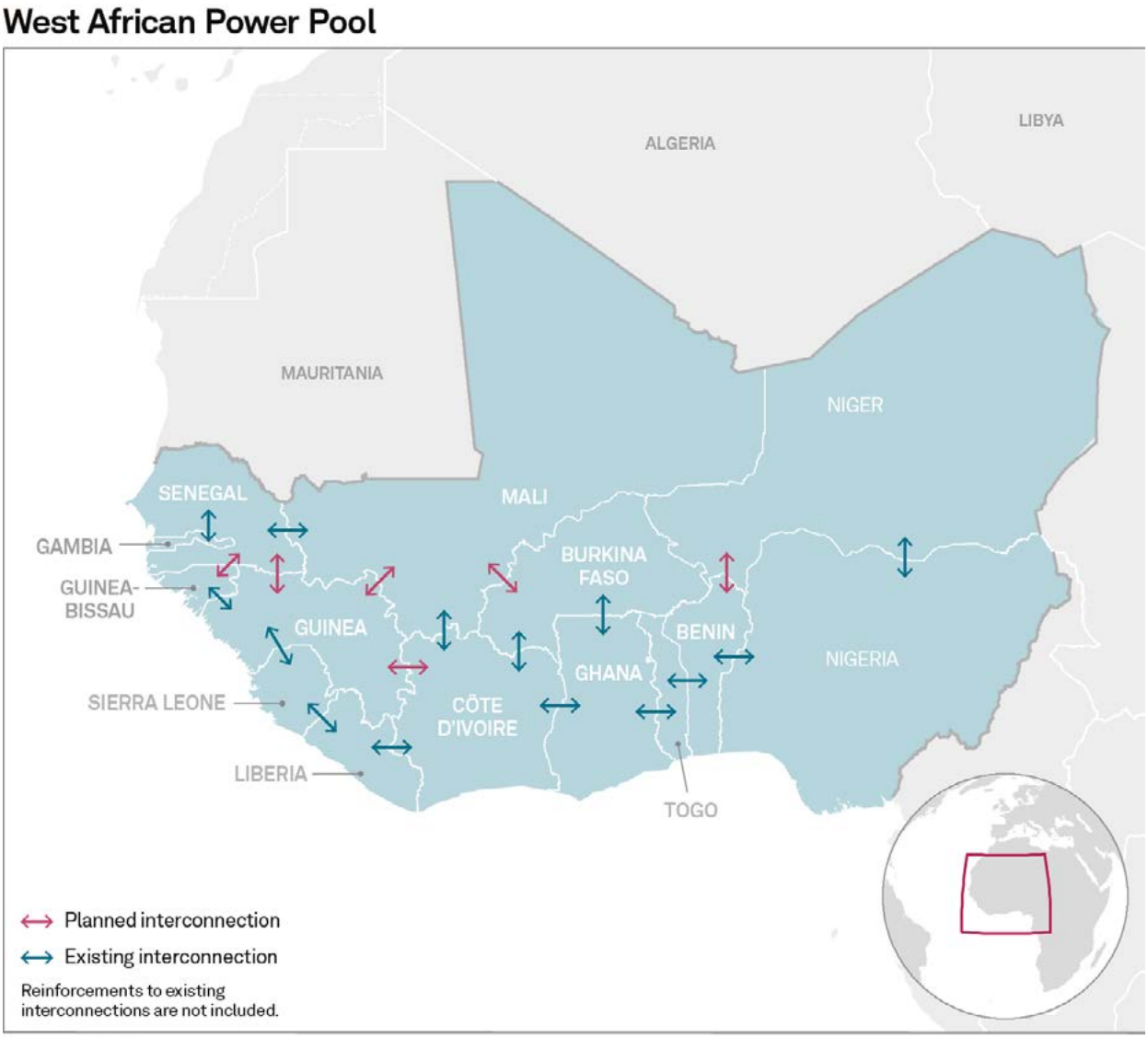
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Insights into Africa's other power pools

West African Power Pool (WAPP): Established in 2000, the West African Power Pool (WAPP) aims to integrate the electricity systems of all 15 West African countries into a single regional market. A major milestone was achieved in November 2025 when WAPP successfully demonstrated synchronized operation of the interconnected regional grid, paving the way for permanent synchronisation targeted for mid-2026. Cross-border electricity trade currently accounts for around 7% of regional electricity consumption, reflecting the growing role of regional power exchanges in balancing differences in resource availability, generation costs, and supply adequacy across member countries. However, further growth remains constrained by utility payment arrears, weak utility finances, and transmission infrastructure limitations. Key strategic interconnection projects include:

- **CLSG Interconnector:** A 1,300-km, 225-kV line with 400 MW capacity, operational since late 2024.
- **OMVG Interconnection:** 1,677-km, 225-kV loop completed in 2025 with an 800 MW trade capacity connecting Senegal, Gambia, Guinea-Bissau, and Guinea.
- **Dorsale Nord (North Core):** An 880-km, 330-kV double-circuit line with 600 MW capacity connecting Nigeria, Niger, Burkina Faso, and Benin, nearing completion.

Figure 12: Western African Power Pool

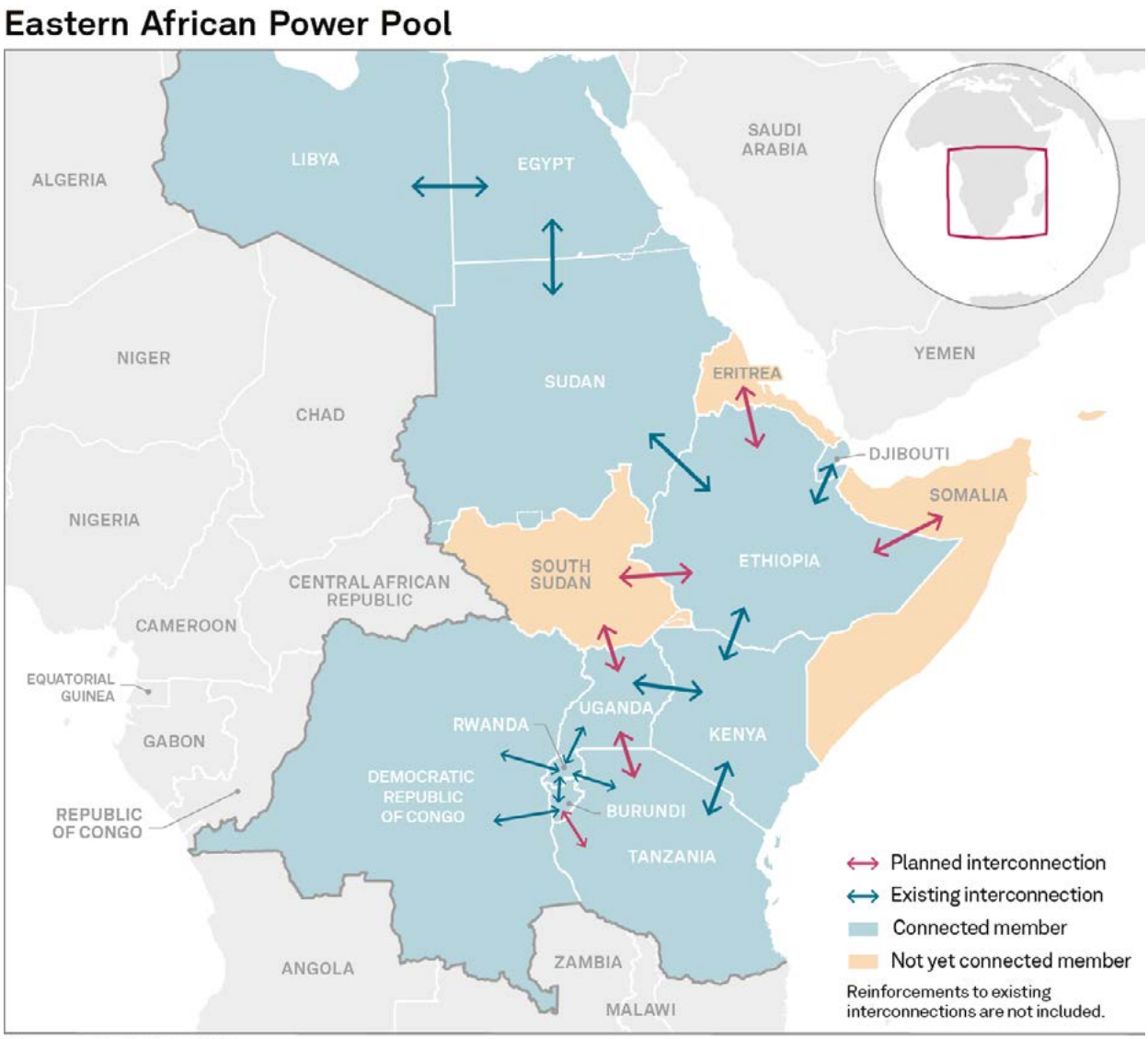


Data compiled Jan. 29, 2026.
Source: S&P Global Energy: 262605-01.

Established in 2005, the Eastern African Power Pool (EAPP) connects electricity systems across Eastern and parts of Central Africa through Northern, Eastern and Southern network blocks. Cross-border electricity trade remains limited relative to the size of the regional market and is largely concentrated along the Ethiopia-Kenya-Tanzania corridor. Member states are working towards the establishment of an independent system and market operator and the launch of a competitive regional electricity market. However, progress has been slower than anticipated due to a combination of transmission constraints, evolving market structures, regulatory harmonisation challenges, and the financial weakness of several regional utilities. Key interconnection projects include:

- Ethiopia-Kenya Interconnector: A 2 GW high-voltage direct current line commissioned in 2020, that enables exports of Ethiopian hydropower and wind generation into Kenya and the wider East African region.
- Uganda-South Sudan: A planned 299 km, 400 kV double-circuit interconnector intended to connect South Sudan to the EAPP network and reduce its reliance on isolated thermal generation.
- Kenya-Tanzania Interconnector: A 400 kV interconnector commissioned in 2024-25 that closes a critical gap in the East African transmission backbone and enables power flows between Ethiopia, Kenya and Tanzania.

Figure 13: Eastern African Power Pool

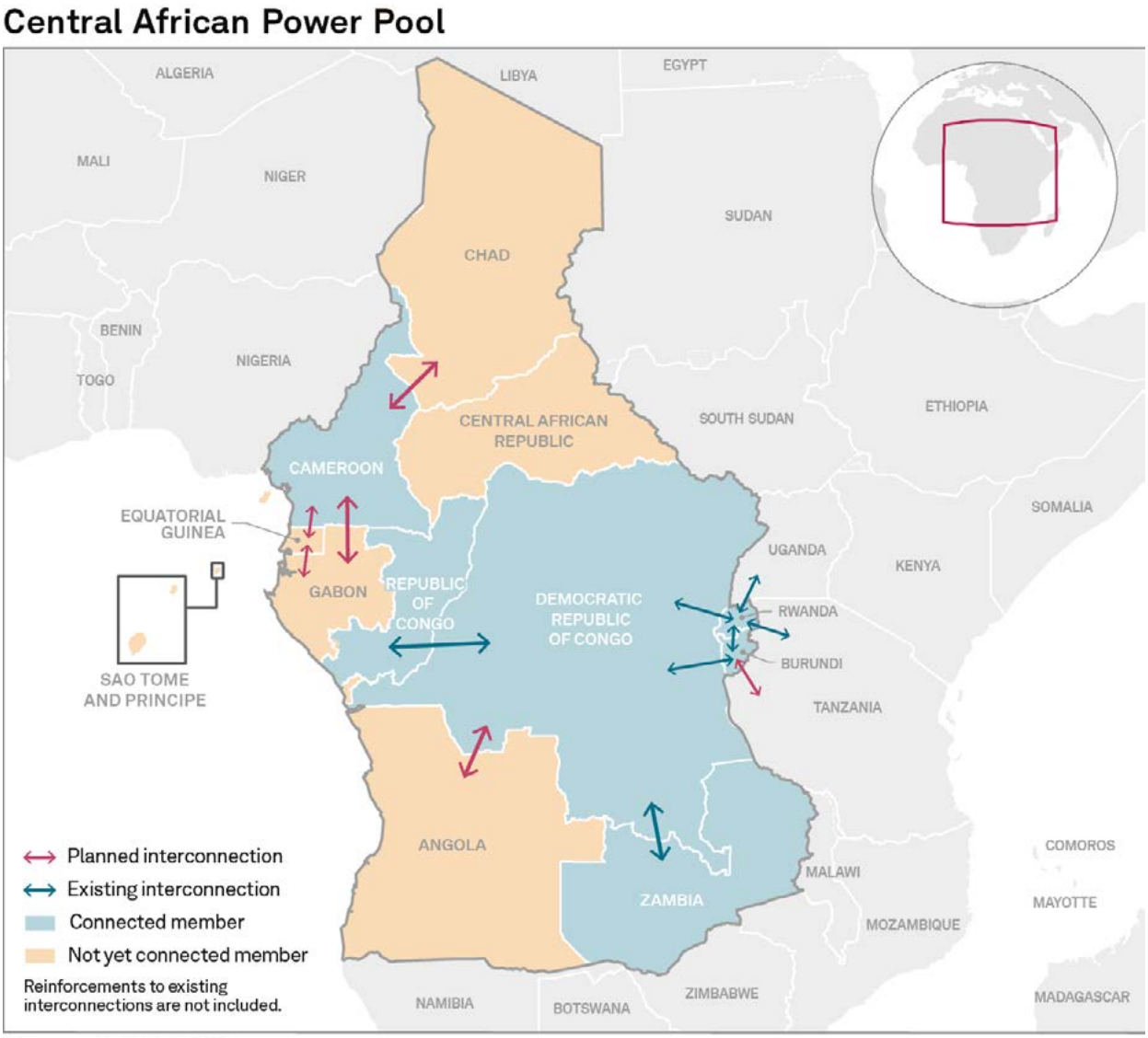


Data compiled Feb. 3, 2026.
Source: S&P Global Energy: 262628-01.

Central African Power Pool (CAPP/PEAC): Formed in 2003, CAPP covers 11 member countries of Central Africa, but remains the least interconnected pool on the continent, characterized by small, fragmented national systems. Vast geographical distances, limited transmission infrastructure and relatively small power systems are key constraints across the region. Strategic projects under development include:

- **RIS-RNI (Cameroon-Chad Interconnector):** A 1,020-km, 225-kV line with 100 MW of planned transfer capacity, currently under construction with AfDB support and set to become operational in 2027.
- Inga-Kolwezi-SAPP (DRC-Zambia): A 2,000-km, 500-kV line originating from the Inga Dam, where World Bank and AfDB-funded rehabilitations are ongoing from 2024 to 2026 to stabilize exports to Southern Africa.
- Kalumbila-Kolwezi: A 330-kV, 700-MW private-sector-led interconnection currently in the financing stage to deliver power from Zambia to DRC's mining sector.

Figure 14: Central African Power Pool



Data compiled Feb. 3, 2026.
Source: S&P Global Energy: 262629-01.

North African Power Pool (NAPP): Formally established in 1989, the North African Power Pool (NAPP) comprises Algeria, Libya, Mauritania, Morocco and Tunisia. While the region benefits from some of the highest electrification rates and installed generation capacities in Africa, cross-border electricity trade remains relatively limited and is largely conducted through bilateral agreements rather than a centralized competitive market. Cross-border electricity trade remains relatively limited, accounting for only a small share of regional electricity production and largely comprising bilateral exchanges focused on reserve sharing, system balancing, and occasional surplus energy transfers.

Regional integration remains constrained by political fragmentation, limited market harmonisation and differences in regulatory frameworks. At the same time, several North African countries are increasingly prioritising electricity interconnections with Europe, where access to larger and potentially more lucrative export markets provides a strong commercial incentive for power exports. Internal projects include:

- **Algeria-Tunisia Corridors:** A network of 400-kV and 150/225-kV AC lines with an operational thermal limit of roughly 1,200 MW. This is the most active intra-African link within COMELEC, utilized primarily by Sonelgaz (Algeria) to export bulk electricity to STEG (Tunisia).
- Libya-Egypt Link: A 220-kV line (with ongoing efforts to upgrade to 500-kV) connecting the eastern edge of the Maghreb grid to the (EAPP) and Arab grid.

Integration of Europe and North Africa transmission networks

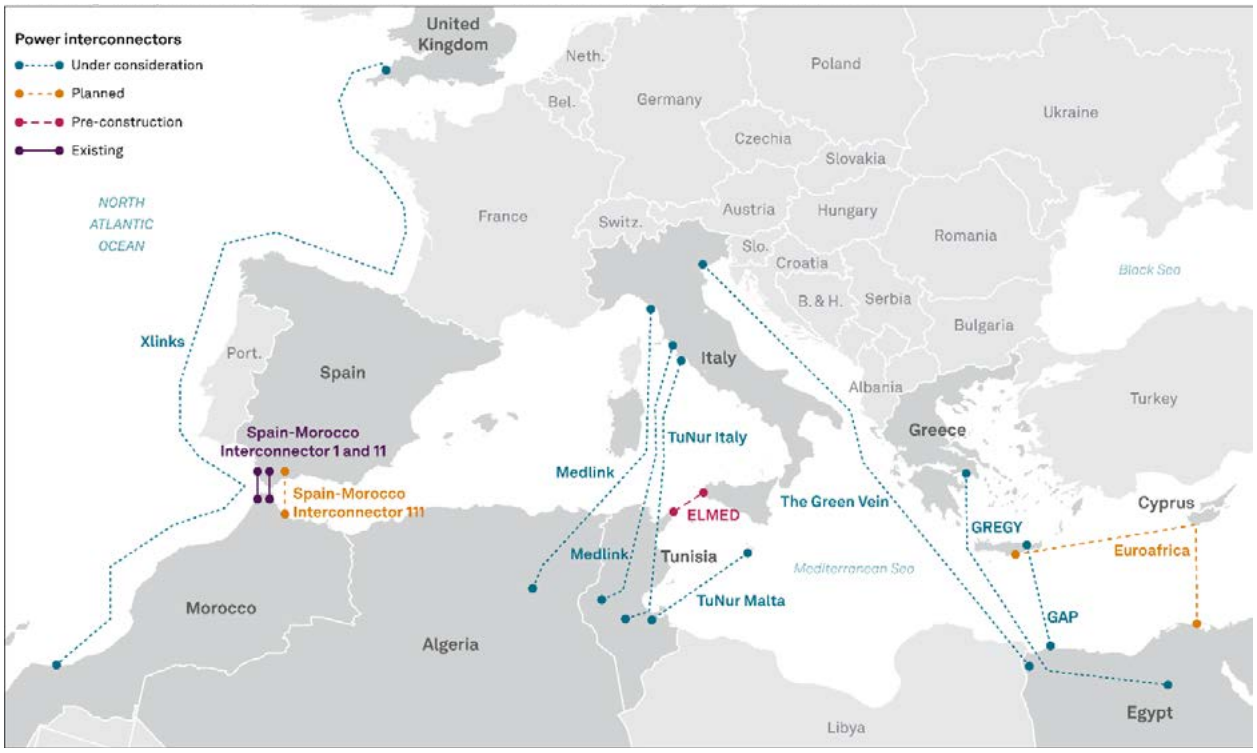
North African countries are actively leveraging their geographical proximity to integrate their transmission networks with European electricity markets. To date, the Morocco-Spain interconnection remains the only operational electricity link between Africa and Europe, comprising two subsea cables with a combined capacity of 1,400 MW. A third subsea line of 700 MW is planned for commissioning in 2026.

The ELMED interconnector is currently the most advanced planned integration project. Comprising a 600 MW subsea link between Tunisia and Italy, ELMED is expected to be completed in 2028 at a cost of €850 million, supported by $268.4 million in World Bank financing approved in 2023. Other planned interconnectors under active consideration include:

- **Morocco-UK (Xlinks):** A proposed 3,600 MW subsea HVDC project, frozen since June 2025 following the withdrawal of UK government support.
- **Algeria-Italy (Medlink):** Algeria is planning two 2,000 MW subsea links to export renewable electricity to Italy by 2030, alongside Tunisia's separate 2,000 MW link to Italy planned by 2034.
- **Egypt-Europe:** Egypt is involved in multiple projects, including the Green Vein interconnection to Italy, expected to be operational by 2032, and the GREGY project to Greece, set for 2030. The Greece-Africa Power Interconnector (GAP) plans to enhance green hydrogen production between Greece and Egypt and is expected to start in 2030.

Although the pipeline of Africa-Europe interconnection projects is expanding rapidly, many remain subject to significant financing, regulatory, permitting and commercial risks. The suspension of the proposed Morocco-UK Xlinks project illustrates the challenges associated with developing large-scale cross-border infrastructure, even where strong strategic rationale exists.

Figure 15. Europe to Africa interconnectors



As of July 2025
Source: S&P Global Commodity Insights

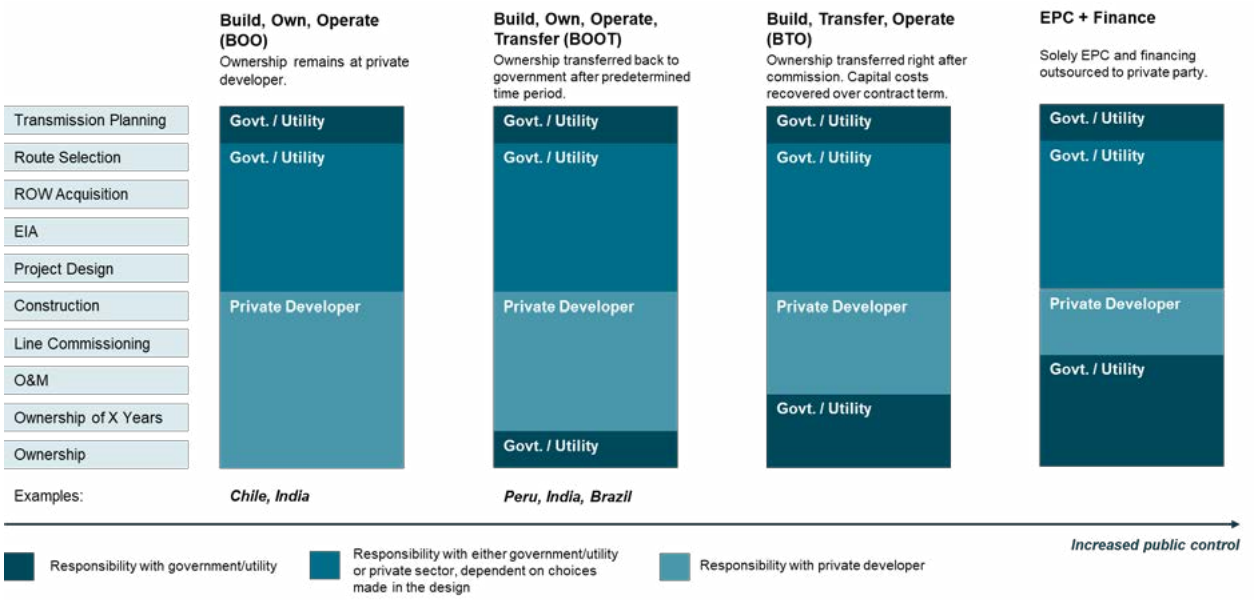
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6.3.2 PPPs and Independent Transmission Projects (ITPs) to support the infrastructure financing gap

The expansion of transmission infrastructure is becoming increasingly important across Africa as countries seek to integrate growing volumes of renewable energy, strengthen regional power trade, and improve electricity security. However, the scale of investment required is often beyond the fiscal capacity of governments and state-owned utilities, many of which face mounting debt burdens and constrained balance sheets. As a result, governments are increasingly exploring public-private partnerships (PPPs) and Independent Transmission Projects (ITPs) to mobilise private capital and expertise for the development of critical transmission infrastructure. By allocating risks between the public and private sectors, these models can accelerate project delivery while reducing pressure on public finances.

There are four main models used to allow the private sector to participate in the transmission infrastructure development.

Figure 16. Exploring PPP models



Key African ITP precedents include:

- **Kenya Ketraco ITP:** A $311 million public-private partnership executed by Africa50 and Power Grid Corporation of India Ltd. to construct and operate two high-voltage transmission lines and associated substations under a long-term availability concession with Ketraco.
- **Uganda Amari Grid Project:** Developed by Gridworks Development Partners LLP under a long-term services contract, the private developer finances, builds, and maintains four high-voltage substations in exchange for availability payments from UETCL. Two substations are strategically positioned at the Kenyan and DRC borders to facilitate future SAPP-EAPP trade.
- **Mozambique LTEC Project:** Launched in 2024 by Gridworks and EDM, this PPP entails the private partner financing and constructing 460 km of high-voltage lines between Chimuara and Nacala to boost north-south power flows.
- **South Africa National ITP Program:** Formalized in 2025, the program targets the integration of 53 GW of new renewable capacity by 2033, requiring over 14,000 km of new transmission lines and 133,000 MVA of transformer capacity. The first phase has prequalified seven international consortia to bid on the construction and maintenance of 1,164 km of high-voltage lines across seven strategic corridors.

While these projects demonstrate growing momentum for private participation in transmission infrastructure, ITP and PPP models remain at an early stage of adoption across most African markets. Transmission investment continues to be dominated by state-owned utilities, with private sector participation largely limited to a small number of pioneering jurisdictions. Broader adoption will depend on establishing clear regulatory frameworks, improving utility creditworthiness, and creating bankable revenue mechanisms that provide investors with confidence in long-term cost recovery.

6.4. Strategic market reforms to strengthen power sectors across Africa

Historically, electricity sectors across Africa have been dominated by state-owned, vertically integrated utilities operating under single-buyer market structures. While these models played an important role in expanding access to electricity, many utilities have struggled with chronic underinvestment, cost-recovery challenges, transmission constraints, and supply reliability issues. In response, governments and regulators across the continent are increasingly pursuing power sector reforms aimed at improving financial sustainability, attracting private investment, strengthening transmission networks, and increasing competition.

While over 50 countries in Africa operate national electricity sectors, only a small number have implemented meaningful elements of wholesale market liberalization, independent system operation, and open-access transmission frameworks. As a result, reform efforts remain concentrated in a limited number of leading markets, with South Africa, Kenya, Nigeria, Uganda, and Zambia representing some of the continent's most significant ongoing reform initiatives.

Figure 17. Assessment of unbundling and wholesale development status in select African countries

	Transition from vertically integrated model to liberalized market	Main utility unbundling efforts	Independent transmission system operator	Regulated market	Private participation	Wholesale market
South Africa	✓	✔	✔	✔	✔	✓
Zambia	✓	⊘	⊘	✔	✔	⊘
Kenya	✓	✔	✔	✔	✔	⊘
Ghana	✓	✔	✔	✔	✔	⊘
Nigeria	✓	✔	✔	✔	✔	✓
Uganda	✓	✔	✔	✔	✔	✓
Morocco	⊘	⊘	⊘	✔	✔	⊘
Egypt	✓	✔	✔	✔	✔	⊘
Tanzania	✓	✔	⊘	✔	✔	⊘

Developing ✓ Completed ✔ Not Materialized ⊘

Kenya
Kenya has established one of East Africa's most progressive regulatory and market frameworks under the Energy Act of 2019 and the National Energy Policy 2025–2034. Unbundling has structurally separated generation (KenGen) and high-voltage transmission (Kenya Electricity Transmission Co. Ltd. - KETRACO) from distribution, while the Energy and Petroleum Regulatory Authority (EPRA) enforces performance standards and cost-reflective tariffs. KETRACO operates as an independent transmission entity with open-access guidelines, which insulated the transmission backbone from retail collection volatility and successfully attracted private capital—most notably enabling a $311 million ITP Public-Private Partnership with Africa50 and Power Grid Corp. of India Ltd. to construct and operate 400 kV transmission corridors. Under the National Energy Policy 2025–2034, Kenya is exploring reforms intended to increase competition, expand private-sector participation, and facilitate more open access arrangements within the electricity sector.

South Africa
South Africa is undertaking one of the continent's most ambitious power market reform programs through the Electricity Regulation Amendment (ERA) Act, which came into effect in January 2025. The reforms establish the framework for transitioning from Eskom's historical single-buyer model toward a more competitive electricity market, supported by the unbundling of transmission activities into the National Transmission Company South Africa (NTCSA). Alongside the development of a competitive wholesale electricity market, South Africa is also expanding private sector participation in transmission infrastructure through a national Independent Transmission Projects (ITP) program.

Zambia
Zambia's power sector remains dominated by state-owned ZESCO Ltd., which continues to operate across generation, transmission, and distribution. However, recent reforms have focused on expanding private sector participation and improving market access. A significant milestone was the introduction of the Electricity (Open Access) Regulations No. 40 of 2024, which enable independent generators to sell electricity directly to consumers using transmission and distribution infrastructure owned by ZESCO, CEC, and other network operators.

Nigeria
Nigeria has implemented one of Africa's largest power sector restructuring programs through the Nigerian Electricity Supply Industry (NESI) reforms, which unbundled the national utility into separate generation, transmission, and distribution entities. The Electricity Act of 2023 represents a further milestone by enabling state-level electricity markets, expanding private sector participation, and establishing the Nigerian Independent System Operator (NISO) to support the gradual transition toward more competitive market structures.

Uganda
Uganda is often regarded as one of Africa's more successful examples of electricity sector unbundling and private sector participation. Beginning in the early 2000s, the former Uganda Electricity Board (UEB) was unbundled into separate generation, transmission, and distribution entities while the Electricity Regulatory Authority (ERA) was established as an independent regulator. The reforms introduced long-term private participation in distribution through the Umeme concession, contributing to significant operational and commercial improvements across the sector.

Egypt
Egypt has undertaken one of Africa's most significant power sector reform programs, combining tariff reform, large-scale generation investment, and expanded private sector participation. While the sector remains centred around the state-owned Egyptian Electricity Holding Company (EEHC) and a single-buyer market structure, reforms have improved sector financial sustainability, attracted private investment, and enabled substantial transmission and renewable energy development.



Chapter 07

7. The importance of Africa in energy transition from a critical minerals perspective

Sector Narrative: From Resource Wealth to Industrial Opportunity

Critical minerals have emerged as one of the most important strategic battlegrounds of the global economy. Driven by the energy transition, electrification, artificial intelligence, advanced manufacturing and national security concerns, governments and corporations are competing to secure reliable supplies of minerals such as copper, cobalt, lithium, graphite and rare earth elements. Against this backdrop, Africa occupies a uniquely important position, hosting some of the world's largest and most strategically significant mineral endowments.
The continent already plays a critical role in global supply chains. Africa accounts for the majority of global cobalt production, substantial shares of global copper and bauxite supply, and hosts world-leading reserves of graphite, manganese, platinum group metals and other critical minerals. As global demand accelerates and supply deficits emerge for several key commodities, Africa's importance as a source of future supply is expected to increase significantly.

This strategic importance is attracting growing geopolitical attention. China's long-standing investments across African mining assets have provided it with a significant first-mover advantage in securing future supply, while the United States, Europe and a growing group of middle powers including Japan, India and Australia are increasingly seeking partnerships and investment opportunities across the continent. As a result, critical minerals are reshaping investment flows, trade relationships and infrastructure development strategies throughout Africa.

Yet the largest opportunity for African countries extends beyond extraction. Increasingly, governments are seeking to capture more value domestically through beneficiation, processing and refining. Moving further downstream can create jobs, strengthen industrial capabilities and reduce dependence on the export of raw materials. However, successful beneficiation requires more than policy ambition. It depends on robust governance, reliable power supplies, technical capabilities, transportation infrastructure, and access to capital. The experience of countries such as Zimbabwe and the DRC demonstrates both the opportunities and challenges involved in moving up the value chain.

Infrastructure is emerging as a key enabler of this transformation. Major transport corridors such as Lobito and TAZARA are being developed or upgraded to connect mineral-rich regions to international markets, while also generating wider economic benefits through improved connectivity, logistics and regional integration. These investments are not only reshaping mineral trade routes but are increasingly serving as catalysts for broader economic development.

Ultimately, Africa's critical minerals story is no longer simply about resource ownership. The real opportunity lies in converting geological advantage into industrial capability. Countries that combine stable policies, infrastructure development, value-added processing and strategic partnerships will be best placed to capture a larger share of the economic benefits while securing a more influential role in the future global energy and industrial system.

7.1 Global context

Our global energy and industrial infrastructure is undergoing a profound transformation. As the world transitions from traditional fossil fuels to clean technologies, a rapidly growing reliance on critical minerals has emerged. Clean technologies such as solar panels, wind turbines, and electric vehicles (EVs) require significantly more critical minerals than their conventional counterparts. However, the demand drivers extend far beyond the energy transition. The United States and China are currently competing for global leadership across four deeply connected pillars that underpin national strength: future energy security, AI leadership, advanced manufacturing, and defense capabilities.

As clean energy deployment and EV adoption accelerate, global demand for these minerals is projected to increase up to five-fold by 2035. Supply-demand forecasts suggest substantial supply deficits as we approach the early 2030s for several minerals such as copper, nickel, lithium and graphite. This potential shortfall raises critical questions: Where can these minerals be securely sourced, and how will capital-intensive projects be developed when confronted with the immediate short-term challenges of price volatility or temporary oversupply? Amid these frictions, securing mineral access is no longer just an economic goal; it is a national security imperative.

7.1.1. The Strategic Vulnerability and China's First-Mover Advantage

Currently, critical mineral access, processing, and refining represent the United States' weakest link. Even though the US leads in capabilities like semiconductors and advanced electronics—driving its edge in AI—China dominates the critical mineral foundation and is leveraging that position to strengthen its influence across strategically important supply chains.

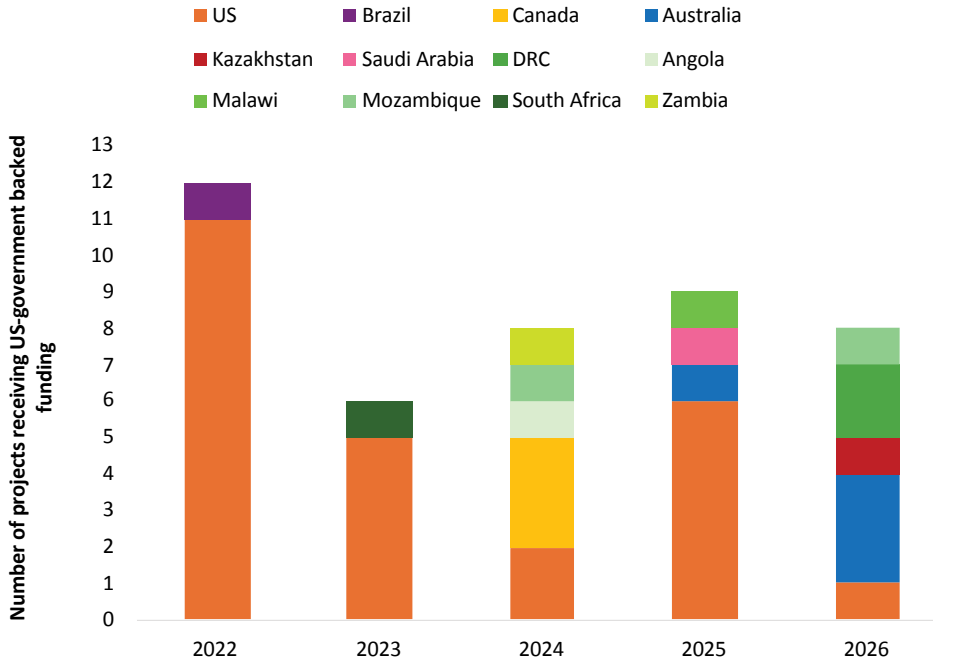
China is one step ahead in securing active production assets globally, possessing a head start in Africa that spans over decades. Bolstered by substantial state support and its Belt and Road Initiative, China is the continent's fifth largest investor in terms of foreign direct investment stock. Over the last decade, Chinese M&A has aggressively targeted gold, copper, and lithium. Since 2016, Chinese companies have spent $13 billion acquiring copper assets—including CMOC's strategic 2016 purchase of the Tenke Fungurume Mine in the DRC from a US company—and $8.5 billion on combined lithium assets. These acquisitions reflect an intensifying global race to secure ownership of strategic mineral deposits.

China's dominance in metal refining and rapidly growing domestic mineral demand drove Chinese companies to invest heavily upstream to secure feedstock. By controlling both mineral production and downstream processing capacity, China has consolidated a commanding position across multiple critical mineral value chains. Today, the operating production from these early African investments is mostly sent directly back to China to feed its domestic refining and downstream industries.

7.1.2. The US Pivot and the Rise of Middle Powers

The heavy concentration of mineral refining capacity in China, combined with the threat of supply chain disruptions, has forced the US to play catch-up. The US formally re-engaged with the sector through the 2020 Energy Act, expanding government-level investments through the DoD, the Office of Strategic Capital, the DFC, and the EXIM Bank. While much of this funding remains domestic, US investments in Africa picked up in 2023, focusing on rare earths, graphite, copper, lithium, and cobalt assets. However, a stark contrast remains: while China possesses active operations, US investments in Africa are focused mostly on projects still under development, with the Balama Mozambique graphite operation being the rare exception in active production

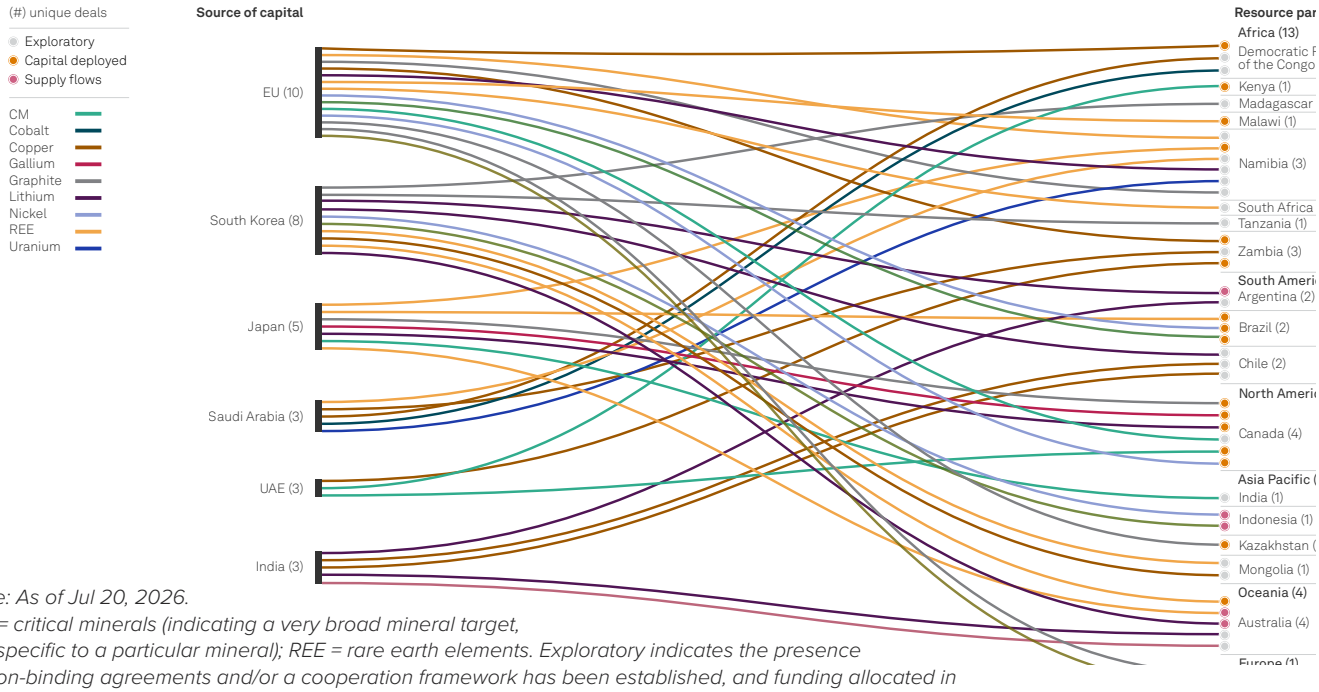
Number of projects receiving US-government backed funding by country



Note: As of Jul 20, 2026
Source: S&P Global Energy

Simultaneously, a third faction has entered the race. Traditional US allies, middle powers like Japan, India, and Australia are pursuing independent critical mineral strategies. Caught between China's broadening export controls (particularly on rare earths) and US policies driven primarily by American domestic priorities, these nations are seeking their own partnerships. Africa has become their most popular destination for bilateral resource deals, though most of these frameworks remain exploratory, with no capital formally deployed yet and no investment targets identified.

A new nexus of capital, resources, and supply security



Note: As of Jul 20, 2026.
CM = critical minerals (indicating a very broad mineral target, not specific to a particular mineral); REE = rare earth elements. Exploratory indicates the presence of non-binding agreements and/or a cooperation framework has been established, and funding allocated in some cases, but no specific investment target has been identified. Capital deployed indicates that a specific investment target has been identified and that capital has been deployed. Supply flowing indicates material already being supplied through an established supply relationship.
Map credit: Omar Shamsuddin. Source: S&P Global Energy. *© 2026 S&P Global.*

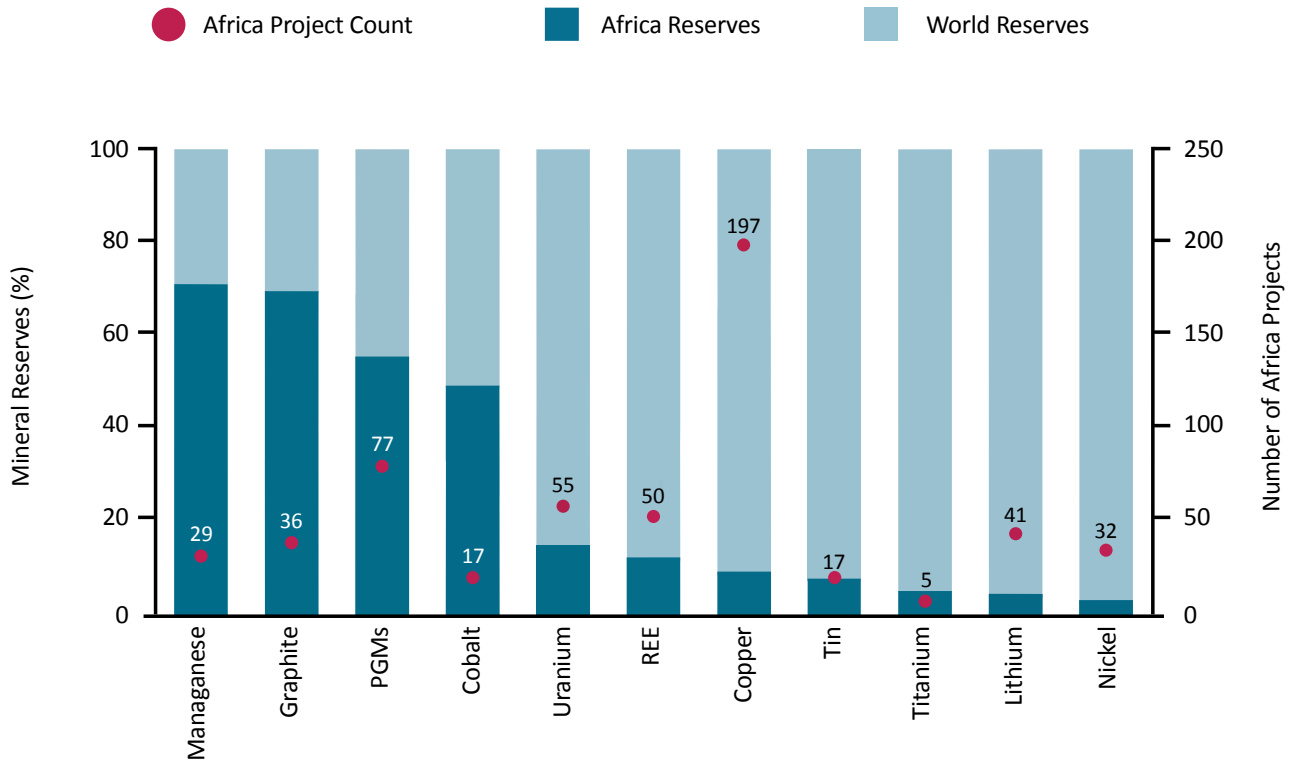
7.2 Africa's mineral wealth

Africa sits at the centre of the growing competition for critical mineral supply. The continent hosts some of the world's largest mineral endowments, accounting for more than half of global ore reserves for manganese, graphite and platinum group metals (PGMs), and just under half of global cobalt reserves. Significant deposits are distributed across major mineral provinces, including the Central African Copperbelt in Zambia and the DRC, the graphite-rich regions of Mozambique, Tanzania and Madagascar and the lithium districts of Zimbabwe. This exceptional resource base positions Africa as a strategically important supplier of the minerals needed to support global industrial development, energy transition objectives and supply chain diversification.

Africa is also a major producer of several key minerals, accounting for approximately 76% of global mined cobalt supply, 41% of bauxite production and 18% of copper mine supply. However, for a number of critical minerals, particularly graphite and rare earths, the continent's share of global reserves exceeds its current contribution to global production, highlighting significant potential for future supply growth. As demand driven by clean energy technologies, industrial decarbonisation and digital infrastructure continues to rise, Africa's ability to develop these resources in a sustainable and reliable manner will play an increasingly important role in supporting global supply security.

Major African mineral suppliers are increasingly leveraging their dominant market positions to actively shape global commodity markets. No longer content with just supplying raw materials, these nations are becoming active players to protect domestic resources and maximize fiscal revenue. A prime example of this market intervention is the Democratic Republic of Congo's (DRC) recent overhaul of its cobalt export policy.

Figure 73. Africa critical mineral reserves in the global context



Note: PGMs: platinum group metals; REE: rare earth elements

Source: S&P Global Energy

The catalyst for the DRC's intervention occurred in 2024 when domestic cobalt production surged 30%. Because cobalt is naturally mined as a byproduct of copper, companies aggressively chasing lucrative copper production inadvertently flooded the market with cobalt. This drove cobalt prices to their lowest level in nine years. Recognizing that the market was in a deep surplus, the DRC government took decisive action to rein in supply and influence global prices.

In February 2025, the DRC announced a temporary cobalt export ban, which was later extended and formally transitioned into a system of export quotas in October. This bold policy works because there is realistically no alternative to DRC cobalt given the country commands an overwhelming 76% of global mine supply. Other sources of supply, including higher recycling rates and increased output from countries such as Indonesia, are unable to close the supply gap.

By shutting off the export tap, the DRC successfully managed its own supply while forcing global consumers to rapidly draw down their inventories. The price impact was dramatic: prices for refined cobalt metal rose by approximately 150%. Even more significantly, the price of cobalt hydroxide—the semi-refined product that the DRC exports the most—increased more than threefold since the export controls kicked in.

While a rising cobalt price is good news for the DRC, actual fiscal revenue is determined by the equation of price multiplied by export volume. In terms of volume, the implementation of the quota system has been far from smooth sailing. Total quota volumes set for 2026 are restricted to just half of what was exported in 2024.
Furthermore, since exports resumed, producers have faced widespread administrative and technical challenges in applying for and executing their quotas. Stricter export requirements caused a series of delays, resulting in the first trial shipment taking almost two months to depart after exports were formally permitted again. As a direct result of these bottlenecks, one-third of the DRC's base quotas, the volumes specifically assigned to individual companies, have been essentially forfeited as of July 6.

To consolidate state control over the market, any unused base quotas are reassigned into a "strategic quota pool." This smaller pool accounts for about 10% of the total quota and is designated at the complete discretion of the state, reserved for projects of national importance. However, to date, no shipments have been sent out under this strategic pool as far as we are aware. Ultimately, the DRC case study demonstrates both the potential and the challenges of capturing greater value from Africa's critical mineral resources. While supply-side interventions can strengthen prices and enhance revenue generation, realizing the full benefits requires efficient export, logistics and administrative systems capable of supporting reliable market participation.

Figure 74. Chinese cobalt imports by source country

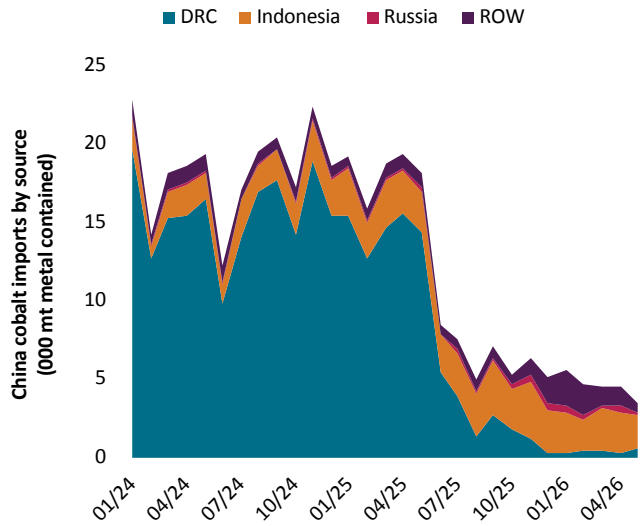
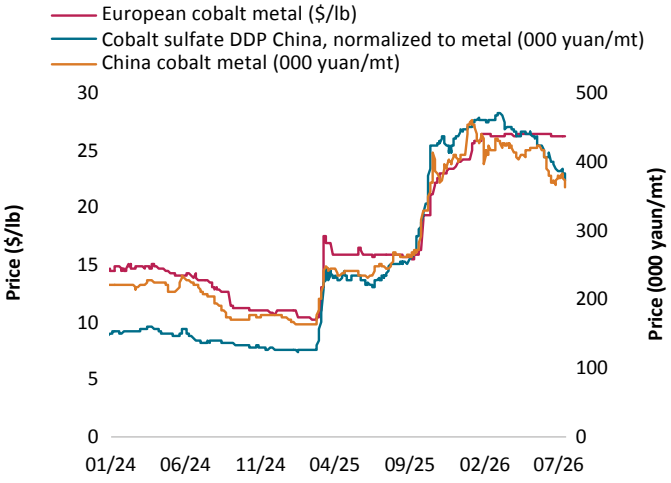


Figure 75. Cobalt prices by major product type



Note: As of July 20, 2026
DDP = delivered duty-paid; DRC = Democratic Republic of Congo; ROW = rest of world.

Sources: S&P Global Energy; S&P Global Market Intelligence Global Trade Analytics Suite.

7.3 Initiatives, partnerships and requirements for developing in-continent critical mineral valorisation in Africa

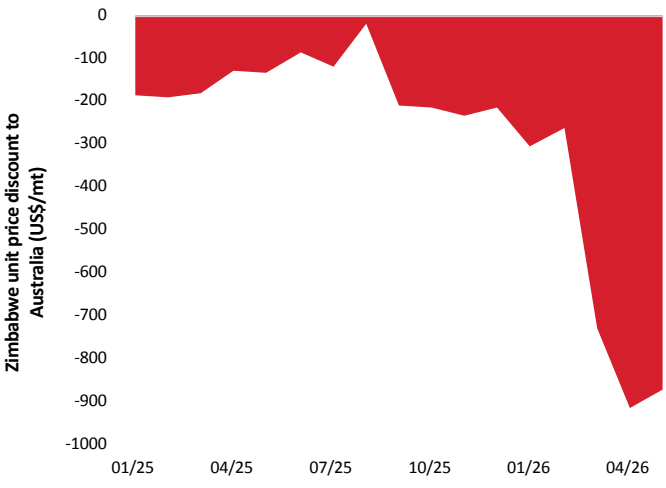
7.3.1 Upgrading the Value Chain & Refining Complexities

Moving beyond raw extraction to local processing and beneficiation remains a key opportunity for African countries to create jobs, strengthen industrial capabilities and capture greater value from their mineral resources. Realizing this opportunity will require continued progress in governance, technical expertise, infrastructure and processing capabilities to support the development of globally competitive refining industries.

Mineral Leakage and the Governance Gap

Before countries can successfully refine minerals, they must capture their full baseline value. Zimbabwe's lithium sector provides a cautionary case study. Following an influx of Chinese capital in 2023, Zimbabwe rapidly expanded production to become China's second-largest supplier of seaborne lithium concentrates (spodumene). Despite this volume success, Zimbabwe's realized prices for these concentrates have been 30% to 40% lower than Australian equivalents. While partially due to lower ore grades, a primary driver is "mineral leakage." Due to structural gaps in mineral governance—specifically a lack of comprehensive geographical mapping and rigorous assay testing—high-value trace minerals like tin, samarium oxide, and NdPr oxide are inadvertently mixed into the exported spodumene uncompensated. To capture full value, African nations must prioritize robust geological mapping, proper testing at the mine gate, and strict border policing.

Zimbabwe unit price discount of spodumene concentrate to Australia



Note: As of July 20, 2026

Sources: S&P Global Energy; company reports; General Administration of Customs of the People's Republic of China

The CapEx and Infrastructure Reality

Once governance is established, transitioning to refining presents distinct hurdles. Unlike raw extraction, refining is a highly capital-intensive manufacturing process requiring substantial initial capital expenditure, skilled labor, and specialized imported equipment. Furthermore, refining is inherently power-intensive, demanding stable, consistent electricity. It also relies on robust logistical networks to import complex chemical reagents and efficiently export finished goods.

The "Midway" Strategy

Because jumping directly from raw mining to battery-grade chemical production is incredibly difficult, a step-by-step approach often proves most effective. To catalyze downstream investment, Zimbabwe is currently capping raw lithium concentrate exports to compel miners to build refineries. Rather than demanding fully refined lithium carbonate or hydroxide—which requires stringent purity controls—the intermediate goal is to produce lithium sulfate. This semi-refined product acts as a highly effective first step because it requires lower capital expenditure and is significantly more tolerant to impurities.

Chemical Complexity Dictates the Pace

Ultimately, the ability to move downstream is dictated by the chemical complexity of the specific mineral. For example, the DRC has successfully compelled the build-out of copper processing, the country now exports most of its copper as refined copper cathodes rather than copper concentrates. This was achievable because many of DRC's operating copper deposits are oxide deposits, making the separation and refining processes relatively straightforward. Conversely, the DRC still predominantly exports cobalt hydroxide, a semi-refined product. Processing cobalt beyond the hydroxide stage requires a much more complex chemical process and an expensive set of reagents, making immediate domestic refining less economically feasible.

Proximity to Customers and the Rise of Regional Hubs

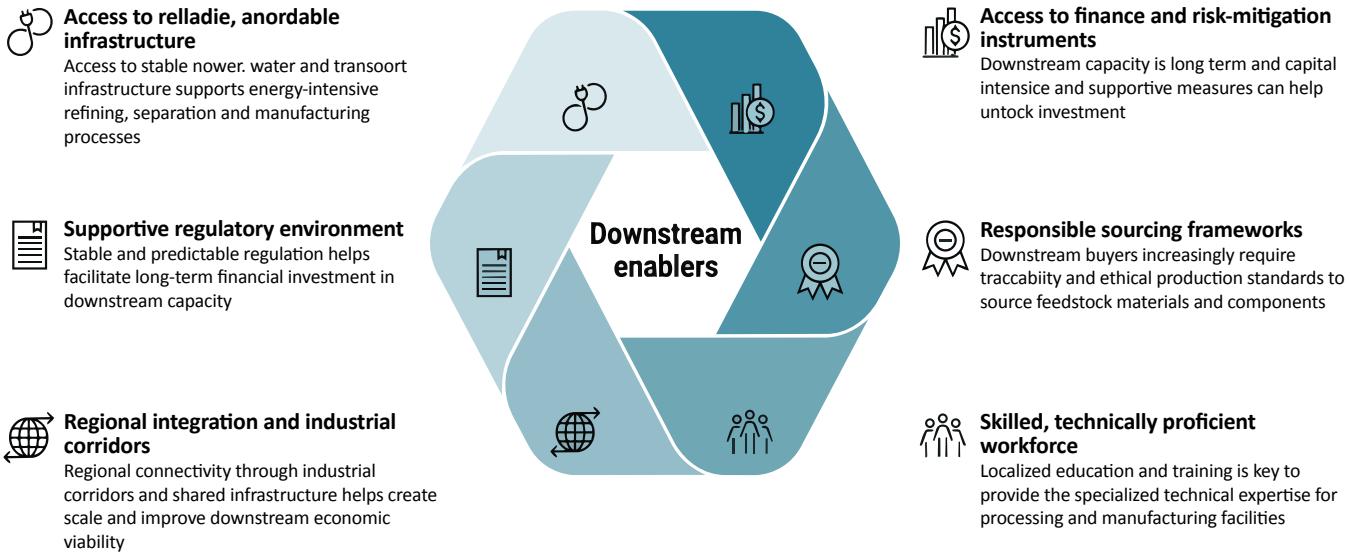
This mining-to-refining imbalance is also evident in graphite. While East Africa leads in natural graphite projects, the expansion of downstream anode active material (AAM) capacity is

concentrated in North America and Asia. Battery-grade materials represent products from a specialized electrochemical industry where proximity to the customer base (battery cell and EV producers) is far more important than proximity to the raw resource. This is driven by strict product precision requirements and joint customer qualification processes.

Consequently, Morocco is emerging as the chosen hub for integrated cathode and anode production in Africa. By aggregating continental resources such as lithium, cobalt, graphite, aluminum, and copper, Morocco leverages its geographical proximity to European EV hubs to complete the supply chain.

The Ultimate Balancing Act

Converting Africa's mineral wealth into national capability is a complex balancing act. The continent holds immense strategic leverage, but fully realizing this potential requires navigating significant challenges. African nations must ensure policy stability and secure property rights to attract long-term foreign capital, all while balancing the competing agendas of global powers to advance domestic industrialization and economic development.



Source: S&P Global Energy

7.3.2. Infrastructure Logistics & Continental Development

The critical minerals boom is not only reshaping trade alliances and mining policies; it is physically redrawing the logistical map of Africa. Historically, one of the greatest barriers to unlocking Africa's geological potential has been the lack of reliable transport and power infrastructure. Today, the intense geopolitical competition for resources is acting as a catalyst for massive infrastructure development, turning landlocked mineral deposits into accessible global assets.

Geopolitical Rivalry Driving Mega-Corridors

The race to secure minerals has sparked a parallel race to build the railways and ports needed to export them. The most prominent example is the Lobito Corridor. Backed by a powerful public-private partnership (PPP) involving the US, the EU, the African Development Bank, and private consortiums, this major railway project is designed to unlock the lucrative copper and cobalt resources in the DRC and Zambia, directing them westward to the Lobito port on the Atlantic coast of Angola. While key sections of the corridor are already operational and handling growing mineral freight volumes, further investment is required to expand rail capacity, improve cross-border connectivity and deliver the planned Zambia extension. The corridor's full strategic potential is therefore likely to be realised progressively over the longer term.

At the same time, China is advancing alternative routes in East Africa, including investments in and proposed upgrades to the TAZARA Railway and related infrastructure, to channel minerals from Zambia, the DRC, and other inland producers to Tanzania's Port of Dar es Salaam on the Indian Ocean destined for Asian markets. This competing infrastructure reflects the broader superpower rivalry, as both the US and China race to control the physical logistical routes from the mine gate to the ocean.

Similarly, the operationalization of the Simandou railway in Guinea is facilitating the extraction of massive iron ore reserves, positioning Guinea to rival South Africa as one of the world's top iron ore producers.

Crucially, the development of these multi-billion-dollar transit corridors offers spillover benefits that extend far beyond mining. African governments are strategically utilizing this mining-funded infrastructure to enhance other vital sectors of the economy, such as agriculture, allowing farmers to transport goods to market more efficiently and cheaply.

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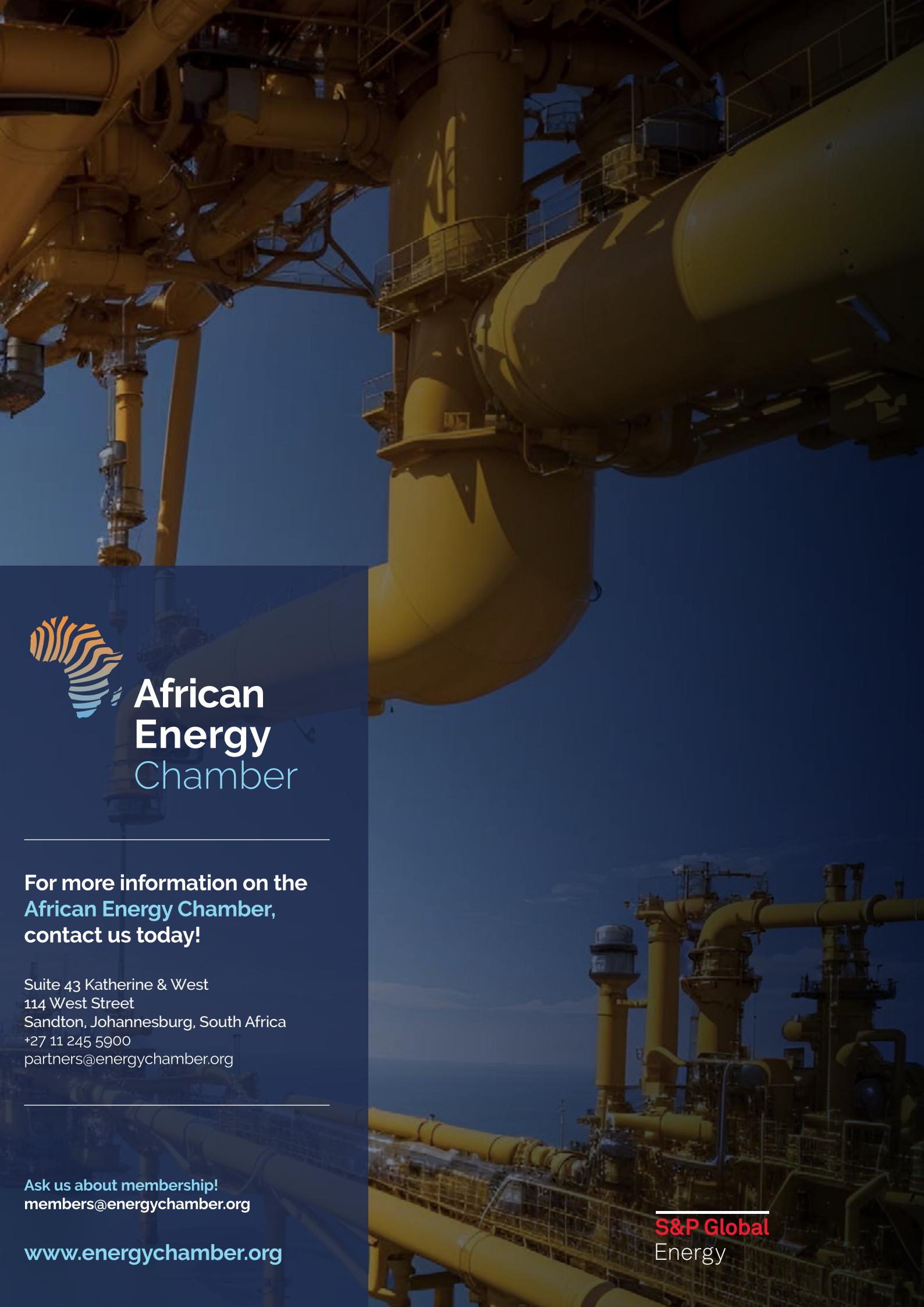
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