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Signs of Demand Destruction Emerge in US

As retail gasoline prices in the US breach the $5 per gallon level nationwide, concerns about demand destruction are growing. Market players from traders to refiners are virtually unanimous that achieving a balance and lowering prices will be a function of consumer behavior. In short, there is almost nothing that can be done to alleviate the high cost of gasoline from the supply perspective, much to the dismay of the Biden administration. The main question is not if demand destruction will take place, but when. While Russia's invasion of Ukraine and resulting sanctions catalyzed a jump in petroleum prices, the stage was already set for a painful summer. Inventories across the board are well below 2021 levels, US refiners have cut capacity by almost 1 million barrels per day since before the pandemic struck, and until recently ran at lower utilization as well — a function both of the energy transition and Covid-19's impacts on demand. The US downstream also sees more incentives to produce diesel than gasoline due to sanctions on Russia. Nymex diesel futures trade at a stunning 63¢ per gallon premium to gasoline, and Energy Intelligence's refining model shows diesel cracks against incremental medium, sour crude in a complex Gulf Coast facility outperform those for gasoline by over $4.

One school of thought is that there is so much pent-up demand that drivers in the world's largest economy will grit their teeth and bear high pump prices through the summer. After almost three years of living with varying degrees of pandemic protocols, consumers may be prepared to throw fiscal discipline — never a strong suit in the US to begin with — to the winds and follow through on planned vacations and road trips. In addition, many point out that while prices and inflation have increased, so too have savings. Government data show the rolling four-week average for US gasoline

(Please turn to p.4)

Total Gets Nod for Qatar's LNG Game Changer

Doha kicked off partner selection for the 32 million ton per year Phase 1 of its LNG expansion, awarding TotalEnergies a 6.25% stake in the $28.75 billion megaproject. Other awards are expected soon in the heated competition for one of the most attractive industry opportunities in years. The North Field East (NFE) project benefits from the same economies of scale, low-cost upstream gas and profitable associated liquids that made Qatar's first phase of LNG development so appealing. And for NFE, state-owned QatarEnergy is investing heavily in green technologies, such as carbon capture and solarization of facility utilities to produce what will be the lowest emissions LNG project on the planet, future proofing investment against the energy transition. Total's selection comes as no surprise given its recent track record in bidding big for major Mideast projects, such as the United Arab Emirates' onshore offering in 2015. The French major is a long-standing partner of QatarEnergy, and it will be keen to reinforce its comparatively weak regional gas presence — made weaker by the expiry of its Qatargas-1 stake late last year. But it will be NFE's environmental credentials that will be the real draw. Total is the major that has most clearly articulated low-emissions hydrocarbons as core to its future. It is pioneering large-scale solarization of oil and gas projects, both in Iraq and in Qatar's Ras Laffan. NFE's low emissions were perhaps the key inducement for Total to sign a contract for a relatively lengthy 27 years.

The Ukraine war looks to be reshaping the LNG industry, with the EU aggressively seeking supply as it seeks to wean itself off Russian gas. This further boosts the attractions of NFE, but other

projects are benefitting too. Berlin recently announced some €3 billion ($3 billion) of support for floating storage and regasification units. Canada last month announced it was studying how to revive up to five long-stalled Atlantic Coast LNG projects. The EU, Egypt and Israel this week signed a memorandum of understanding targeting East Mediterranean LNG sales to Europe, while Shell, Equinor and Tanzania's government signed a framework deal for a much-delayed project that could see some 10 million ton/yr flow by the end of the decade. But translating investment rationale into concrete projects will be challenging. For starters, quantifying the LNG opportunity created by Europe's decision to fast-track its exit from Russian supply is no easy task. "There is a scramble now to replace Russian gas, but how durable is that going to be?" notes Ian Nathan of Energy Intelligence's Research & Advisory unit. The simultaneous push to "accelerate renewables penetration" means Europe is sending mixed messages "regarding ultimate longer-term gas needs," he warns. But NFE is well insulated from this demand uncertainty, not just by virtue of its low-cost and environmental credentials, but also by the fact Doha's location enables it equally to service both eastern and western markets.

Amid all the focus on NFE's impact on the LNG industry and the regional investment profiles of selected partners, it is easy to overlook its transformative influence on QatarEnergy itself. The firm has leveraged the expansion to establish itself as a major international portfolio player. It has invested in regasification and storage capacity in the UK and France, massively expanded its LNG tanker fleet and joined with Exxon Mobil in the 16 million ton/yr Golden Pass LNG project in the US. Perhaps most significantly, QatarEnergy has managed to build an international upstream empire spanning over 70 blocks by partnering, albeit as a minority equity holder, with short-listed firms for NFE. While some in the industry initially dismissed Doha's upstream ambitions as a vanity project, they have been proven wrong. QatarEnergy now holds stakes in Shell's highly prospective Namibia acreage, Total and Petrobras' Santos Basin blocks, where output is set to double to 350,000 barrels per day, and in promising blocks in South Africa, Surinam, East Coast Canada, and Cyprus. Of the short-listed firms — Exxon, Total, Shell, ConocoPhillips, Eni and Chevron — only ConocoPhillips has failed to partner with QatarEnergy internationally. Reuters reports that all these firms, except for Chevron, will be awarded stakes in the coming weeks. And QatarEnergy is likely to add certain key Asian customers to its NFE equity mix. Selection for NFE should confer advantages in the bidding process for the 16 million ton/yr Phase 2 of the expansion, North Field South.

Kazakh Output Capacity Set for Small Increase

With oil markets facing a supply crunch, it doesn't look like Kazahkstan can do much to help the situation. The Opec-plus producer will see its production capacity — crude and condensate — grow by about 200,000 barrels per day to roughly 2.2 million b/d with the expansion of the Chevron-operated Tengiz field, which is due for completion in mid-2024. But elsewhere in Kazakhstan, the picture is gloomy. The expansion of Tengiz will take the field's output to around 850,000 b/d. There will also be some small increments at another huge project, Kashagan, where production is due to rise from 400,000 b/d to 500,000 b/d by 2025 through increased gas reinjection and the debottlenecking of existing facilities on and offshore. But further capacity expansion currently looks difficult to achieve. A third world-class development, Karachaganak, will hold its current levels of around 250,000 b/d for the next few years, but more gas will be needed to be reinjected to keep output stable. In Kazakhstan's oil heartland in the West, fields such as Uzen and Emba, operated by state oil company Kazmunaigas (KMG), have been in production for more than 50 years and face inevitable declines that could be rapid. This is what happened at the Kumkol field in the southeast, where output has plummeted over the past decade.

One of Kazakhstan's short-term worries is about the impact that Western sanctions against Russia will have on its oil production, given that most of its exports of around 1.5 million b/d cross Russian territory. To mitigate the consequences, the Kazakhs this month introduced a new crude stream — Kazakhstan Export Blend Crude Oil — for the 300,000 b/d or so of oil it pumps via Russia and markets as standard Russian Urals blend. Kazakh producers who use the pipeline complain they must sell their oil at a $30-plus per barrel discount to the North Sea benchmark Brent, because it is assumed to be of Russian origin. These changes do not apply to the 1.2 million b/d of Kazakh crude that is exported via the privately owned Caspian Pipeline Consortium (CPC) pipeline that runs to the South Ozeyerevka terminal on the Russian Black Sea, which is sold as CPC blend. This is the route that is used by the Tengizchevroil joint venture, led by Chevron with 50% alongside Exxon Mobil (25%), Kazmunaigas (20%) and Lukoil (5%), and the seven shareholders in the Kashagan project: KMG with 16.88%, Exxon, Shell, Eni and TotalEnergies with 16.1% and China National Petroleum Corp. and Japan's Inpex. CPC, which has a total capacity of around 1.4 million b/d, also handles most of the liquids production from Karachaganak.

To boost its long-term production capacity, Kazakhstan has tried to drum up interest among the international oil companies (IOCs) in new onshore exploration. Two licensing rounds have been held over the past three years, but the IOCs were nowhere to be seen. Instead, it was mostly Kazakh-owned entities which bid for the acreage, making the whole process an anticlimax. As for new offshore exploration, the steep costs involved have deterred most of the Western majors. Eni has projects with Kazmunaigas to develop two blocks in the North Caspian, Isatay and Abay, but they have yet to get off the ground. The company making all the running offshore is Russia's Lukoil, which has signed several agreements with KMG to develop Caspian blocks, building on its success in bringing on stream the Filanovskoye and Yu Korchagin fields in the Russian sector of the Caspian Sea.

Europe's Refiners Call Attention to Transition Risks

Europe's refining industry is calling on the EU to develop a liquid fuels strategy to help balance the continent's move away from fossil fuels. The Ukraine war has exposed Europe's fragile energy security and dependence on Russian supplies. It has given European consumers a shock preview of the fuel price spikes that could characterize the energy transition unless policymakers adjust course, said John Cooper, director of Fuels Europe. "We have tens of millions of customers every day for petrol, diesel, jet fuel, marine fuel and all the specialty products ... Many of them will want us to be very active on climate action but they still need to get to work tomorrow," Cooper told Energy Intelligence. The war and resulting sanctions have also given policymakers a taste of the possible backlash if carbon pricing is seen as just another form of fuel tax. Most European governments have been forced to cut fuel duty and other energy taxes recently to protect consumers from record fuel prices. Refinery closures during the pandemic, following years of underinvestment in what is seen as a dying industry, have seriously damaged Europe's ability to cope without the 2.2 million barrels per day of crude and 800,000 b/d of diesel it normally imports from Russia. "Right now, we think maybe that was in some elements foolish. It's certainly unusual for us to see policymakers calling for more oil … at the same time [as] setting a trajectory toward much lower consumption," said Cooper.

Current EU plans are for electric vehicles (EVs) to completely obviate the need for liquid road fuels, leaving biofuels, which are set to remain scarce, available only for the harder-to-decarbonize aviation sector. The refining lobby thinks this is a missed opportunity: Rather than banning the internal combustion engine, Fuels Europe wanted Brussels to ban just the emissions and recognize that second-generation biofuels can be just as effective in decarbonizing transport. That would also allow Europe's refining industry to survive, at least in some form, as well as making use of existing fuels distribution infrastructure to help guarantee interim fuel supplies. Liquid fuels currently make up 93%-95% of Europe's transport demand. Current EU proposals will treat EVs as carbon-free no matter how the electricity is made, whereas cars running 100% biodiesel would be treated exactly the same as vehicles running on 100% fossil diesel. Cooper argues that the lack of policy incentives to make biofuels will make it harder for the EU to meet its targets on sustainable aviation fuel use. These sometimes contradictory policies are included in the EU's Fit for 55 package of proposals aimed at cutting carbon emissions by 55% from 2009 levels by 2030. The legislation is currently stalled in the European Council, but Cooper thinks Fuels Europe has already lost the argument over passenger vehicles and is now lobbying hard to make the same case for road haulage. Earlier EU legislation on first-generation biofuels backfired when it opened the door to rainforest-damaging palm oil imports.

Refiners argue that a broader fuels policy would create the right business model for much needed investment in all advanced biofuels, including for aviation. "Diesel fuel is very similar to jet fuel and so investment in diesel for road transport is a no regret option," argues Cooper. "If the haulage fleet does go to either hydrogen or electrification, you've got additional production of distillate type fuels that can go into aviation," he explains. "A bit of that excitement around the ability to do renewable [fuels] would be very helpful," he adds. Fuels Europe has already worked with its sister technical organization Concawe to develop its own Clean Fuels for All strategy. That envisages a much smaller European refining industry by 2050 making only advanced biofuels and synthetic fuels from a variety of waste feedstocks.

"We may be only 40% of the size that we are today by 2050," says Cooper. Low-carbon liquid fuels would be made using a variety of technologies ranging from relatively straightforward refining of used cooking oil or other waste fats to Fischer-Tropsch processing of municipal solid waste, fermentation of industrial waste and power-to-liquids efuels. Cooper says more work also must be done on carbon pricing, especially at the border so that European refiners can compete. In particular, Fuels Europe wants carbon pricing on imports and for its members to be able to export to markets that don't have carbon pricing.

Signs of Demand Destruction Emerge in US

(Continued from p.1)

demand at 9.016 million b/d for the week ended Jun. 10, down just 100,000 b/d from the same period a year ago. Some market players see robust demand persisting in the face of pain at the pump through the summer, which is typically peak demand season for gasoline. "The current bull market should continue well into the summer but a descent from these summits might begin as the year draws to an end," according to broker PVM's Tamas Varga. In addition, some traders note that with the economy and workplaces open and functioning largely without Covid-19 restrictions, demand has a floor as commuters head back to the office. Reinforcing that trend are demographic movements, with populations growing in cities with less-than-stellar public transit sectors.

However, the outlook gets much murkier at current price levels and will continue to dim the longer prices remain around $5 per gallon — and especially should they climb, a development some see as virtually inevitable. Indeed, there are signs demand destruction has already started in some areas, mostly cities facing the highest prices. Retailers say much depends on geography. "Where we look at our top quartile of retail prices, which is well north of $5 a gallon at this point, we are starting to see some erosion in volume in the low single digits. And in the middle two quartiles, we're kind of flattish to maybe slightly down," said Darren Rebelez, CEO of Casey's General Stores. He added that he expects that destruction would pick up the pace at the $6 mark. However, surveys of consumers have identified that $5/gallon becomes an inflection point that could hasten demand destruction. According to the American Automobile Association, some 75% of American drivers polled said they would change their driving habits at $5/gallon prices, mostly by two mechanisms — carpooling among younger drivers and making fewer trips outright for those over 35. Data on consumer spending through April seem to suggest drivers were already changing habits then; while gasoline and other fuels rose as a proportion of spending, this was a function of higher prices rather than demand itself.

Meanwhile, with low inventories, strained refining capacity and a tight market globally, the onset of hurricane season could knock out some pipeline or downstream capacity and send prices rocketing even higher, adding to consumers' pain. In 2021, Hurricane Ida shuttered large swaths of the Gulf Coast's refining sector for weeks, resulting in over 20 million bbl of gasoline, diesel and other fuels going unproduced.

Gazprom Still Raking in Cash From Sales to EU

Russia's Gazprom is making huge profits despite sharply lower exports to Europe, thanks to soaring natural gas prices. However, the EU's plan to end its reliance on Russian fossil fuels by 2027 in response to the Ukraine war means that Gazprom must make a more aggressive pivot to China to secure a future market for its gas production. Moscow is trying to build up pipeline gas exports to China, but the shift will take time and new infrastructure. Russian gas supplies via the eastward Power of Siberia pipeline began in late 2019 and are now ramping up according to schedule — but not enough to immediately offset the drop in supplies to Europe already experienced this year. In the first five months of 2022, Russia piped a combined 61 billion cubic meters to Europe (including Turkey) and China, down 23.2 Bcm, or 28%, from the same period of last year, according to Gazprom. Power of Siberia shipments are understood to be in line with the annual plan of 15 Bcm, or 41 million cubic meters per day, up from 10.39 Bcm supplied in 2021. That means exports to Europe, including Turkey, might have dropped 32% on the year to some 54.5 Bcm, or some 360 MMcm/d, in the January-May period.

Before June, Russian gas exports to Europe fell mainly due to demand destruction from record-high prices, but non-market capacity restrictions have started to factor in more recently. Many suspected Gazprom was tactically restricting supply in the months leading up to Russia's Feb. 24 invasion of Ukraine, and suspicions of politically driven moves were revived this week when Gazprom limited supplies via its Nord Stream pipeline. Prior to that, price factors appeared to affect Russian gas flows more than deliberate efforts to cut off six buyers who rejected Moscow's new two-step payment scheme. These buyers were Poland's PGNIG, Bulgaria's Bulgargaz, Finland's Gasum, the Netherlands' Gasterra, Shell (for supplies to Germany) and Denmark's Orsted. The war and capacity restrictions — deliberate or not — keep spot prices high, which means that Gazprom's hub-linked prices will also remain elevated this year. Oil prices of around $120 per barrel will also hike Gazprom's oil-linked prices this year, making it harder for Gazprom to compete during periods when spot gas prices are eased by an inflow of LNG and mild weather — if and when transport capacity restrictions are eased.

The drop in Gazprom's pipeline gas exports to Europe has not hurt the company's revenues. With its average export prices now at around $30 per million Btu, up from $7/MMBtu a year ago, Energy Intelligence estimates Gazprom earned about $46 billion from exports to Europe, excluding Turkey, in January-May. That compares to an estimated $52.2 billion in all of 2021 for exports to Europe — including Turkey — according to Gazprom's price estimates, which are typically conservative. EU sanctions do not target Russian gas imports, as the bloc has no adequate and immediate replacement. Shortly after Feb. 24, the EU announced plans to slash imports or Russian gas by two-thirds, or by 100 Bcm, this year, but this target is increasingly looking too ambitious.

Gazprom's oil-linked export price in China is now far lower — some $200 per thousand cubic meters in the first four months of 2022, according to Energy Intelligence estimates. High spot prices are prompting Beijing to increase pipeline gas imports, including from Russia, and reduce LNG offtakes. But Gazprom's supply growth is limited by the availability of infrastructure. The 15 Bcm plan for this year is based on the ramp-up schedule of the Chayandinskoye feeder gas field in East Siberia and the construction plan for compressor stations along the Power of Siberia pipeline. Next year, gas exports will increase further with the launch of gas production from the second feeder field, Kovyktinskoye, and an extra 800 kilometer section of Power of Siberia connecting the field with the already operational 2,200 km pipeline. But the Power of Siberia contract will only reach its 38 Bcm/yr plateau in 2025. Gazprom wants to eventually increase exports to China to 130 Bcm/yr, but its recently signed second contract with Beijing is for only 10 Bcm/yr and it is not clear when supplies might start. Gazprom is also in talks over several more deals, with the highest priority being the 50 Bcm/yr Power of Siberia 2 project, which should enable Gazprom to redirect some gas from West Siberia, a region now supplying Europe.

South Asia Buckles Under High Prices

With global energy markets on high alert for demand destruction, South Asia is a key area to watch. High oil, gas and coal prices have added to the economic turmoil caused by the pandemic in the import-dependent region. Pakistan and Sri Lanka are struggling to keep the lights on, while India and Bangladesh are dealing with slowing economic growth. All eight South Asian economies are net oil importers, making them particularly vulnerable to price shocks, particularly under a stronger dollar. India meets 85% of its oil, 50% of its gas and 25% its coal demand via imports. Pakistan imports 70% of its oil and 25% of its gas needs. Bangladesh meets about a fifth of its gas demand, and like Sri Lanka, imports almost all its crude. The region last witnessed oil prices of over $120 per barrel in 2008 but bounced back quickly. This time, the pain may hurt more since economies are still fragile from Covid-19 and high prices could stay longer due to supply issues. The World Bank recently cut its outlook for real GDP growth in South Asia this year to 6.8% from 7.6% in January.

Governments are scrambling for solutions but are faced with only bad options. They can reduce the burden on consumers through costly subsidies, raise fuel prices to reflect market rates or resort to rationing or blackouts to reduce consumption. Pakistan, which is facing a balance of payment crisis, last week reduced its work week by a day, reduced officials' fuel quota by 40%, asked municipal authorities to turn off streetlights on alternate days and launched hours-long blackouts to save on energy costs. Although Pakistan recently raised liquid fuel prices by 40%, it continues to sell products below market rates due to rising public anger. Pakistan's foreign exchange reserves dwindled to just $9.2 billion for the week ended Jun. 3 — down by almost half from a year ago and barely enough to cover imports for six weeks. Cash-strapped Sri Lanka will introduce weekly fuel quotas for citizens starting next month. In India, the government has forced retailers to sell oil products below market rates. Indian refiners are also lapping up discounted Russian barrels to cut costs.

High prices have upended the region's move to lean on gas as a transition fuel. LNG importers India, Pakistan and Bangladesh have been turning to cheaper coal and renewables recently. Sri Lanka's plans to include gas in its energy mix may not see any real action now. India, Pakistan, Bangladesh, which shunned spot LNG markets during winter, have been forced to buy their costliest cargoes now as demand spikes amid a heatwave. India is doubling down on domestic production and importing more coal as gas-fired units are idled due to exorbitant prices. Prime Minister Narendra Modi's plan to more than double gas' share in India's energy mix to 15% by 2030 appears on shaky ground. Meanwhile, cash-strapped Pakistan is in discussions with Qatar, its largest LNG supplier, to defer payments for cargoes. Pakistan's government is shifting its focus away from imported fuel-based projects. Most of a proposed

11,386 megawatts of power generation capacity would be fueled by domestically produced coal or hydro.

Pakistan and Bangladesh are due to hold general elections next year. In 2024, India will hold general elections and Sri Lanka its presidential polls. Governments in the meantime will focus on managing inflation in the short term, which may lead to burning cheaper, dirtier fossil fuels and/or higher subsidies. Consumer price inflation in Pakistan and Sri Lanka reached double digits late last year and has accelerated further, while India has breached the upper end of the central bank's headline inflation target range of 2%-6%. Both Pakistan and Bangladesh, which recently unveiled federal budgets for the next fiscal year starting Jul. 1, have proposed heavy gas and power subsidies. Pakistan's subsidy bill for the current fiscal year more than doubled to 1,515 billion Pakistani rupees ($7.5 billion) from what was budgeted earlier. Bangladesh has increased subsidies on fuel, electricity, gas and fertilizers by 25% to $8.9 billion for the fiscal year starting Jul. 1 and said it could hike it by a further 20% due to rising oil prices. Those subsidies may support demand in the near term but are unsustainable in the long run.

Industry Gets Serious About DAC, Geothermal

Energy transition strategies in the oil and gas sector typically focus on two leading technologies seen as critical in the global push to decarbonize: carbon capture and sequestration and hydrogen. Many companies, particularly on the E&P side, see these technologies fitting within their core competencies while offering the potential to reuse or repurpose existing midstream infrastructure. But some firms are thinking even bigger. Excitement is growing and investment is ramping up for nascent technologies like direct air capture (DAC) and geothermal energy. Both hold tremendous promise but have a long road ahead before either can be deployed at anything approaching scale. DAC and geothermal technologies target two different but important aspects of the decarbonization picture. By pulling carbon dioxide (CO2) directly from the air, DAC could be a viable engineered approach to achieving negative emissions and offsetting pollution from hard-to-abate industrial sectors. Geothermal's promise lies in its potential as a baseload power and heating source that could enable and derisk various other clean technologies such as wind and solar, or even fuel more emerging technologies like DAC and zero-emissions hydrogen. But even proponents warn that excitement over these new technologies should not distract from the more pressing need to reduce absolute emissions and increase energy efficiency.

DAC has a clear lead on other unproven decarbonization technologies thanks to some high-profile backers and a handful of successful pilot projects. Occidental Petroleum, for instance, has gone nearly all-in on the technology, teaming with leading DAC player Carbon Engineering to develop what would be the world's largest and first commercial DAC project. The plant, due to start up in late 2024, would capture an estimated 1 million tons per year of ambient CO2, a big leap from the roughly 10,000 tons/yr currently captured by DAC projects globally. DAC's advantages include flexibility in sizing and siting, with a relatively small land footprint and generally modularized design options. The drawbacks, as with any emerging technology, are the high costs and undeveloped markets. Cost estimates of pulling CO2 directly from the air today range from about $250-$600 per ton, limiting the commercial appeal in the absence of robust carbon markets. Oxy's DAC strategy hinges on using the captured CO2 for enhanced oil recovery in the Permian Basin, a potentially lucrative but controversial use of CO2-removal technology. Oxy also has designs to use some captured CO2 as feedstock for synthetic fuels; it believes it can build up to 70 DAC plants worldwide by 2035. The near-term goal for the sector is to get the per-ton cost below $100. The US Department of Energy (DOE) last month launched a $3.5 billion program to fund up to four DAC projects that can capture at least 1 million tons/yr of CO2, preferably for less than $100/ton. Experts see innovations in the sorbent materials used to capture CO2 and building scale as the keys to driving down costs. Other oil giants such as Shell are believed to be quietly working on DAC solutions as well.

New approaches to geothermal have raised hopes that the immense heat just a few miles below our feet — historically only accessible in certain parts of the world — can now be more widely tapped for use aboveground. Start-up companies pushing "advanced" and "enhanced" geothermal technologies — known by some as "Geothermal 2.0" — offer the enticing possibility that subsurface heat can be harnessed virtually anywhere on earth. Early results have been enough to attract interest from some heavy hitters in energy, particularly in the oil-field services sector, which sees geothermal as a natural fit for their specialized expertise. "We poke holes in the earth for a living," says Guillermo Sierra, vice president of strategic initiatives for driller Nabors Industries, which has invested in at least four geothermal concerns. Baker Hughes and Schlumberger each have growing interests in geothermal, while BP, Shell and Chevron also have exposure. Start-ups are actively soliciting workers with oil-field experience who may have grown disaffected with the oil and gas sector and are looking for a more climate-friendly line of work.

What's New Around the World

GENERAL

IEA — The International Energy Agency (IEA) says high fuel prices have started to erode fuel consumption but that markets for refined products remain tight because refiners are struggling to process enough crude oil to meet demand for fuel. In particular, refiners don't have enough capacity to meet demand for middle distillates such as diesel and that situation will persist into 2023, the IEA said in its latest monthly *Oil Market Report* released Wednesday. Low OECD inventories of diesel, kerosene and jet fuel — down 25% since January 2021 and now at their lowest level since 2004 — are not providing much of a cushion and are contributing to current "extraordinary" prices for middle distillates, the IEA said. Because of the backlash against the invasion of Ukraine, Russia's exports of refined products have fallen by some 500,000 b/d, limiting diesel supply and pushing up prices. The resulting run-up in prices stalled the recovery in consumer demand in April and May. "Preliminary data point to an almost instant demand cutback in response to the price surge," the IEA said. The IEA expects refineries to ramp up their crude runs by 3.5 million b/d from May to August, which would lift the supply of products above demand. However, product inventories for the whole year are expected to show a draw.

CORPORATE — Continental Resources founder and Chairman Harold Hamm has made an all-cash offer to take the oil and natural gas producer private. Some suspect the move is intended to foster other bids for the Oklahoma City-based E&P, while others see a desire to escape the capital discipline and climate disclosure pressures on publicly held producers. Continental said Tuesday that Hamm, acting on behalf of himself and his family's trusts, offered to buy the remaining 17% of the company's shares that the family does not already hold for $70/share. That would represent a premium of about 9% over Continental's closing price on Jun. 13 and 11% over the average of the last 30 days, according to the company. The offer values the firm at roughly $25.4 billion. Several analysts indicated that while Hamm's offer was reasonable and roughly in line with current valuations of the firm, it was also well below what shareholders will likely demand in order to green-light a sale. Privately owned oil companies, which are not subject to the same capital discipline and climate pressures as their public peers, have been the driving force behind the surging rig count in the US over the past year.

COUNTRIES

AUSTRALIA — BP is taking over operatorship of the Asian Renewable Energy Hub (Areh) in Western Australia, which it says could become one of the largest renewable power and green hydrogen projects in the world. The UK major has agreed to acquire a 40.5% operated stake in Areh but did not provide financial details of the transaction. Areh was first proposed in 2014 but has struggled to get off the ground, with the federal government rejecting plans last year to convert it into a green ammonia export project. However, the change of operator and a new Labor government in Canberra could provide the impetus needed to finally move the project forward. Prime Minister Anthony Albanese, who took office last month, has vowed to turn Australia into a renewables powerhouse. BP said the project is targeting the phased development of up to 26 gigawatts of onshore wind and solar power generation. Most of the power will be used to produce around 1.6 million tons/yr of green hydrogen or 9 million tons/yr of green ammonia. BP said this will help abate around 17 million tons/yr of carbon dioxide emissions in domestic and export markets.

CANADA — Oil sands operator Cenovus Energy and UK major BP announced an asset swap worth up to C$1.2 billion that will see the large oil producers reshape and consolidate their respective Canadian operations. Under the terms, BP will sell its 50% stake in the Sunrise oil sands project in Alberta to Calgary-based Cenovus for C$600 million (US$465 million) and another contingent payment of up to C$600 million that expires after two years. BP will meanwhile secure Cenovus' 35% stake in the Bay du Nord project in the Flemish Pass Basin off the coast of Newfoundland and Labrador. The deal is expected to close in the third quarter this year with an effective date of May 1, 2022, and advances each of the participants' Canadian upstream strategies. Cenovus has operated the 50,000 b/d Sunrise project since inheriting it in its acquisition of Husky Energy last year, and will become the sole owner of the development when the deal closes. Analysts at Scotiabank said the asset swap "is in line with [Cenovus'] strategy of consolidating" oil sands assets and "offers potential upside from increasing Sunrise's production and improving its cost structure." The deal will mark BP's exit from the carbon intensive Canadian oil sands and expand its presence in the Eastern Canadian offshore.

INDIA — TotalEnergies has signed an agreement with India's Adani Enterprises that extends their existing partnership in LNG and solar power to green hydrogen. The French energy major said it will acquire a 25% stake in the Indian conglomerate's Adani New Industries Ltd. (ANIL) subsidiary. Financial details were not disclosed. Adani said that ANIL intends to invest over $50 billion in carbon-free "green" hydrogen over the next 10 years, with an initial development phase targeting output of 1 million tons/yr by 2030. Total said that production target would be underpinned by around 30 GW of new renewable power generation capacity. India has set a target of producing 5 million tons/yr of green hydrogen by 2030, with 75% of its hydrogen coming from renewable sources by 2050. It intends to use green hydrogen to reduce carbon emissions from heavy industrial processes such as steel manufacturing and cement production that cannot be easily decarbonized by other means. India is the world's third-biggest emitter of greenhouse gases and its green hydrogen ambitions are part of its plans to achieve net-zero emissions by 2070.

IRAQ — Iraq's oil ministry has ordered companies operating under contracts with the Kurdistan Regional Government (KRG) to terminate them within three months as Baghdad steps up efforts to bring the region's oil sector under its control. The order — communicated in a letter seen by Energy Intelligence — follows a bombshell Feb. 15 ruling by Iraq's Supreme Court that rejected the KRG's right to manage the oil resources within the territory of the largely autonomous region. This latest step appears to mark an escalation in the quarrel, with the federal ministry in Baghdad now addressing companies directly. The letter requires all lead contractors and their subcontractors to pledge not to work on contracts or projects in Iraqi Kurdistan that are at odds with the court's decision. Those with existing contracts in the region must terminate them "within three months from the date of their notification." And if they fail to comply, "the companies involved will be blacklisted," it adds. International oil companies operating in the Kurdistan region of northern Iraq include US major Chevron, Norway's DNO and London-listed Gulf Keystone. Very few of the remaining companies that signed production sharing contracts with the KRG also have operations in the rest of Iraq. The notable exceptions are Russia's Rosneft and Gazprom Neft.

UNITED STATES — The White House is now setting its sights on the refining industry as its frustration over high fuel costs grows. In a letter to multiple refiners and integrated oil companies, President Joe Biden said high refinery profit margins were exacerbating the high prices at the pump for consumers. "At a time of war, refinery profit margins well above normal being passed directly onto American families are not acceptable," said Biden. The president's letter called for an increase in fuel supplies — something that's likely difficult or unappealing for the refining industry to execute, particularly on a timeline that would bring near-term relief to consumers. The White House indicated it was willing to use emergency powers — including the Defense Production Act — to increase supply. But it did not get into any specifics, and it's not clear how the defense law would ease the path for restarting shuttered refineries. Biden's letter — which was sent to executives at Marathon Petroleum, Valero Energy, Exxon Mobil, Phillips 66, Chevron, BP and Shell — comes less than a week after Biden hit out at Exxon for making "more money than God."

Marketview

Full Frontal

Driven by uncertainty, this oil market lives in the here and now. Ever since Russia launched its invasion of Ukraine on Feb. 24., the market has seen "crazy" and "unsustainable" premiums for spot crude oil cargoes, traders say. But they are not expected to subside anytime soon.

These premiums suggest an extremely tight crude market, but that is not the case. Instead, they are a function of physical and financial traders moving increasingly to the front of the price curve, since it so hard to predict what the world — and the oil market — will look like in a couple months.

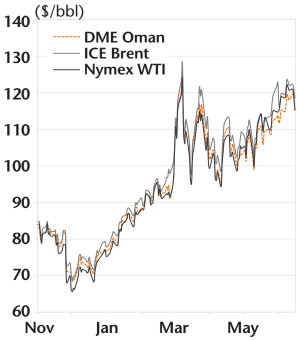
One trader explains that the financial market is driven by fundamentals beyond three months, "and nobody knows how they will look." Most trading done now is based "on sentiment and psychology. At this stage, that means buy high and sell higher."

Physical traders are focusing on short-haul cargoes, especially in Europe, and crude producers are playing hard to get. Crude sellers know refiners can pay huge premiums as they are making a mint on selling refined products.

In a normal market, the huge spot premiums would drain crude inventories. Instead, crude storage is slowly rising as refiners ramp up runs to try meet summer demand. Some unsold Russian crude moves into tanks.

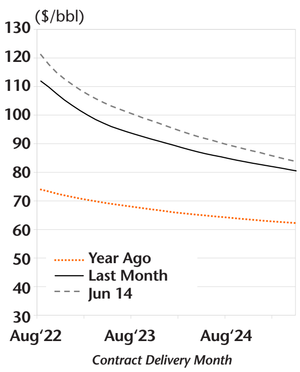
Financial traders thrive on price volatility and are more concentrated in the first few months of the market. All that liquidity, combined with the uncertain geopolitical outlook, is keeping prices on the boil — not just for crude but especially refined products, which are genuinely in short supply.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

ICE Brent Forward Curves



In the second half of 2021, as Opec-plus slowly opened the taps and kept the market artificially tight, front-month futures contracts on the exchanges would trade at an average $3 premium over deliveries in six months. After the Ukraine war, that ballooned very quickly to $11 per barrel.

Spot oil in Europe — dated Brent, a cargo with a loading date — is even more expensive and now trading at $6.40 over the front-month contract. Adding to prompt pressure is that Libyan production is down close to 1 million barrels per day, which is all short-haul crude. Libya's impact is hard to assess. Before it went out, dated Brent was at times trading at even higher premiums.

The war has made the future particularly murky. US and EU bans on Russian petroleum exports mean that by the start of 2023, Russia must find new markets for nearly 4 million b/d of crude and refined product exports.

So far, roughly 1 million b/d of Russian seaborne export crude has been diverted, with the bulk going to India, while product exports have fallen by 500,000 b/d. Further changes in trade flows will deliver more price shocks.

Over time, high prices will eat into fuel consumption, mostly in the non-OECD. Economic headwinds from inflation and rising interest rates could lead to slower demand growth. And the pandemic could rear its ugly head again.

Oil markets suggest that uncertainty and fear of shortages are the dominant price drivers. The war and sanctions on Russia exacerbate those sentiments. They will keep spot oil premiums high — even if there is enough crude oil.

Freeport LNG Outage Roils Gas Markets

News that Freeport LNG will be off line for several months sent US and global gas markets into chaos this week, with European prices soaring on renewed supply fears and US domestic futures prices plunging due to the sharp drop in summer feed gas demand.

Freeport LNG Development said its Texas Gulf Coast terminal, shut by an explosion and fire on Jun. 8, could resume partial operations in about 90 days with full operations not expected until late 2022. US July gas futures plummeted from nearly $9/MMBtu to around $7/MMBtu on the announcement. In Europe, the TTF August 2022 contract surged from €92.55/MWh ($28.24/MMBtu) to €101.3/MWh ($30.92/MMBtu), boosted also lower Nord Stream flows from Russia.

PIW Market Indicators

($/barrel)	Jun 13-Jun 15	Jun 6-Jun 10	May 16-May 20
Spot Crude			
Opec Basket	$122.20	$121.59	$114.41
UK Brent (Dtd.)	127.06	127.69	113.03
US WTI (Cushing)	118.34	120.42	112.18
Nigeria Bonny Lt.	135.52	134.04	114.95
Dubai Fateh	116.86	117.09	108.53
US Mars	110.87	114.35	108.54
Russia Urals (NWE)	93.42	92.24	77.93
Crude Futures			
Brent 1st (ICE)	120.65	121.75	111.97
Brent 2nd (ICE)	117.44	119.06	109.74
B-wave (ICE)	121.40	121.54	111.69
WTI 1st (Nymex)	118.39	120.44	112.33
WTI 2nd (Nymex)	115.87	118.03	109.73
Oman 1st (DME)	116.35	117.54	108.71
Oman 2nd (DME)	112.32	113.92	106.32
Murban 1st (ICE)	119.44	120.86	110.48
Murban 2nd (ICE)	116.01	117.26	108.50
Forward Spreads			
Brent (1st-Dtd.)	-$6.41	-$5.95	-$1.05
Brent (2nd-1st)	-3.21	-2.68	-2.23
WTI (2nd-1st)	-2.52	-2.41	-2.59
WTI (3rd-2nd)	-2.69	-2.66	-2.99
Oman (2nd-1st)	-4.04	-3.62	-2.40
Oman (3rd-2nd)	-1.93	-2.98	-2.77
Murban (2nd-1st)	-3.43	-3.61	-1.98
Murban (3rd-2nd)	-2.96	-2.85	-2.81
Grade Differentials			
WTI-Brent (1st)	-$4.78	-$3.72	-$2.24
WTI-LLS	-1.15	-1.47	-1.81
WTI-Mars	+7.47	+6.07	+3.64
Brent(Dtd)-Dubai	+10.21	+10.60	+4.50
Brent(Dtd.)-Urals	+33.64	+35.46	+35.09
Brent(Dtd.)-Bonny Lt.	-8.46	-6.34	-1.93
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$118.00	$121.48	$115.67
Arab Lt.-Europe (Med)	123.30	123.44	116.59
Arab Lt.-Far East (f.o.b.)	121.13	121.95	118.22
Nigeria Bonny Lt.	128.72	129.35	114.97
Arab Light Gross Product Worth			
Rotterdam	$137.69	$141.03	$128.21
US Gulf Coast	147.88	152.10	134.66
Singapore	134.21	133.00	120.28
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$151.24	$155.56	$122.66
UK Brent Margin	+22.78	+27.15	+8.69
US Gulf Coast			
Mars GPW	141.25	145.77	130.19
Mars Margin	+30.28	+31.32	+21.55
Singapore			
Oman GPW	134.79	132.35	120.38
Oman Margin	+17.79	+13.96	+10.61
US Nymex			
WTI 3-2-1 Crack	+$54.61	+$58.22	+$48.99
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$1351.27	$1437.56	$1242.36
Gasoil (0.1%)	1345.50	1343.10	1081.10
Fuel Oil (0.5%)*	888.67	909.30	790.75
US Gulf Coast (¢/gal)			
RBOB Gasoline	399.83¢	422.75¢	374.87¢
ULS Diesel	437.87	435.25	363.94
Fuel Oil (0.5%, $/ton)	$944.67	$950.20	$871.40
Singapore ($/bbl)			
Naphtha	$87.06	$90.97	$98.81
Gasoil (0.05%)	170.61	169.43	138.17
Fuel Oil (0.5%, $/ton)	1098.00	1122.60	922.80

*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.