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Russia's Export Windfall Starts to Wane

Russia's windfall hydrocarbon revenues have diminished, particularly for crude oil and petroleum products, now that benchmark prices have slid 20% since June. Though still in surplus, the federal budget, fattened in the first half of the year, is losing its luster, official data show. Energy Intelligence now believes that Russia's oil and product exports will bring in $252 billion this year, down $8 billion from a previous estimate in mid-June when Brent hovered around $120 per barrel. In fact, the premium that Russia enjoyed in the second quarter thanks to the war in Ukraine has eroded in the third — compared to what it would have earned if it hadn't invaded its neighbor — while in October-December the country will earn less on oil and product revenues than in a no-war scenario, our assessment shows. Due to the conflict and subsequent sanctions, Russia is poised to produce 500,000 barrels per day less in crude and condensate this year than in the no-war scenario, while refining throughput will be 400,000 b/d lower. In addition, Russian crude exports are discounted on average $15 per barrel compared to Brent. When Brent was sky-high, Russia could produce less and earn more — to the tune of $5 billion during the second quarter — despite the discount. But this war premium vanishes in July-September: export volumes fall slightly, the average price realization slips by $12/bbl to $85/bbl, and Russia ultimately rakes in $40 billion from crude exports — the same as the no-war scenario. In the fourth quarter, this trend intensifies so that crude and product exports bring in $60 billion, or $3 billion less than the no-war scenario. Tellingly, Russia's finance ministry announced this week that the budget surplus, which had been 482 billion rubles ($8 billion) after the first seven months of the year, shrank to $2.3 billion after August.

The decline in oil and product revenues may continue in 2023, although market uncertainties

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Can Mideast Sustain Higher Exports to EU?

The looming EU embargo on Russian crude may not have significantly dented the continent's intake of Urals yet. But Mideast crude flows to Europe are on the rise, and at least in the case of Saudi Arabia, they are set to grow, with refiners seeking to secure additional future supplies. Saudi crude exports to Europe topped 1 million barrels per day last month, their highest since March 2020, according to Kpler. Highlighting the strength of demand, the surge came despite Saudi Aramco setting record-high official formula prices for August-loading cargoes of Arab Light to the Mediterranean and Northwest Europe. Aramco is eyeing higher exports particularly to Eastern Europe under a long-term supply deal with Poland's PKN Orlen. Other Mideast grades heading to Europe in bigger volumes include Iraq's Basrah crude, which averaged 620,000 b/d over the past three months, according to Energy Intelligence data, up by around 200,000 b/d from the previous six-month average. In Aramco's case, stronger European demand ahead of the Dec. 5 embargo appears to explain the trend. "It is more Saudi crude that seems to be the solution in the short term. But I think we will start to see more [Mideast] grades move west from November onwards," says a European oil trader. Less clear is whether the increased flows from Iraq and elsewhere have essentially been displaced by cheap Russian barrels in Asia. Iraqi state marketer Somo insists that is not the case. But while Aramco's allocations to Asia so far remain unaffected, Basrah exports to India have fallen.

European refiners' preference for light sweet crude poses a problem for Mideast sellers, for

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now. A surge in flows from Latin America, and the deeper discounts set by Aramco and Somo for October-loading cargoes to Europe, both point to the competition they face. Complex refineries in Northwest Europe and the Mediterranean running sour crude can take advantage of these discounts to boost their margins. But less complex refiners are choosing to run sweet crude to minimize their desulfurization costs, inflated by soaring natural gas prices. That puts particularly high-sulfur Basrah crude at a disadvantage to rival Mideast grades. "Everyone is running light sweet crude," notes the European trader. "They're not really replacing Urals with a Urals lookalike such as Basrah Medium." The sharp rise in exports from Guyana and Brazil appears to bear this out. Seven cargoes of light sweet Guyanese crude headed to Europe in 2021, averaging around 20,000 b/d. But flows have since shot up — to 108,000 b/d in the first eight months of 2022, according to Kpler, with nearly 40% of those volumes exported in August alone. Brazil is also selling more crude to Europe, with flows approximately doubling over the past five months, compared with the previous five-month average of 165,000 b/d. Both countries are in the process of boosting production.

Exactly how European oil demand evolves in the coming months remains hugely uncertain. The effectiveness of EU sanctions on Russian oil and the proposed price cap, as well as the severity of any recession, are key variables. Doubts persist about how some refiners can feasibly live without Russian crude, with around 1.8 million b/d of it still heading to the EU. Some of this could be stockpiling ahead of the embargo. But sellers are certainly questioning how big — and permanent — the surge in Europe's appetite for non-Russian crude will be. That will, to a large extent, determine the flows of Mideast crude west of Suez, though clearly other factors are at play. The prospect of Iranian crude returning to Europe and squeezing exports from rival producers has receded, with a return to the 2015 nuclear deal and lifting of US sanctions now considered unlikely before November. Separately, an escalating row between Baghdad and Erbil could disrupt the 400,000 b/d of Kurdish crude currently sold in the Mediterranean, with Somo's legal actions potentially causing real difficulties for buyers, and sellers and pushing some volumes to Asia. Iraq's ability to benefit from higher European demand is hampered by its export capacity, which is effectively maxed out right now, unlike Saudi Arabia's. The trading cycle will also make it harder for Mideast producers — who tend to sell two months in advance — to respond to European demand. But for all of them, the Russian oil embargo is both an opportunity and a threat to their business in Asia — the market with the biggest growth potential. As Aramco CEO Amin Nasser pointedly remarked last month, "in Europe, honestly when you look at the growth, it's not significant and actually it is declining slightly year-on-year."

Russia Sets Path to Overcome Sanctions

Russia has set several goals for its oil and gas industry to stay competitive as it copes with sanctions and an escalating economic war with the West. They relate to import replacement of Western technologies and expertise, infrastructure development to accommodate shipments of Russian hydrocarbons shunned by the West to alternative markets in the East and South, and cutting reliance on the dollar and euro in global trade. The price cap on Russian oil planned by G7 countries has also added urgency to construction of a bigger tanker fleet and establishment of a new national insurance company. Likewise, a freeze on Russia's $300 billion-plus in foreign currency reserves after the Feb. 24 invasion of Ukraine has elevated the push to move away from the dollar and euro, although efforts started earlier after a round of Western sanctions in 2014. Russia has made at least some progress in coping with sanctions in most areas, but the most visible success has been in de-dollarization. Gazprom and China National Petroleum Corp. (CNPC) agreed last week to switch payments under their long-term pipeline gas supply agreement to rubles and yuan. Russia and Turkey had previously agreed on partial payment in rubles for supplies of Russian gas. Rosneft placed 15 billion yuan ($2.2 billion) in 10-year bonds this week. Russian oil exporters are already using yuan and United Arab Emirates' dirham in contract settlements, and Russia's finance ministry is considering issuing sovereign bonds denominated in yuan. Russia sees the yuan as the best international currency on which to rely.

Import replacement has been particularly challenging, especially as more Western companies

withdraw from Russia and sanctions start to bite. Software and new equipment remain problem areas, particularly in the downstream. Progress has been made with catalysts for hydrocracking and hydrotreatment, which should help satisfy Russia's needs for the next few years. But to fulfill Moscow's strategic modernization program — which envisages reconstruction of some 30 conversion or secondary units by 2030 — the Russian refining fleet, the world's third-largest, needs to find equipment and technologies that have become unavailable because of sanctions. Possible solutions include imports from friendly countries and greater development of domestic capabilities, but the results could be more expensive and less advanced.

There are fewer concerns about upstream technologies and equipment. Russian companies have made some technological progress in shale oil, Arctic and deepwater projects — areas that the West sanctioned in 2014. Even though major oil-field service companies like Baker Hughes and Halliburton left Russia, they sold their businesses and assets to local management, who had deep involvement in day-to-day operations and knew how to work with the technologies and equipment already provided to Russian companies. Top service firm Schlumberger still continues it activities in Russia. But future upstream developments still could be more expensive and less sophisticated. Liquefaction technologies for large-scale LNG trains also remain a challenge.

Western technology was also at the core of Russia's decarbonization drive, which envisaged partnerships with international firms. Debates continue on whether Russia should proceed at all with its low-carbon agenda given the deterioration of relations with the West. Nevertheless, Russia's decarbonization plans remain unchanged — although the pace of some initiatives might now slow. Russia started on Sep. 1 the experiment on Sakhalin island aimed at reaching carbon neutrality for the region in 2025 and testing the country's carbon trading system. A 1,000 ruble ($16.70) fee for each extra metric ton of carbon emissions — to be paid to the regional budget — was set for participants. However, Russian Economic Development Minister Maxim Reshetnikov says the government will think twice before adopting any new initiatives that could put an extra burden on the country's business. Longer-term, decarbonization would help transform Russia's economy and make it attractive for friendly partners that target carbon neutrality.

Upper Zakum Expansion Would Fit UAE's Plan

Upper Zakum, Abu Dhabi's largest producing oil field and one of the biggest offshore fields in the world, might be up for another expansion. The giant field in which Exxon Mobil and Inpex are concession partners alongside Abu Dhabi National Oil Co. (Adnoc), reached production capacity of 1 million barrels per day in late 2021 — well ahead of a 2024 target. The partners are now understood to be mulling a major expansion that could double capacity to 2 million b/d by the early 2030s. The scope of the project and how large the expansion might be has not been decided. The plan remains in the early stages and will hinge on the concession stakeholders coming to an agreement on key issues, notably fiscal terms, which are presently under discussion, Energy Intelligence understands. But interest among the parties in proceeding with the field's expansion is understood to be strong given its proven reserves of around 50 billion barrels, low production costs and long-term potential. Inpex, whose subsidiary Japan Oil Development Co. (Jodco) started development of Upper Zakum with Adnoc in 1978 and began production in 1982, previously said the field "has lots of room for expanding production capacity in the future."

The expansion of Upper Zakum would be of great significance for several reasons. It would become one of the largest oil field developments of its kind at a time when global upstream investments have been lagging in the face of the energy transition. For Abu Dhabi, it would be a way to accelerate the monetization of its vast hydrocarbon reserves before global decarbonization efforts add more momentum and put pressure on oil demand. The project would also support the United Arab Emirates' plans to boost oil production capacity and further position itself as one of the world's largest low-cost, low-carbon producers — providing a competitive advantage over its rivals in the transition. As such, the field's expansion would fit into the UAE's larger strategy aimed at implementing wide-ranging economic diversification and energy transition initiatives. The Opec member has committed to achieving net-zero emissions by 2050 by investing more in renewables, adding more nuclear power in coming years, applying technologies such as carbon capture and storage (CCS) and developing green hydrogen and renewable projects.

Since Sultan al-Jaber took over as Adnoc CEO, the long conservatively managed state oil giant has moved swiftly to prepare itself for today's rapidly changing energy landscape. Adnoc is wasting no time boosting its production capacity, which presently stands at over 4 million b/d. Indeed, Adnoc appears to be speeding up plans at a time of favorable market conditions and high energy prices. The company is understood to have quietly hastened its oil production capacity expansion program and may target reaching 5 million b/d by 2025 rather than its internal 2027 deadline, which itself was moved forward from the still official 2030 timeline. Upper Zakum and other offshore concessions are integral to achieving such targets — and an expansion could help achieve another potential goal: a plan to boost oil production capacity by an extra 1 million b/d to 6 million b/d, which industry sources told Energy Intelligence is under consideration. Importantly, any significant capacity increase could be a game changer for possible plans by Adnoc and Intercontinental Exchange (ICE) to establish an Upper Zakum futures contract, enabling the grade to potentially replace Oman crude as a regional sour crude benchmark and giving it another futures contract after Murban.

For Exxon and Inpex, another Upper Zakum expansion would likely come with an extension of their concession, which would lock in steady, long-term income from the production of advantaged barrels. Discovered in 1963, Upper Zakum, together with the field's lower portion known as Lower Zakum, is the world's second-largest offshore oil field. Exxon joined the Adnoc/Inpex concession in March 2006 as plans to raise output capacity to 750,000 b/d by 2015 were getting under way. The concession was then extended in 2014 by 15 years. In November 2017, the companies agreed to further lift production capacity to 1 million b/d by 2024, at which point the concession was extended by another 10 years to December 2051. Under new fiscal terms agreed in the same year, Abu Dhabi raised the amount that Exxon and Inpex are paid to $2.85 per barrel from the previous $1/bbl.

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abound. Our base-case scenario assumes: (1) the war will continue, (2) the EU bans on Russian oil and products imports will go ahead, (3) Asia will not be able to purchase all the orphaned Russian crude, and (4) Russian refiners will not find buyers for a 1 million b/d surplus of petroleum products that used to head to Europe. Annual crude and condensate production will decline by over 1 million b/d to 9.35 million b/d in 2023, and refiners will have to slash runs by some 500,000 b/d, our base scenario shows. This means that, using Energy Intelligence's Research & Advisory forecast of $103/bbl for Brent next year, export revenues from crude and products would plummet to $185 billion, down $67 billion year on year. But 2023 will be terra incognita for energy markets, and reality is certain to dash some assumptions. A large part of the seaborne oil trade could go dark, and Russian crude and products could find their way into prohibited ports. China and India could agree to soak up additional barrels. Then again, there might not be enough vessels to handle such long-haul trips from the Baltic and Black seas to Asia due to shipping sanctions. And assuming the fleet is secured, it will be tough love for Russia since India and China will insist on significant discounts. So either way, Moscow could lose on crude income. Regarding oil products, refining margins have started to fall this month, and the outlook is dire ahead of the EU product embargo set for Feb. 5. With federal revenues slipping, Moscow can ill-afford to boost generous subsidies that it has been forking over to refineries.

The picture is more balanced when natural gas is thrown in. State-controlled Gazprom has been the quintessential case study of how a monopoly can cut supplies and bolster the top line. In January-August, it generated some $74 billion from sales to Europe, based on Energy Intelligence's border price estimates, up from $34 billion in the same period a year ago. Volume sales to Europe and Turkey, however, tanked 42% to about 72 billion cubic meters. Gazprom is forecasting that its 2022 revenue will significantly exceed last year's, which was a record 10.2 trillion rubles ($169 billion at the current rate). Moscow's decision to restrict gas flows to Europe to just one line — via Ukraine — has catapulted spot prices and should keep Gazprom's hub-linked prices high for at least the next couple months. Still, the policy is showing signs of risk: Gazprom's revenues in August are estimated at $8.3 billion, which is lower than in all months from October 2021 to May 2022 even though the export price was significantly higher during the period. Unless the gas giant ramps up supplies, it is likely to encounter difficulties keeping 2023 revenues at current record-high levels. A price cap on gas, currently on the table in the EU, may help ensure that.

Norway Wrestles With Response to Energy Crisis

Norway is reaping major benefits from the energy battle between Russia and Europe. Norwegian upstream players have responded to calls to increase near-term production, revenues are booming, and the country has quickly become Europe's reliable supplier of choice. But there are headwinds: uncertainty over the regulatory outlook for Europe's gas market is raising red flags for longer-term investment in projects and infrastructure. And firms complain that the lack of offshore wind opportunities — a key plank of Norway's energy transition — will create a bottleneck for its deployment that could undermine Oslo's aggressive renewables goal. Around $145 billion in tax income from Norway's upstream sector is expected to flow into government coffers this year versus around $35 billion last year, according to Rystad Energy. Producers have stepped up gas output by 10% this year to keep supplies flowing to Europe and help offset the drop in gas flows from Russia. As a result, non-EU member Norway is now the largest supplier of energy to Europe, accounting for roughly one-quarter of the region's consumption.

Norway's relatively stable upstream tax regime may help incentivize near-term investment, just as policymakers in Brussels are pushing for national levies on energy companies' windfall profits. Yet at the same time, the high level of activity driven by Oslo's beneficial tax package, which expires this year, is putting pressure on the local supply chain amid raw materials cost inflation and capacity constraints. Germany's Wintershall Dea intends to maintain high activity levels in Norway after investing roughly three-quarters of its overall capital budget there last year. But CEO Mario Mehren acknowledged at the recent Offshore Northern Seas (ONS) conference in Stavanger that it would be a "challenge" to keep up the same pace given the "very tight and competitive" Norwegian market. Moreover, Norway's gas export infrastructure is almost fully utilized, he added.

Longer-term, fixed price contracts now being discussed by Norwegian gas producers and their European customers to help stabilize prices could offer companies predictable revenues, making it easier to plan investments. And energy ministry officials believe the European Commission's formal push earlier this year for continued long-term Norwegian upstream activity to help secure European energy supply beyond 2030 will underpin demand — although climate advocates argue this endorses Oslo's "develop not dismantle" mantra for the industry, a policy they say allows vested interests to continue with "business as usual." Still, more exploration will be needed to replace mature fields and to fill a dwindling pipeline of development opportunities. Aker BP, Norway's second-largest producer, has earmarked upward of $15 billion for developments to lift its production to 525,000 barrels of oil equivalent per day by 2028 — up to 25% gas — from 400,000 boe/d now. CEO Karl Johnny Hersvik told Energy Intelligence he believes the energy crisis has "cemented gas as a transition fuel, maybe as a permanent fuel." But he said it would depend how much gas is found and how markets develop as to whether there would be investment in new gas export infrastructure.

The crisis has also sharpened Norway's ambition to become a key producer and exporter of renewables. In May, the government launched a major offshore wind push targeting 30 gigawatts of power generation capacity by 2040, up from 4.6 GW (almost all onshore wind) now. Yet, executives say the government must accelerate efforts and implement policies to meet its goals — including opening up new acreage to allow the sector to grow. "It's just not going quick enough. There is a lack of a sense of urgency," said Aker Solutions' head of renewables, Stephen Bull. Oslo has defined two large areas — Southern North Sea II and Utsira North (floating wind) — for development of up to 4.5 GW of projects. A first tender for 1.5 GW of bottom-fixed wind will be launched later this year. But Equinor's head of renewables, Pal Eitrheim, points to a lack of projects after it completes the floating Hywind Tampen scheme later this year.

Law Puts US in Front on Clean Hydrogen

Purveyors of clean hydrogen in the US stand to reap some of the most significant benefits from the recently passed Inflation Reduction Act (IRA). IRA provisions — headlined by a generous production tax credit of up to $3 per kilogram of hydrogen — provide lucrative incentives for producers and could accelerate both supplies and the deployment of infrastructure, as demand for clean hydrogen and associated products ramps up. Beyond the tax credit, regulatory certainty for the next decade-plus and a "direct pay" option to maximize tax benefits will give developers more confidence and could help projects get off the ground faster. The IRA is Congress' latest and most impactful piece of legislation for hydrogen players, coming on the heels of last year's infrastructure law that allotted $8 billion to help develop regional clean hydrogen hubs across the country. The efforts have made the US into one of the world's most attractive jurisdictions to build clean-hydrogen projects.

So-called green hydrogen that is produced with an electrolyzer and renewable power looks poised for a big boost post-IRA. Andrew Marsh, CEO of Plug Power, a supplier of electrolyzers and itself a producer of hydrogen, said the new incentives will make green hydrogen immediately competitive with conventional gray hydrogen produced through steam methane reforming (SMR). Some observers wonder if the $3/kg tax credit is almost too generous since it will stay at that level well into next decade, as green-hydrogen costs continue to fall. "Everyone wants green hydrogen — now there is a path that always makes it competitive," Marsh says. Unsubsidized green hydrogen production in the US costs around $2.60-$3.75/kg, before any transportation expenses, according to Morgan Stanley. Those costs will fall to $1.91-$2.82/kg by 2025 and $1.44-$2.25/kg by 2030, the bank reckons. At those costs, the IRA's subsidies would instantly put green hydrogen on equal footing with gray, which costs roughly $1-$2/kg to produce, making it economical about a decade earlier than previously expected, according to S&P Global Markets. With more green hydrogen available, feedstock markets for hard-to-decarbonize industrial sectors like fertilizer and refining could open up.

Blue hydrogen produced with SMR and carbon capture and storage (CCS) also stands to gain from the IRA, although the scale of the potential benefit is a bit murkier. The full $3/kg tax credit is available only to projects producing hydrogen with full life-cycle emissions of less than 0.45 kg of carbon dioxide equivalent (CO2e) per kg of hydrogen, falling to $0.60/kg for hydrogen with an intensity rate of 2.5 kg-4 kg of CO2e. That will put pressure on natural gas suppliers to clean up their operational upstream emissions, and on blue hydrogen producers to verify that their feedstock is as low-emitting as possible. A "methane fee" embedded in the IRA for producers should help. But the law also stipulates that projects cannot stack hydrogen-production credits with CCS benefits under section 45Q, potentially making blue hydrogen less attractive than other forms.

Equipment providers see a massive opportunity in a post-IRA world. KR Sridhar, CEO of equipment maker Bloom Energy, said the IRA will make the market for electrolyzers and fuel cells "grow enormously." Plug Power sees incremental demand for electrlolyzers rising by 10 gigawatts in the US if just a fifth of current hydrogen consumption in the refining and ammonia sectors converts to green volumes. Ongoing supply chain constraints could slow the rollout of some of this crucial kit, but companies are looking to simplify designs and source more materials domestically. It's not clear if wind and solar power deployments will be able to keep up with the projected demand coming from a wave of green hydrogen production. Critics say growing demand from hydrogen could siphon off renewable power supplies and slow broader electrification efforts. But ancillary technologies like geothermal and advanced nuclear may gain momentum as baseload power supplies, and novel energy-storage schemes involving hydrogen could drive further innovation and efficiency in the renewables sector. Emerging methods of producing clean hydrogen that use less power could also start to gain traction.

Asia Takes Steps to Avoid Winter Gas Crisis

Europe's scramble for gas has put extra pressure — and costs — on Asian importers looking to guarantee their energy security this winter. Northeast Asian LNG buyers are furiously trying to fill storage capacity ahead of what some expect to be a "winter from hell" in gas markets. Only China largely remains out of the spot markets, since its strict "zero Covid" policy is capping demand, which is also met partly by cheaper pipeline gas from Russia and domestic LNG supply. In South Asia, buyers have been priced out of the ultra-expensive LNG market for months. Rather than seeking to buy spot cargoes, traders there have been trying to close swap deals to optimize their positions. Over the past two months, Taiwan's CPC, South Korea's Kogas, and Japanese firms Kansai Electric and Jera have been active in the spot market to secure winter cargoes. While many cargoes have traded at discounts to the historically high Japan Korea Marker, Asia's de facto benchmark, they are still pricey.

Kogas has been actively building LNG inventories since April, with the aim of reaching 90% storage by November. Japan's Jera began stepping up its procurement strategy in July, securing a several cargoes with delivery starting from November. Kogas is believed to have bought over a dozen cargoes in July for delivery over the October to March period. Inventories were 34% full about a month ago with 1.81 million tons of LNG in stock, the ministry of energy said, after a higher-than-expected drawdown due to high summer temperatures. Jera, along with Tokyo Gas, also decided to continue LNG imports from Sakhalin-2 in Russia despite geopolitical risks. Japanese utilities' LNG inventories have reached 2.65 million tons — much higher than a year ago and the five-year average.

Northeast Asian governments are also carving out energy conservation measures to reduce gas and power consumption to head off a potential crisis. Fuel switching and the restart of nuclear power plants provide more options for governments. In South Korea, the ministry of energy said liquefied petroleum gas (LPG) co-firing is being implemented to help lower consumer gas bills. An energy supply and demand emergency response team has been set up, comprising public and private stakeholders, to monitor the evolution of the market and storage capacity and "take prompt response measures in case of emergency." In Japan, the ministry of economy is considering restrictions on the usage of city gas by industries this winter to ensure stable supply.

Despite such preparations, spot LNG traders are bracing for some dicey months ahead in a tight market where supply fears are driving sentiment. Much will depend on what happens in Europe, where storage facilities are now over 80% full, ahead of the EU's November target. "If EU storage facilities can be filled up to 100% of capacity before the northern winter arrives, the region will have between 2-2.5 months' worth of gas, assuming monthly demand of 140 billion-150 billion cubic meters," Rystad Energy senior analyst Wei Xiong said in a note. That would give Europe sufficient gas supply for the early winter months of November and December. However, a supply risk for the first quarter of 2023 would remain. An early and cold winter in the Northern Hemisphere, combined with delays in the restart of the US Freeport LNG export terminal or production issues elsewhere, would trigger extreme volatility.

What's New Around the World

GENERAL

CORPORATE — Shell said its CEO Ben van Beurden would step down at the end of 2022 and be replaced by the UK supermajor's head of integrated gas and renewables, Wael Sawan. Van Beurden, who is 64, has served as CEO since 2014 and worked at Shell for 39 years overall. He will stay on as an adviser to the board of directors for six months, until June 30, 2023, before leaving the company. The 48-year old Sawan will assume the CEO role on Jan. 1 and become a member of the board. He will take over one of the world's largest energy companies as it adjusts to the loss of its Russian operations, strives to achieve net-zero emissions by 2050 and comes under fire from climate activist shareholders and protesters. Sawan was recently reported to be one of four internal candidates Shell was considering to replace Van Beurden alongside downstream director Huibert Vigeveno, upstream chief Zoe Yujnovich and Chief Financial Officer Sinead Gorman. His renewables background — he has been head of integrated gas, renewables and energy solutions at Shell since October 2021 — made him a natural choice for CEO as the energy transition takes center stage in oil majors' priorities.

OPEC — Opec sees robust economic growth driving increases in oil demand this year and next, but it also acknowledges downside risks associated with factors such as geopolitical tensions, Covid-19 and inflation. The producer group expects the global economy to grow at 3.1% in both 2022 and 2023 and notes a positive impact on oil consumption from the recovery in travel and transportation. "This matches the average pre-pandemic growth level of around 3.1% between 2009 and 2019," Opec said in its latest *Monthly Oil Market Report*. It added that consumer spending, in value terms, had performed better in recent months than sentiment had indicated, led by Western economies. A mix of strong growth in commodity-exporting economies and rising global trade had contributed further to this trend, it said. Opec sees this translating into growth in oil demand of 3.1 million b/d in 2022 and 2.7 million b/d in 2023, when average annual demand will surpass pre-Covid-19 levels to reach 102.7 million b/d. These annual demand forecasts are unchanged versus Opec's August report.

COUNTRIES

CANADA — Canadian oil producer Tamarack Valley Energy has reached a C$1.425 billion (US$1.1 billion) cash-and-stock deal to acquire privately held Deltastream Energy. Tamarack said the acquisition will make it the largest producer in the Clearwater conventional heavy oil play in central Alberta, which it describes as the "most economic play in North America." The Deltastream acquisition will add over 500 net future development locations in areas adjacent to Tamarack's core Nipisi and Marten Hills operations, according to the company, as well as boost its output in the Clearwater play to an expected 23,000 boe/d (94% oil) in 2023. The Clearwater heavy oil play lies north of Edmonton and features low-cost wells and stellar break-even prices under US$30/bbl, according to Tamarack. The play's stellar economics have made it an attractive target for E&P bargain hunters, particularly Tamarack, which has built up a large position in the play over the last couple years through a series of acquisitions.

INDIA — India is considering several options to try to secure a stable supply of oil at below-market prices amid concerns that the global oil market could remain tight and prices high in 2023, sources say. Several factors have contributed to market uncertainty recently including the possibility that China could lift all Covid-19 lockdowns, the possible return of Iranian crude exports and a proposed price cap for Russian oil. India is weighing various measures like increasing the volume of imports under term contracts, diversifying its supply sources and reaching out to Iran. India imports more than 85% of the roughly 5 million b/d of crude oil that it uses, which makes it highly vulnerable to price spikes and supply disruptions. A source said India has recently stepped up its outreach to Iran so that it would be able to start importing Iranian crude, but earlier optimism about a revival of the Iran nuclear deal and the lifting of sanctions of Iran's oil sector has faded in recent weeks. Indian refiners have been looking into procuring additional supplies from Opec suppliers like the United Arab Emirates, Gabon and Nigeria. They have also been working on broadening their supplier base via deals with non-Opec producers such as Guyana, Canada and Brazil, another source noted.

RUSSIA — Russia's Lukoil looks set to replace Repsol in a Siberian joint venture with Gazprom Neft that the Spanish company withdrew from in late 2021 as part of a global review of its upstream oil and gas portfolio. Russian business daily *Kommersant* reported that the country's number 2 and number 3 oil producers will team up in a joint venture based around Gazprom Neft's Eurotek-Yugra subsidiary. Eurotek-Yugra holds the license for the Erviye field, which is estimated to hold almost 250 million boe of recoverable resources. The field was discovered in 2013 and is located in the Karabashsky blocks 1 and 2 in West Siberia. Lukoil's joint venture deal with Gazprom Neft is the latest example of Russian companies stepping in to pick up assets abandoned by Western companies, while companies from Russia-friendly countries such as China and India hold back. In another recent example, Russia's top independent gas producer Novatek is set to replace Shell in the Sakhalin-2 project in Russia's Far East.

SAUDI ARABIA —Saudi Aramco has started the tendering process for contracts related to the expansion of its giant Safaniya offshore oil field which is expected to be completed by 2027, industry sources told Energy Intelligence. State-controlled Aramco is targeting a 1 million b/d of its overall oil production capacity to reach a total of 13 million b/d by 2027. Much of the additional capacity will come from the kingdom's offshore fields, including Safaniya. Aramco kickstarted the tendering of contracts this month for the Safaniya expansion, which currently has a production capacity of around 1.3 million b/d from two reservoirs — Safaniya and Khafji — according to industry sources. The plan is to expand capacity by 700,000 b/d of Arabian heavy crude by 2027, the sources said. Global investment in the upstream oil and gas industry has been limited in recent years, but Aramco believes that oil demand will continue to grow for decades to come. The phased capacity expansion program is therefore a top priority for the company. CEO Amin Nasser told reporters last month that Aramco's maximum sustainable capacity will rise to 12.3 million b/d in 2025, 12.7 million b/d in 2026 and 13 million b/d by 2027.

UAE — Italy's Eni has spoken to Abu Dhabi National Oil Co. (Adnoc) about accelerating gas projects in the Mideast Gulf emirate. The discussions — between CEOs Claudi Descalzi and Sultan al-Jaber — come as Europe scrambles to find alternative sources of gas as quickly as possible to replace a sharp drop in imports from Russia following its invasion of Ukraine. Meeting in Abu Dhabi, Descalzi and al-Jaber "discussed the acceleration of the multibillion-dollar Ghasha project," Eni said, without giving a specific time frame. Adnoc holds a 55% stake in the Ghasha offshore concession to Eni's 25%. It has previously said that it hopes to achieve first production from the sour gas project around 2025. At its peak, Ghasha is expected to produce more than 1.5 Bcf/d of raw gas, as well as 120,000 b/d of oil and condensate. Al-Jaber has spoken about exporting surplus gas volumes as LNG. Descalzi also presented al-Jaber with fast-track development options for Eni's recent gas discovery in Abu Dhabi's offshore Block 2. Eni said in July that its first exploration well drilled on the block had found a total of 2.5 Tcf to 3.5 Tcf of gas in place.

Marketview

Fundamental View

Oil prices continue to swing widely, and futures for both crude and products remain reactive to the slightest stimulus, whether it be inflation data, inventories or other headlines. But against this backdrop of volatility and intraday price movements of several dollars, the market remains tight and could get even tighter, especially when it comes to diesel.

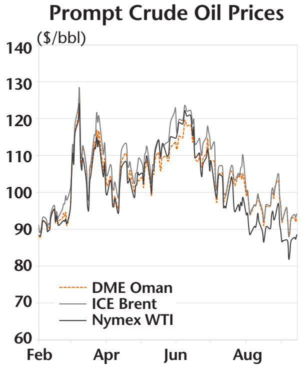
Recession concerns and inflation have contributed to recent downward pressure on oil prices. Many experts are now convinced that Europe faces a recession, which would theoretically knock oil demand down a few pegs. Meanwhile, across the Atlantic, US inflation numbers for August came in well above expectations, smashing hopes for a slightly more dovish approach to monetary policy by the US Federal Reserve.

Central banks tend to address inflation hawkishly, raising interest rates. That has a direct impact on crude prices — when the Fed raises rates, it bolsters the dollar. Given the oil is priced in dollars, that immediately makes petroleum less affordable, hurting consumption.

But bearish as these challenges are, significant upside risks and potential remain. The EU's intensifying embargo of Russian petroleum is one key bullish element, as are potential Russian responses to the G7's price cap on Russian oil, not to mention logistical hurdles facing those seeking to trade within the cap's framework. Meanwhile, sky-high gas prices, especially in Europe, are likely to lead to fuel switching. This would increase demand for oil products such as propane and diesel.

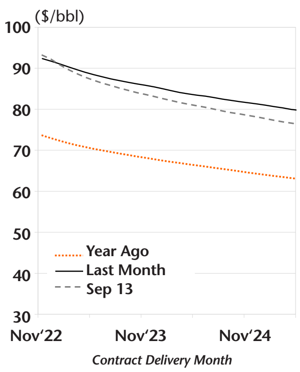
But the global downstream has little to no slack. Capacity to produce fuels is in a pinch. Refiners in China are keeping a lid on product exports, while those in North America are coming off a massive rationalization and running full tilt. Portions of the world's refinery complex are under maintenance, though in the US downstream players are running at 91.5% regardless. Hurricane season has been mercifully quiet, but has not yet passed. Between storms and frenetic utilization, the risk of unplanned outages is not to be dismissed, especially against the backdrop of thin inventories.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

ICE Brent Forward Curves



Oil, and more specifically products and especially diesel, therefore sees more fundamental support — certainly on the supply side. Futures prices may not always reflect this, but other metrics do. Energy Intelligence's refining model shows margins for complex US Gulf Coast facilities processing incremental medium, sour barrels have come off their highs. But they remain robust at almost $28 per barrel. In Europe, they have risen against incremental Brent for four straight weeks and hover just under $20/bbl.

And while flat prices for oil futures continue to descend, the forward curve maintains backwardation. Front month contracts trade at a premium to later-dated barrels, which indicates a tight market and incentivizes immediate sales, preventing inventory build-up and perpetuating tightness.

For now, recessionary fears and other concerns about the health of demand have outweighed the bullish elements facing the market in futures and options. But this could be partially the result of low liquidity. As prices swing widely almost daily, the cost of trading oil rises, which has prompted many players to leave the market. That leaves trading action on a hair trigger, which could just as easily shoot prices higher.

IEA Sees Tight Diesel Market

The International Energy Agency (IEA) sees crude supply running ahead of demand for the rest of 2022, but with pockets of severe tightness for diesel and jet fuel.

Diesel is in short supply because of refining capacity constraints, while demand for diesel and fuel oil has risen as it replaces expensive gas for power generation in Europe and the Middle East. The IEA said this fuel switching could boost demand by up to 700,000 b/d day over the coming winter. Diesel supply was already under pressure from lower Chinese exports. A looming EU ban on the import of refined products from Russia will further complicate the supply picture. From Feb. 5, the EU will ban imports of diesel from Russia, which currently amount to 600,000 b/d.

PIW Market Indicators

($/barrel)	Sep 12-Sep 14	Sep 5-Sep 9	Aug 15-Aug 19
Spot Crude			
Opec Basket	$97.58	$96.56	$98.22
UK Brent (Dtd.)	93.10	90.19	96.25
US WTI (Cushing)	88.20	85.27	91.81
Nigeria Bonny Lt.	95.81	93.84	101.83
Dubai Fateh	93.16	92.23	92.82
US Mars	87.58	84.34	89.57
Russia Urals (NWE)	69.38	67.04	69.33
Crude Futures			
Brent 1st (ICE)	93.76	91.71	94.88
Brent 2nd (ICE)	92.76	90.71	94.18
B-wave (ICE)	93.83	91.93	94.50
WTI 1st (Nymex)	87.86	84.79	89.06
WTI 2nd (Nymex)	87.45	84.39	88.65
Oman 1st (DME)	93.36	90.99	94.20
Oman 2nd (DME)	90.60	88.34	91.46
Murban 1st (ICE)	95.10	93.21	95.48
Murban 2nd (ICE)	92.98	90.36	93.35
Forward Spreads			
Brent (1st-Dtd.)	+$0.66	+$1.52	-$1.37
Brent (2nd-1st)	-1.00	-1.00	-0.70
WTI (2nd-1st)	-0.41	-0.40	-0.41
WTI (3rd-2nd)	-0.63	-0.52	-0.38
Oman (2nd-1st)	-2.76	-2.65	-2.74
Oman (3rd-2nd)	-2.80	-2.05	-1.84
Murban (2nd-1st)	-2.12	-2.85	-2.13
Murban (3rd-2nd)	-2.26	-1.88	-1.53
Grade Differentials			
WTI-Brent (1st)	-$6.31	-$6.31	-$6.23
WTI-LLS	-2.35	-2.36	-2.34
WTI-Mars	+0.62	+0.92	+2.24
Brent(Dtd)-Dubai	-0.07	-2.04	+3.43
Brent(Dtd.)-Urals	+23.72	+23.15	+26.92
Brent(Dtd.)-Bonny Lt.	-2.71	-3.65	-5.58
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$95.21	$91.97	$96.70
Arab Lt.-Europe (Med)	98.53	96.63	99.60
Arab Lt.-Far East (f.o.b.)	104.67	103.57	104.20
Nigeria Bonny Lt.	99.01	96.10	102.71
Arab Light Gross Product Worth			
Rotterdam	$98.47	$99.44	$106.67
US Gulf Coast	102.63	101.86	109.07
Singapore	97.27	98.97	100.92
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$110.40	$111.56	$106.62
UK Brent Margin	+15.46	+19.89	+8.47
US Gulf Coast			
Mars GPW	97.11	96.20	104.09
Mars Margin	+9.43	+11.76	+14.41
Singapore			
Oman GPW	96.75	98.61	99.15
Oman Margin	-0.89	+2.39	+1.16
US Nymex			
WTI 3-2-1 Crack	+$30.78	+$31.71	+$44.07
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$832.27	$817.92	$926.82
Gasoil (0.1%)	1046.08	1081.35	1072.05
Fuel Oil (0.5%)*	652.00	633.25	678.75
US Gulf Coast (¢/gal)			
RBOB Gasoline	243.92¢	231.42¢	274.95¢
ULS Diesel	345.76	351.84	350.89
Fuel Oil (0.5%, $/ton)	$687.67	$685.20	$719.60
Singapore ($/bbl)			
Naphtha	$71.80	$70.48	$72.55
Gasoil (0.05%)	130.42	133.68	131.20
Fuel Oil (0.5%, $/ton)	700.67	687.60	749.40

*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.