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Saudis Warn of Dwindling Spare Capacity

There will be no additional supply hitting oil markets immediately as a result of US President Joe Biden's Jul. 15 visit to Saudi Arabia. But relations between the two states appear to be on the mend, with potentially important implications for global energy markets. How this plays out in future Opec-plus output policy remains to be seen, but all eyes are fixed on the group's next meeting on Aug. 3, when it will consider how to manage oil markets after its current production deal ends in September. Riyadh has already made a couple of things clear: It is reluctant to fully tap its spare capacity to try to lower oil prices, and it wants other global producers to pitch in and hike upstream investments. In a regional summit in Jeddah and closed-door talks with the US, Saudi officials held back from making any explicit commitment to supply additional barrels to the current oil market, sources told Energy Intelligence. US officials also said they did not expect an immediate move to increase production but that they were hopeful of action in the medium term — including possibly from September. Energy Intelligence understands that Saudi Arabia is open to the idea of a gradual increase in production, within the context of the Opec-plus alliance. Officially, Washington and Riyadh signed an agreement in which Saudi Arabia "committed to support global oil market balancing for sustained growth." It also said they had discussed "further steps" to "help stabilize markets considerably."

Dwindling spare capacity is the elephant in the room for high-priced oil markets — and helps explain Saudi caution. Energy Intelligence currently estimates Opec-plus' quickly available spare capacity at 3.32 million barrels per day based on June production, with Saudi Arabia holding the most at 1.63 million b/d and the United Arab Emirates at 920,000 b/d. But this continues to nar-

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Realigned Oil Trade Upends Market Pricing

Sanctions on Russian oil have forced European refiners to buy more crude closer to home and further afield, while Russian oil now must bypass Europe and attract more customers in Asia. Both forces have pushed Europe's dated Brent to a huge $10 per barrel premium and Russian Urals to a steep $35/bbl discount — blowing out spreads that used to be $3/bbl during tense times before the Ukraine war started in February. The distortions seem bound to intensify as Europe is only halfway to displacing Russian crude ahead of the EU ban, which takes effect by year-end. Finding alternatives for yet another 1 million barrels per day or so of Russian crude is possible but will be costly. Western European refiners are replacing seaborne Russia's Urals cargoes, which take a week to sail, with short-haul crude from the North Sea and are bidding up prompt cargoes. The war has also made prices extremely volatile, spurring refiners to favor the spot market to shuttle supply on an "as needed" basis. This way, they also avoid expensive hedging and margin calls on cargoes tied up in long sea journeys. In the Mediterranean, outages in Libya have kept the regional light, sweet market on edge, with only Algeria emerging as a steady but maxed out supplier. More distant spot options include Atlantic Basin crudes. Discounts for light US crude, which sails to Europe in 20 days, have widened to $17/bbl versus dated Brent. More valuable Nigerian crude takes 12 days to travel and is fetching up to $9/bbl premiums over dated Brent.

Norway's 525,000 barrel per day Johan Sverdrup field shows the trend toward more local buying. It is now shipping the bulk of its monthly export program to Europe instead of Asia. A 220,000 b/d

increase in field capacity by year-end should provide more relief. Cheap Russian oil going to India and China is freeing up some Mideast grades. Iraqi Basrah crude exports to Europe and Turkey in June hit 860,000 b/d, their highest in 12 months, while Basrah exports to India fell below 1 million b/d for the first time since October. But Europe's appetite for Basrah is hitting its limits, traders say. European refiners don't see Basrah as a great replacement for Urals, even after Iraq dropped its selling prices by more than Saudi Arabia. Sverdrup is seen as an ideal replacement for Urals. It is similar in quality, on the doorstep of European refiners, and volumes are growing. Neste Oil's Porvoo refinery in Finland and Preemraf's Lysekil refinery in Sweden have emerged as two of the leading buyers. More seaborne US volumes are also making a headway to Europe, notably Midland or West Texas Light (WTL). Buyers include TotalEnergies' Normandy refinery in France and the Eni/Kuwait Petroleum Corp. Milazzo refinery in Italy.

A big question is whether Europe can secure more term contract oil from the Mideast. That will come down to price. Prices for Mideast grades in Asia have remained strong despite the influx of discounted Urals. For now, both India and China are keen to keep the security of supply from term contracts with Mideast producers. But Russian flows to Asia should only get bigger. Deep discounts could persuade India and China to sign term contracts with Russia, freeing up Mideast crude for Europe. India and China have each already absorbed more than 1 million b/d of discounted Urals. When Europe stops buying entirely, that volume would need to double. Norway, West Africa, the US and the Mideast can all supply more and create a workable mix of grades that European refiners can handle. For now, the new trade flows are also causing a huge premium for light, sweet oil like Brent over heavier and sour oil from the Mideast. These premiums could deflate once new patterns stabilize. But even if European prices for sour Mideast oil stay lower than Asia, Mideast producers would still need to sell their crude — and if not in Asia, than in Europe.

A proposed price cap on Russian oil is another variable. Such a system would allow Russian oil to continue sailing on Western vessels if buyers get Urals at a preset low price. Traders fear this system could backfire and cause higher oil prices globally if Russia refuses to sell at capped prices set by the West. Urals could be priced somewhere between the $15/bbl it costs to produce and the $80/bbl Russia now gets after the discount. The EU sanctions package includes a ban on using Western vessels, insurance and financing. Talks are underway to wave this restriction if buyers can prove they buy oil at the price cap set by Western nations. Traders think Russia might limit exports in response, further tightening the market.

Mideast Enters Golden Age of Natural Gas

These are halcyon days for the Mideast Gulf's gas industry. Output is up almost 200 billion cubic meters per year (19.3 billion cubic feet per day) from a decade ago. And growth is set to continue. By 2030, spearheaded by Qatar's 48 million ton per year LNG mega-expansion and Saudi Arabia's $110 billion Jafurah shale gas project, the United Arab Emirates, Saudi Arabia and Qatar alone should be adding over 15 Bcf/d. This is a most improbable renaissance. Just 10-15 years ago: crude burn trajectory in Saudi Arabia appeared out of control, Kuwait was suffering from regular summer blackouts, a looming gas crunch meant Oman had to consider shutting in LNG liquefaction capacity, while the UAE's northern emirates were forced to burn coal to meet peak summer demand. Today, gas balances for all in the region, except Iraq, are in exponentially better shape. An easing of subsidies, the 2015-16 oil price crash, and a shift to more efficient combined-cycle generation helped curb runaway demand in the early part of last decade. Going forward, huge investment in renewables is key to managing the demands on gas resources. In the UAE's case, an embrace of nuclear has also been transformational, enabling it to proceed with a new 9.6 million ton/yr LNG project in Fujairah. Such is the scale of future Saudi demand that the 2 Bcf/d Jafurah and another 3.5 Bcf/d of conventional gas additions will probably all be needed in-kingdom. But together with solar, the new gas is targeting displacing crude and fuel oil burn in power generation, freeing up almost 1 million barrels per day of Saudi oil for export.

Qatar, Iran and Iraq — if it ever manages to turn around its gas industry — have the luxury of abundant, low-cost conventional reserves, much of it ultra-cheap associated gas, on which to rely. But for most in the region, expensive unconventional gas is playing and/or will play a key role. The

UAE is rolling out a string of multibillion-dollar unconventional developments, both on- and offshore. In Oman, BP's 1.5 Bcf/d Khazzan tight gas project has reversed a looming gas deficit, not just securing the country's future as an LNG exporter but enabling a 10% expansion of capacity to 11.4 million tons/yr. Cost optimization is critical with these huge projects, but economics have been enormously boosted by volumes of valuable associated liquids, most of which are exempt from Opec supply restrictions. Jafurah is expected to deliver some 630,000 b/d of condensate and natural gas liquids (NGLs), including 418 million cubic feet per day of ethane. In addition to 32 million tons/yr of LNG, Phase 1 of Qatar's LNG expansion will produce 260,000 b/d of condensate, 11,000 tons per day of liquefied petroleum gas and 4,000 tons/d of ethane. Abu Dhabi's 1.5 Bcf/d Ghasha sour gas project comes with a projected 75,000 b/d of crude, 61,000 b/d of condensate, 5,400 tons/d of NGLs, and 8,600 tons/d of sulfur. In addition to Ghasha, the UAE is planning for around 500 MMcf/d from each of the Umm Shaif and Bab gas caps, and 1 Bcf/d from Ruwais- Diyab shale, on top of conventional gas growth.

Energy transition plans will play key roles in shaping gas utilization, with hydrogen, LNG and local industry all placing claims on incremental production. Both the UAE and Saudi Arabia are gearing up to be significant producers of blue hydrogen from natural gas, and it is very possible that additional Qatari gas growth beyond its announced plans could focus on hydrogen. If recent announcements to push a regionwide electricity grid are realized, power generation could soak up the lion's share of future supply, if Iraq doesn't step up its gas game. The 2 Bcf/d Dolphin gas project, which expires in 2032, will also be significant. Current UAE plans for a new 9.6 million ton/yr LNG project appear to factor in the loss of Dolphin gas, meaning a continuation of Dolphin flows could theoretically mean a bigger LNG project, notes Siamak Adibi of energy consultancy FGE. With political tensions between Doha and Abu Dhabi easing after the end of the June 2017 to January 2021 blockade on Qatar, he also sees "no problem with renewing" the Dolphin contracts. "[The UAE] can continue importing 2 Bcf/d, and that leaves an even bigger surplus," Adibi argues. And unlike the UAE's Das Island LNG exports, which have quality issues, new UAE supplies could flow west to Europe. Oman, whose entire 11.4 million tons/yr of sales volumes will be up for grabs when contracts expire in 2025, could also be an option for the EU as it weans itself off Russian supply, Adibi adds.

Europe Ready to Fight for New African LNG Supply

Upcoming floating LNG (FLNG) export projects in Africa are set to benefit from Europe's renewed supply diversification efforts and will likely offer much needed additional LNG volumes to the continent. But their smaller size will limit their supply role, and European buyers will probably need to pay a premium for these volumes to fight off competition from their Asia counterparts. Still, these projects could offer relevant advantages compared to supplies from some of the top LNG exporters. Mozambique's Coral South FLNG is gearing up to start production by the end of this year, while the Congo FLNG project is set to follow it in the second quarter of 2023. After that, the Greater Tortue Ahmeyim project offshore Senegal and Mauritania is slated to begin full-scale production in 2024. These projects will bring to the global market close to 8 million tons/yr of LNG, with potential to further output growth through additional phases. While that might not sound like much, competition for these volumes will be fierce in a gas-thirsty market. In the cases of both Coral South and Greater Tortue, the entire output of these projects has already been purchased by BP via a 20-year offtake contract, allowing the UK major to deliver the cargoes anywhere in the world. Some could supply BP's contracted customers, but some will also likely end up where the offer is highest. Supply from the Congo FLNG, developed by Italian major Eni, is set to be even more price sensitive as the entire output will be sold on the spot market.

From a European perspective, the Greater Tortue project in Senegal and Mauritania, developed by BP and Kosmos Energy, looks the best placed to provide additional supplies for the continent. Beside its geographical proximity, the project also has a significant carbon intensity advantage compared to other suppliers, Mike Anderson, senior vice president, sustainability and external affairs at Kosmos, told Energy Intelligence. "If you look at carbon content of our gas in Tortue, it is under 1%. If you compare with US LNG, it is 40% less carbon intensive. If you compare it with Qatar, it is 25% less carbon intensive," Anderson said. Additionally, the political stability in both Senegal and Mauritania make the Tortue project a prime candidate to supply Europe. These advantages have already attracted Germany's interest as it seeks new supply to wean itself off Russian gas in the coming years. German Chancellor Olaf Scholz said last month on an official visit to Senegal that the countries have opened talks to develop gas and LNG projects there, although the exact details were unclear. The most crucial question will be the duration of any cooperation agreement or supply contract. Germany, and the EU in general, remain keen to honor their climate commitments while trying to obtain additional gas and LNG volumes. On the other hand, producing countries and project developers need long-term commitments to make projects commercially viable. "[Germany] need their gas now, [but] they cannot work out exactly how many years they will need it for — they know it's at least five, it could be 10, and the European Union was clear that they expect [gas supplies] into Europe for 2035 and beyond," Anderson said. The EU is also pushing for a real supply diversification after learning the hard way the consequences of relying on just one major supplier. This also favors these African LNG projects.

Due to their dire needs for gas and LNG, European countries are now looking much more favorably toward funding hydrocarbon developments than just a couple of years ago. And providing funds for African gas and LNG projects would not only give Europe early access to these fuels, but also to the fuels of the future, such as blue ammonia or hydrogen, which will likely be produced in the same facilities. Anderson says Europe's quest for extra LNG supply in Africa is increasingly becoming a broader issue about development. Europe is now looking at the domestic energy needs of the African exporting nations to develop their own industries and achieve their energy transition goals.

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row: The combined Saudi-UAE spare of 2.55 million b/d, which constitutes the world's true emergency cushion, would drop to 2.1 million b/d based on August quotas and just 1.25 million b/d if they were to unwind cuts fully and return to baselines from September. The problem is that, as spare capacity thins, it becomes riskier to use, as tapping the emergency cushion can inflame market sentiment rather than cool it. Such concerns arise periodically when levels are depleted — including back in 2004, for example, when Opec's spare capacity shrank to as little as 500,000 b/d.

Riyadh is working to increase its production capacity by 1 million b/d to 13 million b/d — but "after that the kingdom will not have any additional ability to increase production," Crown Prince Mohammed bin Salman warned during Biden's visit. Saudi officials stressed the broad need for more upstream investment to resolve oil market pressures, while Prince Mohammed decried climate policies that deter fossil fuel spending. He warned that "unrealistic policies to reduce emissions by excluding major sources of energy" could lead to "unprecedented inflation, rise in energy prices […] extremism and terrorism." In the US, the Biden administration has faced criticism that its bold climate ambitions have soured the investment environment for domestic oil companies and helped fuel inflation. The roots of upstream underinvestment lie in the 2014-16 oil price crash, with transition strategies and the Covid-19 pandemic extending those pressures.

If Saudi capacity is, in fact, capped at 13 million b/d, it begs the question of where additional supply could be sourced this decade, during which most experts foresee continued demand growth. Indeed, Saudi Foreign Minister Faisal bin Farhan al-Saud warned of "a real danger in the future that there will be no spare capacity." The United Arab Emirates plans to increase its capacity by roughly 1 million b/d, and possibly 2 million b/d, in the coming years, but elsewhere in Opec-plus, major expansion plans are scarce. Many Opec-plus members have been struggling to meet their individual production quotas for some time, with output roughly 2.8 million b/d below targeted levels in June among the 19 producers with a quota. Various operational, technical, financial and geopolitical issues have squeezed several members including Nigeria and Angola. Now, the outlook for Russia, the co-leader of Opec-plus with Saudi Arabia, has dimmed due to harsh Western sanctions following its invasion of Ukraine. A majority of capacity growth in the next few years will come from non-Opec-plus countries such as the US, Brazil, Guyana and Norway, according to our upstream tracker database.

China's Refiners Cramped by Policies, Prices

China's massive refining sector is not providing much help relieving the shortage of oil products in global markets. Repeated and widespread Covid-19 lockdowns brought China's refining runs sharply lower in the second quarter, while Beijing's restrictions on product exports are preventing Chinese refiners from capitalizing on surging demand in Asia and elsewhere. Chinese refinery throughput tumbled 8.7% from the first quarter to 12.94 million barrels per day in the second quarter as Covid-19 lockdowns hit domestic demand. Jet fuel, gasoline and asphalt were hit especially hard. This left China's refinery throughput down 6% to 13.43 b/d in the first half of 2022 — its first such contraction since at least 2009, Energy Intelligence estimates.

It's hard to see Beijing changing course on either its zero Covid-19 or export policies anytime soon, particularly as crude prices remain high at around $100 per barrel. Energy security concerns and environmental goals help explain the actions, and now the rising threat of recession provides another reason to remain cautious. China's downstream sector looks set for a rough ride until at least end-2022. High oil prices — Brent averaged $112/bbl in the second quarter, after Russia's invasion of Ukraine — also hit refining demand, especially as China's regulated product prices impose lower margins on refiners once prices exceed $80/bbl. Allowing refiners to export some of their excess transportation fuels would help them recoup some of these lower margins, but Beijing appears intent on keeping product exports under control. In August 2021, the government started allocating sharply lower export quotas for gasoline, gasoil and jet fuel to discourage refiners from overproducing and cap carbon emissions. The lower quotas have left China's exports of transportation fuels down almost 55% in the first half from a year ago at 11.9 million tons. Exports of diesel, where world markets are particularly short, have plunged 84% to 85,000 b/d despite surging regional demand. "Two arguments work in favor of lower export quotas: the energy security and the environment arguments," says Oxford Institute for Energy Studies' China director Michal Meidan. If the government needs to create stimulus, it could allow more exports, but "the general plan is to lower exports," he adds.

Barring a relaxation of product exports quotas, the best hope for Chinese refiners is a strong rebound in domestic oil demand in the second half of 2022. But demand will hinge on how resurgent Covid-19 cases are handled. Refinery runs in June rose 5.3% from May to 13.42 million b/d, and China's oil demand rose by 270,000 b/d from May, Energy Intelligence estimates. The government, worried about first-half GDP growth of only 2.5% — against its 5.5% target for 2022 — is pouring money into large infrastructure investments, which tend to support trucking diesel demand, and into stimulus policies that will support the aviation and automobile industries, helping jet and gasoline demand in the process. But two sources with small, private refiners from Shandong, which hosts half of China's "teapot" refiners, tell Energy Intelligence that demand is at best recovering to pre-lockdown rates and that more upside may have to wait until September. Rising Covid-19 cases over the past two weeks have meanwhile brought back discussions of localized lockdowns. Until President Xi Jinping is re-elected at the head of the Chinese Communist Party, likely in October, he is unlikely to significantly relax his signature zero Covid-19 policy.

Most analysts see China's 2022 oil demand relatively flat — at best — with 2021 levels, which could cap the country' s crude imports. Energy Intelligence forecasts a 1% or 211,000 b/d fall in demand to 14.05 million b/d. China's Covid-19 policies could leave the country's demand 600,000-700,000 b/d below initial expectations in the second half of 2022, says China expert Mia Geng of energy consultancy FGE, which now expects Chinese demand this year to be flat with 2021. OIES expects a 200,000 b/d demand increase from last year, while the International Energy Agency sees a 40,000 b/d decline. China's crude imports were down 3.1% in the first half of this year to 10.26 million b/d after falling 5.4% in 2021 to 10.3 million b/d.

Sanctions to Test Rosneft at Vostok Project

Moscow is not shedding too many tears over the departure of international commodity traders Trafigura and Vitol from Rosneft's Vostok Oil megaproject. Their withdrawal from the $85 billion onshore Arctic scheme won't impact its financing, and Rosneft is sure it can market Vostok's flows of light, sweet crude alone. That's not to say there won't be consequences. There will be a reputational hit — Rosneft had wanted to attract foreign investors for a 49% stake in the project. And Vostok will face challenges because of Western sanctions that ban exports to Russia of equipment, technologies, software and other things needed to realize the massive development. Trafigura's $8.5 billion purchase of a 10% stake in Vostok in late 2020 was a benchmark deal that set a price for other possible international investors. Vitol and Singaporean Mercantile and Maritime Energy later bought a joint 5% stake in Vostok, but negotiations with other traders, international oil companies and "national champions" failed to bear fruit.

Rosneft has said it was never desperate for outside investors because unprecedented tax breaks granted by Moscow fully covered Vostok's infrastructure costs, which account for 50% of the project's capital expenditures. However, funds from partners could help lower Rosneft's debt. Infrastructure includes some 800 kilometers of trunk pipelines, 7,000 km of infield pipes, a port at the Sever Bay on the Arctic shore, airports, 3,500 km of grid facilities and 2,500 megawatts of power generation. The other half of capex is for developing the reserves to reach production of 600,000 barrels per day in 2024 and 2.3 million b/d in 2033. Vostok, which has a confirmed resource base of 45 billion barrels of liquid hydrocarbons, will offer buyers crude that is higher quality than Brent or East Siberia-Pacific Ocean, with 40° API and sulfur content of less than 0.05%. It will be delivered to global markets via the Northern Sea Route (NSR), going either east or west.

Rosneft insists all Vostok targets will be achieved despite "inevitable difficulties." CEO Igor Sechin assured at last month's St. Petersburg International Economic Forum that there are no technological complications, Rosneft possesses all the necessary competence and knowledge, and 98% of the equipment and materials are domestically manufactured. But this sounds overly optimistic, since Russia's oil industry is still heavily dependent on imports, particularly software, where foreign dependence was over 90% in 2018. Rosneft plans to drill 30,000 production and injection wells at Vostok and has a long-term contract for 100 heavy drilling rigs with a unique design for conditions in the north with Russian manufacturers. But seismic data interpretation, geological and hydrodynamic modeling, geoinformation systems and effective well management require special software, which Russia lacks in most cases.

Vostok is supposed to be a key driver of Russian production growth and Rosneft's 2030 strategy. Moscow is sure that Vostok barrels will be needed in an oil market facing supply deficits, although adjustments to expectations could be reflected in Russia's new 2050 energy strategy, which is now in the making. Vostok's success will largely depend on Russia's to replace Western technologies. Rosneft's strategy now envisages oil and gas output of 6.2 million barrels of oil equivalent per day by 2030, a 24% increase from 2021. Vostok comprises the operational Vankor cluster of fields — Vankor, Suzun, Tagul and Lodochnoye — as well as Irkinskoye and West-Irkinskoye, together with the Payakha field. The Vankor cluster is already producing more than 300,000 b/d, but it could be challenging to double Vostok's output in two years. The project has great importance to Russia, as it is expected to add 2% to Russia's GDP, increase shipments via the NSR and develop expertise in shipbuilding and other areas, which could be harder to achieve without Western partners.

Crisis Won't Hasten India's Transition

High oil and gas prices are not adding urgency to India's energy transition plans. India meets 85% of its oil and 50% of its gas demand via imports, but its soaring fossil fuel bills are not prompting it to accelerate the shift to alternatives. State-owned explorers and refiners see no dramatic change in operations for at least next two decades. That's because India's expanding population, which should overtake China's in 2023, and continued robust sales of vehicles powered by internal combustion engines — estimated at 18 million annually — will keep driving demand for fossil fuels. Energy security and affordability now tops the agenda for the state-owned firms that dominate India's oil and gas sector. State refiners are bleeding cash as the government forces them to sell diesel and gasoline below market rates to help keep inflation in check. The top state refiners — Indian Oil, Bharat Petroleum Corp. Ltd. (BPCL), and Hindustan Petroleum Corp. Ltd. (HPCL) — are likely to post a combined loss of $1.9 billion for the April-June quarter, according to the Mumbai-based brokerage Emkay Research. State explorers like Oil and Natural Gas Corp. (ONGC) and Oil India, which account for 75% of India's production, will see also see earnings squeezed by a windfall tax, which will shave off $40 from every barrel of crude they sell.

The government squeeze on state firms' earnings leaves little for them to make investments in new, riskier energy technologies. State refiners and explorers remain limited to token investments in ventures like green hydrogen, electric vehicle (EV) charging stations, biofuels, batteries and renewable power to stay aligned with Prime Minister Narendra Modi's goal of net-zero emissions by 2070. State refiners, which have 75,000 retail fuel stations, are aiming for 22,000 EV charging stations in five years. But that is a pittance compared to the 2.9 million that New Delhi-based Centre for Energy Finance says India will need by 2030. Green hydrogen plans also look insufficient to meet India's target of 5 million tons per year by 2030. Indian Oil is building a 5,000 ton/yr green hydrogen unit at its Mathura plant and a 2,000 ton/yr unit at its Panipat refinery. HPCL plans a 370 ton/yr unit at its Vizag refinery. BPCL has entered a deal with Bhabha Atomic Research Centre to scale up alkaline electrolyzer technology for making green hydrogen and plans an eletrolyzer at its Bina refinery. Both BPCL and ONGC eye 10 gigawatts of renewable generation by 2040, but this pales next to India's goal of 500 GW of renewable power by 2030, even with privately owned Reliance Industries having committed to 100 GW. The refiners' plans to diversify their fuel offerings by including natural gas also faces significant headwinds now with tight LNG markets looking like they will remain expensive in the medium term.

With oil and gas meeting a third of India's primary energy supplies, the government cannot push state oil firms to reinvent themselves anytime soon. Most of their investments will continue to be channeled into building more refining capacity and boosting domestic oil and gas production. The inertia to transform is evident in government policies that do little to check fossil fuel demand, including subsidies for diesel, gasoline and liquified petroleum gas. The transition path for state firms will not only be slow but it could also be painful if sudden technological breakthroughs in batteries or hydrogen disrupt markets. Decarbonization may be driving energy politics in the West but does not influence voters in India, the world's third-largest greenhouse gas emitter, where per capita energy consumption is just 9% of the US and 23% of China, the top polluters. State-owned firms control half of India's power generation, 90% of its coal operations, 75% of oil, 70% of gas and 66% of refining capacity. That means their investment decisions hold the key to India's energy future. But the government is in no hurry to change course despite the current energy crisis.

What's New Around the World

GENERAL

CORPORATE — Canadian oil sands giant Suncor Energy has agreed to adopt certain measures demanded by activist investor Elliott Management to help right the listing firm. Per the agreement, Suncor said it will add three new independent directors to its board, two of whom will help select the replacement for now-former CEO Mark Little, who resigned a week earlier after the latest in a string of worker deaths at the company's facilities. Elliott retains the right to nominate another director to Suncor's board should certain performance goals not be met by year-end. Suncor will also conduct a strategic review of its downstream business, including the potential sale of its Petro-Canada retail fuel station network, one of the largest in the country, to help boost shareholder returns and fund the company's carbon reduction efforts. Elliott initially demanded the changes at Suncor in April after disclosing that it had taken a 3.4% stake in the firm. The hedge fund cited its subpar financial performance compared to its oil sands peers as well as its poor safety record, which at the time included four worker deaths in the past three years and 12 since 2014. Another fatality occurred earlier this month.

COUNTRIES

IRAN — National Iranian Oil Co. (NIOC) and Russia's Gazprom signed a memorandum of understanding (MOU), as Moscow and Tehran seek to build a stronger relationship to counter western sanctions. The agreement — potentially worth up to $40 billion — was signed just hours before President Vladimir Putin arrived in Tehran for one of his first trips abroad since ordering Russia's invasion of Ukraine in February. Iran's Shana oil news service said the MOU between NIOC and Gazprom covers development of the Kish and North Pars gas fields, raising reservoir pressure at the giant South Pars gas field, and developing six oil fields. Development of the offshore Kish and North Pars fields alone is worth $10 billion, Shana said, with the project to boost pressure at South Pars worth another $15 billion. Gazprom said the MOU covered cooperation to develop Iranian oil and gas fields, natural gas and petroleum product swaps, LNG projects, construction of natural gas export pipelines, and the exchange of technology. Putin was accompanied by Deputy Prime Minister Alexander Novak, who oversees Russia's energy industry, and economic adviser Maxim Oreshkin. Russia already appears to have picked up some tips from Iran on evading US and EU sanctions that target its oil exports.

CHINA — Imports of Russian crude dropped by 211,000 b/d from May to 1.78 million b/d in June, according to Chinese customs data. But data analytics firm Vortexa says that seaborne Russian crude imports rose by 30,000 b/d from May to 1.13 million b/d. Given that 774,000 b/d of Russian pipeline crude flowed into China last month, that would put overall Russian imports at 1.9 million b/d. This leaves 124,000 b/d of "missing" oil in the official data, says a China-focused analyst. One possibility is that some Russian seaborne crude did not manage to clear customs by the end of June, she noted. Another possibility is that importers and traders of Russian crude are now using the playbook for sanctioned Iranian and Venezuelan crudes, which are typically relabeled under a different country of origin or blended with other crudes to obscure their true identities, other sources said. Suspicion has fallen on imports officially originating from Kazakhstan and Malaysia to disguise some of these Russian crude inflows, they add.

China's Major Crude Suppliers June 2021

('000 b/d)	Jun '22	May '22	Vol. Chg.	Jun '21	Vol. Chg.	Jan-Jun '22
Russia	1,780	1,991	-211	1,626	154	1,673
Saudi Arabia	1,236	1,849	-613	1,760	-524	1,752
Iraq	783	1,108	-326	869	-86	1,083
UAE	763	967	-204	424	340	787
Malaysia	649	521	128	286	362	449
Angola	575	744	-170	900	-325	696
Kuwait	514	616	-102	587	-72	693
Oman	507	940	-434	937	-431	852
Brazil	490	522	-33	574	-84	438
Kazakhstan	257	64	194	162	95	145
Others	1,199	1,513	-315	1,682	-483	1,657
Total	8,752	10,835	-2,083	9,806	-1,054	10,227

Energy Intelligence calculations of data from China's General Administration of Customs. Figures have been rounded.

IRAQ — The commissioning of the long-delayed 140,000 b/d Karbala refinery could begin in October, providing a welcome domestic outlet for additional Iraqi crude and slashing Baghdad's costly fuel import bill. The $6.4 billion construction contract was awarded to a South Korean consortium led by Hyundai E&C in 2014 and was supposed to take four and half years to complete. But mismanagement, late payments and the Covid-19 pandemic all contributed to the delays. Iraq hopes to finally start sending crude to the refinery in October, Oil Minister Ismael Ihsan said during a visit to the plant on Monday. When it is up and running, the plant will allow the country to reduce its imports of refined products by 60%, the minister added. Iraq's domestic refining throughput topped 600,000 b/d in May, for the first time in a year, but its existing refineries are old and have a fuel oil yield of more than 50%, necessitating imports of gasoline and diesel to meet domestic demand. The country is thought to spend about $3 billion a year on fuel imports, despite being Opec's second-largest producer. It currently exports around 3.8 million b/d of crude oil.

RUSSIA — Russia's combined production of crude oil and condensate inched up by about half a percentage point in the first 17 days of July to 10.76 million b/d, according to official data seen by Energy Intelligence. Exports declined by about 4% over the same period, while refinery throughout rose 5% as oil companies ran their units harder to meet summer demand, replenish stocks of motor fuel, and boost exports of highly sought diesel. The numbers suggest that Russian output may have reached a plateau after pulling a stunning rebound in June, when the world's third-largest producer jacked up its output by over 500,000 b/d, or 5%, to 10.7 million b/d. Energy Intelligence estimates that Russia's crude oil production (excluding condensate) amounted to 9.86 million b/d in the first 17 days of July, an increase of 80,000 b/d over June. Under the Opec-plus production deal, Russia's crude output ceiling for July is 10.83 million b/d. Condensate production is exempt from Opec-plus quotas. The numbers for the first 17 days of July show Russia's crude production running just 2% below pre-war levels.

RUSSIA — President Vladimir Putin has suggested that Russian exports of gas to Europe could remain at sharply lower levels, even after the Jul. 21 restart of deliveries via the Nord Stream 1 pipeline. The European Commission, meanwhile, has proposed that EU member states should reduce their gas consumption by 15% until next spring as a precaution against low deliveries from Russia, or even a complete halt in its exports to Europe. Speaking during a trip to Iran on Tuesday, Putin said recent reductions in flows of Russian gas to Germany were attributable to problems with the maintenance of turbines at a Nord Stream 1 compressor station in Russia. Putin said Western sanctions have delayed maintenance work carried out by the manufacturer of the turbines, Siemens Energy of Germany. European politicians have dismissed this, saying Russia is using the issue as a pretext to retaliate against Europe for sanctions that were imposed in response to Putin's war in Ukraine. Nord Stream 1 is capable of carrying about 170 MMcf/d, but since mid-June volumes were limited to around 40% of that capacity, or around 68 MMc/d.

YEMEN — Austria's OMV is poised to exit Yemen, becoming the last Western oil and gas company to give up operatorship of a producing upstream asset in the war-torn Mideast country. Pakistani engineering firm Spec is tipped to take over operatorship of the S-2 upstream block, which OMV had acquired back in 2003. Yemen has produced less than 100,000 b/d of for the last eight years, while TotalEnergies' Yemen LNG plant suspended operations in 2015. OMV had hoped to expand production at S-2 to 30,000 b/d, but in recent years output ranged from 10,000 b/d to 15,000 b/d, and it has recently dipped even lower. The Austrian company confirmed that it is "in a sales process of our Yemen business" as part of a "strategy of reducing the share of oil in the portfolio." It did not disclose the identity of a potential buyer. Spec declined to comment.

Marketview

Vicious Cycle

Crude oil futures continue to gyrate wildly, with intraday swings of $3 per barrel or more quite common.

The high volatility is becoming its own fuel as well, with the dramatic price shifts prompting some to step out of the market, leading to lower volumes and liquidity that amplify movements.

One driver of high volatility is the plethora of often contradictory factors facing the market.

Physical markets are trading in concert with fundamentals and have been relatively stable compared to futures. But so-called paper barrels seem to be the sphere in a game of pinball, being battered first one way and then the other as the market seeks direction.

On the bullish side, supply concerns remain present. The EU continues to phase out large volumes of Russian petroleum and needs to source replacements. Recent upheaval in Libya has also spooked markets, and elsewhere — such as in Ecuador — temporary outages keep popping up.

Opec, meanwhile, has very limited spare capacity and US production growth, while increasing, is growing at a slower pace than it previously has. Products in particular are tight, and the downstream in North America is running into operational ceilings, with US refiners running at a whopping 94% capacity.

But supply worries clash with several bearing cross currents. For starters, demand is starting to come under pressure. This is especially evident in the most recent US gasoline demand numbers, which came in well under 9 million barrels per day last week for the second consecutive period — almost 775,000 b/d below 2021 and far from pre-pandemic levels.

In China, a zero-Covid-19 policy could lead to another round of lockdown protocols that impact demand. Across the globe, refinery margins are narrowing as high consumer prices start to eat into consumption.

Currency also factors in. The euro is now close to parity with the dollar. Given that oil is denoted in dollars, that makes the commodity even more expensive for European buyers at the same time they are looking to replace roughly 3 million b/d in Russian seaborne crude and products by year's end.

Macroeconomic fears further pressure oil. Central banks' response to soaring inflation has sparked mounting recession fears.

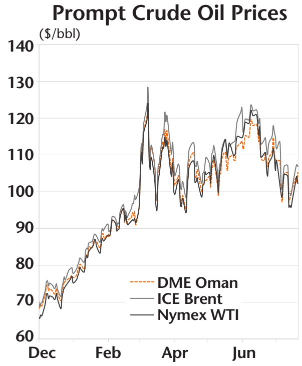
As volatility increases, it becomes more expensive and difficult to trade oil. This has prompted many speculators to head for the exits. Open interest is dwindling, and trading volumes are low. Brokers PVM point out that daily trade in US benchmark West Texas Intermediate (WTI) futures was over 1.2 billion contracts in the first quarter, while on one day early this week the total was just 718 million.

To a degree, this development is seasonal — summer tends to be a slow time in oil trade, especially towards the later part of the season. But this year's lull has been more pronounced.

That, in turn, feeds into even more volatility. Low trading volumes tend to amplify price swings, and the oil market has grown accustomed to seeing heavy losses early in the session reverse themselves, and, on occasion, vice versa.

Compounding matters, with volatility this high, no one is willing to sell protection against it, one trading source said, especially given the risks of a recession in the near term.

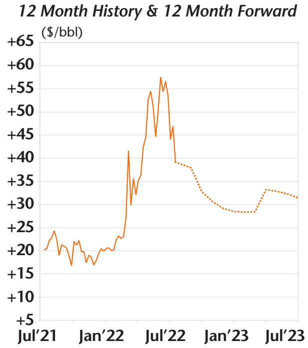
Prompt Crude Oil Prices



Source: Nymex, ICE, DME

Nymex 3-2-1 Crack Spead

12 Month History & 12 Month Forward



3-2-1 = 3 parts crude, 2 parts gasoline, 1 part heating oil

Libyan Oil Exports Pick Up

Libya's oil exports are picking up again after force majeure closures were lifted at key ports and terminals following the appointment of a new chairman to lead the country's National Oil Corp. (NOC).

Libyan Prime Minister Abdulhamid Dbeibeh dismissed Mustafa Sanalla as the head of NOC last week and appointed former Central Bank Governor Farhat Bengdara as his successor. A July loading schedule issued by NOC on Tuesday showed some 24 million bbls — about 780,000 b/d — are set to be exported this month, now that all ports are open again, according to a Libyan shipping source. Until a recent series of disruptions, Libya's export volumes had been running at a steady rate of around 1.1 million b/d.

PIW Market Indicators

($/barrel)	Jul 18-Jul 20	Jul 11-Jul 15	Jun 20-Jun 24
Spot Crude			
Opec Basket	$109.65	$105.44	$112.79
UK Brent (Dtd.)	115.61	109.79	116.52
US WTI (Cushing)	104.82	99.88	108.36
Nigeria Bonny Lt.	125.23	118.31	124.06
Dubai Fateh	103.95	99.14	107.97
US Mars	102.33	96.53	99.98
Russia Urals (NWE)	82.73	76.81	82.16
Crude Futures			
Brent 1st (ICE)	106.85	101.28	112.74
Brent 2nd (ICE)	102.37	97.70	109.47
B-wave (ICE)	105.59	101.04	112.19
WTI 1st (Nymex)	103.03	97.92	107.18
WTI 2nd (Nymex)	100.01	95.15	104.89
Oman 1st (DME)	105.59	100.31	108.65
Oman 2nd (DME)	100.54	95.56	105.12
Murban 1st (ICE)	108.74	103.08	114.20
Murban 2nd (ICE)	102.56	97.23	108.46
Forward Spreads			
Brent (1st-Dtd.)	-$8.77	-$8.50	-$3.78
Brent (2nd-1st)	-4.48	-3.58	-3.27
WTI (2nd-1st)	-3.01	-2.77	-2.30
WTI (3rd-2nd)	-3.12	-2.72	-2.46
Oman (2nd-1st)	-5.05	-4.75	-3.54
Oman (3rd-2nd)	-3.84	-3.43	-3.27
Murban (2nd-1st)	-6.18	-5.85	-5.74
Murban (3rd-2nd)	-4.06	-3.14	-3.15
Grade Differentials			
WTI-Brent (1st)	-$6.83	-$6.13	-$5.49
WTI-LLS	-2.80	-1.95	-0.40
WTI-Mars	+2.48	+3.35	+8.38
Brent(Dtd)-Dubai	+11.66	+10.65	+8.55
Brent(Dtd.)-Urals	+32.88	+32.98	+34.36
Brent(Dtd.)-Bonny Lt.	-9.62	-8.52	-7.54
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$102.46	$96.66	$107.11
Arab Lt.-Europe (Med)	105.59	101.04	114.09
Arab Lt.-Far East (f.o.b.)	104.54	99.87	112.92
Nigeria Bonny Lt.	115.61	109.79	118.18
Arab Light Gross Product Worth			
Rotterdam	$111.18	$113.51	$139.20
US Gulf Coast	117.81	120.52	143.59
Singapore	106.09	105.75	131.85
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$125.08	$128.70	$138.75
UK Brent Margin	+6.87	+17.28	+20.61
US Gulf Coast			
Mars GPW	112.85	114.95	136.70
Mars Margin	+10.42	+18.32	+36.61
Singapore			
Oman GPW	106.17	105.20	130.88
Oman Margin	+0.47	+4.05	+21.39
US Nymex			
WTI 3-2-1 Crack	+$39.68	+$45.34	+$60.89
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$1063.93	$1084.28	$1302.82
Gasoil (0.1%)	1117.00	1164.20	1343.80
Fuel Oil (0.5%)*	754.67	726.05	836.80
US Gulf Coast (¢/gal)			
RBOB Gasoline	313.93¢	319.19¢	382.32¢
ULS Diesel	359.63	370.03	433.69
Fuel Oil (0.5%, $/ton)	$832.00	$806.00	$883.40
Singapore ($/bbl)			
Naphtha	$84.38	$84.73	$86.56
Gasoil (0.05%)	133.33	136.51	171.41
Fuel Oil (0.5%, $/ton)	987.33	998.00	1069.00

*ARA fuel oil prices for 1% sulfur fuel oil (LSFO) have been discontinued as the market becomes increasingly illiquid. The new 0.5% sulfur fuel oil (VLSFO) specs reflect the transition to new emissions standards set by the International Maritime Organization effective Jan. 1 2020. Latest week's data are preliminary. For GPW and margin calculations, see Refining Profitability Methodologies on the Energy Intelligence website in Reference Tools Publication Methodologies. Spot prices from Thomson Reuters. Opec basket source, Opecna. 3-2-1 crack spread for 3 parts crude, 2 parts gasoline, and 1 part heating oil. PIW Numerical Datasource subscribers can download all indicators in Excel worksheets.