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THE STATE OF AFRICAN ENERGY

Q2 2022

African Energy Chamber

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Q2 2022 Outlook

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Index

Key Highlights

- 2022 Brent average estimated at US$111 on the back of resilient demand and the risk of full Russian oil embargo
- A tight balance between supply and demand expected in 2022 as supply remains relatively tight while demand sees an increase
- Maritime sector mainly driven by the reroutement of Russian exports to Asia and petchem sector in the Middle East drive an upward revision in demand for 2022
- Nigeria, Algeria, Libya, Angola and Egypt are expected to be the top oil + condensates producers for the year 2022 in Africa
- 2022 crude oil and condensates production estimated at about 6.85 million bbls/d (90% crude oil), a drop from Q1 forecast of just over 7 million bbls/d (90% crude oil), mainly driven by downward revisions in Libya due to production outages
- The uncertainty over Russian supplies and sanctions on energy exports are expected to result in higher European LNG spot prices of over US$30/MMBtu as the expectation is that Europe will import large volumes of LNG
- Exit of operators from Russia is expected to result in a revised development timeline for multiple projects in Russia, leading to a drop of cumulative output of 1435 Bcm over the years 2022 – 2030
- The sanctions and production drop are also expected to result in a global LNG demand – supply gap of about 120 million tpa by 2030
- Algeria, Egypt and Nigeria lead the gas producers in Africa, contributing to over 80% of the output
- Over 65% of the LNG exports from Africa come from Nigeria and Algeria together
- Majors' exits from Russia can have a positive impact on the African projects operated by these European and American operators
- 50% of the 2022 – 2025 cumulative gas flows from the top 10 producers in Africa are expected to be exported as LNG to International exports
- 2010 – 2020 European natural gas imports show that Russian gas constituted to an average 62% of the overall cumulative volumes whereas, African volumes were about 18%
- Bulk of the Russian exports to Europe were via pipelines whereas, African exports have been a mix of pipeline and LNG exports
- Historical gas trade relations and presence of pipeline infrastructure from Northern Africa to Europe places Africa in a good position of increase its exports to Europe
- Talks of cross country long distance pipelines have picked up in the recent months, aiming at taking West African gas all the way to Europe
- While the overall capital expenditure forecast has not seen any major change from the Q1 2022 forecast, the greenfield spending has increased mainly driven by greenfield developments in Mozambique, Uganda and Congo, and NLNG T7 in Nigeria
- Venus and Graff wildcat successes offshore Namibia have resulted in a steep jump in year-on-year discovered volumes in Africa
- Recent exploration drilling success offshore West Africa and South Africa are expected to have a positive impact with 13 more high impact wells (HIWs) expected to drilled in the near term
- 18 exploration licensing rounds offering onshore and offshore acreage across Africa are expected to be closed by the end of 2023
- Majors BP and Eni come together in Angola to form a joint venture Azule Energy, which is expected to be the largest producer in the country after Sonangol
- More M&A activity in Angola as Sonangol divests its stakes in six offshore blocks to a mix of experienced and newcomers in Angola
- SPDC looking to divest its stakes in 19 onshore oil mining leases (OMLs) where Shell Plc and TotalEnergies are targeting a full exit whereas Eni is reported to have decided to hold on to natural gas interests
- Congo – Brazzaville takes both Fast LNG and LNG route to monetize its excess natural gas output after catering to the domestic gas-fired power plants
- Cote d'Ivoire and Namibia break into the African E&P scene in a big way with giant offshore discoveries looking at multi billion dollar greenfield investments

1 OIL MARKETS OUTLOOK **AND SUPPLY**

2022 Brent average estimated at US$111 on the back of resilient demand and the risk of full Russian oil embargo

A tight balance between supply and demand expected in 2022 as supply remains relatively tight while demand sees an increase

Maritime sector mainly driven by the reroutement of Russian exports to Asia and petchem sector in the Middle East drive an upward revision in demand for 2022

1.1 Brent running high in the wake of Russia – Ukraine conflict

A weaker demand growth, the mega-SPR release and more resilient Russian exports and production than previously assumed contribute to a lower price profile than expected previously. The Brent price scenario is still expected at somewhat elevated level to account for the risk of a slower than planned SPR release, resilient demand and the risk of the EU actually implementing a partial or full Russian oil embargo. Despite certain macro headwinds, seasonal demand growth is expected to materialize in the summer, and would further widen the supply gap, which could be further exacerbated by unplanned outages not yet accounted for in a base case supply forecast. In conclusion, 2022 price levels are expected to stay at an average US$111/barrel compared to a pre-war price forecast of US$64/barrel and a Q1 2022 price forecast of US$70/barrel.

Figure 1.1 Brent running high in the wake of Russia – Ukraine conflict

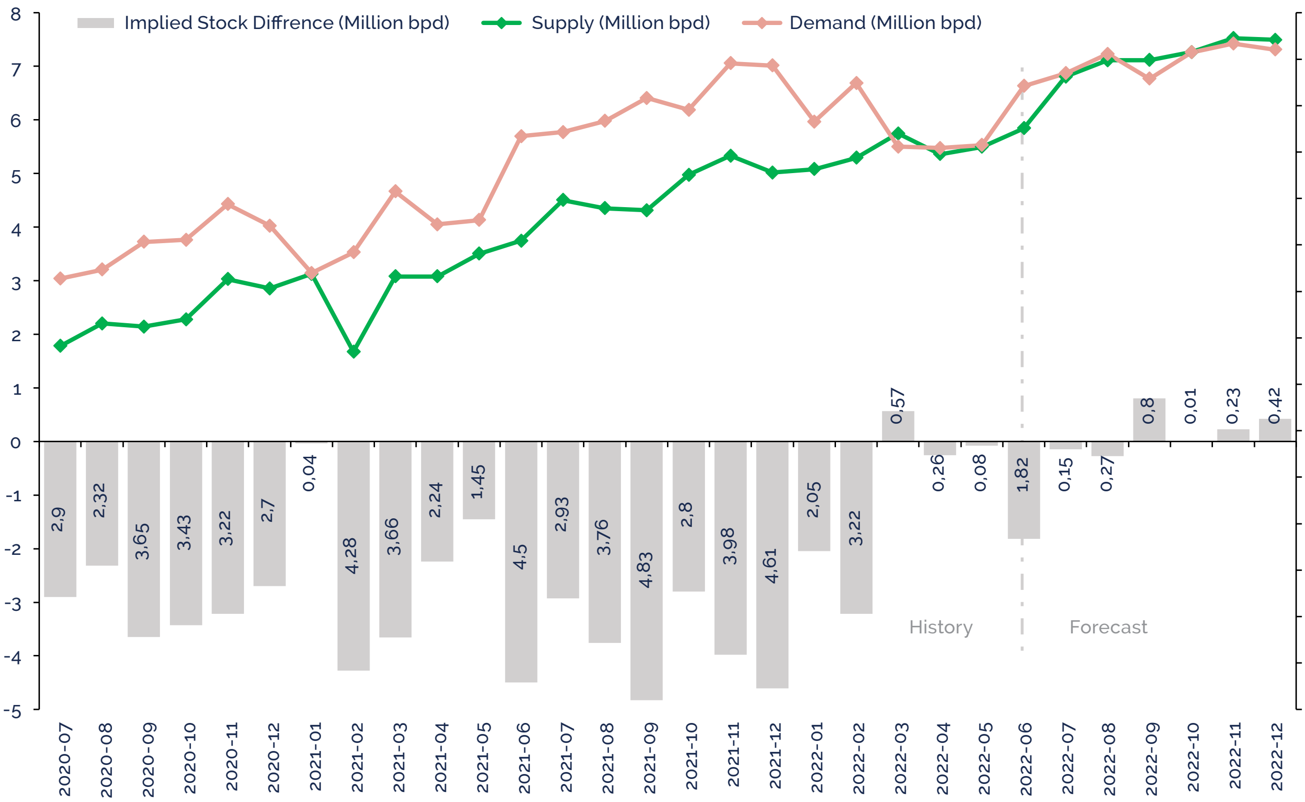
Source: Rystad Energy UCube

1.2 As consumption surges, tight supply – demand balance expected in 2022

A relatively more bullish total implied liquids balance is expected for the remainder of 2022 as demand is expected to see an upward revision versus supply staying relatively tight despite the high price environment. A 0.9 million bpd draw is expected is Q3 2022 based on an estimated 900,000 bpd increase in demand versus tighter average supply as a result of decrease of 500,000 bpd. The demand revisions are driven by boosted maritime activity as more Russian cargoes travel further to Asian markets, as well as increased petchem demand in the Middle East with the ramp up of the Jizan and Al-Zour refineries, as well as the seasonal increase as oil is burned for cooling. Boosted demand for LPGs in the US market is also expected, as the price for the fuel becomes more competitive against alternative fuels.

A summer draw of 2 million bpd of products would sync with the currently tight market and expected strong summer driving season ahead. A downside risk driven by China lockdowns reemerging cannot be ruled out, so is a bearish turn if the technical recession hits GDP growth. The supply decrease is mainly due to downward expectations in Brazil, new assumptions on Libya production woes, downside risk to Russian oil output as domestic demand remains tepid, and slight revisions in the US oil forecast after some logistical interruptions in fracking and flowback schedules were observed. Further signposts to watch closely will be aviation and road fuel consumption in China post lockdowns relaxation and refinery openings staying on schedule.

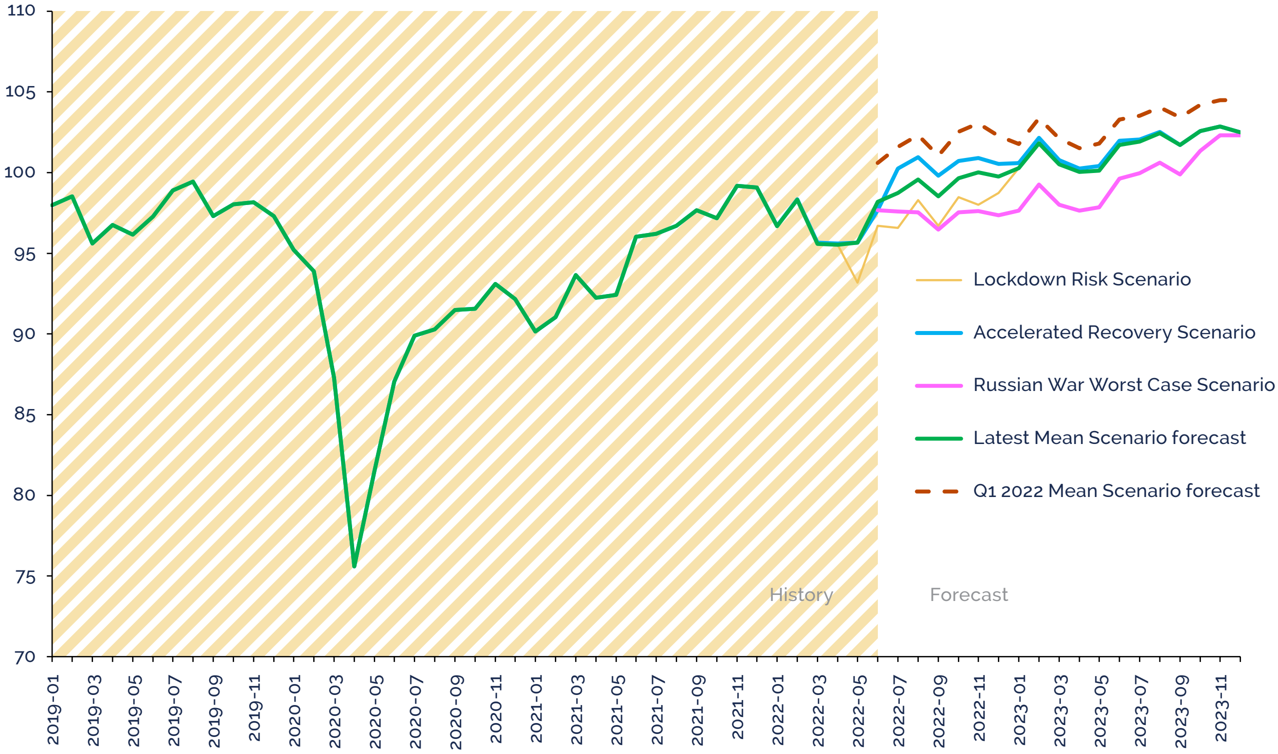
Figure 1.2 Post lockdown slump, oil consumption on the rise leading to tight supply – demand balance



Source: Rystad Energy Research and Analysis, Rystad Energy Oil Trading Analyst Solution

1.3 Maritime & petchem sectors and Middle East drive upward revision in 2022 global demand

Figure 1.3 Maritime & petchem sectors and Middle East drive upward revision in 2022 global demand (Million barrels per day)

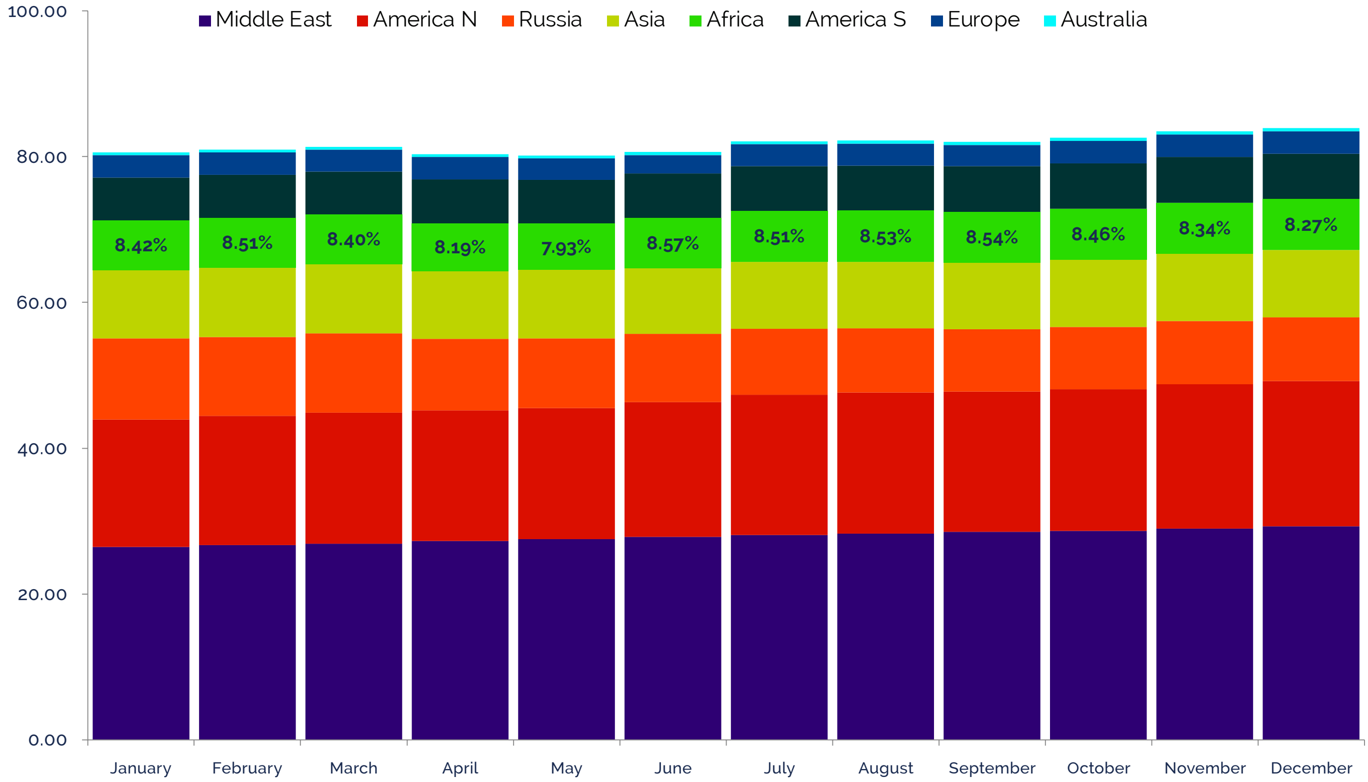


Source: Rystad Energy Research and Analysis, Rystad Energy Oil Trading Analyst Solution

On the demand side, maritime sector demand is expected to increase by 350,000 bpd due to the major rerouting of Russian crude exports from Europe (currently delivered via pipeline and short costal navigation) to China and India, delivered on blue water. Fuel oil and diesel are the products mostly affected, while Singapore, Middle East, Western Europe and South America are benefiting the most in terms of increased demand. Also, demand from Saudi Arabia is expected to see an increase by 294,000 bpd, of which ~60% is from the petchem sector. This is due to increases in integrated refining/petchem demand, in part due to the commissioning of the Jizan refinery, and the rest due to increased GDP growth in the country. Kuwait demand also is estimated to see an increase of about 153,000 bpd, of which close to 66,000 is from the petchem sector again and about 48,000 bpd is fory own-use energy generation. This is in part due to the commissioning of the Al Zour refinery, and the rest due to increased economic activity in the country. A demand resilience shown from the building sector in the US is expected to drive a total increased liquids demand of 390,000 bpd, of which 240,000 bpd is LPG demand majorly from the building sector. Overall, 2022 average oil demand is now estimated at 100.6 million bpd, slightly higher than 2019. Key signposts to monitor are China's lockdowns and direct and indirect effects of high oil prices on demand growth, risks that are already backed into our forecast, but could intensity and warrant downside revisions.

1.4 Steady oil + condensates flows from Africa through the year

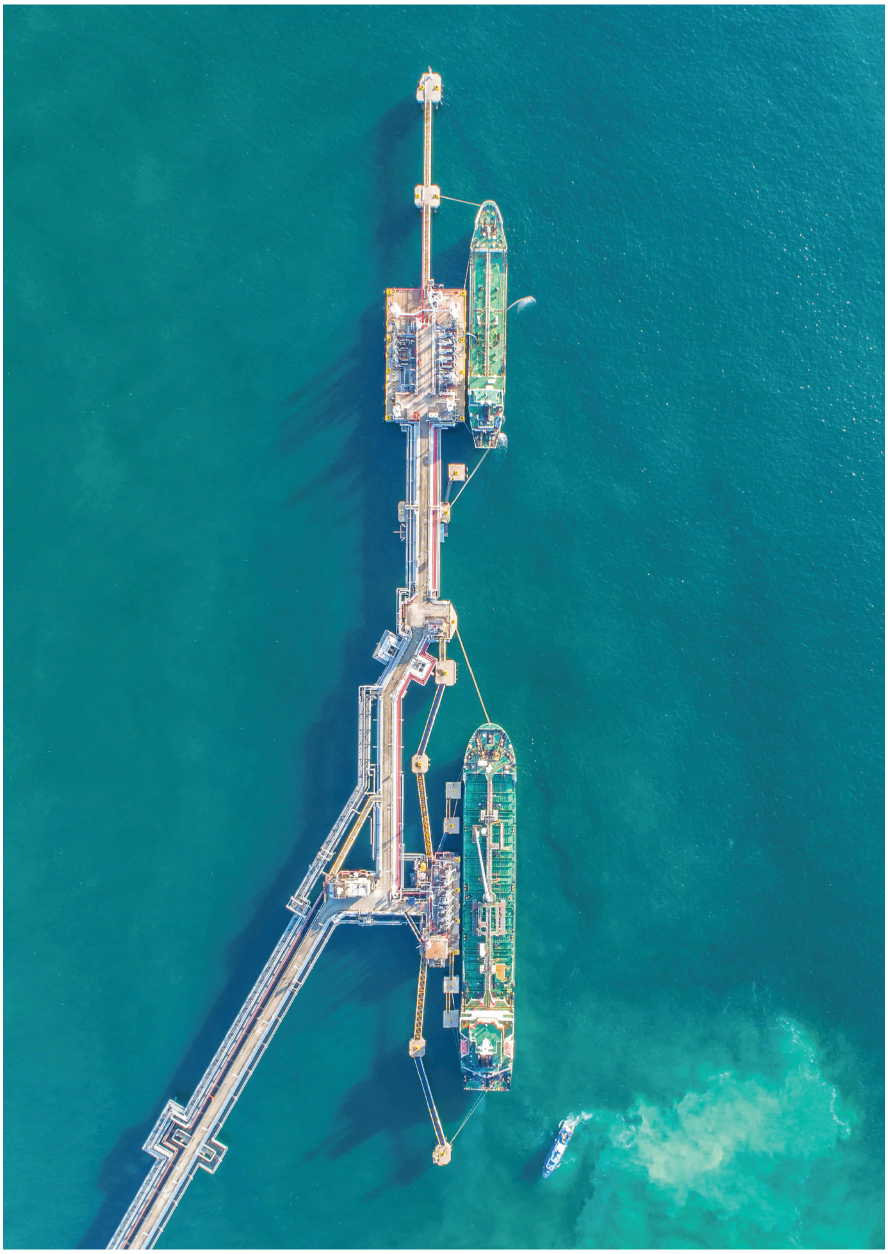
Figure 1.4 Steady oil + condensates flows from Africa through the year (Million barrels per day)



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 about 84 million bbls/d in Dec, resulting in an average of about 81.7 million bbls/d for the entire year. This is a downward revision from Q1 annual average estimate of about 83.3 million bbls/d mainly driven by the drop in Russian output. Russia estimated 2022 annual crude oil + condensates output is now estimated to be close to 9.5 million bbls/d as opposed to 11.3 million bbls/d estimated in Q1 2022. Even post this drop, 2022 levels are expected to rise from the lows of 2020 – 2021 which ended at an average of 76.7 – 78 million bbls/d. The Middle East is expected to see flows of upto one-third the global levels and, together with the North American output, is expected to contribute to over 55% of the global supply. Average annual crude oil + condensates supply from the Middle East region is estimated to reach close to 27.9 million bbls/d and North American volumes are expected to reach annual average levels of about 18.7 million bbls/d. Asia, Africa and South America are estimated to see annual average flows of 9.26 million bbls/d, 6.85 million bbls/d and 6.1 million bbls/d respectively.

Source: Rystad Energy UCube August 2021



1.5 Drop in Libya flows resulted in lower volumes through Q2

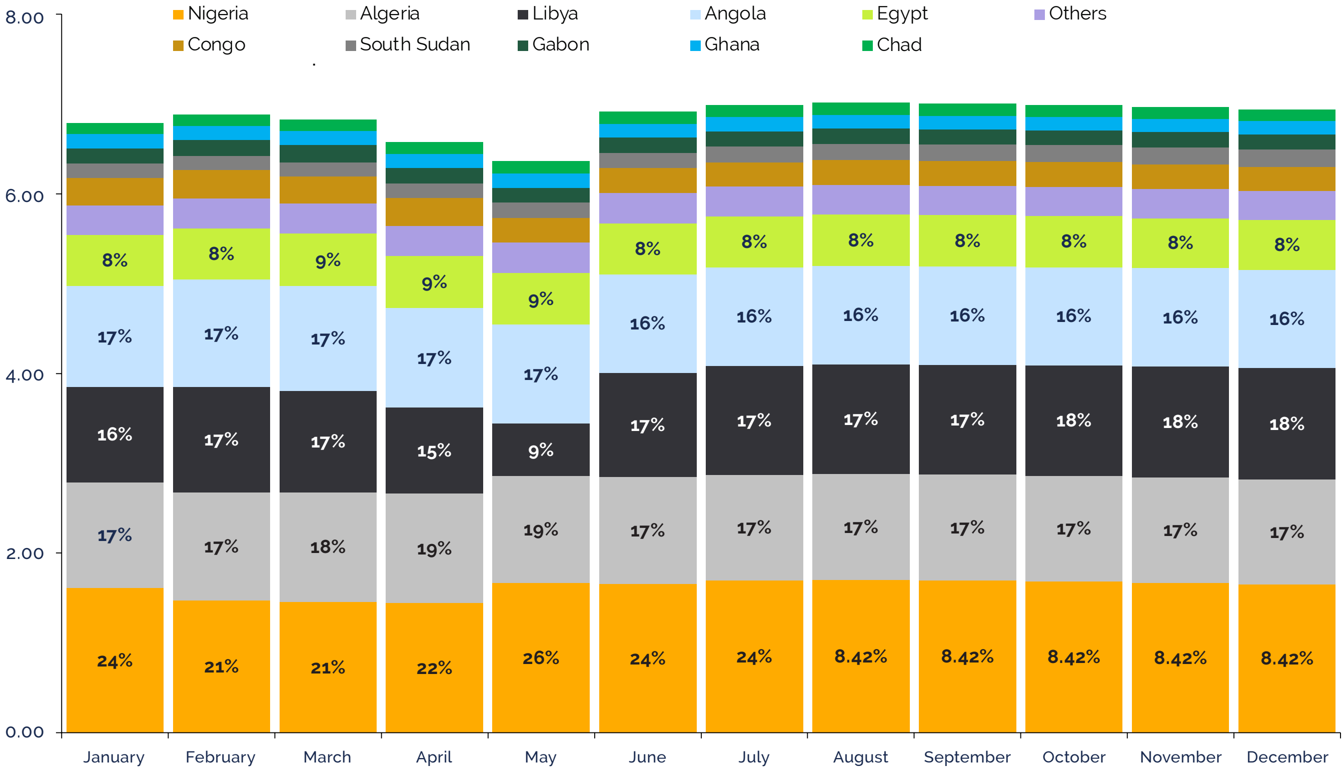
Nigeria, Algeria, Libya, Angola and Egypt are expected to be the top oil + condensates producers for the year 2022 in Africa

2022 crude oil and condensates production estimated at about 6.85 million bbls/d (90% crude oil), a drop from Q1 forecast of just over 7 million bbls/d (90% crude oil), mainly driven by downward revisions in Libya due to production outages

Africa 2022 crude oil and condensates production is estimated at about 6.85 million bbls/d (90% crude oil). While the Q1 forecast was just over 7 million bbls/d (90% crude oil), downward revisions in Libya driven by production outages have led to drop in annual forecast for the entire continent. Nigeria, Algeria and a few other sub-Saharan African (SSA) countries are expected to see increase in their crude oil output from 2021 to 2022 but this is being offset by the drop in production mainly in Libya, Angola and Congo. As a result, average crude oil output from Africa for the year 2022 is expected to see a marginal increase of about 20,000 barrels per day from 2021 levels of about 6.2 million bbls/d.

Nigeria is expected to lead the list of top producers – Algeria, Libya, Angola and Egypt which together are expected to drive over 80% of the continent's oil + condensate output for the year 2022. Lower output in Q2 has driven the annual production from Nigeria from Q1 estimates of 1.72 million bbls/d to a current forecast of 1.62 million bbls/d. No

Figure 1.5 Drop in Libya Q2 flows resulted in lower volumes through Q2 but production expected to be stable going forward in 2022 (Million barrels per day)



Source: Rystad Energy Oil Markets Cube

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. 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.

Algeria, Egypt and Angola round off the top 5 outside of Nigeria and Libya in terms of crude oil + condensates output from Africa in 2022. While Egypt and Algeria have been in a state of marginal year-on-year decline since about 2015, Angola has been in a steep decline losing about 10% of the previous year's output in the past five years. However, the cumulative sum of the three coutries is expected to see a marginal increase from 2021, thanks to increase of output from the legacy fields in Algeria. 2022 crude oil + condensates output from Algeria, Angola and Egypt is estimated at 1.19 million bbls/d, 1.11 million bbls/d and 570,000 barrels per day respectively.

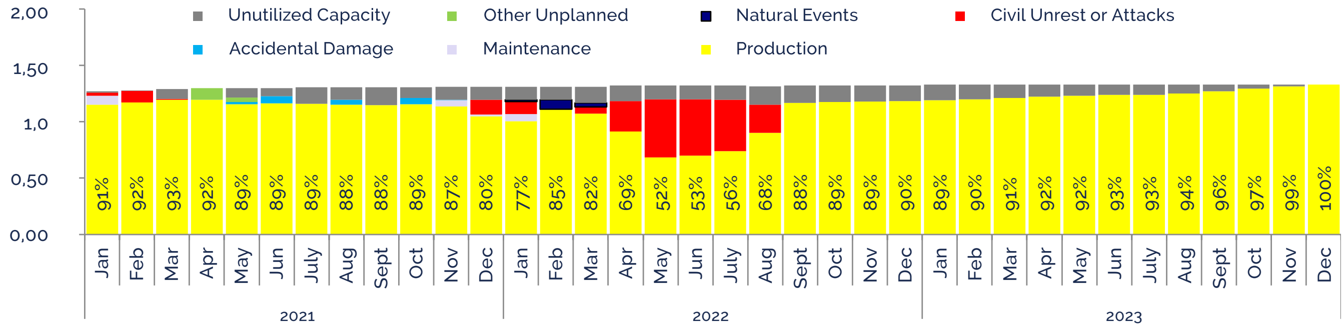
1.6 With continuous outages, what does the future hold for Libya?

After relatively stable and peaceful 2021, Libya's crude oil production in 2022 started on a bumpy road. With the presidential election, due to be held last December, now delayed to June and the continued existence of two parallel governments, the situation in Libya remains strained due to the lack of a single decision-making body. This instability has in the past led to numerous production halts and the current scenario is no different. Since the start of this year, there has been a wave of port closures and production halts.

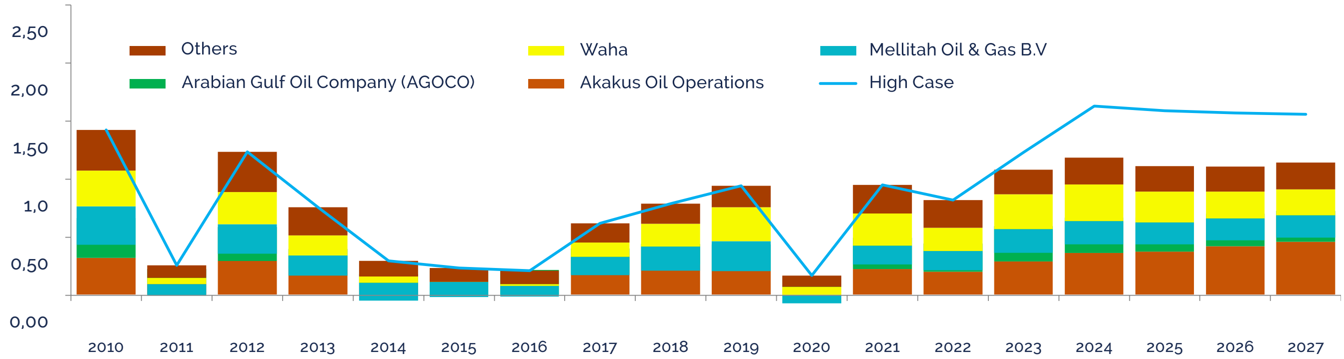
The Petroleum Facility Guards (PFG) taking over El Sharara and El Feel oil fields in western Libya towards the end of Dec-21, shutting down 350,000 – 380,000 barrels per day till the 10th Jan-22. Oil production took another hit when Waha Oil had to shut down 150,000 – 200,000 barrels per day for a week in early Jan-22 for pipeline maintenance. On 3rd February, six Libyan ports had halted the exports of crude and refined products because of adverse weather conditions leading to an outage of 90,000 barrels per day. Before they could revive from this outage, another round of outages followed owing to valve closures. Crude production was stopped from the country's biggest oil fiels, El Sharara and El Feel, from 3rd march to 8th march due to civil unrest leading to an average outage of around 100,000 barrels per day for the month of March. Everything was functioning well till mid April, when another round of closures began where in numerous ports along with El Sharara and El Feel fields, were shut again on 17th

Figure 1.6 With continuous outages, what does the future hold for Libya?

Libya oil operating at 75% capacity through 2022 (Million bpd)



Libya production in high case scenario to exceed base case scenario by 500,000kbd in 2025



Source: Rystad Energy UCube, Rystad Energy Oil Markets Cube, Rystad Energy Research and Analysis

April as a part of protest demanding transparency in the distribution of oil revenues and the ousting of current interim prime minister Abdul Hamid Dbiebah leading to force majeures and there is no clarity as of now whether the production from fields has resumed or is still halted. There was an outage of whopping 290,000 barrels per day for the month of April. Again on 17th May, Clashes erupted as Fathi Bashagha tried to take control of the government from the rival administration of Abdel Hamid Dbeibeh, making the situation even worse. With such continuous instances of production halts, it will be difficult for Libya to meet its ambition of achieving 2 million bbls/d of oil production in the next two years.

The country has a capacity of 1.2 million bbls/d and has designs on hitting 2 million bbls/d by 2024, while interim Prime Minister Abdul Hamid Dbeibah recently announced plans to reach 1.4 million bbls/d by the end of this year and a staggering 3 million bbls/d by 2024. However, these targets seem too ambitious. With such repeated instances of civil unrest and the lack of a decision-making body, the base case scenario estimates the 2022 oil production to be around 985,000 bbls/d which could gradually raise to around 1.25 million bbls/d by 2023, provided no major outage takes place. However, if elections take place and political stability prevails, then in our high case scenario, Libya can even reach 1.8 million bbls/d by 2024, still shy of its 2 million bbls/d target.

2 GAS MARKETS OUTLOOK **AND SUPPLY**

The uncertainty over Russian supplies and sanctions on energy exports are expected to result in higher European LNG spot prices of over US$30/ MMBtu as the expectation is that Europe will import large volumes of LNG

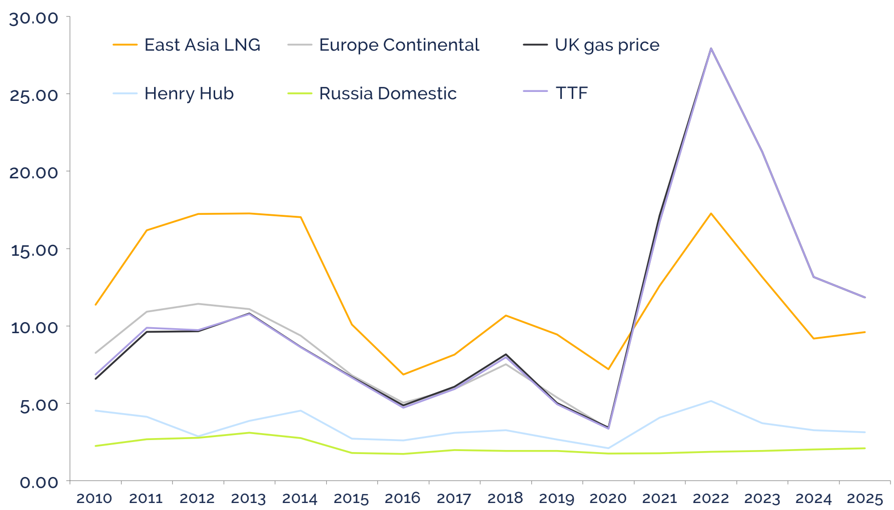
Exit of operators from Russia is expected to result in a revised development timeline for multiple projects in Russia, leading to a drop of cumulative output of 1435 Bcm over the years 2022 – 2030

The sanctions and production drop are also expected to result in a global LNG demand – supply gap of about 120 million tpa by 2030

2.1 Gas prices in Russian gas dependent regions impacted by Russia – Ukraine conflict

With the uncertainty over Russian supplies and sanctions on energy exports, the expectation is that Europe will continue to import large volumes of LNG. This requires European buyers to pay a premium over Asian buyers to ensure that spot cargoes continue to arrive at European terminals, keeping prices at their current high level. The Japan-Korea Marker (JKM) forward curve is at a slight discount to European prices, making Europe the most attractive market for spot cargoes for the remainder of the year. TTF prices for the northern summer are trading at more than $30/ MMBtu. Asian countries are turning to coal in order to limit their use of gas (and avoid paying such high prices), especially in the power sector. The need to replenish underground stock levels in Europe has added support for the summer price as operators are obliged to inject regardless of the price. There is a strong upside risk for winter prices as they are currently trading below the summer contracts and operators need a premium in order to recover the price of the gas and their operational costs. In summary, the summer-winter spread needs to widen. The forward curve for both markets remains in steep backwardation for 2023 as there is less risk priced in. It is likely that European buyers will continue to take volumes from their long-term contracts with Gazprom, unless the European Commission imposes sanctions on energy exports which looks unlikely for now. Russia has continued to threaten that payments for gas will have to be made in rubles, but we also see this as being difficult to achieve. Contracts normally state the currency which must be used for the transaction and this is normally in US dollars or euros. If the Russian government insists on implementing this measure, there will likely be a strong price response as this would further complicate gas deliveries to Europe.

Figure 2.1 Gas prices in Russian gas dependent regions impacted by Russia – Ukraine conflict
USD/kcf



Source: Rystad Energy UCube

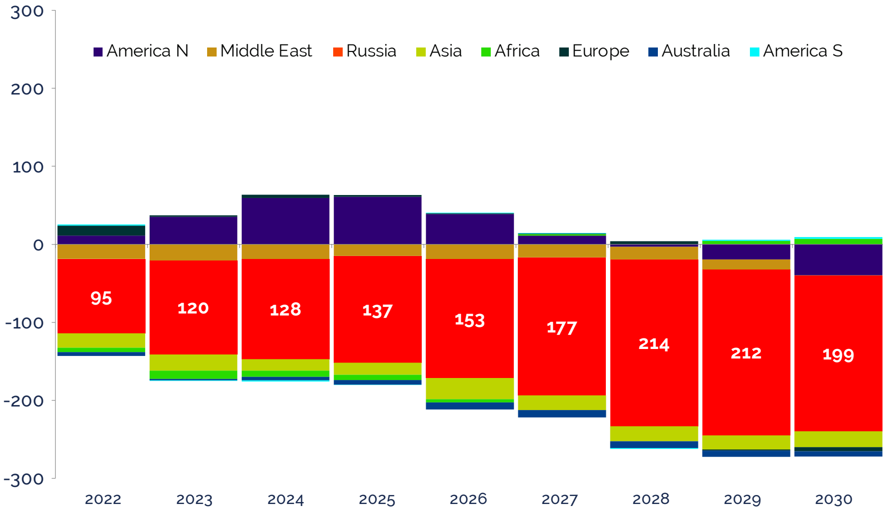
2.2 The Russian – Ukraine conflict destroyed the Russian gas supply forecast as operators exit

The ongoing conflict in Ukraine has sent shockwaves through the global energy industry, with the European Union (EU) bloc and other nations on the continent announcing that they would look for alternative sources of gas supplies and cut down their dependence on Russian imports. A series of exits from many upstream companies including majors followed in reporнse to the Russian aggression in Ukarine. This has resulted, in the long term, a revised development timeline for multiple projects in Russia. And this, in turn, is expected to result in a cumulative drop in overall global natural gas supply compared to the pre Russia – Ukraine conflict forecast. The main obvious reason behind this is the exit of operators owning stakes in many natural gas projects in the country.

A comparison between the pre-war year-on-year production and the current situation suggests that the estimated annual natural gas production for 2022 from Russia was expected to be about 745 Bcm before the invasion, while the latest supply estimates are close to 650 Bcm, showing a drop of 95 Bcm for the year 2022. A similar comparison for the year 2023 suggests the pre-war Russian natural gas production estimate was 770 Bcm while the latest situation reflects in a 2023 production estimate of 650 Bcm, hence a production loss of 120 Bcm. Ths production drop has an obvious impact on the global natural gas output as well. While pre-war estimates put the global natural gas supply for the year 2022 at about 4,146 Bcm, the current estimates in a post Russia – Ukraine war era put 2022 output at about 4,029 Bcm. 2023 comparison is about 4,250 Bcm (pre-war) versus 4,113 Bcm (current post-war) and 2022 – 2030 cumulative flows comparison suggests 40,764 Bcm (pre-war) versus close to 39,113 Bcm (current post-war).

While 2022 global natural gas output is expected to decline by about 115 Bcm compared to the pre-war estimates, largely driven by 95 Bcm (~85%) by the drop in Russian output, the long term impact is much larger. Compared to a pre-war estimate, the cumulative Russian natural gas output through the period 2022 – 2030 is expected to see a drop of about 1435 billion cubic metres (Bcm).

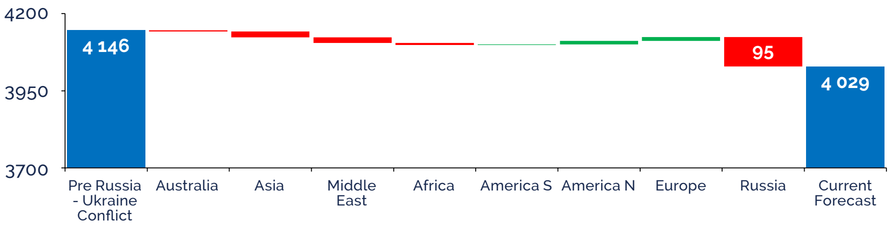
Figure 2.2.1 Difference between pre Russia – Ukraine conflict annual continent level natural gas flows and the latest forecast (Bcm)



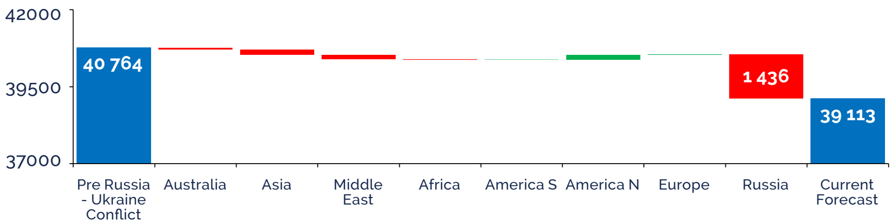
Source: Rystad Energy UCube

Figure 2.2.2 Natural gas flows see a drop in forecast compared to the pre-war situation

115 Bcm of global natural gas supply drop for 2022 driven by 95 Bcm drop in Russian flows



2022 – 2030 cumulative global natural gas flows expected to be impacted by close to 1650 Bcm

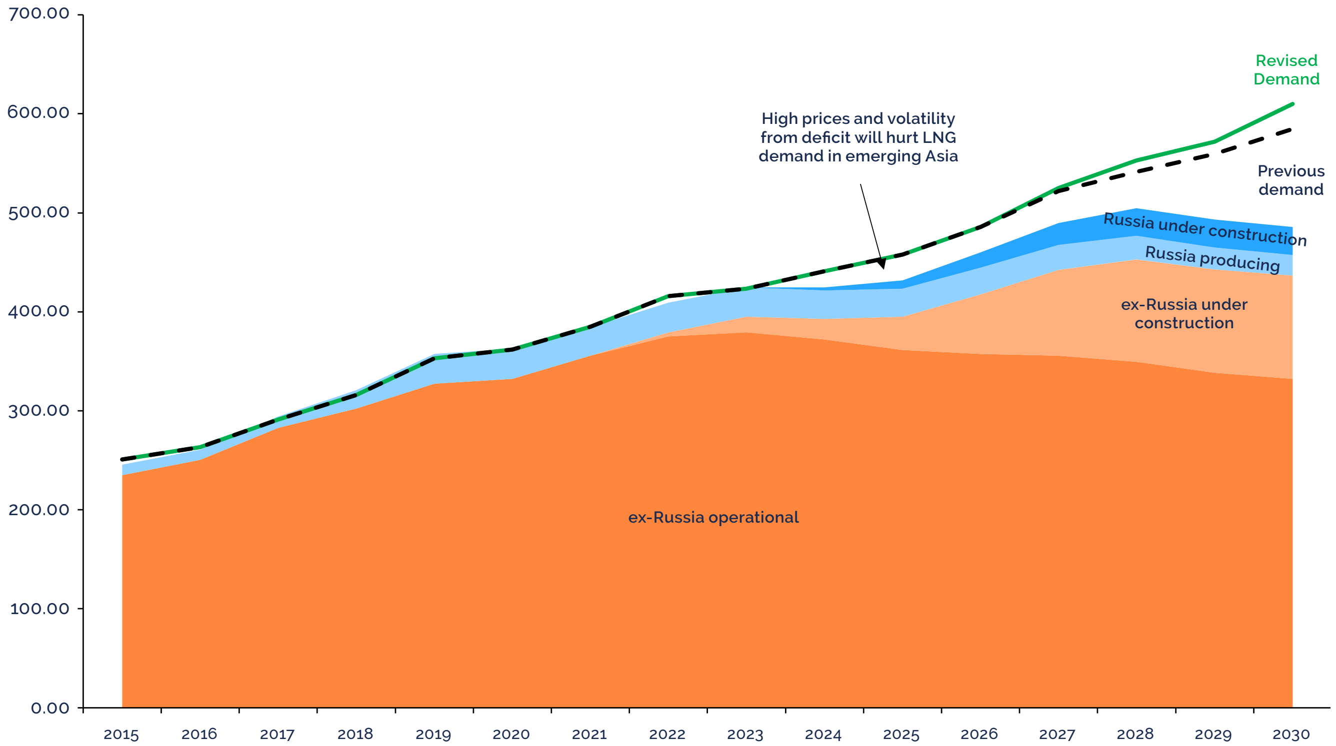


Source: Rystad Energy UCube

2.3 2030 supply gap to widen to over 120 MMtpa, further upside as Russian LNG is at risk

Russia's invasion of Ukraine and Europe's subsequent decision to wean itself off Russian gas dependence has resulted in a tectonic shift in LNG demand expectations: from Asia-centric previously to Europe-centric now. In a scramble to reduce Russian gas imports, Europe will consider multiple levers such as raising domestic gas production, accelerating the rollout of renewables and demand-side responses such as efficiency measures and the installation of heat pumps. However, in any scenario in which those levers are considered, the volume of Russian gas exports (around 140 Bcm in 2021) is so high that only LNG can meaningfully displace this in the medium term while minimizing the impact to the economy. Therefore, LNG demand in Europe is expected to grow from around 70 Million tpa (MMtpa) in 2021 to over 100 MMtpa in 2022, where it is likely to remain through 2030, representing an incremental 20 – 40 MMtpa of demand each year compared to previous forecasts. For the 2022 – 2026 timeframe, when the LNG market is expected to be in deficit , incremental demand in Europe is likely to be met by paring demand growth in Asia, as high prices and volatility from Europe's energy security-based demand may raise affordability concerns in the more price sensitive countries. As a result, this region may depend on coal and fuel oil longer than previously expected, resulting in a delayed energy transition even as Europe's is accelerated. Based on currently producing and sanctioned projects, a likely 120 MMtpa supply gap by 2030 can be expected, which may expand to over 150 MMtpa if the extreme downside risk of losing all Russian production (over 50 MMtpa from four projects) materializes.

Figure 2.3 Global LNG Supply vs Demand (Million tpa)



Source: Rystad Energy Gas Markets Cube

2.4 Majority 2022 – 2025 gas and LNG flows driven by Algeria, Nigeria and Egypt

Figure 2.4.1 Algeria, Egypt and Nigeria expected to account to 80% of the African gas output from 2022 through 2025 (Bcm)

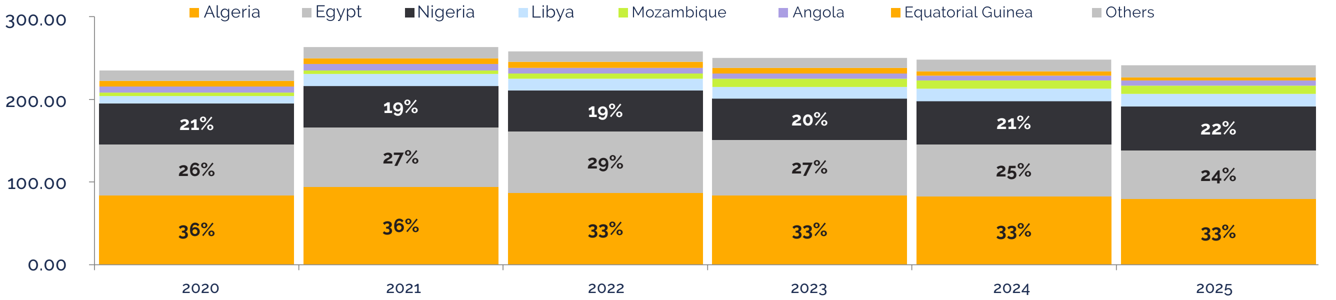
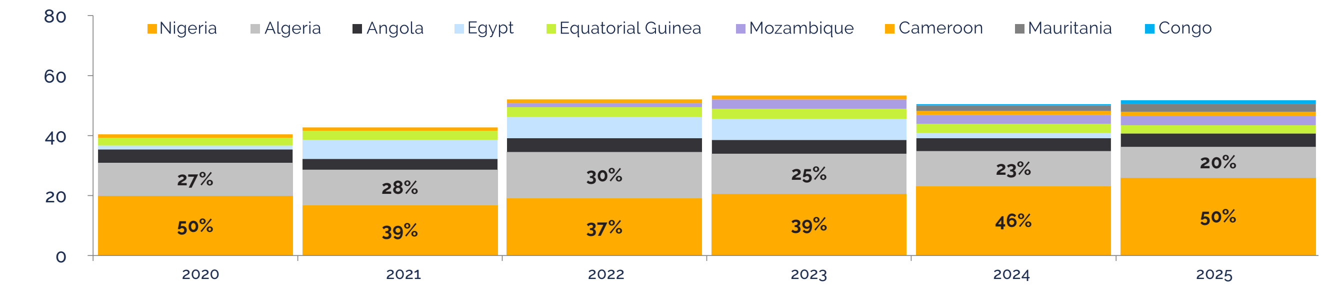


Figure 2.4.2 Over 65% of the African LNG exports from 2022 through 2025 expected from Nigeria and Algeria (Million tpa)



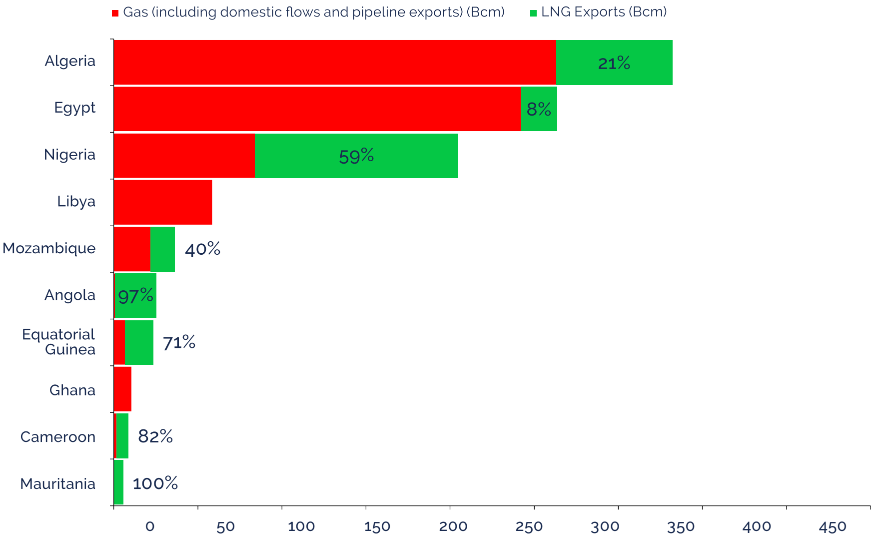
Source: Rystad Energy UCube

- **Algeria, Egypt and Nigeria lead the gas producers in Africa, contributing to over 80% of the output**
- **Over 65% of the LNG exports from Africa come from Nigeria and Algeria together**
- **Majors' exits from Russia can have a positive impact on the African projects operated by these European and American operators**
- **50% of the 2022 – 2025 cumulative gas flows from the top 10 producers in Africa are expected to be exported as LNG to International exports**

Numerous African countries are well positioned to help plug a looming gas supply void in Europe as governments and companies in the latter continent look to scale back their dependence on Russian supplies following the invasion of Ukraine. Africa is conservatively forecast to reach peak gas production at 470 billion cubic meters (Bcm) by the late 2030s, equivalent to about 75% of the expected amount of gas produced by Russia in 2022. 2022 natural gas output from Africa is expected to reach about 260 Bcm. While near term forecast suggests drop in output to about 240 Bcm by 2025, the trend is expected to reverse post 2025, with 2030 natural gas flows expected to reach over 335 Bcm.

Main producers in the near term include Algeria, Nigeria and Egypt accounting for about 80% of the entire continent natural gas production through the years 2022 – 2025. Nigeria and Algeria together are expected to contribute to over 65% of the LNG exports from Africa to international markets. Even with the number of gas projects being developed or currently delayed, Africa still has significant production potential. If oil and gas operators decide to up the ante on their gas projects on the continent, near and mid-term natural gas production from Africa could surpass the above conservative forecasts. Recent signals from oil and gas majors such as BP, Eni, Equinor, Shell, ExxonMobil and Equinor indicate a shift, however, in strategy towards further investment in Africa, with several projects that were previously on ice – including liquefied natural gas (LNG) projects – as they consider restarting or accelerating previously shelved projects in response to rising global demand.
BP chief executive Bernard Looney has said the decision to exit Russia is not only the right thing to do but is also in the company's long-term interests.

Figure 2.4.3 50% of the 2022 – 2025 gas flows from Top 10 African producers to be exported to International markets as LNG



Source: Rystad Energy UCube

The UK giant recently booked pre-tax charges of $24 billion and $1.5 billion in its first-quarter 2022 financial results due to its decision to pull out of Russia. The company is now looking to African projects to seize the opportunity to target European markets with gas supplies. BP has several big gas projects in Senegal and Mauritania – the Greater Tortue Ahmeyim (GTA), Yakaar-Terenga and BirAllah LNG projects. LNG volumes from the 2.5 million tonnes-per-annum (tps) GTA floating LNG (FLNG) Phase 1 have already been sold, and some gas from Yakaar – Teranga Phase I will be used as feedstock for Senegal's gas-to-power plant. Meanwhile, gas from GTA FLNG (Phase 2), the remaining gas from Yakaar–Teranga and BirAllah are still uncontracted and these volumes could benefit from what is expected to be a supply-constrained LNG market in the coming years. GTA FLNG Phase 2 has a planned capacity of 2.5 million tpa, while the Yakaar–Teranga and BirAllah LNG facilities could have capacity of 10 million tpa. However, front-end engineering and design (FEED) on Yakaar–Teranga, which was kicked off in November 2021, will determine the final capacity for the project, and BP is also currently carrying out studies to see whether to accelerate development of the Bir Allah project targeting sales to Europe. Like BP, other major companies might also look towards their African gas portfolios to address the likely gas supply deficit.

Italian major Eni has said that it can alleviate Europe's dependence on Russian gas to an extent through supply from its African projects, including in Algeria, Egypt, Nigeria, Angola and Congo-Brazzaville. In the past month, Italy, in association with Eni, signed deals to boost gas imports from the North African nations of Algeria and Egypt, and then more recently, two more gas supply agreements with two Sub-Saharan African nations, Congo-Brazzaville and Angola. Other African nations where Eni holds important upstream portfolios on the back of which the Italian authorities could potentially sign gas-related deals include Mozambique, Nigeria, Ghana, Cote d'Ivoire and Libya. Nigeria is currently in the process of ramping up capacity at the Nigeria LNG project from 22 million to 30 million tpa through its Train 7 scheme and debottlenecking, and Eni is a stakeholder in many upstream fields that provide feed gas to the LNG plant as well as in the processing plant.

Equinor, ExxonMobil and Shell, like BP, have significant LNG portfolios in Africa that are yet to be developed, and they can look to these massive gas resources to counter the potential gas supply deficit in the future. ExxonMobil has a 25% stake in Area 4 in Mozambique, with significant potential to add further expansion trains. Mozambique was expected to benefit from the EU's move to classify gas investments as green, even after an Islamist insurgency in the gas-rich Cabo Delgado province had paralyzed planned investments. The current scenario of a potential gas supply crunch could see the country accelerate the development of its gas resources. The US major's pullback from Russia could lead to it finally sanctioning its envisaged Rovuma LNG scheme in Mozambique.

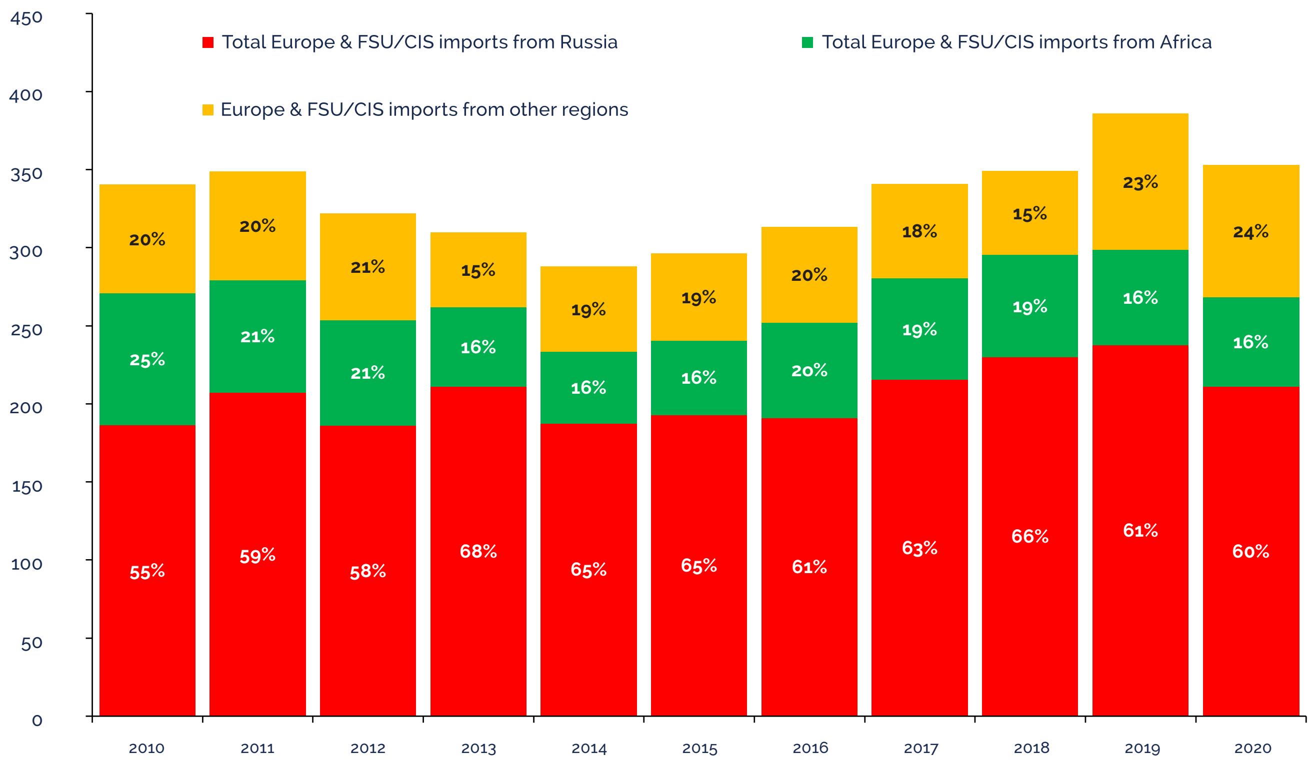
Algeria and Egypt are expected to lead the 2022 natural gas production charts with outut levels of over 86 Bcm and about 75 Bcm respectively. Nigeria' overall 2022 monetised natural gas production, excluding the volumes pumped to the Eleme Petrochemicals Company Limited (EPCL), is estimated at about 50 Bcm. The overall LNG exports from Africa during the year are estimated at about 52 Million tpa with about 19 Bcm coming from Nigeria and Algeria estimated to export 15.5 Million tpa of LNG. The overall 2022 to 2035 split between gas utilized domestically and exported via pipelines vs. gas exported to internation markets as LNG is 50 – 50. Nigeria leads the LNG producers over the years 2022 – 2025 with over 120 Bcm from an overall output of 205 Bcm being exported as LNG. Algeria also is expected to result in a fifth of its gas produced being exported as LNG. In terms of LNG constituting to most of the natural gas produced, Angola, Equatorial Guinea and Cameroon have the highest liquefaction and export percentage of 97%, 71% ad 82% respetively.

2.5 Africa second to only Russia with respect to gas exports to Europe

- **2010 – 2020 European natural gas imports show that Russian gas constituted to an average 62% of the overall cumulative volumes whereas, African volumes were about 18%**
- **Bulk of the Russian exports to Europe were via pipelines whereas, African exports have been a mix of pipeline and LNG exports**
- **Historical gas trade relations and presence of pipeline infrastructure from Northern Africa to Europe places Africa in a good position of increase its exports to Europe**
- **Talks of cross country long distance pipelines have picked up in the recent months, aiming at taking West African gas all the way to Europe**

Russia has historically been the dominant natural gas supplier to Europe. Considering European gas imports in the past decade, Russia is the clear top supplier, driving an average of about 62% of overall gas imports to Europe in that time. Africa, on the other hand, has been a consistent gas exporter to Europe. On average 18% of European gas imports over the last decade have come from Africa. The majority of Russian supplies to Europe are driven by pipeline exports to the likes of Germany, Italy, France and the UK, while numerous other European nations get the bulk of their natural gas supplies from Russia. While Russian supplies are primarily via pipelines, African supplies include a mix of pipeline and LNG exports. Pipeline exports from the continent to Europe are from Algeria and Libya, and LNG exports have predominantly been from Nigeria and Algeria, with smaller volumes from Egypt, Angola and a fraction from Equatorial Guinea. African nations that have his-

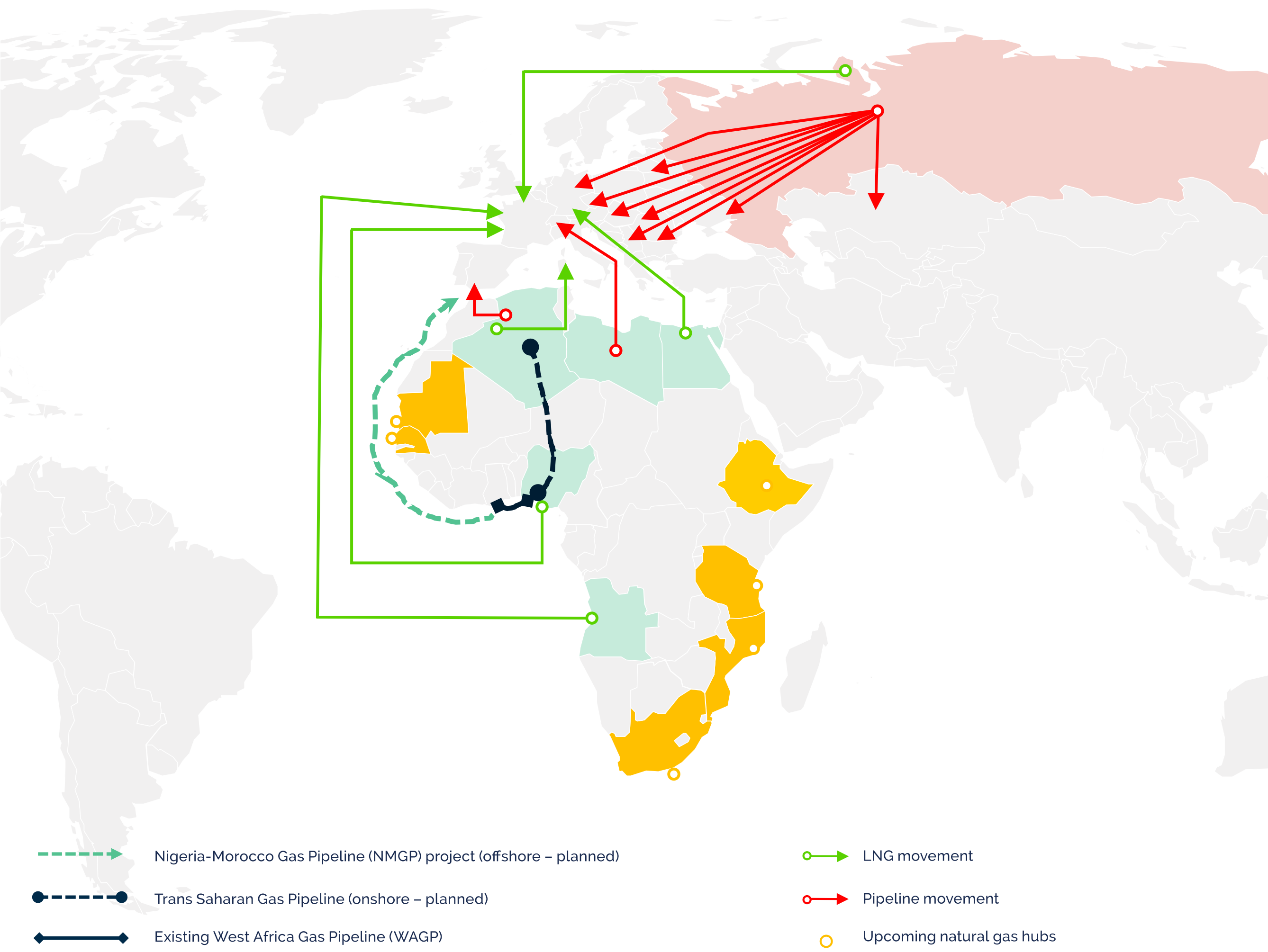
Figure 2.5.1 Africa second to only Russia with respect to gas exports to Europe Billion cubic metres



Source: BP Statistical Review of World Energy 2011–2021 torical been gas suppliers to Europe continue to be well placed to continue their exports. In addition to this, large-scale discoveries offshore the likes of Mozambique, Tanzania, Senegal, Mauritania and South Africa could yield additional natural gas export hubs in the future.

African nations that have historically been gas suppliers to Europe are well placed to scale up their exports. Africa's advantage is that it already has existing pipelines connected with the wider European gas grid. Current pipeline exports from Africa to Europe run through Algeria into Spain and from Libya into Italy. Talks of long-distance pipelines connecting gas fields in Southern Nigeria to Algeria via the onshore Trans Saharan Gas Pipeline (TSGP) and the offshore Nigeria Morocco Gas Pipeline (NMGP) have picked up in recent months. While the TSGP aims to utilize existing pipelines from Algeria to tap into European markets, NMGP aims to extend the existing West Africa Gas Pipeline (WAGP) all the way to Europe via West African coastal nations and Morocco. Further afield, African LNG exports have predominantly come from Nigeria and Algeria, with smaller volumes from Egypt, Angola, and a fraction from Equatorial Guinea. In addition, large-scale discoveries offshore in Mozambique, Tanzania, Senegal, Mauritania, and South Africa have the potential to yield additional natural gas exports once developed.

Figure 2.5.2 Ample trade history, reserve potential and, existing and planned infrastructure put Africa in a good spot to partially cover Europe's dependence on Russia for natural gases



Source: BP Statistical Review of World Energy 2011–2021; Rystad Energy UCube; Rystad Energy research and analysis

3 AFRICA INDUSTRY **OVERVIEW**

While the overall capital expenditure forecast has not seen any major change from the Q1 2022 forecast, the greenfield spending has increased mainly driven by greenfield developments in Mozambique, Uganda and Congo, and NLNG T7 in Nigeria

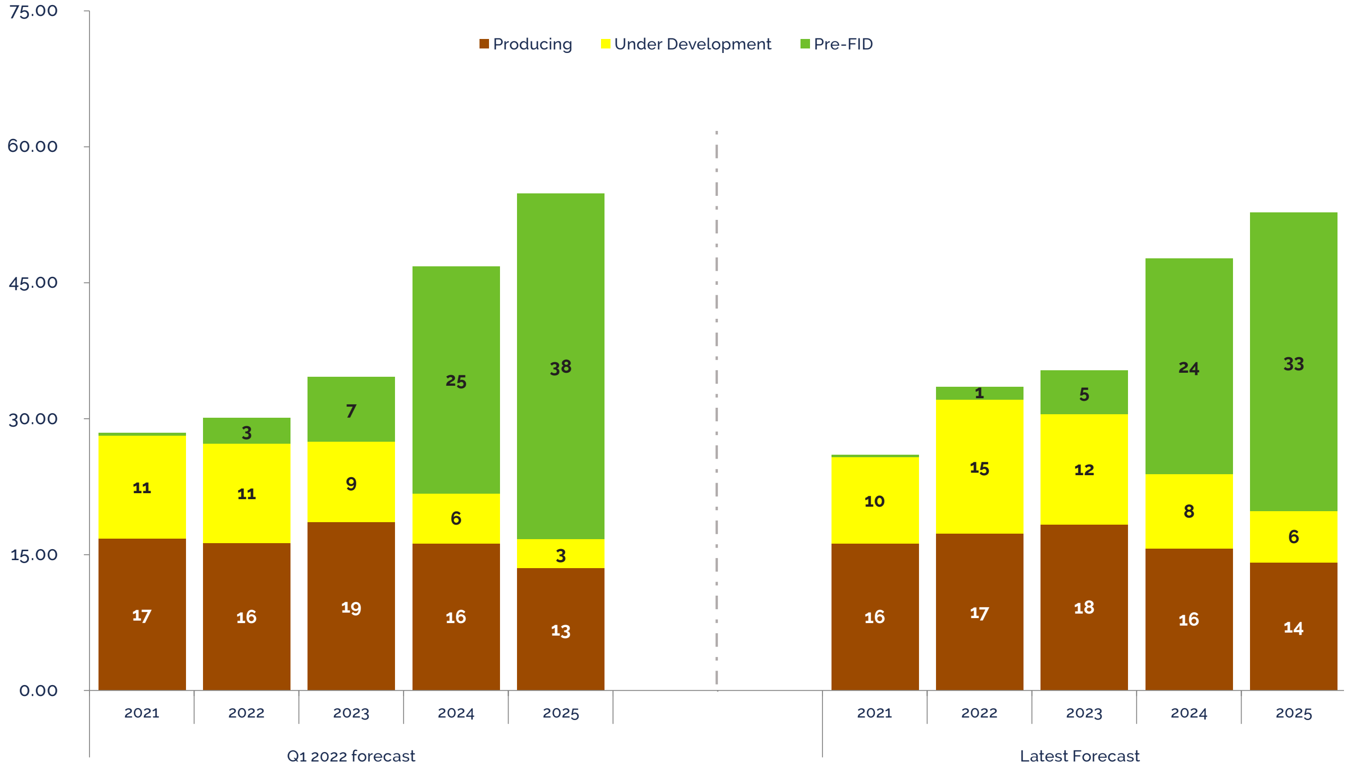
3.1 Business as usual with respect to capital expenditure in the near term in Africa

Marginal changes in capital expenditure outlook have been observed since Q1 2022 as operators in Africa stick to the post pandemic and energy transition focused strategy of significant cuts to their capital spending and operational expenditure. 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, Africa spending levels and trend have hardly seen any changes in the after effects of the Russia – Ukraine conflict.

Figure 3.1.1 Business as usual with respect to capital expenditure in the near term in Africa

Source: Rystad Energy UCube

Figure 3.1.2 Higher greenfield spending expected as more projects get the green light



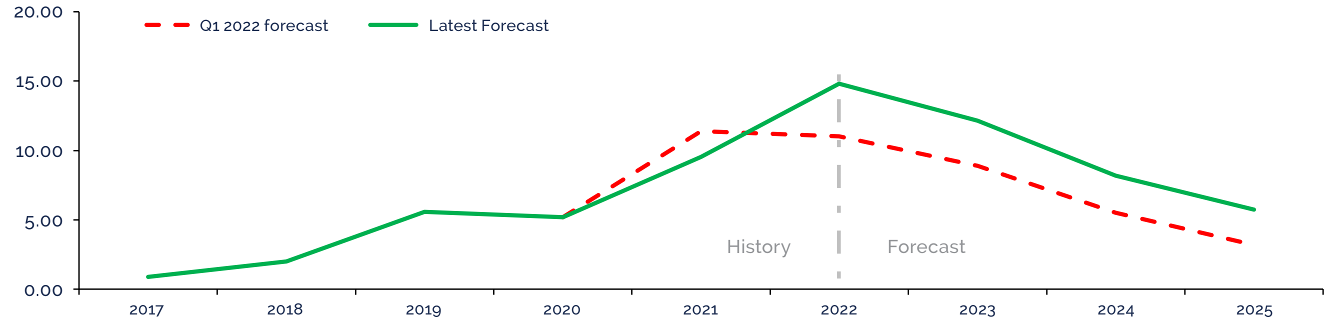
Source: Rystad Energy UCube

While the overall spending levels have not changed by much, one clear change in pattern has been the reduction in brownfield spending and increase in greenfield spending in the near term. As projects like TotalEnergies operated Tilenga and China National Offshore Oil Corporation (CNOOC) operated Kingfisher in Uganda, and Eni's Marine XII Fast LNG and Marine XII LNG offshore Congo had their Final Investment Decision (FID) made in 2022 along with the 2019 FID of Area 1 LNG in Mozambique also operated by TotalEnergies, the greenfield spending over the years 2022 – 2025 is expected to see an increase to over US$40 billion from a much lower Q1 2022 estimate of about US$29 billion.

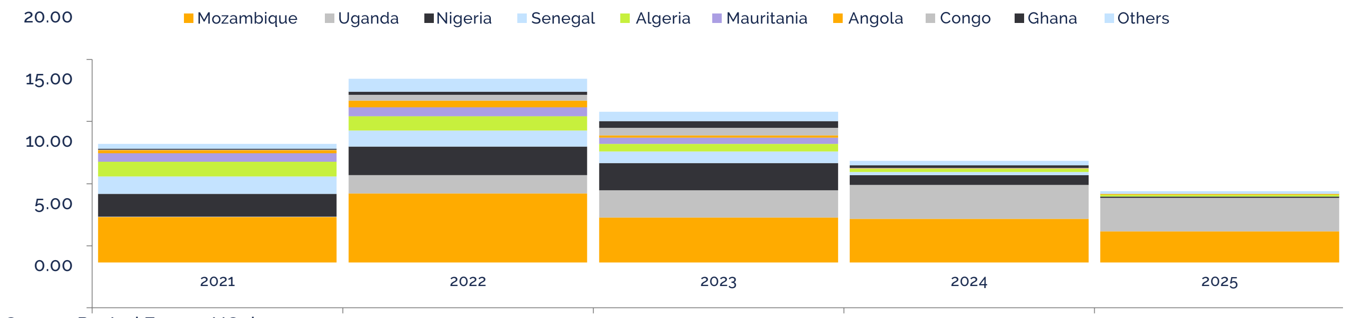
Investments related to onshore projects continue to be the single greatest category with investments reaching over US$70 billion during the 2022 – 2025 period. Big investments are also expected in Uganda and Kenya related to the greenfield onshore development of Lokichar basin. This greenfield development 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.

Figure 3.1.3 Sub-Saharan African greenfield spending drives Africa CAPEX in the near term

Increase in greenfield spending observed compared to Q1 2022 forecast (Billion USD)

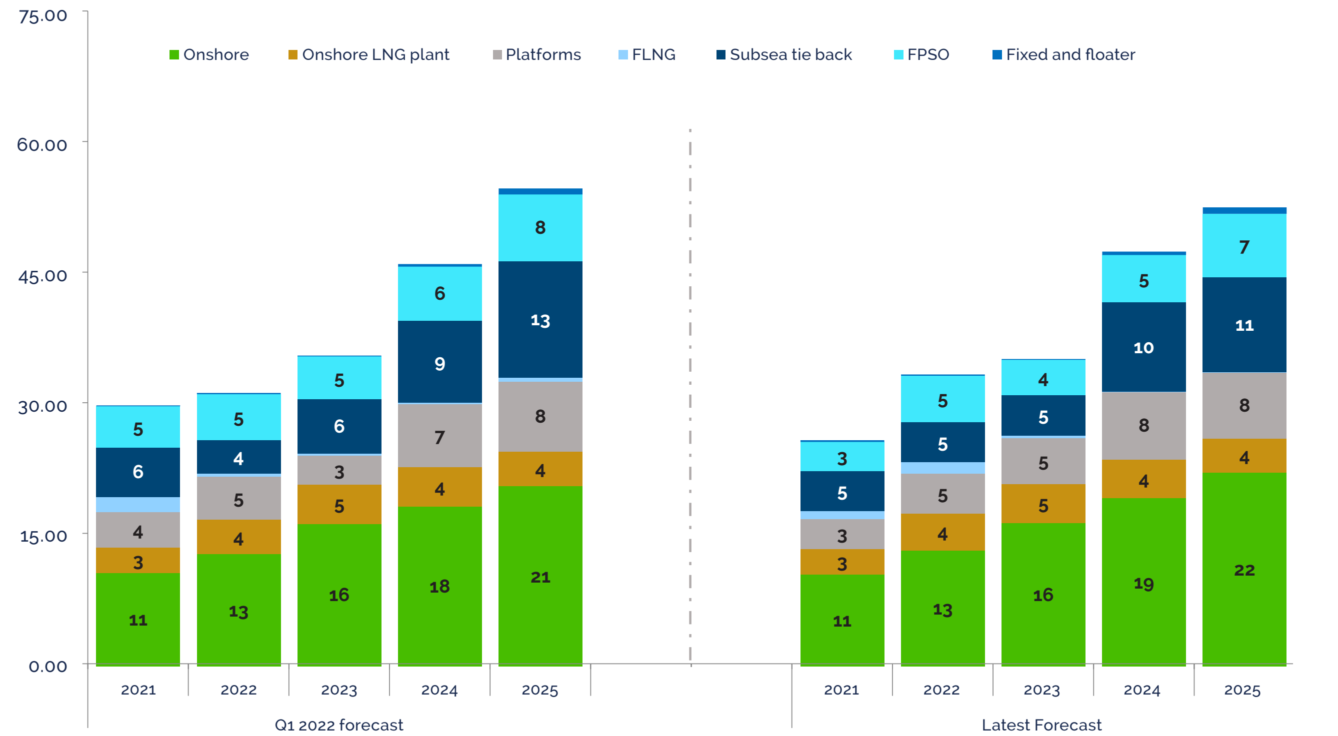


Mozambique and Uganda lead the greenfield spending in the near term (Billion USD)



Source: Rystad Energy UCube

Figure 3.1.4 No major revisions in CAPEX spending on facility type as onshore and offshore facilities share the spoils equally



Source: Rystad Energy UCube

3.2 Top upcoming investment driving Projects

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.

Near term greenfield expenditure to be largely driven by natural gas/LNG projects

PROJECT	Country	Operator	FID*	Start-up*	Resources* (MMboe) ■ Liquids ■ Gas
Area 1 LNG (T1 – T2)	Mozambique	TotalEnergies	2019	2026	3590
NLNG Seven Plus**	Nigeria	NNPC	2019	2024	2500
Area 4 LNG (T1 – T2)	Mozambique	ExxonMobil	2024	2029	2330
Tilenga	Uganda	TotalEnergies	2022	2026 - 2027	1055
Greater Tortue Ahmeyim FLNG Phase 1	Mauritania	BP	2018	2023	920
A&E Structures	Libya	Mellitah Oil & Gas	2023	2025 - 2026	725
Baleine	Cote d'Ivoire	Eni	Phase 1 - 2022 Phase 2 - 2024	Phase 1 - 2023 Phase 2 - 2027	525
Quiluma/ Maboqueiro (Northern Gas Complex)	Angola	Eni	2023	2026	425
Cameia – Golfinho	Angola	TotalEnergies	2023	2027	420
South Lokichar Phase 1	Kenya	Tullow Oil	2023	2026	365
Calub/Hilala (domestic supply)	Ethiopia	Poly GCL	2023	2027	335
Greater Tortue Ahmeyim (GTA) FLNG	Mauritania	BP	2022	2027	320
Marine XII Fast LNG	Congo	Eni	2022	2024	320
Afina	Ghana	Springfield E&P	2024	2027	285
HI – 1	Nigeria	Shell	2023	2027	265

Source: Rystad Energy UCube, *Conservative estimates, **midstream LNG plant

Near term greenfield expenditure to be largely driven by natural gas/LNG projects

PROJECT	Country	Operator	FID*	Start-up*	Resources* (MMboe) ■ Liquids ■ Gas
Fortuna FLNG	Equatorial Guinea	Golar – New Fortress – Kosmos	2024	2028	260
Coral FLNG	Mozambique	Eni	2017	2022	240
Kingfisher South	Uganda	CNOOC	2022	2026	240
Sangomar Phase 1	Senegal	Woodside	2020	2023	230
Agogo FFD	Angola	Eni	2023	2026	210
HA	Nigeria	Shell	2024	2027	190
Marine XII FLNG	Congo	Eni	2022	2024	150
Egina	Nigeria	TotalEnergies	2023	2026	140
Agadem Phase 2	Niger	PetroChina	2021	2024	120
PAJ	Angola	BP	2023	2026	115
Sanha Lean Gas (SLG)	Angola	Chevron	2021	2023	115
Luiperd EPS	South Africa	TotalEnergies	2024	2026	105
ACCE	Angola	TotalEnergies	2023	2027	85
Pecan Phase 1	Ghana	Aker Energy	2023	2026	75

Source: Rystad Energy UCube, *Conservative estimates

4 AFRICA EXPLORATION **OUTLOOK**

Venus and Graff wildcat successes offshore Namibia have resulted in a steep jump in year-on-year discovered volumes in Africa

Recent exploration drilling success offshore West Africa and South Africa are expected to have a positive impact with 13 more high impact wells (HIWs) expected to drilled in the near term

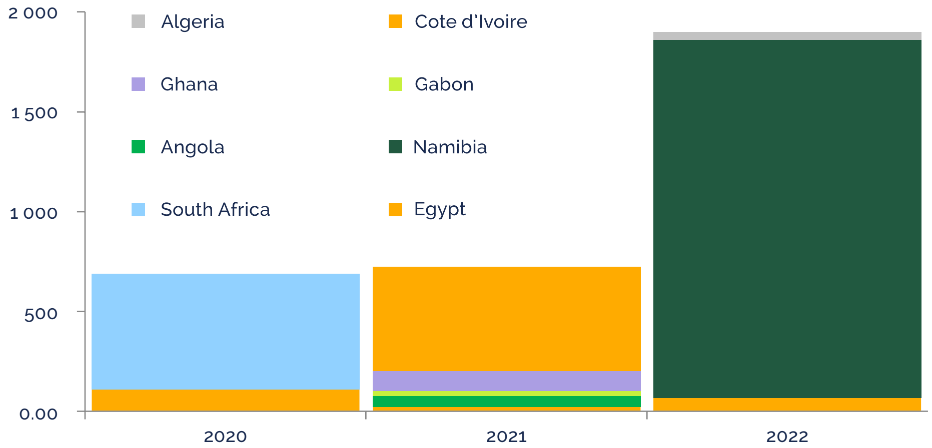
18 exploration licensing rounds offering onshore and offshore acreage across Africa are expected to be closed by the end of 2023

4.1 2022 – A bumper year so far compared to the likes of 2020 and 2021!

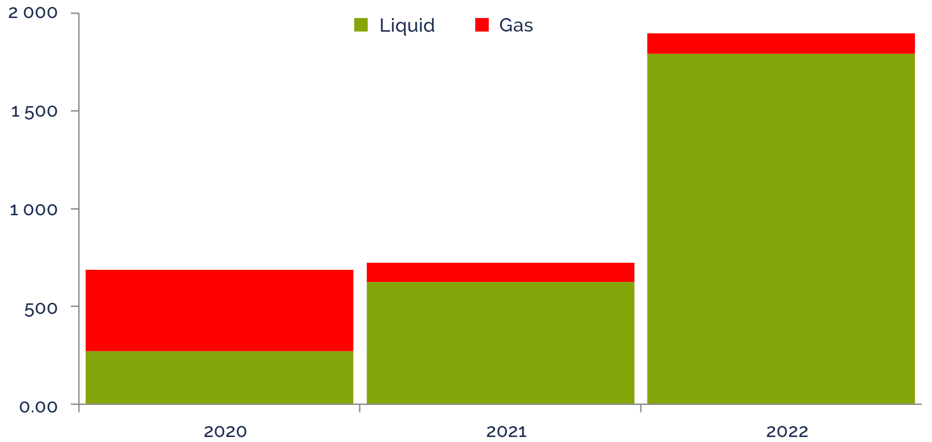
Post pandemic approval and development as well as exploration activity in Africa has been slow but resilient. The years 2020 – 2021 would have been far worse if not for the discoveries offshore Angola and Cote d'Ivoire respectively. However, 2022 began on a far better note with super majors TotalEnergies and Shell encountering huge volumes of hydrocarbons with the successful drilling of Venus and Graff wildcats respectively in the deep waters off Namibia. These discoveries have taken the overall estimated recoverable volumes discovered so far from Africa in 2022 to almost 1.9 billion boe compared to a cumulative 1.4 billion bow over the years 2020 – 2021 . The Namibian discoveries are also encouraging to players holding acreage in the vicinity or offshore Namibia.

Figure 4.1 2022 – A bumper year so far compared to the likes of 2020 and 2021!

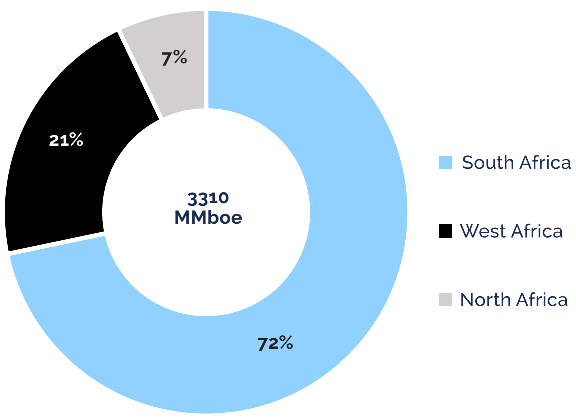
Discovered resources by country (Million boe)



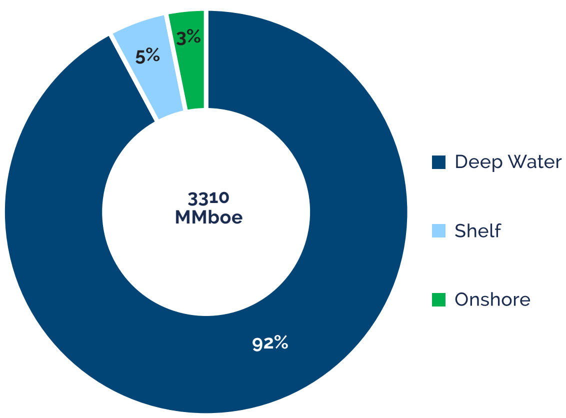
Discovered resources split by hydrocarbon type (Million boe)



2020 – 2022 Discovered resources by region (Million boe)



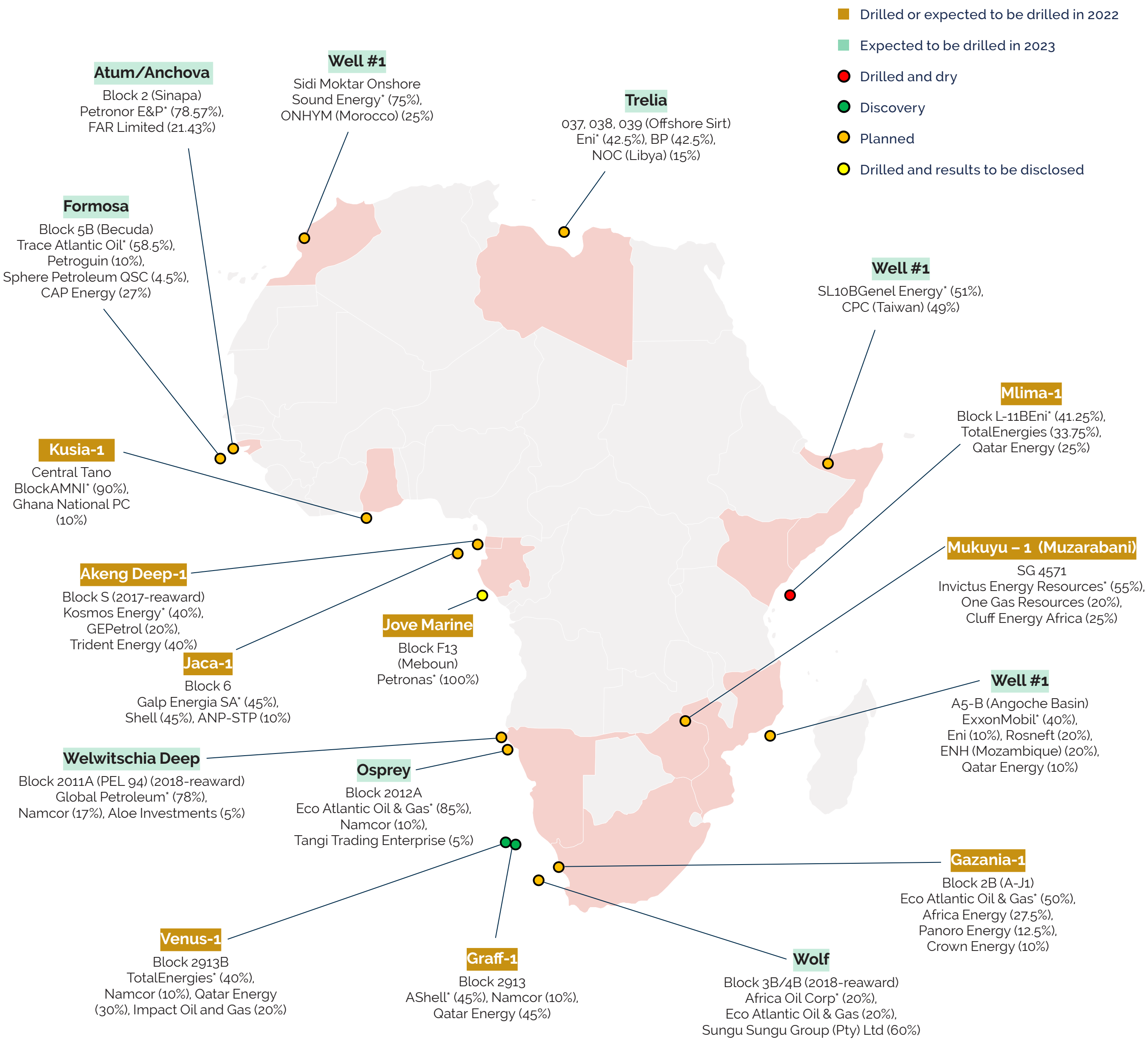
2020 – 2022 Discovered resources by region (Million boe)



Source: Rystad Energy UCube, ECube

4.2 14 more High Impact Wells expected to be drilled in the next 18 months

Figure 4.2 14 more High Impact Wells expected to be drilled in the next 18 months



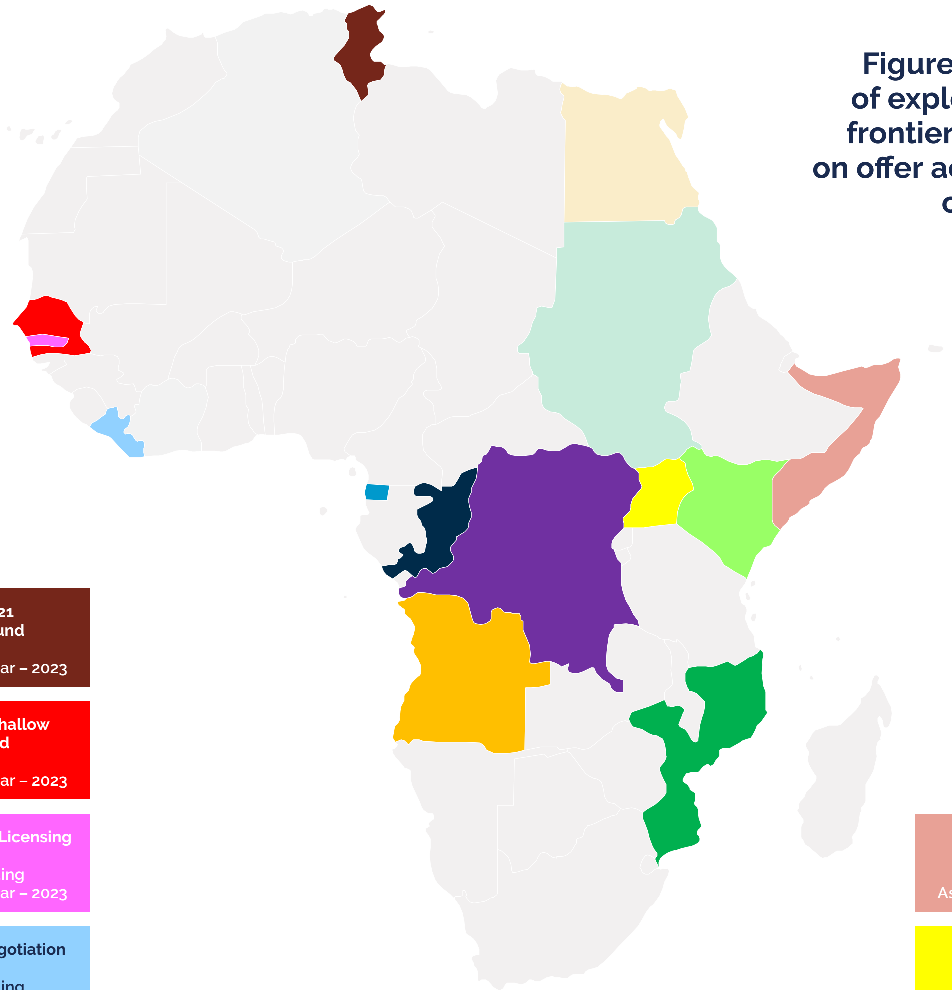
Source: Rystad Energy ECube

Post the successful drilling of Brulpadda and Luiperd offshore South Africa, and the more recent Venus and Graff discoveries offshore Namibia, the region has become a new exploration hub of sorts. 3 more high impact wells (HIWs) – Osprey (Namibia), Gazania and Wolf (South Africa) are expected to be drilled in the coming months. The Mauritania, Senegal, Gambia, Guinea-Bissau and Guinea Conakry (MSGBC) Basin is home to several recent high-profile oil and gas discoveries and this success streak canresult in two more HIWs – Atum/Anchova and Formosa to be drilled in the waters off Guinea-Bissau. On the eastern side of the continent, Invictus Energy has raised US$8.53 million to fund the much-anticipated Mukuyu-1 wildcat. The well is planned to spud in July, targeting a 8.2 trillion cubic feet of gas and about 250 million barrels of condensate prospect. Along with these, 14 such HIWs are expected to be drilled across the continent in the next 18 months.

4.3 Lots of explored and frontier acreage on offer across the continent

A lot of buzz around exploration license awards, planned licensing rounds is currently taking over Africa. Egypt has already announced close of its EGPC and EGAS bidding round with results yet to be announced. Uganda, Egypt and Angola are currently evaluating bids they have received for a total of 15 blocks (11 offshore and 4 onshore) that are up for grabs. Blocks offshore Somalia and Mozambique in the eastern side and both onshore and offshore in Congo, Liberia and Gambia on the western side of the continent are open for bidding currently. Along with these, 7 more rounds are planned and might be opened in the next 18 months giving operators ample opportunities to break into the exploration scene in Africa.

Figure 4.3 Lots of explored and frontier acreage on offer across the continent



Source: Rystad Energy ECube

5 MERGERS AND ACQUISITIONS **ACTIVITY**

Majors BP and Eni come together in Angola to form a joint venture Azule Energy, which is expected to be the largest producer in the country after Sonangol

More M&A activity in Angola as Sonangol divests its stakes in six offshore blocks to a mix of experienced and newcomers in Angola

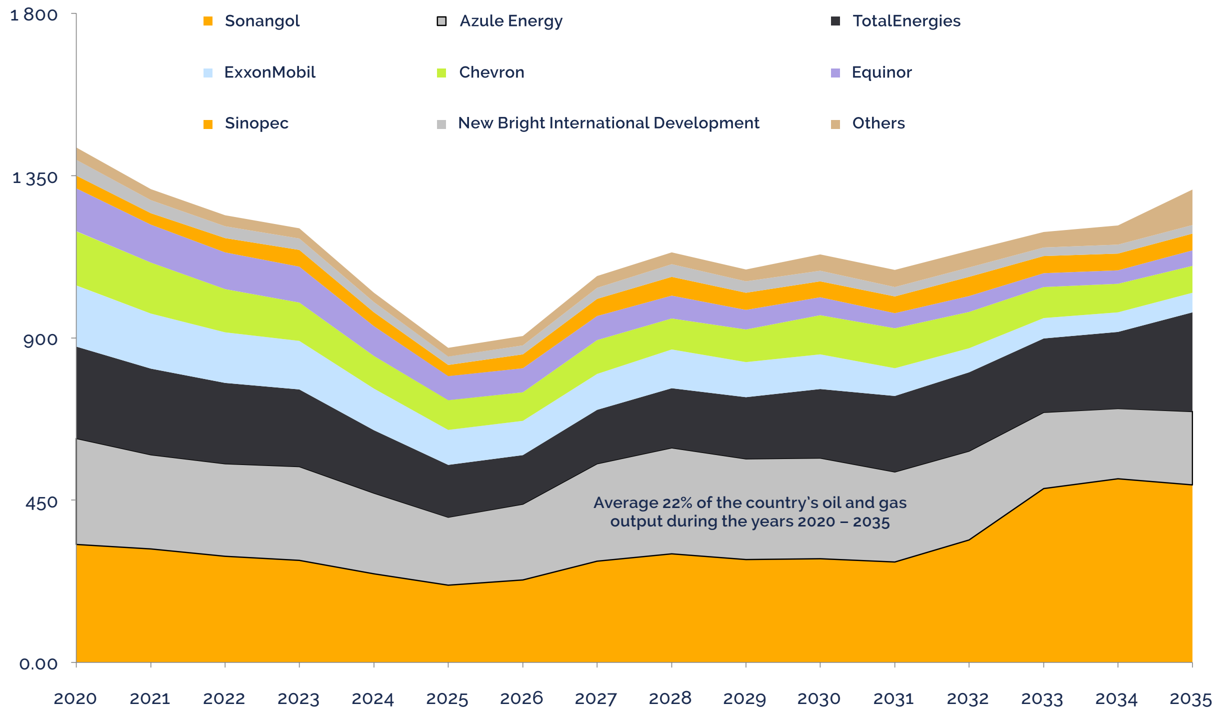
SPDC looking to divest its stakes in 19 onshore oil mining leases (OMLs) where Shell Plc and TotalEnergies are targeting a full exit whereas Eni is reported to have decided to hold on to natural gas interests

5.1 Azule Energy, BP – Eni JV in Angola, expected to be the second largest producer in Angola after the state owned Sonangol

In an attempt to mitigate the declining output in Angola, Eni replicated its Vaar Energi joint venture in Norway with a similar tie-up with BP in Angola. As part of the new joint venture, the assets of both companies in the major West African producer are merged under a new entity named Azule Energy. The combined portfolio is expected to benefit from synergies in nearby blocks to improve cash flows from existing production and cost optimization efforts for newer, smaller developments, also mitigating current production declines in the country. Block 15/06, Block 31 and the Northern Gas Complex will all benefit from the merger, with multiple opportunities that could be exploited through the creation of the joint venture. This new entity is expected to be the second largest producer in Angola, only second to the Angolan NOC, Sonangol.

Eni's operated Block 15/06 will be the largest producing block in the combined portfolio after the merger. Currently Eni owns a 36.84% interest in the block. The block produced an average of 130,000 barrels of oil equivalent per day (boepd) in 2021 and has multiple opportunities in the discovery lifecycle that might see an accelerated development after creation of the new entity. The Western Hub is currently producing from the Mpungi, Vamdumbo, Ochigufu, Sangos and Cinguvu fields. It has the Ndungu and Ngoma discoveries in the pipeline for development to mitigate an anticipated production decline over the next few years. The Eastern Hub has the Agidigbo development in the pipeline and will need an accelerated sanctioning to avoid an expected decline after 2024. In 2021, the Cuica and Cabaca Norte fields started production in the hub as subsea tiebacks. The Agogo full field development is the next significant project set to be sanctioned in the block next year. The field is expected to contain more than 200 million barrels of recoverable oil reserves and will see another leased floating production, storage and offloading (FPSO) unit deployed in the block. The field was discovered in March 2019 and saw an accelerated development, with an early phase starting production in January 2020 with wells tied back to the Western Hub. Multiple other opportunities include the Kalimba cluster with the Kalumba and Afoxe fields discovered in 2018, while older smaller discoveries such as Lira, Olombendu, Nzanza, Mukuvo and Mukupela are also in the block and can be developed as tiebacks to existing hubs to maximize recovery.

Figure 5.1 Azule Energy, BP – Eni JV in Angola, expected to be the second largest producer in Angola after the state owned Sonangol



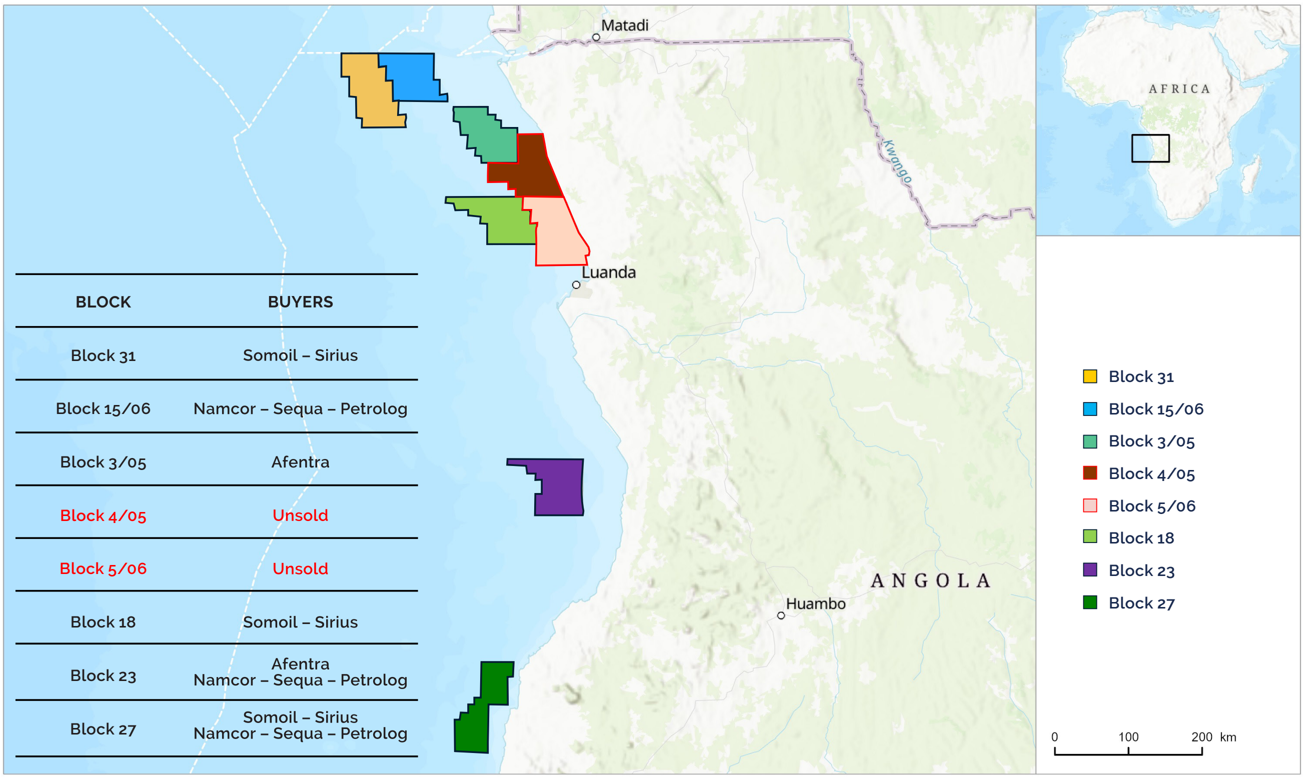
Source: Rystad Energy UCube

BP-operated Block 31 can also be expected to benefit from the merger. BP owns a 26.67% interest in the block. The PVSM project is the key development in the block consisting of four fields – Plutao, Saturno, Marte and Venus. Production has declined significantly in recent years as compared to plateau of 160,000 barrels per day reached in 2014. The PAJ development – consisting of the Palas, Juno and Astraea fields – has seen sanctioning being delayed since 2020. With the merger, these developments could get sanctioned in late 2023 or early 2024, commercializing more than 100 million barrels of oil reserves. Block 31 also contains more than 10 additional opportunities discovered between 2005 and 2009 with a cumulative reserve size of more than 200 million barrels. The merged entity will be able to focus on these smaller discoveries and look to maximize production from the block. BP and Eni also each own a 13.6% stake in Angola LNG Train 1 (T1), which has a capacity of 5.2 million tonnes per annum of liquefied natural gas (LNG). The project currently relies on associated gas production from nearby deepwater fields, which was earlier being flared. In order to sustain LNG volumes in the future, however, new gas developments will need to be sanctioned. Eni (operator) and BP own 25.6% and 11.8% stakes, respectively, in the Northern Gas Complex, which includes the Quiluma and Maboqueiro fields and needs to be developed to continue producing at current levels from Angola LNG. The merger will accelerate the development of this complex and commercialize close to 400 million boe of gas reserves.

The merger in Angola is structured on similar lines as that of Vaar Energi. That joint venture was created between Eni (70%) and HitecVision-backed Point Resources (30%) in 2018 to merge the pair's assets in Norway. The joint venture went on to acquire ExxonMobil's assets in Norway for $4.5 billion and will effectively double its production to 350,000 boepd in the middle of this decade compared to 170,000 boepd at the time of the merger. The Eni – BP joint venture in Angola could seek to acquire similar opportunities in Angola to further build on its portfolio.

5.2 Sonangol runs a successful divestment campaign with stakes in all but 2 blocks sold

Figure 5.1.1 Sonangol runs a successful divestment campaign with stakes in all but 2 blocks sold

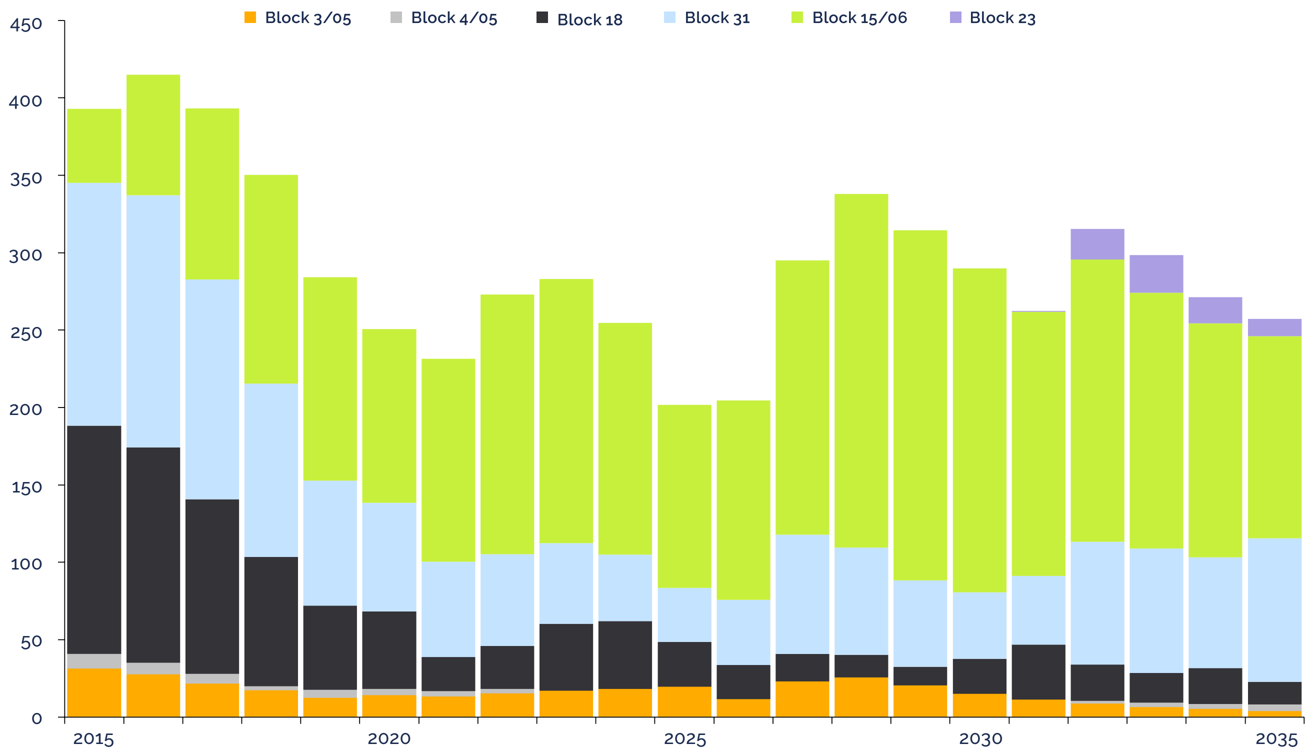


BLOCK	BUYERS
Block 31	Somoil – Sirius
Block 15/06	Namcor – Sequa – Petrolog
Block 3/05	Afentra
Block 4/05	Unsold
Block 5/06	Unsold
Block 18	Somoil – Sirius
Block 23	Afentra Namcor – Sequa – Petrolog
Block 27	Somoil – Sirius Namcor – Sequa – Petrolog

Source: Rystad Energy UCube; Rystad Energy GIS Services; Rystad Energy research & analysis

Sonangol successfully concluded the divestment of its stakes in a number of offshore blocks in Angola. The sale which was targeted at bolstering the state owned company's financial position saw strong interest w ith seven of the eight blocks attracting bids. The list of blocks included Eni-operated Block 15/06, BP-operated blocks 18 and 31, and Sonangol-operated blocks 3/05, 4/05, 5/06, 23 and 27. Stakes of 10%, 8.28% and 10% were on offer in producing blocks 15/06, 18 and 31, respectively. Existing partners in blocks 15/06 and 18 were also eligible to exercise their preferential rights. It was no surprise that the tracts operated by European majors BP and Eni received the majority of offers. Eni's Block 15/06 secured the highest number of bids and was the only tract to garner interest from a large player, Chinese state giant Sinopec. The block holds both producing fields – in the East Hub and West Hub – along with upcoming field startups, including Agogo, which was granted marginal field status that allows tax benefits to the field partners. Block 31 holds the producing PSVM (Plutao–Saturno–Venus–Marte) floating production, storage and offloading (FPSO) vessel. This block also holds the PAJ (Palas–Astraea–Juno) FPSO and this project was also granted marginal field status similar to Agogo. Undeveloped discoveries, meanwhile, offer additional potential.

Figure 5.1.2 Blocks 15/06 and 31 most prolific in terms of oil production
Thousand barrels per day



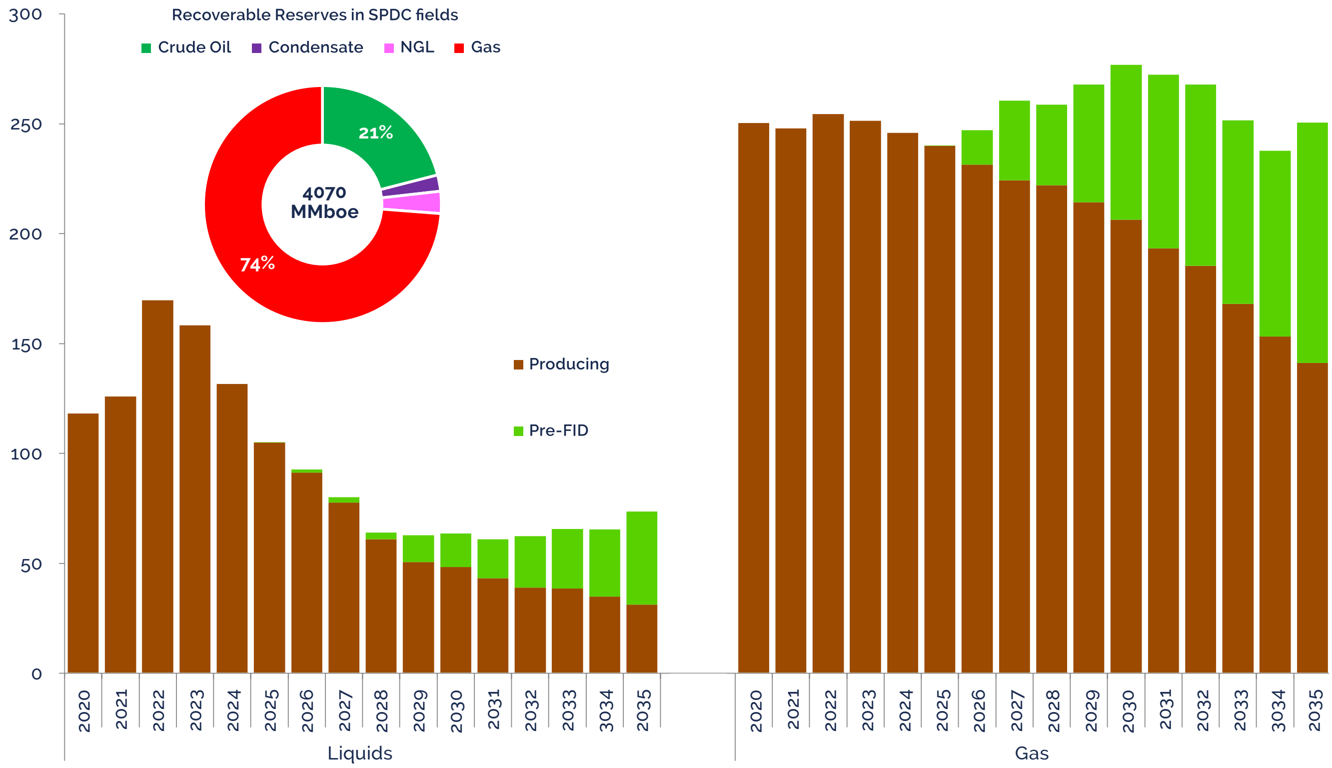
Source: Rystad Energy UCube

While the majors elected to stay away, Sonangol received a total of 35 bids from 19 companies, comprising a mix of players with experience and ones looking to make a maiden splash in Angola's oil and gas sector. Bidders included Namibia's state oil company Namcor, China's Sinopec, Cote d'Ivoire-based Tyr Conseil, Nigerian outfit Equinox, as well as investment banks and financial advisers including Sancorp and Arctic Securities. Canada's MTI Energy and Somoil, both of which were recently awarded blocks in the Agency for Petroleum, Gas & Biofuels (ANPG) onshore licensing round, also bid for stakes in these offshore blocks.

The Namibian NOC Namcor, London-based Sequa Petroleu and local player Petrolog joint venture took the 10% stake in Block 15/06, 40% stake in Block 23 and also a 35% stake in Block 27. The Somoil – Sirius consortium won the 8.5% and 10% stakes in BP-operated blocks 18 and 31, respectively. The consortium also secured a 25% stake in Block 27. Afentra secured a 20% stake in producing shallow water Block 3/05 and also a 40% interest in Block 23. Two blocks in the Congo basin — 4/05 and 6/05 — were not awarded.

5.3 With over 4 billion boe of reserve potential and capacity to maintain output at over 300,000 boepd through to 2035, SPDC portfolio is very significant to Africa

Figure 5.3.1 With over 4 billion boe of reserve potential and capacity to maintain output at over 300,000 boepd through to 2035, SPDC portfolio is very significant to Africa

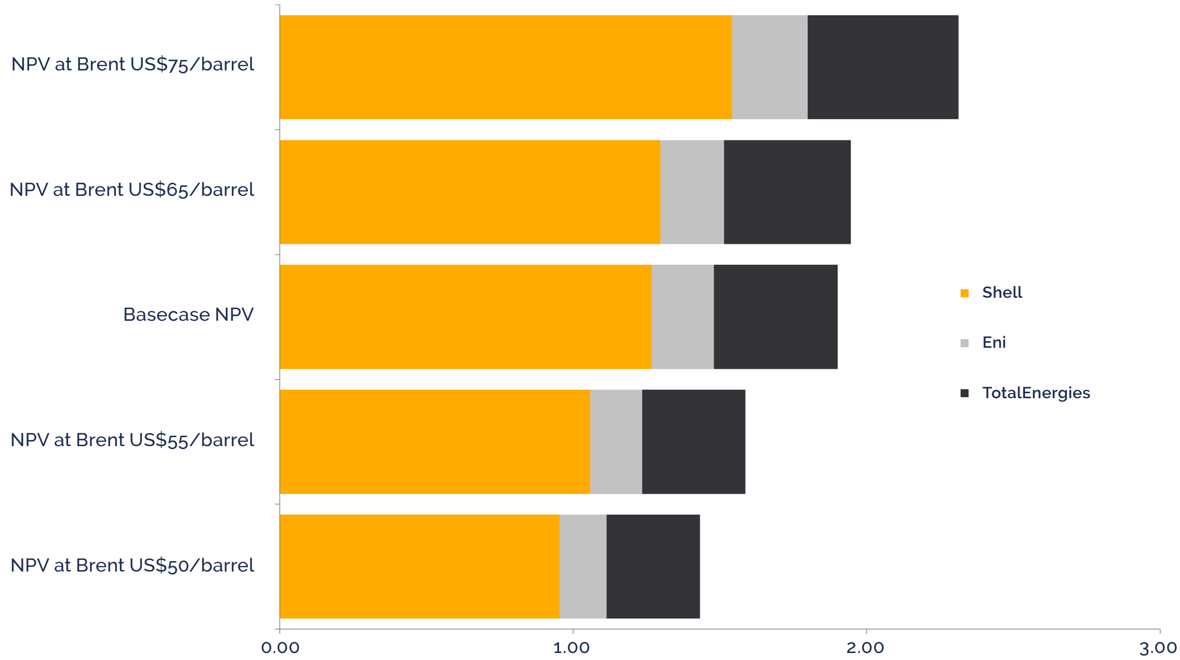


Source: Rystad Energy UCube

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. In partnership with the country NOCs, majors have played an active part in shaping the hydrocarbon production profile of the continent. One such partnership is the longstanding Nigerian joint venture of Shell Petroleum Development Company (SPDC) and Nigerian National Petroleum Corporation (NNPC). The partners of SPDC – Shell Plc, TotalEnergies and Eni held 30%, 10% and 5% stakes respectively in blocks where they were present as this JV, with NNPC holding the remaining 55%. While the JV has been largely responsible for the majority of production in the country, many onshore blocks with large potential are yet to be developed. While government delays in implementing fiscal reforms, the operators' focus on other regions and supply segments, dynamic oil and gas markets have been a few reasons for delays in development in other cases, SPDC's non-development of these onshore blocks can be attributed to heavy production losses due to pipeline sabotages and eventual environment related legal wrangles.

The 19 onshore/swamp blocks that SPDC has put up for sale are expected to hold a cumulative recoverable reserves of over 4 billion barrels of oil equivalent (boe) (74% gas and 26% liquids). The peak cumulative production capacity is in excess of 300,000 boepd. It is to be noted these high volumes of undeveloped reserves demand high greenfield investments. Shell Plc and TotalEnergies are reported to have put up all their stakes in all thes blocks for sale , while Eni is reported to hold back on its natural gas interests and do away with the oil blocks. 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. 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 (OMLs).

Figure 5.3.2 SPDC portfolio can fetch over an estimated US$2 billion at a conservative level



Source: Rystad Energy UCube

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 UPCOMING OIL AND GAS ECONOMIES OF AFRICA

Congo – Brazzaville takes both Fast LNG and LNG route to monetize its excess natural gas output after catering to the domestic gas-fired power plants

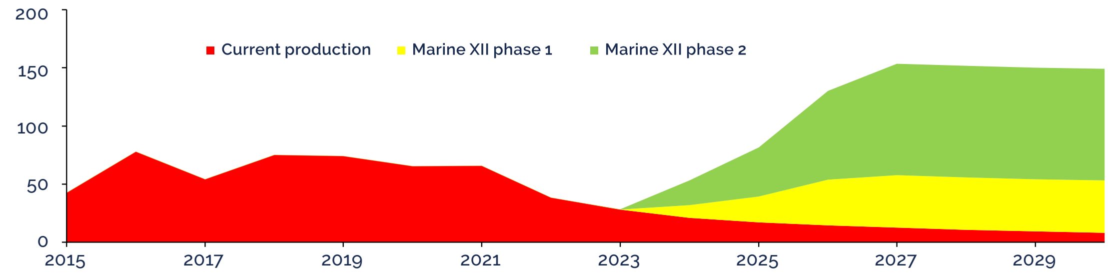
Cote d'Ivoire and Namibia break into the African E&P scene in a big way with giant offshore discoveries looking at multi billion dollar greenfield investments

6.1 Congo-Brazzaville closes in on gas export dream as Eni lines up LNG project

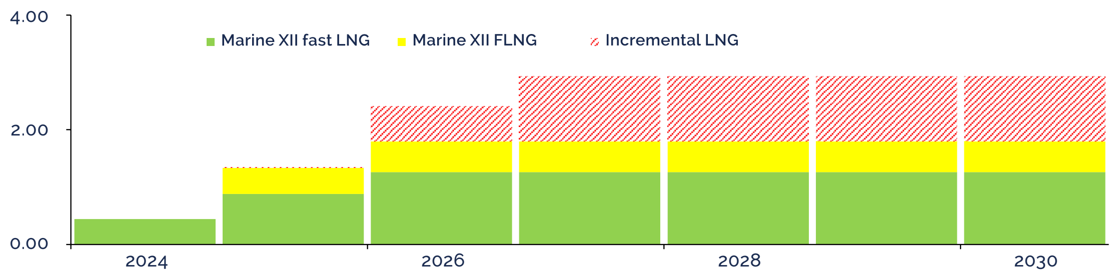
Congo-Brazzaville is on the cusp of realizing long-held gas export ambitions as Eni looks to fast-track a liquefied natural gas (LNG) project. Eni's upcoming LNG development is going to be little over 3 million tpa increased from the initial 2 million tpa capacity. The initial plan comprised of a 0.6 million tpa FLNG expected to start next year followed by a 1.4 million tpa jack-up based LNG facility expected to start a year later. Although Congo-Brazzaville has significant gas resources, it does not export any gas at present, primarily because of the lack of infrastructure in the country. Available gas production is already more than sufficient for domestic gas-fired power plants, leaving the country with no choice but to inject or flare the excess gas. However, the successful LNG developments will not only be tapping the already stored gas associated gas, but it will also be minimizing the gas flaring from Marine XII to zero. Italy recently clinched a deal to boost its gas imports from the Republic of Congo. The gas is primarily to come from the LNG developments in Marine XII block. The LNG exports will allow the commercialization of gas that exceeds Congo's internal market needs and make the west African nation, that neither imports nor exports gas currently, a net exporter.

Figure 6.1 Congo-Brazzaville closes in on gas export dream as Eni lines up LNG project

Congo gas production forecast (Billion cubic feet)



Expected LNG flows from Marine XII Project (Million tpa)

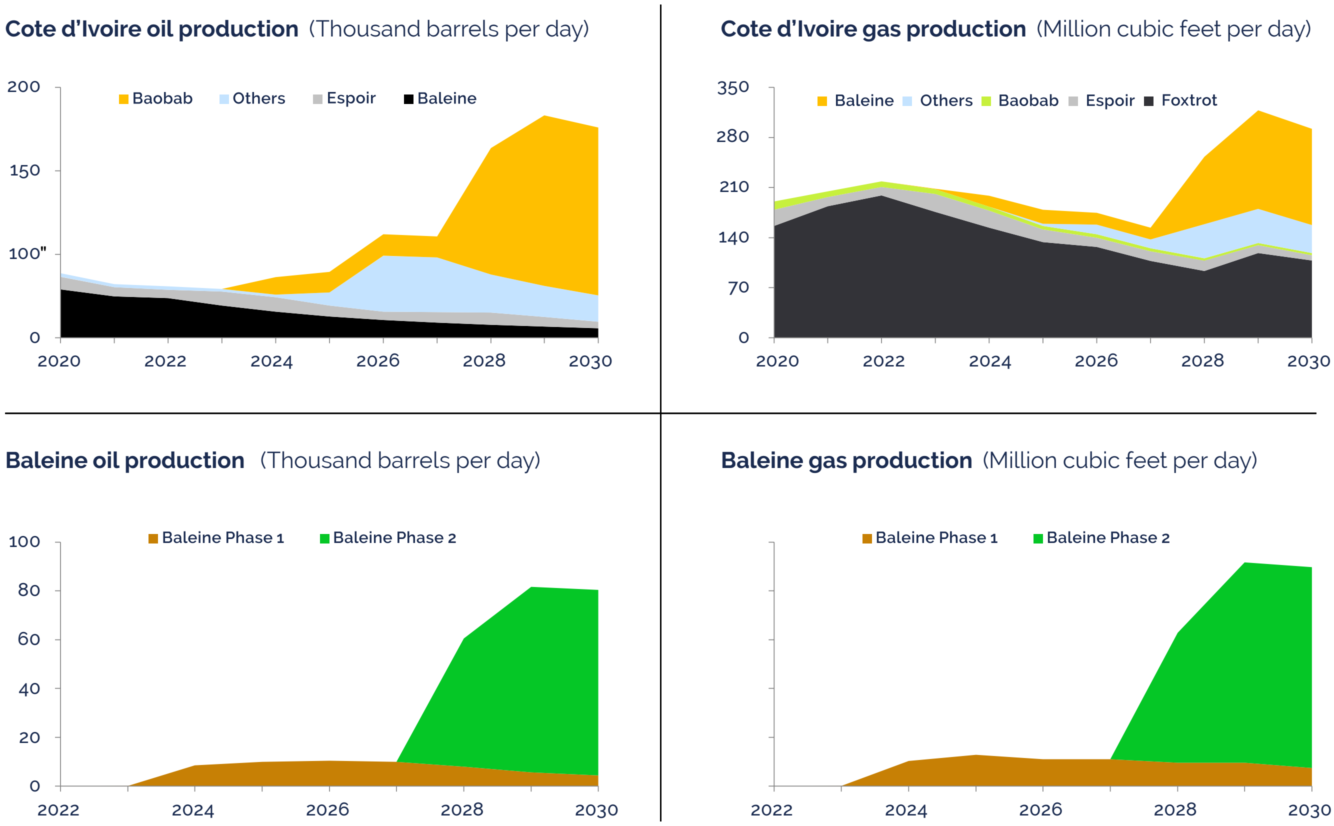


Source: Rystad Energy UCube, Rystad Energy Research and Analysis

6.2 Eni's Baleine directing Cote d'Ivoire towards multiple fold production ramp up

The Operator Eni is expected to fast-track the Baleine development with a multi-phased scheme. Phase one, due on-stream next year, will include three development wells tied back to an FPSO with a capacity of 12,000 barrels per day of oil and 17.5 Million cubic feet per day (MMcf/d) of associated gas. Meanwhile, phase two, due on-stream in 2026, will include 60 development wells tied back to a bigger FPSO with a capacity of 75,000 – 100,000 barrels per day of oil and 140 MMcf/d of associated gas. The new discovery is expected to increase the country's oil output to over 3X from around 25,000 barrels per day in 2021 to around 90,000 barrels per day by late 2030s while the country's gas production set to increase by more than 40% from around around 220 MMcf/d in 2021 to around 320 MMcf/d. Ivory Coast, a country that neither exports or imports gas, has a well-developed gas infrastructure that is used to feed its gas-powered thermal plants to generate electricity. The country was expected to face deficit of gas in near future with no upcoming major gas developments until now. However, the gas volumes from the Baleine discovery development is not only expected to fill this deficit in the short-term but could also increase production to a level where surplus volumes would be available to transform the country into a much bigger regional electricity export hub.

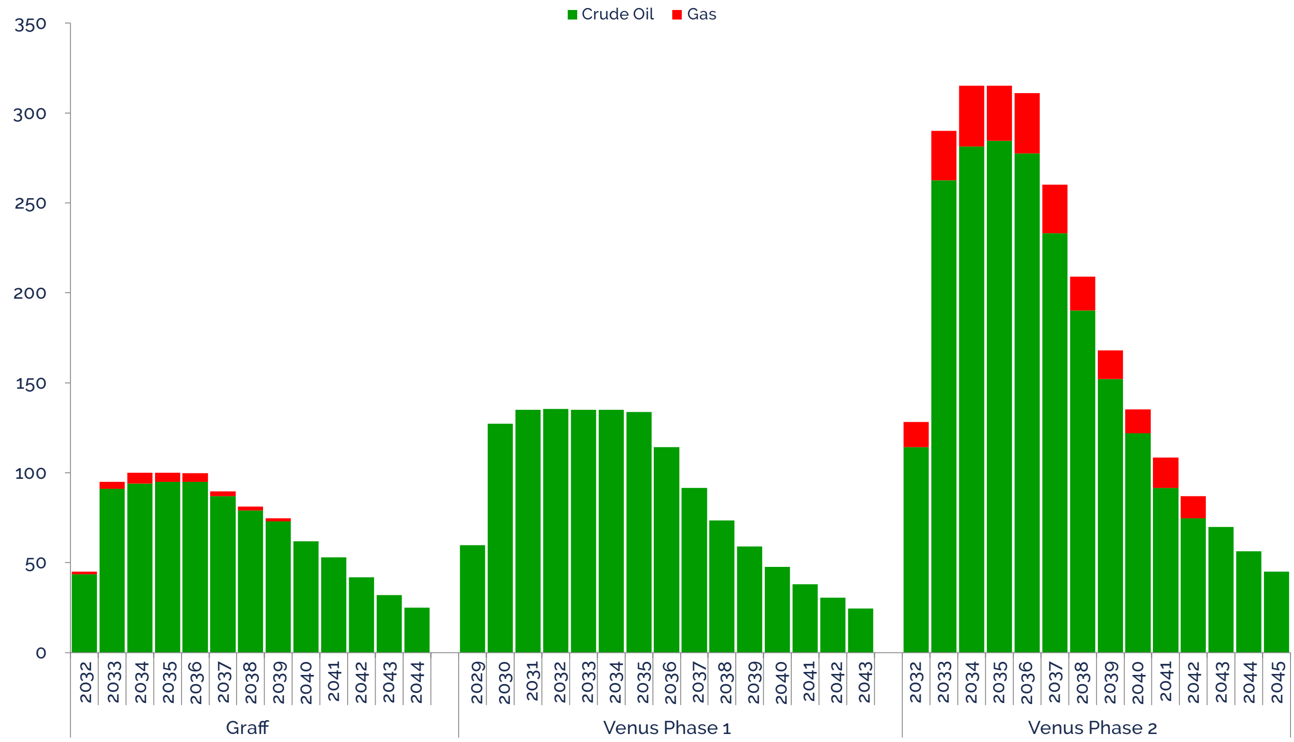
Figure 6.2 Eni's Baleine discovery directing Ivory Coast towards multiple fold production ramp up



Source: Rystad Energy UCube, Rystad Energy Research and Analysis

6.3 Namibia – Riding high on the back of Venus and Graff discoveries!

Figure 6.3 Namibia – Riding high on the back of Venus and Graff discoveries!



Source: Rystad Energy UCube

Namibia is estimated to hold huge resources of oil and gas, but for years its exploration sector has failed to live up to expectations, with Chevron's Kudu gas field discovery in the 1970s an exception. Venus-1X hit 84 meters of net oil pay, much higher than the pre-drill estimates of 60 to 70 meters of net pay. We Expect the field to be sanctioned by 2025 and commence by 2028. Fast-track solutions could, however, also be considered as the government is keen to get fields onstream as soon as possible.

Current assumption is that the development will utilize a leased floating production, storage and offloading (FPSO) unit with a capacity of 150,000 barrels per day (bpd) of oil. However, this will only be finalized, once front-end engineering and design (FEED) studies are completed. Current estimates suggest the initial phase will tap around 550 million boe of recoverable reserves, however the total estimate is 1.5 billion boe of recoverable resources. This could further increase as the expected potential is significant, however anything can only be confirmed once the appraisal is completed. Graff-1, the smaller of the two finds, was spud on 8 December 2021, only a few days after TotalEnergies spun the bit on its highly anticipated Venus well in neighboring Block 2913B. The estimated recoverable reserves at Graff is around 350 million boe, with majority being crude oil. Shell has also started drilling an appraisal well and the field could be tapped via a single FPSO. While the operator assesses commerciality with further appraisal drilling, the field can be expected to be sanctioned by 2027 and start producing by 2032. These huge discoveries in Namibia have thrust the Orange Basin off Southern Africa into the spotlight as a significant exploration hot spot. Although both discoveries were made in Namibian waters, the South African portion of the Orange Basin could hold even more potential for fresh resources. Eco Atlantic Oil & Gas' Gazania and Africa Oil's Marul are some of the upcoming prospects for potential drilling in South Africa's portion of the basin.

These upcoming hydrocarbon producers along with the legacy producers 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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