AGBI
ARABIAN GULF BUSINESS INSIGHT

BEYOND OIL

Charting Mena's energy transition

Insight Report: ENERGY

COVER IMAGE: SHUTTERSTOCK

OPINION OIL & GAS

Saudi Arabia and Russia's marriage of convenience

There have been bumps in the road but oil price binds the countries together

By Frank Kane
Editor-at-Large and consultant to the Ministry of Energy of Saudi Arabia

The alliance between Saudi Arabia and Russia in the global oil industry may have begun as a marriage of convenience, but it has endured long beyond its origins in 2016. It has survived some scares and mutual suspicions, and must be credited with the recent recovery and current surge in crude prices.

When the two countries signed the Declaration of Co-operation in Vienna in December 2016, it was the most visible sign of a new relationship between the two countries that had been bedevilled by decades of suspicion between "godless" Soviet communism and the Islamic kingdom, Saudi support for the Muslim resistance in Afghanistan, and disdain in Riyadh for the chaos and instability of the first post-Soviet decade.

Most important of all was the fact that Russia — despite its status as a leading crude oil producer — had remained outside the Opec organisation, in which Saudi Arabia was the biggest and most influential member.

Saudi Arabia's role as a swing producer aiming to balance global oil output, with the unstated ambition to ensure optimal crude prices, was at risk from Russia's desire to maximise revenue through high output at the best price possible.

What brought the two together in 2016 was the threat from the US shale industry.

For most of the previous decade the shale producers had been deploying vast financial resources and clever new technology which led to a boom in US oil production. North America had become virtually self-reliant in energy and reduced demand for oil from the next two biggest producers — Saudi Arabia and Russia.

Russian President Vladimir Putin, left, met with Saudi Arabia's then deputy Crown Prince Mohammed bin Salman in 2016 to agree to cooperate on global oil markets

REUTERS/PAVEL GOLOVKIN

By early 2016, Brent crude — having been above $100 a barrel for most of the preceding five years — was trading at $25 in a world suddenly awash with American oil. The inclusion of Russia in Opec+, and Moscow's agreement to production cuts along with the other members, immediately led to an improvement in price. By October 2018, Brent was back above $80 a barrel.

It then stayed in a $70-$80 band for the next few years. But by March 2020, when the ravages of Covid-19 were becoming apparent, the oil price was falling fast and Saudi Arabia decided drastic action was needed. It suggested big cuts, which the Russians initially resisted, precipitating a price war between the two. In a demonstration of shock and awe Saudi Arabia then massively increased production and cut its official selling prices.

By April that year Moscow decided that it had had enough, and took part in a globally orchestrated round of cuts. This was claimed as a victory by then US President Trump, who said he had used his good relations with both countries to help achieve the biggest oil cut in history — 10 million barrels a day — from Opec+ producers.

The short-lived battle left a nasty taste in Moscow. One Russian oil executive even compared the deal which ended the price war to the treaty

> “Riyadh’s self-declared ‘neutrality’ in the war has been a big factor in Opec+’s ability to steer output and prices in the right direction”

of Brest-Litovsk, the humiliating pact forced on the young Bolshevik regime by Germany in 1918.

The new relationship within Opec+ survived this potential flashpoint largely thanks to the increasingly close alliance between the Saudi government and President Putin. Prince Abdulaziz bin Salman, the Saudi energy minister since September 2019, and Alexander Novak, the Russian deputy prime minister with responsibility for Opec+ policy, enjoy a good working relationship.

Saudi energy minister Prince Abdulaziz bin Salman
REUTERS

Caps and cuts push prices up

The proof of the pragmatic efficacy of the Saudi-Russia alliance lay in the oil price, which recovered from the depths of April 2020 to jump back above $100 a barrel when Russia invaded Ukraine in February 2022.

Riyadh’s self-declared stance of “neutrality” in the war has been a big factor in the Opec+ group’s ability to steer output and prices in the right direction. Saudi Arabia condemned the US-led price caps and sanctions on Russian oil almost as loudly as the Russians did, claiming that they would distort the global crude markets.

There were some signs of impatience in Riyadh earlier this year, when it seemed as though Russia was lagging on promised cuts, as Saudi Arabia reduced its output to 9 million barrels a day — the lowest level for many years, inflicting some pain on the Saudi economy.

That now appears to have been smoothed over, as Moscow cuts materialise — even though some traders believe that they have more to do with lack of refinery capacity than to adherence to Opec+ policy. This September Saudi Arabia decided to roll its own supply cuts over, in sync with Russia, at a meeting of Opec+ officials. The price per barrel rose to $95. Some analysts are looking at $100 a barrel by the year end.

The oil price war of early 2020 seems a long way off. Marriage of convenience it may be, but the Saudi-Russia oil alliance shows that such arrangements may prove to be long-lasting and effective — as long as both parties find them convenient.

Read more from Frank Kane

- On the G20 sidelines, history in the making
- A new nuclear age dawns — against all odds
- Climate change too much for environmentalists

Gulf invests in major oil refinery upgrade programme

Oman's Duqm refinery has a capacity of 230,000 barrels of oil per day

XINHUA NEWS AGENCY VIA REUTERS

Gulf states are undergoing a major expansion in oil refinery capacity, a move that goes hand-in-hand with the region's determined drive towards net zero and the transition away from a reliance on petroleum and natural gas

By Jonathan Gorvett
Middle East specialist

Gulf states are expanding their oil refining capacity through a series of massive upgrades, at the same time as they drive towards net zero and seek to move away from petroleum and natural gas. The apparent contradiction is, however, only apparent.

From Az-Zour in Kuwait to Duqm in Oman, the refinery upgrades are central to plans to produce higher value-added products in-country. They are part of long-term diversification strategies, but also act as hedges against future hydrocarbon volatility.

While the expansions are likely to boost the Gulf's position as a major global supplier of non-renewable resources, they are being balanced out by huge investments in the green economy.

"The Gulf is building out refinery capacity to integrate this with petrochemical and plastics production," says Gabor Petroczi, director of oil and gas for Europe, Middle East and Africa at ratings agency Fitch. "This is relatively less exposed to the energy transition. New refinery output will be offset by renewables, carbon credits and capture, hydrogen and biofuels."

Long-term plans

Refinery expansions have long lead times and require major capital commitments. Bahrain's $6 billion Bapco Modernisation Programme (BMP), for example, is approaching completion only now, six years after the site was first handed over to the project developers. Upon launch the BMP should boost Bahrain's crude refining capacity by 42 percent, to 380,000 barrels per day (bpd).

In Kuwait, the giant Az-Zour Refinery Project will reach output of 615,000 bpd by the end of this year, after a third crude distillation unit comes online. The expansion was first approved in 2012 and construction work started in 2017, with overall investment in the plant estimated at $27 billion.

Next door in Saudi Arabia, Aramco's $21 billion Jazan refinery started producing at the end of 2021, providing 400,000 bpd of capacity. Elsewhere in the kingdom, clean fuels projects are under way in Ras Tanura and Riyadh.

Saudi Arabia has also built out abroad, having taken a 30 percent stake in the $10 billion Huajin Aramco Petrochemical Company (Hapco), an integrated refinery and petrochemical complex in northern China.

Closer to home, Adnoc's $3.5 billion Crude Flexibility Project will add 420,000 bpd of refinery capacity, capable of handling heavier and more sour crude grades from offshore Abu Dhabi and around the world.

Oman's $7 billion Duqm Refinery and Petrochemical Complex should add 230,000 bpd of extra capacity. Under the OQ8 joint venture between OQ and Kuwait Petroleum International, 65 percent of the feedstock is due to come from Kuwait. The refinery should begin operations at the end of this year.

These elements of the Gulf refinery upgrade programme add up to a lot of extra capacity at a time when Opec+ states are cutting output and worries are growing over the Chinese economy's demand. Yet, given their time lags and the capex

Aramco workers at Saudi Arabia's $21 billion Jazan refinery
ARAMCO

commitments, refinery projects have to take a decades-long outlook. Short-term fluctuations in demand and pricing are lesser considerations.

Rory Fyfe, managing director of consultancy Mena Advisors, says this is part of a longstanding industrial diversification strategy.

He says all the Gulf states have been pursuing diversification strategies for many years, with integration between the crude refineries and associated petrochemical plants a part of the plans. "This is particularly important for states like Bahrain that have limited crude," Fyfe adds. "The modernisation programme has significantly boosted revenue."

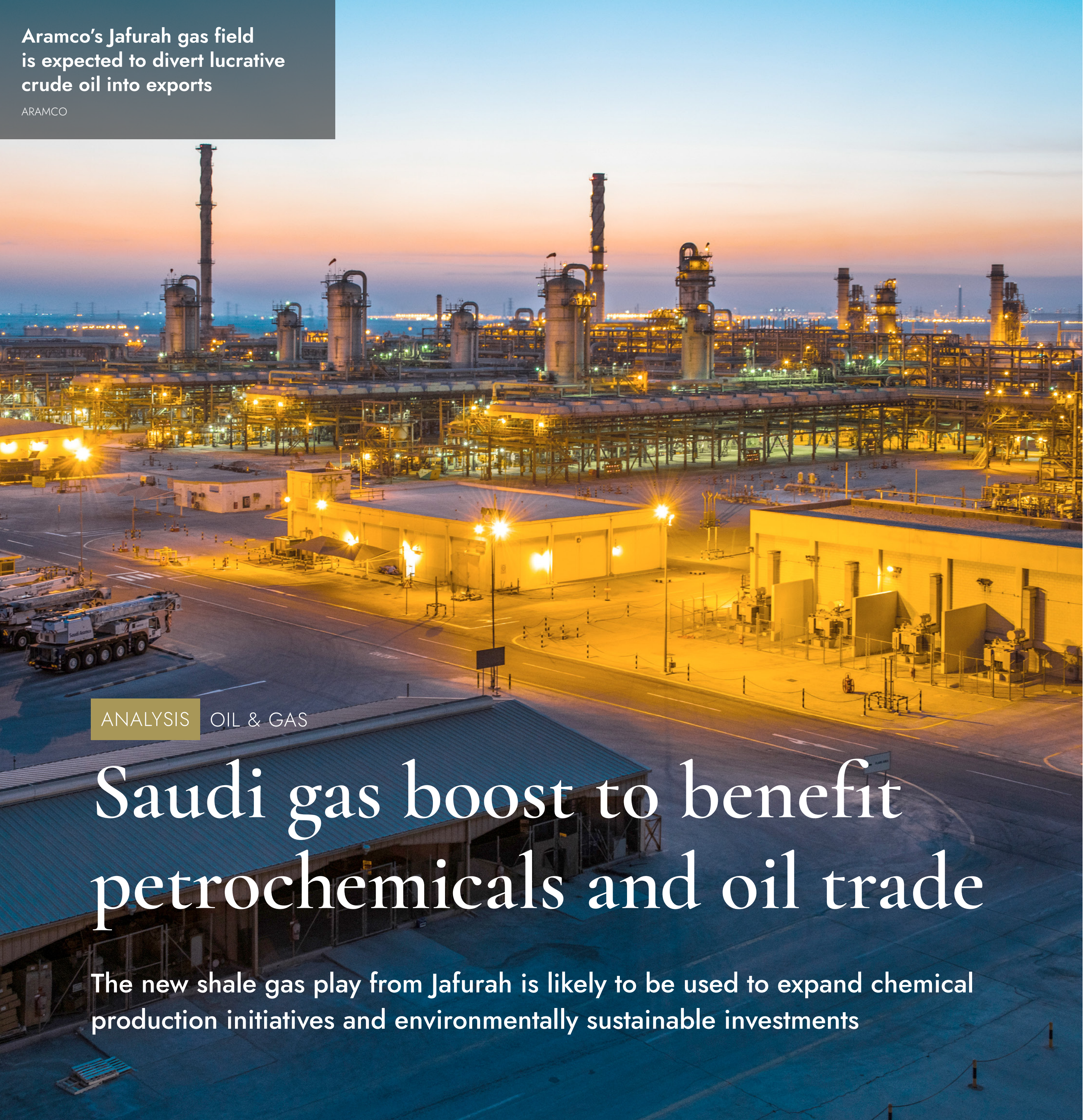
More sophisticated petrochemical products can provide for local industrial and manufacturing development. This creates jobs and hedges against oil and gas volatility. While demand for petroleum may be in long-term decline, demand for specialised fuels that are not easily replaced by renewables or hydrogen should continue to rise, along with demand for petrochemical products such as plastics and fertilisers. This helps to "justify the capex," Fyfe says.

Currently those high costs can be borne easily, given "a fairly large windfall for all these operators in recent times," says Petroczi. "There are unlikely to be any financial constraints."

With the Gulf investing heavily in the green economy, the emissions created by extra refinery capacity should balance out, at least locally. The UAE's 5 gigawatt Mohammed bin Rashid Al Maktoum solar plant, Adnoc's 5 million tonne annual carbon capture target for 2030 and Saudi Arabia's 1.2 million tonne green ammonia project at Neom all aim to help bring the net emissions back into balance.

A balancing act will play out in the future between climate targets and all these refineries. For now, their expansion is set to continue.

Read more from Jonathan Gorvett
- Kuwait PM's in-tray: debt and budget reform
- Bahrain reboots oil and gas to reduce debt
- What does 'net zero' really mean?



Aramco's Jafurah gas field is expected to divert lucrative crude oil into exports
ARAMCO

ANALYSIS OIL & GAS

Saudi gas boost to benefit petrochemicals and oil trade

The new shale gas play from Jafurah is likely to be used to expand chemical production initiatives and environmentally sustainable investments

By Andrew Hammond
Saudi Arabia correspondent

Saudi Arabia is likely to use an enormous shale gas play due to come into production next year to develop upstream petrochemicals and divert lucrative crude oil into exports, analysts say.

Saudi Aramco, the state oil giant, says that the Jafurah field contains an estimated 200 trillion standard cubic feet (scf) of natural gas, which would make it the largest liquid-rich shale gas play in the Middle East.

The field is expected to reach output of 2 billion cubic feet per day (bcf/d) by 2030. Crucially, the gas is non-associated – free from an oil play – and can therefore be extracted without implications for reservoir pressure or for Opec+ commitments.

Saudi Arabia is, however, far from becoming a significant gas exporter like its Gulf neighbours Qatar and Oman. Nor would it want to be, given that oil is by current prices four times as profitable. Instead domestically produced gas allows it to develop other upstream projects and free up oil for future exports. Aramco is targeting 13 million barrels per day as its maximum sustainable oil capacity by 2027, and can use its refining capacity to manage the crude.

"We've been closely observing the growing allocation of capital expenditures towards gas projects within Saudi Arabia over the last few years," Dylan Hattingh, analyst at Energy Aspects, says.

"We anticipate a growing portion of Aramco's future expenditure to be directed towards gas-related initiatives and environmentally sustainable investments."

Gas output increase

Energy Aspects expects that Saudi Arabia's gas output will increase by around 50 percent by 2030. Jafurah will also help position the kingdom as an ammonia exporter as part of the growing hydrogen economy. Other projects include the Hawiyah Unayzah gas storage reservoir, which will help manage seasonal gas demand.

Aramco, one of the largest public companies in the world after its 2019 listing on the Saudi bourse, says that when Jafurah reaches peak production, it is expected to generate energy for domestic consumption equivalent to around

Aramco CEO Amin Nasser has said it is considering taking overseas upstream stakes, rather than restricting itself to downstream projects

REUTERS/HAMAD I MOHAMMED

500,000 barrels of crude oil. Jafurah will also generate 420 million scf per day of ethane and 630,000 barrels of natural gas liquids per day, which can serve as feedstock for the petrochemicals industry.

Figures from this year show Aramco has gone beyond its seasonal increase in gas production ahead of the summer months, though it was still obliged to ramp up fuel oil imports from Russia to meet summer power generation demand. Despite oil cuts by Opec+ which came into effect in May, overall production rose in the second quarter of 2023 by 5 percent once gas is factored in. Non-crude production jumped from 2.54 million barrels of oil equivalent per day to 3.44 million.

The state-run oil companies of both Saudi Arabia and the UAE want to expand their chemical

Aramco's aim has been to put a further 3 million bpd of oil into producing petrochemicals

ARAMCO

production capacity. The ambitions mark a strategic shift that could have huge implications for a global petrochemicals industry that is already suffering from its lowest margins in two decades.

Aramco's longstanding aim has been to put a further 3 million bpd of oil into petrochemicals production. The company's CEO Amin Nasser has said that it is considering taking overseas upstream stakes, rather than restricting itself to downstream projects – refineries and petrochemical plants – as it has done historically. "We will continue to assess opportunities for development and if there is something that is commercially viable and meets our criteria in terms of investment, we will announce that deal at that time," Nasser told journalists on August 7.

Flexibility is key for Aramco

According to Bill Farren-Price, a macro oil analyst, Aramco wants to retain the flexibility to maximise its oil export position into the 2030s, despite the fact that oil demand globally is expected to wane. "Given the Saudis burn so much oil in these summer months – around a million barrels a day – there is a considerable amount of volume available if you could switch the power sector into gas and nuclear and wind farms," he says.

"With the oil cuts they've instituted there is a lot of spare capacity that's not online. When oil demand peaks globally by the end of this decade they'll be fighting over pieces of a shrinking cake and will want to optimise the volumes they can put on water and export."

Read more from Andrew Hammond

- Saudi giga-projects lead to banks slowdown
- More companies set up Saudi HQs
- Saudi defence spend to rise further

IN FOCUS OIL & GAS

TotalEnergies pins hopes on desalination for Iraq project

There's a lot at stake for both sides in the development deal between the French energy firm and Baghdad

By Matt Smith
Senior editor

TotalEnergies' $27 billion development deal with Iraq includes building a water desalination plant crucial to Baghdad's efforts to raise oil production, but doubts persist over the financial and logistical viability of the long-delayed project.

Iraq's government wants to nearly double oil production to 8 million bpd by 2028

REUTERS/ESSAM AL-SUDANI

> "Exxon failed to make it happen, so what is Total's secret to make this doable now? There are a lot of question marks around it"

The multifaceted agreement signed in July foresees constructing a 1 gigawatt solar power plant, capturing waste gas from oil fields to make much-needed electricity, and raising crude production at the Ratawi oil field to 200,000 barrels per day from 60,000 bpd currently.

"What's significant is that TotalEnergies is committing to investing in, and fixing, a lot of the longstanding challenges that had plagued investments by other companies," says Bill Farren-Price, an independent Middle East oil analyst.

"The big question is: how well will Total be able to deliver on the plan?"

The Baghdad government, under prime minister Mohammed Shia al-Sudani, wants to nearly double Iraq's oil production to 8 million bpd by 2028, from 4.1 million bpd in May, according to the latest Opec data.

May's production was down from 2022's average of 4.4 million bpd and far from a long-lapsed target of reaching 12 million bpd. To raise production significantly, Iraq needs more water injection capacity to maintain reservoir pressure in its rich southern fields, which account for about 90 percent of national crude production.

Deploying Iraq's meagre freshwater supplies is inadequate and socially unpopular. Basra, the province in which most of the country's oil production is located, receives rain for just 32 days per year. Basra's annual rainfall totals around 150 millimetres.

"The southern fields have been starved of water for years," says Alexandre Araman, head of Middle East Upstream research at Wood Mackenzie, the consultants.

"They need more water — without that, many wells won't be able to continue producing oil."

TotalEnergies' desalination plant will produce up to 5 million barrels of fresh water daily, according to TotalEnergies chairman and CEO Patrick Pouyanné, speaking at the signing ceremony in July.

According to Araman Exxon Mobil had spent around a decade trying to build a similar plant — known as the Common Seawater Supply Project — to supply the oil fields but never succeeded in making the logistics or economics of such a scheme work.

Unanswered questions

The US firm and Iraq abandoned talks over the plant in 2018. The project had been slated to be operational in 2013, Reuters reported.

Germany's ILF Consulting Engineers conducted the front-end engineering and design work for the Exxon seawater project. In a report, it said that a seawater treatment facility would be built 40 kilometres south of Basra. Its first phase would produce 7.5 million barrels of water per day, with production ultimately rising to 12.5 million bpd.

The water was intended to be transported 270 kilometres to supply eight southern fields. ILF estimated the project's cost at $12 billion and said it would take three years to build.

"Exxon failed to make it happen, so what is Total's secret to make this doable now?" Araman asks. "There are a lot of question marks around it."

Water desalination plants are crucial to Baghdad's efforts to raise oil production
REUTERS/NIR ELIAS

Various international oil companies operate the fields and Araman suggests that because margins are razor thin, IOCs might prefer to let production decline versus paying water tariffs higher than their remuneration fees.

"Will they buy the water from TotalEnergies?" he asks. "Who's responsible for the infrastructure? Who's building the water pipelines to deliver the water? What will the cost be to produce the water?"

During oil production, natural gas is typically released as a by-product. Because of infrastructure inadequacies, some countries simply burn this gas in a process known as flaring, rather than capturing and using it. Iraq has the second-highest gas flaring volumes worldwide, according to a March report by the World Bank.

Yet domestic demand for electricity far outstrips capacity. The shortfall has widened over the past five years in spite of Iraq's supply increasing by one-third, according to the International Energy Agency, which notes outages are a daily occurrence for most households. Power cuts are especially common in summer during peak demand for air conditioning.

TotalEnergies' deal aims to address this and provides the Iraqi government, which has been in office for less than a year, with an incentive to make it happen. The agreement includes the so-called Gas Growth Integrated Project, which will supply gas-fired power plants with gas captured from three oilfields.

"Iraq's power sector is terrible and the lack of reliable electricity has been a key cause of social unrest – people can see that Iraq is a major oil exporter and yet they don't have basic services," says Araman.

"So, fixing these problems will be key to the government maintaining its popularity."

Read more from Matt Smith
- TotalEnergies' $27bn bet on Iraq
- Saudi and Kuwait reassert Durra claims
- Doubts persist in aviation offset rules

ANALYSIS OIL & GAS

Saudi Arabia and Abu Dhabi set to bet on crude-to-chemicals

A strategic plan to switch from refined products to chemical production will mitigate the risk of a future decline in demand for oil

Saudi Aramco's Ras Tanura oil refinery. The kingdom's main chemicals producer Sabic intends to build a new facility in Ras Al Khair

REUTERS

By Matt Smith
Senior editor

Saudi Arabia and Abu Dhabi's state-run oil companies both want to expand their chemicals production capacity in a strategic shift that will have huge implications for a petrochemicals industry already suffering from its lowest margins in two decades.

Saudi Aramco and Abu Dhabi National Oil Co (Adnoc) together provide almost half of Opec's entire crude output. Aramco produced 10 million barrels of oil per day (bpd) in June, while its refinery capacity is 3.3 million bpd. It owns 70 percent of Saudi Basic Industries Corp (Sabic), the kingdom's top petrochemicals company, and wants both to expand oil production and place more oil within its own network of businesses.

"Saudi Arabia, supported by Sabic, is massively shifting towards chemical products rather than refined products," says Oliver Connor, vice-president of energy equity research at Citi in London.

Adnoc is pursuing a similar strategy as part of a target to raise its crude production to 5 million bpd by 2030. The company launched a 37.5 billion reais ($7.5 billion) takeover bid for Brazil's largest petrochemicals producer, Braskem, and has offered 11 billion euros to buy Germany's Covestro, Reuters reported.

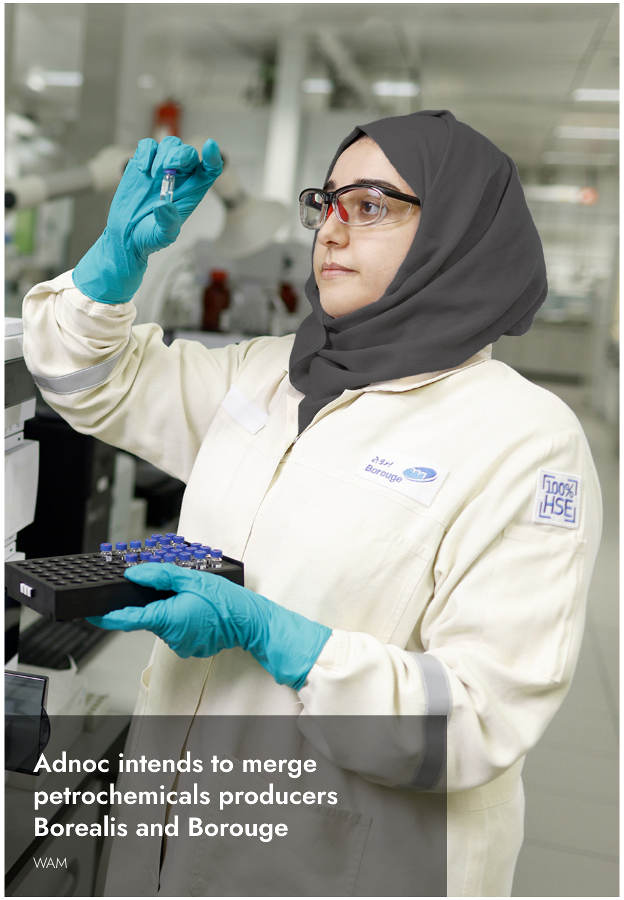
Adnoc will also merge petrochemicals producers Borealis and Borouge, in which it owns 25 and 54 percent stakes respectively.

Crude placement

"There's a clear step up in terms of Adnoc's appetite to do chemical M&A. Why? It comes back to crude placement," says an analyst, speaking on condition of anonymity.

"Rather than building refinery capacity, it's buying chemical businesses. It's build versus buy. Build would take five years, but it can buy these plants now. That's the cost of placing the product."

Gasoline and diesel demand could decline as consumers adopt electric and other greener vehicles, whereas demand for plastics can be reliably expected to expand at around 1 to 1.5 times annual global GDP growth. This is a major factor in both Aramco and Adnoc's expansion of their chemicals



Adnoc intends to merge petrochemicals producers Borealis and Borouge
WAM

> "Saudi Arabia, supported by Sabic, is massively shifting towards chemical products rather than refined products"

capabilities. Aramco has a longstanding aim to put an additional 3 million bpd of oil into petrochemicals production.

A question of supply and demand

"The focus is on monetising additional oil supply, both in the UAE and Saudi Arabia – by upping chemicals manufacturing they're de-risking demand for their oil," says Connor. Yet questions remain over who will buy their additional chemicals volumes.

"The historical growth model was to build and ship to China. But now maybe China doesn't need this additional product," Connor says.

Aramco and Adnoc's petrochemicals production expansion could worsen supply-demand imbalances, weighing on prices and pressuring margins further. "But because they will be making money upstream on oil, they won't care so much about downstream returns," says the analyst.

According to Aramco, only 8-12 percent of oil consumed at a typical integrated refining complex will be made into chemicals.

The most advanced refineries produce around 50-55 percent chemicals and 45-50 percent fuels, says Yousef Husseini, director of chemical equity research at EFG Hermes in Cairo. "The technology doesn't fully exist yet to push this towards 70 percent and make oil-to-chemicals a practical reality," he says.

Saudi petrochemicals producers' two main products are polyethylene and polypropylene plastics. The former is primarily made from ethane gas and is a compound with two carbon atoms, while the latter is usually made from propane and has three carbon atoms. "The heavier the chemical, the more expensive it is to use as feedstock, but also the more products you can produce," says Husseini.

Making polyethylene from ethane is cheap, partially because it only requires breaking hydrogen bonds and not carbon bonds, which are stronger and need more energy to dismantle.

Crude conversion rates

Crude oil, in contrast, is a mixture of various hydrocarbons. Through the distillation process, refineries separate crude into its constituent compounds but do not necessarily alter their chemical composition. In crude-to-chemicals, hydrocarbons are broken down, changing their composition, which requires greater energy.

"The big problem is how to do this in a way that makes sense economically – to achieve that requires better technology," says Husseini.

Sabic intends to build a new facility in Ras Al Khair that will directly convert 400,000 bpd of crude into chemicals. "That's a huge shift away from the current refining setup," he adds.

Husseini also highlights long-term uncertainties over the impact of recycling on plastics demand. Currently, plastics recycling is mechanical, so in many cases does not produce resins that are of high enough quality. Yet over the past few years, advances have been made in chemical recycling of plastics, which breaks down plastic molecules and reforms them. This would enable the recycling of plastic food packaging and its re-use in the food industry, for example.

"We're probably still 10 to 15 years away from this technology being commercial but given the long-term plan for oil-to-chemicals, it's something to consider," adds Husseini.

Read more from Matt Smith

- Carbon credits trading predicted to hit $4bn
- Saudi Arabia feels petrochemicals slump
- Mena targets US as M&A deals jump 53%

Algeria's state-run Sonatrach plans to develop its gas fields to help offset declining production
REUTERS/ZOHRA BENSEMRA

IN FOCUS OIL & GAS

Investment needed to unlock Algeria's gas supplies

Algeria has played an important role since Russia's invasion of Ukraine but deals with international oil companies could be crucial to ensure it can keep up supply

By Melissa Hancock
Associate editor

Algeria has helped to plug Europe's gas needs following Russia's invasion of Ukraine, but industry experts say that future growth in exports can only be sustained with further investment.

Africa's largest gas exporter saw its share of EU gas imports increase to 44 billion cubic metres last year, accounting for around 12 percent of the total, S&P Global data showed, up from 10 percent in 2021. In total, Algeria produced 102 billion cubic metres of gas.

"A lot of Algeria's production is from legacy fields that have been in production for decades," says Martijn Murphy, principal analyst for North Africa at energy consultancy Wood Mackenzie.

"So part of the issue is countering the natural decline at these fields. And to that end green fields developed by Sonatrach [Algeria's state-owned oil and gas company] are planned for the latter half of this year and into next year.

"Ain Tsila is the largest among them and could add 600 million cubic feet – 16.9 million cubic metres – a day once production ramps up," adds Murphy.

Smaller developments in the south-west of the country such as Hassi Ba Hamou, Hassi Mouina and Ahnet will lead to an incremental increase in production.
"The ability to bring these projects on schedule in a timely manner so that they're able to offset declining production from legacy fields will be critical," says Murphy.

International oil companies (IOCs) are also expected to play a bigger role in Algeria's gas production. In February this year the Italian oil and gas major Eni bought BP's stakes in two key Algerian gas projects – In Amenas and In Salah – which together produced 11.2 billion cubic metres in 2022.

In Salah and In Amenas are significant gas-producing fields for Algeria, accounting for around 28.3 million cubic metres – or

Sonatrach is working with Italian gas company Eni
REUTERS

> “Sonatrach is keen to keep some of the big investors and incumbents such as Eni on side as it will need IOC investment and expertise”

one-tenth of Algeria’s output — according to Wood Mackenzie. Energy analysts have noted that if new licences can be agreed beyond the current term, which ends in 2027, this could then unlock additional investment to stave off decline.

New licences in the pipeline

Murphy believes “it’s quite likely” that new licences will be agreed.

“There seems to have been a step change in Sonatrach’s attitude toward inward investment and the need to retain IOCs. We know that Sonatrach is doing its best to court some of the North American majors to invest in unconventional gas,” he says.

The company has already taken on projects “that IOCs have departed from over the past decade because they were unable to agree commercial terms”, according to Murphy.

Algeria is Italy’s largest gas supplier

APP VIA REUTERS CONNECT

“It’s now keen to keep some of the big investors and incumbents such as Eni on side, as some of these projects are technically challenging, so it will need IOC investment and expertise to develop them,” says Murphy.

In April 2022 Sonatrach and Eni signed an agreement that would allow the latter to provide increasing quantities of gas imported through the TransMed/Enrico Mattei pipeline — reaching up to 9 billion cubic metres per year in 2023-24.

Eni then signed a new production-sharing contract in July that year for blocks 404 and 208, located in eastern Algeria’s Berkine basin, with Sonatrach, Oxy and TotalEnergies which will enable the partners to boost investments and extend the fields’ production life by 25 years.

Then, in October, Eni started production from two gas fields related to the Berkine South contract in Algeria. At the time it stated plans to double its production capacity to around 2 million standard cubic metres of gas per day.

Last year Algeria became the largest supplier of gas into Italy with pipeline exports via the TransMed pipeline.

Read more from Melissa Hancock

- Egypt’s green hydrogen goals get BP boost
- Carbon targets deter power project developers
- ‘A long way to go’ to cut Gulf emissions

Carbon capture and storage is cheaper in the Gulf

Carbon capture transports CO2 via pipelines to underground storage facilities

REUTERS

Technology and transportation are key factors for carbon capture. The Gulf has both, making storage in the region a cost-effective option for emitters compared to Europe

By Matt Smith
Senior editor

Carbon capture and storage in the Gulf is considerably cheaper than in many regions including Europe. However there are several other variables that determine the overall cost of cutting CO2 emissions from industrial activity.

Energy consultant Wood Mackenzie forecasts that carbon capture and storage (CCS) will account for 20 percent of the emissions reductions that are needed to achieve global net zero by 2050.

The CCS process involves capturing CO2 and transporting it, usually via pipeline, to underground sinks where it is injected into rocks for permanent storage.

Gulf oil companies have used CO2 capture technology for more than 40 years to purify

The closer the capture and storage sites are to each other, the cheaper the transportation

WAM

natural gas, but executing similar processes in cement or steel manufacturing, for example, is more complex. The full costs of CCS projects — including capture, transportation and storage — currently range from between $20 and $150 per tonne of CO2, according to Wood Mackenzie estimates. The average weighted cost is $58 per tonne.

Two-thirds of a CCS facility's lifetime costs are upfront, Wood Mackenzie says, but it predicts that project costs will fall 20-25 percent over the next 20 years.

Transporting the carbon

Costs for CO2 transportation and storage in depleted oil and gas fields — as is usual in the Gulf — range from $15-40 per tonne, according to estimates by Oslo-based Rystad Energy. These are substantially lower than in Europe, where CO2 is usually stored in saline aquifers at a price of around $40-50 per tonne. As such, the Gulf has a sizeable cost advantage.

The biggest factor that determines the cost of transportation is distance. The closer that the capture and storage sites are located to each other, the cheaper the transportation.

"The remaining part is capture and that influences how much your levelised cost per tonne will be," says Yvonne Lam, head of carbon & CCUS (carbon capture, utilisation and storage) research at Rystad Energy in Oslo.

"That depends on the concentration of CO2. If it's coming from a gas processing plant, it's very cheap because it's a very mature technology, the CO2 concentration is high and the energy needed to (capture) CO2 comes from an abundant, on-site source."

In such situations, carbon capture can be achieved for less than $25 per tonne. But if it's chemical, steel or cement plants, "then it can go up to $75-100 per tonne", according to Lam. Industrial plants are rarely located near to underground sinks.

The cost of capture

Such costs are "very significant", Lam adds.

"Carbon capture and storage doesn't generate any revenue," she says — it is only a cost to the emitters themselves. "So, if there is no incentive, if you can emit CO2 for free, then why do you want to invest and create extra costs?"

Nevertheless, Gulf policymakers seem serious about expanding the region's CCS capacity, which currently represents around one-tenth of the global total.

For example, Abu Dhabi National Oil Co (Adnoc) aims to increase its CO2 capture capacity more than sixfold to 5 million tonnes per year (mtpa). Adnoc said that this will be collected mostly from its gas processing plants and that it will provide the same amount of carbon capture as a forest twice the size of the UAE.

Beyond capture and storage, carbon capture, utilisation and storage (CCUS) attempts to find uses for the captured carbon rather than simply storing it.

The Middle East is home to nearly 5 percent of announced CCUS projects worldwide, according to a Rystad report, and is ranked fifth in terms of planned and operational CCUS facilities.

Read more from Matt Smith
- Gulf geology ideal for carbon capture
- Oil rally to bolster Gulf stock markets
- Petrochems sector shows signs of recovery

OPINION RENEWABLE ENERGY

How Mena's infant solar boom is affected by rising costs

Solar power remains attractive despite new challenges

By Robin Mills
Robin Mills, CEO of Qamar Energy and author of The Myth of the Oil Crisis

The Middle East has set record low prices for solar power. The second phase of Dubai's Mohammed bin Rashid Solar Park in 2016 was awarded at 5.6 cents per kilowatt-hour (kw), and 1.04 cents was offered in April 2021 for the Faisiliyah project in Saudi Arabia.

Mena solar power tenders benefitted from the region's excellent solar resources; the allocation of large areas of empty, flat land; the provision of grid connections by the utility; the huge scale of the projects; and low financing costs as banks grew comfortable with the low technical and business risks. National governments or state utilities with strong credit profiles usually stood behind the agreements to purchase the generated electricity.

Solar system costs declined worldwide, driven by the ramp-up in Chinese manufacturing capacity, as well as technical innovations, notably bifacial panels that can collect light reflected from the ground.

In the Mena region, the UAE, Jordan and Morocco led the way, with enthusiasm spreading to Saudi Arabia, Oman, Egypt and Qatar. The bulk of the capacity has been in giant 'utility-scale' projects including the 5gw planned ultimate capacity at the Mohammed bin Rashid Solar Park and the 2gw Al Dhafra plant in Abu Dhabi, the world's biggest single-site solar installation.

Home to 3.5 million solar panels, Al Dhafra will power about 160,000 typical UAE homes. It will save 2.4 million tonnes of carbon dioxide emissions a year – roughly 1 percent of the UAE total. Dubai also has a successful solar rooftop programme, mostly taken up by factories, car parks, malls and the airport, which now totals 0.5gw.

War-ravaged Yemen and crisis-hit Lebanon have also turned to small solar installations to replace non-existent state provision.

Pushing up costs

But now three factors are pumping up solar costs: headline inflation, a rise in the real-terms costs of solar systems and higher financing costs as interest rates go up.

General inflation should not affect future projects but it does create problems for companies who signed power purchase agreements for near-term developments at now uneconomic rates.

It also affects the mindset of governments and utilities firms. A solar bid price of 2 cents per kw-hour, which would have seemed excellent in 2018, now seems disappointing compared to the world-record low bids in 2020 and 2021.

The rise in real costs is more problematic. In 2021 solar component prices jumped due to supply-chain bottlenecks and the pandemic-related stimulus spending.

In 2022 Russia's invasion of Ukraine and its cut-off of most gas supplies to Europe sent energy prices soaring worldwide. Europe has

The economic case for solar power has become even more attractive despite solar costs increasing

REUTERS

turned to solar power and other renewables to reduce its dependence on gas for electricity, while the US's Inflation Reduction Act improves tax credits for solar installations.

The boom in green hydrogen production will also add to demand for solar systems, which are used to generate electricity to split water via electrolysis.

These cost rises could be persistent as solar deployment worldwide accelerates. One solar developer estimates that capital costs of solar power rose 56 per cent between its previous 2021 estimates and 2022, and will fall back only moderately by 2025, bucking a long trend of cost declines.

This is substantial compared to the rock-bottom rates of barely over 1-1.3 cents per kw-hour achieved in auctions in Saudi Arabia and Chile in 2020-21. Rooftop installations, with higher upfront costs and more expensive financing, could suffer more.

An attractive economic case

But this doesn't mean the end of the Mena region's infant solar boom – in fact the economic case for solar power has become even more attractive. The price for power generation from gas has risen more dramatically than that of solar. Dubai Electricity and Water Authority's top tariff for residential consumers is more than 12.5 cents per kw-hour.

Even in Mena countries, where domestic gas prices are usually government-regulated, the cost of burning gas for electricity instead of exporting it or using it in industry has gone up.

Some Middle East gas exporters, including Algeria, Egypt, Oman and Iran, have seen domestic demand eat into their available gas for export at times of record international prices. The same goes for Iraq, Saudi Arabia and Kuwait, which still burn substantial amounts of oil in their power sectors.

Much more can be installed

The levels of solar penetration in the electricity mix are still modest across the region. Much more can be installed before intermittent output becomes a problem.

As much of Mena's electricity consumption is for air conditioning, it correlates well with solar output – a different situation from northern Europe or the US in winter.

Longer-term falls in battery prices offer the potential to pair with solar to provide reliable 24-hour electricity at moderate costs.

The Emirates Water and Electricity Company's latest statement of long-term capacity needs recommends that it should increase its total solar capacity from about 3.3gw today to 7.3gw by 2030, and install 300mw of batteries.

The UAE, Oman, Saudi Arabia and Bahrain all have net-zero carbon targets. With the Cop28 UN climate conference coming up in Dubai in November, regional states face more environmental scrutiny.

Their export-oriented businesses, including petroleum, fertilisers, steel and aluminium, face the threat of European tariffs if they do not reduce their carbon footprint.

The real rises in solar power costs should only be temporary – but its advantages are permanent.

Read more from Robin Mills
- Peak oil by 2030? We won't know until later
- Adnoc and Occidental team up to capture CO2
- The UAE has a difficult path to negotiate

ANALYSIS RENEWABLE ENERGY

Oman takes green hydrogen gamble

With a high rate of sunshine, a good wind profile and a strategic location, the sultanate is well placed to create renewable energy

By Jonathan Gorvett
Middle East specialist

Sometimes it takes a country.

Oman is dedicating an area the size of Slovakia to solar power projects to produce green hydrogen: gas produced entirely from renewable sources.

On June 1 Salim bin Nasser Al Aufi, minister of energy and minerals, signed $20 billion of contracts with partners including BP, Shell and the newly formed Hydrogen Oman (Hydrom) to produce 500,000 tonnes of green hydrogen each year.

Oman is dedicating an area the size of Slovakia to solar power projects to produce green hydrogen
REUTERS

By July 28 Hydrom announced that "solidified commitments" to initiatives in the sultanate had risen to $30 billion. Production targets are 1 million tonnes by 2030, 3.75 million tonnes by 2040 and 8.5 million tonnes by 2050.

This should make the sultanate the world's sixth-largest exporter of hydrogen by 2030.

By 2040, those exports are projected to be worth 80 percent of Oman's current exports of liquefied natural gas (LNG), according to the International Energy Agency.

By 2050 they may be worth twice as much as the sultanate's current overseas LNG sales.

Yet hydrogen is not without challenges. Technical issues limit long-distance transportation of the gas, while regulations and international markets are also still being worked out.

Hydrom signs its first deals. Oman has set bold targets to develop green hydrogen.

OMAN GOVERNMENT/ IMAGO VIA REUTERS CONNECT

"There's a lot to do before hydrogen will be up and running and delivering," says Charles Dolphin, a partner in Muscat law firm CMS. This uncertainty is reflected in the wide range of approaches that have been taken to the gas in the Gulf.

Gulf nations taking different paths

While Oman is focusing on green hydrogen, the UAE is putting its efforts and finances into blue, pink and green hydrogen (see 'The hydrogen rainbow' at the end of this article).

Saudi Arabia has taken a similar approach to that of the UAE. Both countries are also investing in developing domestic industrial uses of hydrogen – whatever colour – to produce commodities such as green steel, mitigating the challenge of exporting the gas.

Qatar is largely outsourcing hydrogen production, continuing to ship its LNG to destinations where – if the off-taker desires – it can be used to produce blue hydrogen.

Bahrain has decided that its combination of depleted wells and small land area make it more suited to carbon capture, storage and utilisation than hydrogen.

Kuwait, meanwhile, has yet to announce a domestic hydrogen strategy, although it has invested in schemes abroad. For example, EnerTech Holding, a Kuwaiti state-owned company, is a partner in one of the new Omani projects.

Oman is also pursuing its own path when it comes to industry organisation. The sultanate has offered blocks of land on which companies can build renewable energy projects. The Omani state – via Hydrom – will also hold a stake in those schemes.

"Other Gulf states are taking a more private sector approach," says Dolphin.

"The UAE and Saudi Arabia aren't seeing so much government involvement, except for some gearing up of renewable energy projects to supply the electrolysers making the hydrogen."

Oman's decision to go for green is partly explained by the fact that it has some of the world's leading renewable energy resources, according to S&P.

The sultanate enjoys a strategic location, a good wind profile and high irradiance (the power per unit area received from the sun), according to global energy transition reporter James Burgess. Combined with large amounts of available and unused land, the sultanate is therefore perfect for green hydrogen production, he says.

The relatively high price of the gas compared to the huge quantities of cheap renewable energy that are set to become available – plus Oman's relatively small population and economy – means that the bulk of the hydrogen generated will be for export.

This means getting to grips with the problem of transportation. Converting it into hydrogen-heavy ammonia for shipping on tankers is one possible solution. It is then converted back into hydrogen at its destination.

Yet, "while ammonia is definitely seen as the vector for transport at the moment, there are conversion losses at every step of this process," says Burgess.

Another challenge is market development. Hydrogen is currently a niche gas, traded and used in small quantities. Scaling it up to an industry the size of the LNG market is a major task.

Potential export markets in Europe and Asia-Pacific are currently developing rules on hydrogen, while independent certification standards are also being developed, but are not yet in place.

Germany will be a test case for these, as it has recently sent out specifications to suppliers for ammonia produced from green hydrogen. Pricing on a global market scale is also still evolving.

"It could evolve like the early LNG market," says Burgess. "You might see some surplus hydrogen volumes from the big hubs eventually developing into a spot market."

Local demand may well be the shape of the industry in the immediate future. Many of the projects being announced – in Oman and elsewhere – also have seven-year timelines up to 2030.

Dolphin says: "Maybe, by the time they come online, the market will have matured and the project's time will have come."

The hydrogen rainbow

Green hydrogen is produced on a CO2-neutral basis through the electrolysis of water.

Turquoise hydrogen is created when natural gas is broken down into hydrogen and solid carbon using methane pyrolysis.

Blue hydrogen is generated from the steam reduction of natural gas.

Grey hydrogen is obtained by steam reforming fossil fuels such as natural gas or coal.

Yellow hydrogen is produced from a mixture of renewable energies and fossil fuels.

Sometimes other colours are ascribed to hydrogen, based on how it is produced. For **red, pink and violet hydrogen**, the electrolysers are driven by nuclear power.

Hydrogen that is merely a waste product of other chemical processes is referred to as **white hydrogen**, while the use of coal as a fuel produces **brown hydrogen**.

Read more from Jonathan Gorvett
- Kuwait PM's in-tray: debt and budget reform
- Bahrain reboots oil and gas to reduce debt
- What does 'net zero' really mean?

Arabian Gulf Business Insight helps readers understand new trends, explore new territory and formulate new ways of doing business that are more profitable, sustainable, imaginative and impactful.

To read more go to www.agbi.com
Contact our team at contact@agbi.com

Special report editor: **Sarah Townsend**
Creative director: **Tomaso Capuano**
Chief sub editor: **Anna Kierstan**
Sub editor: **Sally Vanderpump**

SHUTTERSTOCK