African Energy Chamber

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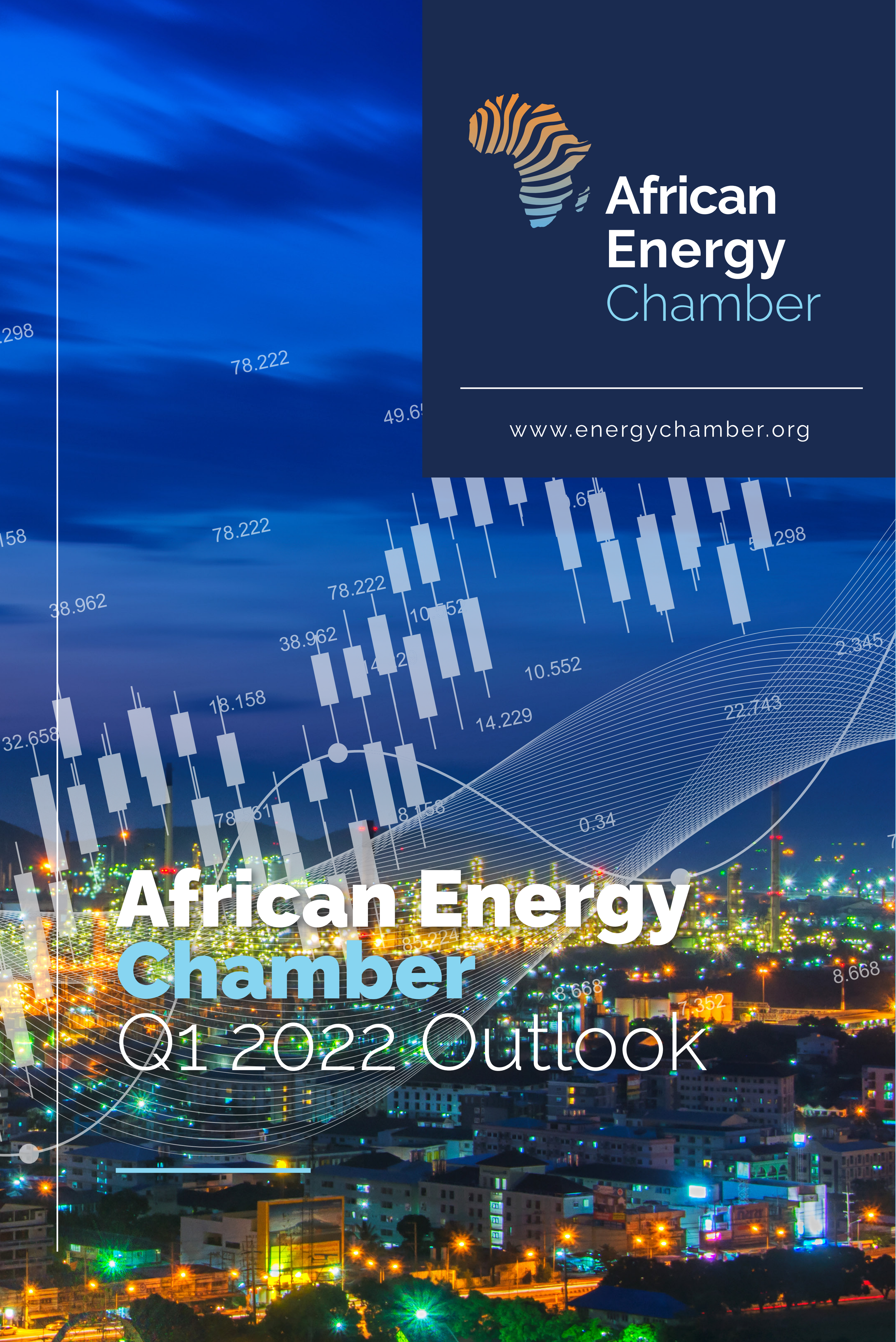

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Q1 2022 Outlook

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Key Highlights

- As the pandemic transitions towards an endemic, Brent benchmark rallied at high $80s-per-barrel
- With the lockdowns being a thing of the past globally, demand levels on the rise again challenging the temporary bullish Brent run
- 2022 supply levels on a month-on-month basis expected to stay at just over 8% of the global crude oil plus condensates volumes
- Nigeria, Libya, Algeria, Angola and Egypt expected to retain the top 5 producers spots for 2022
- 2022 overall crude oil and condensates output expected at a slightly higher level than 2021 driven by a 5% growth in crude oil production
- Nigeria to retain the highest producer status with the annual average crude oil production expected to reach 1.46 MMbbls/d and overall crude oil plus condensates at 1.72 MMbbls/d
- Libya, Algeria, Angola and Egypt round off the top five spots along with Nigeria
- Angola expected to manage to stay afloat at above 1 MMbbls/d mark
- Natural declines in legacy projects and outages caused due to accidents refrain growth despite no effect of OPEC sanctions
- Demand and supply seeing further growth post the lows in 2020 due to the pandemic
- As the producing fields supplying feedgas for LNG exports decline, increasing natural gas demand is expected to be met by new start-ups
- Algeria, Egypt and Nigeria round off the top 3 natural gas producers in 2022 contributing to just over 80% of the overall natural gas flows from Africa
- As the region sees a relatively increased sanctioning activity, 2022 – 2025 cumulative capital expenditure from Africa has seen an increase of US$23 billion
- Greenfield investments in Nigeria, Mozambique, Angola, Ghana, Uganda drive the capital expenditure during the period
- While previous forecast suggested an estimated US$32.5 billion capital investment for the year 2022, new estimates reflect a reduced capital expenditure of US$30 billion
- However, 2023 – 2025 cumulative expenditure has seen an increase from US$110 billion to US$135 billion
- While 2020 saw the second lowest discovered volumes in the past decade, 2021 so far has seen much lower discovered volumes so far
- 2022 is expected to be a much more encouraging year with 9 high impact wells in the drilling schedule
- Results of as many as 14 exploration licensing rounds across the continent are expected to be announced in 2022 with Egypt already having closed for bids
- Of the remaining 13 rounds, bids are under evaluation for 2 licensing rounds, bidding is open in 5 rounds and 6 more rounds are currently in the conceptual phase
- Majors forming the group of companies looking to divest their portfolios especially across West Africa, with SPDC being the prime entity looking to exit
- Majors' exit expected to dent the production and investment outlook greatly across the region
- Indigenous operators to take over portfolios being exited by majors and NOCs
- Major fiscal regulatory changes have been announced in Nigeria with the more-than-a-decade in the making Petroleum Industry Bill (PIB) finally passed recently to Petroleum Industry Act (PIA) after 14 years of legislative deadlock
- The legislation is aimed at providing a legal, governance, regulatory and fiscal framework for the country's oil and gas industry, and the development of host communities
- PIA reverses some of the terms introduced in the 2019 PSC deep water revision but has been labelled as controversial in sections of the media, due to the addition of a price-based royalty to the already existing production-based royalty

1 OIL MARKETS OUTLOOK **AND SUPPLY**

As the pandemic transitions towards an endemic, Brent benchmark rallied at high $80s-per-barrel

With the lockdowns being a thing of the past globally, demand levels on the rise again challenging the temporary bullish Brent run

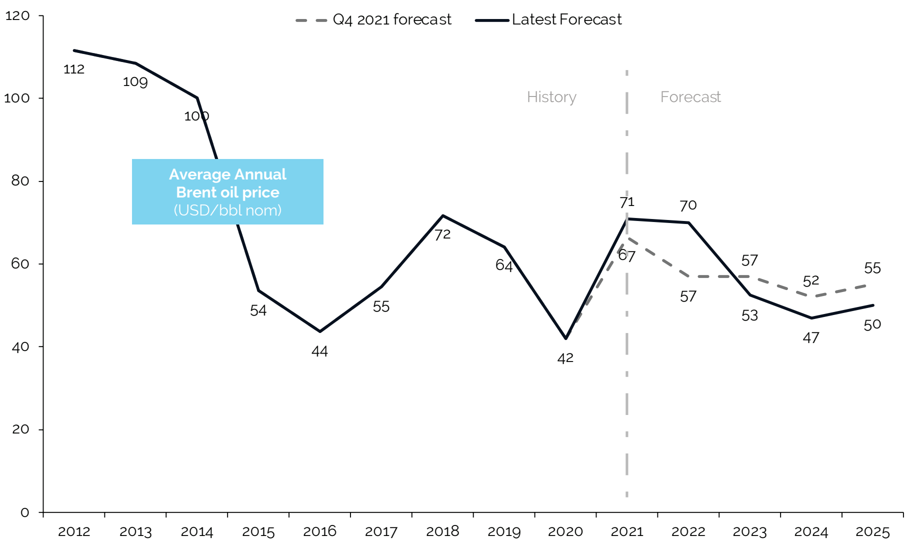
2022 supply levels on a month-on-month basis expected to stay at just over 8% of the global crude oil plus condensates volumes

Nigeria, Libya, Algeria, Angola and Egypt expected to retain the top 5 producers spots for 2022

1.1 Crude price outlook

From the record lows of Covid-19 first wave and Delta variant driven second waves, crude price has seen a recovery on the back of some market balancing acts from the major suppliers like the OPEC cartel. The easing of restrictions globally led to a demand growth which in turn resulted in a rise in the Brent benchmark which hit an annual average of US$71/bbl for 2021, compared to a lower forecast of US$67/bbl predicted during early Q4-2021. As the demand grows towards pre-pandemic levels and peak consumption is estimated to again touch 100 Million barrels per day (MMbbls/d) in the coming 12 months, the current temporary rally of crude price is expected to cool down to an annual average of US$70/bbl for 2022. To be noted, this is still an improvement from the peviously expected 2022 annual average of US$57/bbl.

Figure 1.1: Oil price outlook
USD/bbln ominal

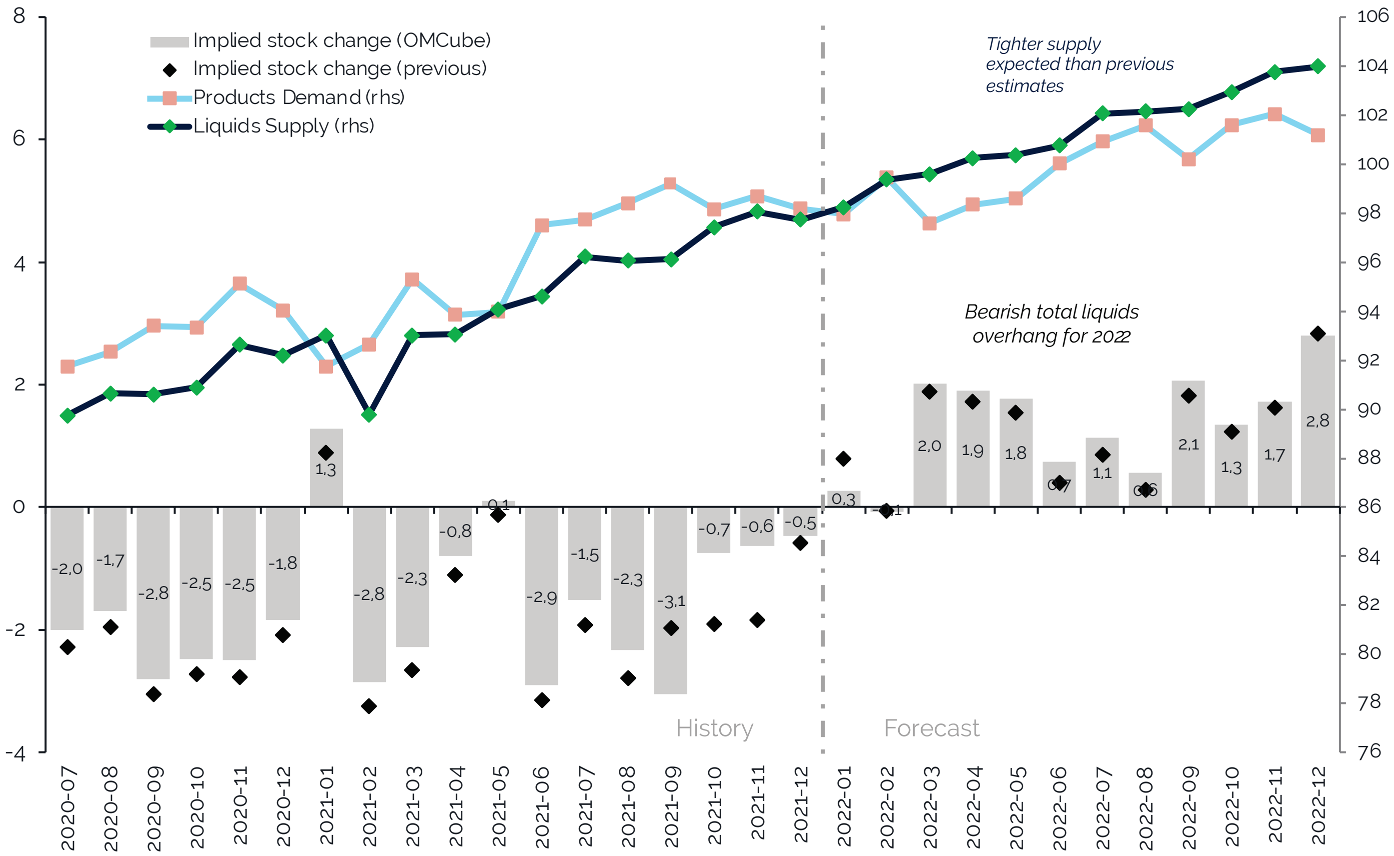


Source: Rystad Energy UCube

1.2 Short term Global Supply – Demand Balances

The liquids market is expected to remain oversupplied in 2022 as the estimated consumption of refined products is more lethargic than the expected demand for crude from refineries, at least for 1H22. Total implied liquids balances are set to swing from an implied build of 0.3 million bpd in Jan-22 to a surplus of 2.0 million bpd in Mar-22. For 2022 overall, the balances overhang remains incredibly bearish with 1.4 million bpd in implied stock builds, versus 1.2 million bpd projected in our last report. The slightly adjusted view is driven by downwards revisions to supply (-137,000 bpd on a monthly average) that offset the average yearly downwards revisions (-26,000 bpd) to demand. Our base case price assumption of $70 per barrel Brent for 2022 has been revised since the last report, and will continue to drive strong shale activity and associated production, such as NGLs, in particular in the US and Canada and other liquids in India and Indonesia. Conversely, there will be some NGLs shrinkage in particular in Kuwait, as we revise down our output capacity at various fields for 2022. A full realization of OPEC+ achieving its 400,000 bpd incremental increase would throw the balance even further off, and thus we expect a relaxed re-calibration of supply from the producing group until the current bout of supply shortages is alleviated by other marginal barrels. Upside to our total liquids demand forecast of an average of 100 million bpd could further tighten the bearish liquids overhang expected for most of 2022.

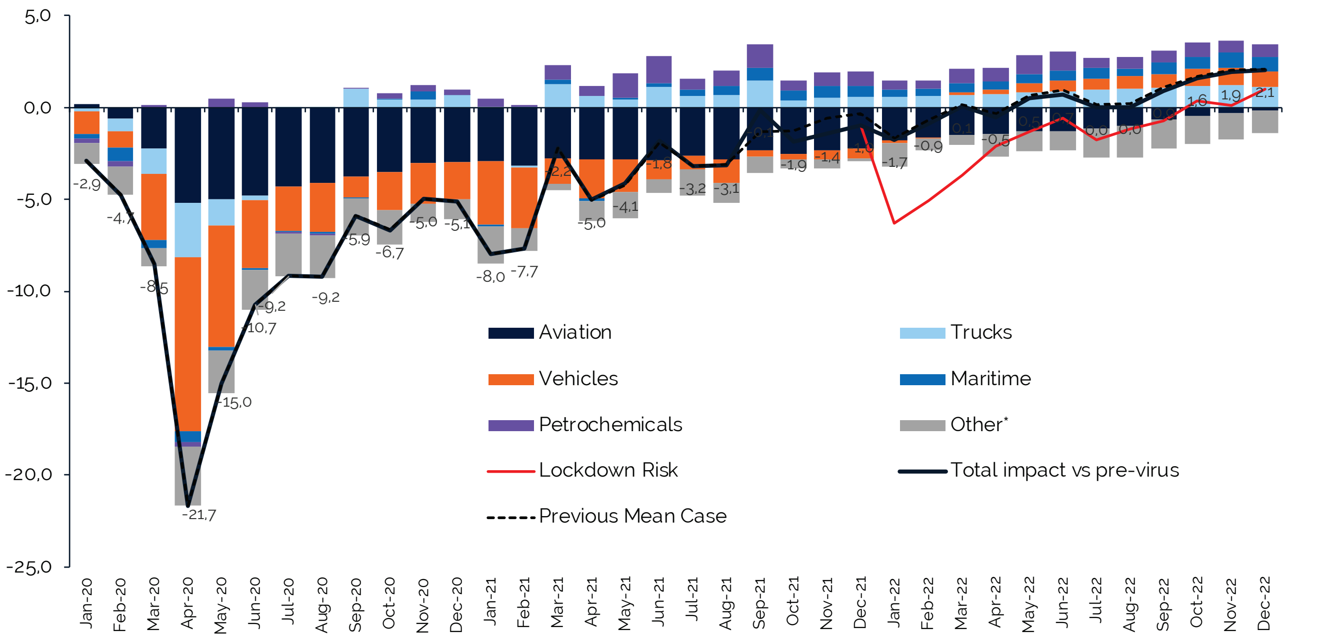
Figure 1.2: Global liquids supply and demand balances, current base case
Implied stock change, Supply and demand (million bpd)



Source: Rystad Energy research and analysis; OilMarketCube

1.3 Short term Demand forecast by scenario

Figure 1.3: Global oil demand difference compared to pre-virus levels, by sector
Million barrels per day



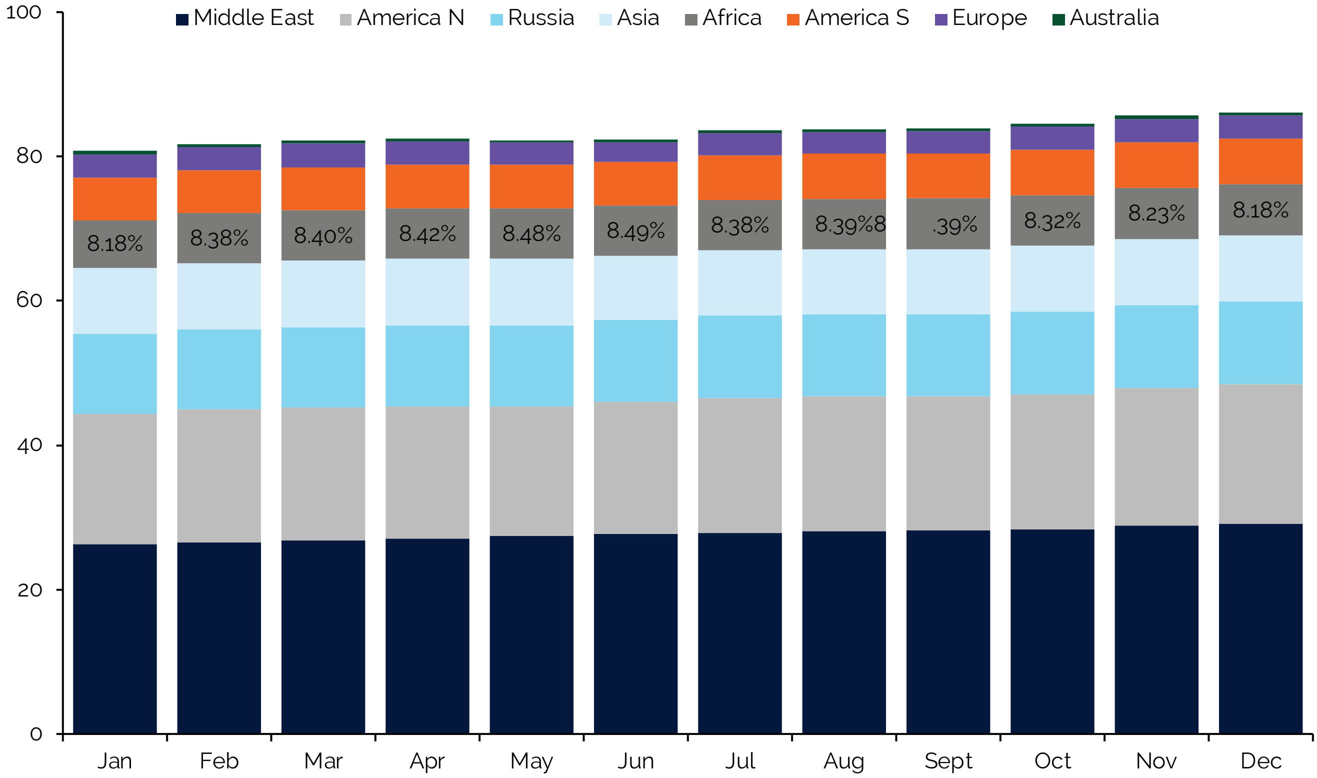
*Structural declines represent legacy declines regardless of Covid in the following sectors: agriculture, industry, energy own use, buildings, non-energy use and power **Structural growth represents growth regardless of Covid in the following sectors: buses, maritime and petrochemicals. *** Pre-virus levels are 2019 demand for the corresponding month of the year. Other sectors include: agriculture, buildings, energy own use, industry, non-energy use and power.

Source: Rystad Energy research and analysis

In 2021, the demand levels remained 3.3 million bpd below 2019 levels. After losing 4.8 million bpd in 1H21, the efforts of the vaccination campaigns allowed governments to reopen their economies, and the negative demand impact in 2H21 was reduced to 1.8 million bpd. The recovery of oil demand in the second half of the year was primarily held back by the aviation sector, which suffered from the international travel bans still in place. Looking ahead, the downside risks to oil demand recovery in 2022 is expected to stay, due to the risk of new restrictions in response to Omicron and other new variants. It is the case of China in particular, where the lockdown strategy has not been abandoned yet, while European countries, which had imposed strict measures, have moved towards targeted restriction that mainly concern non-vaccinated people. The transport sector is most sensitive to lockdown risks. The Lockdown Risk scenario shows the risk of new full lockdowns to oil demand, assuming that not only the transport sector, but also industry and the petrochemical sectors will be affected. Assuming that all regions respond simultaneously to the new outbreak, in 1H22, up to 4.8 million bpd is lost in this scenario. At this point, this is an unlikely scenario, as no joint response to the Omicron spread has been noticed till now.

1.4 Short term Crude oil Supply

Figure 1.4: 2022 month-on-month global crude + condensates supply
Million barrels per day



Source: Rystad Energy Oil Markets Cube

2022 global crude oil + condensates supply is expected to see a steady growth from about 80 million bbls/d in January to just over 86 million bbls/d in Dec, resulting in an average of about 83.3 million bbls/d for the entire year. These numbers suggest the global supply levels are expected to rise back to 2018 – 2019 levels from the lows of 2020 – 2021 which ended at an average of 76.5 – 77.5 million bbls/d. The Middle East is expected to see flows of up to one-third of the global levels and, together with the North American output, is expected to contribute to over half of the global supply. Average annual crude oil + condensates supply from the Middle East region is estimated to reach close to 27.72 million bbls/d and North American volumes are expected to reach annual average levels of about 18.5 million bbls/d. Russia, Asia, Africa and South America are estimated to see annual average flows of 11.3 million bbls/d, 9.1 million bbls/d, 6.95 million bbls/d and 6.15 million bbls/d respectively, with a cumulative 40% of the global output.

1.5 Africa short term Crude oil Supply

2022 overall crude oil and condensates output expected at a slightly higher level than 2021 driven by a 5% growth in crude oil production

Nigeria to retain the highest producer status with the annual average crude oil production expected to reach 1.46 MMbbls/d and overall crude oil plus condensates at 1.72 MMbbls/d

Libya, Algeria, Angola and Egypt round off the top five spots along with Nigeria

Angola expected to manage to stay afloat at above 1 MMbbls/d mark

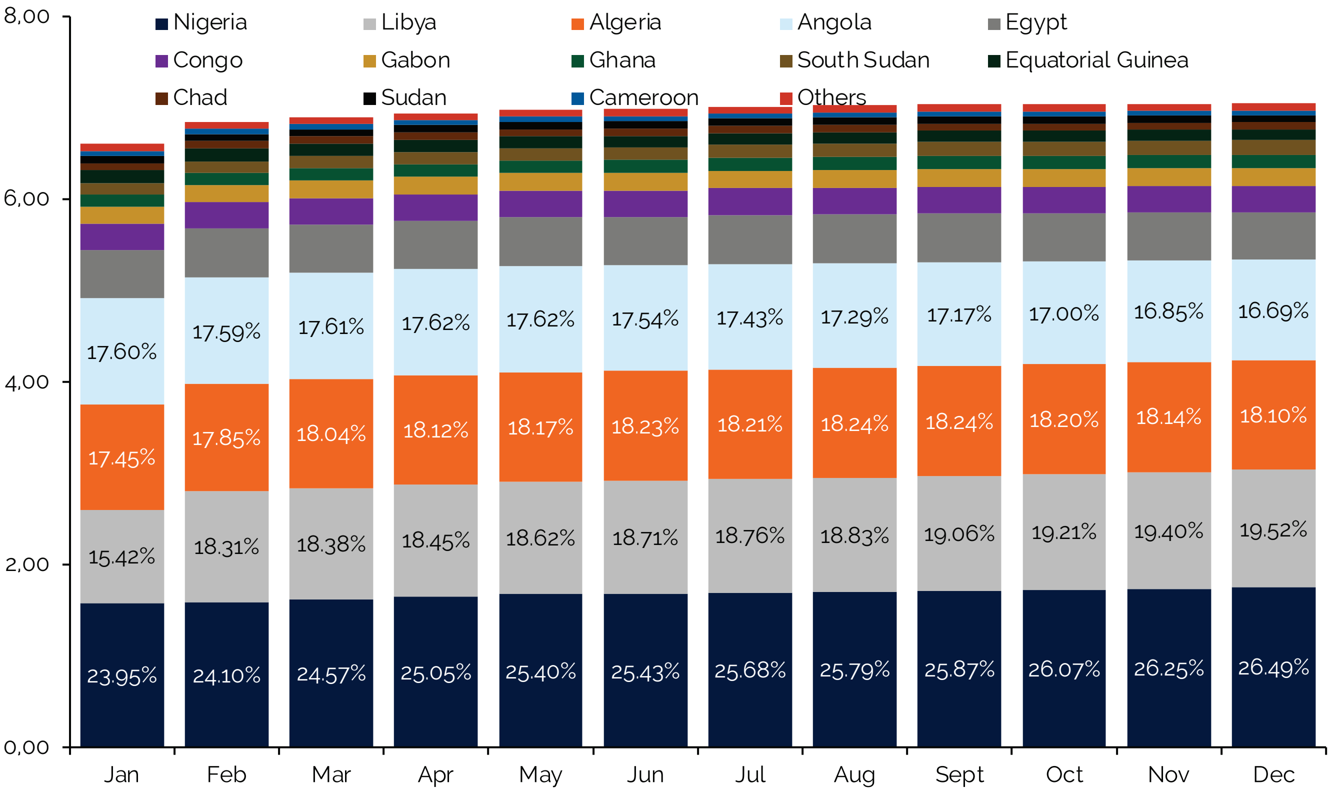
Natural declines in legacy projects and outages caused due to accidents refrain growth despite no effect of OPEC sanctions

Africa 2022 crude oil and condensates production is estimated at just over 7 million bpd (90% crude oil). As OPEC+ production sanctions on the member nations were lifted, sub-Saharan African (SSA) countries and Libya picked up crude oil production. As a result, crude oil production is estimated to grow by about 315,000 barrels per day from 2021 levels of 6.03 million bpd to 6.35 million bpd in 2022. However, as natural decline takes its course and projects get pushed out, this production growth is expected to be shortlived.

Nigeria, an OPEC member, is currently the largest crude oil producer in Africa. 2022 oil and condensate output is estimated at 1.72 million bpd. Crude oil production in 2022 is expected at 1.46 million bpd and the month-on-month production is expected to marginally increase from lower levels of 2021 to marginally higher levels of 2023. However, this increase is short-lived, and the production is expected to decline going forward from 2023 until the mega deep water projects drive some production trend reversal. Close to 65% of the 2022 crude oil production comes from offshore projects and just over a quarter of the overall crude output is expected to come from the deep water projects.

No significant liquids projects are expected to be approved or come online in 2022, as the country is still reeling and recovering from the pandemic and its after effects on the industry. Many high profile projects like the Shell operated Bonga North and Bonga Southwest – Aparo, and ENI operated Etan – Zabazaba project are now expected to be delayed further as such investment intensive deep water projects have come on the chopping block as Majors and E&Ps across the world are now focused on cutting down investments and delaying projects with high breakeven oil price. The decade long in-the-making Petroleum Industry Bill (PIB) was finally passed in 2021 and is now the Petroleum Industry Act (PIA). While this is a positive step from the government, several industry insiders opine that the multi-layered PIA and its implementation of fiscal terms needs further clarification. Another significant fiscal parameter that the PIA includes is introduction of the cost price ratio (CPR) that restricts the capital allowance claimable in a given accounting year to 65% of the gross revenues determined at the measurement points when setting the hydrocarbon tax payable, but any cost not deducted upon termination of upstream operations will be lost. The 2020 Marginal Field Licensing Round also concluded but the fields awarded as well as the final winners list has so far been kept undercover. These fields come with a develop within five years or lose clause and have the capacity to add a 200,000 bpd production by 2025. However, industry sources are pessimistic about the chances of these fields coming online by the prescribed five year period. While the decision to conduct the bid-round was a step in the right direction and generated a lot of buzz, the development of these oil fields in a post pandemic energy transition focused world may be challenging, given the development will require a substantial amount of funding.

Figure 1.5: 2022 month-on-month Africa crude + condensates supply
Million barrels per day

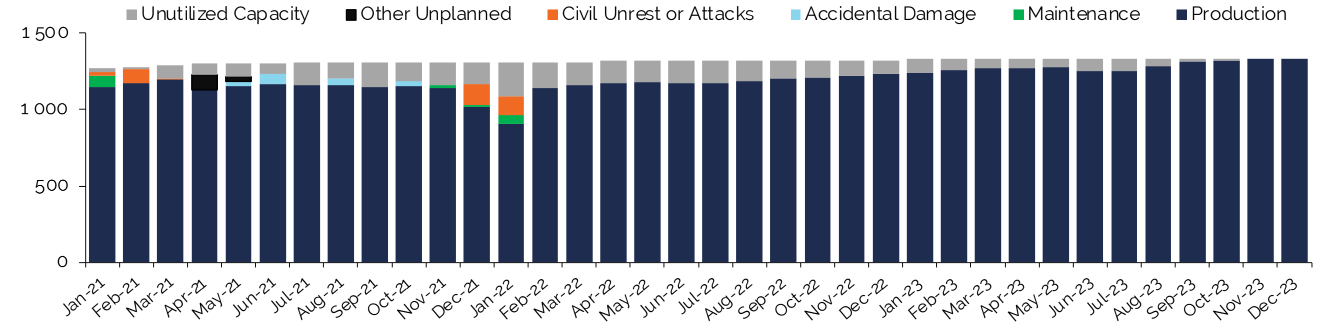


Source: Rystad Energy Oil Markets Cube

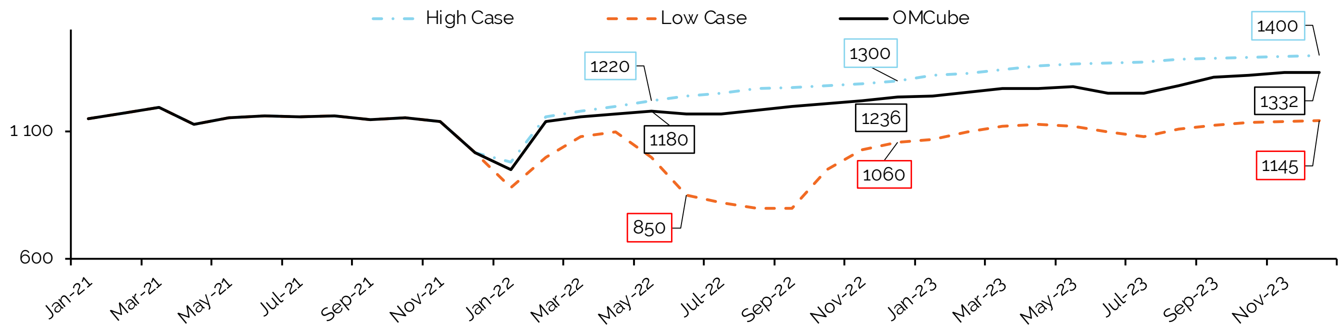
After relatively stable and peaceful 2021, Libya's crude oil production in 2022 started on a bumpy road with Petroleum Facility Guards (PFG) taking over El Sharara and El Feel oil fields in western Libya towards the end of Dec-21, shutting down 350,000-380,000 bpd till the 10th Jan-22. Oil production took another hit when Waha Oil had to shut down 150,000-200,000 bpd for a week in early Jan-22 for pipeline maintenance. In our base case, we estimate that Libya's crude oil production would stay around 1.15 to 1.17 million bpd in 1H22 if no major civil unrest emerges in the nation. And estimate to exit 2022 at 1.23 to 1.25 million bpd. In slightly medium-term we estimate Libya's crude oil production would continue to gradually increase to a stable production levels of 1.25 to 1.3 million bpd by the end of 2023. In our high case, which is under the assumption that the Presidential elections are conducted peacefully, and the budgetary issue of the Libyan NOCs are resolved we could see Libya's oil production rapidly growing to 1.3 million bpd by the end of 2022 and further reach 1.4 million bpd by the end of 2023. At the same time, historically we have seen that the downside risk to the Libya's crude oil production has always been much higher compared to the upside potential. Thus, if the elections towards the end of the 1H22 don't go well, we might see another armed uprising in the western Libya like what happened towards the end of the 2021 and crude oil production can plummet to 750,000 to 800,000 bpd and this continued in medium to long term can hamper Libya's overall oil production capacity keeping Libya's production below 1.15 million bpd by the end of 2023.

Figure 1.6: Libya outlook

Libya's crude oil production, by capacity details
Thousand barrels per day



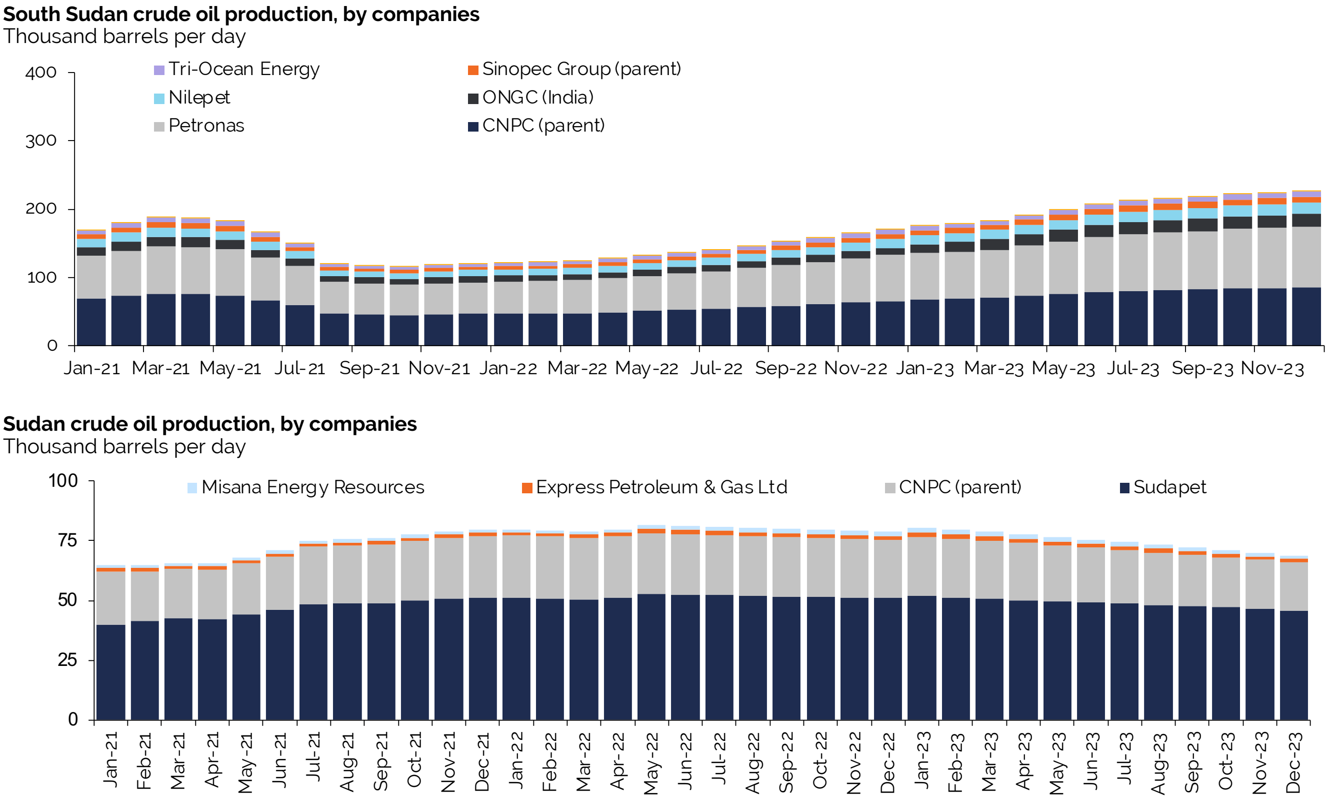
Libya's crude oil production in different scenarios
Thousand barrels per day



Source: Rystad Energy Oil Markets Cube

Combined Sudan and South Sudan oil production was close to 475,000 bpd in 2010. But the South Sudanese independence struggle and the violence that followed led to a steep drop in production to about 120,000 bpd by 2012. The civil war that broke out in 2013 led to prolonged oil field shut-ins in both the countries and the production hasn't been able to recover to previously seen highs of 2010, with the output languishing at 240,000 - 250,000 bpd since then. In past couple of years, while Sudan's crude oil production has continued to gradually decline due to lack of any new major investment, South Sudan on the other hand has been able to pick itself up and ramp-up production to 180,000-200,000 bpd by late 2020 and early 2021 with the help of foreign investments from companies like CNPC, Petronas, and ONGC. South Sudanese government was targeting an ambitious oil production levels of 300,000 bpd by 2023 and then ramp-up to 350,000-400,000 bpd by 2025. But we estimate that dependence on Sudan's oil transport infrastructure for crude oil export would continue to hamper South Sudan's future growth plans in two major ways. Firstly, the high transport tariff South Sudan need to pay to Sudan for using their crude oil pipeline continues to weigh on the project's profitability, which would severely impact the revenues in case crude oil prices go below current high levels of 80-85 $/bbl. Additionally, the ongoing political instability in Sudan poses a serious threat to South Sudan's crude oil production as they currently hold negligible crude oil storage capacities and an attack on pipeline infrastructure in Sudan during these protests forces South Sudanese operators to halt their production. Currently, we estimate Sudan's oil production to remain slightly flat while South Sudan would ramp-up gradually towards, 170,000-180,00 bpd by the end of 2022 and then further ramp-up to 220,000-240,000 bpd by the year-end 2023.

Figure 1.7: South Sudan outlook



Source: Rystad Energy Oil Markets Cube

Algeria's crude oil production has also been on a gradual declining trend as it still relies on legacy mature fields. The country's oil production has declined from 1.2 million bpd in 2010 to 927 thousand bpd in 2021. Hassi Messaoud is the largest producing field and still contributes to about 40% of the country's production. The country's current production levels are suppressed from its available capacity due to the OPEC+ cuts that began in 2020 as a response to reduced demand due to COVID-19. As the cuts ease out going forward, we estimate Algeria to produce about 1 million bpd this year. Algeria's government has also passed the new hydrocarbon law to boost foreign investments in the upstream industry as a result of which Eni also signed an agreement under the new law to explore in the Berkine basin.

Angola added over half a billion barrels of recoverable crude oil volumes to the country's coffers in 2018 and 2019. The Angolan government, committed to turning around the country's depleting hydrocarbon reserves and attracting foreign investments in its local oil and gas industry, introduced tax incentives which halved royalties and the petroleum income tax for "marginal" discoveries. Majors like BP, Eni and TotalEnergies applied for this status on a few of their deepwater projects and were also granted the status by the government. However, the country's declining production trend has seen no improvement. 2021 output was about 1.12 million bpd and 2022 output is expected to drop marginally further down to 1.1 million bpd. The cost intensive deepwater projects require increased focus as only these delayed projects can reverse the production trend for a short period. However, the country is headed towards a sub-1 million bpd annual output despite new production from new start-ups in the future.

Egypt's crude oil and condensates production has been on a decline especially from the second half of last decade, reducing by 15% from 663 Kbbl/d in 2010 to about 564 Kbbl/d in 2020. This has been due to lack of any major discoveries as the country continues to produce from mature fields where decline rates have been strong. More than 60% of liquids production comes from onshore region, mainly from the Western Dessert region. Apache, Eni and Capricorn Energy together contribute to around 55% of the onshore production. While Apache and Eni have been present for long, Capricorn Energy only recently acquired its asset base from the acquisition of Shell's onshore portfolio last year. We expect the country to produce around 530 Kbbl/d in 2022, reflecting a very slight decline from the levels of 540 Kbbl/d last year. The country's government has also been proactively signing many new contracts with revised fiscal terms to boost the investment and reduce the decline rates, if not reverse the production trend.

2 GAS MARKETS OUTLOOK **AND SUPPLY**

Demand and supply seeing further growth post the lows in 2020 due to the pandemic

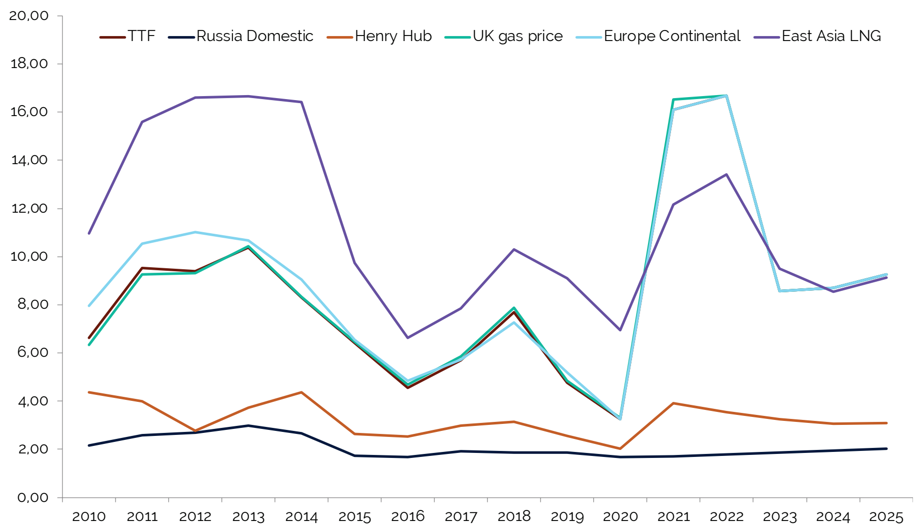
As the producing fields supplying feedgas for LNG exports decline, increasing natural gas demand is expected to be met by new start-ups

Algeria, Egypt and Nigeria round off the top 3 natural gas producers in 2022 contributing to just over 80% of the overall natural gas flows from Africa

2.1 Short term Gas reference prices

The near-term forward curve suggests continued high prices and volatility due to low storage and supply concerns in Europe that are expected to give the Dutch Title Transfer Facility (TTF) global price influence through much of 2022. Our average price forecast for 2022 is $16.7 per million British Thermal Units (MMBtu) for the TTF and $18.6/MMBtu for the Asian spot price. We expect the US to be shielded from the international turmoil, with an improved production outlook for 2022 keeping the Henry Hub price at around $3.5/MMBtu.

Figure 2.1: Short term gas reference prices forecast
USD/MMBtu nominal

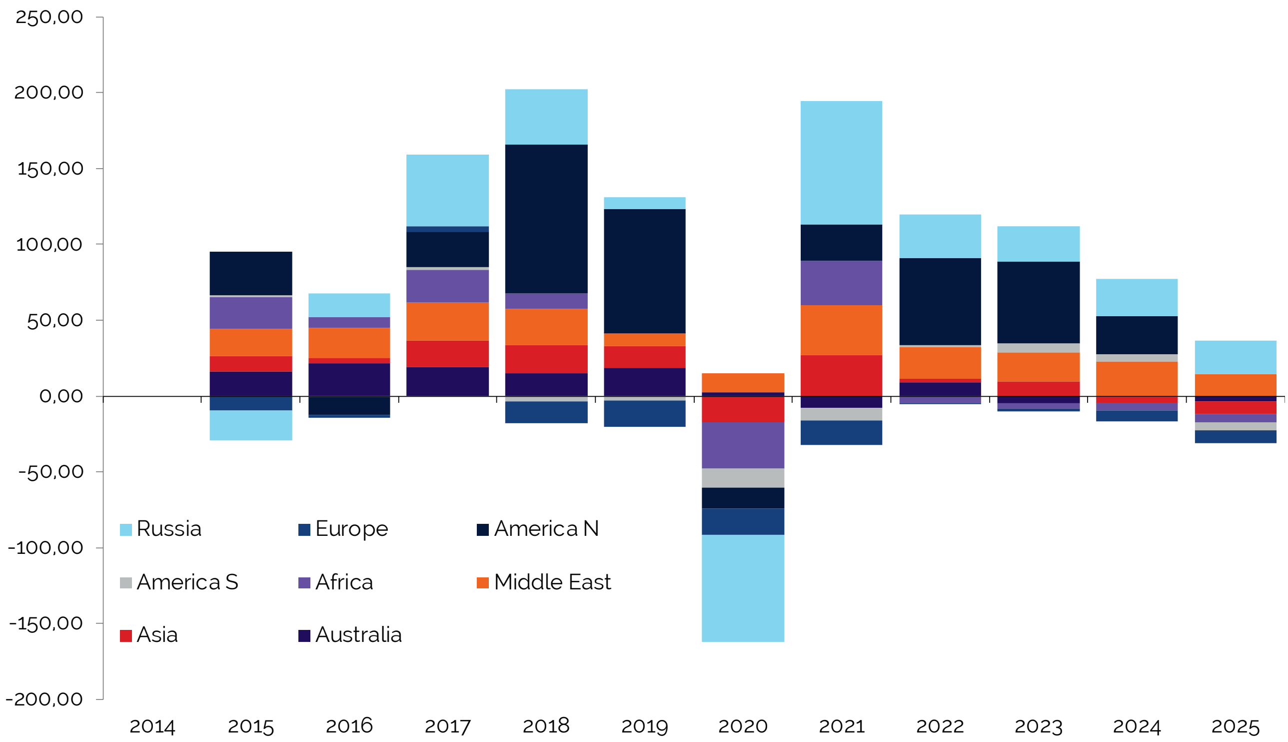


Source: Rystad Energy UCube

2.2 Short term Global Natural Gas Supply Growth

Both gas demand and gas production have consistently grown over the last decade, representing a trend that is expected to continue going forward as global decarbonisation efforts intensify. However, last year witnessed a drop due to COVID-19 restrictions impacting gas demand and supply, which fell by 3% and 4% respectively. As illustrated in chart, the majority of the reduction in gas production came from Russia, followed by North America. Demand from Asia remained resilient while dropping slightly for most of the other continents including North America, Russia and the Middle East. Apart from the immediate gas production curtailments, several LNG projects also faced sanctioning delays and expected first gas. One such case is the 13 MMtpa Mozambique LNG project in Area 1, the start-up of which is likely to get delayed significantly as the country handles threats from insurgency. That said the project is still anticipated to go ahead and the status remains suspended. Sanctioning of the other Area 4 project, the 15 MMtpa Rovuma facility, has also been delayed. On the back of LNG supply delays, the long-term outlooks for TTF and Asia LNG prices have increased and a peak in gas price is expected in 2025. As new projects come online by 2027, the gas prices will see some downward pressure.

Figure 2.2: Global Natural Gas Supply Growth
Billion cubic meters

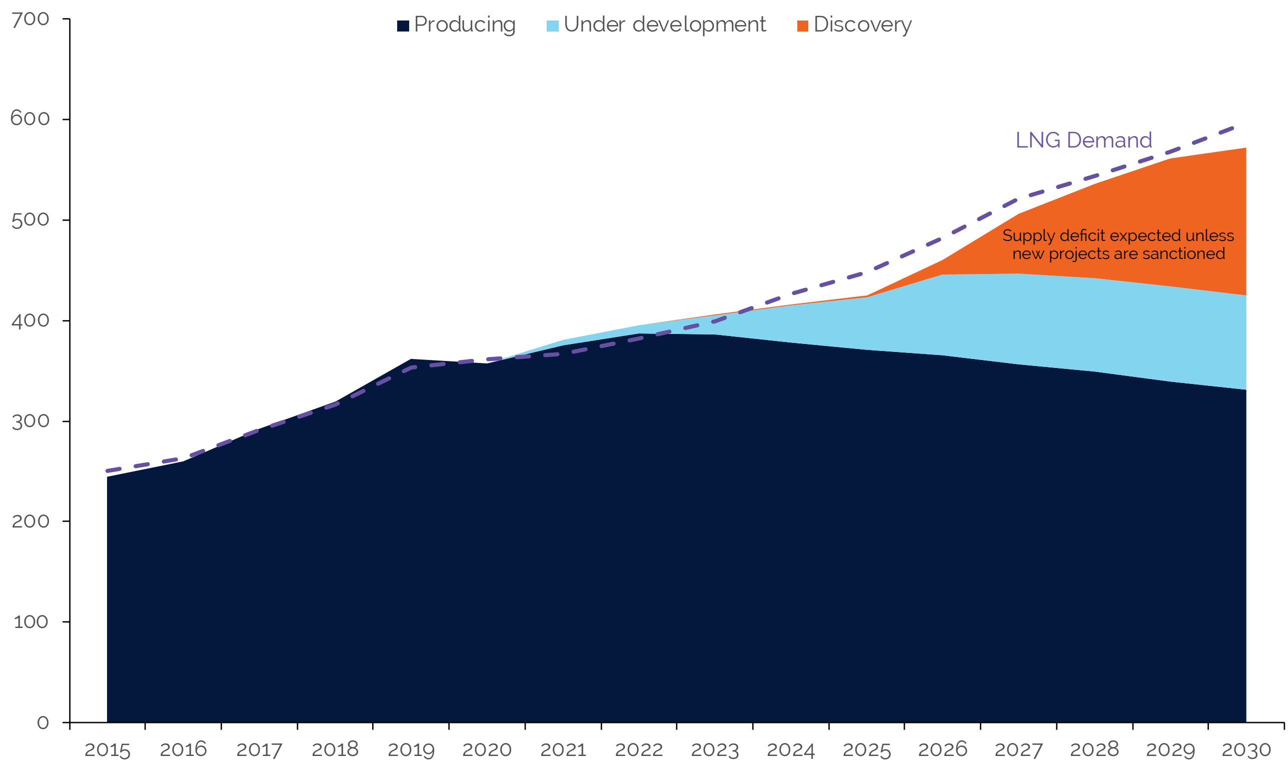


Source: Rystad Energy UCube

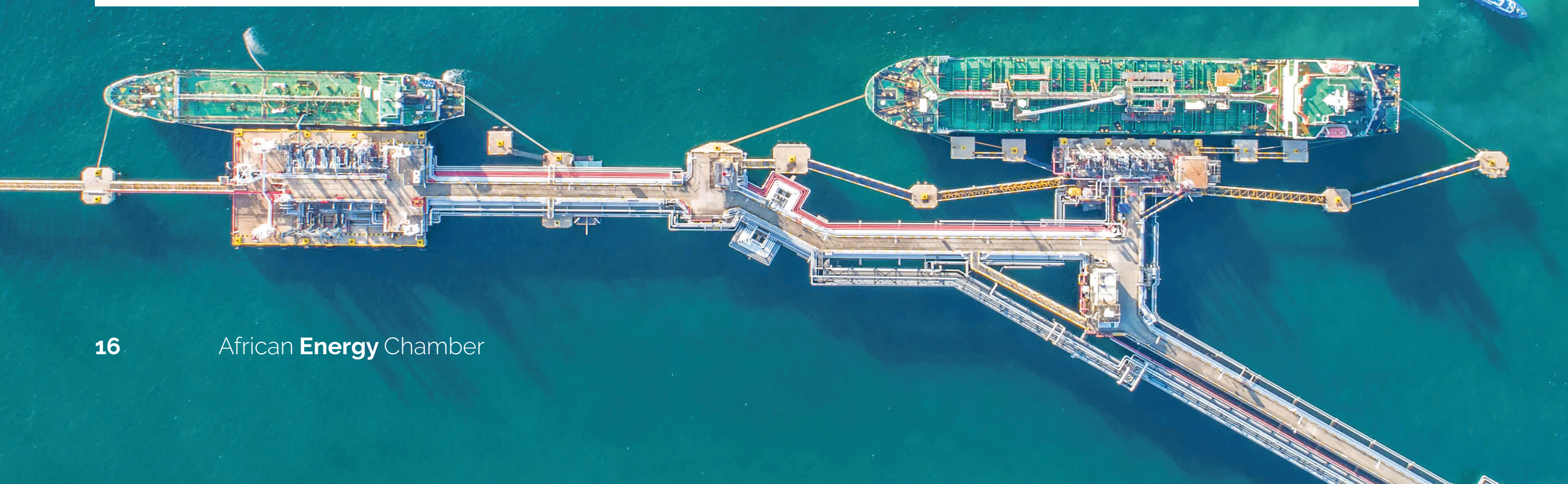
2.3 Global LNG Supply vs Demand

2022 – 2023 supply vs demand levels suggest there is sufficent LNG supply to satisfy the demand, as new projects come online in 2022 such as Coral FLNG in Mozambique, Tangguh Train 3 in Indonesia and Calcasieu Pass in the US. During this time, LNG demand is expected to grow at a healthy CAGR of 5%. Despite the start up of key LNG projects including Arctic LNG 2, Golden Pass, Nigeria LNG Train 7 and Qatar's North field expansion project, a supply deficit is expected from 2024 onwards. This is driven mainly by strong demand resulting from gas-fired power generation as increased environmental pressure stymies coal-fired generation.

Figure 2.3: Global LNG Supply vs Demand
Million tpa

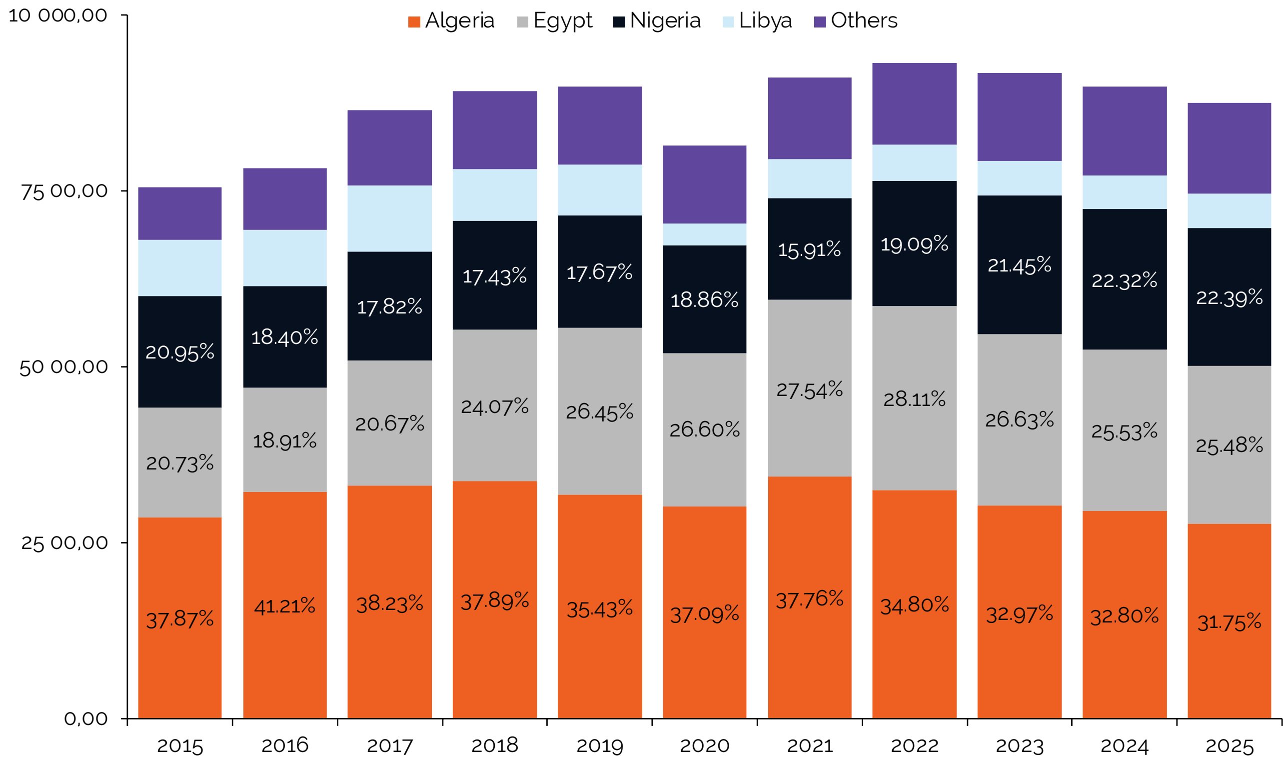


Source: Rystad Energy GasMarketsCube



2.4 Africa Natural Gas Supply

Figure 2.4: Africa Natural Gas Supply
Billion cubic feet



Source: Rystad Energy UCube

Algeria's gas sector is in need of more investments and new major gas discoveries. The country depends heavily on oil and gas export revenue for its economy and is the major source of foreign currency. Although it is able to meet its growing domestic gas consumption, it is eventually going to add pressure on the capability to sustain the export levels. The country is a significant gas and LNG exporter to Europe and enjoyed increased export volumes of about 53 Bcm in 2021, up from 40 Bcm in 2020 on the back of strong demand from Europe. We estimate around 46 Bcm of gas exports for 2022, mainly due to uncertainty caused due to non-renewal of the contract for GME pipeline as a result of the conflict between Morocco and Algeria. The country is no longer going to use the 12 Bcm GME pipeline and will only rely on the 8 Bcm Medgaz pipeline for its pipeline gas exports to Spain. In the medium term, we estimate the gas exports to fall below 30 Bcm by 2025 as more gas will need to be diverted to the domestic market. The country has also passed the new hydrocarbon law to attract foreign investments and recently Eni has signed an agreement with the government for exploration and development in the Berkine basin. Although many MOUs were signed with IOCs such as ExxonMobil, Chevron, Eni, OMV, Cepsa, Lukoil, TPAO and Zarubezhneft- Eni's signing is the only signing till date, a positive development nevertheless.

Egypt became a net exporter in the second half of last decade due to the major discoveries such as Zohr coming on stream. Other projects such as Atoll, Nooros and West Nile Delta also contributed to the increasing supply.

However, the lack of any new discoveries coupled with the ever-growing gas demand poses a challenge as the domestic consumption is set to outpace the supply by next year. We estimate the country to produce about 74.5 Bcm of gas this year and start declining post that, reaching 50 Bcm by 2030. On the other hand, the domestic gas consumption is estimated to increase from 61 Bcm in 2020 to 72 Bcm in 2030, leading to a 12 Bcm supply deficit by the end of this decade. The government has been conducting many licensing rounds in offshore frontier regions which has led to many majors, including new entrants entering the country's upstream industry. Any discovery from successful exploration, hopefully as significant as Zohr, could change the dynamics of the country and help not only meet its domestic demand, but also sustain the LNG exports.

Nigeria' overall monetised natural gas production, excluding the volumes pumped to the Eleme Petrochemicals Company Limited (EPCL), has been hovering around 1450 – 1550 billion cubic feet through the years 2016 – 2020. But 2021 volumes saw a low point at 1450 billion cubic feet. 2022 production is expected to see a healthy recovery to about 1780 billion cubic feet. The existing producing projects and the projects currently under development are expected to ensure the supply growth till about 2025. Post this, the producing fields are expected to see a steep decline going forwards and the supply heavily relying on the currently undeveloped discoveries and any brownfield investments on the existing projects that might enhance production. Reduction of flaring and re-injection, with more marketed volumes can also help boost the declining supply to both domestic and export markets. Majority of the supply is driven by the onshore and shelf water depth fields that are not so cost intensive as deepwater projects. Any preponement of the currently delayed projects will help maintain the mid-term and long-term domestic supply.

The gas potential of Mozambique and Tanzania is quite well known with plans to tap most of the gas for LNG export purposes. Mozambique has made much more progress as the country looks forward to starting LNG exports from its 3.4 MMtpa Coral FLNG project this year. The 12.8 MMtpa Mozambique LNG project, on which Total took an FID in June 2019, is also under-development, however with no construction activities ongoing since April last year when Total announced a force majeure because of the growing insurgency in Palma. Insurgency is one of the key threats to project development in the region as we expect the start-up of Mozambique LNG project in 2026, a delay of two years from the original plan of 2024. The 15.2 MMtpa Rovuma LNG project which was expected to be sanctioned a few months after Mozambique LNG project has also been delayed significantly as the partners try to bring down costs and improve the GHG emissions. We expect the project to be sanctioned in 2024 and commence in 2029, unless the project partners make a major change to their plans. COVID-19 had already delayed the procurement activities for the Mozambique LNG project and further exacerbated by the insurgency. On the other hand, Tanzania has been sitting on high potential gas resources but the planning of LNG projects has been long delayed as the government has failed to reach any conclusion on talks to finalize the fiscal terms around the projects with various IOC's such as Shell and Equinor. Equinor had also written off USD 900 million from its books related to Tanzania LNG projects last year due to higher break-even from its average portfolio break-even. The new government has resumed the talks and is more proactive to prioritize the LNG development, however it remains to be seen if the talks convert into any concrete outcomes. We estimate a potential 20 MMtpa LNG development for the country but in a phased approach.

3 AFRICA INDUSTRY **OVERVIEW**

As the region sees a relatively increased sanctioning activity, 2022 – 2025 cumulative capital expenditure from Africa has seen an increase of US$23 billion

Greenfield investments in Nigeria, Mozambique, Angola, Ghana, Uganda drive the capital expenditure during the period

While previous forecast suggested an estimated US$32.5 billion capital investment for the year 2022, new estimates reflect a reduced capital expenditure of US$30 billion

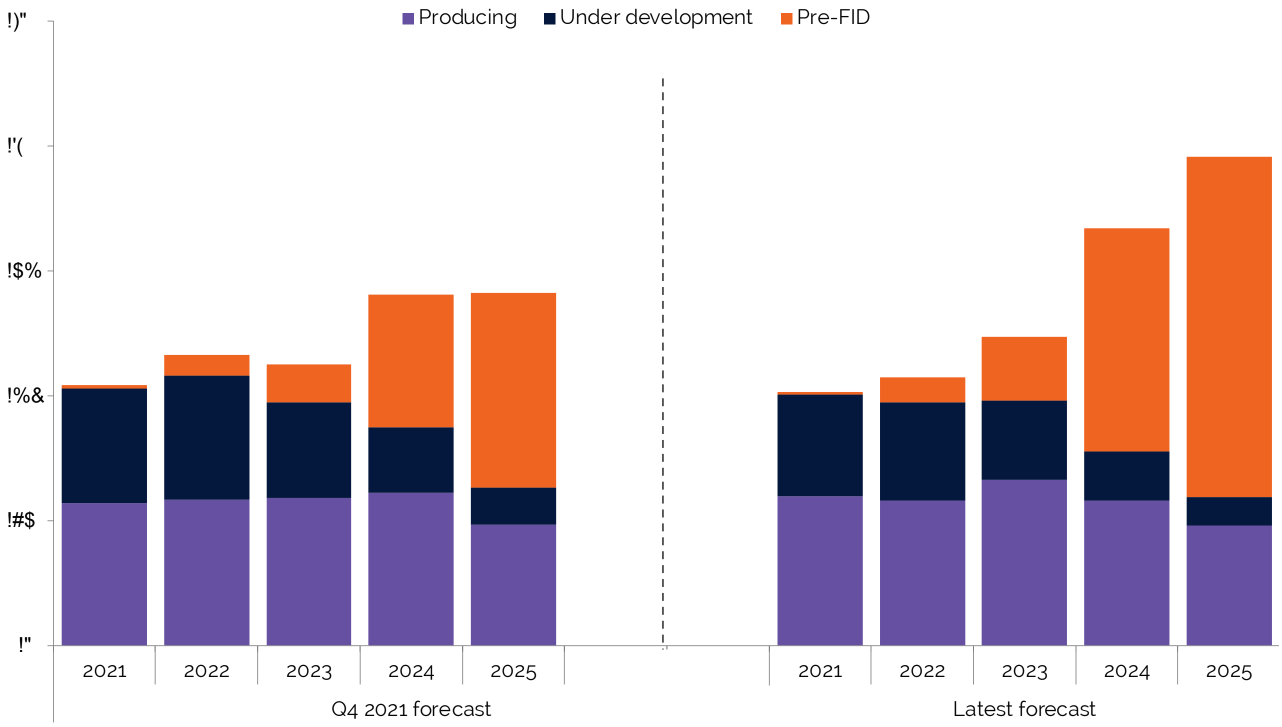
However, 2023 – 2025 cumulative expenditure has seen an increase from US$110 billion to US$135 billion

3.1 Impact of new variants of Covid-19

In the post pandemic and energy transition focused era, many global E&P players are looking at significant cuts to their capital spending and operational expenditure. International majors and Independents alike are focusing on cutting down their upstream exposure and expenditure, and are progressing towards meeting their respective emission targets.

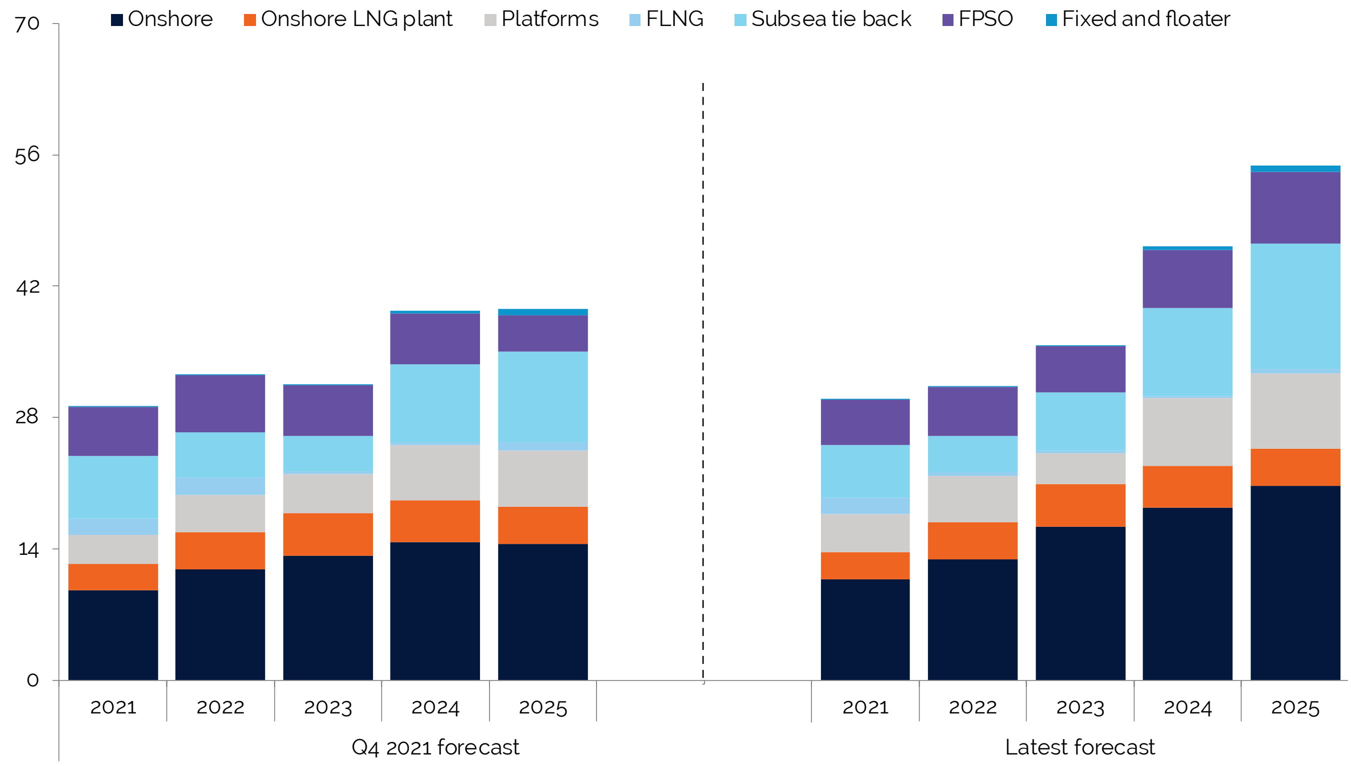
From the peak in 2014 at about USD 60 billion, capital expenditure in Africa declined to close to US$22.5 billion in 2020. This decline is a result of lower activity from new projects, general cost compression in the industry and friction in getting new projects sanctioned due to external influences such as export route disagreements and fiscal parameters. However, the spending levels are expected to gradually increase as per the latest forecast with the estimated 2022 capital expenditure at US$30 billion. At the current expected project sanctioning levels, upstream spending towards 2025 is expected to see an increase.

Figure 3.1a: Africa Capital expenditure forecast comparison between pre-Omicron vs latest forecast
Billion USD



Source: Rystad Energy UCube

Figure 3.1b: Pre-Omicron vs latest capital expenditure forecast split by facility
Billion USD



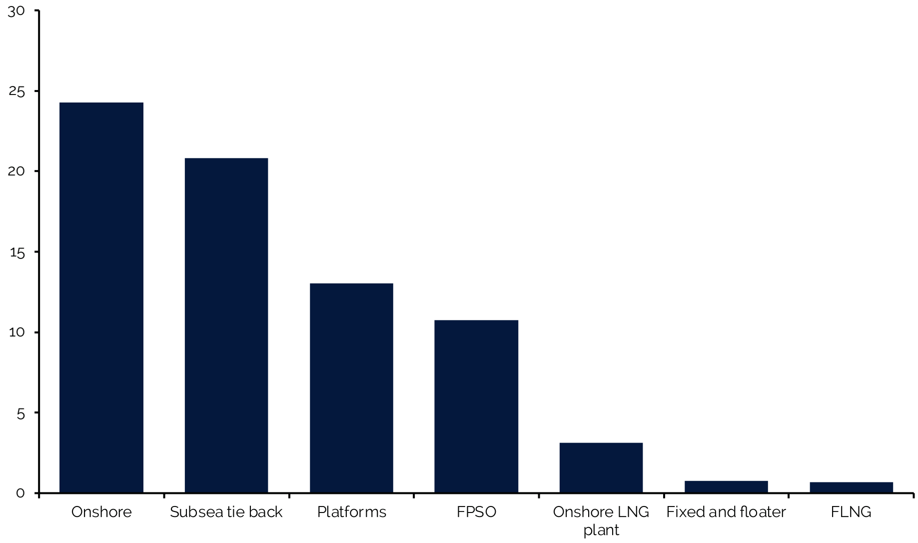
Source: Rystad Energy UCube

The deferred projects and the projects originally slated for investments from 2022 onwards will together have the potential to contribute to a significant growth potential. Should the projects materialize the potential expenditure may increase to almost US$49 billion by 2024.

Investments related to onshore projects is the single greatest category with investments reaching over US$68 billion during the 2022 – 2025 period. Big investments are also expected in Uganda and Kenya related to the greenfield onshore development of Lokichar basin. This greenfield development may be one of, if not the last, big conventional onshore project in the world. Subsea tiebacks take the second spot in 2022 – 2025 cumulative spending and are likely to be more and more common as it makes commercial sense to piggyback smaller hydrocarbon accumulations on existing infrastructure. The breakeven therefore achieved from such a development solution is typically also very competitive. The category also includes the offshore related part of LNG developments which further boosts this category in light of the mega-projects expected in Mozambique.

Years 2020 and 2021 showed that African oil and gas industry was one of the hardest hit in the aftermath spurred by the Covid-19 outbreak. The initial after effects of the demand vacuum and price crash caused by the pandemic led to production sanctions imposed on the African OPEC member nations. The initial reaction from the operators included delays to the projects with high breakeven prices, reduction of capital and operating expenditure, and cashflow neutral forecast at lower oil price curves. However, as the region saw a few project sanctions, 2022 – 2025 forecast now shows a relativey increased spending. To be noted, Q4-2020 versus Q4-2021 capital expenditure comparison showed a contraction of about US$33.5 billion during the same period.

Figure 3.1c: Cumulative 2021 –2 025 contingent expenditure per project type
Billion USD



Source: Rystad Energy UCube

3.2 Upstream Investment changes since Q4 2021

Figure 3.2: Upstream Investment changes since Q4 2021
Billion USD

Source: Rystad Energy UCube

3.3 Top upcoming investment driving Projects

Figure 3.3: 2020 – 2025 major investment driving projects in Africa

Project	Country	Operator	FID*	Start-up*	Resources (MMboe)* ■ Liquids ■ Gas
Area 1 LNG (T1&T2)	Mozambique	TotalEnergies	2019	2026	615
Greater Tortue Ahmeyim FLNG	Mauritania	BP	2018 (Phase I) 2023 (Phase II)	2024 (Phase I) 2027 (Phase II)	1220
Tilenga	Uganda	TotalEnergies	2022	2026	1055
AT (Isarene)	Algeria	Sonatrach	2019	2023	480
Cameia-Golfinho	Angola	TotalEnergies	2023	2027	420
Quiluma/ Maboqueiro (Northern Gas Complex)	Angola	Eni	2023	2026	405
South Lokichar Phase 1	Kenya	Tullow Oil	2023	2026	370
SNE	Senegal	Woodside	2020 (Phase I) 2024 (Phase II)	2023 (Phase I) 2027 (Phase II)	365
Baleine	Cote d'Ivoire	Eni	2022 (EPS) 2024 (FFD)	2023 (EPS) 2027 (FFD)	345

*Conservative estimates; Source: Rystad Energy UCube

Tables below illustrate key information about upcoming major projects in Africa that will drive the majority of the greenfield expenditure in the short term. Majority of the volumes are to be sanctioned and developed are natural gas with projects like Area 1 LNG project in Mozambique and GTA FLNG offshore Senegal – Mauritania leading the list.

Figure 3.3: 2020 – 2025 major investment driving projects in Africa

Project	Country	Operator	FID*	Start-up*	Resources (MMboe)* ■ Liquids ■ Gas
OML 18	Nigeria	Eroton	2024	2025	330
Assa North/Ohaji South (Phase 1)	Nigeria	Shell	2018	2022	285
HI-1	Nigeria	Shell	2022	2027	260
Kingfisher South	Uganda	CNOOC	2022	2026	240
Pecan Phase 1	Ghana	Aker Energy	2023 (Phase 1a) 2025 (Phase 1b)	2026 (Phase 1a) 2027 (Phase 1b)	230
Agogo FFD	Angola	Eni	2023	2026	205
HA	Nigeria	Shell	2024	2027	195
Agadem Phase 2	Niger	PetroChina	2021	2024	120
Sanha Lean Gas	Angola	Chevron	2021	2023	115

*Conservative estimates; Source: Rystad Energy UCube

4 AFRICA EXPLORATION **OUTLOOK**

4.1 Recent exploration success and drilling outlook

Africa upstream exploration too, similar to project approval and development investments, took a major hit due to Covid-19. The devastation was to such extent that it led to the offshore rigs being left on idle state in Angola – something that even years of civil war did not do. 2020 saw the second lowest volume of discovered resources in all of the last decade.

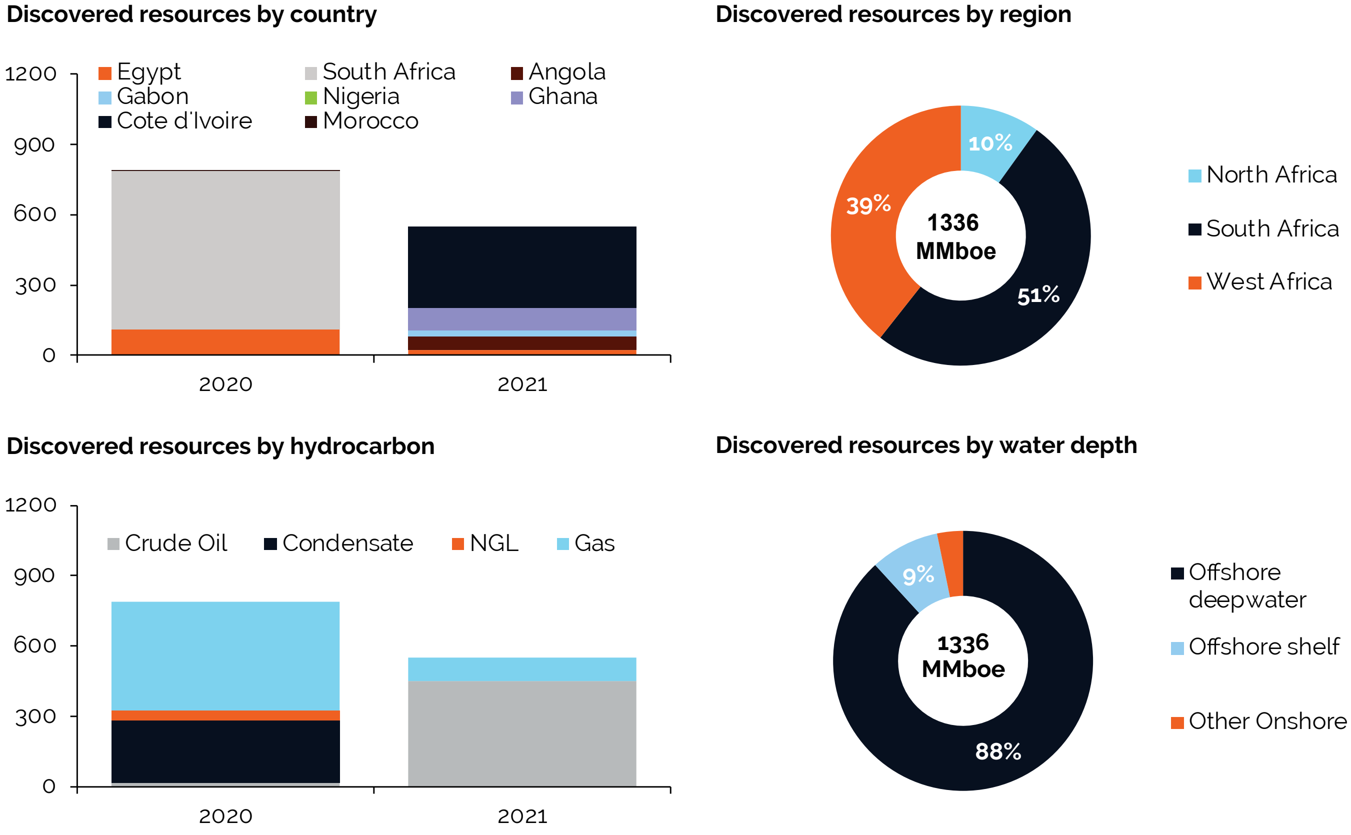
While 2020 saw the second lowest discovered volumes in the past decade, 2021 so far has seen much lower discovered volumes so far

2022 is expected to be a much more encouraging year with 9 high impact wells in the drilling schedule

Results of as many as 14 exploration licensing rounds across the continent are expected to be announced in 2022 with Egypt already having closed for bids

Of the remaining 13 rounds, bids are under evaluation for 2 licensing rounds, bidding is open in 5 rounds and 6 more rounds are currently in the conceptual phase

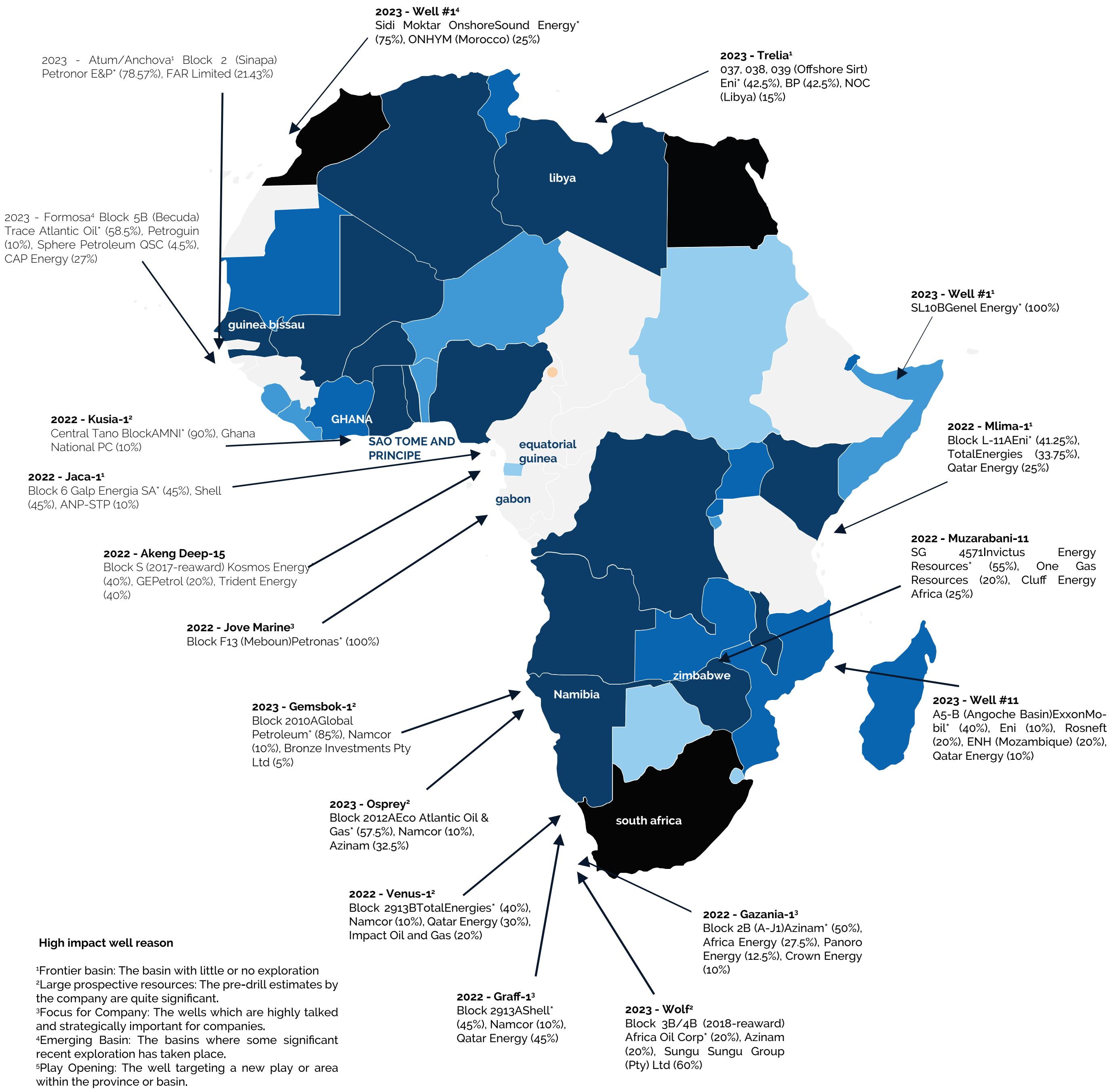
Figure 4.1: Discovered volumes in Africa
Million boe



Source: Rystad Energy UCube

4.2 Expected High Impact Wells Drilling

Figure 4.2: Africa High Impact Wells drilling in 2022 – 2023

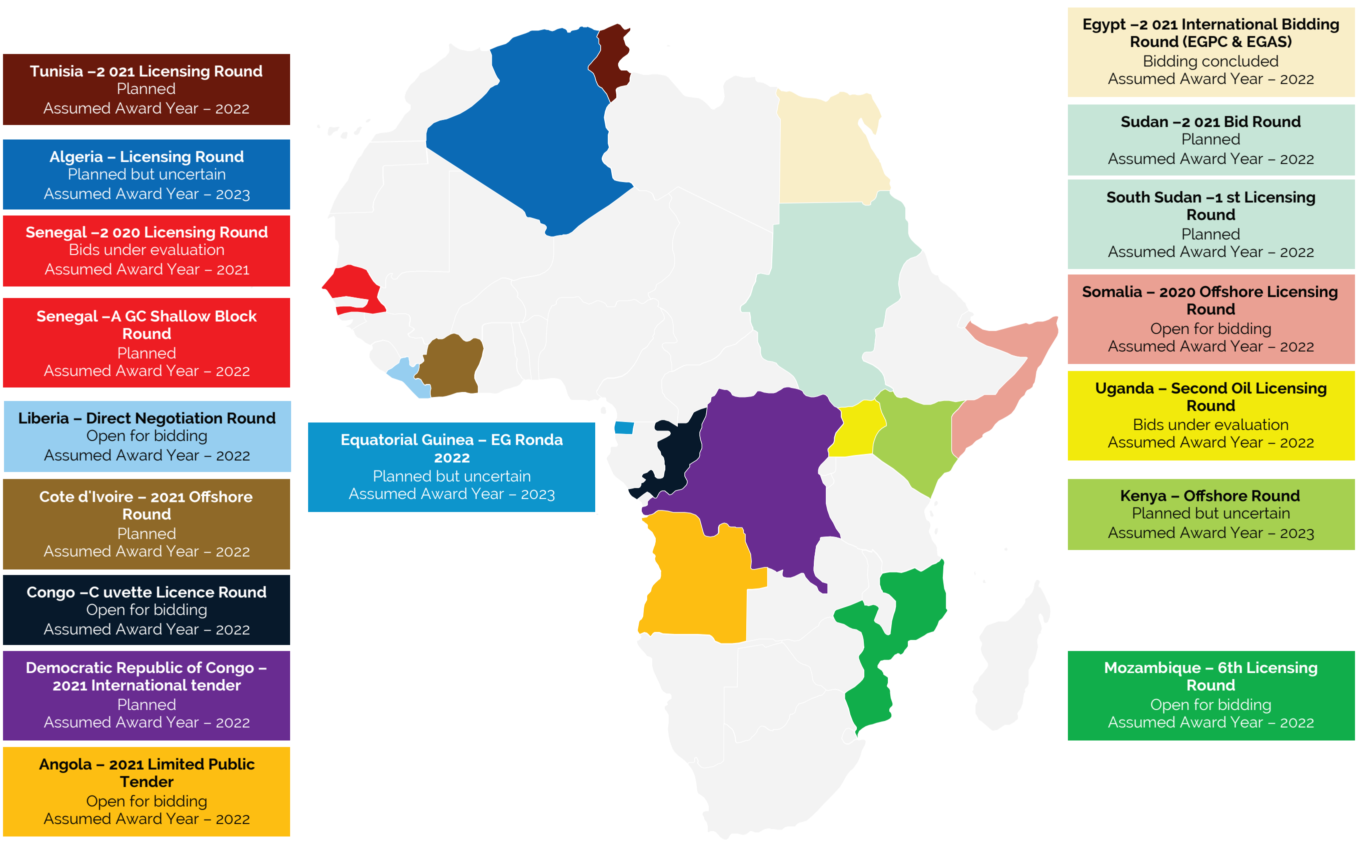


Exploration is returning to the continent in 2022 with 9 high impact wells in the drilling schedule for the year. Shell Plc's high profile Graff-1 probe off Namibia has already completed drilling with the results yet to be announced. Shell, however, has announced that the wildcat has resulted in a discovery although technical evalution results are yet to be disclosed. Eni's Mlima-1 wildcat in Kenya is also currently in progress. A mix of majors, independents and local companies are expected to participate in the high impact well drilling in 2022. 10 more high impact wells are expected to be drilled in 2023 and majority of these wells will be drilled in the unexplored basins in both East and West Africa.

4.3 Upcoming Exploration Licensing Activity

An uptick in licensing activity was observed in 2019 and the same or higher level of license awards was estimated in 2020. Licensing rounds were opened in the countries – Angola, Egypt, Equatorial Guinea, Ghana, Gabon, and Congo, in 2019. But many such rounds were either delayed or cancelled eventually due to the industry downturn. Some licensing rounds which opened before 2020 and were expected to close in 2020, also got spilled into 2021. Most of these rounds are expected to conclude in 2022. As many as 14 licensing rounds including public tenders and direct negotiations are expected to be closed in 2022. Egypt has already announced close of its EGPC and EGAS bidding round with results yet to be announced.

Figure 4.3: Upcoming exploration licensing rounds in Africa



Source: Rystad Energy ECube

5 MERGERS AND ACQUISITIONS **COMMENTARY**

Majors forming the group of companies looking to divest their portfolios especially across West Africa, with SPDC being the prime entity looking to exit

Majors' exit expected to dent the production and investment outlook greatly across th region

Indigenous operators to take over portfolios being exited by majors and NOCs

5.1 Recently concluded and/or announced divestments

Projects operated by majors, especially across West Africa are notorious for high emission rates and the deep water projects are cost intensive. Add to this, the historically prevalent above-the-surface risks ansd the region becomes a tricky area to operate. Many a times, the delays in the "conceptualization to implementation" in the required fiscal changes or announced fiscal changes has also led to many projects getting delayed. Nigeria has also been plagued by the pipeline vandalism which has resulted in millions of barrels lost to oil spills and environamental issues. The major Nigeria onshore operator – Shell Plc has been often faced with legal actions in the recent past. All of these issues along with the growing influence of stakeholders in shaping future strategy away from less clean fossil fuels has resulted in divestments being announced in the region from majors.

Figure 5.1: Recently concluded and announced transactions in Africa

Country	Seller	Deal Heading	Buyer	Status
		TNOG acquires 45% stake in OML 17 from SPDC	TNOG	Closed
		Cairn Energy and PICO Cheiron Group acquires stakes in Western Desert assets from Shell	Cairn Energy PICO Cheiron	Closed
		Uganda National Oil Company acquires interest in Lake Albert project from Total and CNOOC	UNOC	Closed
		Savannah Energy to acquire assets in Chad and Cameroon from ExxonMobil	Savannah Energy	Announced
		BP is in early stage talks to offload its Algeria assets		On-offer
		SPDC in talks sell onshore OMLs in Nigeria		On-offer
		Chevron seeking to sell its Equatorial Guinea oil and gas assets		On-offer
		Sonangol to fast-track sale of offshore Angolan blocks		On-offer
		Eni to exit Tunisia		On-offer
		Gemcorp Capital eyes potential stake in Sonangol		On-offer

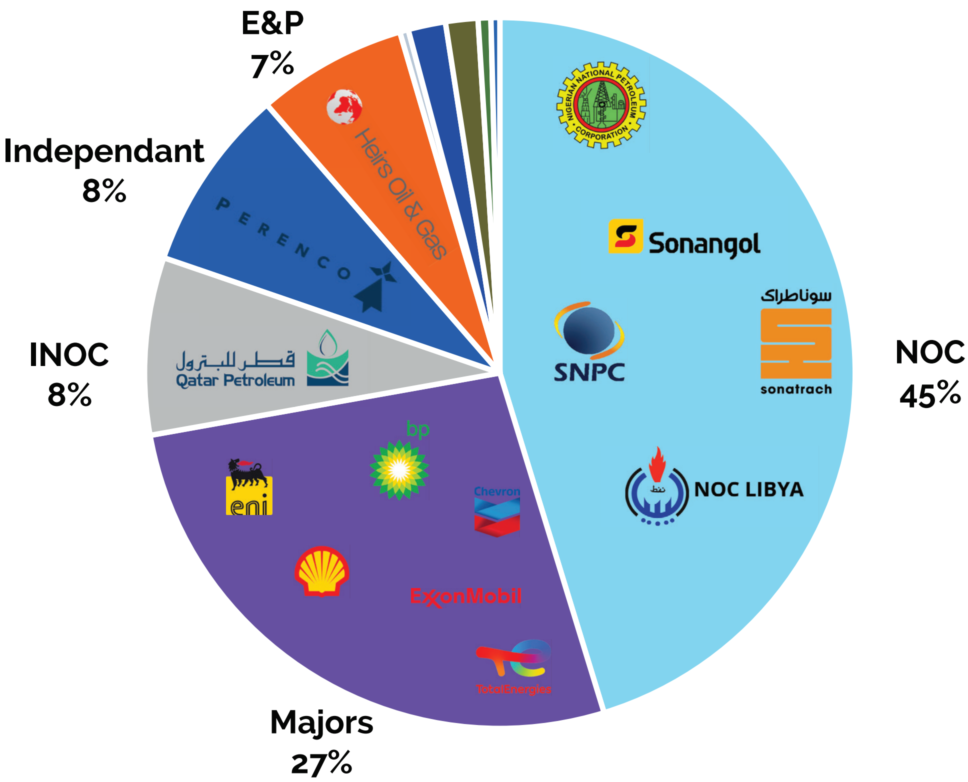
5.2 Impact of Majors' exit on upstream sector

Africa's upstream sector can see a significant change if the oil and gas majors that are lined up to shed assets in key producing nations eventually divest their portfolios to the relatively lesser known and lesser funding rich indigenous companies. Large international players have long been the driving force of the sector in the region – mostly notably in OPEC members Nigeria and Angola. The sales are, however, giving smaller players and, in Nigeria in particular, indigenous exploration and production (E&P) companies the chance to expand their portfolios. However, it remains to be seen as to what would be the eventual investments that these smaller players can drive in.

Majors have historically been a major driving force of West Africa's oil and gas production. In partnership with the country NOCs, majors have played an active part in shaping the hydrocarbon production profile of the continent. The upcoming five year period (2022 – 2026) is expected to be no different with over 70% of the overall oil and gas production from Africa estimated to be from the partnership of majors and NOCs. As such, the impact can be severe on the production if the majors decide to make an exit.

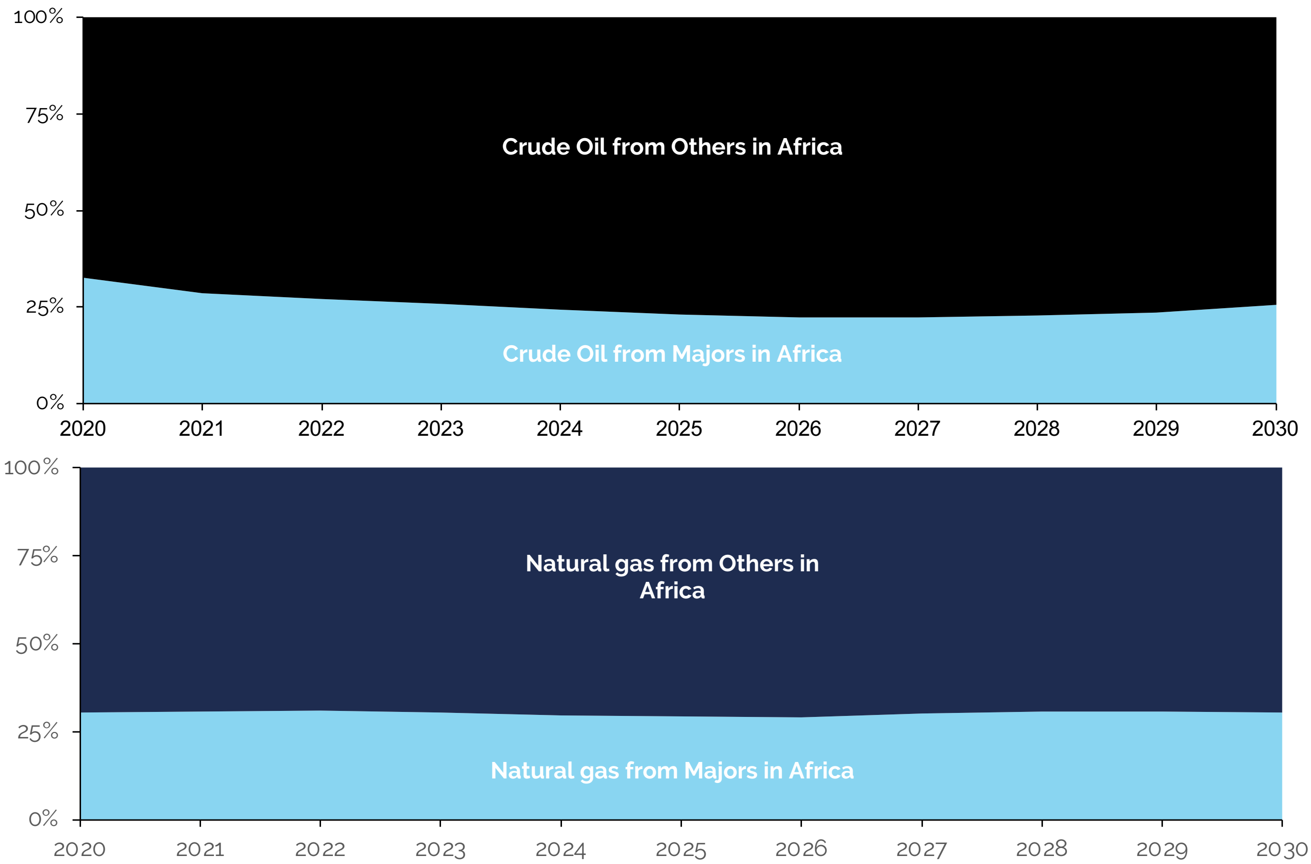
A year-on-year outlook from 2020 to 2030 suggests contribution of majors in the continent's crude oil output is expected to stay at around a quarter of the entire volume. 2022 estimated production from the majors is just over 27% of the overall volumes.

Figure 5.2: 2022 – 2026 overall cumulative production splitb yc ompany segment



Source: Rystad Energy ECube

Figure 5.3: Majors' Contribution to oil and gas production in Africa

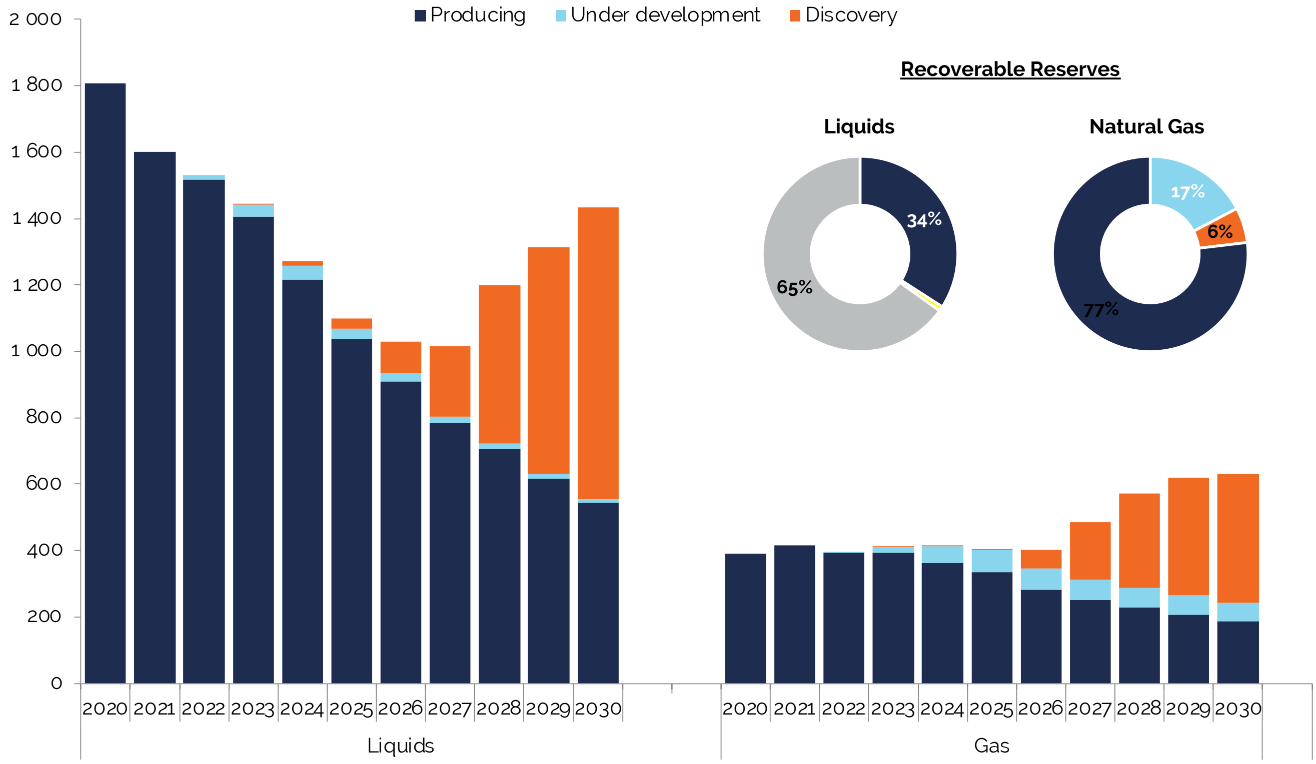


Source: Rystad Energy UCube

This is expected to slightly decline to 22% in the next five to six years but as the deep water projects come online later in the decade, where majors are prime shareholders, their production share takes a reverse turn towards increase again with 2030 share estimated to be at just over 25%. When it comes to natural gas, as majors continue their investments in the gas-focused projects as the transition to natural gas is being perceived as the first step towards cleaner and greener fuels, majors' contribution to the continent's natural gas output is expected to stay around 30% throughout. Several majors continue to remain key players in LNG projects across the continent in countries like Nigeria, Angola, Senegal, Mauritania, Mozambique, South Africa, Egypt, Algeria, Equatorial Guinea among others.

While the majors have been largely responsible for the majority of production in the region, many high-profile deepwater projects and onshore blocks with large potential that are currently held by these companies have yet to be developed. Numerous onshore blocks held by SPDC in Nigeria, mega deepwater projects offshore Nigeria and Angola, and BP's scaled-down liquefied natural gas (LNG) developments on the Senegal–Mauritania maritime border are just some of the projects that have faced challenges. Government delays in implementing fiscal reforms, the operators' focus on other regions and supply segments, dynamic oil and gas markets and legal wrangles are just a few reasons behind many of the project delays. In terms of recoverable reserves in the region, about 65% of liquids and 75% of natural gas held by the majors are currently in the pre-final investment decision phase, with development of many of these volumes delayed to the second half of this decade and some beyond that. While less expensive onshore projects might see some progress in the hands of local players that have sources of funding, any exits by majors from the cost-intensive deepwater projects could lead to major project revisions, downsizing and further delays.

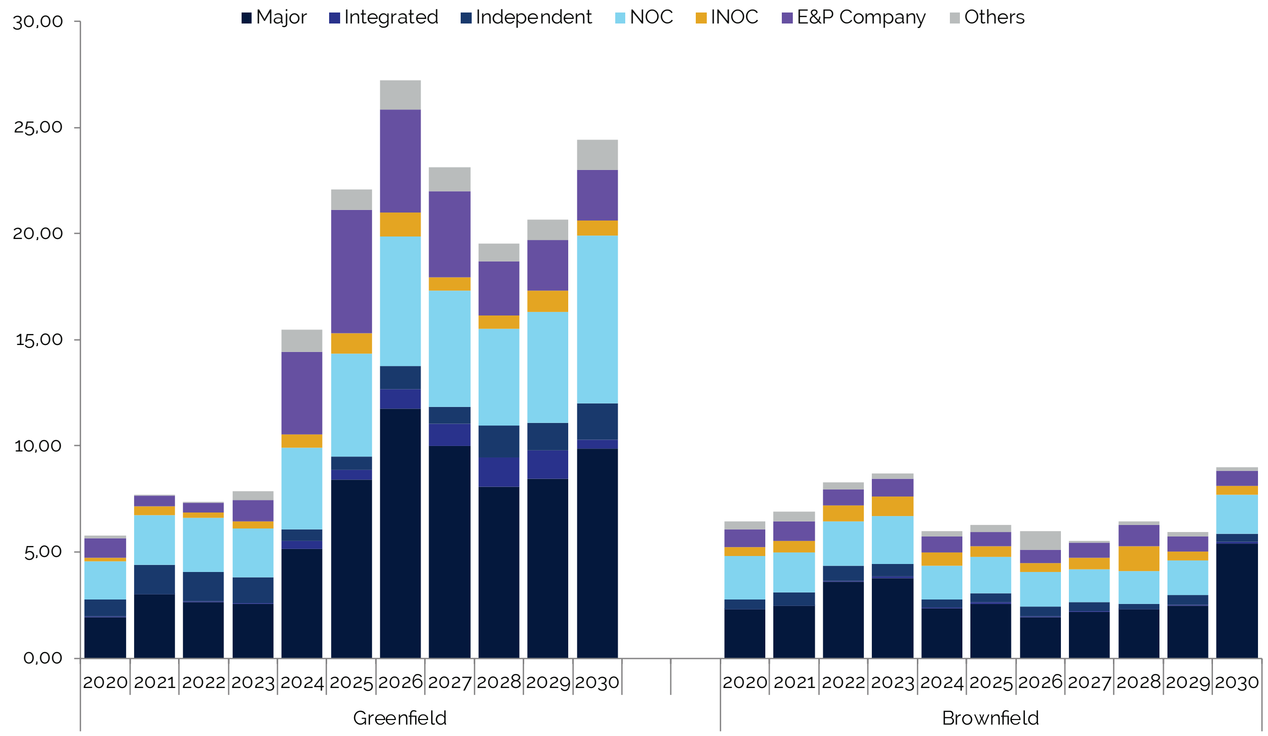
Figure 5.4: Majors' production forecast and reserves in West Africa
Thousand barrels of oil equivalent per day



Source: Rystad Energy UCube

These high volumes of undeveloped reserves demand high greenfield investments. The currently declining production from fields in the region also requires brownfield investments to stabilize output or at least minimize the decline. Between 35% and 40% of the estimated required greenfield investments in the region through this decade are expected to come from the majors and this is an estimated $70 billion. While not all the assets held by majors in the region are up for sale, the overall estimated valuation of the majors' portfolios in the most significant producing countries in the region is estimated to be over $50 billion. Shell hopes to raise $3 billion from the sale of its 30% stake in the assets owned by SPDC. Any player wishing to buy into this portfolio will require funding for the stake purchase as well as investment in the assets going forward.

Figure 5.5: West Africa capital expenditure forecast split by company segment
Billion USD



Source: Rystad Energy UCube

Many local players have already bought into or are reported to be actively bidding for the assets put up for sale by majors, particularly in Nigeria and Angola. Five companies – Sahara Group, Seplat Energy, Famfa Oil, Nigeria Delta Exploration & Production (NDEP) and Troilus Investments – are reportedly planning to bid for Shell's stakes in as many as 19 oil mining leases (OML) in Nigeria, where the deadline for submitting bids is 31 January this year. Seplat is also reported to be considering acquiring ExxonMobil's shelf portfolio offshore Nigeria, while Somoil, as mentioned above, is gaining assets in Angola from TotalEnergies and Inpex.

While these transactions, if completed, could see the local companies focus more on development of the assets than the majors, many risks remain. Raising sufficient funds for the acquisition and development of such assets is a major factor as many international banks and investors have become increasingly wary of oil and gas assets in the region, especially in Nigeria due to various above-ground concerns – although some African and Asian banks are reported to be still willing to finance fossil fuel operations in the region. However, this is just the tip of the iceberg. As Nigerian independent Aiteo learned the hard way, following its $2.7 billion acquisition in 2014 of OML 29 and SPDC's share of the Nembe Creek Trunk Line (NCTL), managing the assets in a risky environment and volatile oil market is no easy task.

Pending the finalization of fiscal terms, any further tax changes and regional price regulations can create more challenges. If these indigenous or locally experienced players can overcome these issues and channel funds to the yet-to-be-recovered resource potential, additional production can help stem forecast output declines in some countries in the region. These smaller players will also be hoping for more regulatory, security and fiscal incentives from governments in West Africa as they target some of the majors' assets.

6 REGULATORY **LANDSCAPE**

Major fiscal regulatory changes have been announced in Nigeria with the more-than-a-decade in the making Petroleum Industry Bill (PIB) finally passed recently to Petroleum Industry Act (PIA) after 14 years of legislative deadlock

The legislation is aimed at providing a legal, governance, regulatory and fiscal framework for the country's oil and gas industry, and the development of host communities

PIA reverses some of the terms introduced in the 2019 PSC deep water revision but has been labelled as controversial in sections of the media, due to the addition of a price-based royalty to the already existing production-based royalty

6.1 Recently announced and soon to be implemented fiscal regulation changes

Nigeria's staple oil and gas sector received a welcome boost in late 2021 after the administration of President Muhammadu Buhari signed the Petroleum Industry Bill (PIB) into law. The PIB and, now, the PIA have long been a topic of significant importance to Nigeria's oil and gas sector. Some deepwater projects have been delayed as the operators – often majors – awaited the bill's passing, which was anticipated to bring clarity and certainty with respect to fiscal and industry regulations. In the meantime, there has been a series of tax regulations, the latest of which was the 2019 deepwater production sharing contract (PSC) revisions, but lawmakers remained unable to reach agreement on this bill. The Covid-19 pandemic and resultant industry downturn seemed, however, to have spurred the Abuja administration to implement these much-needed reforms.

- The Act replaces the Petroleum Profits Tax (PPT) with the Hydrocarbon Tax (HT), which will be charged at varying rates depending on water depth:
- For onshore mining leases, the HT will be 30% along with a Companies Income Tax (CIT) of 30%, capping the overall tax at 60% compared to a high of 85% under the Petroleum Profits Tax Act (PPTA).
- The tax rates for shelf water-depth fields will be the same as onshore fields
- Deepwater operators are liable to pay a HT of 10% and a CIT of 30%
- Production-based royalty will be between 5% and 15% for crude oil and condensates, and 5% for gas, with the rate being 2.5% if the gas is feeding domestic demand.
- Price-based royalty will apply to crude oil and condensates, when the Brent crude price exceeds $50 per barrel (a $100 per barrel price will attract 5% and above $150 per barrel will attract 10%).
- The additional price-based royalty will be credited to the Nigerian Sovereign Wealth Fund.
- Another significant fiscal parameter includes the introduction of the cost price ratio (CPR) that restricts the capital allowance claimable in any given accounting year to 65% of the gross revenues determined at the measurement points when setting the hydrocarbon tax payable, but any cost not deducted upon termination of upstream operations will be lost.

Figure 6.1a: Petroleum Industry Act (PIA) parameters for new PSCs

Royalty (Oil & Condensates)				
Water depth*	Price (USD/bbl)** → / Production (kbbls/d)*** ↓	$50/bbl	$100/bbl	$150/bbl
Onshore	0 – 5	5.00%	10.00%	15.00%
	5 – 10	7.50%	12.50%	17.50%
	More than 10	18.00%	23.00%	28.00%
0 – 200m	0 – 5	5.00%	10.00%	15.00%
	5 – 10	7.50%	12.50%	17.50%
	More than 10	16.00%	21.00%	26.00%
More than 200m	0 – 15	7.50%	12.50%	17.50%
	More than 15	10.00%	15.00%	20.00%

Royalty (Gas & NGLs)		
Water depth*	Onshore	Offshore
Royalty (%)	7.50%	5.00%

Depreciation	5 year straight line depreciation

*Look-up scale **Interpolation ***Sliding scale
Source: Rystad Energy Research and Analysis

The fiscal terms in the PIA will apply upon the conversion of existing Oil Prospecting Leases (OPL) and Oil Mining Leases (OML) into Petroleum Production Licenses (PPL) and Petroleum Mining Licenses (PML), the termination or expiration of unconverted leases and the renewal of OMLs.

Industry insiders opine the new regulations may not tick all the boxes wished for by the petroleum industry. For instance, restrictions on the deductibility of valid operating expenses could have negative consequences for some investors, and industry sources have noted that the terms for existing PSCs that are converted are not as beneficial for deepwater developments as it could seem at first glance. One important aspect is the introduction of the cost price ratio (CPR). The PIB abandons the restriction to capital allowance claimable in a given accounting year, but restricts it to 65% of the gross revenues determined at the measurement points when setting the hydrocarbon tax payable. Any excess cost not deductible due to the above will be carried forward to subsequent years, and any cost not deducted upon termination of upstream operations will be lost. It is unclear whether the CPR will apply only to deductible expenses or also to capital allowance claimable. Several industry sources have indicated the same, saying the complexity around the incentive that the PIB might allow and the CPR, in particular, could make the PIB less beneficial. Although the objective of this provision may be to boost revenues to the government, the cash flow implications for upstream companies may discourage investments, especially for the cost-intensive new deepwater projects. Sectors of the

Figure 6.1b: Petroleum Industry Act (PIA) parameters for new PSCs

Profit Oil Government Share for Liquids						
Cumulative Production (MMbbls)*0	– 50	50 – 1001	00 – 3503	50 – 7507	50 – 1500	Above 1500
Rate (%)	5.00%1	0.00%1	5.00%2	5.00%3	5.00%	45.00%

Profit Oil Government Share for Natural gas	0%

Nigeria Hydrocarbon Tax (NHT)			
Water depth*	OnshoreS	helf	Deep water
Rate (%)	42.50%3	7.50%1	0.00%

Corporate Income Tax (CIT)	30.00%

Cost Ceiling	65.00%

Uplift	5 years

*Look-up scale **Interpolation ***Sliding scale
Source: Rystad Energy Research and Analysis

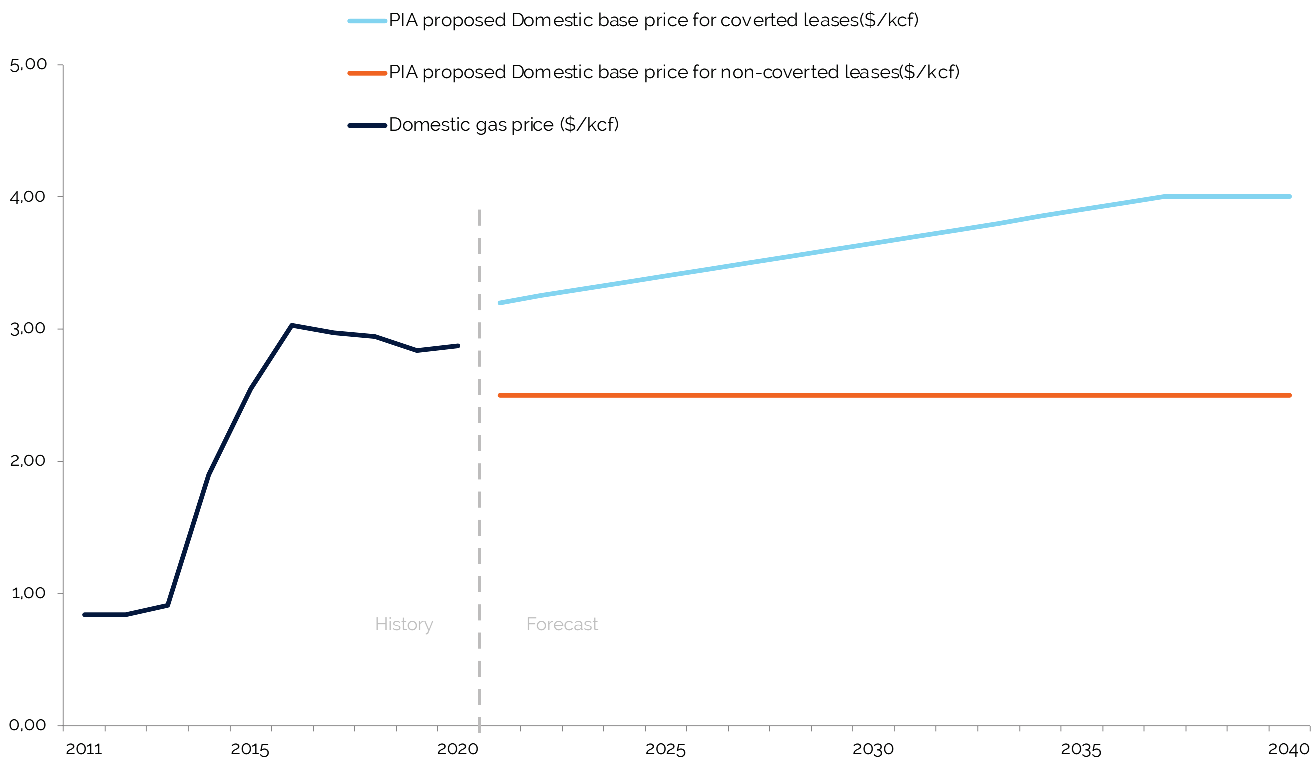
industry anticipate there could be amendments to the legislation at a later date, particularly in relation to the revenue share element for host communities, while the resultant Petroleum Industry Act (PIA) has been labelled as controversial in sections of the media, due to the addition of a price-based royalty to the already existing production-based royalty.

Egypt's government has recently signed many new contracts with revised and improved fiscal terms that could trigger growth in investments and consequently the production. Apache, Transglobe Energy and Pharos Energy have reported such contract signings. In the case of Apache and Transglobe Energy, what is common is merging of many concessions into one to benefit from one common cost pools. The revised terms include lower taxes and increased cost recoveries. This also allows previously ring-fenced concessions, where the costs recoveries were slow due to lower revenues to utilize the unrecovered costs faster due to combined concessions- technically eliminating the ring-fencing effect. Apache has already started increasing the rig count and estimates an increase in oil production going forward. Capricorn Energy, who recently acquired Shell's onshore BAPETCO operated assets could also explore this option but has communicated no plans as of now and intends to increase production by increased drilling going forward. This is a great initiative as it increases the investor sentiment in the country's upstream industry and helps reduce the decline rates, if not increasing the production in the future.

6.2 Impact of these Regulations

While the fiscal terms under the PIA kick in on conversion of existing leases, the government has now announced a timeline for the other administrative, gas price and flaring-related regulations, and establishment of a community trust fund. The government has set November 2022 as the target date by which to establish a domestic gas base price.

Figure 6.2: Domestic Gas Price comparison in Nigeria

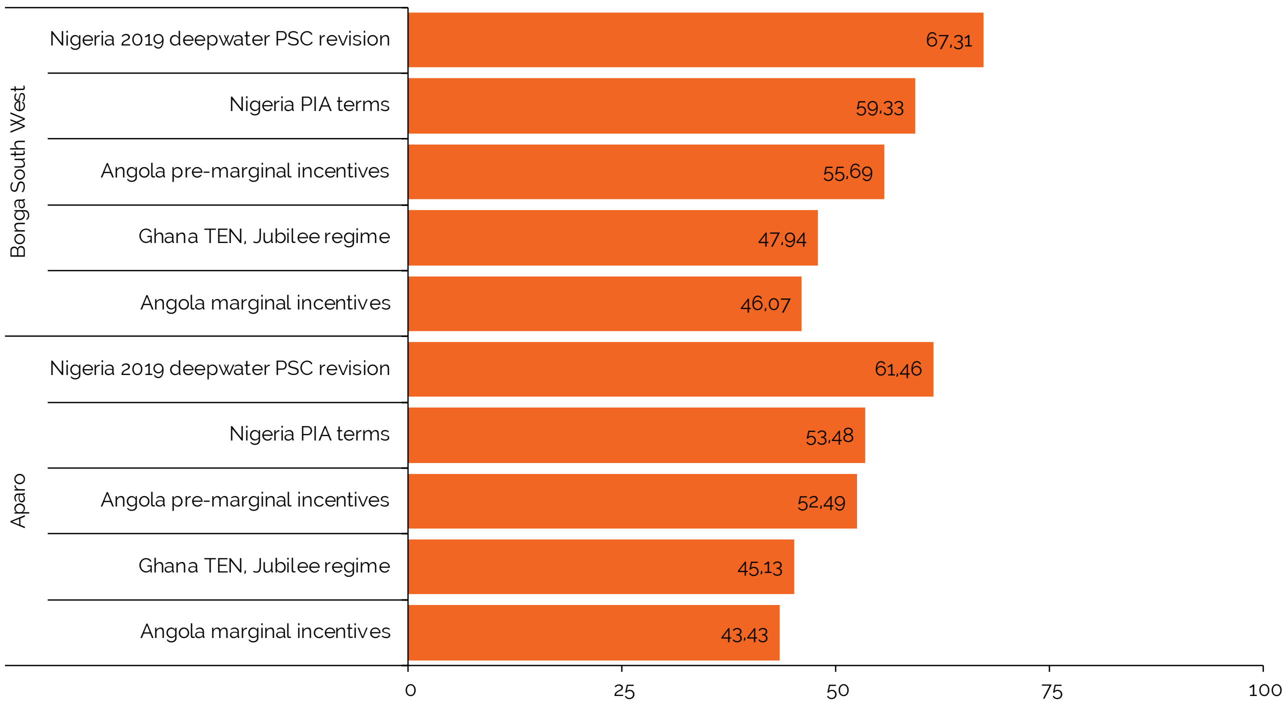


Source: Rystad Energy Research and Analysis

Gas prices in Nigerian domestic market are de-linked from the oil price. The average weighted realised domestic gas prices in Nigeria have risen from a sub-$1/kcf to close to about $3/kcf by 2021. The Domestic Supply Obligation (DSO) price also has seen a similar increase from a a sub-$1/kcf to close to about $2.5/kcf by 2020. Proposals from the Federal Government suggested reduction to the DSO prices from $2.5/kcf to $2/kcf in 2020. This is being monitored to ensure cost-reflective pricing for gas. The PIA proposes a domestic base price as of $3.2/kcf from January 1st, 2021, with an annual increase of $0.05/kcf till 2037 when the price reaches $4/kcf. However, this is applicable for the leases which convert to the new fiscal terms under PIA with the older leases operating at a flat $2.5/kcf domestic base price till the lease expires or they convert to PIA terms.

A specific analysis of the impact of the PIA on breakeven oil price on a project such as Eni's Etan tie-back shows that it is more contractor friendly than the existing terms under 2019 deep water PSC revisions. However, the PIA is still less contractor-friendly compared to the pre-2019 deepwater terms. The terms for the Tweneboa–Enyenra–Ntomme (TEN) field in Ghana and the 2019 Angolan marginal field terms are more contractor-friendly by comparison. It can also be seen that the terms Angola offered under its marginal field regime result in a larger improvement in project breakevens.

Figure 6.3: Breakeven oil price of Bonga South West –A paro project under different tax regimes
USD per barrel



Source: Rystad Energy UCube, UCube Economic Model

The PIA also set a timeline for the conversion of the Nigerian National Petroleum Corporation (NNPC) into a limited liability company, and for the creation of committees and nomination of board members for the company. More administrative terms, such as the transfer of assets and liabilities to NNPC Limited and establishment of a framework for payment of non-transferable liabilities, have deadlines of February 2023 and August 2023, respectively. The incorporation of NNPC has so far garnered mixed reactions from industry experts. Those in favor claim it will result in transparency, with the country benefitting from taxes to be paid by NNPC as a company and a probable eventual listing on the stock exchange as well as private shareholding. Others have questioned issues such as the re-appointment of current NNPC board members as the members of the NNPC incorporated board and the absence of articles in the PIA that guarantee transparency of the board. Nigerian crude production has declined by almost 700,000 barrels per day since the first draft of the bill was presented to the National Assembly in 2007. The PIA is a welcome move in a country where lack of a clear and stable legal framework has stalled foreign investment in the oil and gas sector for the past decade or more. However, there remain issues to be addressed and questions to be answered for the law to result in a positive outcome for the country and its government. The Buhari administration will look to resolve these issues as soon as possible as the next general election, set for the first quarter of 2023, draws closer.

Apart from this, Angola has approved the application of marginal field tax incentives on a few more of the country's deep water projects operated by majors. These incentives allow royalties and taxes to be halved and as such, encourage the operators to accelerate the development of the currently undeveloped projects. Other African nations also need to work on their fiscal and other administrative terms more favourable to encourage investments from international oil players. Africa has many heavily hydrocarbon dependant economies where declining crude oil production trend is very worrying. The country-level administrations need to work on making their respective hydrocarbon development more attractive to recover their full potential and step towards ending energy poverty across the continent.

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Q1 2022 Outlook

African Energy Chamber

For more information on the African Energy Chamber, contact us today!

Suite 43 Katherine & West
114 West Street
Sandton, Johannesburg, South Africa
+27 11 245 5900
partners@energychamber.org

Ask us about membership!
members@energychamber.org

www.energychamber.org