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Healthy or hazardous?

What the Opec+ output decision means for global oil markets

Rising to the challenge

The economic mayhem unleashed by US president Donald Trump's trade policies this year means the oil market has been paying less attention than usual to the goings-on within the Opec+ alliance, but all that has changed over the past fortnight.

Opec+ ministers meeting on 3 May chose to further accelerate the return of production to the market, agreeing a nominal 411,000 b/d increase in output for June from the eight producers that implemented voluntary cuts of 2.2mn b/d at the end of 2023.

Explaining its decision, Opec cited "currently healthy market fundamentals", but the reality is a much more complex outlook for oil markets in light of the economic uncertainties created by Trump's trade tariffs. Prices weakened in the immediate aftermath of the decision and several banks, including Barclays and Morgan Stanley, cut their oil price forecasts.

But Opec+ producers may also have had broader geopolitical considerations in mind. They agreed their increase shortly before Trump was due to head to the Middle East in his first overseas trip since returning to office, including scheduled visits to key Opec members Saudi Arabia and the UAE. The US president's aggressive trade policies have raised inflation and recession risks for the global economy, but higher Opec+ oil output could, in theory, help offset some of those dangers — and do Trump a favour — by pushing prices lower.

In this Insight Paper, drawn from recent analysis in three of our flagship oil market business intelligence reports — *Argus Global Markets*, *Argus China Petroleum* and *Argus Eurasia Energy* — we look at the rationale for Opec's decision, the likely impact on both prices and rival producers outside the Opec+ alliance, and the market context in terms of recent developments in China's crude buying and Russian oil trade.

Opec+ prioritises output discipline

As white smoke ascended from the chimney at Opec's headquarters in Vienna on 3 May, a conclave of eight oil ministers delivered another unexpectedly large production increase. The group of eight has raised its collective quota by just over 410,000 b/d for June, three times the monthly rate agreed earlier this year and a repeat of the decision reached in April for May output. The question for the market is why now and is this what production policy looks like for the rest of 2025?

The public justification for the big increase is "healthy market fundamentals, as reflected in the low oil inventories". In narrow, classical measures, there is a case to be argued. Commercial oil stocks in OECD countries — the historic yardstick for market watchers — fell by over 900,000 b/d in January-February, the most recent IEA data show. They fell by another 200,000 b/d in March-April, *Argus* estimates. But OECD inventories have become less relevant to the oil market balance this century as demand growth has shifted to the industrialising economies of Asia-Pacific and the global south.

OECD stocks figures miss out, for instance, China's heavy stockpiling programme that has drawn in nearly 60mn bl of crude to storage, including most likely Beijing's strategic reserve, over the past three months as oil prices have fallen. It also misses the increasingly important role of oil in transit — inflated over the past two years by sanctions forcing Russian oil to Asia-Pacific and detours around troubled waterways in Panama and the Red Sea. A seasonal rise in oil at sea, mostly products, adds another 80mn bl build since the end of last year.

In fact, global inventories have risen by 600,000 b/d this year. This goes part of the way to explaining the $20/bl fall in oil prices since mid-January even before factoring in aggressive US trade policies souring the macroeconomic outlook. It also undermines the stated rationale of the decision of the Opec+ inner circle.

The policy-making part of Opec+ has now effectively shrunk to the eight members that agreed in November 2023 separately to reduce their production by an extra 2.2mn b/d. These eight — Saudi Arabia, Iraq, Kuwait, the

UAE, Algeria, Russia, Oman and Kazakhstan — represent more than 90pc of Opec+ production, and crucially, nearly 97pc of its spare capacity. The eight now meet once a month to adjust the rate at which their own extra cuts are wound down. Opec has proved in the past that smaller political bodies can be more nimble. It became a more effective market manager after the Great Recession in 2008-09 as Saudi Arabia became the only major source of spare production capacity and, particularly in 2020, brought the cudgel of its own output flexibility to punish anyone who stepped out of line.

In 2020 that was Russia. The source of discord this time is mostly Kazakhstan. The newly expanded Tengiz field has left Kazakhstan busting its quota by 300,000 b/d for most of this year and it appears to be doing little to rein in overproduction. And while this may not sound like much set against a 100mn b/d market, it is roughly half the current surplus signalled by rising global inventories. Other producers, particularly core Mideast Gulf members holding the most output off the market, are losing patience and pushing up the target as a punitive measure. Raising quotas to punish one member may seem counterproductive with oil prices so much lower than at the start of the year. But until there is some sign of contrition from the overproducers, extra increases could well become a monthly habit.

Price falls likely as Opec changes course

Analysts have sharply lowered their price forecasts for the rest of this year and next after Opec+ agreed to accelerate plans to unwind production cuts.

Atlantic basin benchmark North Sea Dated will average under $62.40/bl in the fourth quarter and just over $60.50/bl in 2026, an average of analysts' forecasts shows — around $6.80/bl and $5.70/bl lower, respectively, than the previous *Argus* survey in March (*see table*). US marker WTI is expected to drop by nearly $7.50/bl in the fourth quarter and by $5.70/bl in 2026 from the March figures.

The lower forecasts follow the Opec+ decision to pivot away from its plan to phase out 2.2mn b/d of additional output cuts over 18 months. A group of eight core members — Saudi Arabia, Iraq, Kuwait, Russia, the UAE, Algeria, Oman and Kazakhstan — agreed for a second month running to raise their collective target by over 410,000 b/d for June. This pushes their quota up by a combined 822,000 b/d in May-June — triple the amount envisaged under their original plan.

Goldman Sachs expects Opec+ to boost supply again by over 410,000 b/d in July because "the expected demand slowdown is unlikely to be visible" for the group when it meets on 1 June to decide July targets. The bank estimates that the full return of the 2.2mn b/d in increments of over 410,000 b/d, which would take 5-6 months, would push Brent prices down to the high $40s/bl by late 2026.

Barclays also now expects Opec+ to phase out the additional voluntary adjustments by October, although the group "could be a bit too confident of the outlook and might have to turn around a few months down the line", it notes.

Morgan Stanley also interprets the Opec+ decision as a precursor for further supply increases. It expects steady monthly increases of around 130,000 b/d towards the end of the third quarter, developing such a market surplus that the bank expects the quota to flatline from October 2025.

Stocks position

Low global crude stocks were probably a key factor behind the Opec+ decision, Goldman Sachs and Barclays note. Goldman Sachs says supporting internal cohesion within the group also played a part, while Barclays says "compliance concerns are likely not primarily behind the Opec pivot". Iraq's compliance was around 79pc in the first quarter, Barclays says, and while Kazakhstan has been a serial overproducer in recent months, it has not been a persistent issue. Higher quotas may make it easier for Astana to compensate for its previous overproduction in the coming months.

Crude price forecasts *$/bl*

	Brent						WTI					
	4Q25	±*	1Q26	±*	2026	±*	4Q25	±*	1Q26	±*	2026	±*
ABN Amro	60.00	-2.00	58.00	na	59.00	0.00	56.00	-2.00	54.00	na	55.00	0.00
Barclays	60.00	-10.00	60.00	na	60.00	na	57.00	-10.00	57.00	na	56.00	na
BNP Paribas	62.00	-9.00	60.00	na	62.00	-9.00	58.00	-10.00	57.00	na	58.00	-9.00
Goldman Sachs	59.00	na	58.00	na	56.00	na	55.00	na	54.00	na	52.00	na
Morgan Stanley	60.00	-7.50	57.50	na	56.25	-13.75	56.00	-11.50	53.50	na	52.25	-13.75
UBS	68.00	-12.00	68.00	na	na	na	64.00	-11.00	64.00	na	na	na
Argus Consulting†	67.67	**-0.33**	68.67	na	69.88	0.00	63.47	-0.36	64.47	na	65.67	-0.02
Average	**62.38**	**-6.81**	**61.45**	**na**	**60.52**	**-5.69**	**58.50**	**-7.48**	**57.71**	**na**	**56.49**	**-5.69**

**change from previous survey in Mar 2025 †Argus Consulting is a division of Argus Media*

Opec+ policy has also shifted to managing the market over the long term and "strategically disciplining US shale supply", Goldman Sachs says. Higher supply could push WTI prices below the breakeven point for shale producers. If demand is undermined by tariffs as predicted, either Opec+ or non-Opec+ producers "will need to balance the market eventually", Morgan Stanley says.

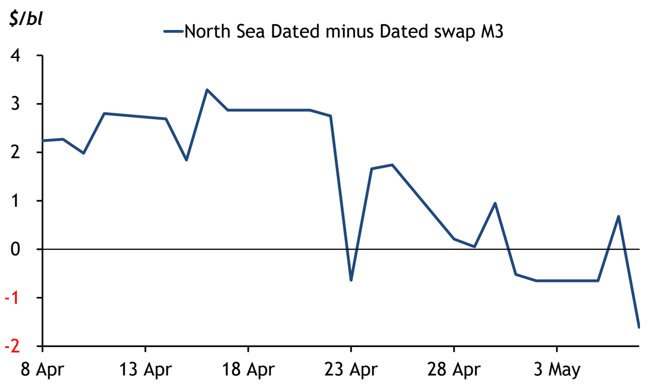
China weighs spot versus term crude

China is restocking crude, taking advantage of low prices to fill its growing storage system.

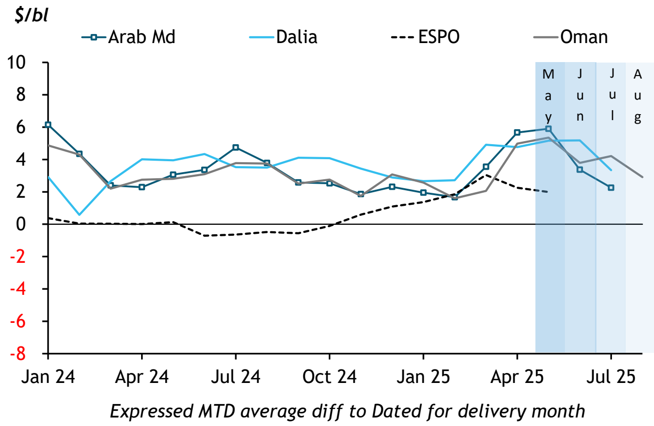
Sweet crude markets have pitched into contango, with prompt prices below forward contracts. Atlantic basin marker North Sea Dated fell by $2.03/bl between 30 April and 7 May, to $61.04/bl. This has pushed it $1.61/bl below the July Dated swap, against which grades such as Brazilian Tupi are presently trading for delivery to China, to the benefit of long-haul arbitrage economics (*see graph: Sweet crude market structure*). Opec+ has agreed to extend accelerated output returns into June, when it will add back another 411,000 b/d of output, following a similar decision on May production. But an influx of light sweet grades US WTI and Caspian CPC Blend into Europe in May, at a time when BP's large Rotterdam refinery is partly shut for maintenance, has eclipsed the prospect of that bump in future sour crude supply, pushing the regional sweet crude market into a prompt surplus.

Core Mideast Gulf producer Saudi Arabia has raised official formula prices for July-arriving cargoes — but from a low baseline and by 20¢/bl rather than the 30¢/bl cut implied by recent changes in the Dubai market structure. As a result, Middle East crude supplied under term contracts to Asia-Pacific remains among the most attractive on cost (*see graph: China trade cycle differentials*). This, in turn, is forcing west African crude differentials, also trading for July delivery, to adjust lower. Delivered China differentials for Congolese Djeno fell by $1.20/bl in early May to a $3/bl premium to Ice September Brent.

Sweet crude market structure



China trade cycle differentials



Chinese companies began buying July-arriving cargoes from Brazil in March but are now in the process of deciding how much Saudi crude to take under term contract in July, and how much of their remaining July requirements to cover from the west African spot market. They have so far bought only 2mn bl — a cargo of Angolan Pazflor destined for independent refiner Shandong Jincheng, and a cargo of Djeno for state-controlled Sinopec.

Russian and Iranian crude are the key feedstocks for independent refiners in Shandong province, but they have slowed buying of these grades in response to weaker refining margins and tighter US sanctions. Russian ESPO Blend trading for May/June delivery is also under increasing pressure from weakening differentials for unsanctioned grades. Shandong firms have not yet begun bidding for June ESPO Blend and may scrutinise west African grades more closely as differentials weaken.

Power move

Investment banks are pruning their crude price forecasts in response to Opec+'s push to restore its 2.2mn b/d of "voluntary" output cuts faster than expected. Barclays has cut its expected Brent crude price for 2025 by $4/bl to $66/bl, while Morgan Stanley has cut its Brent forecast for the second half of this year by $5/bl to $57.50/bl.

Opec's move will increase the relative abundance of sour crude. Higher Opec output typically forces up the Brent-Dubai EFS, a swap contract used to convert Dubai-linked sour crude purchases into Ice Brent hedges. But sour output increases from Opec+ producers in the Middle East are unlikely to translate into higher exports on a one-to-one basis over the summer, potentially supporting sour crude marker Dubai relative to Ice Brent. Regional cooling requirements increase during the hotter summer months, requiring more oil to be used domestically to fuel power generation. The EFS initially shot higher ahead of the 3 May Opec+ meeting, but fell back in the days following to 88¢/bl by 7 May.

And while US-China trade tensions are likely to curb oil demand, China may still step up crude imports. Flat prices are relatively low, the country is aggressively expanding its crude storage system and its central bank trimmed interest rates to 1.4pc on 7 May, lowering crude storage costs. Chinese firms aim to open 125mn bl of commercial storage capacity in 2025 which, on a time-weighted basis, will allow them to add around 130,000 b/d to inventories. China is already building stocks at a rate of nearly 900,000 b/d this month, Vortexa data indicate.

US shale under pressure from price fall

Lower oil prices are bringing forward the tipping point for US crude output as shale oil firms cut back drilling and postpone completions, setting the scene for legacy declines to exceed new production.

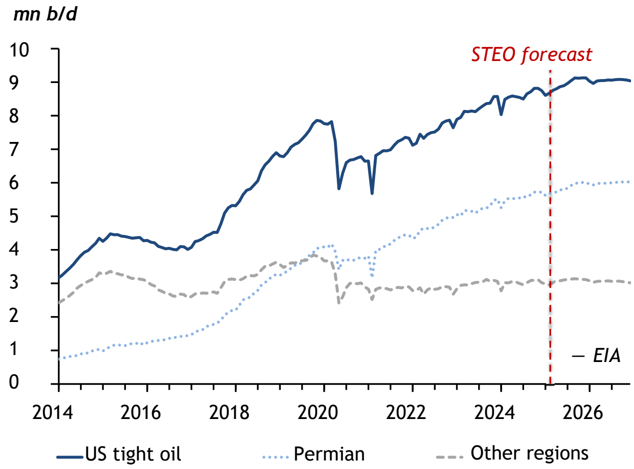
"It is likely that US onshore oil production has peaked and will begin to decline this quarter," outgoing Diamondback chief executive Travis Stice says in his last quarterly letter to stockholders. "The shale revolution has evolved from proof of concept (outspend cash flow to prove up basins) to manufacturing mode (significant growth) and is now in a more mature stage of development (free cash flow generation and return of capital). Today, geologic headwinds outweigh the tailwinds provided by improvements in technology and operational efficiency."

Stice blames low oil prices for the industry's current state, something he fears it may never recover from. Using a traffic light analogy for the industry's sensitivity to crude prices, he says: "I think red is probably something with a four in front of it, and I would say yellow is something with a five in front of it, and green needs to be somewhere in the mid-to-high 60s with a path to 70 to accelerate through that green light." US benchmark WTI has been trading in a $55-60/bl range.

Diamondback says it will drop three rigs and one completion crew this quarter, cutting $400mn from its 2025 budget, preferring "to repurchase shares and pay down debt over drilling and completing wells at these prices today". And Stice expects new-well output to drop below legacy declines from existing wells, with other firms also cutting spending. "It doesn't take much capital to come out of the equation for that base decline to really be seen in production," Stice says.

Devon Energy is still making operational efficiency gains — drilling longer wells faster with fewer rigs than last year — and has no plans to cut spending with the forward curve "hovering around just under $60/bl", chief executive Clay Gaspar says. But "when the market gets a little closer to the low 50s and we feel like that has some sustainability, I think we'd be more likely to take more aggressive actions in addition to the maintenance capital mode that we are in now," he says.

US tight oil production



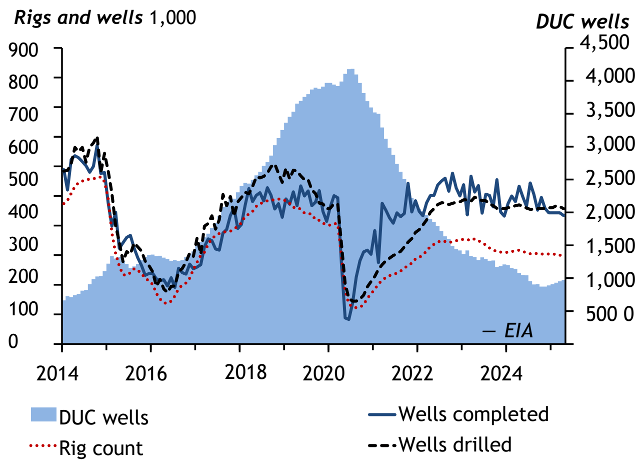
Tipping point

EIA forecasts echo Stice's prediction of a looming tipping point. US tight oil output peaks at 9.3mn b/d in August and then slowly declines, the EIA says in its latest *Short-Term Energy Outlook*. Permian production edges up, but output from all other shale regions combined falls (*see graph above*). The Permian represents 63pc of US tight oil output today — up from 50pc in early 2020 — after growth shifted from the more mature Bakken and Eagle Ford to the less-developed Permian Midland and Delaware basins. But even the Permian struggles at current crude prices.

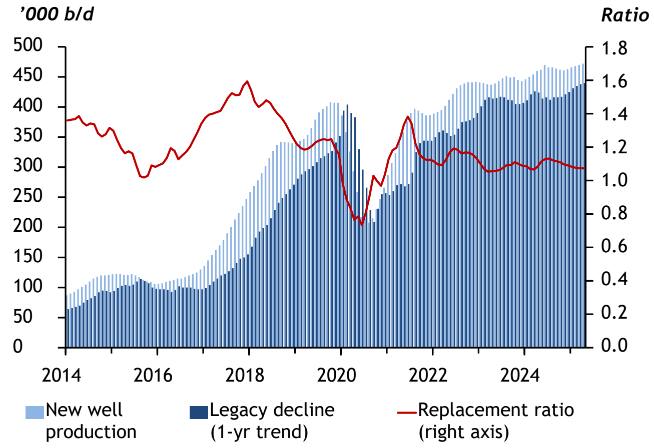
Permian rig counts are falling, and with fewer wells completed than drilled since the end of last year, there is now a growing backlog of drilled-but-uncompleted (DUC) wells (*see graph below*). Well completions fell by 11pc in January-April compared with the same period last year, while wells drilled fell by just 1pc. And there are 85 more DUC wells since the end of last year.

With the Permian basin now maturing, it is harder to offset growing legacy declines. "As dollars get allocated to lower

Permian shale oil production drivers



Permian production replacement



and lower quality inventory, your natural decline will be impacted where you're making less improvements than you did early on in the development of that asset," Stice says. Replacement ratios for new-well output relative to legacy declines show a downward trend since the early days of Permian development, falling from an average of around 1.3 in 2014 to 1.1 over the past 12 months (*see graph above*).

Lower prices spur Russian crude buying

Buyers that turned away from Russian crude after the US announced new sanctions in January appear to have returned to the market against a background of persistently lower prices.

Turkish refiner Tupras has resumed buying Russian Urals crude, market participants say. Up to nine cargoes loaded in April could be heading to the port of Tutunciftlik on the Sea of Marmara, where crude is delivered for Tupras' 227,000 b/d Izmit refinery, according to trade analytics platforms Vortexa and Kpler. All shipments are expected to arrive at Tutunciftlik on 17-24 May.

Tupras has already received three Urals cargoes loaded in April, two at Tutunciftlik on 17-22 April and a third at Aliaga on 16 April, for the firm's 238,000 b/d Izmir refinery. Tupras stopped buying Russian crude from February, when total Turkish imports from Russia dropped by 39pc to 220,000 b/d.

China's state-controlled Sinopec has bought Russian far east-loading ESPO Blend for the first time since January, with 1.5mn-2.2mn bl expected to arrive in May. The light sweet grade now looks more competitive with the west African crudes that some Chinese refiners turned to after 10 January.

Chinese crude imports from west Africa were 35pc higher than the full-year 2024 average at 1.11mn b/d in March-April, Vortexa data show. But this could drop to 822,000 b/d with the return of interest in ESPO Blend, traders say.

The US' January sanctions targeted 183 "shadow" fleet tankers used to transport Russian oil, reducing vessel availability and pushing up shipping costs. And Washington ended a sanctions waiver on 12 March that had allowed buyers to use dollar-based financial systems.

The return of Tupras and Sinopec as buyers of Russian crude reflects falling prices, against a wider background of uncertainty about the global economic outlook and oil demand. Most of the April cargoes heading for Tutunciftlik would have traded in March, when outright Baltic Urals prices averaged $57/bl and Black Sea Urals cargoes $58.29/bl.

Urals has largely traded below the G7-led $60/bl price cap on Russian crude exports since 24 February, while ESPO Blend traded below $60/bl for much of April. Prices below $60/bl allow sellers to access shipping and insurance services in G7 and EU countries, increasing the availability of unsanctioned tankers to transport Russian oil and reducing freight costs.

Outright Urals prices dropped below $50/bl on 30 April, largely falling in line with benchmark North Sea Dated crude. Apart from a one-day drop on 9 April, prices are the lowest in almost two years at $48.47/bl fob Primorsk and $49.82/bl fob Novorossiysk. ESPO Blend fell to $53.52/bl fob Kozmino on 30 April — the lowest outright price since the end of 2020, apart from a one-day slump on 9 April.

Sustained lower prices may make Russian crude more attractive to buyers, but low prices will further undermine exporters' profits and budget revenue for the state. Federal oil and gas revenue was down by 10pc compared with a year earlier to Rbs2.64 trillion ($31bn) in the first quarter, because of lower oil prices and reduced exports. Oil and gas sector revenue accounts for almost a third of Russia's overall budget.