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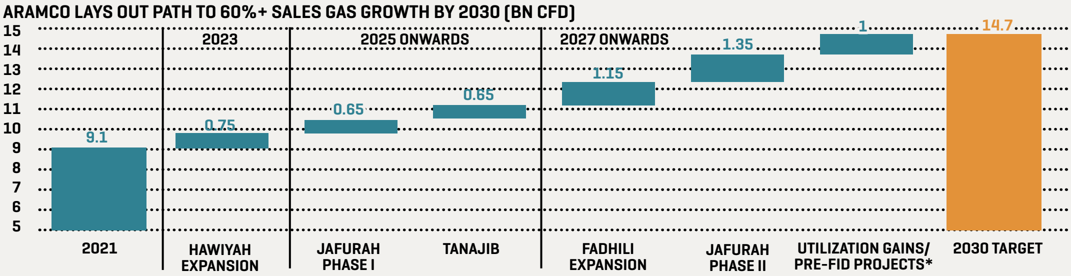
CORPORATE

Aramco Capex Record Amid Oil & Gas Capacity Surge

Aramco's capex hit a record $53bn for 2024 and could rise further to $58bn for 2025. This comes as huge offshore crude oil increment projects are approaching the finishing line, whilst first gas from the giant Jafurah Basin unconventional project is expected in Q3. ***Page 7, 8, 9***

ARAMCO LAYS OUT PATH TO 60%+ SALES GAS GROWTH BY 2030 (BN CFD)



OPEC & GLOBAL MARKETS

Opec+ Confirm Plan To Taper From April

Opec+ will begin easing production cuts in April in line with its December roadmap, despite geopolitical uncertainty and falling prices threatening another deferral. ***Page 10***

GEOPOLITICAL RISK

Speedy Kurdistan Oil Return? Don't Bank On It

Baghdad, the KRG and the region's IOCs remain far apart on terms to restart exports through the Iraq-Turkey Pipeline. ***Page 12***

UPSTREAM OIL & GAS

Oman Taps BP's Khazzan For LNG Boost

BP and its partners on Oman's Block 61 plan to boost gas capacity beyond the current 1.5bn cfd with additional volumes earmarked for Oman LNG's planned 3.8mn t/y fourth train. ***Page 2***

DOWNSTREAM

Adnoc, OMV Agree $60bn Petchems Terms

Adnoc's XRG aims to be a top 5 global petchems firm. This week, terms were agreed with OMV to create 'Borouge Group International' with XRG's stake worth $28bn. ***Page 14***

UPSTREAM OIL & GAS

Egypt: Apache Gas Gains, Eni Slump Continues

Egypt's top onshore producer Apache says gas output will rebound this year on increased drilling after securing higher prices. But Zohr operator Eni's production is down. ***Page 4***

DOWNSTREAM

Algeria: Sinopec Upstream & Refining Stakes

China's Sinopec will spend $850mn upstream on the new Hassi Berkane North block and is joining Sonatrach and Spain's TR in building a new Hassi Messaoud refinery. ***Page 15***

UPSTREAM OIL & GAS

Libya: New Bid Round, New Era?

Libya has finally launched its first oil and gas bid round in 17 years. It hopes for a surge in international investment after years of political instability. ***Page 5***

ECONOMY & FINANCE

Tunisia Blowout Import Bill As Output Slumps

Tunisia's oil and gas output collapse continues with energy import dependence surging to a record 59% for an import bill equivalent to 7% of GDP. ***Page 18***

Oman Taps BP's Giant Khazzan Gas Field For LNG Boost

BP and its partners on Oman's Block 61 are updating the Field Development Plan to boost gas capacity beyond 1.5bn cfd. Additional volumes are earmarked for Oman LNG's planned 3.8mn t/y fourth train.

A consistent theme in Oman's energy landscape over the past decade has been the rapid growth of its gas sector. IOCs have led the charge in bringing record amounts of gas online, while Oman's gas grid operator is expanding capacity across the network to ensure that takeaway capacity keeps up with the upstream growth.

This focus on the gas sector can be traced back to a single sector-defining change: the discovery and development of the massive Khazzan unconventional gas field on Block 61 in the center of the country. Back in 2017, BP brought the 1bn cfd Khazzan first phase online, followed by a further 500mn cfd under the second phase Ghazeer expansion in 2020.

Capacity has been at 1.5bn cfd ever since, but Khazzan spurred a new era of gas development, with the likes of Shell and TotalEnergies signing up to develop neighboring acreage. Each year Oman's gas output has broken annual output records with last year setting a new peak of 5.26bn cfd (54.51bcm: MEES, 24 January). To utilize this gas the Ministry of Energy and Minerals has greenlit expansions to existing downstream facilities, the largest being a proposed fourth 3.8mn t/y liquefaction train at Oman LNG's 11.4mn t/y facility in Sur by 2029 (MEES, 2 August 2024).

While recent gas gains from Shell and TotalEnergies have been earmarked for their own integrated projects, the energy ministry appears to be tapping Block 61 for gas to feed the fourth LNG train.

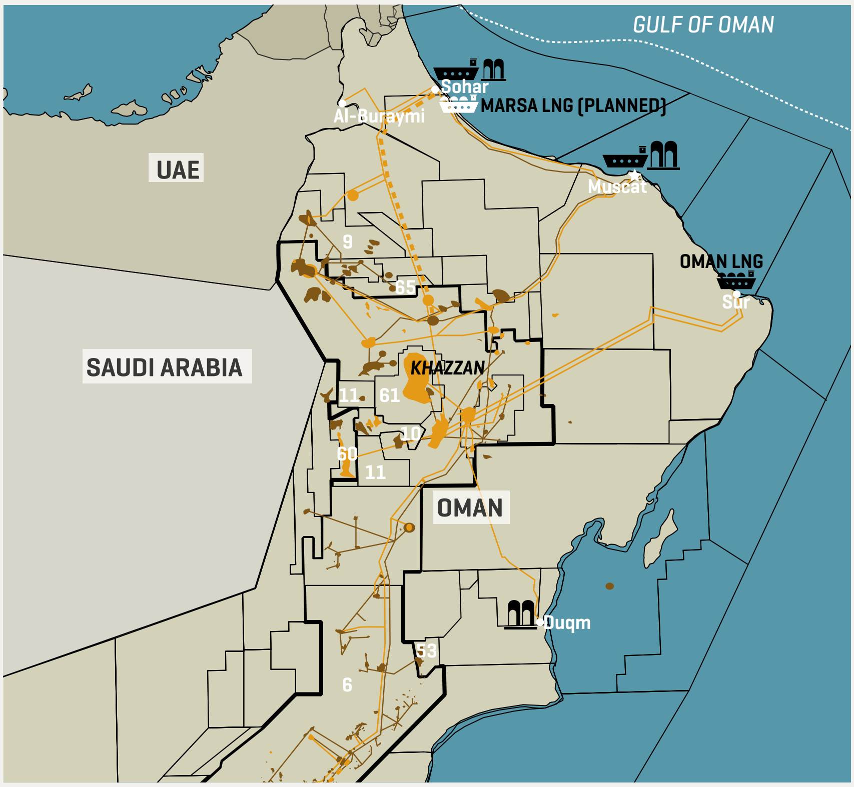
EXPANDING KHAZZAN

The Khazzan development was a frontrunner in the region as the first large-scale unconventional gas development to come online. But the unconventional revolution is now firmly underway across the GCC. Saudi Arabia is pursuing unconventional gas development through the huge Jafurah Basin, where the first 200mn cfd phase is due online this year (see p8). Adnoc and TotalEn-

Continued on – p3

OMAN'S KEY UPSTREAM INFRASTRUCTURE

GAS FIELD/PIPELINE · OIL FIELD/PIPELINE · REFINERY · LNG TERMINAL · OIL TERMINAL



TOTAL KICKS OFF MARSA LNG CONSTRUCTION

Construction at the site of TotalEnergies' 1mn t/y Marsa LNG in Sohar, Oman, has been underway since the beginning of the year. As part of a monthly visit to the site, Total's Oman country chair Sergio Giorgi posted on LinkedIn the progress of work including laying the foundation for the facility's storage tank. Satellite imagery confirms that initial building work is underway after site preparation at the end of 2024.

Total took the final investment decision in April last year with an expectation of the plant being online by the first quarter of 2028 (MEES, 26 April 2024). It also secured a bunker vessel in October with an eye to deploying it offshore Sohar (MEES, 11 October 2024).

State firm and gas network owner OQ Gas Networks (OQGN) is set to start construction on a new 42" gas pipeline between Fahud and Sohar, for which it received final approvals on 17 November (MEES, 22 November 2024). OQGN says it will increase pipeline capacity to Sohar by 9mn m³/d (116mn cfd) by 2027.

Oman has recently been benefiting from higher upstream gas output and is sanctioning further gas-fed downstream projects. Key among these is a fourth 3.8mn t/y liquefaction train at its 11.4mn t/y Oman LNG facility in Sur. BP is reportedly updating its Field Development Plan at its massive 1.5bn cfd Khazzan gas field to increase its output to feed the LNG expansion (see main story).

Total's Marsa LNG project also involves the construction of a 300MW solar facility to feed into Oman's grid to offset emissions associated with the plant. For now, the location and status of this plant remains unclear.

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Continued from – p2

ergies meanwhile have brought online the Ruwais-Diyab gas project recently, while in Bahrain, US shale specialists EOG Resources plan to start producing unconventional gas in 2026 (see p6).

The Khazzan partners are now examining further potential developments at Block 61 to push capacity beyond 1.5bn cfd. BP is updating its Field Development Plan with view to expanding output, according to state firm and Block 61 partner OQ Exploration and Production (OQEP). In its 26 February full-year results OQEP says the update seeks to "evaluate the block['s] full potential recoverable gas resources for future growth projects beyond the Gas Sales Agreement (GSA) and to supply gas for potential new LNG train in Sur." BP did not respond to questions from MEES.

Oman's energy ministry seems to have tasked OQEP with helping find new gas resources "to provide the required gas feedstock to cater for such upcoming LNG demand." This could potentially go beyond expanding Block 61 output.

Output from the block reached a record annual figure of 1.511bn cfd last year, almost 30% of Oman's total output of 5.26bn cfd. Khazzan also produces condensate, though output has edged lower in recent years and was 56,000 b/d for 2024, slightly below 2021's peak of 60,000 b/d.

Linking upstream gas expansion with future LNG output makes sense in Oman as the LNG sector is the largest source of gas demand and a growing export opportunity for the country. Official data does not break down industrial gas consumption by end use, but LNG has in the past accounted for 44% of total gas consumption which would imply a little more than 1.4bn cfd last year.

MEES back-of-the-envelope calculations imply a fourth 3.8mn t/y train at the facility would require around 570mn cfd of feed gas. This figure aligns with the 580mn cfd of increased pipeline capacity to Sur (site of Oman LNG's liquefaction facilities) that gas grid operator OQ Gas Networks (OQGN) is pursuing under the Central 48 Rich Lean Segregation project (MEES, 22 November 2024).

NO LACK OF GAS GROWTH

Oman has not been short of new gas opportunities in recent years. After Block 61, the next largest single gas asset is Block 10 (Shell 53.45%, TotalEnergies 26.55%, OQEP 20%) where partners ramped up the Mabrouk North East field to its 500mn cfd capacity last year after January 2023 startup.

The three companies are also partners on Block 11 (Shell 67.5%, TotalEnergies 22.5%, OQEP 10%) where OQEP last year revealed that discovery wells at the Jaleel field included "high gas production rates" from one of the wells (MEES, 27 September 2024). OQEP is anticipating a declaration of commerciality at the field which has been undergoing appraisal.

For their existing gas output from Block 10, Shell and Total have linked their equity volumes to key downstream projects. Total has earmarked its future equity volumes for its planned 1mn t/y Marsa LNG bunkering project currently under construction at Sohar (see box). Shell has been less clear about the end use of its future gas from Block 10. But it could use equity volumes for its proposed 200,000 t/y Blue Horizons blue hydrogen project in Duqm, though it has only awarded pre-FEED contracts so far (MEES, 26 July 2024).

For its part, American independent Occidental has been bullish on possible oil and gas growth in Oman despite its net output from the sultanate declining in recent years (MEES, 28 February). Further gas could also come from Oman Petroleum Development (PDO), the largest oil and gas producer in Oman, which has tamped down its own gas output to make space for IOC gains. ◆◆

OMAN GREEN H2: 'FID BY 2027'

Oman energy minister Salim al-Aufi says he expects FID on the first of eight planned green hydrogen projects in the sultanate to be made in 2026 or 2027.

The most likely to advance is the 60,000 t/y first phase of Hyport Duqm. Beyond being manageably small Hyport has the combined backing of state firm OQ Alternative Energy (25.5%) and BP (49%) (MEES, 2 August 2024). Belgium's Deme also holds a 25.5% stake. The partners plan to install 1.4GW of renewable energy capacity and a 500MW electrolyzer under the first phase of the project, with plans to later scale up the electrolyzer to 1GW.

Whilst state hydrogen firm Hydrom has awarded land for eight green hydrogen projects (MEES, 3 May 2024), even were a first FID to be achieved in 2026, Oman's ambitious target of 1-1.5mn t/y green hydrogen capacity by 2030 looks unachievable. Undeterred, Hydrom on 11 December announced plans for its third hydrogen bid round "in the first quarter of 2025."

Low-carbon hydrogen projects across the globe are being scaled back (see p9), while US firm AirProducts' high profile investments in the sector contributed to the recent ousting of long-time CEO Seifi Ghasemi by shareholders. The firm has since axed three planned US low-carbon hydrogen projects.

BP MAURITANIA/SENEGAL IMPAIRMENTS HIT $4.5BN

BP's 2024 annual report, released 6 March, reveals $1.495bn in new impairments for Mauritania and Senegal on top of a similar 2023 write-off of $1.434bn (MEES, 17 March 2024), $729bn for 2022 and $834mn for 2021, bringing the four-year total to a whopping $4.492bn.

For both 2023 and 2024 the Mauritania/Senegal impairments were the major's largest globally.

BP has recently chosen to highlight the 'good news' of start-up of the 2.45mn t/y first stage of its Tortue LNG project on the two countries' maritime border, with the first LNG cargo imminent (MEES, 28 February). But Tortue has been both much delayed and scaled back from the original plans which envisaged 10mn t/y capacity by 2025 (MEES, 20 May 2020). Partner Kosmos continues to tout the potential for Tortue's recoverable resource of 15tcf to ultimately support five times first phase 400mn cfd output. Whilst BP has sounded less keen, prospects for the major signing up now look brighter following its latest 'back to black' strategy shift (MEES, 28 February).

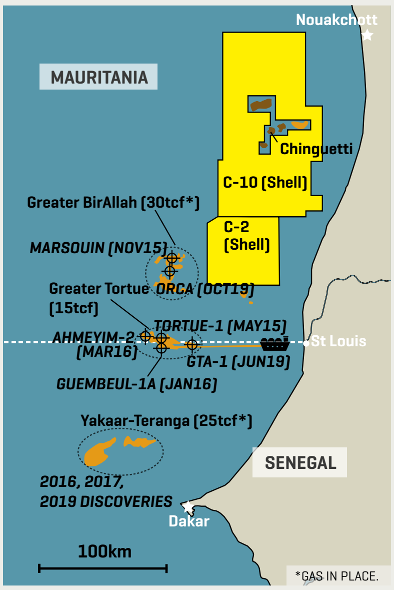
Whilst Tortue expansion remains a possibility, the key reason for the write-offs relates to BP relinquishing its interests in what it had long flagged up as two other prospective LNG projects off Mauritania and Senegal, BirAllah and Yakaar-Teranga.

At Mauritania-only BirAllah, around 60km north of Tortue, BP and Kosmos touted a 30tcf gas-in-place resource on the back of a drilling success. However BP relinquished its 62% operators' interest on 29 April last year leaving Kosmos to potentially go it alone (or, more realistically, search for a new majority partner: MEES, 17 May 2024).

BP walked away from Senegal-only Yakaar Teranga and its apparent 25tcf gas in place resource in late 2023.

MAURITANIA OFFSHORE GAS

OIL FIELD/PIPELINE GAS FIELD/PIPELINE
LNG EXPORT TERMINAL



*GAS IN PLACE.

◆◆

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EGYPT: APACHE EYES GAS GAINS AS ENI OUTPUT SLUMPS

Egypt's top onshore producer Apache says gas output will rebound this year on "promising early results" of increased drilling after securing higher prices for its output. But Zohr operator Eni continues to see production fall.

A decade on from shareholders pushing for a country exit (MEES, 17 October 2014), Egypt returned to (joint) top billing in Apache's Q4 results on 27 February. The US independent says it is "building a sustainable base, anchored by [the] Permian and Egypt."

Following a late-2024 agreement that brings "gas-focused investment to economic parity with oil," by hiking the price for new gas output to $4.25/mn BTU (MEES, 15 November 2024), Apache is increasing gas-focused drilling in the Western Desert, home to all of its Egypt acreage. In January it signed up to five more blocks totaling 6,300km², a 30% acreage hike (MEES, 10 January).

With legacy output declining and "new" output coming onstream, Apache's average realized price is already rising. From $2.96'/'000 ft³ for Q4 (around $2.93/mn BTU) – Egypt's standard 'legacy' price of $2.65/mn BTU plus an adjustment for liquids content – CFO Stephen Riney says Apache expects its average price to rise "to at least $3.15" (c. $3.12/mn BTU) for Q1 and average $3.4-3.5 for the year as a whole.

The new terms saw Apache add an extra Egypt rig, taking the total to 12, and launch a gas-focused drilling campaign in 4Q24. "We are very pleased with the early results," CEO John Christmann says.

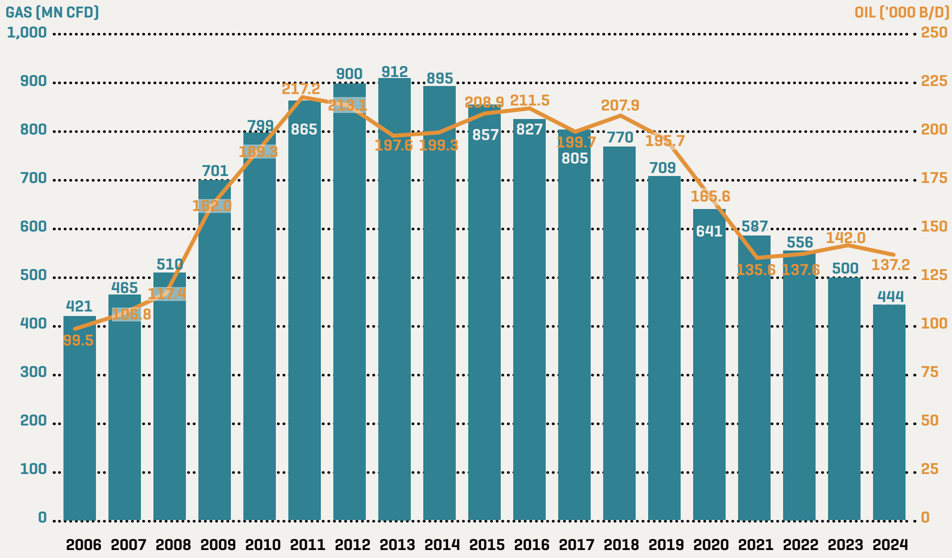
Having slumped to an 18-year low 444mn cfd for 2024 and a lower-still 438mn cfd for Q4, the firm is confident of growing its gross Egypt output for 2025. "[We] now expect year-over-year gas production to increase for the first time in over a decade," Mr Christmann says.

That said, the gains will in part come from harvesting "low-hanging fruit" rather than stepping up investment. "We found a lot of gas in the Western Desert when we were looking for oil," Mr Christmann says, adding that with higher prices the firm will be "going after" this inventory and looking again at "some of the areas that we avoided because we knew they were gas-rich."

Notwithstanding Apache's gas-focused activity uptick, for now the firm remains far more important to Egypt as an oil producer. For 2024, Apache's gross Egypt oil output of 137,000 b/d accounted for 25% of the national total of 547,000 b/d, versus 9% for gas, and more than half of 266,000 b/d Western Desert output.

And this increased gas focus is not good news for the firm's Egypt oil output. Having essentially flatlined after hitting a 13-year low in 2021 (see chart), Apache projects that oil output will "decline modestly" for 2025. For Q4, output was down again, by 2% on Q3 and 5% year-on-year at 134,504 b/d.

APACHE* EGYPT GAS OUTPUT SLUMPS TO 18-YEAR LOW 444MN CFD FOR 2024 WITH OIL JUST ABOVE 2021'S NADIR



*GROSS OUTPUT INCLUDING 1/3 SINOPEC STAKE IN APACHE EGYPT. SOURCE: APACHE, MEES

Oil focused investments are on workovers, recompletions and waterfloods which "have provided a much more predictable oil production profile, increasing the overall efficiency and longevity of our operations," Mr Christmann says in comments that sound more like managed decline than a platform for growth.

Egypt national oil output of 547,000 b/d for 2024 was a multi-decade low (MEES, 21 February). For gas, Egypt's overall output of 4.87bn cfd for 2024 was the lowest since 2016, whilst Q4's Western Desert figure of 764mn cfd was little more than half the 3Q 2015 peak of 1.412bn cfd.

As such national gas output is back at levels last seen before the 2017 start-up of Eni's giant Zohr offshore field.

ENI: ZOHR SLUMP

And falling output at Zohr itself is a key part of the reason. Production has fallen to less than half the field's 3.2bn cfd capacity, leading Eni for the first time since Zohr start-up to fail to split out Egypt production in its Q4 results.

Eni confirms that this is due to "an SEC reporting requirement that requires separate disclosure of production and reserves for individual countries that meet a certain threshold." That is to say the firm's Egypt output has now fallen below this threshold. Indeed, in reference to the firm's overall Q4 gas output, Eni says gains elsewhere "were offset by mature fields decline and a slowdown of activities in Egypt due to issues on part of state-owned companies to fund their share of expenditures."

Whilst tardy payments from Egypt state entities are a longstanding bugbear of foreign operators in the country, it is rare for one of the larger operators – such as Eni or Apache – to be so outspoken. Indeed, Apache's Mr Christmann was more circumspect, saying that "we have reason to believe we'll make some progress" on reducing the monies it is owed in 2025.

For 3Q 2024, the latest results that split out Eni's Egypt production figures, net gas output of 1.133bn was lowest since 2Q 2020 while oil output of 61,000 b/d was the lowest since 4Q 2020 (MEES, 1 November 2024).

Eni's Egypt oil output comes mostly from the Western Desert, though it sold some of its stakes last year to US firm Apex Energy which is now in the process of being taken over by Chinese firm UEG (MEES, 14 February), whilst MEES understands that Eni is in the market to further sell down its Western Desert stakes.

Eni's remaining Western Desert output comes via its Agiba JV with state firm EGPC and while gas output has increased five-fold since the turn of the decade, averaging 84mn cfd for the 2023-24 financial year (to 30 June), oil output slumped 31% to 29,000 b/d.

The firm's key expansion project in the region, Phase 2 of the Meleiha field, has been constantly pushed back since FID was taken in 2022. Planned output of 20,000 boe/d (mainly oil) is now due for start-up in 2027 (along with a dedicated gas plant), a further delay after the firm last year gave a 2026 start-up date (MEES, 26 April 2024).

'FIGHTING DECLINE'

Still, the firm attempted to provide a modicum of positivity during its Capital Markets call on 27 February. "We see encouraging signals," exploration and production chief Guido Brusco says and while also admitting that "production was declining" over the last year, "the whole industry is fighting this current trend."

In a bid to fight decline at Zohr, Eni is currently drilling the first of two sidetrack wells to be potentially followed by a further development well (MEES, 21 February). ◆◆

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Libya Upstream Enters 'New Era' With Launch Of Long-Awaited Bid Round

Libya has finally launched its first oil and gas bid round in 17 years. It hopes for a surge in international investment after years of political instability.

Libya this week announced the launch of a long-awaited bid round for oil and gas exploration, the first in 17 years (MEES, 17 December 2007), with officials hailing the "new era" in the country's lifeblood sector.

Though officials did not provide details at the launch event on 3 March, NOC had previously said the bid round would cover 22 onshore and offshore concessions across the Murzuq and Ghadames basins, as well as offshore acreage (MEES, 6 December 2024).

The bid round targets international investment in the country's upstream sector, with officials hoping to attract $3-4bn to reach an oil production target of 2mn b/d later this decade via an intermediate end-2025 target of 1.6mn b/d (MEES, 24 January).

Ongoing political instability – including protests, oil blockades, and leadership rivalries – has left foreign companies wary of investing in the turbulent country over the past decade (MEES, 31 January).

Libya saw its crude output more than halve between August and October in a political crisis over the leadership of the central bank, which receives and distributes the country's lifeline oil and gas revenues (MEES, 4 October 2024).

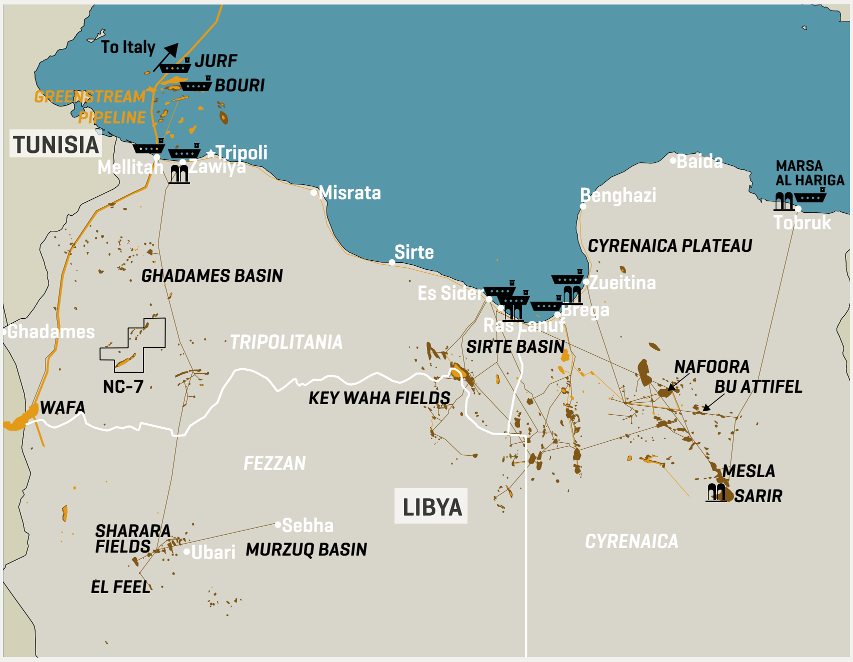
More recently, an abrupt change in the leadership of state oil firm NOC (MEES, 7 February) has brought about a sweeping reform drive amid corruption scandals at top oil companies (MEES, 14 February).

But recent output gains on the back of increased drilling activity have restored some faith in the sector, with existing partners like Spain's Repsol and Austria's OMV optimistic about further gains in 2025 (MEES, 28 February).

Repsol and OMV, as well as Italy's Eni, recently resumed drilling in Libya for the first time since 2014 (MEES, 1 November 2024).

LIBYA: KEY OIL AND GAS INFRASTRUCTURE

OIL FIELD/PIPELINE · GAS FIELD/PIPELINE · LNG EXPORT TERMINAL · OIL TERMINAL · REFINERY



'LIBYA IS BACK'

In a televised event in Tripoli, acting NOC chief Massoud Suleiman launched the bid round, saying it marks the end of 17 years of "neglect" of Libya's resources and "years of fragmentation and fear."

"This [bid round] will add new oil and gas reserves to make up for previous [losses], which will increase Libya's oil and gas output under NOC's strategy," he said, also noting economic development and employment opportunities.

Libya's crude output has hovered around an 11-year high of 1.4mn b/d since late 2024 (see p10), with NOC aiming to hit 2mn b/d over the next three years (MEES, 3 January).

Oil minister Khalifa Abdelsadiq, meanwhile, told the attendees that the new bid round was not only an investment opportunity, but also "a clear sign of Libya's strong comeback to the international arena after years of challenges."

"The new opportunities and technical framework on offer make this [bid round] different," Abdelsadiq said. "We no longer look at bid rounds as a mere means to increase output, but also as a tool to ensure long-term production sustainability to guarantee Libya's continued role as a key actor in international energy markets."

Tripoli-based Prime Minister Abdul Hameed Dbeibeh also said the launch of the bid round was a "clear message that Libya is back at the forefront of oil and gas investment."

'DEEP CONCERNS'

The launch of the bid round has not come as good news for everyone. A parliament bloc in the Tripoli-based High State Council (HSC) was quick to issue a statement on 4 March "condemning" and "expressing deep concerns" over the bid round, noting it comes amid "political and institutional divisions and a lack of transparency and accountability."

"Launching a bid round for oil and energy resources under these circumstances is considered a waste of national wealth and a threat to national and economic security," says the statement by the Libyan Alliance for National Consensus Parties.

Moreover, the Benghazi-based House of Representatives (HoR), which regularly challenges the rival Tripoli government, had previously issued a decree to "stop any new measures, contracts, or amendments to existing agreements in relation to national resources, such as oil, gas, gold, and others."

Analysts say this is rooted in east-west rivalries over shares in revenues from new or amended agreements, such as the controversial NC-7 gas development deal (MEES, 15 November 2024), among others. ◆◆

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Bahrain Unconventionals: EOG Eyes First Output In 2026

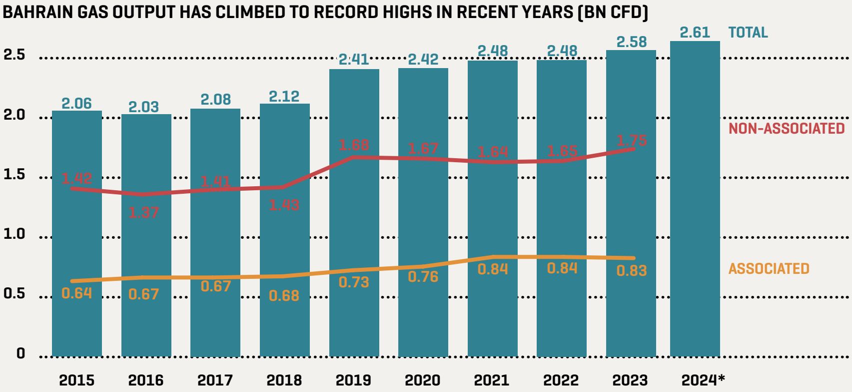
US shale specialist EOG Resources expects first gas from its recently agreed partnership to develop deep tight gas in Bahrain's main onshore field.

EOG Resources expects first gas in 2026 from a partnership deal signed last week with Bahrain state firm BapcoEnergies. The 25 February deal with the US shale specialist is to "evaluate a promising gas exploration prospect" (MEES, 28 February). The reference appears to be the deep pre-Unayzah gas layers sitting under the Bahrain onshore field, which the country's previous oil minister estimated holds 35tcf gas in place (MEES, 15 July 2022). Bapco has been targeting development of the gas as part of its $4.2bn Bahrain Field Oil and Gas Development Expansion project.

Currently all of Bahrain's production comes from the various reservoirs of the onshore Bahrain (also known as Awali) field (see map). MEES calculates oil production in Bahrain averaged 38,500 b/d last year while gas appears to be continuing its upward trajectory to average 2.61bn cfd (see chart). These figures exclude Bahrain's right to 50% of production from Saudi Arabia's 300,000 b/d Abu Safah field, which is operated by Saudi Aramco, with the Saudi firm currently marketing Bapco's share.

Speaking about the pre-Unayzah gas layers, BapcoEnergies Group CEO Mark Thomas told MEES last year that while "unconventional gas is never easy" Bapco was "now confident going into a development phase" (MEES, 8 November 2024). EOG Resources appears equally optimistic.

BAHRAIN GAS OUTPUT HAS CLIMBED TO RECORD HIGHS IN RECENT YEARS (BN CFD)



*MEES CALCULATIONS. SOURCE: JODI, MOO, MEES.

'A LONG-TERM PARTNERSHIP'

Speaking on his firm's Q4 earnings call on 28 February, CEO Ezra Yacob was clear about his company's hopes: "we have [a] pretty strong conviction from an exploration standpoint" because "the formation has previously been tested using horizontal technology, delivering positive results." Two appraisal wells were drilled in 2022, kickstarting a further drilling campaign in 2023.

EOG will be operator and expects to start drilling in the second half of 2025 with COO Jeffrey Leitzell estimating that first gas will "be pushed probably more into 2026." And according to Mr Yacob "the agreement does anticipate selling the production into the local market," but "as far as gas price in-country, we haven't talked about that." As with elsewhere in the region, gas prices are relatively low in Bahrain, with key industrial player Alba paying BapcoEnergies $4/mn BTU for gas feedstock.

Once first gas is achieved, EOG will become the first foreign firm to produce in Bahrain since US firm Oxy and Abu Dhabi's Mubadala pulled out of the Tatweer Petroleum JV in 2016 (MEES, 10 June 2016).

The Bahrain entry marks EOG's second bite at the GCC cherry. In 2020, the firm was awarded stakes in two Oman blocks with unconventional potential, but after only 18 months EOG relinquished its stakes in both (MEES, 4 March 2022). Mr Yacob is hopeful of a more lasting presence in Bahrain saying "We expect this to be the beginning of a long-term partnership with Bapco Energies."

ANOTHER GO OFFSHORE?

The agreement is the first positive sign for Bahrain's unconventional developments in years. Bahrain had built up big hopes around the offshore Khalij al-Bahrain basin after discovering sizeable oil and gas resources (MEES, 29 May 2020). France's TotalEnergies and America's Chevron signed up to preliminary agreements while Italy's Eni inked an exploration and production sharing agreement (EPSA) for offshore Block 1 and a preliminary deal for offshore Block 2. But hopes were eventually punctured by the departure of all three IOCs by 2023 (MEES, 29 September 2023).

Despite failure to keep IOCs during the first round of excitement BapcoEnergies is not deterred. It is continuing to de-risk its offshore acreage to entice international companies back into its waters. "This is the point," Mr Thomas told MEES last year, "our actual geophysical coverage to date has been fairly limited and lower quality. So, to attract IOCs to come in using that quality of data is very difficult. That's why we took the step of saying we will take on our own 3D seismic campaign."

Mr Thomas says the campaign will run from 2025 to 2026 and cover 4,500km^2 around the island shooting at a depth of 6,000 meters. From there BapcoEnergies envisages beginning exploration drilling from 2027. If successful, EOG may eventually be joined by other IOCs in Bahrain.

BAHRAIN & NEARBY SAUDI OIL & GAS INFRASTRUCTURE

OIL FIELD/PIPELINE GAS FIELD/PIPELINE
EXPORT TERMINAL REFINERY

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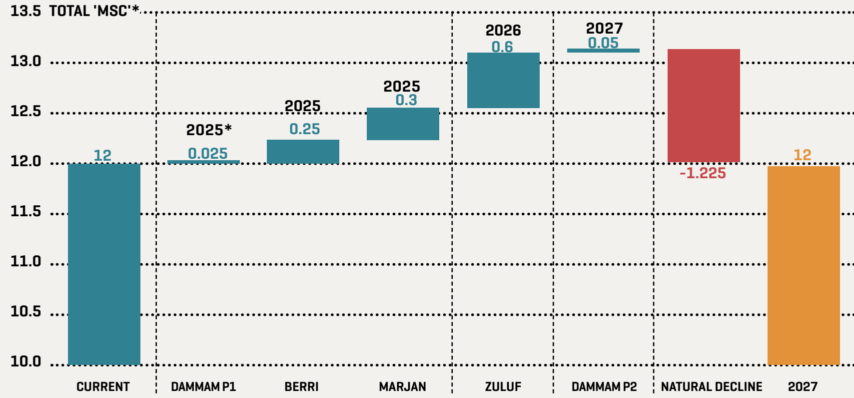
Aramco Approaches Finishing Line For Offshore Crude Increments

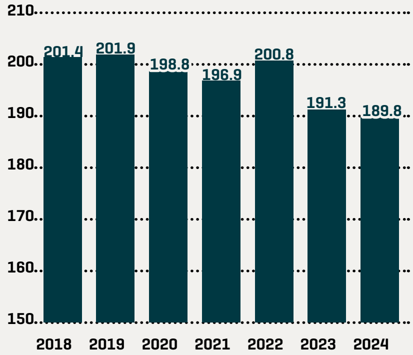
Aramco's huge offshore crude oil increment projects are approaching the finishing line. CEO Amin Nasser says the firm's spare capacity adds tremendous value given the cyclical nature of oil markets.

1: SAUDI ARAMCO'S INCOMING CAPACITY ADDITIONS ARE SLATED TO OFFSET 1.2MN B/D OF NATURAL DECLINE TO ENABLE CAPACITY TO STAY FLAT AT 12MN B/D (MN B/D)



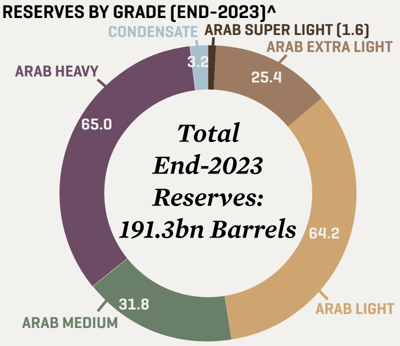
*DAMMAM PHASE 1 COMMISSIONING UNDERWAY, PRODUCTION ONLINE IN 2025. SOURCE: ARAMCO, MEES.

2: ARAMCO CRUDE & CONDENSATE RESERVES HAVE BEEN DECLINING (BN BARRELS)



SOURCE: ARAMCO, MEES.

3: SAUDI ARAMCO CRUDE AND CONDENSATE* RESERVES BY GRADE (END-2023)^



*MEES ESTIMATE FOR CONDENSATE RESERVES BASED ON LATEST DATA.
^ARAMCO RESERVES LESS THAN KINGDOM'S RESERVES FROM ARAMCO FIELDS DUE TO CONCESSION TERMS. SOURCE: ARAMCO, MEES.

Saudi Aramco is set to bring onstream its Manifa and Berri crude oil increment projects later this year, with the offshore fields forming a key pillar of efforts to maintain its 12mn b/d crude production capacity. The two increments have combined capacity of 550,000 b/d, and are part of a huge program which will bring online a total of more than 1.2mn b/d by 2027 (see chart 1) – equivalent to 10% of total capacity.

Although Aramco dropped its plans to increase capacity to 13mn b/d early last year (MEES, 2 February 2024), the claimed 12mn b/d capacity figure implies that the firm currently has in excess of 3mn b/d spare capacity. Saudi Arabia has been producing just under 9mn b/d since July 2023 (see p10), including around 200,000 b/d from the Partitioned Neutral Zone (PNZ) which is not included in Aramco's concession.

The firm emphasizes that it sees maintenance of this spare capacity as highly valuable, as it "provides an opportunity to capture significant incremental cashflow" when global markets tighten. "We sit on 3mn barrels [per day] of capacity, readily available. It can be activated in a matter of weeks when needed. We've seen what happened in 2022," CEO Amin Nasser said during a 4 March media call, highlighting that year's geopolitical turbulence which drove profits to a post-IPO record of $161bn.

Although the key projects intended to bring capacity to 13mn b/d were maintained, Aramco is allowing capacity to decline elsewhere, while pre-FID projects such as a planned 700,000 b/d increment at the Safaniyah offshore field and 300,000 b/d at the offshore Manifa field have been shelved (MEES, 16 February 2024). This appears to have contributed to a 1.5bn barrel drop in Aramco's crude and condensate reserves last year (see chart 2), as resources previously slated for development in the Aramco concession's lifetime have been pushed back.

RESERVES LEAN HEAVY

Aramco says that it ended 2024 with 189.8bn barrels of proved crude and condensate reserves, down from 191.3bn barrels last year and 204.8bn barrels in 2017 – the highest figure on record.

The firm is hopeful that it will be able to tap into more of its reserve base from now on, with Saudi Arabia beginning the gradual process of unwinding voluntary production cuts next month . Under the current roadmap, Saudi Arabia is due to add 1mn b/d of production over the course of 18 months, to bring its Opec+ quota to 9.98mn b/d in September 2026. "Every 1 million barrel [per day] of additional production that is put in the market will give us approximately $12 billion of additional operating cash flow [per year]" says Mr Nasser – based on average 2024 oil prices.

At just 56,000 b/d the monthly increases are modest, but if they are not paused will swiftly add up to sizeable additional production. Aramco will have to decide which crude oil grades to bring back to the market, assessing market conditions and requests from its buyers.

Of Aramco's crude and condensate reserves, around 186bn barrels are of crude oil. Aramco markets five grades of crude oil, and by far the two largest components are of its <29° API, >2.9% Sulfur Arab Heavy (65bn barrels) and the 32-36° API, 1.3-2.2% Sulfur Arab Light (64bn barrels) (see chart 3).

Aramco is tapping into its reserves of these crude grades, as well as the 29-32° API, 2.2-2.9% Sulfur Arab Medium (32bn barrels), through its offshore developments. This year, the Marjan increment will yield 300,000 b/d of Arab Medium capacity, and the Berri increment another 250,000 b/d of Arab Light. Meanwhile next year will see the larger Zuluf increment unlock 600,000 b/d capacity of Arab Heavy.

Despite many of its largest oilfields having produced for decades, Aramco's use of enhanced oil recovery is minimal. The firm says the "main recovery mechanism for its oil reservoirs is peripheral water injection," adding that at some fields gas is re-injected. It has low depletion rates across its portfolio, with 73% of its crude reserves as of end-2023 in reservoirs that were less than 40% depleted. 41% of reserves are in reservoirs with less than 20% depleted.

As a result of this, Aramco puts its industry-leading low upstream production costs of just $11.8/boe, of which $3.5/boe is lifting costs, against what it says is an IOC average of $27.7/boe. Meanwhile upstream carbon intensity of 9.7kg of CO_2e/boe remains well below industry average, although it edged up from 9.6 the previous year (MEES, 25 October 2024). As Aramco seeks to decarbonise further, Mr Nasser pointed to last year's FID for a 9mn t/y carbon capture facility at Jubail (MEES, 6 December 2024) which is now due online in 2028. ◆◆

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UPSTREAM OIL & GAS
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Saudi Arabia Eyes 'Competitive Advantage' From Gas Output Growth

First gas from Saudi Arabia's giant Jafurah Basin unconventional project is expected in Q3. The highly symbolic development will help boost Saudi gas output to record highs and is central to Aramco achieving its ambitious 2030 gas growth target.

The unconventional revolution is set to truly take hold in Saudi Arabia this year when the first phase of the $110bn Jafurah Basin gas development starts up in Q3. Slated to produce 2bn cfd of natural gas by 2030, alongside substantial liquids byproducts, initial output will be around 200mn cfd.

The Jafurah development in Eastern Province is a lynchpin of Aramco's efforts to increase sales gas output by more than 60% versus 2021 levels to at least 14.7bn cfd by 2030 (see chart 1). This in turn is seen by Saudi Arabia as a key enabler of economic growth. As well as displacing upwards of 1mn b/d of liquids from the utilities sector, low-price, low-carbon gas is intended to underpin industrial growth.

"Gas is a competitive advantage for industries here in the kingdom. That's why it is it is always in demand, and [Saudi Arabia] will continue to see more demand for gas," Aramco CEO Amin Nasser told a media call for the firm's 2024 earnings. The CEO also highlighted ongoing work on expanding the Master Gas System distribution network (MEES, 5 July 2024), which "has a lot of branches going to different cities and places around the kingdom, connecting not only the utility side, but also industrial sites that will avail a lot of industrialization opportunities across the kingdom."

Aramco says that sales gas is the largest single energy source in the kingdom, accounting for 37% of the energy mix and 56% of the utility sector's fuel mix last year. Gas reserves at end-2024 stood at 209.8tcf, up from 186tcf in 2018 (see chart 2), with Aramco noting that "non-associated gas exploration activities have yielded a number of major discoveries, with particular success in the Ghawar area and in deep reservoirs in the Arabian Gulf."

JAFURAH DRIVES FURTHER GAS GAINS

The US was the first mover and remains the dominant producer of unconventional gas globally. The move across to the Middle East has been slow to occur, but is now picking up pace. Oman was the pioneer, with the BP-led Khazzan tight gas project starting up in 2017, and Muscat is now looking to increase output from the development above current levels of 1.5bn cfd (see p2). Meanwhile in Abu Dhabi, Adnoc's Ruwais-Diyab unconventional gas development recently started up at around 100mn cfd (MEES, 28 February), whilst Bahrain is looking to get in on the act via a recent agreement with US firm EOG (see p6).

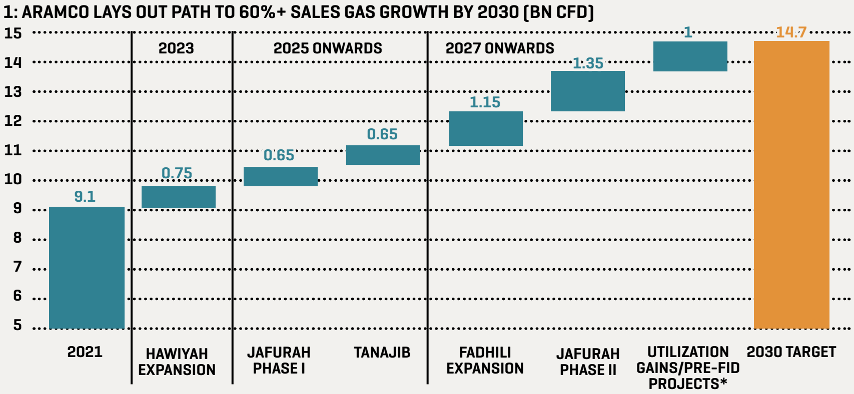
Aramco started up its own 240mn cfd North Arabia unconventional project in 2018 followed by the 300mn cfd capacity South Ghawar project in 2023 (MEES, 17 November 2023), but Jafurah is the centerpiece of its unconventional gas projects. The firm estimates that Jafurah contains total resources of 229tcf of raw gas and 75bn barrels of condensate and last year booked reserves of 15tcf and 2bn barrels respectively.

Mr Nasser is confident that Phase 1 output will begin this year, while Aramco awarded $12.4bn of contracts for Phase 2 development last July (MEES, 5 July 2024) and has begun the process of awarding Phase 3 contracts (MEES, 31 January). "The first phase of the Jafurah development is also on track, and is expected to produce 200mn cfd of sales gas later this year. But we are not stopping there. Contracts have been awarded, and work has already started on the second phase of the project," says the CEO.

The Jafurah Basin is the highest profile project coming online this year, but Aramco also plans to bring onstream the Tanajib gas processing plant. Tanajib will be able to process up to 3.6bn cfd of raw gas from the Zuluf and Marjan fields – associated and non-associated – although Aramco's figures indicate that after stripping out valuable liquids and impurities such as H_2S, sales gas yields will be just 650mn cfd.

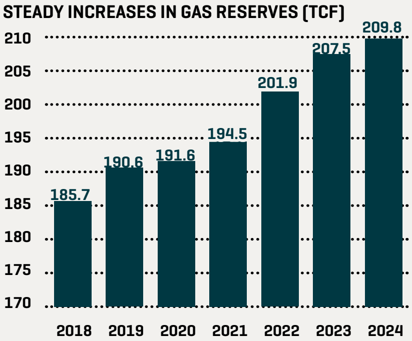
Output of sales gas and ethane – Aramco no longer provides separate figures – increased by 160mn cfd last year to a record 10.83bn cfd (see chart 3), of which around 9.8bn cfd will have been sales gas. Output has been consistently, albeit slowly, growing year-on-year and the new facilities should yield further gains this year. With Saudi Arabia starting the process of tapering its voluntary Opec+ crude oil production cuts from next month (see p10), Aramco could also manage to increase output of associated gas volumes in 2025. ◆◆

1: ARAMCO LAYS OUT PATH TO 60%+ SALES GAS GROWTH BY 2030 (BN CFD)



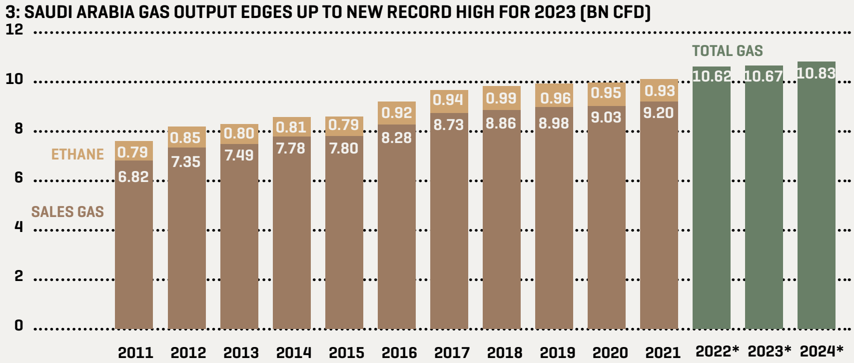
*AT LEAST 1BN CFD. SOURCE: ARAMCO, MEES.

2: ARAMCO EXPLORATION SUCCESSES DRIVE STEADY INCREASES IN GAS RESERVES (TCF)



SOURCE: ARAMCO, MEES.

3: SAUDI ARABIA GAS OUTPUT EDGES UP TO NEW RECORD HIGH FOR 2023 (BN CFD)



*ARAMCO HAS STOPPED BREAKING OUT SALES GAS AND ETHANE OUTPUT. SOURCE: SAUDI ARAMCO, MEES.

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Saudi Aramco Maintains Investment Focus Despite Falling Profits

Aramco's capex could rise as high as $58bn for 2025, the firm says, as it presses ahead with a swathe of ambitious projects across the energy mix. But last year's lower oil prices mean a much-reduced dividend to Saudi state coffers.

Saudi Aramco remains committed to counter-cyclical capital investment, resisting any temptation to curtail spending despite falling profits. Net income dropped to a four-year low $106bn for 2024 amid lower oil prices and a full year of voluntary Opec+ production cuts, and free cash flow fell well short of covering its dividend distributions, but the firm is sticking to its guns.

"Don't forget, this is a cyclical market. You need to remain resilient," says CEO Amin Nasser, pointing to Aramco's expectations of 1.3mn b/d global oil demand growth this year.

"We continued to deliver a strong and resilient financial performance in 2024 despite market volatilities," CFO Ziad al-Murshed told the firm's 4 March earnings call, adding that "our net income was $106.2bn in 2024 which while down by 12% versus 2023 demonstrates our relative resilience, as our peers saw a 26% decline in net income over the same period."

Instead of cutting investment, dividend payouts on which the central government's budget rely heavily are set to fall by a sharp 32% this year. The firm says that although it is increasing its Q4 base dividend (for distribution this month) by 4.2% year-on-year to $21.1bn, last year's weaker financial performance means that the performance-linked dividend is set to slump from around $10.8bn/quarter to just $200mn. The performance dividend is based on free cash flow levels, which were down 16% on 2023.

On an annual basis, Aramco says that it expects the combined dividend payout to slump from $124bn to $85.4bn.

SAUDI ARAMCO: KEY 2024 STATS ($BN)

	2024	%chg	2023
Net Income	106	-12	121
EBIT	206	-11	231
Capex	53	+7	50
Free Cash Flow	85	-16	101
Dividends Paid	124	+27	98
Gearing	4.5	-171	-6.3
Hydrocarbon Output (boe/d)	12.40	-3%	12.77
o/w Liquids	10.29	-4	10.68
Gas (bn cfd)	10.83	+1	10.67
Crude Oil Price ($/B)	80.2	-4	83.6
Upstream Carbon Intensity*	9.7	+1	9.6

*KG CO2e/BOE. SOURCE: SAUDI ARAMCO, MEES.

FIRM INVESTMENT COMMITMENT

Capital expenditure increased by 7% last year to a record $53bn, with upstream investment of $39.2bn accounting for nearly three quarters of the total. Aramco has long maintained that capex will continue rising into the middle of the decade, and its initial guidance for 2025 shows that Aramco remains committed to this goal. The firm is guiding for investments of $52-58bn for the current year, with a midpoint of $55bn representing a 5% year-on-year increase.

Regarding the split between sectors, Mr Nasser says that "in the short term, you're looking at upstream oil and gas 60%, then 30% for downstream and 10% for new energies. If you look at the long term, capex is split 50% for upstream, 35% for downstream and 15% for new energies."

On the upstream front, the firm is approaching the finishing line for key offshore crude oil increments (see p7), and intends to boost sales gas production by 60% from 2021 levels by 2030 (see p8).

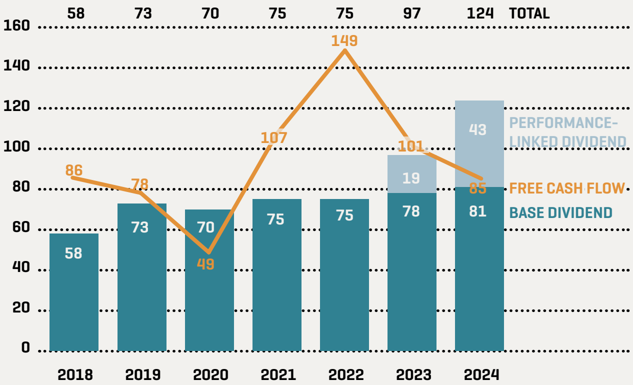
Meanwhile on the downstream side, it is advancing domestic projects such as the Amiral petrochemicals complex with TotalEnergies (MEES, 8 November 2024), as well as large scale liquids-to-chemicals projects in Korea and China (MEES, 23 December 2022). Aramco's strategy is based on firming up outlets for its primary crude oil production, and the firm says that last year its downstream facilities consumed a record 53% of its crude output, up from 47% the previous year and just 38% in 2019.

When it comes to new energies, Saudi Aramco has made significant progress in the development of solar PV plants. Partnering with the PIF sovereign wealth fund and Acwa Power, Aramco now has stakes in three plants with combined capacity of 4.16GW, and last year reached financial close on three more projects with capacity of 5.5GW (MEES, 6 September 2024).

It's less plain sailing for Aramco's blue hydrogen plans, as industry faith in the fuel fades away due to its high costs against conventional fuels. Aramco had targeted 11mn t/y of blue ammonia (as a carrier of hydrogen) by 2030, but Mr Nasser says that has now been downsized to just 2.5mn t/y – and that target is itself hanging by a thread. "We have ongoing commercial discussions with regard to blue ammonia... we will not even pursue that [2.5mn t/y] unless we sign an offtake [agreement]."

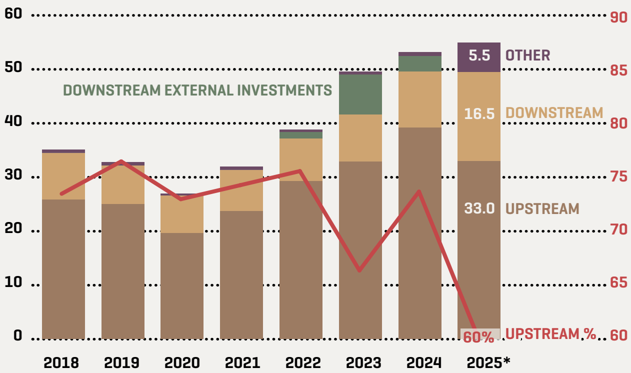
Instead, Aramco is placing more hope in the potential development of in-kingdom lithium reserves. The firm eyes production potentially beginning in 2027 (MEES, 17 January). "One diversification example that we are excited about is our exploration of opportunities in energy transition minerals such as lithium in Saudi Arabia, which aligns with our growth strategy and aim to support our move into alternative energy sources," says Mr Nasser. ◆◆

1: ARAMCO FREE CASH FLOW PLUNGED BELOW DIVIDEND DISTRIBUTIONS IN 2024 ($BN)



SOURCE: ARAMCO, MEES.

2: ARAMCO GUIDES FOR FURTHER CAPEX INCREASES IN 2025 DESPITE REDUCED EARNINGS ($BN)



*MID-POINT OF $52-58BN GUIDANCE. SPLIT BASED ON CEO COMMENTS. SOURCE: ARAMCO, MEES.

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OPEC+ TAPER TO BEGIN NEXT MONTH

The Opec+ 'Group of Eight' will begin easing production cuts in April in line with its December roadmap, resisting speculation that global geopolitical uncertainty would force another deferral. 'Compensation' cuts from overproducers are slated to offset the tapering, while the group emphasizes its flexibility to pause the process if required.

The 'Group of Eight' put an end to weeks of market speculation on 3 March when the producers reaffirmed that they will begin unwinding 2.2mn b/d of voluntary cuts from 1 April. With prices weakening in the buildup, speculation had been building that another deferral might be required, although MEES assessed that production increases remained the likeliest outcome (MEES, 28 February). Voluntary cuts will ease by 138,000 b/d in April as a result (see table 1).

As well as unwinding the cuts, the UAE's underlying 'Required Production' level is to be gradually increased by 300,000 b/d through September 2026, bringing the total increase in production to 2.5mn b/d by the latter date.

The announcement surprised many in the market, prompting questions about why the eight producers – Saudi Arabia, Russia, Iraq, UAE, Kuwait, Kazakhstan, Algeria and Oman – decided to increase production at this time. But given that they had already agreed to increase production from April (MEES, 6 December 2024), this is not the question that the producers will have been asking. The key question for the group will instead have been, is the market so weak that they should deviate from the plan?

The answer for now at least, was no. Certainly, if Opec+ is to return additional barrels, April is a good time to start the process as refineries exit winter maintenance programs and begin to gear up for the high demand season – the highly watched US driving season kicks off with Memorial Day on 26 May. Having already deferred the tapering multiple times last year, doing so again would also generate speculation about the group's ability to manage the market.

HEALTHY MARKET FUNDAMENTALS?

Opec says that the eight producers met virtually "to review global market conditions and the future outlook." The decision to proceed as planned was reached after "taking into account the healthy market fundamentals and the positive market outlook."

Global oil stocks are relatively low and the market remains backwardated as buyers seek near-term supplies, but few analysts describe the market as healthy amid concerns that the new US administration's policies on tariffs risk a global economic slowdown. Even Opec in its latest monthly report noted that "the new US Administration's trade policy has added more uncertainty into markets, which has the potential to create supply-demand imbalances that are not reflective of market fundamentals, and therefore generate more volatility" (MEES, 14 February).

Even within the producer group, questions over the health of the market were being asked. In the buildup some delegates told MEES they were unsure that conditions were ripe for production increases, while others were more confident.

However, with the Group of Eight having decided in December to slow down the pace of the tapering by extending the timeframe from 12 months to 18 months, the monthly increments are modest. With both the IEA and Opec itself forecasting Q2 global demand of around 104mn b/d, 138,000 b/d is barely 0.1% of the total. Again, the question becomes is this market so weak that it warrants Opec+ delaying its plans?

Following the meeting, one delegate told MEES that he sees demand as being stronger than generally perceived, pointing to China and India in particular. Certainly, Chinese buying demand for crude oil from Gulf producers has been strong in early 2025, but much of this has been driven by geopolitics amid a tightening of US sanctions on Russia and Iran rather than by strengthening domestic demand and may be a temporary development. That said, low prices typically fuel Chinese buying, which could kick in with Brent now trading around $70/B.

"I see the market is balanced so far, but we'll keep monitoring closely the market fundamentals on a regular basis," says another delegate.

A key barometer of market conditions is the shape of the curve for oil futures, with Opec+ seeking to maintain backwardation when front-month prices are higher than prices for future delivery. Backwardation has eased substantially over the past week, but key crude benchmarks have not flipped into a contango. "As far as we are concerned, the future curve will not flip in contango, and mild backwardation is likely to prevail - this is the price structure that Opec prefers as it maximizes the impact of the marginal barrel it decides to add or subtract from the market," says Harry Tchilinguirian, Group Head of Research at Onyx Capital Group

FRONTLOADING COMPENSATION

Nominally, the group's output is set to rise by 138,000 b/d in April. However, this is without the application of any 'compensation cuts' from producers which have previously overproduced. "Countries with overproduced volumes have also agreed to frontload their compensation plans, so that more of the overproduced volumes are compensated in the earlier months of the compensation period," says the Opec announcement.

Theoretically this could completely offset the April increment, potentially even outstripping it. "The compensation cuts could prevent there being any increase in overall production for some time," says a source. Iraq, Russia and Kazakhstan are routinely singled out as having overproduced, and the Opec Secretariat says that overproducers will have to submit updated compensation schedules by 17 March, which will then be posted online.

In practice, substantial compensation cuts will be hard to achieve. Iraq has only once come close to achieving full compliance with the voluntary cuts, in January when it was 10,000 b/d above quota, let alone managed to compensate, and MEES calculates that production last month increased by 100,000 b/d. With electricity demand beginning to increase seasonally

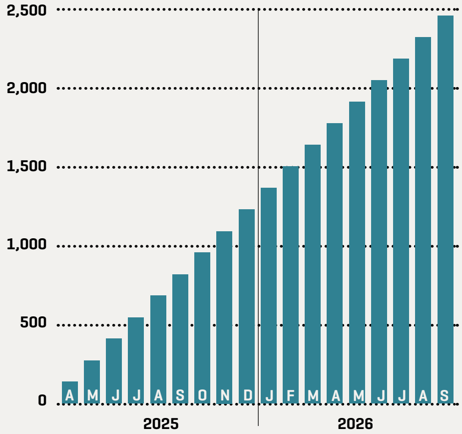
Continued on – p11

OPEC+ BEGINS TO TAPER ('000 B/D)

	Current Allocation	Change	April Allocation
Algeria	908	+3	911
Congo	277	-	277
Eq. Guinea	70	-	70
Gabon	169	-	169
Iraq	4,000	+12	4,012
Kuwait	2,413	+8	2,421
Nigeria	1,500	-	1,500
S Arabia	8,978	+56	9,034
UAE	2,912	+26	2,938
Opec9*	**21,227**	+105	**21,332**
Azerbaijan	551	-	551
Bahrain	196	-	196
Brunei	83	-	83
Kazakhstan	1,468	+5	1,473
Malaysia	401	-	401
Mexico	1,753	-	1,753
Oman	759	+2	761
Russia	8,978	+26	9,004
Sudan	64	-	64
S Sudan	124	-	124
Non-Opec	**14,377**	+33	**14,410**
Opec+ Total	**35,604**	+138	**35,742**

*LIBYA, IRAN, VENEZUELA EXEMPT. SOURCE: OPEC, MEES

CUMULATIVE RETURN OF BARRELS* UNDER NEW OPEC+ ROADMAP TO UNWIND 2.2MN B/D OF VOLUNTARY CUTS ('000 B/D)



*INCLUDES IMPACT OF UAE REQUIRED PRODUCTION UPLIFT. SOURCE: OPEC, MEES.

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Continued from – p10

in the coming weeks as temperatures rise, Iraq will be looking to maximize production of liquid feedstocks and associated gas for its power plants, especially as the US pressures energy imports from Iran (MEES, 14 February). Deep compensation cuts will be difficult to pull off.

Meanwhile, Kazakhstan's ability to comply is undermined by the ramp-up of expansion capacity at Chevron's Tengiz oilfield, with oil output hitting a new record high in February.

At a virtual press conference on 7 March, Kazakhstan's deputy energy minister Alibek Zhamauov said that production will be cut to 1.45mn b/d this month, slightly below quota. But for this to be achieved, cuts will have to be deeper still for the second part of the month. Talks with IOCs on how to implement this are set to extend into next week.

Overproducing countries can expect to come under significant pressure to improve compliance going forward, although from a market balances perspective, if they are already overproducing then they won't be increasing production as quotas unwind.

ADAPTABILITY TO UNCERTAINTY

The decision to unwind the cuts coincided with US President Donald Trump's move to officially impose tariffs on Canada, Mexico and China this week. The impact of the Opec+ decision on prices was therefore overshadowed by a broader market sell-off affecting a range of commodities and currencies not just oil. Brent had closed the previous week at $73.18/B, but dropped below $70/B on 5 March and was just above the threshold as MEES went to press.

Amid this uncertain global landscape, Opec emphasizes that it remains "adaptable to evolving conditions. Accordingly, this gradual increase may be paused or reversed subject to market conditions. This flexibility will allow the group to continue to support oil market stability." One delegate also emphasizes that the option to potentially reverse the process is a very real one, should market conditions require.

A reversal would come with challenges, as it would potentially face internal resistance and would risk criticism from US President Donald Trump who has called on Opec to help bring down oil prices. Morgan Stanley notes that its balances suggest "it is possible that the group will have just a few monthly output increases, before they come to a halt again later this year."

TRUMP'S SANCTIONS SQUEEZE

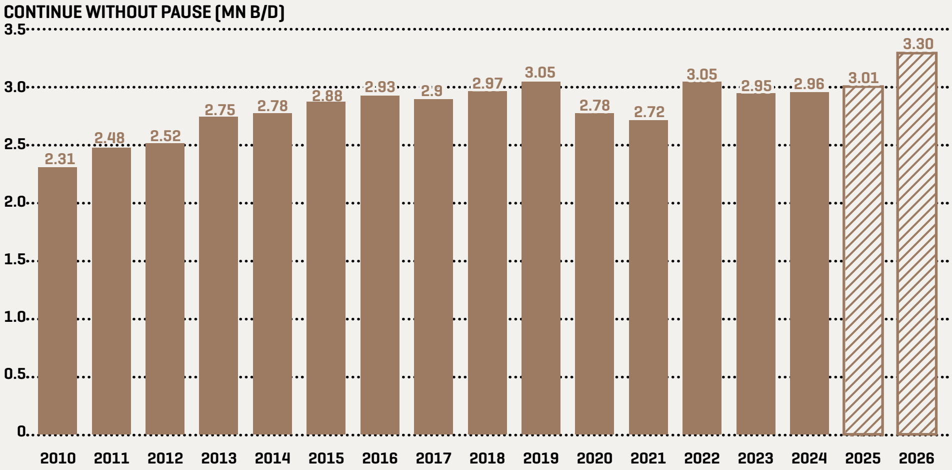
If Mr Trump's tariffs policy is causing geopolitical volatility, so too are his administration's policies on sanctions, albeit exerting a more bullish influence on prices. Recent sanctions moves have targeted Opec producers Iran and

OPEC WELLHEAD PRODUCTION, FEBRUARY 2025 (MN B/D, MEES CALCULATIONS)

	Feb25	vs Jan25	vs Feb24	vs Allocation	Allocation**	Jan25	Dec24	4Q24	vs 4Q23	2024	vs	2023
Algeria	0.91	-	-	+0.00	0.91	0.91	0.91	0.91	-0.05	0.91	-0.06	0.97
Congo	0.26	-	+0.01	-0.02	0.28	0.26	0.26	0.26	+0.01	0.25	+0.01	0.25
Eq Guinea	0.06	-	+0.01	-0.01	0.07	0.06	0.06	0.06	-	0.06	-0.00	0.06
Gabon^	0.22	-0.01	+0.01	+0.05	0.17	0.23	0.23	0.22	+0.01	0.21	+0.01	0.20
Iran^	3.28	+0.03	+0.18	n/a	n/a	3.25	3.27	3.28	+0.15	3.22	+0.41	2.81
Iraq^	4.11	+0.10	-0.25	+0.11	4.00	4.01	4.03	4.06	-0.27	4.21	-0.11	4.31
Kuwait*^	2.40	-0.01	-0.01	-0.01	2.41	2.41	2.42	2.41	-0.14	2.42	-0.20	2.62
Libya^	1.38	-0.02	+0.22	n/a	n/a	1.40	1.31	1.24	+0.06	1.12	-0.06	1.18
Nigeria^	1.49	+0.02	+0.07	-0.01	1.50	1.47	1.49	1.45	+0.05	1.41	+0.10	1.31
S Arabia*	8.95	-0.02	-0.02	-0.03	8.98	8.97	9.01	9.01	+0.03	9.00	-0.65	9.65
UAE	2.91	+0.01	-0.06	-0.00	2.91	2.90	2.86	2.93	+0.04	2.96	+0.01	2.95
Venezuela^	0.92	+0.03	+0.12	n/a	n/a	0.89	0.89	0.88	+0.11	0.84	+0.11	0.73
TOTAL^	**26.89**	+0.13	+0.28	n/a	**n/a**	**26.76**	**26.74**	**26.70**	-0.01	**26.59**	-0.44	**27.04**
Opec 9	21.31	+0.09	-0.24	+0.09	21.23	21.22	21.27	21.30	-0.33	21.41	-0.90	22.31

^REVISED *INCLUDES SHARE OF NEUTRAL ZONE. ** INCLUDES VOLUNTARY CUTS, EXCLUDES IRAQ'S COMPENSATION CUTS. SOURCE: MEES.

UAE's OPEC+ UPLIFT MEANS PRODUCTION CAN COME CLOSE TO 2022's RECORD ANNUAL HIGH THIS YEAR, SHOULD TAPERING CONTINUE WITHOUT PAUSE (MN B/D)



*BASED ON ROADMAP AGREED ON IN DECEMBER 2024 MEETING. SOURCE: OPEC, MEES.

Venezuela. Both are exempt from production cuts and have managed to implement production rebounds over the past two years thanks to lax US sanctions enforcement, and the new US administration wants these gains reversed.

While many remain skeptical that these measures will result in large supply outages, given the proliferation of sanctions workarounds and the large shadow fleet now serving sanctioned crudes, even a partial success would create room for new Opec+ volumes.

On 24 February, the US Treasury sanctioned Hamid Boord, CEO of National Iranian Oil Company, in addition to oil brokers, tanker operators and ship managers in the UAE, Hong Kong, India and China. This follows recent reluctance by Chinese buyers and ports since December to receive sanctioned tankers carrying Iranian volumes (MEES, 7 February).

There are indications that China is again increasing its imports of Iranian crude, much of which has been left stranded on floating storage offshore Malaysia and Singapore.

Kpler's Senior Commodity Analyst, Homayoun Falakshahi estimates that floating Iranian storage "remains elevated at 21mn barrels, with 16mn barrels around Malaysia and Singapore," but notes that the increase in Chinese imports has already seen oil outflows from Iran rise by more than 340,000 b/d last month, to more than 1.8mn b/d. Iranian oil production was at a three-month high 3.28mn b/d in February.

The Trump administration has emphasized its plans for a 'maximum pressure' campaign on Iranian oil exports, but as yet action has not matched rhetoric. In contrast to this the US made true on its promise to cancel a license allowing Chevron to operate in Venezuela on 26 February, giving the firm until 3 April to wind down its exports. The US major's early-2023 license was key in boosting Venezuela's oil production close to 900,000 b/d last year. The fate of other exemptions to European firms Repsol, Eni and Maurel & Prom is yet to be determined, but if a US major couldn't escape sanctions, the outlook for their operations is highly questionable. ◆◆

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Speedy Kurdistan Oil Return? Don't Bank On It

Baghdad, the KRG and IOCs operating in Kurdistan remain far apart on terms to restart exports through the Iraq-Turkey Pipeline. The focus of recent discussions has been the scope of work for a consultant to assess production costs and payment for past debts. Erbil wants to remain an intermediary when it comes to payment.

Baghdad's optimistic assertions in recent weeks that a resumption of Kurdistan pipeline oil exports via Turkey was imminent, after being offline nearly two years, have run into cold reality. Key counterparties from the federal government, the KRG and IOCs met twice this week in the Iraqi capital, but major disagreements remain and the outcome is that working committees will now be formed to address various areas of disagreement.

Following the completion of the second meeting on 6 March, the parties plan to reconvene early next week, an attendee tells MEES.

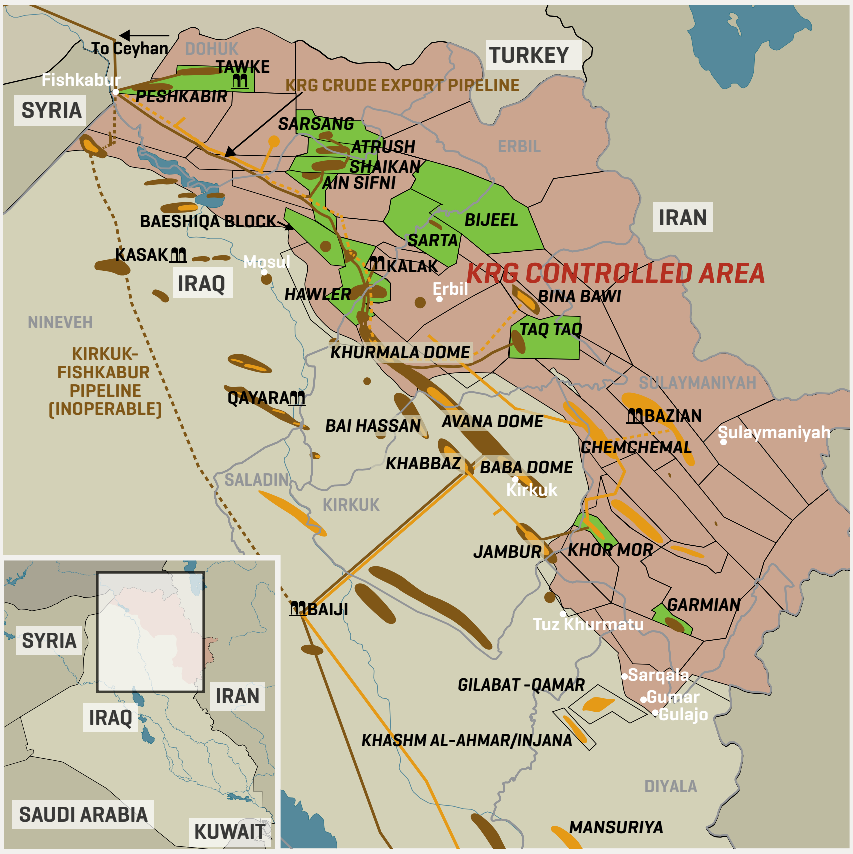
In a 6 March press release after the second meeting, Apikur, the industry body representing IOCs in Kurdistan, reiterated that its members stand ready to restart exports "as soon as the conditions communicated repeatedly since November 2023 are met," adding that these conditions should treat "oil producers in Iraq's Kurdistan Region in a similar manner as oil producers in Federal Iraq."

Calling for further meetings to finalize terms, Apikur says that "Fair and transparent agreements are necessary that include payment surety, transparent implementation of Iraq's budget law stipulations, and resolution of payments that are in arrears."

The meetings come while Iraq is facing pressure from two directions. The US government is pushing for a restart of the export pipeline, whilst Iraq is also under pressure from Opec+ to make 'compensation cuts' for previous overproduction (see p10). Implementing such cuts would grow even more complicated were the pipeline to restart.

IRAQ'S NORTHERN OIL AND GAS INFRASTRUCTURE

OIL FIELD/PIPELINE ■ GAS FIELD/PIPELINE ■ KEY BLOCKS ■ REFINERY



TWO MEETINGS

The first meeting was brought forward from 4 March to 2 March and was headed by oil minister Hayan Abdulghani and his KRG counterpart Kamal Mohammed of the Ministry of Natural Resources (MNR). The meeting included representatives from the IOCs, who for the first time were included formally in Baghdad-Erbil discussions following last month's passage of an amendment to Iraq's Federal budget, increasing an envisaged per-barrel fee for handing over oil production from $6.90/B to $16/B.

That meeting ended with all parties sticking to their guns, with the scope of work of a consultant to be hired to assess production costs at Kurdistan's oilfields emerging as the most contentious issue amidst concerns of "encroachment on the sanctity of our [the IOCs'] Production Sharing Contracts [PSCs] by Baghdad," MEES is told. Despite recent rulings by a Baghdad court upholding the PSCs, Baghdad's oil ministry remains adamant that they are illegal, basing its position on a 2022 ruling by Iraq's Supreme Court.

The lack of progress prompted a follow-up meeting on 6 March, this time including the head of PM Mohammed al-Sudani's office, Ihasan al-Awadi, and the US embassy's Deputy Chief of Mission Elizabeth Kennedy Trudeau. But, despite the political pressure, it appears that none of the parties have drastically changed their pre-existing positions. Each party reiterated their priorities in the second meeting, and while there were hopes of potential progress in upcoming meetings, no detailed solutions were proposed. Fears remain that committee discussions could delay a decision or lead to a "deadlock," MEES is told.

The oil ministry and MNR had agreed the previous week that when exports resume 185,000 b/d would be allocated

Continued on – p13

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Continued from – p12

to the Iraq-Turkey Pipeline, leaving around 115,000 b/d of Kurdistan's current c.300,000 b/d production to be marketed locally. Last week's discussions suggest that the KRG itself would market these volumes to local traders, some of which have been buying crude directly from the IOCs.

The oil ministry has already formed a committee to determine the consultant, which it says would include the MNR. A second "technical committee" is now expected to be formed in order to determine a framework for a mutually-acceptable payment mechanism and to decide which volumes will be exported and which sold locally. It is unclear whether initial discussions to resolve the debt issue would include the IOCs, as a political agreement is first needed between both governments.

Given the distance between the positions of the relevant parties, swift agreement will be no easy task.

CONSULTANT REMIT CLASH

Last month's budget amendment mandated that an "international technical consulting firm" be jointly hired by the oil ministry and MNR within 60 days of its passage on 2 February (MEES, 7 February). The consultant would adjust the $16/B fee for each oilfield in line with production costs, with IOC payments to be backdated to include volumes handed over in the meantime.

The IOCs and MNR were keen to define the scope of work for the consultant, demanding that the firm's remit be limited to auditing financial statements rather than deep-diving into the intricacies of the PSCs. "If they [Baghdad/consultant] evaluate all technical terms and come up with a number, we will not agree as this could interfere and alter the PSC terms," a source says.

Apikur reiterated this in its statement, saying the consultant's scope should be "agreed by all parties and limited to confirming that the Companies' oil sales invoices are prepared in accordance with the PSCs, and there needs to be formal agreed dispute resolution provision within the [consultant's] confirmation process." It adds that its members have recommended consultants to the KRG.

Baghdad's oil ministry has maintained that it can only implement the amendment's text as is, telling the other parties on 2 March that the consultant will evaluate all terms "from A to Z," whether technical or financial, and "field by field." The ministry adds that further study by the joint committee is required before selecting the consultant. However, the IOCs' position remains unwavering, seeing the ministry's views, and both "the amendment and budget law as conflicting with our PSC terms," MEES is told. Baghdad, however, has somewhat relaxed its tone, with a source in the 6 March meeting saying "they said that the consultant will not interfere with contract terms."

The legality of Kurdistan's PSCs has long been central to the dispute between the firms and Baghdad. Oil ministry officials have always denounced the model as detrimental to Iraqi state revenues, compared to the fixed-remuneration service contracts preferred by Baghdad. Apikur says "The Companies' existing contracts are legally valid and their terms must prevail. The economic model within the PSCs must be respected."

The IOCs and KRG have also demanded that Baghdad recognizes the PSCs after recent court rulings, but the oil ministry's Legal Directorate took a hardened position on 2 March. According to an Iraqi source, the directorate said the court has simply recognized the legality of the contracts between signatories, the KRG and IOCs, to "provide ample time for both parties to resolve their existing problems before implementing the Supreme Court's decision."

That decision calls for the PSCs to be replaced. But the oil ministry's legal position has been further impaired this week after Washington "hit hard on Baghdad" following the ministry's 25 February final appeal to the Court of Cassation to review its ruling to uphold the contracts. MEES is told the ministry has "temporarily paused its appeal as a sign of goodwill during talks."

An Iraqi source adds that Mr Abdulghani attempted to re-offer the firms Baghdad's 'profit sharing' Development and Production Contract (DPC) model as a replacement, but IOCs see the model as unworkable in Kurdistan, given existing investment, geological uncertainty and far higher per-barrel development costs than in southern Iraq's oil production heartland.

The IOCs argue that most foreign operators in southern Iraq operate brownfields and that their investment is fully recoverable from Baghdad, with production costs on top. "We don't have existing fields like BP and Total, our wells are deep and expensive...we have a contract and would like it to be honored," says one.

PAYMENT FOR ARREARS

Another major issue the IOCs are keen to see addressed by both Erbil and Baghdad before exports are resumed is payment for their past arrears. Apikur has stated in the past that the MNR owes its members over $1bn for production from September 2022 to March 2023. In its 6 March statement, it says "These payments need to be made directly and transparently to the Companies, without intermediaries or undue delays."

The Iraqi source says that the MNR has sought, in both meetings, to offload the payment obligation onto the oil ministry. But the latter says it is not a legal party to the PSCs, and as such bears no obligation. The MNR claims that it would have fully paid its debts were it not for the pipeline closure following the result of the country's ICC arbitration (MEES, 3 February 2023) and Baghdad's repeated attempts at undermining its independent sector.

Mr Abdulghani was open to reaching an arrangement to pay the debts on 2 March either "in cash or in kind [crude shipments]" if a political agreement results in a government authorization from the Federal finance ministry to do so. But reaching this 'political agreement' would require a separate high-level dialogue between both governments, risking further delay.

One issue on which there are indications of progress is payment for oil delivered to state oil marketer Somo. The oil ministry has informed the MNR and IOCs that it has received a letter from the finance ministry confirming that it will honor invoices sent by Somo for exported Kurdish oil. Officials from PM Sudani's office reiterated verbally these assurances on 6 March, but most IOCs prefer a formalized arrangement including the three parties.

But such an arrangement may eventually be blocked by the KRG. The MNR has indicated to some IOCs that it refuses their proposals of direct payment by Somo, preferring that the finance ministry deposit oil revenues in a KRG bank account, following which it will pay the firms.

Apikur says "The Companies need formal sales/lifting agreements with the buyers of any exported oil, setting out terms and conditions and providing surety that Companies will be fully paid for the oil – even if in two tranches." This indicates willingness to sign separate sales contracts with Somo and the MNR, but it is unclear whether such a proposal was discussed in either meeting.

Another IOC proposal to open an escrow account to guarantee that Erbil does not "tap into the [oil revenues] account" appears for now a matter for later discussion by the two parties once they guarantee payment from Baghdad.

Furthermore, Baghdad appears willing to honor existing sales agreements with oil traders signed by Erbil, even agreeing they "pay the KRG directly but invoice Somo [for the volumes sold]." These firms had marketed Kurdish oil in the past, under prepayment deals with the KRG through which they fronted Erbil with billions in upfront payments. In May 2023, Somo signed temporary contracts with the traders to retain their access to customers in the Mediterranean basin (MEES, 12 May 2023).

But one issue that could become another source of contention is the MNR's demand that the ministry also pay production cost for oil marketed locally by the KRG, according to the Iraqi source. The IOCs' position is that they want to be paid for handing over oil to whichever of the two governments, but KRG revenues from these sales are unlikely to end up in the Federal treasury, and with crude and locally refined volumes sold across border to Iran and Turkey, Baghdad has labelled the practice "smuggling." ◆◆

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Adnoc, OMV Agree On Terms To Create $60bn Petrochemicals Giant

Adnoc's XRG aims to be a top 5 global petrochemicals firm. This week, terms were agreed with OMV to create 'Borouge Group International' which will be the global No.4 polyolefins firm, with XRG's stake worth $28bn.

After nearly two years of talks, OMV and Adnoc have agreed on terms for the merger of their Borouge and Borealis polyolefins companies (MEES, 21 July 2023) to create an industry behemoth with a valuation in excess of $60bn. Upon completion, the newly created "Borouge Group International" will acquire Nova Chemicals from Abu Dhabi's Mubadala for a purchase price of $9.4bn, with an enterprise value of $13.4bn.

The parties expect the transactions to complete simultaneously in 1Q 2026, and following start-up of the under-construction Borouge-4 plant in Abu Dhabi later that year, the merged entity will have polyolefins capacity of 13.6mn t/y across Europe, the Middle East and North America, making it the fourth largest firm in the sector behind CNPC, Sinopec and ExxonMobil.

Upon completion, OMV and Adnoc will each hold 46.9% in Borouge Group International – with OMV injecting $1.6bn into the entity to equalize shareholding – while 6.15% will be listed on Abu Dhabi's ADX exchange. Adnoc's stake will be held by its new XRG subsidiary, which is also finalizing the purchase of Germany's Covestro petrochemicals firm. The firm will be headquartered in Vienna, and will pursue a secondary listing on the Vienna Stock Exchange.

"These transformative transactions mark a pivotal milestone in Adnoc's global chemicals strategy as we deliver on our international growth mandate," says Adnoc CEO Sultan al-Jaber. "The visionary combination of Borouge and Borealis and acquisition of Nova Chemicals, further futureproofs Adnoc and solidifies Abu Dhabi's status as a leader in the chemicals sector."

"Together with Adnoc, our strategic partner of 25 years, we are creating a global polyolefins leader, exceptionally positioned for value creation by accessing the largest and most cost advantaged markets. We aim to significantly increase the sales volumes of innovative polyolefin premium products and be at the forefront of renewable and circular economy solutions," says OMV CEO Alfred Stern.

JOINT CONTROL, VIENNA HQ

The partners announced the transaction on 3 March, and the following day OMV executives outlined the details to shareholders. CFO Reinhard Florey emphasized that "the equal shareholding structure will enable joint control between OMV and Adnoc, allowing both parties to have equal decision making rights in all strategic matters, in order to facilitate synergy, extraction and integration."

In line with Austrian regulations, Borouge International will have a two-tier board structure – a supervisory board and an executive/management board. The supervisory board will consist of five OMV representatives, five from Adnoc and potentially five employee representatives, with Adnoc nominating the chair and OMV the vice chair.

The Nova acquisition will be funded via bridge-financing, which will subsequently be refinanced through a capital increase of up to $4bn in which OMV and Adnoc are not expected to participate, resulting in an increase of the JV's free float. Mr Florey says the capital increase is expected to occur during 2026, indicating that it will be on the ADX given that any planned Vienna listing would take place in 2027 at the earliest.

Mr Florey adds that increasing "the free float position of the new company [is] for inclusion in the relevant MSCI index, enhancing its visibility and attractiveness to global investors." A source close to proceedings says that a free float of around 10% is required for such inclusion.

BUILDING VALUE

Combining the entities will streamline what is currently a convoluted ownership structure. The Borouge joint venture is listed in Abu Dhabi where 10% is traded on the ADX exchange: Adnoc holds 54% and Borealis the remaining 36%. Borealis in turn is a JV between OMV (75%) and Adnoc (25%). Adnoc itself also holds a 25% stake in OMV. Meanwhile Nova Chemicals is wholly owned by Abu Dhabi's Mubadala, which until recently held Adnoc's stakes in OMV and Borealis (MEES, 7 February).

The partners say that the new entity will have a value in excess of $60bn, which is significantly more than the combined valuation of its three constituent parts; while Nova is ascribed an enterprise value of $13.4bn, Borealis and Borouge are currently valued at $11.3bn and $19.5bn respectively, bringing the combined total to around $44.2bn.

OMV and Adnoc aim to generate considerable value from the new venture's improved scale, new synergies and increased access to low-cost Middle East feedstock. Additional value will also be generated from the recontribution of Borouge-4 as well as upgrades at its second ethane cracker unit (EU2), and EU2's polyethylene units (MEES, 7 February). The partners expect Borouge-4 to be recontributed to Borouge Group International during late 2026 for approximately $7.5bn from OMV (30% - $2.25bn) and ADNOC (70% - $5.25bn).

"The compelling synergies with Borealis and Borouge will further drive value creation across the new group, ensuring a stronger, more competitive position in the global market," says OMV's Mr Stern. The CEO says that the combined entity's earnings (Ebitda) would have averaged $4.5bn over 2020-2024; "this is just the beginning. Borouge Group International has tremendous growth potential, with Ebitda projected to exceed $7bn through the cycle [by 2030]." Borouge-4 alone is expected to generate Ebitda of around $900mn.

EMERGING CHEMICALS PLATFORM

The merger agreement is a major boost for XRG, for which Global Chemicals is one of its three strategic platforms. Once the transaction is complete, Borouge Group International will sit alongside Covestro as discrete entities within the platform. Adnoc says that XRG has an enterprise value of $80bn, and the firm's planned 46.9% stake in a $60bn+ Borouge Group international would represent at least $28bn.

The Covestro transaction also proved a lengthy one, with agreement on the $13bn takeover reached in October (MEES, 4 October 2024). Together, the two deals are major landmarks with Adnoc boosting its holdings in two sizeable European-headquartered chemicals firms.

The Covestro deal is currently going through the lengthy process of securing regulatory approval in the many jurisdictions in which it operates, and on 5 March it secured foreign investment clearance for Spain. The two big jurisdictions on which shareholders are awaiting clearance are the US Committee on Foreign Investment in the United States (Cfius) and China.

Securing Chinese approval is taking longer than expected, prompting minor shareholder concerns, with the issue brought up during Covestro's recent earnings call. Covestro management reassured investors that they are confident in the process, and a source tells MEES that while they have noted that approval is taking longer than expected, they have seen nothing to raise cause for concern. Meanwhile regarding Cfius, they noted that the process is moving faster than initially expected, and is now ahead of schedule. ◆◆

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Sinopec-Algeria: $850mn Exploration Deal As Work Starts On Long-Delayed Refinery

Algeria's Sonatrach and China's Sinopec have signed an $850mn contract for exploration and development of the new Hassi Berkine North block. Meanwhile, Sonatrach with Sinopec and Spain's Técnicas Reunidas have finally begun work on a long-delayed new 110,000 b/d refinery at Hassi Messaoud.

Algerian state oil and gas giant Sonatrach and Sinopec on 25 February signed an exploration and production sharing agreement under which the Chinese state firm agreed to invest $850mn on the newly-created 9,700km² Hassi Berkine North block southwest of the country's key oil hub of Hassi Messaoud (see map).

The agreement will see Sinopec cover 100% of exploration costs. "If this [exploration] yields good results, Sonatrach will cover 30% of development costs, while Sinopec will cover the remaining 70%," Sonatrach CEO Rachid Hachichi said at the televised signing ceremony. The 30-year contract is subject to one extension for up to 10 years, Sonatrach says.

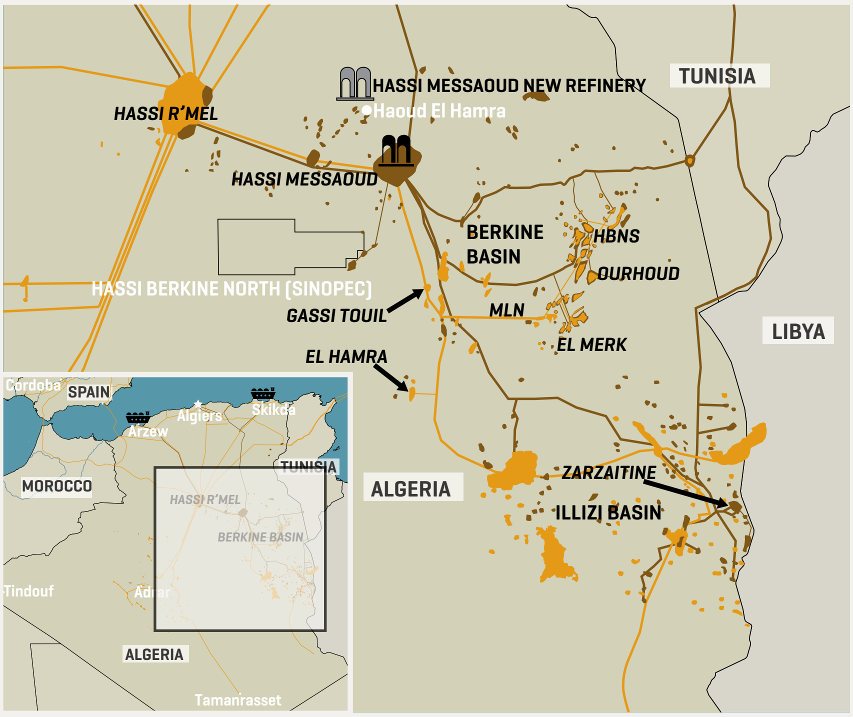
The Chinese firm is already involved in an enhanced oil recovery project at the aging Zarzaitine field on the Libyan border under a 2003 arrangement that was extended for another 25 years under a $490mn contract in 2022 (MEES, 3 June 2022).

During the signing ceremony, Mr Hachichi also said that Sonatrach is in "advanced negotiations" with six international companies for a total of seven "hydrocarbon contracts" and that these would be signed "soon." In addition to Sinopec, Mr Hachichi names Italy's Eni and France's TotalEnergies, the top two current international players in Algeria's upstream, as well as ExxonMobil and Chevron. Snagging one or both of the US majors, neither of which has a current upstream presence in Algeria, would be a big prize for Sonatrach which has indicated on several occasions in recent years that deals were close – perhaps for shale-focused exploration and development (MEES, 21 June 2024). "A Swedish company" would be the last of the six firms, Mr Hachichi says, in apparent reference to a provisional deal inked last year with Tethys Oil (MEES, 19 April) which has since been taken over by China's Roc Oil (MEES, 20 September 2024).

Algeria in October launched a long-awaited bid round with six large onshore blocks encompassing both gas and oil-prone areas of the country (MEES, 18 October 2024).

ALGERIA'S BERKINE BASIN OIL HEARTLAND

OIL FIELD/PIPELINE GAS FIELD/PIPELINE LNG TERMINAL REFINERY



REFINERY RELAUNCH

Sinopec is also now joining Sonatrach and Spain's Tecnicas Reunidas in relaunching the long-delayed 5mn t/y (110,000 b/d) Hassi Messaoud new refinery (MEES, 23 August 2024). Speaking on his firm's Q4 earnings call on 28 February, TR CEO Juan Llado Arburua confirms that a revamped EPC deal with "new price, scope, schedule and contract conditions," as well as Sinopec as a new partner, was finalized in November, a "very successful accomplishment."

In a ceremony marking the 54th anniversary of Algeria's oil nationalization on 24 February, Prime Minister Nadir Larbaoui "laid the foundation stone" at the project site, greenlighting the beginning of construction of the refinery at Haoud el-Hamra, just north of Hassi Messaoud, according to a Sonatrach statement.

The two-phase project is expected to begin initial production of diesel in October 2027, says Sonatrach.

A joint venture of Técnicas Reunidas (55%) and South Korea's Samsung Engineering (45%) in January 2020 were awarded a $3.7bn EPC (MEES, 10 January 2020). But work never begun as Sonatrach sought to re-write the contract in a bid to cut costs (MEES, 26 May 2023).

As for trimming costs, TR says the new EPC contract is worth €4.1bn ($4.45bn), of which the Spanish firm's share is €2.1bn implying a 51:49 split between TR and Sinopec.

TR says that with the relaunch "TR and Sonatrach strengthen their relationship." That said, a legal dispute over repeat technical problems at the 400mn cfd Touat gas project where TR was lead EPC contractor (MEES, 19 April 2024) rumbles on: TR now says the arbitration tribunal has indicated that "a resolution is not expected before the end of 2026." ◆◆

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Nuclear, Renewables Drive Abu Dhabi's Gas-For-Power Demand To Fresh Lows

Low-carbon power plants now account for more than 40% of Ewec's power generation, with gas demand dropping further to a 14-year low.

The transformation of Abu Dhabi's power mix continued apace last year, as the start-up of the Barakah nuclear power plant's fourth and final unit propelled low-carbon power generation to new highs. This year is shaping up to be a quieter one, with no new low-carbon capacity additions due online until the second half of 2026. But Abu Dhabi's clean energy ambitions show no signs of abating, with a steady pipeline of new projects set to come online from 2026 onwards.

Low-carbon plants generated a record 45.9TWh of electricity last year. This accounted for 42.3% of total electricity across state-offtaker Ewec's network, up from less than 1% in 2018 (see chart 1). Of this, the 5.6GW Barakah plant accounted for a massive 39TWh, making it by far the largest contributor to the power mix last year with a 36% share just by itself.

Alongside Barakah came contributions from 2.74GW of renewables capacity, primarily solar, which chipped in with a new record 6.86TWh – up 10% year-on-year. The largest renewables plant is the 1.58GW Al Dhafra solar PV plant which generated 4.38TWh last year. The next planned capacity addition will be the 1.5GW Al Ajban solar PV plant, located close to the 1GW Noor plant, which is due online in 2H 2026; construction began in November (MEES, 22 November 2024).

Unlike nuclear power, renewables suffer from intermittency, but Ewec and fellow state firm Masdar announced in January that they will develop a $6bn plant integrating solar generation with battery storage to provide 1GW of baseload 24/7 power from 2027 (MEES, 17 January).

NUCLEAR CLEANS UP

The fourth unit of the Barakah nuclear power plant started up in September, with the Emirates Nuclear Energy Corporation (Enec) stating that its 40TWh annual power generation removes 22.4mn tons of carbon emissions annually.

Enec CEO Mohamed al-Hammadi said at the time that the scale of Barakah's contribution shows that "integrating nuclear energy into the UAE power's mix and alongside growing renewable energy sources was the right decision, boosting energy security and establishing the UAE as a regional leader in this growing sector." Chairman Khaldoon al-Mubarak added that "this source of clean electricity will act as a magnet, attracting additional investment in the UAE by sustainably-minded, but energy intensive industries from around the globe."

Adnoc already powers its onshore facilities with around 1.6GW of low-carbon electricity supplied by Ewec, and by end-2026 key offshore facilities are due to be connected to the grid (MEES, 24 January). A similar arrangement is planned for Emirates Global Aluminium (EGA) which operates 6.5GW of gas-fired power plants in Abu Dhabi and Dubai.

Firms in Abu Dhabi can offset emissions through purchasing Clean Energy Certificates (CEC) from Ewec through quarterly auctions – the Q1 auction closes on 14 March. Enec notes that "85% of the clean energy certificates managed by Ewec are powered by Barakah, which are used by companies such as Adnoc, EGA and Emirates Steel Arkan to produce greener products that can be sold at a premium, providing a unique competitive advantage for Abu Dhabi-based companies."

The UAE sees this as a key driver of its strategy to boost the industrial sector's contribution to GDP to AED300bn ($82bn) by 2031 (MEES, 27 October 2023), up from last year's projected AED210bn ($57bn).

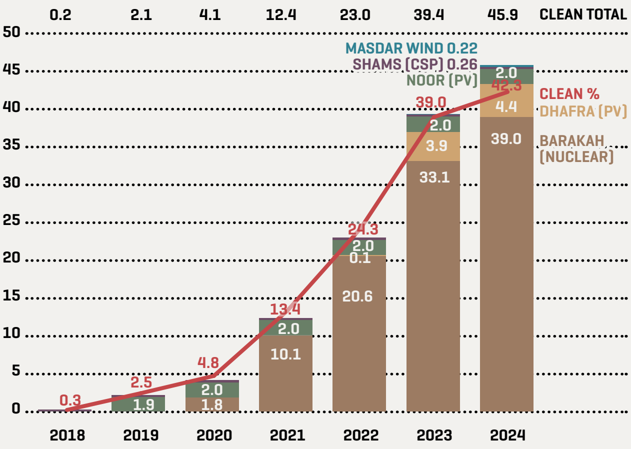
GAS-FOR-POWER DOWN AGAIN

Power generation from Ewec's fleet of plants across Abu Dhabi and Fujairah increased by 6% last year to a record 108.5TWh. The continued growth in clean-power generation means that Ewec's gas consumption fell for the seventh consecutive year to 1.67bn cfd, the lowest figure since 2011 (see chart 2). Ewec's gas consumption is now down 680mn cfd from its 2017 peak, providing a huge boost to the UAE's target of gas self-sufficiency by 2030.

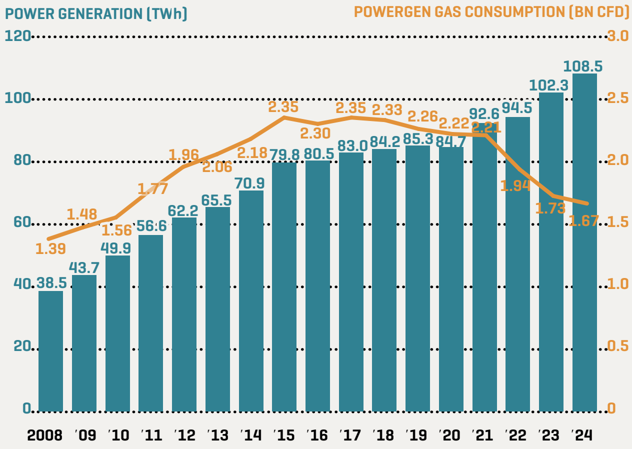
Ewec's changing gas demand profile led the firm to recently sign a new $10bn ten-year gas supply deal with Adnoc Gas which prioritizes flexibility over baseload supplies (MEES, 24 January). The role of gas in Ewec's power mix is set to fall further in the coming years, with the firm increasingly seeing its role as providing flexibility to ramp up generation at short notice to respond to outages elsewhere or surges in demand (MEES, 7 February).

Of course, Ewec doesn't need gas just for power, it is also the offtaker for water produced from desalination plants. Here, Abu Dhabi's $620mn 550,000 m³/d Mirfa 2 reverse osmosis plant is due online in Q4 and will boost Ewec's gas demand. ◆◆

1: ABU DHABI 'CLEAN' POWER GENERATION (TWh): OUTPUT HAS SOARED WITH BARAKAH NUCLEAR RAMP-UP, NOW ACCOUNTS FOR MORE THAN 40% OF GENERATION



2: ABU DHABI'S EWEC GAS FEEDSTOCK REQUIREMENTS FALL 30% FROM THEIR 2017 PEAK DESPITE OVERALL GENERATION SOARING (TWh)



SOURCE: EWEC, MEES.

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Morocco Renewables Powergen Share Hits Record 25% For 2024

*Morocco's power generation from 'new renewables' (overwhelmingly wind and solar, excluding hydropower) leapt by 25% year-on-year to a record 10.75TWh for 2024. This equates to 24.6% of the country's total 43.7TWh of power generated, also a record (see chart 1).

*Whilst the latest figures, included as part of the Moroccan finance ministry's February stats bulletin, do not give a wind/solar split, both wind and solar PV likely notched up output records for 2024.

*Installed wind capacity rose by 320MW to 2.39GW over the course of 2024, with the key addition 270MW at Essaouira on the Atlantic coast north of Agadir (MEES, 25 October 2024). As for solar PV, capacity ended 2024 up around 100MW at 430MW with the largest start-up April's 34MW 'Green Power Morocco-1'. Concentrated solar power (CSP) capacity for now remains ahead of PV, with a nominal 510MW of installed capacity. However one of the three plants that make up this capacity, 150MW Noor III at Ouarzazate, has been offline for the past year (MEES, 28 February), with repeated technical difficulties leading Morocco to shelve plans for further CSP capacity (MEES, 29 March 2024).

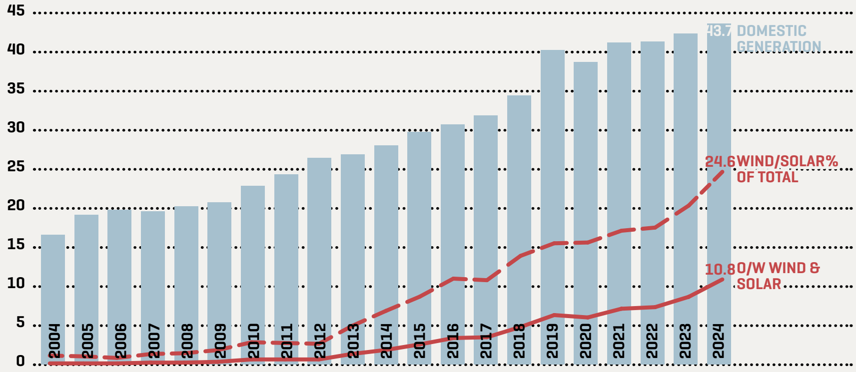
*Renewables accounted for a record 41.3% of Morocco's total end-2024 installed capacity figure of 11.22GW; for 'new renewables' the figure was 28.6% according to a combination of the official stats and MEES project tracking (see chart 2). 2024 also saw the start-up of Morocco's largest to-date pumped storage hydro project, 350MW at Abdelmoumen in the Atlas mountains above Agadir (MEES, 3 January). Whilst MEES excludes pumped storage from its figures for primary generation capacity, Morocco includes pumped storage in its headline figures for official total renewables capacity of 5.45GW, 45.3% of overall 12.03GW capacity including pumped storage.

*Latest stats from the finance ministry also indicate a 3.9% rise in power demand to a record 45.71TWh for 2024, with consumption up 1.9% at 35.10TWh. Power imports from Spain were up 27.5% at a record 2.32TWh, or just over 2TWh once Morocco's modest exports in the other direction are netted off.

*Morocco's thermal power plants, which despite the renewables gains continue to comprise the majority of the country's power generation, remain dominated by coal. However gas-fired powergen, having slumped for 2022 following the halt in deliveries from neighbor Algeria at the end of October 2021, has since rebounded. Imports from Spain (regassified LNG) rose to a record 95mn cfd for 2024 (see chart 3).

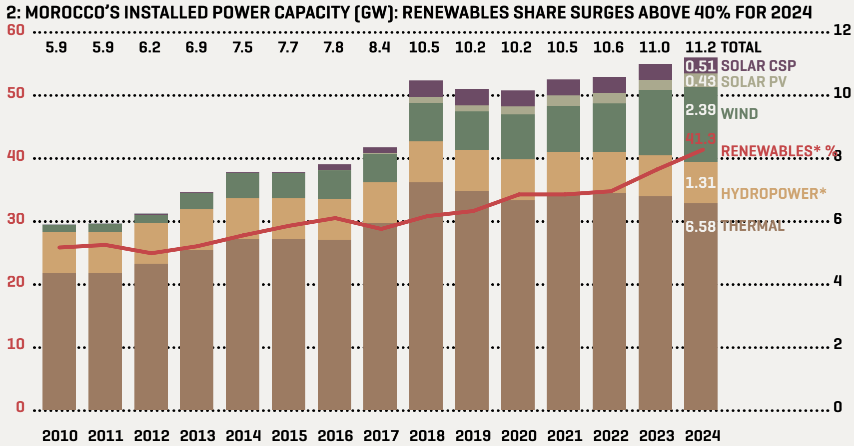
*On the back of rising gas supplies, Morocco's state power firm ONEE last month said it had completed financing and awarded a MD4.2bn ($430mn) EPC contract to a Sino-Japanese consortium comprising China Energy Engineering Corporation and Mitsubishi Power for the 990MW Al Wahda CCGT plant. "The plant is scheduled to be commissioned in early 2027," ONEE says. The state generator adds that use of gas as a "transition fuel" to "ensure that electricity demand is met during peak periods and provide the electricity system with the flexibility required for optimal use of renewable energies" is compatible with Morocco's goal of generating 52% of power from renewables by 2030.

1: MOROCCO POWER GENERATION (TWh): WIND & SOLAR PROVIDED A RECORD 10.8TWh FOR 2024, ALMOST 25% OF THE NATIONAL TOTAL



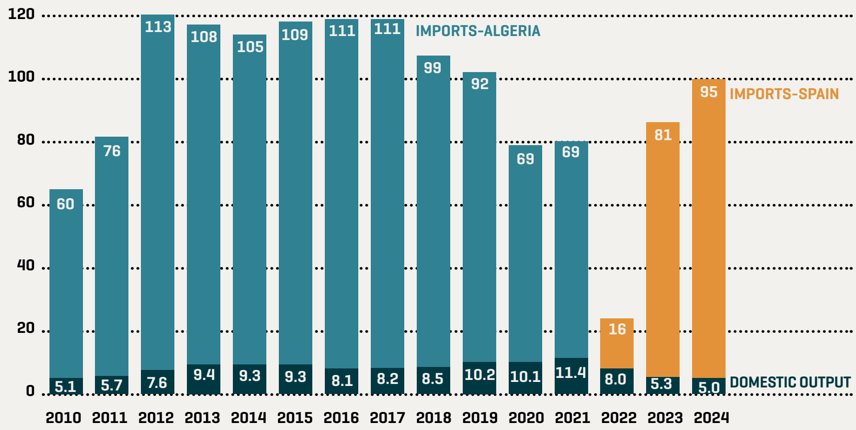
SOURCE: ONEE, MOROCCO FINANCE MINISTRY, MEES.

2: MOROCCO'S INSTALLED POWER CAPACITY (GW): RENEWABLES SHARE SURGES ABOVE 40% FOR 2024



END-YEAR FIGURES. *EXCLUDES PUMPED STORAGE HYDRO (814MW END-2024). SOURCE: ONEE, MOROCCO FINANCE MINISTRY, MEES.

3: MOROCCO GAS DEMAND (MN CFD): IMPORTS FROM SPAIN HIT A RECORD 95MN CFD FOR 2024, MORE THAN EQUAL WITH THE LATTER YEARS OF ALGERIAN SUPPLIES*



*ALGERIA HALTED DELIVERIES FROM NOV 2021. SPAIN VOLUMES ARE RE-EXPORTS OF GAS IMPORTED AS LNG. SOURCE: ENAGAS, JODI, ONHYM, SDX, MEES.

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Tunisia Oil & Gas: Output Collapse, Record Import Dependence

Tunisia's domestic oil output slumped again to 28,800 b/d for 2024, the lowest since Tunisia's first ever year of production in 1966 both in absolute terms and as a share of demand (29%). For gas, output has fallen by almost 60% since peaking at 310mn cfd in 2010. Back then domestic output met 58% of demand; for 2024 the figure was just 28%.

Tunisia's energy stats for 2024 do not make pleasant reading. The country's level of 'energy independence', as per official stats, fell to a multi-decade low 41% with the 'energy trade deficit' balooning by 19% to a record 10.72bn dinars ($3.45bn), the equivalent of 7% of the country's GDP.

This comes as domestic output of both oil and gas fell to new multi-decade lows. For crude and condensate, production of 28,800 b/d was down 4% for the country's lowest ever full year of crude production since first output was achieved with the start-up of Eni's El Borma field in 1966. With oil demand up 3% at 98,400 b/d, the country's oil import dependence hit a record 70.7% (see chart 1).

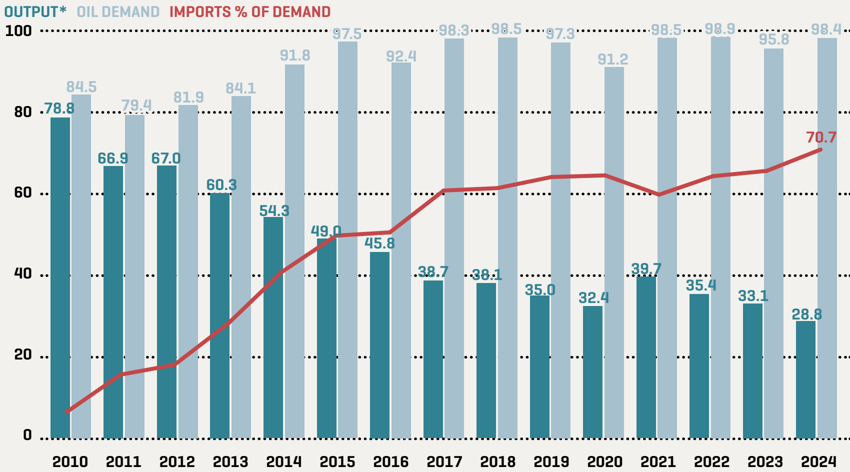
And for gas the picture is no better. Import dependence was even higher at 72.4%, also a record, as output collapsed by 24% to just 134mn cfd, a 16-year low (see chart 2). Gas imports, all from Algeria, were 351mn cfd of which 251mn cfd was paid for and 100mn cfd received in lieu of a transit fee for the 21.1bcm (2.03bn cfd) of gas that Algeria exported to Italy via the TransMed pipeline that traverses Tunisia (MEES, 3 January).

Almost all of Tunisia's gas producers have seen output fall (see chart 3) whilst the country as a whole saw just one exploration well drilled last year (versus five for 2023) and zero development wells (three for 2023), according to official stats.

Tunisia also imported a record 3.22TWh of power, up 29%, almost all from Algeria, with imports accounting for a record 14% of total power supply of 22.51TWh. Algerian state power firm Sonelgaz on 16 February reported a record €268mn in annual export revenue for 2024 (versus €219mn for 2023), the bulk of which is from power exports to Tunisia.

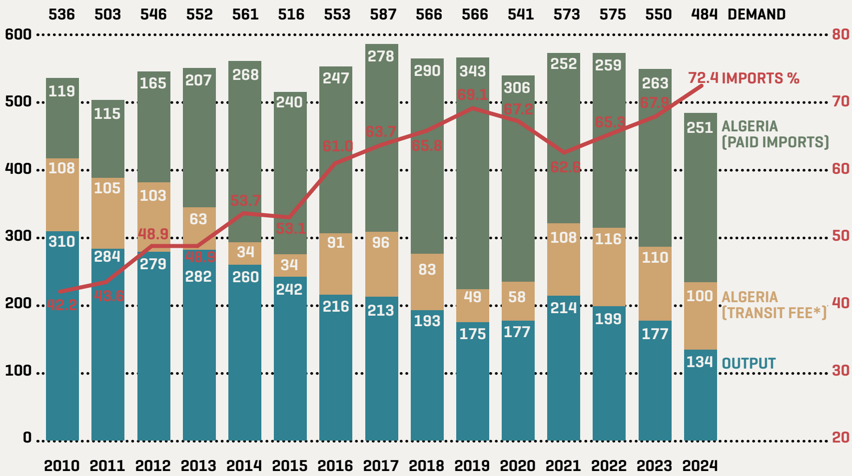
Domestic generation fell 2% to 19.39TWh with 94% of this (18.16TWh) coming from gas-fired plants. One piece of good news came from small-scale solar, output from which rose 34% to 556GWh for 2024, just under 3% of domestic power generation. Tunisia is also finally moving forward on expanding its commercial-scale renewables capacity (MEES, 3 January). ◆◆

1: TUNISIA WAS RELIANT ON IMPORTS FOR A RECORD 71% OF OIL DEMAND FOR 2024 AS PRODUCTION FELL TO A RECORD LOW 28,800 B/D ('000 B/D)



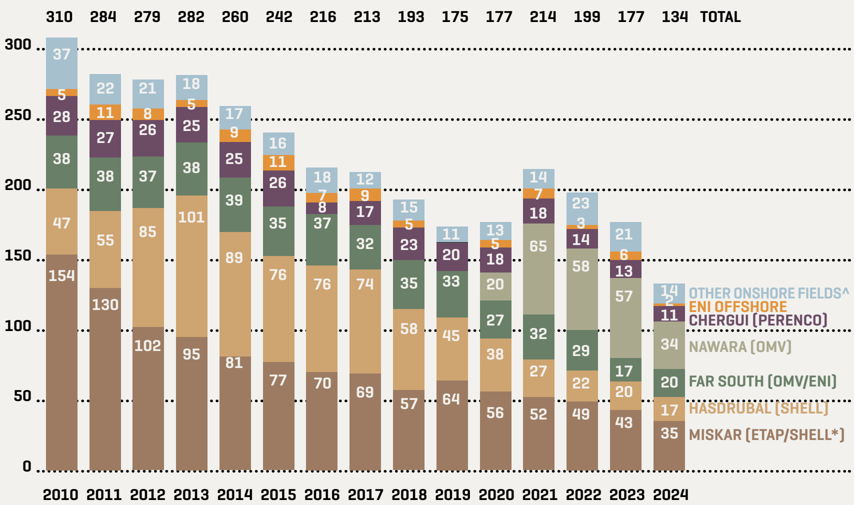
*CRUDE & CONDENSATE. SOURCE: TUNISIA ENERGY MINISTRY, ETAP, JODI, MEES.

2: FOR GAS, TUNISIA'S 2024 DEPENDENCE ON IMPORTS, ALL FROM ALGERIA, HIT AN EVEN HIGHER 72% AS OUTPUT SLUMPED TO A 16-YEAR LOW (MN CFD)



*FOR USE OF TRANSMED PIPELINE TO ITALY. SOURCE: TUNISIA ENERGY MINISTRY, ETAP, JODI, MEES.

3: TUNISIA GAS OUTPUT (MN CFD): ALMOST ALL PRODUCERS AND REGIONS ARE SEEING OUTPUT FALL, WITH ENI'S SOUTHERN FIELDS THE ONLY EXCEPTION



*SHELL TO JUNE 2022. ^MOSTLY PERENCO'S FBT FIELDS. SOURCE: TUNISIA ENERGY MINISTRY, ETAP, JODI, MEES.

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NEWS IN BRIEF

QATAR: 500MW POWER BOOST

Qatar state power firm QEWC is to begin construction of a 500MW single cycle gas fired power plant at Ras Abu Fontas following the 26 February signing of a power purchase agreement with state offtaker Qatar Electricity and Water Corporation (Kahramaa). Kahramaa says the project will cost $440mn and come online in January 2027, though the unit, which is less efficient than the 9GW of CCGTs that dominate Qatar's current 11.4GW power fleet, will be used only intermittently to meet peak power demand.

In a further boost to baseload capacity, QEWC is adding the 2.4GW Ras Abu Fontas Facility E CCGT in partnership with Japan's Sumitomo and Shikoku Electric for 1H 2028 start-up and full capacity by 1H 2029 (MEES, 14 February).

US DESIGNATES HOUTHIS FOREIGN TERRORISTS

US Secretary of State Marco Rubio on 4 March, announced the re-designation of Yemen's Houthis as a Foreign Terrorist Organization (FTO). The designation allows for tighter sanctions for providing "material support" to the Houthis than the existing Specially Designated Global Terrorist (SDGT) label (MEES, 26 January 2024).

The day after the State Department announcement, the US Department of Treasury announced sanctions on seven senior Houthi officials including Muscat-based spokesman Mohammad Abdulsalam. It says the "individuals have smuggled military-grade items and weapons to Houthi-controlled areas" and also "recruited Yemeni civilians to fight on behalf of Russia."

The designation could complicate humanitarian operations in Yemen and throw the country's already fragile financial system into chaos. It also adds to the difficulty of restarting ceasefire talks and resuming Yemen's lifeblood oil and gas exports (MEES, 21 February).

BP EGYPT GAS BOOST

BP on 6 March announced "the successful completion of drilling operations at the El Fayoum-5 gas discovery well in the North Alexandria Offshore Concession, marking the final well in its four-slot drilling campaign in the West Nile Delta."

Whilst initially billed as a development well – the Fayoum field produces modest volumes as part of BP's West Nile Delta project – an oil ministry source confirms that drilling was exploratory in nature.

The well spudded on 14 February using the Valaris DS-12 drillship "encountered four prospective Messinian gas reservoirs with a total sand thickness of 50ms at a measured depth of approximately 2,900ms," BP says. While evaluation is ongoing, BP is hopeful the new find could hold reserves of up to 200bcf, according to the ministry source.

BP says plans are already underway to tie back the discovery to the existing WND facilities. Here output had slumped to just 400mn cfd late last year, the lowest level since 2017 start-up with almost all current output from the 'Phase 3' Raven field.

However the start-up last month of two Raven infill wells – the first two wells of the just-completed campaign – should have hiked output to around 600mn cfd (MEES, 21 February).

The third well of the campaign was the El King-2 appraisal which BP says confirmed the commerciality of 2002's 200bcf El King field which lies 20km east of WND facilities (MEES, 14 February).

"With Raven Infills Phase 2 already contributing to production, we're now fast-tracking the El King and Fayoum discoveries to tie into our West Nile Delta Infrastructure," BP's EVP gas & low carbon William Lin says.

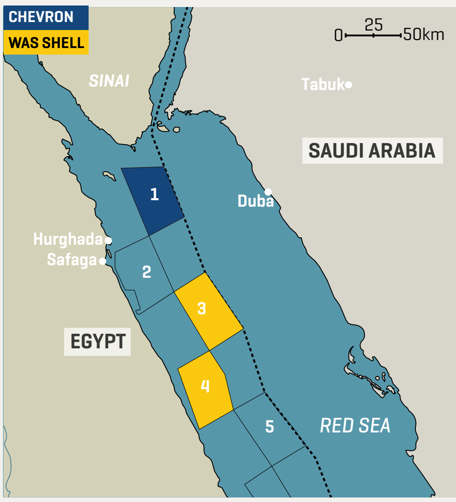
SHELL QUITS EGYPT RED SEA BLOCKS

Shell and its partners have relinquished the two Egyptian Red Sea exploration blocks they were awarded at the end of 2019 (MEES, 3 January 2020). At 'Red Sea 3' Shell (43%op) was partnered by Australia's Woodside (30%) and QatarEnergy (17%), and at 'Red Sea 4' Shell (21%op) was partnered by UAE state firm Mubadala (27%) as well as Woodside (25%) and QatarEnergy (17%). QatarEnergy entered the blocks in late 2021 (MEES, 17 December 2021).

Egypt's latest official blocks map shows the acreage as open, whilst Woodside's 2024 annual report, released last week, says that "exit activities" are ongoing.

This leaves just one active Red Sea block: both Woodside and Chevron's recent annual reports indicates that they retain 'Red Sea Block 1' (Chevron 45%op, Woodside 45%, Egypt state firm Tharwa 10%). Chevron previously flagged up plans to drill the acreage but these were put on hold last year after Yemen's Houthis stepped up attacks on Red Sea shipping.

EGYPT RED SEA EXPLORATION



IRAQ EYES NEAR-TERM LNG IMPORTS

Iraqi officials are confident that the country will have the infrastructure in place to import LNG ahead of the country's summer peak power demand season.

Speaking to local al-Mirbad radio station on 28 February, oil minister Hayan Abdulghani says work is ongoing to convert Berth No 1 at the Khor al-Zubair oil terminal to accommodate an FSRU whilst a 41km 42-inch pipeline linking the berth to the national gas grid has reached "30% progress in a record time of 10 days."

However, even should Iraq be able to install the requisite infrastructure in record time, it will still face a tight market for FSRUs and could struggle to secure a vessel before summer.

The move comes as Baghdad comes under intense pressure from Washington to reduce its reliance on imports of Iranian gas and power – a waiver on the latter is set to expire on 8 March (MEES, 14 February).

CRUDE OSPS ($/B): ARAMCO CUTS APRIL PRICES

	Feb25	Mar25	Apr25
SAUDI ARABIA			
to Asia (FOB Ras Tanura, vs Oman/Dubai average)			
Arab Super Light (>40°)	+2.25	+4.35	+4.05
Arab Extra Light (36-40°)	+1.50	+3.90	+3.30
Arab Light (32-36°)	+1.50	+3.90	+3.50
Arab Medium (29-32°)	+0.75	+3.25	+2.95
Arab Heavy (<29°)	-0.50	+2.10	+1.80
to Northwest Europe (FOB Ras Tanura, vs ICE Brent)			
Arab Extra Light (36-40°)	+1.65	+4.85	+4.65
Arab Light (32-36°)	+0.05	+3.25	+3.05
Arab Medium (29-32°)	-0.75	+2.45	+2.25
Arab Heavy (<29°)	-3.15	+0.05	-0.15
to Mediterranean (FOB Ras Tanura, vs ICE Brent)			
Arab Extra Light (36-40°)	+1.65	+4.85	+4.55
Arab Light (32-36°)	-0.05	+3.15	+2.85
Arab Medium (29-32°)	-0.65	+2.55	+2.25
Arab Heavy (<29°)	-3.35	-0.15	-0.45
to US (FOB Ras Tanura, vs ASCI)			
Arab Extra Light (36-40°)	+5.75	+6.05	+6.05
Arab Light (32-36°)	+3.50	+3.80	+3.80
Arab Medium (29-32°)	+3.70	+3.90	+3.90
Arab Heavy (<29°)	+3.35	+3.45	+3.45
ABU DHABI			
Murban (40.3°)	73.28	80.22	77.62
Das (38.8°)	72.88	79.82	77.27
Das-vs Murban	-0.40	-0.40	-0.35
Umm Lulu (38.7°)	73.53	80.47	77.92
Umm Lulu-vs Murban	+0.25	+0.25	+0.30
Upper Zakum (34.1°)	73.28	80.32	77.92
Upper Zakum-vs Murban	+0.00	+0.10	+0.30

SOURCE: ARAMCO, ADNOC.

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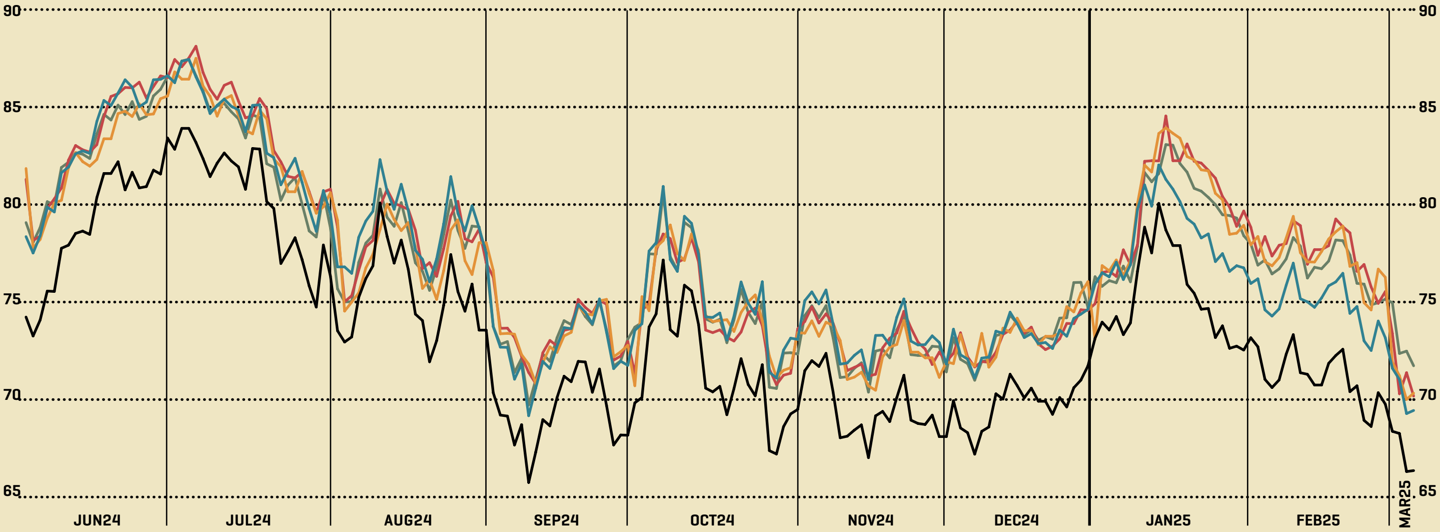
SELECTED DATA

BENCHMARK CRUDE PRICES ($/B)

	6Mar	24-28Feb	17-21Feb	Feb25	Jan25	Dec24	4Q 2024	3Q 2024	2Q 2024	2025 (6Mar)	2024	2023	2022
WTI	66.36	69.67	71.56	71.19	75.22	69.87	70.31	75.38	80.61	72.78	75.79	77.58	94.37
ICE Brent	69.46	73.51	75.60	74.95	78.35	73.26	74.01	78.72	85.02	76.18	79.86	82.18	99.02
ICE Murban	70.35	75.92	78.04	77.34	80.18	73.47	73.76	78.34	85.24	78.13	79.74	82.80	98.84
GME Oman	70.20	75.96	78.46	77.64	80.02	73.34	73.60	78.47	85.20	78.23	79.61	82.02	94.42
OPEC Basket	71.75	75.38	77.52	76.81	79.38	73.07	73.54	78.97	85.31	77.70	79.89	82.95	100.08
JCC	na	na	na	na	76.57	76.50	78.24	85.86	87.48	na	83.92	86.56	102.70

AVERAGE SETTLEMENT PRICES FOR PERIOD IN QUESTION.



INDIA: REFINERY RUN & OIL DEMAND RECORDS

*India's refineries are running at record levels. Throughputs were 23.78mn tons (5.62mn b/d) for January, fractionally down on December's all time high of 5.64mn b/d. January's products output figure of 24.93mn tons was also the second highest ever behind December's 25.24mn tons according to official petroleum ministry statistics.

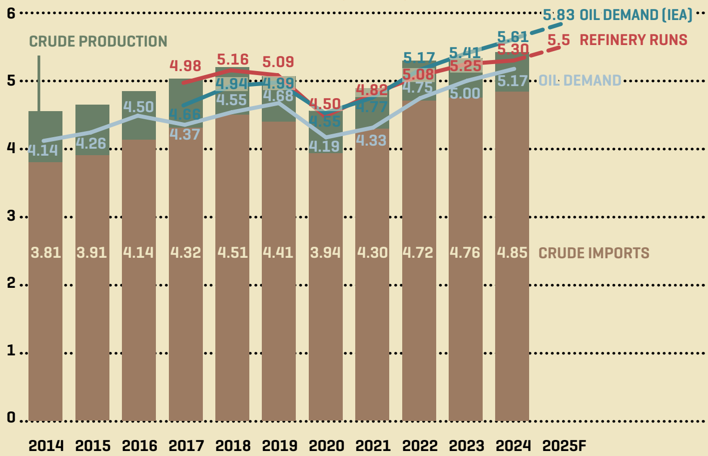
*With oil demand having hit an all-time high of 5.44mn b/d in November, all three indicators hit annual records for 2024, as did crude imports which were up 2% at 4.85mn b/d with top supplier Russia up 7% at a record 1.75mn b/d (see chart & MEES, 28 February).

*India's imports from Russia have, however, dipped in recent months as the US has stepped up sanctions on tankers linked to Russia's 'dark fleet': volumes averaged 1.35mn b/d over the three months to end-February, the lowest such figure since the start of 2023.

*The IEA expects India to lead the world in oil demand growth for 2025 with gains of 210,000 b/d on the back of 2024's world-leading gains of 200,000 b/d (somewhat higher than the 170,000 b/d implied by the official Indian stats due to the IEA's broader definition of oil to include NGLs). "Nevertheless, there are tentative indications of cooling in the economic boom which has underpinned this rise. In addition to slightly underwhelming fuel deliveries, urban consumer goods sales suggest a slowdown amongst middle class households," the IEA says.

*As for refinery runs, the IEA notes that December's record came as five separate plants reported their highest ever monthly figures, and predicts further gains to a new record of 5.5mn b/d for 2025.

INDIA'S CRUDE IMPORTS, REFINERY RUNS & OIL DEMAND ALL HIT NEW RECORD HIGHS FOR 2024 WITH 2025 ON PACE FOR NEW HIGHS (MN B/D)



F= IEA FORECASTS. SOURCE: INDIA MINISTRY OF COMMERCE, INDIA MINISTRY OF PETROLEUM & NATURAL GAS, IEA, MEES.

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