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Japan, Korea Try to Balance Price Cap and Security

As G7 members finalize plans to cap the price of Russian crude, Japan and South Korea are increasingly having to grapple with how strictly to comply with the cap and its associated restrictions on shipping, insurance and other services. While refiners in both countries can easily find substitutes for the relatively small Russian volumes they have historically imported, political considerations could be more significant as both countries are keenly focused on energy security and maintaining some diversity in suppliers. Japan is a member of the G7 and officially supports imposing a price cap on Russian crude. The country can easily amend its regulations to enact the cap, a diplomatic source told Energy Intelligence. But it has also secured an exemption to the cap for volumes from the Sakhalin 2 project where Japanese companies hold an equity stake through at least September next year, according to the latest price cap regulations published by the US. "Japan will not explicitly oppose the price cap sanction among G7, but also will not proactively support the idea," said a Tokyo-based analyst. Hanging over the Japanese government's price cap strategy is the threat by Russia's former Prime Minister Dmitry Medvedev to kick out Japan from its equity interests in Russia's Far East and cut off supplies if it follows the cap. The Japanese consortium Sodeco, retained its 30% stake in Russia's Sakhalin-1 producing venture, with approval from Moscow earlier this month. South Korea is not a G7 member but is a close US ally. South Korean Finance Minister Choo Kyung-ho said in July that the government was willing to back a US-led price cap. But Georgy Zinoviev, head of the Russian foreign ministry's First Asia Department, threatened "serious" economic consequences in September if Korea

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How Fast Can Abu Dhabi Expand Capacity?

Abu Dhabi's ambition to boost its oil production capacity to 5 million barrels per day is well known. But how feasible are plans to move the original 2030 deadline forward by three to five years — and where will the additional capacity actually come from? These are important questions for a global oil market with thin spare capacity. Abu Dhabi National Oil Co. (Adnoc) has officially retained 2030 as the target date for attaining 5 million b/d of capacity but is understood to have brought forward its internal deadline to 2027. Energy Intelligence understands that the idea of moving the target date further forward — to as early as 2025 — was floated by the company's Accelerate 100X unit, which was set up in July to speed up internal decision-making in the face of a rapidly changing global energy landscape. The capacity expansion plans could be fast-tracked and potentially be implemented by 2025 — but this would require large additional investments, a source close to the matter says. "It's feasible but very optimistic because it's a massive investment," the source tells Energy Intelligence. Adnoc has moved swiftly to boost its upstream capacity in recent years. Energy Intelligence estimates that oil production capacity in Abu Dhabi presently stands at nearly 4.3 million b/d, helped in parts by Exxon Mobil completing works to boost capacity at the giant Upper Zakum offshore field to 1 million b/d in late 2021, some three years ahead of schedule.

Where the additional capacity to reach 5 million b/d will come from — whether by 2025 or 2027 — is not entirely clear, however. Adnoc has been making progress on capacity expansions both onshore and offshore in recent years, and has exploration underway in numerous blocks

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awarded in two upstream licensing rounds since 2018. Of the present output capacity, more than 2.2 million b/d are estimated to be available offshore, while roughly 2 million b/d are understood to be available onshore. Several industry sources close to Abu Dhabi's upstream say they are not aware of where exactly additional output will come from. Whether exploration blocks feature in the expansion plans — and if so to what extent — is one of the open questions. Some sources argue this is unlikely because exploration success is not guaranteed.

One project with the potential to add significant capacity in the coming years could be a further expansion of Upper Zakum, Abu Dhabi's largest producing oil field and one of the largest offshore fields in the world. Exxon and Japan's Inpex, which partner with Adnoc in the concession, are discussing a major expansion that might go well beyond the field's existing production capacity, potentially doubling it to 2 million b/d by the early 2030s. However, whether and how much capacity will eventually be added has not been decided. The potential expansion plan is still in the early stages and will depend on the concession stakeholders coming to an agreement on key issues, notably fiscal terms, which are presently under discussion, several sources say. Other capacity additions will, in coming years, be achieved at offshore fields including Satah al-Ras Boot (Sarb)/Umm Lulu and Lower Zakum, and at the onshore Bab, Bu Hasa and Asab fields, among others. More details about Adnoc's expansion plans may emerge in late November when its board meets to approve the next five-year plan for 2023-27, industry sources say. The board late last year approved plans to raise capital spending for 2022-26 to $127 billion from $122 billion for 2021-25 as Adnoc progressed — and accelerated — plans to boost oil, gas and downstream developments, and position the company for the energy transition.

The strategy to build out capacity supports Abu Dhabi's plans to position itself as one of the world's largest low-cost, low-carbon producers, giving it a competitive advantage over its rivals, even in a world that's moving away from fossil fuels in coming decades. For the United Arab Emirates' largest emirate, it is also a way of accelerating the monetization of its large hydrocarbon reserves as the world's inevitable shift towards decarbonization continues. Mideast Gulf Opec-plus officials have regularly warned of the market dangers of thin global spare capacity and chronic underinvestment in new oil supply. The UAE and Saudi Arabia have led the effort to add capacity within the group. Adnoc's acceleration of upstream developments fits into the UAE's larger strategy aimed at implementing wide-ranging economic diversification and energy transition initiatives.

Oil Prices Jumpy But Rangebound as EU Ban Looms

The oil price is showing no signs that oil supplies to the market are about to collapse with the Dec. 5 EU deadline on Russian crude imports less than two weeks away. Brent is volatile and jumping several dollars per day but stays within the established $88-$100 range. Traders say the volatility is a sign of tension and uncertainty. But they caution that the relatively stable range also reflects that actually not much is known about Russian flows in the coming weeks since the shipping fleet is going silent about its activities. Traders work on the assumption that Russia wants to continue selling its crude since it is crucial for the country's finances. One trader notes that Russia "has found ways to minimize the impact" of the EU ban and will continue selling large volumes to Asia instead of Europe using steep discounts and non-Western tankers. Another EU ruling bans any tanker of carrying Russian oil if it has any ties to EU firms, like insurance. A G7 price cap scheme is designed to soften that rule and allow these tankers to be used if Russian oil is bought at or below a low price to be set by the G7. Russia is rejecting that price cap and a "dark fleet" of non-Western tankers is set to shuttle its crude to market. But this fleet, with sovereign insurance and financing from Russia and China, is not reporting its future movements. The trade assumes that the bulk of Russian crude can continue flowing on these tankers.

EU countries have scaled down buying Russian crude ahead of the bans' deadline, shipping data signal for the first three weeks of November. After accounting for countries with exemptions, EU nations were taking in some 700,000 barrels per day of Russian crude, 400,000 b/d less than

October. Replacements for these Urals are lined up, with EU refiners buying more crude from the North Sea, Mideast, US and West Africa. These trading patterns were established early on after Russia invaded Ukraine in February and traders and majors cut back up to 1 million b/d of spot Urals buying under public pressure. Crude price differentials have established new ranges after some dramatic shifts, and they have held, signaling that new flows have been worked out. If the market would be stressed about replacing Urals, prices of other grades would have gone wild versus benchmark dated Brent. Total Russian crude exports are around 4.85 million b/d in November, up 200,000 b/d from October. The EU November intake of Russian crude is 1.3 million b/d lower than average 2021. Russia now sells more to India, China and Turkey. The question is whether Asia can absorb all crude Moscow will have available after the ban. Energy Intelligence assumes that much of that cannot be absorbed and that Russian crude production will fall from its current 9.7 million b/d.

The second EU ban, on Russian refined product imports starting Feb. 5, might not run as smoothly. It is harder for Russia to find new buyers for products, and harder to get products to these new clients since there are insufficient non-Western tankers. Russia is a key exporter of diesel, fuel oil and naphtha. Global product prices are expected to get a jolt if these exports would fall hard. Russia now exports 1.9 million b/d from western ports, of which EU countries took 1.2 million b/d in November, of which 640,000 b/d was diesel, 400,000 b/d fuel oil and 100,000 b/d gasoline and naphtha. The market still has three months to figure out how to keep this oil flowing. Energy Intelligence expects these flows to fall by some 600,000 b/d. Even though the ban starts after peak winter diesel demand, the market is already short diesel and can ill-afford to lose any Russian exports.

Not to be surprised, speculators are positioned for the eventuality that all assumptions are wrong and supplies eventually do collapse. They have assembled historically high bets on Brent passing $149/bbl by April and US West Texas Intermediate breaching $120 by May. One analyst calls that "a cheap war call," as these are call options on crude oil futures.

Politicians Fret as US Northeast Faces Pricey Winter

Consumers in the Northeast of the US could find themselves competing on the international markets for fuel to heat their homes this winter. A lack of infrastructure connecting New England to the rest of the country and minefield of legacy US energy policies leave the region's energy situation looking more like that of European countries than US states. Just two pipelines totaling 3.1 billion cubic feet per day of capacity feed the region and it has little gas storage, according to the nonprofit Energy Policy Research Foundation. That means power companies must turn to the global LNG market when gas use spikes, especially in cold winter months (see table). The Energy Information Administration is projecting residential retail prices of $21.70 per thousand cubic feet in the first quarter of 2023, about 50% higher than the national average. The lack of gas also has left the area heavily reliant on home heating oil. But inventories for distillate fuel oils are significantly lower than in years past and two refineries feeding the region facing extended maintenance. Officials want to avoid a winter with soaring heating prices or, worse, one where customers struggle to find oil to fill up heating tanks.

The Biden administration for months has warned about low inventories for fossil fuels and is eyeing its options to address the issue. It so far has declined to take the step most vocally opposed by industry — to restrict products exports — but officials have repeatedly said all options are on the table. This could include requiring private companies to keep more inventories on hand in the US. Such a move would limit exports at a time when refiners have been incentivized to sell into high-priced overseas markets but would have a muted impact compared to an outright ban on selling abroad. US Energy Secretary Jennifer Granholm said in an interview last week that more legislation might be needed to allow the administration to require private inventory minimums. However, analysts at ClearView Energy Partners posit that the International Emergency Economic Powers Act gives the administration authority to move ahead. Congress also is considering expanding the home heating oil reserve and the US Department of Energy (DOE) seems to be giving itself an opening for storing liquid fuels in the Strategic Petroleum Reserve by signing off on new language this year allowing for the storage of "petroleum products" rather than simply petroleum. But even successful legislation or a commitment from the DOE to begin storing products won't give price relief this winter.

Analysts regularly point to the Jones Act — which restricts

US LNG Imports

('000 tons)	2017	2018	2019	2020	2021	2022
Jan	272.0	349.4	304.1	277.6	133.9	134.0
Feb	178.0	142.2	158.7	119.5	119.4	93.4
Mar	102.4	135.9	73.5	60.0	29.5	54.6
Apr	108.6	65.7	59.7	67.5	—	—
May	115.4	55.7	0.2	59.0	34.9	10.1
Jun	118.4	61.0	0.1	102.3	—	—
Jul	109.0	117.6	59.5	85.6	36.0	57.5
Aug	165.1	114.9	60.6	60.4	—	60.1
Sep	55.7	66.3	—	25.9	25.6	—
Oct	51.6	127.6	116.2	—	—	—
Nov	133.9	58.9	58.4	59.7	36.3	—
Dec	228.1	310.2	220.0	115.1	34.2	—

Source: Energy Intelligence, US Energy Information Administration

shipping options between US ports to protect the domestic maritime industry — as a culprit for higher fuel costs in the Northeast. But apart from one-off exemptions to the law, there is little the Biden administration can do to ease the process of shipping supplies from oil- and gas-rich areas of the country to consuming ones. The Jones Act requires vessels traveling between US ports be US-built, manned and crewed. But the US does not manufacture LNG tankers — which means Northeast consumers rely on international imports in colder months of January and February (see table). For oil trade, Jones Act restrictions mean it's cheaper to ship products to Europe than other places in the US. The Biden administration has repeatedly said it's willing to consider Jones Act waivers to help with energy security. But Congress tightened Jones Act restrictions in 2021, specifically tying blanket waivers to military readiness, says the Cato Institute's Colin Grabow. In August, Granholm told governors of Northeast states in a letter that the White House cannot issue a blanket waiver to facilitate seaborne energy trade in the US. Grabow suggests congressional fixes like a time-limited exception to get through this winter, for example, or a carve-out for LNG vessels since they are not manufactured in the US. "The administration can't issue a blanket waiver, but Congress can do whatever it wants," he said.

Japan, Korea Try to Balance Price Cap and Security

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joined the G7 price cap plan, according to local media.

Japanese refiners voluntarily stopped importing Russian crude in June. Korean refiners have cut back but continue to buy some volumes. The importance of the volumes to overall Russian crude exports and the refiners themselves are small. While the two countries are among the world's largest crude importers, the volumes of Russian crude they bought were low to begin with and are easily replaceable, sources tell Energy Intelligence. Korea and Japan imported a combined 119,000 barrels per day of Russian crude in the first nine months of this year, split between 71,000 b/d for Korea and 47,000 b/d for Japan. The total is down 106,000 b/d from a year ago. But the average is propped up by heavier buying pre-invasion. Japanese refiners have backed away from buying spot Russian crude after the invasion of Ukraine and no Russian imports have arrived at Japanese ports from June onward. Korean buying also plummeted in the wake of the invasion. Korean imports of Russian crude ranged from 96,000 b/d to 169,000 b/d in the first four months of this year. But from May onward, those monthly volumes dropped to levels ranging from zero to a high of 33,000 b/d.

The key question is whether the Korean government might push refiners to completely stop Russian purchases or if the price cap makes it so problematic that refiners stop on their own. If Russian sellers or traders acting as middlemen offer volumes on a delivered basis, then Korean refiners could be able to continue buying, said two Northeast Asian refiner sources. Korean buyers have mainly been buying Russian light, sweet Sokol crude when they do touch Russian volumes, three trading sources told Energy Intelligence. Sokol replacement crudes are easily available, they added. Potential candidates include Abu Dhabi light, sour Murban, other Emirati light sours, Saudi light, sour Arab Extra Light, US grades and Latin American crudes, market sources said. And given that Korean refineries are generally "extremely sophisticated," they wouldn't even need a like-for-like replacement, said an Asian refining source. The economics of a replacement crude rather than how close its quality is to Sokol are likely to be a more important consideration, he added.

COP27: Industry Scores Wins But Pressure Builds

UN COP27 climate negotiations concluded with what can best be described as a mixed win for oil and gas producers. A proposal to extend an existing commitment to phase down coal use to all fossil fuels was resisted by large oil and gas producers. They also succeeded in adding "low-emission" energy as a pathway for curbing greenhouse gases alongside renewables in the final deal — which could create more space for lower-carbon oil and gas. Near term, this was an obvious win for the industry. But advocates of stronger climate action are already looking to COP28 in the United Arab Emirates to push a stronger line against fossil fuels, with next year's "stocktake" of progress toward Paris Agreement goals likely to intensify that pressure. The energy crisis and focus on energy security may have taken some pressure off oil and gas producers this year, but consuming nations seem to be sticking to their positions in the longer term.

In side events outside the formal COP process, policymakers and companies showed a commitment to accelerating key transition technologies. Hydrogen, in particular, which many oil and gas companies are looking to advance, saw broader acceptance despite some remaining skepticism about its role in the future energy mix. Global hydrogen trade is possible on a "mass scale" and is entering a "new era," Andrea Lovato, the director of global hydrogen at Saudi-based Acwa Power — operator of the world's largest commercial-scale green hydrogen project — told Energy Intelligence at COP27. Multiple hydrogen deals were announced there, including an alliance between the EU and Egypt. Countries including Chile, Namibia, Oman, Saudi Arabia and Australia unveiled new hydrogen strategies and projects.

Some developing countries, particularly in Africa, sought to cement the role of gas in helping to transition and grow their economies. However, that bridge may be shorter than before and less certain, as supply security and price volatility concerns add to existing methane emission concerns. One message from the conference was that industry will need to take strong action on methane emissions if gas is to play a lasting role, including as a feedstock to produce hydrogen. More countries joined the Global Methane Pledge launched last year in Glasgow. A total of 150 have now signed up, with the US and Canada also unveiling new plans at COP27 to slash oil sector emissions. Other announcements came from Egypt and, more loosely, a group of the US, EU, Japan, Canada, Norway, Singapore and the UK. A new UN-sponsored methane satellite system means countries and companies will be held to account on those pledges.

Carbon offsetting, which many oil and gas companies are using to help meet emissions reduction targets, gained some credibility. The US-led Energy Transition Accelerator aims to unleash private-sector funds for developing countries in exchange for offsets. The new Africa Carbon Markets Initiative hopes expand the continent's role in the carbon credit sector. Both emphasize the importance of delivering high quality credits, although details of the US plan have yet to be fleshed out. If realized, such initiatives could help to overcome some of the current objections to carbon offsetting. But even if offsets can be shown to deliver genuine emissions cuts, the clear message from COP27 was that companies buying these should not use them as a substitute for making real emissions reductions. Negotiators also made advances ironing out some additional details on Article 6 of the Paris Agreement, which allows for cooperative, cross-border activities to meet promised emissions reductions. International Emissions Trading Association head Dirk Forrister said the changes "provide key elements to implement high-integrity carbon markets." Carbon market advocates have long hoped development of such policies will lead to broader, internationally linked carbon markets.

IRA Boosting Energy Projects But Challenges Remain

The Inflation Reduction Act (IRA) is already making the US more attractive for investments in the energy transition space but the incentives from the IRA alone are not enough to drive continued investment. Carbon capture and sequestration developers, who benefit from an increased tax incentive, are seeing an uptick in interest following passage of the legislation which pledges $369 billion in clean energy spending. Operators' outlooks for other energy transition fuels, such as hydrogen, have also brightened since the IRA's passage. Shell USA President Gretchen Watkins called the landmark legislation a "big step forward" for investment in renewables and low-carbon fuels. "We now see a much longer investment horizon that allows, I think, disciplined capital investment to happen over time," she said at a recent Federal Reserve event in Houston. "So I believe that we're going to see this country is going to have more opportunities to have, frankly, more energy at its disposal and, over time, move toward a lower and low-carbon future."

Industry players have identified permitting reform as the next big regulatory hurdles. Oil and gas players have long lobbied for permitting reform for fossil fuel projects. Now clean energy advocates are also stressing the need to streamline processes to bring new forms of energy online. But the chances of permitting reform passing Congress this legislative session are slimmer now than a month ago. Democrats recently introduced their own, more narrow, electricity-focused permitting reform legislation, exacerbating partisan discord on the issue. "I think the industry is funded enough and ready to go, it doesn't need government money to go kickstart it," Richard Voorberg, North America president for Siemens Energy, said on the sidelines of the Reuters Energy Transition North America conference in Houston earlier this month. "What it needs is permits and everything out of the way to make it happen." Permitting issues are cited as slowing down development across sectors. Watkins pointed to problems getting permits to develop offshore wind as well as deepwater Gulf of Mexico wells.

The question of large-scale hydrogen transportation itself is a huge unknown, though pipeline operators and shippers see potential in pipelines and ammonia conversion. But those efforts will take time and money to succeed. In North America, pipeline operators such as TC Energy and Williams are exploring blending small amounts of hydrogen into the natural gas stream. But blending too much hydrogen can cause pipelines to become brittle and increase the risk of leaks. Meanwhile, pure hydrogen pipelines would be costly and take more time to develop. On the shipping side, Chevron sees the potential for a global hydrogen trade. That would involve converting at least some hydrogen to ammonia, shipping it, and then converting it back when it reaches its destination. But that process is complicated and expensive.

The giant cost, size and expertise requirements of many projects will require collaboration to move forward, even among the largest energy players. This may seem an obvious point, and many partnerships centered on energy transition developments have already been announced. Energy executives stressed that sharing financial and operational resources and risks as well as technology is as vital for the success of low carbon projects as it is for traditional oil and gas developments. "We will not try to do everything nor should we," Chevron New Energies Vice President of Hydrogen Austin Knight said at an event in Houston. "It's about getting the folks in [the] room together to line up that value chain in a way where we're each bringing our strengths."

Kazakh NOC Hopes IPO Opens Doors

Kazakhstan's national oil company, Kazmunaigas (KMG), is in the process of selling around 5% of its shares on the domestic market in a long-awaited initial public offering (IPO). Although the IPO, which will run until early December, is limited in its size and will prioritize Kazakh over foreign investors, it marks a milestone in KMG's corporate history and could be followed up by a larger global offering next year if market conditions are deemed favorable. All the shares will be sold on the Astana and Almaty exchanges by Kazakh sovereign wealth fund Samruk Kazyna, which owns around 90% of KMG, with the remaining 10% held by the Central Bank. The IPO was supposed to happen several years ago but suffered repeated delays due to a combination of Covid-19 and jitters on financial markets. It is part of a wider government program to privatize the largest state companies, which includes gas transmission and marketing company Qazaqgas (formerly Kaztransgas) that was spun off from KMG last year and is now a fully owned subsidiary of Samruk-Kazyna. The first big state company to go for an IPO was uranium producer Kazatomprom, which raised around $3 billion when it sold 15% of its shares in late 2018.

Like national oil companies (NOCs) from around the world, KMG has seen its balance sheet boosted by the rise in oil and gas prices over the past two years. During the first half of this year, its earnings before interest, tax, depreciation and amortization increased some 49% to $2.5 billion, while net profits rose 5% to $1.5 billion. The company has used some of its extra revenues to whittle down its net debt to less than $5 billion — partly by making early repayment of multibillion-dollar oil-backed loans provided by Swiss trading giant Vitol. KMG produces around 440,000 barrels per day of crude and condensate in Kazakhstan, roughly 25% of the country's overall output, and around 8 billion cubic meters of mostly associated gas. Its most valuable single asset is its 20% stake in the Chevron-led Tengizchevroil (TCO) joint venture, which, under an ongoing $45 billion expansion due for completion in 2024, will increase crude output by some 25% to around 850,000 b/d. KMG also owns a 10% stake in Kazakhstan's largest gas producer, the Eni-Shell-operated Karachaganak field, and 16.88% of the North Caspian Operating Co. (NCOC), the international consortium that oversees the giant offshore Kashagan oil development. In September, KMG bought back for $3.8 billion the 8.44% stake in NCOC that it had sold to Samruk Kazyna in 2014.

One of KMG's main priorities for the medium to long term is to step up oil and gas exploration, and to get new projects in the Caspian Sea off the ground. The company has joint ventures with Eni and Russia's Lukoil to develop offshore blocks, but progress has so far been slow due to the high capital costs involved. KMG also hopes to stabilize output at its two largest onshore fields, Uzen and Emba, which have both been in production for more than 50 years and are in steady decline. The company is also keen to boost its refining capacity — it owns three refineries in Kazakhstan with a combined capacity of around 300,000 b/d and has a major shareholding in a plant in Romania — and branch out into petrochemicals. Renewables are now a bigger focus, too. KMG has entered alliances with Shell, TotalEnergies, Eni and others to pursue joint opportunities in carbon capture and storage, green hydrogen and other low-carbon ventures. Eni, via its local affiliate Armwind, is involved in several wind power projects in Kazakhstan, while the Total-affiliated Total Eren is pursuing solar projects in the country.

One area where KMG has scored highly, compared to some other NOCs, is in its corporate governance. For years the company has had several Western executives on its board of directors; its chairman is Australian business veteran, Christopher Walton, while Tim Miller, a former Chevron executive who spent several years as head of TCO, is on the board. Ithaca Energy's difficult start post-IPO suggests oil flotations could be a difficult sell, although markets for oil shares could be tougher in a Western Europe than in resource-focused Kazakhstan.

What's New Around the World

GENERAL

CORPORATE — Saudi Aramco said it will invest $7 billion to build a steam cracker in South Korea that will mark the first commercial use of the company's crude-to-chemicals technology. The cracker will be integrated with the existing S-Oil refinery in Ulsan, South Korea, which is 63% owned by Aramco and has a capacity of 650,000 b/d. The so-called Shaheen project will make petrochemical feedstock and be capable of producing 3.2 million tons/yr of petrochemicals, including high-value polymers. The cracker will convert crude oil into petrochemical feedstock utilizing the TC2C crude-to-chemicals technology developed by Aramco and Lummus. The Saudi oil giant said this will nearly double S-Oil's chemical yield to 25% once the cracker comes on line and reduce capital spending and operating costs by 30%-40% compared with conventional processes. Engineering, procurement and construction work on the project is expected to start in 2023, with mechanical completion due in the first half of 2026.

CORPORATE — Diamondback Energy said it would acquire the Permian Basin assets of privately owned Lario Oil & Gas for $1.5 billion. Diamondback will pay $850 million in cash and 4.18 million shares of its common stock for the assets, which cover 15,000 net acres in Martin County in the northern portion of the Midland subbasin. News of the deal comes one month after Diamondback announced it would acquire privately held Firebird Energy in a cash-and-stock deal valued at $1.6 billion. Diamondback plans to run a single drilling rig next year in the asset, dropping from the two-rig program that Lario is currently operating. The main targets for drilling are the Middle Spraberry, Jo Mill, Lower Spraberry, Wolfcamp A and Wolfcamp B formations, according to Diamondback. The assets are expected produce about 25,000 boe/d — including 18,000 b/d — in 2023.

CORPORATE — Idemitsu Kosan could cut its refining capacity by 300,000 b/d by the end of this decade. Under its business plan for the next three fiscal years, Japan's second-largest refiner said it will adjust its refining capacity to bring it into line with Japanese demand for petroleum products, which is expected to fall 20% from current levels by 2030. Idemitsu had previously announced plans to acquire complete ownership of its Seibu Oil affiliate and close down its 120,000 b/d Yamaguchi refinery by March 2024. The company said it is considering a further reduction of 180,000 b/d in its refining capacity which would reduce its total capacity to 650,000 b/d by 2030. Idemitsu is targeting a 46% reduction in its Scope 1 and 2 carbon emissions by 2030 (versus a base year of 2013) as an interim step toward carbon neutrality by 2050. To achieve the goal, the company also plans to invest 190 billion yen ($1 billion) for sustainable aviation fuels and ammonia production facilities in Japan and an expansion of wood pellet production overseas.

COUNTRIES

CHINA — China's total crude imports from all countries rose by 367,000 b/d versus September to 10.2 million b/d in October — their highest level in five months. September crude runs surged by 1.2 million b/d from August and held more or less steady in October, dipping by just 20,000 b/d to 13.86 million b/d. However, November crude flows into the country appear to be outpacing refineries' demand for feedstock, with more crude flowing into inventories than has been withdrawn from stocks for processing. China landed 1.82 million b/d of Russian crude in October, up just 1,000 b/d from September. But compared to October 2021, imports spiked by 253,000 b/d. Over the first 10 months of this year China imported an average of 1.74 million b/d of Russian crude, which was 151,000 b/d higher than in the same period of last year. Chinese imports of crude from the UAE also surged by 569,000 b/d from September's unusually low volumes to hit 997,000 b/d in October — their highest level since November 2021. China imported an average of 790,000 b/d of UAE crude in the first 10 months of this year, an increase of 217,000 b/d versus the same period of last year.

OMAN — Hydrogen Oman (Hydrom) is gearing up to auction and award up to six blocks of land by the end of 2023 for development of up to 1 million tons/yr of green hydrogen capacity by the end of the decade. Under Phase A of Oman's hydrogen development plans, up to six blocks will be offered in two bid rounds, says Hydrom's acting managing director Firas al-Abduwani. In the first round, two blocks in the Duqm area of central eastern Oman will be awarded by the end of the first quarter of 2023, he says. Under an accelerated timeline, documents for companies seeking to qualify for the auction were released this month, with request for proposal documents following in December. Bids are due to be submitted in January. The second round — for another two to four blocks in the Dhofar region of southern Oman — will be launched in April of next year, with bids due in October and awards expected by the end of 2023. Oman hopes to attract $140 billion of investment for the development of a green hydrogen industry.

QATAR — QatarEnergy has entered a 27-year LNG supply deal with China's Sinopec, marking the longest gas supply agreement in the industry's history. Under the sale and purchase agreement (SPA), Qatar will supply China with 4 million tons/yr of LNG from its North Field East (NFE) expansion project. The volumes will be delivered to Sinopec's receiving terminals in China. Qatar's LNG exports to China have hit 13.6 million tons in 2022, already shattering the previous high of 9.6 million tons in 2021, according to data from analytics firm Kpler. The agreement with Sinopec is the first supply deal announced for NFE after QatarEnergy finalized equity partnerships for both phases of its giant LNG expansion — NFE and North Field South (NFS). Qatar has signed a number of supply deals with China including an agreement with Sinopec in March last year. The earlier SPA is for 2 million tons/yr of LNG over 10 years, starting this year — a substantial increase from what Sinopec had sought in an initial tender in 2020 in which it had invited sellers to compete for a 10-year, 1 million ton/yr LNG contract.

UNITED KINGDOM — The UK government has increased the windfall profits tax for North Sea oil and gas producers and extended it to low-carbon electricity generation companies as it seeks to close a gaping hole in public finances. UK Chancellor Jeremy Hunt raised the North Sea Energy Profits Levy by 10 percentage points to 35% from Jan. 1, 2023, and extended it until the end of March 2028. That lifts the marginal tax rate on the sector to 75%. The original windfall tax legislation included a sunset clause that would have ended the levy by 2025. The investment allowance for spending on new oil and gas extraction will be cut to 29%, while decarbonization expenditure will continue to qualify for the current allowance rate of 80%. Also as anticipated, the government imposed a temporary 45% levy from Jan. 1 on "extraordinary" profits reaped from low-carbon electricity generation. The levy will apply to revenue from power generation at an average price above £75/MWh. It will also be limited to companies that generate over 100 GWh and will only apply to extraordinary profits exceeding £10 million ($12 million). Hunt said these measures would raise a combined £14 billion in the next fiscal year.

Marketview

Plentiful Supply

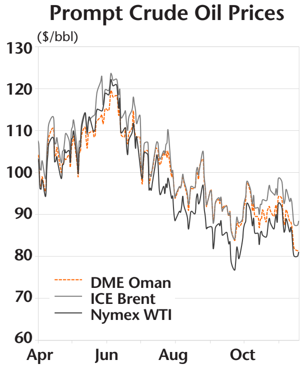
Never mind the war in Ukraine, the looming EU embargo on Russian crude, or threats from Moscow to cease sales to any country adhering to the G7-mandated price cap. Over the course of a week, the nagging supply fears that have spooked oil markets for most of the year have suddenly dissipated, and the sentiment — right now at least — is that there is sufficient supply through the winter, and beyond.

Or so say oil futures. After months of an extremely backwardated price curve — meaning buyers must pay a premium for prompt oil — spreads between front contracts have deflated so that the curve for Brent is now at its flattest in more than a year. The spread between the January and June contracts in 2023 touched a low of $1.17 on Nov. 21, which compares to the $7-$8 range seen in October and $10-$14 during the summer.

West Texas Intermediate has even flipped into contango, or a price curve showing prompt oil is cheaper than future barrels. On Nov. 23, the January contract for the leading US benchmark was around 10c cheaper than the February contract, which in turn was priced at around the same level as the March contract.

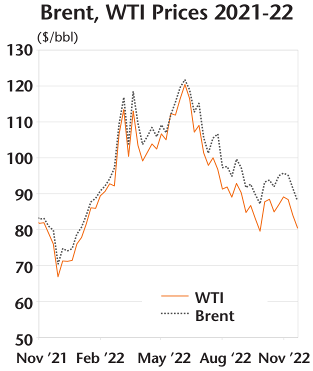
This is telling potential buyers that it makes sense to hang on to barrels rather than sell — the polar opposite of the situation in recent months, particularly since Russia invaded Ukraine in February. The six-month spread on WTI was an ultra-low 50c on the eve of Thanksgiving Day — a level last seen in January 2021 when the world was in the thick of the pandemic crisis and oil was in surplus.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

Brent, WTI Prices 2021-22



Source: CME, ICE

The paper market is shrugging off the upcoming EU embargo, potential fuel-switching, a diesel crunch, and conjecture that Opec-plus may agree to slash output yet again in December to keep Brent in the $90 range. Instead, traders are fixating on weak Chinese demand, a European economy many believe to be already in recession and a belief among many that the US will follow in 2023. With the world's three-largest centers of oil consumption hobbled, the bears are not about to hibernate.

None of this means that volatility has vanished — that salient feature of the current "war market" hasn't gone anywhere. At the start of the week, Brent traded in a $5.50 range, the widest in two-and-a-half months, on a report that Opec-plus might decide to cut production by some 500,000 b/d, which was denied later in the day by Opec ministers. Similar pitfalls are bound to materialize ahead. Any decision by Moscow to slash output in response to the price caps or an inability on the part of oil companies to export crude and products due to shipping constraints would both be game-changers for the market.

And there is always diesel, which remains in short supply. Though stocks in the US grew unexpectedly this week, the EIA said that diesel inventories in the US are 13% below the five-year average. The heating oil crack on Nymex, a measure of how much a refinery can make converting a barrel of crude into diesel, was around $60 this week, a golden incentive for refiners to keep buying crude and churning out middle distillates

India's Crude Imports Rise

India's crude oil imports rose 1.7% in October versus September as refiners cranked up crude runs to satisfy an increase in domestic demand as a result of the Hindu festival season and the end of seasonal monsoon rains, government data showed. The country's 23 refineries — with a combined nameplate capacity of 5.02 million b/d — imported 4.37 million b/d of crude in October versus 4.3 million b/d in September. October crude imports were also up 8.2% versus October of last year. Despite the increase in import volumes, India's import bill stayed flat in October at $12.8 billion, reflecting a dip in global crude oil prices and refiners' continuing purchases of deeply discounted crude from Russia.

PIW Market Indicators

($/barrel)	Nov 21-Nov 23	Nov 14-Nov 18	Oct 24-Oct 28
Spot Crude			
Opec Basket	$85.19	$91.10	$93.48
UK Brent (Dtd.)	88.64	92.00	93.36
US WTI (Cushing)	80.24	84.01	87.87
Nigeria Bonny Lt.	88.28	94.01	95.45
Dubai Fateh	81.68	87.46	91.20
US Mars	75.29	82.48	83.10
Russia Urals (NWE)	62.90	68.63	69.40
Crude Futures			
Brent 1st (ICE)	87.91	91.45	95.04
Brent 2nd (ICE)	87.40	90.44	93.11
WTI 1st (Nymex)	80.50	84.02	86.96
WTI 2nd (Nymex)	80.32	83.58	85.80
Oman 1st (DME)	81.72	85.99	90.60
Oman 2nd (DME)	81.39	85.12	89.40
Murban 1st (ICE)	86.74	90.06	94.16
Murban 2nd (ICE)	85.03	88.69	92.65
Forward Spreads			
Brent (1st-Dtd.)	-$0.73	-$0.54	+$1.68
Brent (2nd-1st)	-0.51	-1.01	-1.93
WTI (2nd-1st)	-0.18	-0.44	-1.15
WTI (3rd-2nd)	-0.22	-0.57	-1.31
Oman (2nd-1st)	-0.33	-0.87	-1.19
Oman (3rd-2nd)	-0.57	-0.82	-2.48
Murban (2nd-1st)	-1.72	-1.37	-1.51
Murban (3rd-2nd)	-0.46	-1.24	-2.32
Grade Differentials			
WTI-Brent (1st)	-$7.41	-$7.87	-$8.08
WTI-LLS	-5.05	-5.61	-2.29
WTI-Mars	+4.95	+1.53	+4.77
WTI Cushing-WTI Midland	-0.35	-0.90	-1.55
Brent(Dtd.)-Dubai	+6.96	+4.54	+2.16
Brent(Dtd.)-Urals	+25.75	+23.37	+23.96
Brent(Dtd.)-Bonny Lt.	+0.36	-2.01	-2.09
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$83.12	$90.31	$90.73
Arab Lt.-Europe (Med)	87.83	92.85	97.27
Arab Lt.-Far East (f.o.b.)	88.74	94.44	97.56
Nigeria Bonny Lt.	90.38	93.74	95.27
Arab Light Gross Product Worth			
Rotterdam	$91.29	$96.53	$107.87
US Gulf Coast	93.09	96.26	115.61
Singapore	89.88	94.60	93.36
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$101.43	$106.37	$112.59
UK Brent Margin	+9.09	+12.42	+17.90
US Gulf Coast			
Mars GPW	87.85	90.97	106.90
Mars Margin	+12.46	+8.39	+23.70
Singapore			
Oman GPW	88.07	93.43	92.86
Oman Margin	+2.37	+2.06	-0.62
US Nymex			
WTI 3-2-1 Crack	+$37.97	+$35.53	+$52.53
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$764.00	$837.26	$925.68
Gasoil (0.1%)	931.25	959.30	1124.25
Fuel Oil (0.5%)*	530.50	560.60	602.70
US Gulf Coast (¢/gal)			
RBOB Gasoline	222.92¢	225.51¢	278.79¢
ULS Diesel	316.37	328.07	422.44
Fuel Oil (0.5%, $/ton)	$585.00	$637.40	$664.00
Singapore ($/bbl)			
Naphtha	$77.29	$78.71	$74.69
Gasoil (0.05%)	121.53	129.00	133.79
Fuel Oil (0.5%, $/ton)	639.00	671.40	709.00

*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.