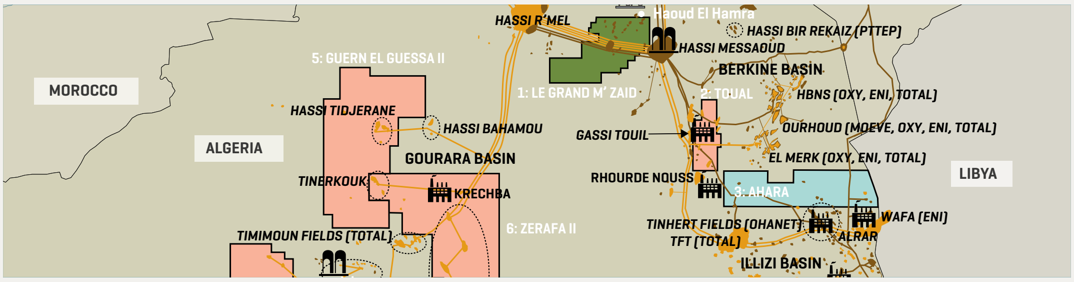
mees

Weekly Energy, Economic
& Geopolitical Outlook
Vol. 68. No. 18
2.May.2025.

UPSTREAM OIL & GAS

Algeria Bidding: Will It Be A Major Success?

Algiers is close to wrapping up its first bid round since 2014. It hopes to attract US majors Chevron & ExxonMobil as well as Asian and Gulf NOCs. But one of the country's current key investors, TotalEnergies, may be shunned amid heightened Algeria-France tension. ***Page 2***



CORPORATE

Egypt Upstream: New Terms Are Not Enough

Egypt's output is on a firm downward trend. Reversing this requires a big investment uptick. But despite new terms, bulging receivables mean IOCs are reluctant to splash the cash. ***Page 6***

POWER & WATER

Israel Looks To Solar Surge To End Coal Burn

Israel aims to end coal-fired powergen next year as it leans on plentiful domestic gas to complement the fast-growing role of renewables in the country's power generation mix. ***Page 12***

ECONOMY & FINANCE

Saudi Vision 2030 Plans Hit By FDI Crunch

Saudi Arabia sees massive FDI inflows as key to keeping Vision 2030 'gigaprojects' on track. But FDI has fallen well behind the $103bn by 2030 target. ***Page 16***

UPSTREAM OIL & GAS

Kuwait Extends Shell's Key Upstream Role

Shell is to retain its role in developing Kuwait's northern oil and gas fields which are central to the emirate's 2040 production capacity targets. ***Page 5***

POWER & WATER

Kuwait Faces Summer Power Meltdown

Kuwait has already started 2024 power imports, well ahead of summer peak demand as an aging powergen fleet requires an increasingly onerous maintenance schedule. ***Page 14***

DOWNSTREAM

Oman Hydrogen Auction Faces Headwinds

Oman has kicked off its third bid round for green hydrogen blocks, offering up land around Duqm. But none of the previously-awarded projects look close to moving forward. ***Page 11***

DOWNSTREAM

UAE Petchems Giant On Growth Trajectory

Borouge targets a 32% organic capacity growth to 6.6mn t/y by 2028 on top of merger plans which will catapult it into the global polyolefins top 5 ***Page 10***

OPEC & GLOBAL MARKETS

IEA Warns Of Energy Security Risks

Whilst fossil fuel reliance is an energy security risk, so is the concentration of critical minerals key to the energy transition, the IEA's Fatih Birol warns. ***Page 8***

Algeria's First Bid Round In A Decade: Will It Be A Major Success?

Algiers is close to wrapping up its first bid round since 2014. It hopes to attract some of the largest international players, including possible country entries for US majors Chevron & ExxonMobil, and a re-entry for BP, with Asian and Gulf NOCs also a strong possibility. But one of the country's current key investors, TotalEnergies, may be shunned amid heightened Algeria-France tension.

There are fewer than 50 days to go before Algeria's first oil and gas bid round in a decade closes on 17 June, with bids to be opened and provisional awards made the same day (MEES, 18 October 2024).

Launched by state hydrocarbon regulator Alnaft in October after several years in the making, the long-awaited bid round offers six large onshore blocks totaling 152,000 km² – substantially larger than England – encompassing both gas and oil-prone areas of Algeria (see map). Alnaft says it expects the successful bidders by 30 July to have inked either production-sharing (PSC) or 'Participation' contracts under the auspices of the country's 2019 oil law (MEES, 15 November 2019).

Algiers is confident it will be able to attract heavyweight bidders to provide a major shot in the arm to upstream investment and output (see chart 1). That of crude was on a firm downward trend long before the introduction of new Opec+ output restrictions which crimped Algeria's output from May 2020. If and when such restrictions end it is unlikely to be able to regain prior output levels of over 1mn b/d, whilst record domestic consumption means that exports and thus revenue are down even more than output (MEES, 21 February). For gas, output did hit a record 104.8bcm (10.1bn cfd) for 2023 but has since fallen. And, as with oil, rising consumption has hit exports and revenues (MEES, 1 January).

Officials hope the latest bidding will do better than the previous flopped round in 2014, when only four out of 31 blocks were awarded (MEES, 3 October 2014). Alnaft president Mourad Beldjehem says the plan is to hold annual bid rounds going forward, with an additional 17 blocks, including in the offshore Mediterranean, already under preparation for future rounds.

Speaking in February, Mr Beldjehem told state news agency APS that at least 37 global companies had already tabled an interest in ongoing bidding. "The call for tenders has attracted companies with previous experience in Algeria and others entering it for the first time," he says, adding they come from various regions in the world including Europe, North America, Latin America, and Asia. Among Mena countries he also singled out Qatar and Oman.

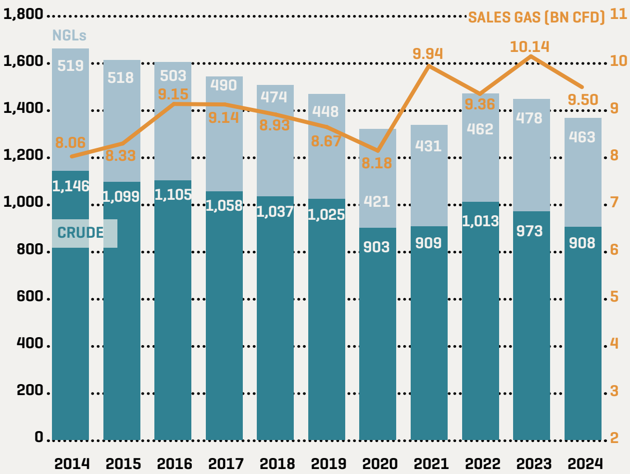
A key prize would be the country entry of US majors Chevron and/or ExxonMobil. Oil minister Mohamed Arkab and Sonatrach CEO Rachid Hachichi courted both in private meetings at the US-Algeria Energy Forum in Houston last month, though it is possible that talks focused on long-touted shale-focused entry rather than the bid round per se (MEES, 21 June 2024).

Other meetings included with US mini-major Occidental (Oxy), which is already a key foreign investor in the country's upstream, having agreed in 2022 alongside TotalEnergies and Eni to spend $4bn on bolstering output at their shared fields in Algeria's Berkine Basin oil heartland (MEES, 22 July 2022).

Oxy entered Algeria by accident after Algiers blocked the US firm's attempts to sell-on to Total its 24.5% operator's stake in Blocks 208 & 404A – including the processing facilities for the key El Merk, HBNS and Ourhoud fields – acquired as part of its $55bn 2019 purchase of Anadarko (MEES, 10 May 2019). CEO

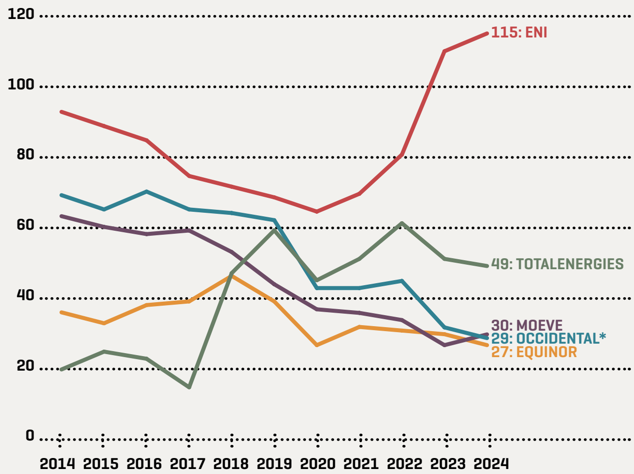
Continued on – p3

1: ALGERIA'S OIL OUTPUT IS DOWN 300,000 B/D SINCE THE LAST BID ROUND IN 2014, WITH THE FALL ONLY PARTLY DUE TO OPEC+ OUTPUT RESTRICTIONS* ('000 B/D)



*RESTRICTIONS HAVE CRIMPED OUTPUT SINCE MAY 2020. ALGERIA HAS PRODUCED ALMOST IN LINE WITH ITS TARGET SINCE. SOURCE: JODI, MEES.

2: ALGERIA'S TOP FOREIGN PRODUCER ('000 BOE/D, NET): ENI HAS EXTENDED ITS LEAD WITH SUCCESSIVE PURCHASES OVER 2022-24

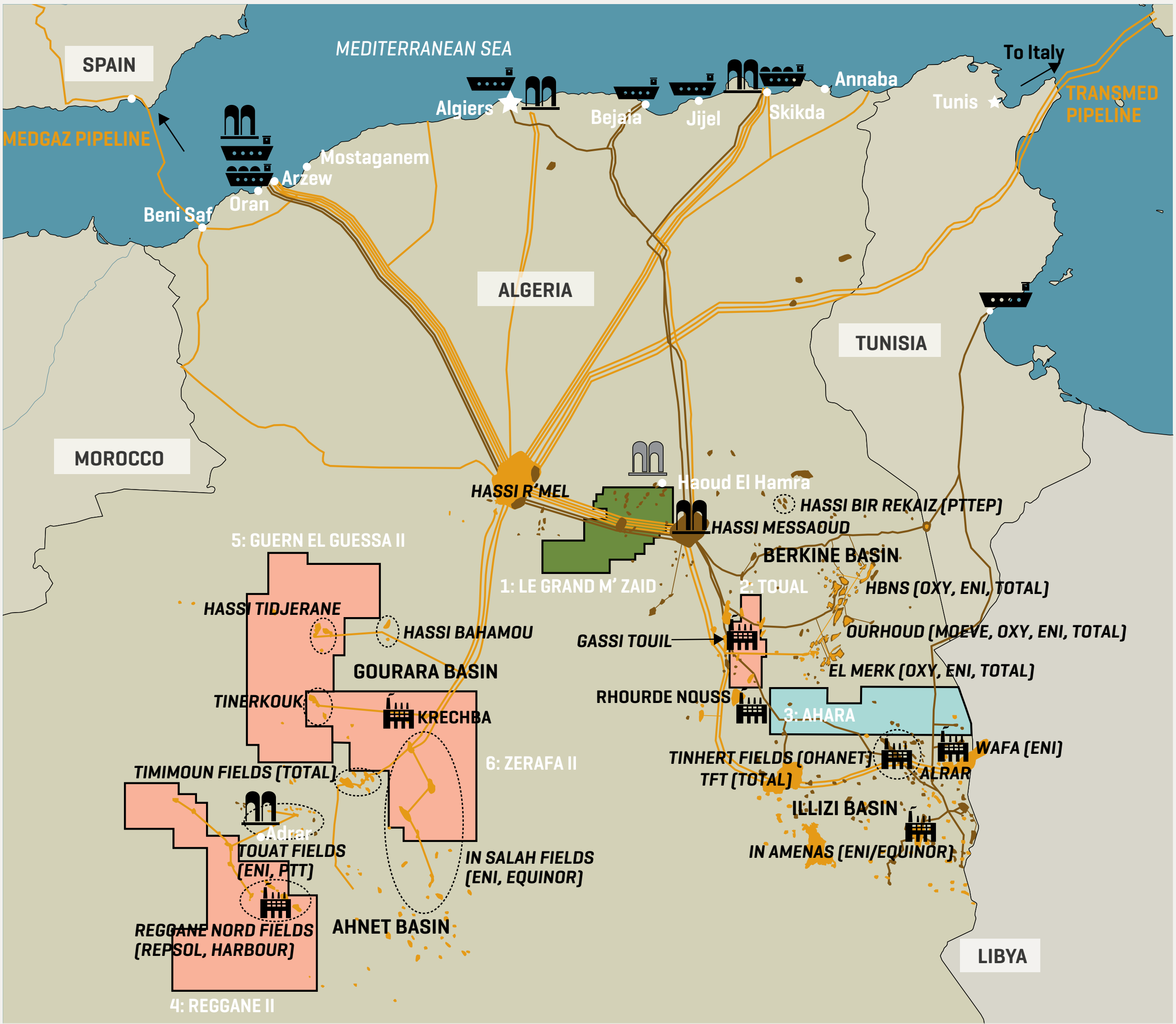


*ANADARKO TO AUG 2019. NEW CONTRACTUAL TERMS FOR JOINTLY-HELD BERKINE BASIS ASSETS CUT OXY'S NET FIGURE BY 15,000 B/D AND ENI/TOTAL'S BY 7,500 B/D FROM MARCH 2023. SOURCE: COMPANIES, MEES.

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

ALGERIA IS OFFERING UP SIX LARGE BLOCKS IN BIDDING SET TO CLOSE NEXT MONTH

OIL FIELD/PIPELINE GAS FIELD/PIPELINE REFINERY EXPORT TERMINAL LNG EXPORT TERMINAL GAS PROCESSING PLANT



FIELDS INDICATED AS WITHIN THE BLOCKS ON OFFER ARE EXCLUDED WITH THE EXCEPTION OF FIVE DEVELOPMENT LEASES WITHIN LE GRAND M'ZAID AND THREE WITHIN TOUAL. ALL LABELED FIELDS ARE CURRENTLY PRODUCING WITH NAMED COMPANIES THE LEAD FOREIGN PARTNERS AT EACH FIELD. FIELDS WITH NO NAMED COMPANIES ARE OPERATED BY SONATRACH ALONE.

ALGERIA'S SIX BLOCKS ON OFFER IN 2024-25 BIDDING...

							Past Exploration			
							Seismic ('000km/km²)		No. of Wells	
No.	Name	oil/gas	Contract	km²	Basin	'Blocks'*	2D	3D	Exp.	Dev.
1	Le Grand M'Zaid	oil	PSC	12,759	Oued Mya	425b, 426a, 438b	8.6	10.4	85	10
2	Toual	gas	Participation	6,424	Berkine	213a, 236c, 237d, 246b	1.3	10.0	30	4
3	Ahara	gas/oil	PSC	17,654	Illizi	211c, 212e, 213a, 221b, 222d, 223d, 235, 238c, 243, 244b, 245a	14.5	13.4	70	
4	Reggane II	gas	PSC	40,828	Reggane	328a, 333a, 334, 335a, 351, 352b, 362c	26.7	11.1	64	
5	Guerne El Guessa II	gas	Participation	36,374	Gourara	316a, 317b, 319b, 321a, 325a	28.1	7.5	46	
6	Zerafa II	gas	PSC	38,698	Gourara	321a, 322b, 325a, 344b, 345, 346, 347b	35.0	3.0	45	
TOTAL				**152,737**			**114.2**	**55.4**	**340**	**14**

...CONTAIN A TOUTED POTENTIAL OF 27TCF GAS RESOURCES

	Existing Development Leases					Undeveloped Discoveries**				Additional Prospects**				
		Output	2P Reserves				"Resource in place"				"Expected resource"			
Block	No.	kbd	mn bl	BCM	TCF	No.	mn bl^	BCM	TCF	No.	mn bls	BCM	TCF	Notes
1	5	8	52			14	536			11	205			Adjoins country's largest oilfield Hassi Messaoud
2	3			83	2.9	1		16	0.5	6		14	0.5	Adjoins Sonatrach's key Rhourde Nouss & Gassi Touil gasfields
3						17	46	112	3.9	16	1,205	39	1.4	Nearby Eni and Total-operated fields
4						10	5	65	2.3	22		143	5.0	Surrounds Repsol-operates Reggane Nord fields
5						5		26	0.9	5		141	5.0	Surrounds key southwest gas project fields
6						7		82	2.9	11		51	1.8	Surrounds Eni & Equinor's In Salah fields
TOTAL	**8**	**8**	**52**	**83**	**2.9**	**54**	**587**	**301**	**10.6**	**71**	**1,410**	**388**	**13.7**	

*ON ALGERIA'S OFFICIAL UPSTREAM MAPS. **P50. ^CONDENSATE FOR REGGANE II & 18MN BLS AT AHARA. SOURCE: ALNAFT, MEES.

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

Continued from – p3

Vicki Hollub has subsequently said that Algeria is "core" for the company (MEES, 14 August), and flagged up the potential for expansion including potentially in shale (MEES, 4 March 2022). However, as yet this has not happened, with Oxy's net Algeria output dwindling alongside that of the aging Berkine Basin fields.

In contrast, Oxy's Berkine Basin partners Eni and Total have been expanding in Algeria. Total has been acquiring and advancing development at additional assets surrounding its TFT field with the aim of boosting output from 60,000 boe/d in 2022 (130mn cfd gas, 37,000 b/d liquids) to 100,000 boe/d by 2026 (MEES, 29 September 2023). However, with Total seen as a French national champion, increasingly tense bilateral relations threaten to scupper the company's chances of further expansion in Algeria (see p9).

In any case it is another European major, Italy's Eni, that has been expanding the most in Algeria. In recent years it has surged ahead of Total as the key foreign producer with new assets around its Berkine Basin heartland, as well as taking BP's stake alongside Equinor at In Amenas in the Illizi basin to the south, and an operator's stake at the Touat project in the country's southwest (see chart 2). All told Eni has pledged to invest "more than €8bn [$9.1bn]" in Algeria over the next four years (MEES, 18 April).

BERKINE & ILLIZI HEARTLAND

The Berkine and Illizi basins near the Libya border in eastern Algeria have long been the core area for IOC-operated oil and gas output in Algeria, though the country's largest overall fields, Sonatrach-operated Hassi R'Mel (gas) and Hassi Messaoud (oil) are northwest of here.

Leaving aside the potential for new entrants such as Exxon and Chevron, and re-entries such as BP and Shell, both of which quit their last Algerian assets in recent years but have left open the possibility of a return, the most obvious bidders for the blocks on offer are those firms with nearby assets.

Of the six blocks on offer, Blocks 2 (Toual) and 3 (Ahara) lie close to Total, Eni and Oxy's Berkine and Illizi basin assets. Moeve (formerly Cepsa) is also an important player here as operator of the Ourhoud field, though given repeated management comments that the Spanish firm is looking to quit its remaining upstream assets (of which Algeria is the largest) it would mark an unlikely reversal were it to bid. Thailand's PTTEP, whose Hassi Bir Rekaiz fields lie in the north of the Berkine Basin, is another potential bidder, as is Norway's Equinor.

Toual is touted as prospective for gas. Unlike the other blocks on offer (with the exception of Le Grand M'Zaid), Toual comes with three existing development leases which collectively have 2.9tcf of 2P reserves (see table). As such, Alnaft touts Toual primarily as a 'Development optimization' opportunity rather than pure exploration. To the immediate west and south respectively of Toual are two of Sonatrach's key producing gas fields, Gassi Touil and Rhourde Nouss: Alnaft touts 16mn m³/d (565mn cfd) of available ullage at the latter's gas processing facilities as a potential outlet for output from the block.

Alnaft notes that the "logistical and operational benefits" of nearby infrastructure "potentially speeding up development timelines."

Ahara is touted as prospective for both gas and oil, with an estimated P50 resource in place of 3.9tcf gas and 46mn barrels of oil as well as a massive "expected resource" of 1.2bn barrels across 16 additional prospects.

Key processing facilities for both oil and gas, both with substantial ullage, lie at the Alrar gas/condensate field to the immediate south. Whilst Alrar is operated by Sonatrach (MEES, 21 February), Eni operates the portion of the field on the Libyan side of the border, where it is known as Wafa. Indeed, Eni is currently conducting an exploration drilling campaign on the other side of the border with the aim of bolstering resources for potential tieback to Wafa (MEES, 1 November 2024) and will likely look to add to its assets in ongoing Libya bidding (MEES, 14 March). Other nearby IOC-operated fields include Total's TFT and Eni/Equinor's In Amenas.

Norway's Equinor also, alongside Shell, previously held the Timissit exploration block immediately north of Ahara on the Libya border. Shell quit in 2018 and Equinor in 2022 (MEES, 24 March 2023). Prior to quitting, the Norwegian firm touted the block's potential for unconventional output, as did Spain's Repsol on the now-relinquished Southeast Illizi block further south on the Libya border (MEES, 28 February 2020). Algeria's recent shale-focused MOUs with Exxon and Chevron have mentioned both the Berkine Basin and the Ahnet Basin in Algeria's far southwest.

More distant from producing IOC-operated fields, but adjoining Sonatrach's 300,000 b/d Hassi Messaoud development lease, is Block 1, **Le Grand M'Zaid**. This is the only one of the six blocks on offer to be touted as only prospective for oil, and the only one with current output, some 8,000 b/d. Alnaft says the target of any PSC will be to "increase and extend the production plateau" – with an accompanying chart indicating an expected 9-year plateau at around 10,000 b/d followed by decline. Alnaft reckons the block's existing five development leases have 52mn barrels of recoverable reserves (2P), whilst the block has an additional 205mn barrels P50 "expected resource" across 11 prospects.

One potential bidder could be Chinese state giant Sinopec which earlier this year agreed to invest $850mn on exploration and development of the 9,700km² Hassi Berkine North block immediately to the south of Le Grand M'Zaid (MEES, 7 March). And just north of Le Grand M'Zaid is the site of the recently-relaunched 5mn t/y (110,000 b/d) Hassi Messaoud new refinery, which groups Sinopec with Sonatrach and Spain's Tecnicas Reunidas (MEES, 23 August 2024). Whilst linking upstream and nearby downstream investment is not common in Algeria, the other foreign company to have inked such a deal was fellow Chinese state giant CNPC, which operates both the 13,000 b/d Adrar refinery in the country's far southwest and nearby upstream assets.

SOUTHWEST GAS FOCUS

The remaining three blocks are all substantially larger and seen as gas prone. All are in the southwest of the country, a relatively frontier area for gas production but one that has seen substantial investment in gas infrastructure in recent years. Alnaft flags up an expected P50 in-place resource of just over 6tcf across the three blocks.

Key IOC-operated projects include Reganne Nord, where Repsol is partnered by UK independent Harbour Energy (was Wintershall Dea: MEES, 6 September 2024); Touat where Eni is in the process of being joined by PTTEP (MEES, 3 January), and Total's Timimoun.

Indeed Block 4, **Reggane II** surrounds the Reggane Nord fields, making it "highly promising due to its substantial hydrocarbon potential and proximity to infrastructure," says Alnaft. Meanwhile the Touat fields lie just outside the block to the northeast. Whilst Alnaft does not flag up spare capacity at either the 310mn cfd-capacity Reggane Nord or 460mn cfd-capacity Touat processing facilities, respective operators Repsol and Eni may well eye firming up nearby prospects for eventual tieback.

To the north of here, Block 5, **Guern El Guessa II** and Block 6, **Zerafa II** surround fields developed in recent years as part of Algeria's southwest gas project (SWGP). At the fields that constituted SWGP Phase-2, Sonatrach ultimately went it alone with development after foreign partners Shell (at Hassi Ba Hamou) and Equinor (Hassi Tidjerane and Tinerkouk) walked away having failed to agree commercial terms (MEES, 29 May 2015). What has changed since is that with the 2023 start-up of the key SWGP Phase-2 fields (MEES, 15 September 2023) there is now substantial existing gas infrastructure in this part of Algeria, potentially making the development of any discoveries an easier prospect. Zerafa II also surrounds several of the fields that constitute Eni and Equinor's In Salah project.

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

Kuwait's Extends Shell's Key Upstream Role

Shell is to retain its role in developing Kuwait's northern oil and gas fields which are central to the emirate's 2040 production capacity targets.

Shell plays a key role in Kuwait's upstream sector, helping Kuwait Oil Company (KOC) develop challenging heavy oil reserves, deep sour gas projects and conventional oil developments in the north of the country. The firm works in Kuwait through three enhanced technical service agreements (ETSA) which were due to expire in 2026.

These contracts have now been extended through 2029, KOC's parent company KPC says. Shell's CEO Wael Sawan and KPC CEO Sheikh Nawaf Al Sabah witnessed the 28 April ceremony for the contract signing in Kuwait City, underlining the importance of the contracts for each firm. The contracts were signed by KOC Deputy CEO for Project Management and Engineering, Fahad al-Kharqawi, and Shell's Country Chair Anwar al-Mutlaq. During his visit to Kuwait, Mr Sawan was also received by Emir Sheikh Mishal Al Ahmad Al Sabah.

KPC's CEO says that "the extension of the ETSAs marks the continuation of the cooperation between KPC's subsidiaries and Shell...Shell's performance during the current term of the ETSAs has been fundamental to growing oil and gas production, optimizing costs and building local capabilities, and we look forward to continued collaboration."

The Kuwaiti state firm says that "this collaboration is aligned with KPC's long-term objectives to boost production capacity to 4mn b/d of crude oil and 2bn cfd of gas by 2040."

ETSAS: CHEQUERED HISTORY

Shell signed Kuwait's first ETSA back in 2010, to develop the northern Jurassic gas fields. The contract was subject to considerable parliamentary scrutiny and the public prosecutor only dropped its investigation into it in April 2016 (MEES, 29 April 2016). With the legal challenges dropped, Shell signed another two ETSAs with KOC in March 2016; to help develop heavy oil reserves in northern Kuwait and to help manage water produced at conventional fields in the north (MEES, 15 July 2016). Its Jurassic ETSA was then renewed in June 2016 for ten years.

Also in 2016, KOC signed an ETSA with BP for work at maintaining capacity at the supergiant Burgan field at 1.7mn b/d; Burgan capacity dropped to just 1.39mn b/d in 2020/21 and KOC subsequently revised down its ambitions to 1.5mn b/d (MEES, 5 February 2021). BP and KOC have yet to extend this ETSA, which runs for 10 years (MEES, 21 March).

There have been no subsequent ETSAs awarded, despite previous plans to award new contracts for heavy oil development (MEES, 2 June 2017) and for West Kuwait (MEES, 20 April 2018). Plans to develop a new contract model have also yet to reach fruition (MEES, 20 April 2018).

Although Shell and BP hold prominent positions in Kuwait, you wouldn't know it based on company statements, which rarely reference the country. The restrictive nature of the ETSAs mean that the firms are not able to book any reserves or production, instead simply providing services to KOC.

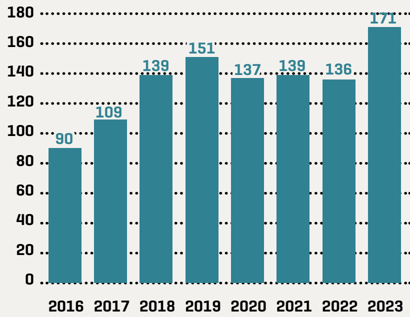
KUWAIT OIL & GAS INFRASTRUCTURE

SHELL KUWAIT, PROFITS TICK UP

Shell says that the scope of work for its Kuwait operations "is to assist KOC with the planning, development and delivery of efficiency measures for the North Kuwait Reservoirs project by providing significant level of skilled professional expertise, proprietary technology, proven business practices to enhance oil and gas recovery and operational practices over the long-term, building KOC's capabilities and promoting the development of the skills of KOC's employees, within the time-frame set by KOC."

Shell Kuwait generated record profits of $171mn in 2023 according to its latest filings (see chart), up 25% year-on-year from $136mn in 2022. The firm attributes this in large part to a higher number of hours delivered to KOC, and "a higher commercial rate adjustment due to the crude oil price."

SHELL KUWAIT PROFITS REACHED RECORD HIGH IN 2023 ($MN)



SOURCE: SHELL, MEES.

Shell has played a key role in two of Kuwait's most high-profile upstream developments. The 'Lower Fars' heavy oil output from the country's northern fields has now reached a record 90,000 b/d, KOC said in January, and is expected to reach 100,000 b/d this quarter (MEES, 3 January). Crude oil from the Lower Fars reservoir is extremely heavy and sour – Ratqa crude is 10-18° API and 5% sulfur, while Umm Niqa crude is 15-22° API and 4-8% sulfur – and long-term capacity targets at the central Ratqa field have been scaled back by 50,000 b/d to 270,000 b/d (MEES, 3 December 2021).

Meanwhile at the Jurassic gas fields, capacity reached 870mn cfd and 263,000 b/d of oil last year following the start up of the JPF-4 and JPF-5 facilities (MEES, 23 February 2024). ◆◆

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

Egypt's Upstream: New Terms Not Enough With IOCs Reluctant To Splash The Cash

Egypt's output is on a firm downward trend. Reversing this requires a big investment uptick. New contract terms have unlocked modest spending pledges, but with hefty receivables bills IOCs remain reluctant to splash the cash.

Since his appointment last July, Egypt's oil minister Karim Badawi has talked a good game on improving the country's investment climate in a bid to halt and potentially reverse a slump in oil and gas output (MEES, 30 August 2024).

In particular, firms have requested, and in many cases received improved terms – most recently Cairo agreed to pay key onshore producer Apache a higher price for new gas output (MEES, 15 November 2024), whilst Dana Gas also secured new and improved terms in a deal finalized last December.

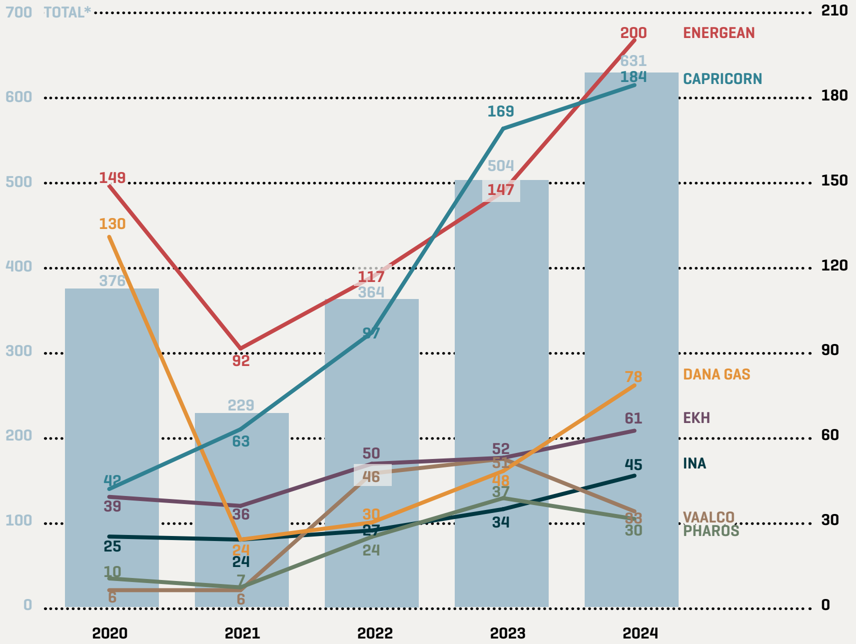
But receivables – that is to say sums owed to producers by Cairo for past output – remain a constant bugbear: after all, to see the benefit of better terms you have to get paid. And, despite a plan rolled out in August last year to help firms reduce their receivables by exporting incremental production and a pledge to at least keep up with monthly payments (MEES, 23 August 2024), many of the midsize firms have seen their receivables continue to increase (see chart 1).

"Many of the mid-size and smaller firms have had to significantly scale down operations in recent times purely for lack of cash. They would accept payments to be made mostly in Egyptian pounds, but even the local currency has been very scarce. The Minister is offering them improved contractual terms, in the hope that better future cash-flows convince them to stay and invest, but they cannot go [spending in excess of revenue] beyond a certain limit," an industry source tells MEES, with another adding that "Worst of all is the lack of clarity and no form of repayment plan".

Though the largest operators in Egypt tend to be reluctant to publicize receivables for fear of drawing Cairo's ire, the total owed is likely north of $6bn, though Italy's Eni, the country's largest gas producer and operator of the 1.5bn cfd Zohr field, notes some good news in its 2024 annual report. "In 2024 the [Egypt receivables] situation has improved and no incremental overdue amounts have been noted," it says.

It would appear that Eni has been able to leverage its position as one of the country's top producers to squeeze out payments from Cairo (MEES, 10 January) and keep its receivables stable over 2024. But for smaller firms the challenge is much harder and MEES understands that despite the minister's pledge to at least keep up with monthly dues, these midcap independents have only been receiving between 30-60% of their monthly arrears.

1: EGYPT INDEPENDENTS* RECEIVABLES UP AGAIN IN 2024 AS MINISTER'S NEW STRATEGY FAILS TO SEE IMPROVEMENT ($MN)



*SEVEN NAMED COMPANIES ONLY. INCLUDES COMPARABLE FIGURES FOR PRECUSROR FIRMS. ALL FIGURES ARE END-YEAR. SOURCE: COMPANIES, MEES.

CAPRICORN: STILL GOT THE GOAT

An example of the worsening situation is UK independent Capricorn, which holds assets in Egypt's Western Desert in a JV with local firm Cheiron, following their near $1bn purchase from UK major Shell in 2021 (MEES, 12 March 2021).

Capricorn confirmed in March that it is close to agreeing improved terms for these assets with Cairo (MEES, 21 March). "A new concession agreement would include the commercial terms and additional investment that would support increased production and reserves, through enhanced activity levels, and strengthened returns, to the benefit of all parties," CEO Randy Neely says in the firm's recently-released 2024 annual report.

Capricorn says that "the ratification of a new concession is forecast to lead to an increase in activity level with potential for an incremental seven wells and an increase in net capex of ~$15m."

That's for the future. Maybe. For now, Capricorn's Egypt capex halved to $63mn for 2024 with output slumping by 22% to 23,739 boe/d (10,400 b/d oil, 74mn cfd gas). Capricorn has indicated on numerous occasions that for it to splash the cash, it requires regular payments (MEES, 21 March), but receivables have increased every year since it entered Egypt, rising to $184mn at the end of 2024.

And notwithstanding the prospect of new concession terms, Capricorn is guiding a further 20% slump in output for 2025 based on the midpoint of its 17-21,000 boe/d guidance. Even the potential $15mn spending boost would leave its outlay way below 2023 levels.

JUST WHEN I THOUGHT I WAS OUT...

Of the small and midsize players to

Continued on – p7

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

Continued from – p6

provide receivables stats, the highest end 2024 figure was posted by one that was until recently heading for the exit door. London-listed Greek firm Energean, which had only entered Egypt in 2020 when it purchased assets from Italy's Edison, had looked to sell up to UK equity firm Carlyle in a deal announced last year, although that ultimately fell through (MEES, 21 March).

"Egypt will often put companies who are on their way out to the back of the queue when it comes to receivables payments," another source tells MEES. Paying down Energean's receivables evidently wasn't a top priority for state firm EGPC, with its dues surging 36% to $200mn over the course of 2024, MEES understands.

Energean notes that "Egypt has faced considerable inflationary pressures, largely driven by economic reforms, reductions in subsidies, and fluctuations in the foreign exchange market... [which] have influenced the rate at which trade receivables are recovered."

At least Energean's rise in receivables is likely in part due to higher output, with 2024 seeing the first full year of production from the NEA/NI fields offshore Alexandria (MEES, 13 September 2024).

And, having tried and failed to quit Egypt, CEO Mathios Rigas is now looking to make the best of the situation. In a 17 April meeting with Mr Badawi "Rigas confirmed the company's commitment to investing and operating in Egypt, as well as supporting the plans to develop natural gas resources through activities in its current concession areas," the ministry says.

That said, MEES understands that Energean is still keen to sell up. As well as surely asking for prompt and regular payment of its dues, Energean is requesting the consolidation of the NEA/NI concessions with its nearer-shore Abu Qir fields.

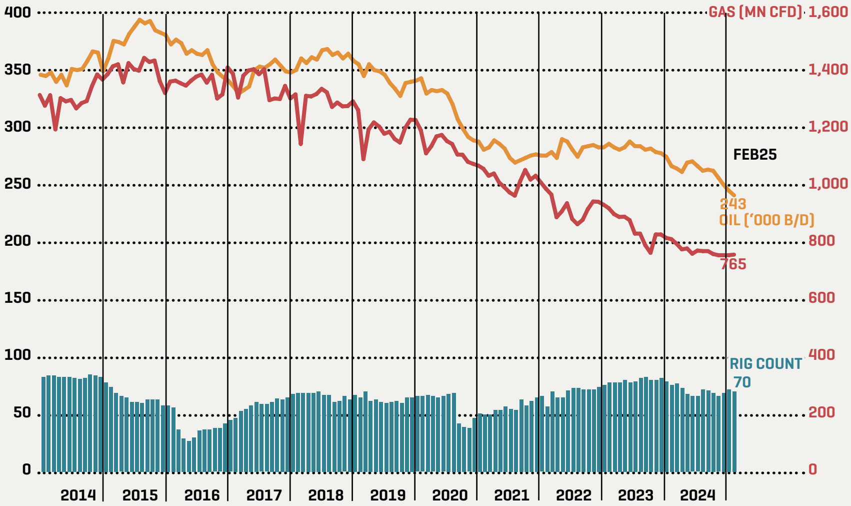
DANA: NEW TERMS, MORE SPENDING. MAYBE

Proportionally-speaking UAE firm Dana Gas saw the biggest year-on-year increase in receivables for 2024, rising 63% to $78mn. Dana's Egypt output dwindled to 16,450 boe/d (80mn cfd gas, 3,100 b/d liquids) for 2024, half levels posted in 2019, as the firm has consistently linked its lack of activity with an absence of payment from Egyptian authorities.

In December last year the firm finally signed a new concession agreement with Cairo to consolidate its existing 13 development leases into one concession named New El Manzala that included improved fiscal terms (MEES, 13 December 2024).

This the firm says will help increase drilling activity with an 11 well campaign and $100mn spending planned for this year. Whether this fully materializes remains to be seen. Dana says that this program is "expected to be internally funded" – that is to say it will be funded out of the revenues received for its Egyptian output – and that it "will also require future regular monthly payments from the Egyptian Government to ensure all phases of the program will be completed."

2: WESTERN DESERT OUPUT: OIL DOWN & GAS DOWN MORE AS RIG COUNT STEADIES



VAALCO OFFSETS PAYMENTS

One firm that saw its Egypt receivables bill fall over 2024 was Eastern Desert focused Canadian firm Vaalco (formerly TransGlobe), with a nominal 34% fall to $33.2mn.

But this was achieved thanks to Cairo agreeing to offset $30mn owed by the company – three $10mn annual payments for 2023, 2024 and 2025 as part of new concession terms agreed in 2021 (MEES, 24 December 2021) – against its receivables bill. This implies receivables would have ended 2024 at $63.2mn, a 26% year-on-year increase had it not been for the payments.

Vaalco's output was down 7% at 10,360 b/d for 2024, with steady output implied by the midpoint of its 2025 guidance of 9,750-11,100 b/d in return for $22-40mn capex.

GLOBAL ECONOMIC HEADWINDS

Of course, it remains to be seen whether 2025 capex plans survive the upcoming round of earnings calls given global economic headwinds and lower oil prices. Of the majors to have already reported for Q1, key Egypt producers Eni and BP both announced global capex cuts, and TotalEnergies may yet follow suit in the coming months. Vaalco, Apache and Dana Gas are all due to report on 8 May.

UK independent Pharos, which has 45% of the 3,200 b/d El Fayum license in Egypt's Western Desert, saw both a slight uptick in output from 3,069 b/d in 2023 and an improvement in its receivables, as they were reduced by 21% to $29.5mn. In absolute terms, however, the backlog of Pharos's unpaid invoices appears to be one of the longest, considering typical monthly net revenues of around $1.5mn.

"The improving macro environment in Egypt has seen our receivables position improve with over $25m received during the year," Pharos says, but warns that "the continued progress of regular receivable payments will determine the pace of our future investment in country."

MEES understands receivables payments have been anything but regular since.

On a somewhat positive note, Egypt's overall gas output did edge higher for February, following twelve consecutive monthly falls, but output remains 979mn cfd down year-on-year at 4.33bn cfd (MEES, 25 April). Oil output has fluctuated but remains on a decidedly downward trajectory, falling to a 40-year low 516,000 b/d for February.

Egypt's rig count has also seen a modest uptick in recent months, steadying at 114, according to oil ministry data, for January and February. The majority of those rigs are focused on the key oil producing Western Desert province.

A significant gas producer also, output from the Western Desert basin has remained relatively flat since October last year at around 763mn cfd. Oil output though continues dropping, falling to a multi-decade low 243,000 b/d for February as the rig count decreased by two to 70 (see chart 2).

The region's top producer is Texas-based Apache which posted gross output of 137,000 b/d oil and 444mn cfd gas last year (MEES, 7 March). The firm is forecasting to average 12 rigs this year, adding one late last year after it managed to secure a 60% gas price hike to $4.25/mn BTU for new output (MEES, 10 January).

Adding one rig though is hardly sufficient to see a significant upsurge in output although Apache is confident that new terms and the increase in drilling will help it post the first year on year gas output increase in over a decade.

Ultimately Cairo will need to find a way to improve payments and make a dent in its growing receivables bill if it hopes to reverse output declines. ◆◆

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

IEA WARNS OF EMERGING ENERGY SECURITY RISKS

The concentration of critical minerals key to the energy transition is a major emerging energy security risk, warns the IEA's Executive Director. European leaders hope to take back control of energy security through domestic clean-energy production, but it's rarely so simple.

London played host to an array of energy sector heavyweights last week for the Summit on the Future of Energy Security, arranged by the UK Government and IEA. Featuring senior government officials from across the globe – although GCC officials were notable for their absence – the summit examined "the geopolitical, technological and economic factors affecting energy security at the national and international level."

Energy security has risen back up the policy agenda in recent years, especially following Russia's 2022 invasion of Ukraine which saw oil and gas prices spike, with Europe in particular seeking to end its reliance on Russian energy flows. The subsequent recalibration of trade flows injected additional friction into the system, although the impact on supply itself was limited, and this was then exacerbated by the effective closure of the Red Sea to most shipping since early-2024 due to Houthi attacks (MEES, 21 March).

Amid this, European leaders were united in extolling the benefits of "homegrown clean energy" as a means to boost energy security. Ed Miliband, the UK's Secretary of State for Energy, told the Summit that "low carbon power is our nationally chosen route to energy security... this is a hard-headed approach to the role of low carbon power as a route to energy security."

UK Prime Minister Keir Starmer echoed this, stating that "homegrown clean energy is the only way to take back control of our energy security." Ursula von der Leyen, President of the European Commission, then added that the world has entered a new paradigm of energy security, before emphasizing that "clean homegrown renewables strengthen our resilience."

TRULY HOMEGROWN?

While the politicians were pointing to "homegrown low-carbon" energy as the silver bullet for energy security threats, they would do well to pay attention to comments by Fatih Birol, Executive Director of the IEA. Mr Birol himself is a strong proponent of increasing the share of such energy sources in the mix, but warned that the IEA is seeing an emerging energy security risk rising from the "remarkable" rise of clean energy technologies.

"Homegrown energy is the best friend of energy security," says Mr Birol, "but to produce, to manufacture these new clean energy technologies we need critical minerals. When we look at where the critical minerals are produced, refined and manufactured, there is a huge concentration. And this is something that we think is risky."

> When we look at where the critical minerals are produced, refined and manufactured, there is a huge concentration."
>
> *-IEA head Fatih Birol*

Certainly, while the energy produced from these sources will be "homegrown," the supply chain required to get to the point of generation is as international as any traditional fossil fuel. This is also an issue that Opec has flagged up, with Secretary General Haitham al-Ghais writing in MEES last year that "On critical minerals specifically, imbalances between reserves concentration and processing capacity present their own set of challenges, such as supply chain bottlenecks, price gyrations and geopolitical tensions" (MEES, 26 April 2024).

Indeed, concerns over China's dominant position in the processing of certain critical minerals, and in the production of solar panels and batteries, is a major policy issue in Europe and the US. The latest US-China trade war will significantly impact trade flows of such products between the two countries, but the EU and UK governments are struggling to balance the desire to accelerate the energy transition with supporting local industry.

ELECTRIFICATION AND RESILIENCE

The summit emphasized the changing risk profiles emerging through the growing electrification of economies. "As electrification of more and more of the economy accelerates, securing power grids becomes both more difficult and more important. Delegates called for long-term policy frameworks that anticipate future system needs, including flexible generation, storage demand-side response and regional interconnection," the IEA notes.

Just a few days later, Spain and Portugal suffered a historic blackout in which more than 50mn people lost electricity. The cause of the blackout has yet to be fully identified, but the event has stimulated discussions over the need for countries to invest heavily in grid upgrades to ensure grid stability as the share of renewables increases (MEES, 8 July 2022). ◆◆

OPEC+ CUTS: ALL OPTIONS ON THE TABLE

When the Opec+ 'Group of Eight' met on 3 April and decided to accelerate the easing of voluntary production cuts in May the news blindsided the market, which had been expecting the group to stick to its pre-agreed timetable (MEES, 4 April). Now, with ministers preparing to discuss production levels for June, the market view is crystalizing around another expected acceleration. The meeting had been planned for 5 May, but was brought forward to 3 May just before MEES went to press.

According to the roadmap agreed on in December, production limits are to be adjusted upwards by around 138,000 b/d each month (MEES, 6 December 2024). Last month's decision was for a 411,000 b/d increase for May, and another such acceleration is widely expected for June. Indeed, the potential for an increase above 411,000 b/d for June shouldn't be ignored, with all options currently on the table. Going into the talks, traders already expect a substantial increase in June from the UAE, which is keen to monetize its capacity expansion investments.

Last month's decision to accelerate the tapering appears to have been largely driven by dissatisfaction at continued overproduction from the likes of Kazakhstan and Iraq; the acceleration provides an "opportunity" for them to comply by increasing quotas closer to where those countries are currently producing. Implicit in this is the potential for prominent producers such as Saudi Arabia to bring sufficient production back onto the market that prices fall, reducing revenues for cheating countries.

Despite Brent prices having fallen back into the low $60s/B this week, market fundamentals continue to point to a relatively tight near-term market with global inventories below recent norms. A report by Morgan Stanley this week noted that the "front of the Brent futures curve signals near-term tightness, consistent with seasonal upswing in demand and still low inventories," but that the shape of the curve then changes and "after the 9th contract signals a rapid weakening later this year, with slowing demand and robust supply growth driving a surplus."

This implies a near-term window for Opec+ to bring volumes back onstream, which then closes as demand seasonally weakens in Q4. Market sources point to a window between now and September. The view that there is near-term scope for more volumes is also shared by Standard Chartered's Paul Horsnell, who this week writes that "our view is that a further acceleration is warranted." 3 May will show whether Opec+ feels the same way.

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

MOROCCO: TROUBLED SOLAR PLANT BACK ONLINE AFTER 14 MONTHS

GEOPOLITICAL RISK

Operator Acwa is confident it has found a 'permanent solution' to repeated salt tank meltdowns at the Noor III CSP plant. But both it and Morocco appear to have had enough of the 'challenging' technology.

Morocco's pioneering 150MW Noor III concentrated solar power (CSP) plant at Ouarzazate in the south of the country is back online following a 14-month outage due to a leak in its molten salts tank (MEES, 29 March 2024), the country's renewables energy agency Masen announced on 21 April.

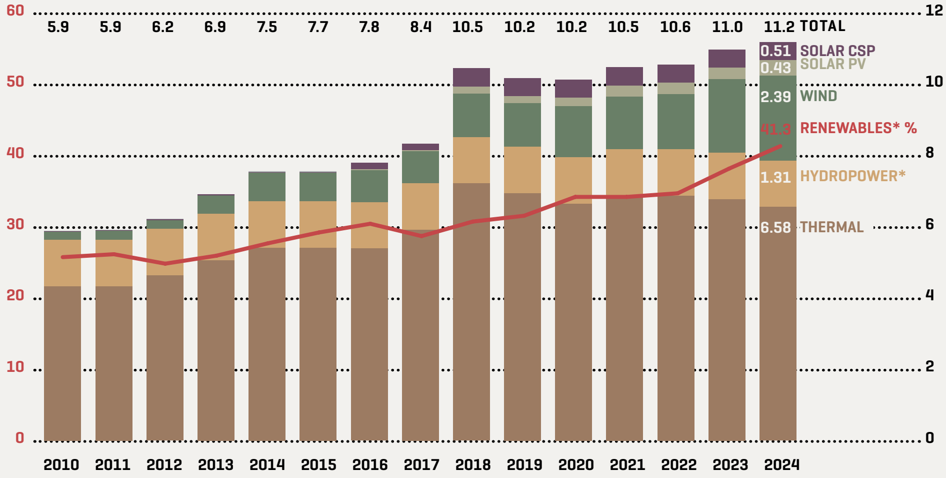
"To ensure the facility's long-term reliability, a second tank with an improved design is currently being constructed," Masen said in its statement. "It will complement the existing infrastructure and strengthen operational resilience."

Saudi operator Acwa Power impaired SAR191.6mn ($51.1mn) for 2024 due to the outage (MEES, 28 February).

Speaking last May, Acwa executives acknowledged that the second such salt tank meltdown at Noor III highlighted potential vulnerabilities which were applicable to the company's other CSP projects. As such the firm stressed it would be taking its time to find a durable permanent solution.

"Because of this incident in Morocco, which is repeating for the second time in a matter of two and a half years, as management, together with our shareholders, we are investigating if we can do anything that is a more permanent solution. There are a lot of actions in place in relation to Noor III," IR chief Ozgur Serin said. CFO Abdulhameed Al Muhaidib added that "There is a big lesson learnt for us related to Noor III... we are this time looking to find a permanent solution, even if it's going to cost us more. We would like to solve it forever."

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.

DUBAI CSP: LESSONS LEARNED?

Mr Muhaidib adds that Acwa had already sought to apply the lessons of Noor III's problems in its second Mena CSP facility – Dubai's MBR Phase IV's joint PV/CSP plant – which started up in 2023 and reached full 700MW capacity in 2024 and has not suffered the same problems as the Morocco plant (MEES, 1 December 2023).

"One of the lessons learnt... [we sought to apply when] we built another CSP plant in Dubai. The way that we are trying to avoid the single point of failure, for example, in Dubai, instead of building that specific technology with one hot molten salt tank and another cold hot molten salt tank, we did a redundancy. We had four different tanks which are hot and four different tanks which are cold. So in case of a failure of a tank, you lose 25% of the plant instead of losing the 100% capacity, like what we are seeing in Noor III," he said.

However, both Acwa and Morocco appear wary of further CSP projects. Acwa's Mr Muhaidib stresses that CSP, "one of the most challenging technologies" represents "2% and less of my overall portfolio [now]" and "going forward, we don't have a big portfolio with the CSP to impact us."

Morocco, meanwhile appears to have scrapped a planned CSP element at the heavily-delayed 800MW Noor Midelt I project in the north of Morocco (MEES, 15 December 2023). Noor III is one of three plants that make up Morocco's current 510MW CSP capacity (see chart & MEES, 7 March). ◆◆

ALGERIA-FRANCE TENSION: CAN TOTAL MELTDOWN BE AVERTED?

Recent escalations between Algiers and Paris are raising concerns over trade ties and the fate of French companies in Algeria.

With Algeria-France relations deteriorating to new lows over the past year, concerns have been raised over the future of bilateral trade ties and French assets in the North African nation.

While relations between Algiers and Paris have long been strained, they reached a new low last year when the latter officially recognized Rabat's sovereignty over the Western Sahara (MEES, 31 January), which Morocco has occupied since the withdrawal of former colonial power Spain in 1975.

This marked a historic shift in the French position on the disputed territory, where Algeria backs the Polisario group fighting for the territory's independence (MEES, 17 November 2023).

Algiers at the time responded by withdrawing its ambassador to Paris, having already severed diplomatic ties with Rabat three years earlier (MEES, 27 August 2021).

This triggered a series of diplomatic incidents, which have included the reciprocal expulsion/detention of diplomats, as well as high-level attempts to contain the crisis that has been described as the worst breakdown of bilateral relations since Algeria's independence from its former colonizer in 1962.

'POLITICAL MANEUVERING'

The Algerian-French Chamber of Commerce and Industry (CCIAF) has cautioned against the implications of the recent tensions for trade ties, warning that they could threaten around $5bn of French exports to Algeria.

"We strongly deplore this escalation, which is a matter of political maneuvering," CCIAF president Michel Bisac said in a 17 April statement, urging all parties to "preserve" economic ties "regardless of the current political tensions."

French-Algerian trade was worth nearly $12bn in 2023, including $7.3bn in Algerian exports to France, mainly consisting of hydrocarbons.

France's TotalEnergies has had a long-standing presence in Algeria since independence, becoming the country's number two foreign producer on a net basis with 49,000 boe/d for 2024.

In April 2024, Total and Sonatrach signed an MoU with the aim of concluding a hydrocarbon contract in the north-east Timimoun region (MEES, 21 June 2024).

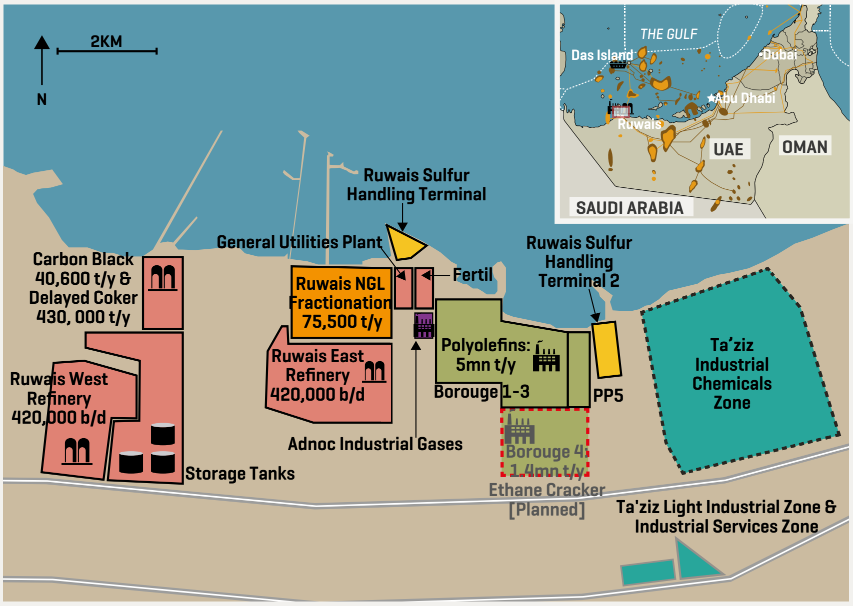
But while Total's current assets remain unaffected so far, Algeria's traditionally nationalistic approach – especially as the current diplomatic crisis continues – could potentially exclude the French partner from bidding in the current licensing round (see p2).

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

UAE Petchems Giant Borouge On Accelerated Growth Trajectory

Borouge targets a 32% organic increase in capacity to 6.6mn t/y by 2028, on top of merger plans which will catapult the firm into the global top 5 polyolefins companies. First up, the completion and integration of the Borouge-4 expansion by end-2026.

ADNOC'S DOWNSTREAM FACILITIES AT RUWAIS



Abu Dhabi petrochemicals firm Borouge has enjoyed a solid start to 2025, with net profits up $10mn year-on-year at $280mn for Q1. The first quarter is typically the firm's weakest quarter, and despite global economic headwinds executives are expressing confidence that a US-China trade war could yield as many opportunities as challenges.

Sales increased 10% year-on-year, and Borouge (Adnoc's XRG 54%, Borealis 36%, free float 10%) is firmly on a growth trajectory as it advances projects to organically expand capacity from 5mn t/y currently to 6.6mn t/y by 2028. This lays "firm foundations" for the ambitious merger of Borouge with its shareholder Borealis and Abu Dhabi-owned Nova Chemicals. The planned entity (Borouge Group International) will have a combined capacity of 16.6mn t/y, with the merger planned to complete in Q1 next year (MEES, 7 March).

BOROUGE EXPANSION ON TRACK

The key expansion project underway is the $7.5bn Borouge-4 complex, which is centered around a 1.4mn t/y ethane cracker and includes polyethylene units, a hexene-1 plant and a cross-linked polyethylene (XLPE) unit. Borouge-4 is planned to be fully operational in 1H 2026. It is being developed by Adnoc and OMV, and will be re-contributed to Borouge by end-2026 with the firm saying that it expects a resultant boost of around $1bn to annual revenue.

Borouge also announced key awards for other expansion projects this week. It confirmed that Linde Engineering has been awarded a Front-End Engineering Design (FEED) contract for a project to increase capacity at the firm's second ethane cracker (EU2) from 1.5mn t/y to 1.73mn t/y by 4Q 2028.

It also awarded an engineering, procurement, and construction (EPC) contract to local firm Target Engineering Construction Company for the revamp of its fourth and fifth polyethylene units (PE4 and PE5) to increase their nameplate capacity from 540,000 t/y to 700,000 t/y each by 1Q 2027. Both units are part of the Borouge-3 facility.

"The expansions of our ethylene and polyethylene capabilities will enable Borouge to meet growing market demands, unlock new revenue streams, and further strengthen our global market position," says Borouge CEO Hazeem al-Suwaidi. The company says the expansions will contribute between $165-200mn in Ebitda, 7-8% of last year's $2.5bn figure.

WORLD LEADING EXPANSION

Borouge says that the expansions will transform its Ruwais operations into the "largest single-site polyolefin complex worldwide" (see map). Ethane feedstock is supplied from Adnoc Gas and Adnoc Refining, which are also located at Ruwais. Adnoc Gas plans to complete its Meram project in 2026 which will yield 2.2mn t/y of ethane and 1.2mn t/y of NGLs (MEES, 27 February).

In the meantime, the company is also carrying out maintenance work at its third ethane cracker during 2Q 2025. "This turnaround is the largest and most complex turnaround project ever undertaken by Borouge," COO Hasan Karam told the company's 30 April results call. Work is focused on "debottlenecking modifications to enhance asset performance and more than 400 tie-ins related to our growth projects," he adds. Output for 2025 will be hit by around 320,000 tons as a result of the ongoing work, the firm says.

TARIFFS: OBSTACLE OR OPPORTUNITY?

Borouge says that first quarter earnings are typically relatively weak and that normal seasonality was compounded by Chinese New Year and Ramadan holidays falling in the same quarter this year.

Looking at the year ahead, Chief Marketing Officer Roland Janssen says the company is monitoring reciprocal tariffs between the US and China "very closely...on a daily or hourly basis almost."

When asked multiple times about the company's predictions on the impact of tariffs on its business, Mr Janssen was sanguine on the recent earnings call. "We have a very robust mix of products which is very resilient in the market and less exposed to the fluctuations... If we see shipments from the US into China are impacted by tariffs that creates an immediate opportunity for Borouge to take over a position and help our customers in those situations," he says.

A key energy market in the ongoing tariff war between the world's two largest economies is China's domestic petrochemicals sector which relies heavily on imports of ethane and propane from the US which were at risk of steep tariffs (MEES, 18 April). According to a 29 April report from Reuters, China has waived a 125% tariff on ethane imports from the US, which might shrink the potential opportunity for Borouge. Another issue to watch is whether the tightening of US sanctions on Iranian LPG exports to China reduces feedstock availability there (MEES, 25 April). ◆◆

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

Oman Announces Third Green Hydrogen Bid Round Amid Headwinds

State hydrogen firm Hydrom has kicked off its third bid round for green hydrogen blocks, offering up land around Duqm. But with none of the previously-awarded projects close to moving forward, Oman's 1mn t/y 2030 target looks out of reach.

More than two years ago Oman unveiled its ambitious green hydrogen targets: 1mn t/y output by 2030, rising to 3.25mn t/y by 2040 and a towering 7.5mn t/y by 2050 (MEES, 28 October 2022).

On the back of these plans the IEA tipped Oman to be the largest Middle Eastern producer of hydrogen by 2030 ahead of both Saudi Arabia and the UAE (MEES, 16 June 2023).

On the surface, it's full steam ahead with Oman now launching its third bid round. But dig a little deeper and tangible signs of progress are harder to find. Eight projects were awarded through the first two rounds (MEES, 3 May 2024), but FID on the most advanced of these isn't expected until next year at best (MEES, 7 March).

THIRD TIME AROUND

On 30 April Hydrom – the Oman state firm responsible for orchestrating bid rounds and common-use infrastructure – announced its third bid round for green hydrogen blocks with an eye to making awards by 2Q 2026.

With the first round having seen five blocks awarded near Duqm, and three blocks north of Salalah awarded in round two, Hydrom is returning to Duqm for round three, offering up to 300km² of near a location it pinpoints some 100km west of the port (see map).

"We've listened to the market," says Hydrom business development manager Rumaitha al-Busaidi touting "the flexibility [for developers] to submit proposals with varying land sizes ranging from 100km² to 300km²." This allows smaller projects than previous bid rounds, but rules out phased projects. Hydrom is also open to developers providing excess renewable energy to the grid for the first time.

Despite these changes, the terms are in the broadest sense the same: "you are expected as a developer to do the renewable energy generation, the green hydrogen production, transforming that green hydrogen into a derivate of your choice, and offtake," Ms al-Busaidi says. Hydrom will continue to provide the shared infrastructure for projects.

PRICED OUT OF A MARKET?

Despite tweaking the size and scope for developers, price remains the central problem facing Oman's green hydrogen ambition. Currently global demand for hydrogen is almost entirely fed by cheaper gray hydrogen that uses natural gas as a feedstock. Green hydrogen currently costs around $6/kg to produce compared to up to $2/kg for gray produced from natural gas, according to MEES averages of estimates from IEA and Irena.

Of the projects Hydrom has awarded, the most likely to get off the ground had appeared to be the 60,000 t/y Hyport project (BP 49%, OQAE 25.5%, Deme 25.5%). But near-term progress looks ever-less likely, with lead-partner BP in February slashing its planned annual "transition" capex from $7bn to a mere $1.5-2bn (MEES, 28 February).

Even state firm and partner OQ Alternative Energy highlights the problem of price with CEO Najla al-Jamali saying "the willingness to commit to a fixed price for 20 years, is very difficult to swallow on both sides" (MEES, 15 December 2023).

Lack of FID is not just an Oman issue, but is indicative of the continued struggle to find offtakers given the price premium of green hydrogen over conventional fuels. The only regional project advancing is Saudi Arabia's 1.2mn t/y Neom green hydrogen plant, due online in 2027. Even here key partner AirProducts which is also the 100% offtaker, has reversed its push into green hydrogen and says it is delaying investments into European downstream outlets until regulatory frameworks are developed.

Regardless, Hydrom has previously said it expects a first offtake agreement from one of the projects in 2026 alongside energy minister Salim al-Aufi's expectation for the first FID in the same year. This would be supposedly be followed by other projects moving to FID in 2027 (MEES, 7 March).

SHARED INFRASTRUCTURE

Hydrom also provided an update on its ongoing work in establishing the common-use infrastructure for future green hydrogen projects including green hydrogen pipelines, power interconnection, and desalination plants. According to the firm they are still in the pre-FEED stage but expect to move onto FEED by the end of 2Q 2025 while targeting FID around 2027.

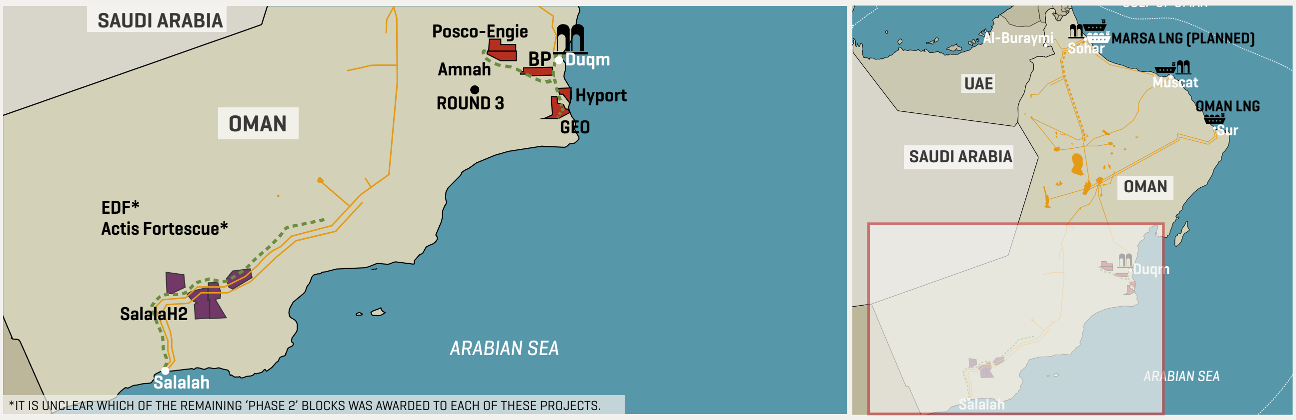
This ties into Oman's plans for a "liquid hydrogen corridor" to facilitate the export of green hydrogen to Europe under an agreement signed on 16 April by eleven private and public sector representatives of Oman, the Netherlands, and Germany. The agreement plans for a hydrogen liquefaction, storage, and export terminal in Duqm developed by OQ to help export the gas on dedicated hydrogen carriers to re-gasification import terminals in Amsterdam to feed European industrial demand.

Similar 'corridors' have been proposed elsewhere in the world, but they are likely to remain on the drawing board so long as the economics of green hydrogen remain sketchy.

Ultimately, potential producers agree that the economics of green hydrogen require governments in demand centers to incentivize purchases through subsidies. But amid a slowing global economy, such a move is becoming an increasingly hard sell to voters. ◆◆

OMAN'S GREEN HYDROGEN DEVELOPMENT PROJECTS

ROUND 1 ROUND 2 H2 PIPELINE (PLANNED) GAS FIELD/PIPELINE OIL TERMINAL REFINERY LNG TERMINAL



*IT IS UNCLEAR WHICH OF THE REMAINING 'PHASE 2' BLOCKS WAS AWARDED TO EACH OF THESE PROJECTS.

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

Israel Looks To Make Coal History With Gas & Renewables Powergen Records

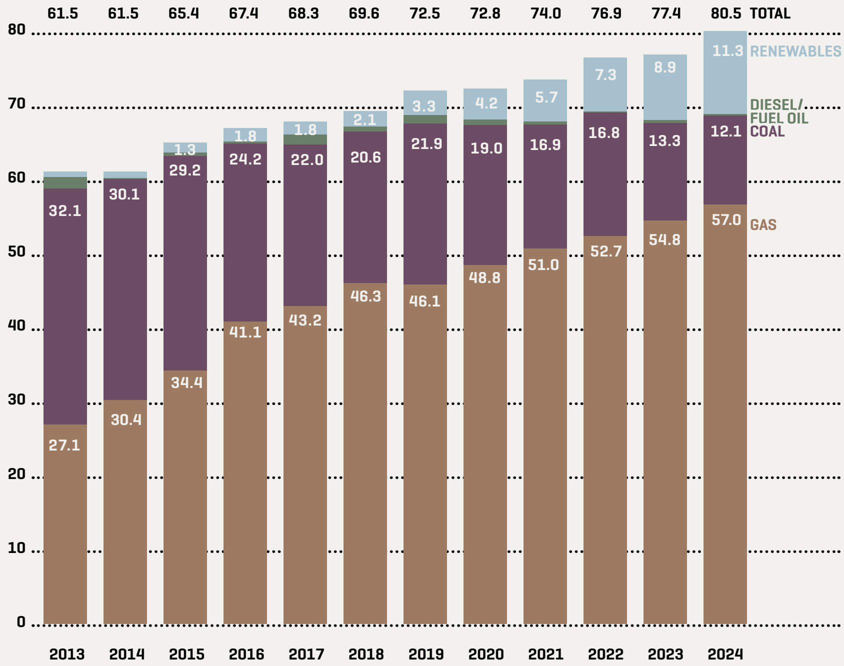
Israel aims to end coal-fired power generation next year as it leans on plentiful domestic natural gas reserves to complement the fast-growing role of renewables in the country's power generation mix.

Israel's plans to end coal-fired power generation have been set back by 18 months of conflict. But, having missed the previous 2025 target (MEES, 10 January 2020), state generator IEC says it "is expected to stop routine coal usage as primary fuel by September 2026," whilst acknowledging the "possibility of postponement to March 2027."

IEC operates all of the country's remaining 4.3GW of coal-fired capacity, though its overall share of Israeli power generation has been falling both due to surging renewables and the growing role of Independent Power Producers (IPPs).

And whilst coal's role in Israel's power generation has also been falling, it still fueled 15% of the 80.5TWh total for 2024, versus respective records for both gas with 57.0TWh or 71%, and 11.3TWh (14%) for renewables (see chart 1).

1: ISRAEL POWER GENERATED (TWh): GAS AND RENEWABLES HIT RECORDS FOR 2024



SOURCE: IEC, ISRAEL ELECTRICITY AUTHORITY, MEES.

COAL CONVERSIONS

IEC, that is to say Israel, has nine remaining coal-fired units. Six of these comprise the 44-year-old 2.59GW Orot Rabin plant on the coast north of Tel Aviv. The remaining three, totaling 1.675GW, are at Ashkelon's Rutenberg powergen complex just north of Gaza on Israel's Mediterranean coast. Rutenberg fourth 575MW steam turbine unit has already been converted to run on gas. Conversion of one of the remaining three is underway (albeit delayed), with the other two to follow.

At Orot Rabin, two of the six units (no. 5 & 6) of the 1981-vintage coal-fired plant will be converted to run on gas and the other four retired. To replace this capacity, IEC is building two efficient new 640MW combined cycle gas turbine (CCGT) units alongside. But, while Unit 70 received a production license on 26 January which saw the start of commercial operations, Unit 80 has seen a "delay in establishing the project due to the security situation," IEC says in its recently-released 2024 results and annual report, adding that it expects commercial operations in August "subject to no further exogenous events."

"The cessation of the [coal] units' activity will be done gradually depending on the commercial operation of two new CCGTs," IEC says, whilst warning that completion of conversion of the remaining coal-fired units "may be postponed to March 2027." With Israeli installed capacity well in excess of peak demand, and the converted steam turbine units (which will still be able to run on coal as well as gas) envisaged for peaking/backup use only, this would not necessarily preclude the end of coal-fired generation before this date.

PRIVATIZATION PUSH

Whilst IEC remains Israel's largest generator, its relative importance has been falling due to the rapid growth of renewables, the gradual privatization of its gas-fired plants and the shuttering of its oldest units – most recently the 428MW Reading plant in Tel Aviv which was decommissioned last year.

In June 2024 IEC completed its largest sell-off yet, with a consortium led by local firm Dalia Power paying $2.4bn for the 1.68GW Eshkol plant in Ashdod just north of Ashkelon (MEES, 17 November 2023).

IEC's share of the country's total installed capacity fell below 50% for the first time in 2022 and fell again to a record low 38.5% as of end-2024. Of Israel's 24.6GW of end-2024 installed capacity, IEC's overwhelmingly-thermal capacity comprised 9.47GW, gas-fired IPP capacity totaled 8.33GW, and 6.80GW of renewables the remainder (see chart 2).

SOLAR SURGE, WIND PICKS UP

That Israel continues to post gains in overall capacity despite the shuttering of aging IEC-operated thermal plants is thanks to a surge in renewables, primarily solar PV.

End-2024 solar capacity of 6.2GW was up from 5.0GW a year earlier and just ahead of the UAE's 5.7GW as the Mena leader.

Wind is also picking up, with Enlight's 207MW Genesis wind farm in the

Continued on – p13

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

Continued from – p12

occupied Golan Heights, which started up at the end of 2023, comprising the bulk of the 340MW total (MEES, 17 November 2023). Compatriot Energix has a further 104MW of wind capacity under construction at the Golan Heights. But work was halted in October 2023 and remains suspended. Commercial operations will begin "12 months after the resumption of the works," the firm says in its recently-released 2024 report.

STORAGE IS VITAL

With the renewables share of Israeli powergen hitting a record 14% for 2024, and the country targeting 30% by 2030 (for an implied 28.4TWh, two and a half times the 2024 figure), plans are also afoot to massively increase both storage and grid capacity to cope with the intermittency of renewables.

While it had just 369MWh of mainly pumped-hydro storage at the end of 2023, Israel's state Electricity Authority targets a massive surge to 8.44GWh by the end of 2030. The bulk of this will be integrated with solar PV projects, with 2024 already having seen a massive surge in capacity.

Local firm Doral Energy is market leader in terms of integrated solar PV/storage capacity, with 632MW/1.226GWh as of late 2024. And Doral also has the country's largest under construction solar/storage plant, 175MW/248MWh Hadarei She'an in the northeast of the country. Panel installation is currently around 50% complete with Doral saying it expects full commercial operations to be achieved in 2026.

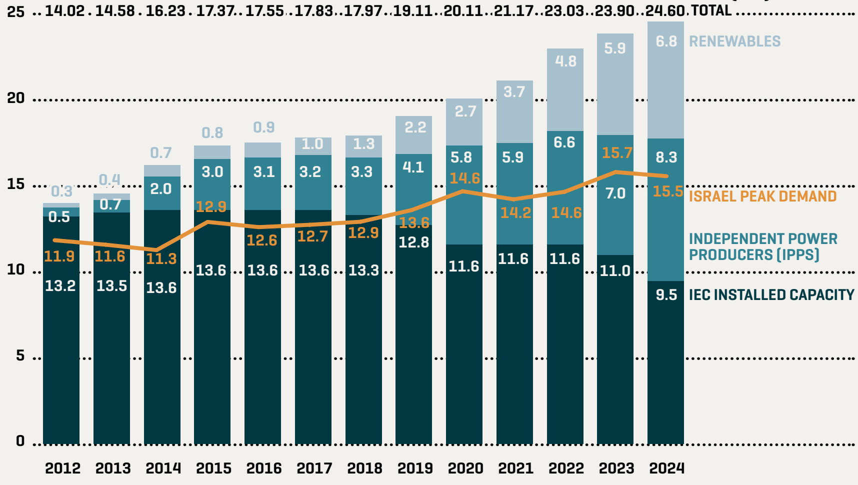
Enlight, meanwhile, has 248MW/625MWh of integrated PV/storage capacity in Israel, much of which came online last year (MEES, 18 October 2024), with a further 186MWh of integrated storage capacity under construction. Energix had 53MW/189MWh of integrated PV/storage as of end-2024 with a further 58MW/158MWh under construction and slated to begin commercial operations in Q4 this year.

Small-scale rooftop solar is also key to the Israeli Energy Ministry hitting its renewables targets with the aim to add 100,000 residential solar rooftop panels totaling 1.6GW by 2030.

GAS: PLENTIFUL & CHEAP

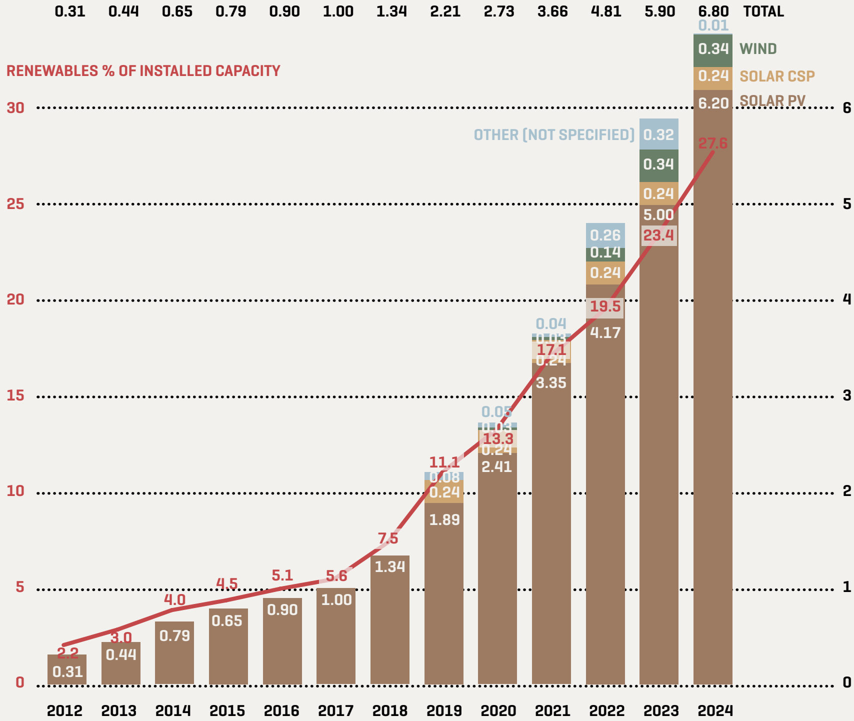
But, even should the planned surge in renewables and associated storage capacity be achieved, gas will retain a leading role in Israel's power generation mix going forward as the country is able to lean on plentiful supplies from its three producing projects. With all three looking at further expansion either by increasing field capacity or

2: ISRAEL INSTALLED CAPACITY CONTINUES GROWING COMFORTABLY OUTPACING PEAK LOAD (GW)



SOURCE: IEC, ISRAEL ELECTRICITY AUTHORITY, MEES.

3: ISRAEL RENEWABLES RISE TO 6.8GW AT END-2024 MAKING UP NEARLY 28% OF OVERALL 24.6GW INSTALLED CAPACITY (GW)



SOURCE: IEC, ISRAEL ELECTRICITY AUTHORITY, MEES.

through tie-ins, Israel will have an abundance of gas in the coming years.

US major Chevron which operates both the 1.2bn cfd Leviathan and 1.1bn cfd Tamar is eying expansion to 1.4bn cfd and 1.6bn cfd respectively by the start of next year (MEES, 28 March), whilst Energean is looking to bolster output at its 775mn cfd Karish project with the tie back of nearby fields (MEES, 26 July 2024).

Domestic gas is not only set to remain plentiful for decades to come – end 2024 2P reserves of 29tcf would last over 30 years at 2024 output levels – it is also a cheap option for Israeli generators.

Domestic customers currently pay an average of \$4.52/mn BTU for gas, with Karish gas priced the lowest at 4.23/mn BTU according to MEES calculations (MEES, 18 April). Wary that Chevron's influence over the country's two fields could translate into higher prices, Israel's Finance Ministry has suggested that the US major be removed from one of the two fields to increase competition and ensure prices remain low (MEES, 28 March).

For now such suggestions remain on the back burner, with an inter-ministerial committee that meets every five years to discuss the country's energy strategy blocking such a proposal and suggesting such a move could potentially spook investors looking to enter Israel's upstream, ultimately having the opposite desired effect.

"Even the officials from the finance ministry themselves haven't decided whether this is a genuine policy idea or a bargaining chip to extract other concessions from Chevron," an inside source tells MEES. "Privately, they admit this notion - that even now, hasn't been really thought through - has a small chance of success."

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

Kuwait Starts Power Imports Early Amid Generation Struggles

Kuwait has already started 2024 power imports, well ahead of summer peak demand as an aging powergen fleet requires an increasingly onerous maintenance schedule. Industry faces power supply restrictions as Kuwait seeks to curb demand.

Kuwait is struggling to cope with record power demand levels and has already been forced to turn to imports from neighboring countries months ahead of the peak demand season. The country's power system was already struggling to meet demand through Q1, despite demand being broadly in line with year-ago levels (MEES, 14 February). And peak load then soared in April to around 1GW above year-ago levels, further adding to the strain (see chart 1).

Preliminary data shows that peak load hit 12.58GW on 30 April, up from the previous April record of 11.59GW set last year and massively up on March's 9.04GW, which in turn was down 1.5% on the year-ago 9.17GW. That drop in peak demand was significantly outstripped by a 5.5% drop in total power generation to a three-year March low of 5.19TWh (see chart 2), indicating that the power network was struggling to meet demand in full. On 2 April, Kuwait then cut power to some agricultural and industrial users (MEES, 4 April).

Amid this, Kuwait imported 164GWh of power through the GCCIA interconnection in March. This is the earliest in the year that Kuwait has imported electricity, having started in June last year when it took 345GWh, peaking at 515GWh in August (see chart 3) for an annual total of 1.71TWh.

August's imports equated to an average 700MW, and for this summer the plan is for imports to increase further to 1GW and then to 1.5GW for summer 2026 (MEES, 6 December 2024).

POWER PLANT STRUGGLES

The latest full data from the electricity ministry shows that when peak load hit 9.04GW in March, available capacity was just 10.16GW leaving it with a buffer of barely 1GW. Not just is this well below installed capacity of 19.38GW, it is the lowest available figure at this time of year in at least a decade. Until last year, available capacity in March was routinely more than 11.5GW and it peaked at 13.5GW in 2021.

That available capacity is declining while demand increases highlights the struggle Kuwait is facing. It is reliant on power plants which are in some cases approaching fifty years old, and which are increasingly dependent on heavy maintenance. For instance, March available capacity included steam turbines at the Doha East power plant which were commissioned in the late 1970s. Meanwhile, generation from the 5.77GW Az Zour South power plant was at a three-year low 882GWh for March, with none of its most efficient 1.17GW combined cycle gas turbines available.

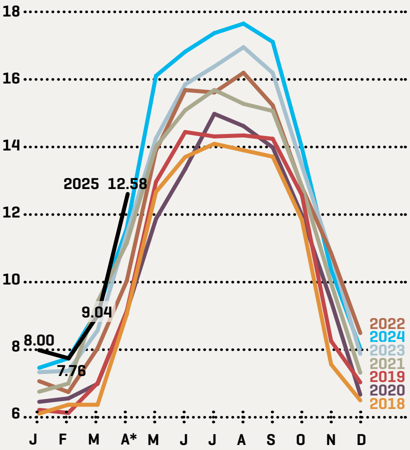
After peaking at 20.25GW in April 2021, installed capacity has been going backwards, dropping to just 19.88GW since May 2024 as political deadlock and red tape has prevented planned new power plants from being awarded.

The suspension of parliament could pave the way for new capacity, with tendering underway for the 2.7GW Az Zour North 2&3 IWPP project for which a consortium led by Saudi Arabia's Acwa Power is the frontrunner (MEES, 21 February). On 17 April, the Central Agency for Public Tenders (CAPT) approved tendering for the 900MW Sabiya-4 expansion, with the tender then opened on 27 April.

However, even if these projects proceed smoothly they will take a number of years to implement and Kuwait is already facing a supply crunch. In light of this, the government is looking at ways to tackle consumption, with the ministry last month agreeing to form a committee for rationalizing electricity and water consumption "especially during the summer period extending from May until the end of September, especially during the peak period, which is usually from 11:00 a.m. to 5:00 p.m."

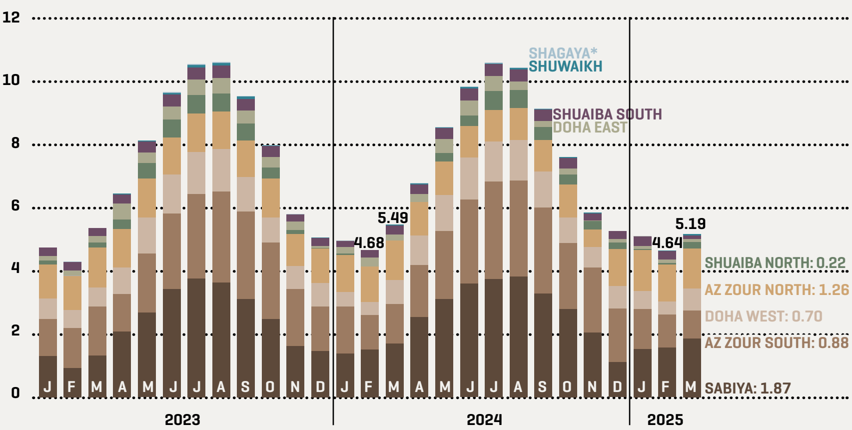
The primary focus appears to be on industrial facilities, with moves to reduce huge subsidies for citizens still politically unpalatable. However, restrictions on major facilities risk having a negative economic impact for Kuwait, amplifying the impact of broader global economic concerns. The IMF's latest Regional Outlook released 1 May forecasts Kuwaiti economic growth of 1.9% this year, lagging well behind the GCC average of 3.0%. ◆◆

1: KUWAIT'S PEAK LOAD BEGINS THE YEAR WITH NEW ALL TIME HIGHS (GW)...



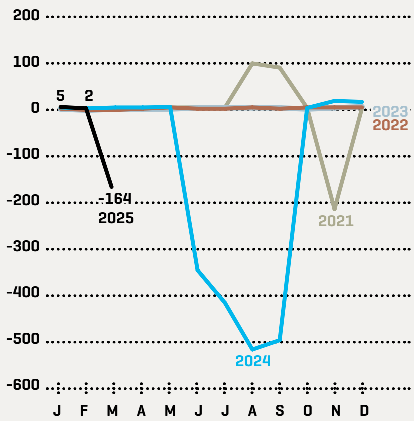
*REACHED ON 30 AUG AT 15:30. SOURCE: MEWRE, MEES.

2: ...BUT POWER GENERATION FELL BELOW 2024 LEVELS IN FEBRUARY & MARCH (TWH)...



*RENEWABLES PARK (50MW CSP, 10MW SOLAR PV, 10MW WIND). SOURCE: MEW, MEES.

3: ..WITH KUWAIT INSTEAD TURNING TO UNSEASONALLY-EARLY POWER IMPORTS (NET FLOWS: GWH)



SOURCE: MEW, MEES.

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

Abu Dhabi's Ewec To Reconfigure, Extend Shuweihat 1 Power Plant

Ewec is reconfiguring its oldest power plant, gas-fired Shuweihat-1, to meet Abu Dhabi's changing power needs amid nuclear and renewables' growing share.

Abu Dhabi state offtaker Ewec announced on 28 April that it is extending the lifetime of the Shuweihat-1 (S1) power plant. The facility is currently a gas-fired combined cycle cogeneration plant with the capacity to produce 1.6GW of electricity and 340,000 m³/d of desalinated water, but it is now to be converted to an open-cycle power plant providing up to 1.1GW of flexible gas-fired reserve supply.

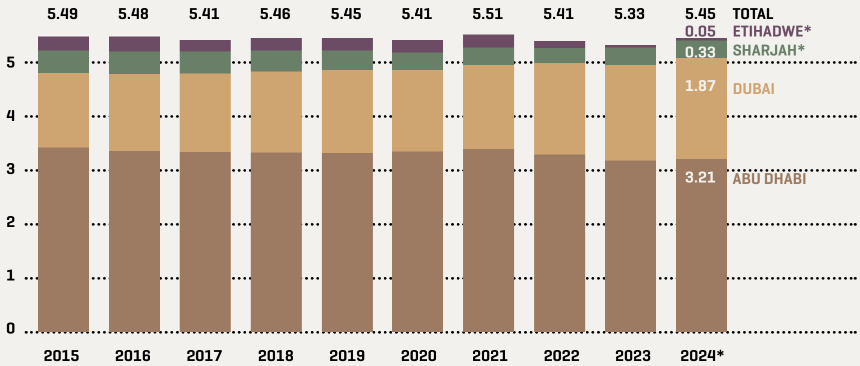
Ewec signed a 15-year power purchase agreement (PPA) with S1 owners Taqa (60%), France's Engie (20%) and Japan's Sumitomo (20%) covering the reconfiguration. With operations due to begin in 2027, the new PPA is slated to expire in 2042. A second agreement saw the three companies – albeit with different stakes: Engie 35%, Sumitomo 35% Taqa 30%– sign up to continue to operate and maintain the plant through the term of the new PPA.

The move comes as part of Ewec's broader focus on high-grading its power and water assets, with the S1 plant the oldest facility in its portfolio. Although the move will reduce S1's power generation capacity, and eliminate entirely its role in producing water, Ewec's capacity in both regards is on an upwards trajectory.

Ewec's installed power capacity increased by more than 2GW last year, driven in large part by the completion of the 5.6GW Barakah nuclear plant and the first 800MW phase of the Fujairah F3 gas-fired CCGT plant. Desalination capacity has been flat at 4.82mn m³/d for the past two years, but the new 318,225 m³/d Shuweihat 4 (S4) reverse osmosis plant is due online in Q3 this year and will more than offset the S1 loss.

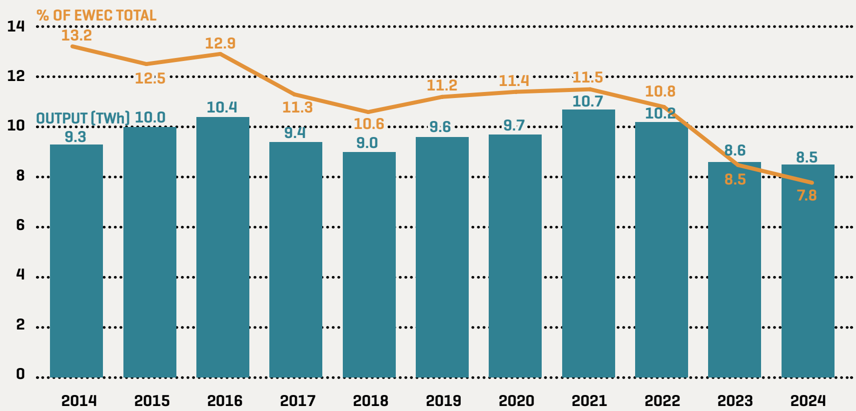
While electricity generation in Abu Dhabi and the UAE more broadly continues to increase at a rapid pace (MEES, 11 April), desalination volumes across the country have broadly flatlined over the past decade at just below 5.5mn m³/d (see chart 1). Ewec is the largest producer of desalinated water in the UAE, with 58.8% of the total last year, but this has dropped steadily over the last ten years from 62.3% in 2015 as capacity has come online in other emirates reducing exports from Ewec's system.

1: UAE DESALINATED WATER PRODUCTION REMAINS BELOW 2021 PEAK (MN M³/D)



*SHARJAH & NORTHERN EMIRATES 2024 FIGURE = MEES ESTIMATE. SOURCE: EWEC, DEWA, SEWA, ETIHADWE, MEES.

2: SHUWAIHAT-1'S ROLE IN EWEC'S POWER MIX HAS BEEN STEADILY DECLINING IN RECENT YEARS



SOURCE: EWEC, MEES.

FLEXIBLE POWER SUPPLY

S1's contribution to the power mix has been steadily declining in recent years, with electricity generation last year 2.2TWh below the 2021 peak of 10.7TWh (see chart 2). As a share of total Ewec generation, the plant accounted for just 7.8% last year. This is part of a broader trend where the rise of renewables and nuclear power has pushed out gas, with gas-powered generation dropping from 83.9TWh in 2018 to 62.6TWh last year (MEES, 7 March). By 2030, Ewec aims to provide more than 50% of Abu Dhabi's electricity from renewable and clean energy sources.

Although the role of gas in the power system has been diminished, it remains the largest single source and will retain a key role going forward. However, that role is changing and is becoming less about being just a reliable baseload and more about providing flexibility to ramp up generation at short notice to respond to outages elsewhere or surges in demand (MEES, 2 August 2024).

"The reconfiguration and extension of S1 facilitates the UAE's transition towards net zero whilst also maintaining reliability during peak power demand periods. The flexible operation of the plant in support of increased renewable and clean energy sources also ensures minimal carbon emissions" says Ewec.

Mohamed Al Marzooqi, Ewec's Chief Asset Development & Management Officer says that "by strategically reconfiguring this power plant we are maximizing the efficient use of existing infrastructure to deliver reliable, flexible power supply while reducing carbon emissions associated with the project. Utilizing natural gas as a flexible transition fuel enables the accelerated integration of renewable and clean energy projects, such as solar and wind, into the energy mix, and preserves resources."

Andreas Collor, the Chief Operations Officer, of Taqa's Generation business added that "S1 will provide power as and when needed to support increased demand spikes and the integration of renewables as Abu Dhabi works towards accelerating the energy transition whilst ensuring a reliable supply of power."

The move to reconfigure the S1 plant could serve as a model for the next expiring PPA. The Umm al Nar's PPA expires in 2027, and the plant has the capacity to produce 1.67GW of electricity and 317,000 m³/d of water. ◆◆

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

Saudi Arabia's Falling FDI Makes Oil Revenue Crunch More Acute

Saudi Arabia has transformed over the past decade as the government has pursued the Vision 2030 reform program launched by Crown Prince Mohammed bin Salman Al Saud in 2016. The kingdom is racing ahead on many metrics, as any visitor can attest, but efforts to ramp up foreign direct investment (FDI) inflows to fund 'gigaprojects' and boost the private sector are struggling to gain traction.

The recently-released Vision 2030 Annual Report for 2024 benchmarks progress in multiple metrics, with Crown Prince Mohammed noting "we have not only met key targets – we have surpassed many." Certainly, the reform agenda is surging ahead, but the struggles to ramp up FDI are problematic.

FDI came in at $25.6bn in 2023 and Saudi Arabia targeted an increase to $29.07bn last year as part of a planned ramp-up to $103bn by 2030. However, far from growing, FDI dropped back to a post-Covid low of $20.69bn for 2024, leaving it more than $8bn off target (see chart 1). With the FDI target rising again this year to $37bn, record FDI is required just to come close to achieving this. Indeed, the 2025 target requires a massive 80% year-on-year increase, and amid the challenging global economic outlook this represents an especially daunting challenge (MEES, 25 April).

Measures are being taken to improve the investment environment, with Minister of Investment Khalid al-Falih earlier this year pointing to the newly established Saudi Investment Marketing Authority as helping stimulate FDI inflows.

The FDI slowdown is arguably more problematic than lower oil prices for Vision 2030, given that Saudi Arabia intends for foreign partners to come into the local market and help stimulate private sector growth. Absent strong FDI growth, the investment burden falls increasingly on the kingdom itself, which is where the drop in oil revenues adds to the challenge.

Oil export revenues were down $1.6bn year-on-year over the first two months of 2025 due to a steep drop in February. February's $18.0bn was the lowest figure for the month since 2021 (see chart 2). And with Brent prices dropping in March before plunging to four-year lows of $66.46/B for April amid the fallout from US tariff announcements and Opec+ production increases, oil export revenues will remain muted (MEES, 4 April).

Looking ahead, downbeat economic forecasts continue to weigh on oil prices, while even the additional barrels from the accelerated tapering of Opec+ cuts will be consumed domestically as seasonal increases in electricity demand require more oil feedstock. Last year, oil burn increased by more than 600,000 b/d between March and August. Oil burn has started the year down 200,000 b/d on 2024 levels and if this momentum is maintained it could have a larger impact on export revenues than production dynamics (MEES, 25 April).

PIF'S STRONG GROWTH

The third pillar of Saudi Arabia's economic strategy is the Public Investment Fund (PIF) which is overseeing the country's 'gigaprojects' such as Neom and has taken on an increasing share of the country's capital expenditure. The Vision 2030 Annual Report describes the PIF as having been restructured into an economic engine, and that "by deploying capital into priority sectors, such as mining, industry, logistics, tourism, culture, and technology, PIF became a central force in shaping the non-oil economy."

PIF's assets under management (AUM) grew by $176bn last year to hit $941bn (see chart 3), well above its target of $880bn. The target for this year is $1.07 trillion.

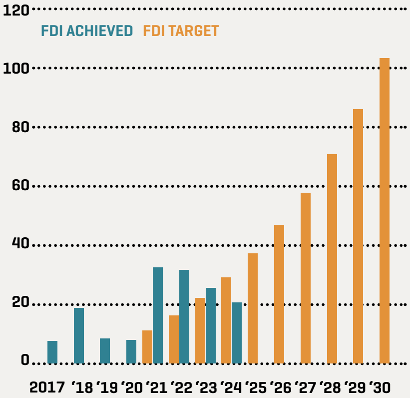
Last year's strong growth was largely driven by the transfer of an 8% stake in Saudi Aramco in March, which increased its position in the energy giant to 16% (MEES, 8 March). That 8% stake was worth around $144bn at the end of last year, accounting for approximately 80% of the total increase in PIF's AUM. But as Aramco's share price has fallen alongside oil prices, its value has dropped back to $144bn currently.

RATIONALIZING INVESTMENT?

The struggles to increase FDI coupled with falling oil revenues leaves Saudi Arabia having to either borrow more to finance investments or scale back its ambitions. The kingdom last year budgeted for a $26.9bn deficit in 2025, but the subsequent deterioration in the global economic outlook and oil markets could push this higher still. With a debt-to-GDP ratio of 29.7%, Saudi Arabia can afford to take on debt, but not indefinitely.

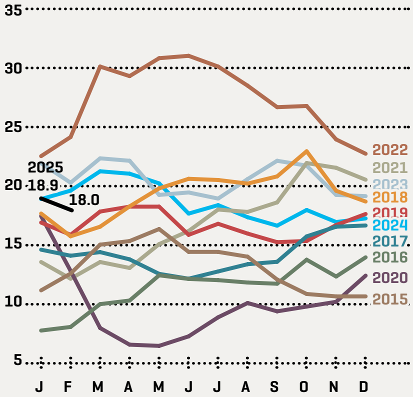
With this in mind, government officials have stated over the past 18 months that the timeframe of some gigaprojects is being extended. Finance Minister Mohamed al-Jadaan has warned that too much spending could overheat the economy and boost inflation, saying in late-2023 that "Certain projects can be expanded for three years — so it's 2033 — some will be expanded to 2035, some will be expanded even beyond that and some will be rationalized." ◆◆

1: SAUDI ARABIA FDI INFLOWS FALL BACK AGAIN IN 2024, DROPPING TO FOUR-YEAR LOW ($BN)



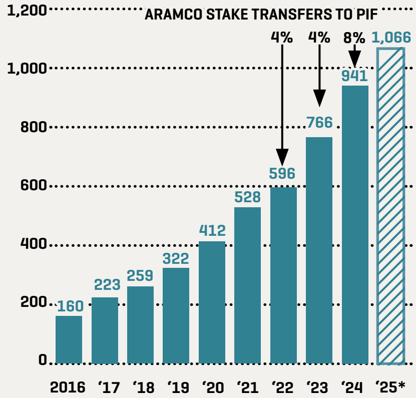
SOURCE: MINISTRY OF INVESTMENT, MEES.

2: SAUDI ARABIA MONTHLY OIL EXPORT REVENUES START 2025 AT FOUR-YEAR LOWS ($BN)



SOURCE: GENERAL AUTHORITY FOR STATISTICS, MEES.

3: PIF ASSETS UNDER MANAGEMENT CLOSE IN ON 2025 TARGET ($BN)



SOURCE: PIF, VISION 2030, MEES.

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

◆◆

NEWS IN BRIEF

GULF NOCS STEP UP LNG TRADING

This week saw two major Gulf NOCs sign new deals to boost their growing LNG trading portfolios. On 30 April, Adnoc Trading signed an agreement to supply India's Hindustan Petroleum (HPCL) with volumes at the latter's recently-commissioned LNG import terminal at Chhara in Gujarat province. The 5mn t/y facility has two storage tanks with combined capacity to store 400,000 tons. India is the largest destination for Adnoc's LNG, although Adnoc Trading could ultimately source cargoes from elsewhere.

The same day, Oman's OQ Trading signed a 15-year LNG Sales and Purchase Agreement (SPA) to receive 600,000 t/y of LNG from Amigo LNG, the Mexican subsidiary of Singapore-based LNG Alliance. The move is intended to diversify its portfolio away from the Middle East and Asia. OQ Trading praises the "logistically efficient supply route" offered by Amigo LNG, as "the West Coast of Mexico provides a direct maritime path to Asia, reducing shipping time and offering flexibility in supply chain operations."

ARAMCO, NABORS CONSIDER IPO OF SANAD DRILLING JV

Saudi Aramco and Nabors Drilling are considering monetizing their 50:50 Sanad Drilling JV through an IPO. Speaking on the firm's Q1 earnings call on 30 April, Nabors CEO Anthony Petrello, described an IPO as "the obvious path...we think Sanad is the most attractive company in the region." He adds that for now plans remain embryonic. "Obviously we have some preparatory work to be done in the meantime. Both parties are looking at that as an option. It's pretty clear that this is one path to realize value and create enormous shareholder value," he says. Nabors last month valued its 50% stake in Sanad at around $1.4bn.

Sanad says that as of 11 March it had 50 rigs operating in Saudi Arabia. According to Mr Petrello, approximately 75% of its fleet works in natural gas after Aramco paused its plans to increase crude capacity by 1mn b/d, with a number of rigs being recently added to the unconventional gas market.

One issue that Mr Petrello highlighted is that "what's underappreciated is the amount of condensate Aramco is generating on their gas production." Saudi Arabia expects its gas projects to yield an additional 1mn b/d of liquids by 2030 (MEES, 28 March).

OMAN: MARSA LNG ADVANCES

Marsa LNG (TotalEnergies 80%, Oman state firm OQEP 20%), has secured a newbuild LNG bunker vessel for its 1mn t/y LNG facility in Sohar where construction is also underway (see map, p11). It will be the region's first LNG bunkering facility, giving Sohar a first mover advantage over Fujairah.

According to a 1 May press release from Total, the 'Monte Shams' is currently under construction and "will be stationed in Sohar from 2028, where it will supply LNG to a wide range of vessels." Previously Total suggested it would use a vessel chartered from Spanish shipowner Ibaizabal (MEES, 11 October 2024).

This week also saw a groundbreaking ceremony at the LNG facility, although construction had already started at the beginning of the year (MEES, 7 March). The facility will be primarily powered by a 300MW solar PV plant, although it will also receive power from the grid when solar availability is limited, with the solar plant injecting power into the grid at other times. Gas feedstock will come from equity volumes from Block 10 (Shell 53.45%, TotalEnergies 26.55%, OQEP 20%) which ramped up output to its 500mn cfd capacity in the middle of 2024 (MEES, 25 April).

QATAR-SHELL INK 25-YEAR CONDI DEAL

On 30 April, state firm QatarEnergy has signed a deal with Singapore-based Shell International Eastern Trading to supply up to 285mn barrels (31,000 b/d) of condensate over 25 years from July 2025.

Qatar exported 190,000 b/d of condensate in 2024 according to Kpler, meaning this deal would equate to around 16% of its exports. The deal follows a ten-year one with Japan's Mitsui for 110mn barrels (30,000 b/d) last year and with Dubai's Enoc for 120mn barrels (32,000 b/d) the previous year.

CAIRO DELAYS BIDDING DEADLINE

Egypt's Petroleum Ministry announced on 27 April that it was pushing back the deadline for its latest bid round by two months, from 2 May to 2 July. MEES understands that the delay was driven by a lack of concrete interest in the seven undeveloped offshore discoveries on offer which are grouped in two clusters (MEES, 14 March).

Meanwhile, no awards have yet been made from Egypt's prior bid round, a 12-block offering (10 offshore, 2 onshore) launched in August last year (MEES, 30 August 2024). Cairo is currently evaluating bids for four blocks, MEES learns.

With mounting receivables, and output on the slide, Egypt may have to sweeten the pot if it is to have any success in finding any takers for its plentiful acreage (see p6).

EXXON SPUDS CYPRUS WELL...

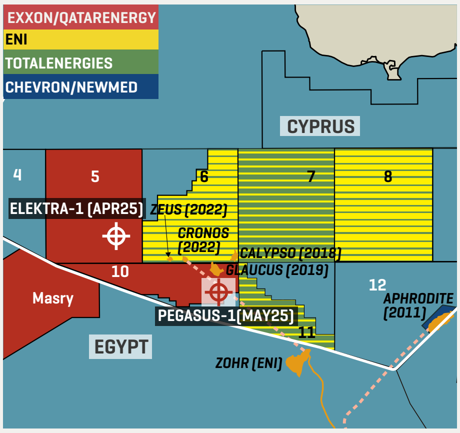
Fresh from the disappointment of sub-commercial gas volumes at the highly anticipated Elektra wildcat on Cyprus Block 5 (MEES, 18 April), US major ExxonMobil is readying to spud the Pegasus-1 well on Block 10 some 12km to the south of its 3.2tcf 2019 Glaucus find (see map & MEES, 1 March 2019). Exxon (60%op) is partnered at both Block 5 and 10 by QatarEnergy (40%).

In contrast to Elektra, where up to 30tcf was targeted, Pegasus is seen as low-risk low-reward with a 1tcf pre-drill estimate and 80% chance of success. Talks have recently been held between Nicosia and Exxon about potential development scenarios that would look at developing Glaucus, and potentially Pegasus, in synergy with other nearby gas discoveries (MEES, 11 April).

Here the most advanced is Cronos on Block 6 (Eni 50%op, TotalEnergies 50%), with the Italian firm planning to tieback the field to its Zohr facilities 60km away in Egyptian waters (MEES, 21 February). Eni says it hopes to take FID before the end of the year which would mean first gas either in late 2027 or early 2028 (MEES, 25 April).

CYPRUS KEY BLOCKS & GAS DISCOVERIES

GAS FIELD/PIPELINE   POTENTIAL PIPELINE   FLOP   ONGOING



...AS IT LOOKS TO OFFLOAD EGYPT FIND

Exxon kicked off its current three-well East Med campaign with a discovery offshore Egypt at the North Marakia block, located in the country's underexplored West Mediterranean region (MEES, 10 January).

The Nefertari-1 well was seen as a success: MEES understands post-drill estimates were of 3-4tcf gas in place.

However this appears to not be enough for the US major. "ExxonMobil believes the discovery does not fit within its portfolio in terms of the reserves required to begin development and production operations. The company focuses on discoveries with reserves exceeding 4tcf of gas, which is not available in this case," an Egyptian government source told London-based daily Asharq Al-Awsat.

A MEES source at the oil ministry says this is somewhat premature, but that "it makes sense because the discovery size is not [as big as] they were targeting." With Egyptian media reporting that the US major is looking to sell its 60% operator's stake (as with offshore Cyprus it is partnered by QatarEnergy with 40%), BP which operates the WND project to the east would be the most likely buyer.

Disposal of North Makaria would leave Exxon's sole Egypt assets as two large deepwater exploration blocks, Masry and Cairo (also held alongside QatarEnergy) that lie near the border with Cyprus where drilling of Exxon's Block 10 is ongoing. Exxon and state firm Egas on 29 April signed an MoU regarding these two blocks granting Exxon a "more attractive" production sharing mechanism should it make a discovery, local media indicate. While 3D seismic has been shot over 11,000km² of the acreage no wells have been planned yet as the US major continues to analyze the data.

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

JAPAN 1Q24 LNG IMPORTS: QATAR RETURNS AS TOP MIDEAST SUPPLIER

SELECTED DATA

Volume (mn tons)	1Q25	vs 4Q24	%	vs 1Q24	%	4Q24	3Q24	2Q24	1Q24	2019	2020	2021	2022	2023	2024	Jan25	Feb25	Mar25
Australia	6.90	+0.37	+5.7	+0.17	+2.5	6.53	6.36	5.59	6.74	30.12	29.10	26.64	30.75	27.52	25.22	2.53	2.31	2.06
% of total	*39.1*	*-0.0*		*+1.0*		*39.1*	*37.9*	*38.0*	*38.1*	*38.9*	*39.1*	*35.8*	*42.7*	*41.6*	*38.3*	*38.1*	*39.4*	*40.0*
Malaysia	3.24	+0.62	+23.8	+0.09	+2.9	2.61	2.20	2.28	3.15	9.33	10.59	10.11	12.05	10.33	10.25	1.47	0.88	0.89
Russia	1.80	+0.22	+14.0	+0.00	+0.1	1.58	1.11	1.20	1.79	6.40	6.14	6.57	6.87	6.13	5.68	0.57	0.59	0.64
Brunei	0.92	+0.41	+79.5	+0.19	+26.1	0.51	0.98	0.52	0.73	4.32	3.96	4.29	3.21	2.49	2.74	0.32	0.46	0.13
USA	0.90	-0.81	-47.3	-0.51	-36.1	1.71	1.79	1.43	1.41	3.70	4.72	7.07	4.14	5.52	6.34	0.45	0.33	0.12
PNG	0.89	-0.17	-16.1	+0.01	+1.1	1.06	0.81	0.92	0.88	3.74	3.42	3.50	3.79	3.82	3.66	0.27	0.34	0.28
Indonesia	0.87	+0.16	+22.2	+0.23	+36.6	0.71	0.95	0.82	0.64	4.15	2.23	1.89	2.54	3.04	3.13	0.24	0.24	0.39
Qatar	**0.85**	+0.27	+46.1	-0.02	-2.6	**0.58**	**0.83**	**0.60**	**0.87**	**8.73**	**8.73**	**8.97**	**2.88**	**2.93**	**2.87**	**0.33**	**0.25**	**0.27**
% of total	*4.8*	*+1.3*		*-0.1*		*3.5*	*4.9*	*4.1*	*4.9*	*11.3*	*11.7*	*12.1*	*4.0*	*4.4*	*52.2*	*5.0*	*4.3*	*5.2*
Oman	**0.77**	-0.07	-8.8	-0.12	-13.6	**0.85**	**0.93**	**0.71**	**0.89**	**2.89**	**2.45**	**1.90**	**2.53**	**2.18**	**3.39**	**0.32**	**0.13**	**0.32**
UAE	**0.18**	-0.06	-24.8	-0.12	-39.7	**0.24**	**0.18**	**0.24**	**0.30**	**2.17**	**1.03**	**1.33**	**1.33**	**0.84**	**0.96**	**0.00**	**0.12**	**0.06**
Nigeria	0.14	+0.08	+132.7	+0.06	+81.9	0.06	0.26	0.13	0.07	0.83	1.36	0.84	0.97	0.25	0.52	0.14	0.00	0.00
Peru	0.14	+0.07	+97.3	-0.00	-1.6	0.07	0.13	0.07	0.14	0.68	0.63	0.53	0.20	0.25	0.42	0.00	0.14	0.00
Mozambique	0.07	+0.07		+0.07-		0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.13	0.07	0.00	0.07	0.00
TOTAL	**17.67**	+0.97	+5.8	-0.02	-0.1	**16.70**	**16.78**	**14.72**	**17.68**	**77.33**	**74.46**	**74.32**	**72.00**	**66.15**	**65.89**	**6.64**	**5.88**	**5.15**
of which Mena	*1.84*	*+0.17*	*+10.4*	*-0.22*	*-10.8*	*1.67*	*1.94*	*1.61*	*2.06*	*13.92*	*12.28*	*12.43*	*7.06*	*6.15*	*7.28*	*0.65*	*0.50*	*0.65*
% of total	*10.4*	*+0.4*	*+4.4*	*-1.2*	*-10.7*	*10.0*	*11.6*	*10.9*	*11.7*	*18.0*	*16.5*	*16.7*	*9.8*	*9.3*	*11.1*	*9.7*	*8.6*	*12.6*
Price ($/mn BTU)	**1Q25**	*vs 4Q24*	*%*	*vs 1Q24*	*%*	**4Q24**	**3Q24**	**2Q24**	**1Q24**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**Jan25**	**Feb25**	**Mar25**
Australia	12.59	+0.12	+1.0	-0.78	-5.8	12.47	12.73	11.90	13.37	10.63	8.25	10.44	17.69	14.53	12.65	12.94	12.56	12.20
Malaysia	12.40	+0.23	+1.9	-0.66	-5.1	12.17	12.34	11.60	13.07	9.80	7.60	9.73	16.28	13.79	12.36	12.84	11.76	12.33
Russia	12.44	-0.71	-5.4	-1.29	-9.4	13.15	13.24	12.97	13.73	10.05	7.98	10.69	15.63	14.19	13.31	12.58	12.73	12.05
Brunei	12.36	+0.14	+1.1	-1.05	-7.8	12.22	12.95	10.72	13.41	10.75	8.21	9.48	15.04	14.18	12.52	12.54	12.74	10.63
USA	12.91	+1.72	+15.4	+0.60	+4.9	11.19	11.27	10.67	12.31	9.80	8.82	12.20	21.08	12.18	11.34	13.49	12.16	12.73
PNG	12.36	-0.89	-6.7	-1.89	-13.3	13.25	13.51	12.15	14.25	10.61	8.26	11.50	19.48	14.53	13.27	12.38	12.64	11.99
Indonesia	12.46	+0.80	+6.8	-2.41	-16.2	11.67	13.26	12.30	14.87	10.51	8.08	9.86	20.22	14.45	12.97	11.67	13.31	12.43
Qatar	**13.13**	+0.36	+2.8	-0.21	-1.6	**12.77**	**12.57**	**11.24**	**13.34**	**10.28**	**7.41**	**9.13**	**20.48**	**15.48**	**12.56**	**14.08**	**12.21**	**12.80**
Oman	**10.73**	-0.51	-4.6	+0.50	+4.9	**11.25**	**10.98**	**10.42**	**10.23**	**8.64**	**8.17**	**9.37**	**14.01**	**12.23**	**10.73**	**10.92**	**8.55**	**11.43**
UAE	**14.64**	-0.17	-1.2	-0.23	-1.6	**14.81**	**12.19**	**12.16**	**14.87**	**10.94**	**8.58**	**10.95**	**30.34**	**16.37**	**13.67**	**-**	**15.71**	**12.47**
Nigeria	13.92	+6.36	+84.1	-9.26	-39.9	7.56	13.06	12.17	23.18	7.16	7.02	12.38	18.69	11.99	13.67	13.92	-	-
Peru	12.03	+3.68	+44.0	-10.55	-46.7	8.35	11.56	12.51	22.58	9.82	8.11	8.69	20.47	17.41	14.91	-	12.03	-
Mozambique	13.20	-	-	-	-	-	-	9.43	-	-	-	-	-	13.26	9.43	-	13.20	-
AVERAGE PRICE	**12.47**	+0.19	+1.6	-0.85	-6.4	**12.28**	**12.53**	**11.68**	**13.32**	**10.29**	**8.05**	**10.40**	**17.71**	**14.16**	**12.49**	**12.79**	**12.38**	**12.15**
Value ($mn)	**1Q25**	*vs 4Q24*	*%*	*vs 1Q24*	*%*	**4Q24**	**3Q24**	**2Q24**	**1Q24**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**Jan25**	**Feb25**	**Mar25**
Australia	4,372	+276	+6.8	-158	-3.5	4,095	4,069	3,348	4,530	16,101	12,082	13,990	27,360	20,107	16,041	1,646	1,462	1,264
Malaysia	1,980	+411	+26.2	-48	-2.4	1,569	1,341	1,303	2,028	4,507	3,968	4,852	9,668	7,025	6,242	929	513	538
Russia	1,075	+78	+7.8	-110	-9.3	997	707	750	1,185	3,095	2,356	3,377	5,163	4,185	3,639	346	358	370
Brunei	570	+256	+81.5	+80	+16.3	314	633	277	490	2,323	1,626	2,035	2,417	1,769	1,714	203	296	71
USA	581	-375	-39.2	-286	-33.0	955	1,006	765	867	1,810	2,083	4,313	4,359	3,366	3,593	306	199	76
PNG	550	-153	-21.8	-77	-12.3	703	544	556	627	1,985	1,413	2,012	3,691	2,775	2,431	168	217	165
Indonesia	553	+129	+30.5	+70	+14.5	423	646	517	483	2,226	917	949	2,620	2,237	2,069	143	163	247
Qatar	**580**	+194	+50.3	-25	-4.2	**386**	**541**	**350**	**605**	**4,679**	**3,373**	**4,265**	**3,077**	**2,367**	**1,882**	**243**	**160**	**177**
Oman	**439**	-66	-13.0	-45	-9.3	**505**	**544**	**394**	**485**	**1,325**	**1,061**	**945**	**1,878**	**1,415**	**1,928**	**183**	**60**	**197**
UAE	**126**	-44	-25.7	-86	-40.6	**170**	**105**	**141**	**212**	**1,132**	**423**	**692**	**1,931**	**658**	**628**	**0**	**90**	**36**
Nigeria	94	+72	+328.3	+8	+9.2	22	170	78	86	298	477	523	907	152	357	94	0	0
Peru	84	+54	+184.2	-76	-47.6	29	77	46	160	332	254	232	203	222	312	0	84	0
Mozambique	48	+48	-	+48	-	0	0	34	0	-	-	-	-	87	34	0	48	0
TOTAL	**11,052**	+766	+7.4	-762	-6.4	**10,285**	**10,543**	**8,624**	**11,814**	**39,922**	**30,072**	**38,770**	**63,961**	**46,993**	**41,265**	**4,262**	**3,649**	**3,140**
of which Mideast	*1,145*	*+85*	*+8.0*	*-157*	*-12.0*	*1,061*	*1,189*	*913*	*1,302*	*7,191*	*4,886*	*6,056*	*7,215*	*4,646*	*4,465*	*426*	*310*	*410*
% of total	*31.5*	*+21.2*		*+20.5*		*10.3*	*11.3*	*10.6*	*11.0*	*18.0*	*16.2*	*15.6*	*11.3*	*9.9*	*10.8*	*10.0*	*8.5*	*13.0*

SOURCE: JAPAN FINANCE MINISTRY, METI, JOGMEC, MEES CALCULATIONS.

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

SAUDI ARABIA 2M 2025 KEY OIL STATS ('000 B/D): OIL BURN DROPS TO 11-YEAR LOW

	2M25	vs 2M24	%	2M24	Feb25	Jan25	Dec24	2019	2020	2021	2022	2023	2024	1Q24	2Q24	3Q24	4Q24
Crude Output	**8,932**	-52	-0.6	**8,984**	**8,947**	**8,917**	**8,905**	**9,809**	**9,218**	**9,117**	**10,589**	**9,613**	**8,955**	**8,980**	**8,936**	**8,969**	**8,934**
Crude Stocks (mn bl)	**145.8**	+1	+0.5	**145.1**	**145.8**	**155.9**	**147.8**	**155.2**	**140.0**	**134.7**	**148.6**	**149.2**	**147.8**	**139.3**	**134.2**	**138.6**	**147.8**
crude stock change (mn bl)	-2.0	+2	-51.8	-4.1	-10.1	+8.2	+2.6	-50.2	-15.2	-5.4	+13.9	+0.6	-1.4	-9.9	-5.1	+4.4	+9.2
('000 b/d)	-33.6	+35	-51.0	-68.6	-362.0	+263.0	+85.2	-137.5	-41.5	-14.7	+38.1	+1.7	-3.9	-109.1	-56.0	+48.0	+98.5
Crude Supply to Market	**9,130**	-62	-0.7	**9,191**	**9,452**	**8,807**	**8,968**	**9,947**	**9,260**	**9,132**	**10,549**	**9,651**	**9,095**	**9,221**	**9,134**	**9,045**	**8,978**
Crude Exports	**6,310**	+3	+0.0	**6,307**	**6,547**	**6,073**	**6,146**	**7,037**	**6,665**	**6,222**	**7,364**	**6,665**	**6,050**	**6,342**	**6,044**	**5,721**	**6,092**
% of crude output	70.6	+0.4		70.2	73.2	68.1	69.0	71.7	72.3	68.2	69.5	69.3	67.6	70.6	67.6	63.8	68.2
% of liquids exports	82.1	-0.6		82.7	82.3	82.0	84.5	84.4	86.8	82.2	83.4	84.0	82.4	83.0	82.0	81.4	83.2
Crude Imports: Bahrain/Abu Safah	148	+14	+10.4	134	143	153	148	0	0	0	0	41	136	129	145	124	144
Crude Exports (net - ex Abu Safah)	**6,162**	-11	-0.2	**6,173**	**6404**	**5920**	**5998**	**7,037**	**6,665**	**6,222**	**7,364**	**6,623**	**5,914**	**6,213**	**5,899**	**5,597**	**5,949**
% of crude output		-			71.6	66.4	67.4	71.7	72.3	68.2	69.5	68.9	66.0	69.2	66.0	62.4	66.6
Direct Burn Crude	**279**	-55	-16.5	**334**	**283**	**275**	**279**	**424**	**422**	**437**	**486**	**472**	**455**	**325**	**452**	**700**	**341**
% of crude output	3.1	-0.6		3.7	3.2	3.1	3.1	4.3	4.6	4.8	4.6	4.9	5.1	3.6	5.1	7.8	3.8
Total Oil Burn**	**678**	-206	-23.3	**884**	**589**	**766**	**906**	**964**	**1,021**	**1,004**	**1,093**	**1,104**	**1,105**	**864**	**1,148**	**1,387**	**1,022**
% of crude output	7.6	-2.2		9.8	6.6	8.6	10.2	9.8	11.1	11.0	10.3	11.5	12.3	9.6	12.8	15.5	11.4
Refinery Crude Intake	**2,540**	-10	-0.4	**2,550**	**2,621**	**2,459**	**2,543**	**2,485**	**2,173**	**2,474**	**2,701**	**2,514**	**2,590**	**2,553**	**2,638**	**2,625**	**2,545**
% of crude output	28.4	+0.1		28.4	29.3	27.6	28.6	25.3	23.6	27.1	25.5	26.2	28.9	28.4	29.5	29.3	28.5
Run rate (% of capacity)	77.3	-0	-0.4	77.6	79.8	74.9	77.4	86.8	75.4	75.3	82.2	76.6	78.9	77.8	80.3	79.9	77.5
Refinery Output	**2,540**	-11	-0.4	**2,551**	**2,621**	**2,459**	**2,543**	**2,587**	**2,188**	**2,547**	**2,769**	**2,529**	**2,618**	**2,554**	**2,708**	**2,666**	**2,545**
Gasoline	624	+55	+9.7	569	617	630	627	548	454	544	631	615	650	589	677	688	647
Jet-Kero	227	+22	+10.5	206	227	227	223	232	146	126	153	158	194	209	170	177	218
Diesel/Gasoil	1,075	+21	+2.0	1,054	1,050	1,099	1,009	1,057	983	1,114	1,209	1,093	1,114	1,046	1,182	1,170	1,057
Fuel Oil	385	-70	-15.3	455	357	413	464	424	344	422	482	440	443	447	435	441	447
Oil Product stocks (mn bl)	**78.9**	-6	-7.4	**85.1**	**78.9**	**69.0**	**77.9**	**87.9**	**94.6**	**98.8**	**86.9**	**80.3**	**77.9**	**91.1**	**93.1**	**89.0**	**77.9**
Total Oil Stocks (mn bl)	**224.6**	-6	-2.4	**230.2**	**224.6**	**224.9**	**225.6**	**243.1**	**234.6**	**233.4**	**235.5**	**229.5**	**225.6**	**230.3**	**227.2**	**227.6**	**225.6**
oil stock change (mn bl)	-1.0	-2	-230.4	+0.8	-0.2	-0.7	-1.4	-57.1	-8.4	-1.2	+2.0	-6.0	-3.8	+0.9	-3.1	+0.3	-2.0
('000 b/d)	-16.6	-29	-232.6	+12.5	-8.8	-23.6	-44.8	-156.4	-23.0	-3.3	+5.6	-16.5	-10.5	+9.6	-34.0	+3.7	-21.1
Refined Products Consumption	**1,465**	-409	-21.8	**1,874**	**1,426**	**1,504**	**2,008**	**1,845**	**1,717**	**1,729**	**1,886**	**1,976**	**2,011**	**1,850**	**2,008**	**2,080**	**2,104**
Gasoline	523	+13	+2.4	511	528	518	512	550	455	480	500	509	514	505	498	525	528
Jet-Kero	102	+4	+3.6	98	115	88	77	103	44	47	72	96	96	100	91	104	91
Diesel/Gasoil	575	-9	-1.5	584	597	553	643	527	492	503	574	609	612	579	593	633	642
Fuel Oil	399	-151	-27.5	550	306	491	627	540	599	567	608	632	651	539	696	687	681
Refined Products Exports	1,372	+56	+4.2	1,317	1,408	1,336	1,131	1,302	1,015	1,343	1,470	1,274	1,290	1,295	1,331	1,309	1,226
% oil exports	17.9	+1	+3.4	17.3	17.7	18.0	15.5	15.6	13.2	17.8	16.6	16.0	17.6	17.0	18.0	18.6	16.8
Naphtha	99	+3	+2.6	97	88	110	107	139	116	169	145	109	93	102	77	91	102
Gasoline	263	+30	+12.9	233	256	269	229	181	151	182	271	257	281	234	291	335	262
Jet-Kero	120	+3	+2.6	117	113	126	157	156	105	77	97	89	117	135	81	116	135
Diesel/Gasoil	603	+9	+1.4	594	668	537	408	611	505	682	671	566	574	562	652	584	496
Fuel Oil	212	+23	+11.9	189	203	220	173	148	72	156	204	183	142	168	138	100	161
Crude & Products Exports*	**7,682**	+59	+0.8	**7,624**	**7,955**	**7,409**	**7,277**	**8,339**	**7,679**	**7,565**	**8,833**	**7,939**	**7,340**	**7,637**	**7,375**	**7,030**	**7,319**
% of crude output	86.0	+1.1		84.9	88.9	83.1	81.7	85.0	83.3	83.0	83.4	82.6	82.0	85.0	82.5	78.4	81.9
Oil Products Imports	**349**	-37	-9.5	**385**	**423**	**274**	**319**	**319**	**353**	**361**	**360**	**433**	**340**	**348**	**312**	**306**	**395**
Gasoline	112	+12	+12.1	100	116	107	106	92	101	83	92	87	84	114	50	68	103
Diesel/Gasoil	62	-45	-42.1	107	99	25	25	20	9	91	64	91	27	77	6	5	20
Fuel Oil	148	-22	-12.9	170	156	140	187	202	236	177	191	241	218	148	239	219	264
Total Net Crude & Products Exports*	**7,186**	+81	+1.1	**7,105**	**7,389**	**6,982**	**6,810**	**8,020**	**7,326**	**7,204**	**8,473**	**7,464**	**6,864**	**7,160**	**6,918**	**6,599**	**6,780**
NET PRODUCTS EXPORTS*	**1,024**	+92	+9.9	**932**	**985**	**1,062**	**812**	**983**	**662**	**982**	**1,110**	**841**	**950**	**947**	**1,019**	**1,002**	**831**
Naphtha	94	-3	-3.1	97	77	110	107	138	116	163	137	97	86	102	66	77	96
Gasoline	151	+18	+13.5	133	140	162	123	89	50	99	179	171	197	120	242	267	160
Jet-Kero	101	-8	-6.9	108	75	126	157	154	102	73	92	86	113	127	73	116	135
Diesel	541	+54	+11.0	487	569	512	383	590	496	592	607	474	547	485	646	579	476
Fuel Oil	64	+45	+234.2	19	47	80	-14	-54	-164	-21	13	-58	-76	20	-101	-120	-104
Products % of net oil exports	14.2	+1.1		13.1	13.3	15.2	11.9	12.3	9.0	13.6	13.1	11.3	13.8	13.2	14.7	15.2	12.3

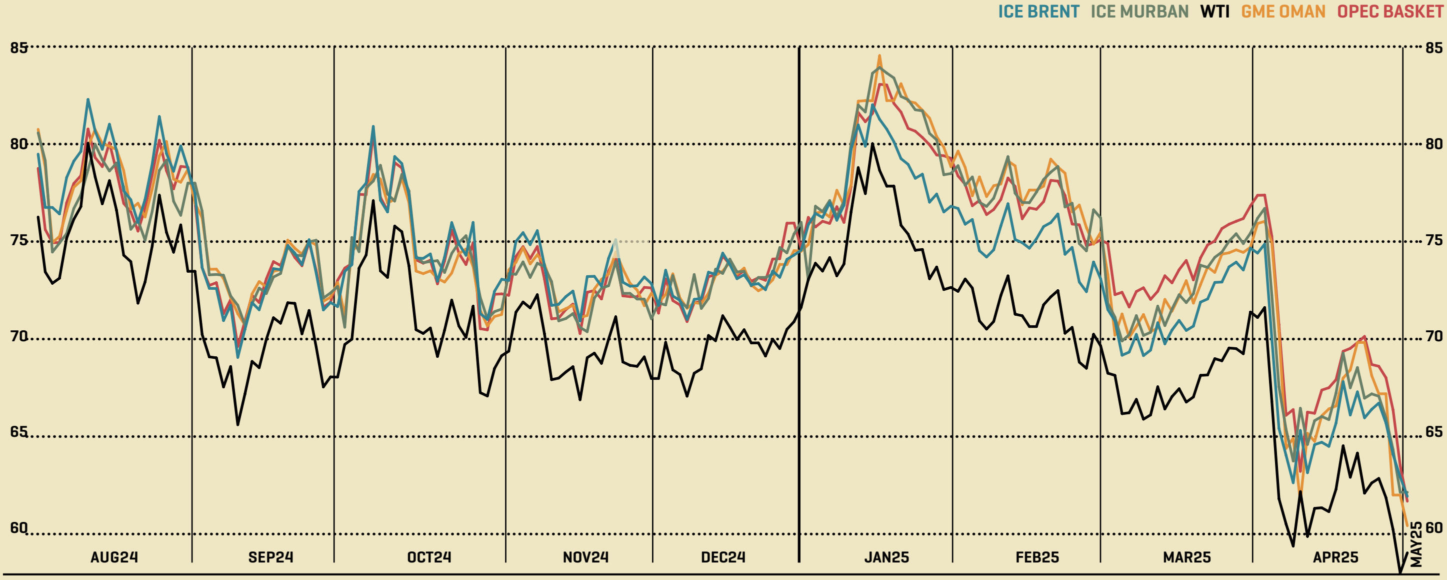
*REFINED PRODUCTS ONLY. EXCLUDES FIELD LPG (AROUND 850,000 B/D OUTPUT), OTHER NGLS AND CONDENSATE. **PRESUMES ALL DOMESTICALLY-CONSUMED FUEL OIL IS BURNT IN POWER PLANTS. SOURCE: JODI, MEES.

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited

BENCHMARK CRUDE PRICES ($/B)

	1May	21-25Apr	14-17Apr	Apr25	Mar25	Feb25	1Q 2025	4Q 2024	3Q 2024	2025 (1May)	2024	2023	2022
WTI	59.24	63.09	62.50	62.96	67.93	71.19	71.51	70.31	75.38	69.25	75.79	77.58	94.37
ICE Brent	62.13	66.65	65.84	66.46	71.47	74.95	74.98	74.01	78.72	72.72	79.86	82.18	99.02
ICE Murban	62.34	67.60	67.25	67.61	72.58	77.34	76.74	73.76	78.34	74.32	79.74	82.80	98.84
GME Oman	60.63	68.81	66.91	67.75	72.51	77.64	76.76	73.60	78.47	74.35	79.61	82.02	94.42
OPEC Basket	61.88	69.48	68.19	68.98	74.00	76.81	76.77	73.54	78.97	74.67	79.89	82.95	100.08
JCC	na	na	na	na	79.49	80.40	78.82	78.24	85.86	na	83.92	86.56	102.70

AVERAGE SETTLEMENT PRICES FOR PERIOD IN QUESTION.



BRAZIL ON PACE FOR 2025 OUTPUT RECORDS

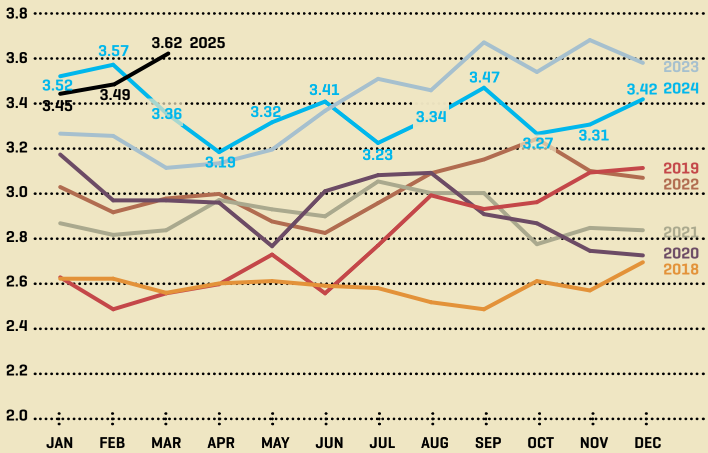
*Leading non-Opec producer Brazil saw its crude output average 3.52mn b/d for Q1, the highest ever Q1 figure, though up only fractionally on the 3.48mn b/d for 1Q 2024 and still below the record output figures set in the second half of 2023 (see chart).

*On a monthly basis March's 3.62mn b/d was the third highest ever behind September and November 2023.

*A disappointing second half to 2024 saw last year's annual output come in at 3.37mn b/d, just shy of the record 3.40mn b/d set in 2023 (MEES, 7 February). But, undaunted, the IEA in its April oil market report predicts that Brazil will be "the largest source of additional conventional supply [over 2025-26] followed by Guyana, the United States and Norway" with five new deepwater FPSOs adding 1mn b/d output capacity over this period and output forecast to surge to a record 3.9mn b/d for 2026.

*Most recently, February saw the start-up of the 225,000 b/d Almirante Tamandare FPSO, the sixth at the giant Buzios field.

BRAZIL CRUDE OUTPUT HAS MADE A STRONG START TO 2025 BUT REMAINS SHY OF LATE-2023 RECORDS (MN B/D)



SOURCE: GOV.BR, MEES.

MEES EDITORIAL STAFF

Publisher:	Dr.Saleh S Jallad	sjallad@mees.com
Managing Director:	Fadi Aboualfa	faboualfa@mees.com
Managing Editor:	James Cockayne	jcockayne@mees.com
Senior Editor:	Jamie Ingram	jingram@mees.com
Advisor:	Basim Itayim	bitayim@mees.com
Consultant:	Walid Khadduri	wkhadduri@mees.com
Editors:	Nada Ahmed	nahmed@mees.com
	Yesar Al-Maleki	yalmaleki@mees.com
	James Marriott	jmarriott@mees.com
	Peter Stevenson	pstevenson@mees.com
Production:	Christian Jocson	cjocson@mees.com
	Ledha Socratous	lsocratous@mees.com

©Middle East Petroleum and Economic Publications (Cyprus) Ltd
Reproducing MEES Is Strictly Prohibited