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Industry Seeks Right Tone For Energy Crisis

The upheaval in energy markets is changing the way major producers talk about their business and strategies. Worries about high prices and security of supply are refocusing attention on oil and gas production. A strong medium-term outlook for natural gas, fueled by Europe's turn away from Russian energy, is shifting focus to global LNG options. While leading oil companies are not backing off their emissions goals, maturing transition strategies mean they are spending less time explaining their carbon cuts and more detailing how they plan to develop low-carbon business lines. But executives remain keenly aware that shareholders remember years of underperformance and continue to demand outsized returns through dividends and buybacks to hold oil and gas shares. Discussion of inflation increased more than four-fold, according to an Energy Intelligence analysis of earnings calls hosted by the five largest Western oil companies in the second quarter 2021 versus 2022. Mentions of LNG and gas prices jumped anywhere from 163% to 500% this year compared to 2021. Terms including "energy security" and "windfall taxes" were almost entirely absent from discussions last year but common in recent earnings calls. Talk of emissions goals — and even the energy transition — declined as analysts and companies focused on specific technologies like renewable power, hydrogen and carbon capture.

Oil and gas companies are trying to position themselves as the solution rather than the source of societies' energy price crises — with varying degrees of success. Bumper profits make this a big challenge. The first front in the fight is pitching their ongoing investments in both hydrocarbons and transition technologies. This can be trickier for publicly traded companies, whose investments are not dramatically accelerating due to investor pressures. But overall, the message seems to be better

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No Easy Fix For Kazakh Export Dilemma

Kazakh oil is facing an existential crisis. Kazakhstan is extremely dependent on Russia to handle its oil exports, but it relies on Western majors — the likes of Chevron, Exxon Mobil, Eni and Shell, all which hail from countries adversarial to Russia — to extract the barrels from the ground. Earlier this summer, Moscow, which is contending with Western restrictions on its oil exports, threatened to halt Kazakh flows through an ultra-important pipeline to the Black Sea. For the Central Asian producer, whose budget is heavily reliant on petroleum sales, the event was a rude awakening, and now the alarm bells of export-route diversification are ringing loud in Nur-Sultan. But the sobering truth is the Kazakhs and foreign majors have precious little room for maneuver in the short- and medium-term. Kazakhstan exported an average 1.4 million barrels per day of crude and condensate in January-July this year, and roughly 80% was shipped via the 1.2 million b/d Caspian Pipeline Consortium (CPC), which runs from the massive onshore Tengiz field to a terminal near Russia's Novorossiysk. Some 200,000 b/d were sent through a Soviet-era pipeline to Russia's Samara region, and a tiny volume is pumped eastward to China in a line that primarily handles Russian crude.

With the long-term reliability of CPC in serious doubt, Nur-Sultan is revisiting an ambitious project dubbed the Kazakhstan Caspian Transportation System (KCTS) that would involve shipping large amounts of crude oil across the Caspian Sea to Azerbaijan. From there the barrels would be blended with Azeri crude and pumped along the Baku-Tbilisi-Ceyhan (BTC) pipeline, which is cur-

rently operating at just over half its 1.2 million b/d capacity. Kazakhstan already uses this route, but the flows — about 2,000 b/d since March — are minuscule due to a lack of large tankers and other infrastructure. The KCTS concept dates back to 2008, but it was eventually shelved since Kazakhstan's top producers, most notably Chevron-led Tengizchevroil (TCO) and an international consortium developing the giant Kashagan field, thought they could rely exclusively on transit through Russia. "Chevron assumed they could carry on using CPC, with no Plan B," a veteran oil executive says. "It proved to be a mistake." Sources involved with the original KCTS blueprint say the project would cost several billion dollars and take at least three years to complete. It would involve building a new export terminal at Kuryk and constructing a fleet of medium-sized tankers that would go back and forth to Baku. A Phase 1 would boast a capacity of at least 250,000 b/d, which would still leave the Kazakhs highly dependent on Russia.

In early July, a day after a Russian regional court ordered a one-month stoppage of the CPC terminal for alleged safety violations, Kazakh President Kassym Zhomart Tokayev instructed state oil company Kazmunaigas (KMG) to come up with the best variant for the trans-Caspian project. He also told KMG to start talks with potential investors, including TCO partners Chevron, Exxon and Lukoil. But the project would also require backing from Azerbaijan's leadership given the need to boost capacity at terminals in Baku and Sangachal. Importantly, BTC's owners, including BP, Equinor, and Hungary's Mol, are keen on ramping up throughput and have succeeded in attracting small Russian and Turkmenistan volumes. Several key questions surrounding KCTS need to be answered first. One is how deeply Chevron would want to be involved, especially given the TCO joint venture contract expires in 2033. Production at Tengiz, which is currently around 650,000 b/d, is due to increase by over 25% from 2024, when the field's $45 billion expansion is completed. Although there is still spare capacity in CPC to handle new volumes, this would mean ever more dependence on Russia's whims. Other routes are under consideration. China is one obvious solution. Kazakhstan could increase oil deliveries eastward via the 400,000 b/d line that runs from Atasu in central Kazakhstan to the Chinese border, but the scope is limited since most of the capacity is taken up by Russia's Rosneft under a long-term supply contract with PetroChina. Finally, there is a pipe running through Azerbaijan to the Georgian port of Supsa that is owned and operated by BP-led partners in the Azeri-Chirag-Guneshli production field, but this is a small terminal that could not make a dent in Kazakhstan's enormous export needs.

Russia, Refining Crunch Threaten Oil Balances

Energy Intelligence balances show the world should have enough crude oil through 2023 if some spare capacity is tapped, with a wider margin of error if an Iran nuclear deal can be clinched. Tepid demand from still-high prices for refined products like gasoline and diesel could also loosen markets, as energy costs have been a key driver of recent inflation in the global economy — particularly high natural gas prices. Global economic recession can not be ruled out, and balances could shift significantly over the next 16 months in response to various events. Russia's ability to continue exports — particularly products — and the global refining sector's capacity to meet consumption must be closely watched. Based on traditional economic growth assumptions and expected pent-up pandemic demand, Energy Intelligence sees product demand growing by 2.1 million barrels per day in 2022 and 1.9 million b/d in 2023. In both years, we envision a small supply surplus, which would help replenish inventories — first for crude, then for refined products. But the effects of the Ukraine war, including sanctions, add significant uncertainty to a market already facing economic upheaval and a low-carbon energy transition.

Russia is by far the biggest wildcard. With some exceptions, EU sanctions will by Dec. 5 ban the remaining 1.7 million b/d of Russian crude that the bloc imports, while the 1 million b/d of Russian refined products it still purchases must cease by Feb. 5, 2023. Even if Russia can find new buyers for this oil, it may not be able to ship it without issues due to proposed EU restrictions on shipping and insurance, which will impact the bulk of the global tanker fleet. Without loopholes on the shipping rules, the world could face shortages, especially for products. Shipbrokers think a non-Western fleet of tankers — using sovereign Russian or Chinese insurance and financing — could still carry most of Russia's crude. But there are not enough tankers for products. To keep these products sailing, workarounds are needed. The US, UK, EU and South Korea are discussing a price cap system for Russian oil where traders could use Western tankers if they stick to the price cap. But analysts fear Russia could restrict its crude and product exports in response, much like it is now inflicting pain on Europe by reducing natural gas flows, prompting electricity prices on the continent to surge fivefold from a year ago.

Even if most Russian oil keeps flowing, there is still the global refining crunch to consider. Several refineries are due to start up this year and next, but everything must go right to ensure the industry can add the capacity needed to meet rising demand. Global refining capacity additions of about 3 million b/d are slated in 2022 and 2023, but this is not enough to offset the 4 million b/d of throughput capacity lost during the pandemic. China is starting up 800,000 b/d, but this may not matter much since its product export volumes have dwindled. Running China's refineries harder could lower the country's product imports and free up products for the region. The US will add some 350,000 b/d, offsetting closures, while the former Hovensa refinery in the US Virgin Islands could restart at 200,000 b/d. The Mideast is key for the world, with a total 1.4 million b/d in additions. India will start up 135,000 b/d, and Malaysia will restart 300,000 b/d. Nigeria's 650,000 b/d Dangote refinery and Mexico's 340,000 Dos Bocas refinery are also scheduled to start up soon, but timelines for both could slip into 2024.

Downstream supply volumes will be key for prices — for both crude and products. Oil demand will grow in the coming months as the Northern Hemisphere prepares for winter, and much like last year, fuel-switching away from expensive natural gas could tighten oil markets. Lagging Chinese demand could also rebound, although it could largely be met by China's domestic refining industry. Fuel switching is likely to be higher and last longer than in the 2021-22 winter as Europe is already switching to preserve natural gas storage. Total fuel switching, including in the Middle East and Asia-Pacific, could ramp up to 1 million b/d at the peak, which would be met by diesel and low-sulfur fuel oil.

The US, Norway, Saudi Arabia and the United Arab Emirates are expected to increase liquids production the next couple months. That will add 1 million b/d to global supply in the short term, with an additional 2 million b/d next year — even after accounting for an estimated loss of 1.3 million b/d of Russian volumes. Iran could add up to 1 million b/d from early next year in case of a nuclear deal.

Size Matters for US Oil Firms in Climate Law

The oil industry's reaction to newly inked US tax and climate legislation has been striated, with smaller producers and the US oil lobby castigating the law's heightened tax burden and potential demand destruction catalysts. Meanwhile, the response of majors has been largely positive. Enhanced certainty over US Gulf of Mexico access and fresh tax incentives for carbon negative technologies give large to midsize producers more to cheer about. The law allocates billions in fresh, generously structured tax incentives for carbon capture and storage (CCS) and hydrogen, although there are limitations that prevent oil companies from double dipping on using credits for both technologies. But for companies that have put low-carbon technologies at the center of their transition strategies, US policy around those technologies just got surer footing. BP CEO Bernard Looney said the tax incentives will aid BP's US-based transition strategies, including hydrogen, offshore wind, and electric vehicles. Exxon Mobil CEO Darren Woods similarly said it anticipates incentives for several low-carbon projects in the pipeline, naming blue hydrogen as one area where the tax incentives could be "beneficial." For companies with more exposure to direct air capture and CCS technologies, the law could be a game changer given the ample hikes to tax credits for both technologies. Richard Jackson, Occidental Petroleum's head of US onshore and carbon management operations, said the bill "gives certainty in some of the revenue to allow us to build this development."

The law also boosts sureness around upstream access, something that has suffered since the Biden administration took office in January 2021. For starters, it forces the US Interior Department to reinstate results of the Nov. 17 Gulf of Mexico lease sale. Exxon, Oxy, BP, and Chevron were the four top bidders who will see their cumulative bids restored for more than 200 tracts. Talos Energy CEO Timothy Duncan said the company's high bids for 10 blocks totaling over 57,000 gross acres have "identified drilling opportunities that will be actionable in our long-term drilling calendar" and that consistent leasing is a key part of its strategy. Indeed, for large producers for whom the Gulf plays a significant role in their strategies, the law's mandated two additional sales before 2023, as well as language requiring a total of 60 million acres per year in oil and gas lease sales offshore before Interior can issue wind leases, gives a solid floor on access.

For smaller E&Ps that have not devoted a lot of their portfolio to low carbon technologies and are not big players in the US Gulf, there is less to like. Smaller producers and medium-cap companies may be hit harder by the law's methane fee and new methane royalties and other leasing policy revisions, like hiking minimum bids and adding a new $5 per acre fee for nominating parcels.

For smaller E&Ps, even incremental operational cost increases affect the bottom line with more oomph. The tax structure changes also have not been popular. The bill would impose a 15% minimum tax on corporate profits over $1 billion — something that larger companies are in a better position to offset with robust CCS or other low carbon tax credits — and a 1% excise tax on share buybacks. In an Aug. 11 letter to Democratic leadership, more than 50 lobby groups, including the American Petroleum Institute, which includes most of the larger US producers but has previously sided with smaller producers on methane regulations, took umbrage at provisions they allege amount to an $11.7 billion tax on crude oil and petroleum products and a $6.3 billion natural gas tax.

Divisions within the industry in Washington have been on display before. Industry-focused lobby groups have not exactly been lockstep with majors who have had to overhaul strategies in response to environmental, social and governance pressures, in part because they also represent smaller producers with different policy priorities. As a result, there are often wide gulfs in how Washington policy is viewed by companies. For example, smaller independents have been far more intently focused on preserving long-standing production tax breaks than majors, who benefit less. Methane has been another divisive issue — majors have made the pivot toward embracing federal methane regulations while smaller E&Ps have been slower to spend the money to adopt controls, something that the new "fee" aims to course correct.

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received in producing countries than importers. Some firms are also paying lip service to growing contributions to public coffers through taxes and royalties. A select few have directly cut consumer fuel prices. "Our people inside the company get it. They want to help. And so the question becomes, what can we do to help?" BP CEO Bernard Looney said, detailing his company's tax payments and the jobs created by plans to invest $18 billion in the UK over the next decade. But the media and politicians still slammed BP for not detailing its actual windfall payments and for a lack of near-term consumer assistance. Exxon Mobil and Chevron both emphasized how their operations in the Permian Basin could add to US crude supplies. TotalEnergies and Repsol both cut fuel prices at their filling stations in France and Spain, with Repsol claiming discounts consumed all of its margin on retail fuel sales.

For much of the past decade, major producers have complained that energy — and their role in providing it — has been an afterthought. Now, companies find themselves at the center of intense social and political debates around the impact of inflation on the global economy and on households struggling to keep up. That dynamic offers an opportunity for energy companies to regain a central place in the discussion over the ongoing overhaul of the world's energy system. But the risk is that heightened public scrutiny finds companies out of step with society's changing needs. Financial impacts from measures such as windfall profits taxes or increased levies on earnings or share repurchases look minimal. But oil companies hoping to regain respect for their voice in the energy transition debate at the upcoming COP27 could erode their standing further if they are seen as unmoved — or even worse, profiting unnecessarily — at society's expense. Despite BP's public pillorying, contenders for the UK prime minister position have not backed increases or extension to the country's windfall tax pushed by the Labor opposition. One industry analyst brushed off financial impacts of any potential windfall levies, pointing out that the industry might pay hundreds of millions in windfall taxes compared to tens of billions of dollars of increased profits. COP organizers in Egypt have promised oil companies "have to be part of the solution." The just-passed US Inflation Reduction Act may offer a glimpse of the benefits of having a seat at the table. The law is seen by many as having significant benefits for much of the US oil and gas industry compared to legislation proposed in the European Union that is focused more purely on climate.

Goals Change Little for India's Fossil Fuel Use

India has formalized climate targets made by Prime Minister Narendra Modi at last year's COP26 summit in Glasgow, but there appears to be ample room for fossil fuels to keep growing. India has pledged to have non-fossil fuels account for about half of its installed power generation capacity and reduce the emissions caused by activities for the nation's economic growth by 45% by 2030. These are upgrades over India's vow under the Paris climate agreement in 2015, when it promised to make non-fossil fuels account for 40% of the installed power base and reduce emission intensity of GDP by 33%-35% by 2030 compared with 2005 levels. The updated Nationally Determined Contribution (NDC) is a step towards India's goal of achieving net-zero emissions by 2070. It could help India avoid international criticism that it is a climate laggard. However, New Delhi's reluctance to formalize all the goals Modi pledged at Glasgow also underlines how the recent energy crisis has prompted some countries to prioritize energy security and affordability over climate goals.

Some bold, actionable targets have been dropped from the NDC. These include establishing 500 gigawatts of non-fossil fuel based power generation capacity, sourcing half of India's power from renewables, and reducing carbon emissions by one billion tons by 2030. This may expose India's intention to keep burning coal, which now accounts for 57% of its primary energy mix. Rather than making renewables account for half of India's actual power generation, the new pledge aims for non-fossil fuels to account for half of just installed power capacity. Expanding India's non-fossil fuel power generation base by threefold to 500 GW from 168 GW now could have helped edge out coal. Last month, federal power minister RK Singh said India's generation capacity will more than double to 820 GW by 2030. Only 410 GW of this will need to be non-fossil fuel-based, giving the existing 204 GW of coal-fired capacity scope to expand. With solar, wind, nuclear and hydro already accounting for 41.5% of India's installed generation base of 404 GW, reaching the 50% milestone does not look very ambitious.

The cornerstone of India's climate polices has been cutting reliance on polluting coal. But the recent spurt in commodity prices in response to the Ukraine war has pushed India to balance its fuel mix by clinging to cheap domestic coal to provide affordable energy for poor. State-owned miner Coal India Ltd. seeks to boost production to 1 billion tons by the fiscal year ending March 2025 from 622 million tons this fiscal year. Since India is expected to be a top driver of global energy demand growth, its choices will have an outsized impact on efforts to combat climate change.

Demand for oil and gas should remain strong, too. State oil and gas companies are confident there will be no hasty exit from fossil fuels and demand for their products will continue for decades. As a hedge, they are investing in new business lines — but most outlays are still flowing into fossil fuels. For instance, India's largest state-owned refiner, Indian Oil Corp., says domestic oil demand will be on rise this decade and beyond. Indian Oil is adding 349,000 barrels per day of refining capacity to take its base to 1.76 million b/d. It is also doubling its petrochemical capacity to diversify its operations, while altering its product slate — replacing diesel with bitumen and jet fuel to adjust to changing demand patterns. Smaller peer Bharat Petroleum Corp. Ltd. (BPCL) has pledged $17.6 billion in investment over the next five years in six new strategic areas to hedge against any possible decline in its liquid fossil fuel business. But three of these are still fossil fuel-based: petrochemicals, natural gas trading and upstream. State-owned explorer Oil and Natural Gas Corp. also recently noted that even in a net zero scenario, there will still be a considerable level of oil and gas demand from petchems, industry and transportation.

Booming Profits Expand Aramco's Spending Options

High oil prices coupled with tight global spare capacity have put state-owned Saudi Aramco in a unique position of strength. Booming profits are a windfall for Riyadh but also provide optionality for Aramco investments as it assesses energy market needs. Aramco's upstream oil expansion plans are moving ahead, but it is also pursuing higher domestic natural gas output and eyeing opportunities in refining, where there is a global capacity crunch. Aramco's second-quarter results reflected the recent oil price boom. The company's net income rose to $48.4 billion versus $25.5 billion in the same period of 2021, while its first-half net income hit $87.9 billion, up 86% compared to the same period last year. The quarterly result is a record for Aramco since going public in late 2019, but the lion's share of revenues are still being funneled to the state, which is using the windfall to diversify the Saudi economy. Compared to Western oil majors Exxon Mobil, Chevron, BP and Shell — which saw their adjusted net income rise by an average of 62% in Q2 compared to Q1 this year — Aramco's quarter-to-quarter profit increase was more moderate. That is because the company's financial obligations to the government increase as oil prices rise under a predetermined system made public in 2020. Under the current guidelines, Aramco pays a royalty of 80% at Brent crude prices above $100 per barrel, and a royalty of 45% at $70 to $100/bbl. In the second quarter, Aramco paid the government around $69 billion in taxes and royalties, which is more than four times the amount allocated to dividends for the quarter. So far, there are no plans to increase the dividend paid to the company's minority shareholders. Management said the board of directors will next discuss the issue in March 2023.

In terms of capital expenditures, Aramco increased its upstream spending by around $2 billion in the quarter while downstream spending was flat. Overall capex guidance remains unchanged for 2022 at between $40 billion-$50 billion, but this will increase from 2023 until 2025. Despite concerns about the global economy, upstream expansion remains a top priority for Aramco, which has warned about thinning global spare capacity due to recent weak upstream investment. "We are progressing very well in our increase of capacity," Aramco CEO

Amin Nasser said after announcing the company's quarterly results on Sunday. He added that the capacity increase from the present level of 12 million b/d would be gradual, with maximum sustainable capacity rising to 12.3 million b/d in 2025, 12.7 million in 2026 and 13 million b/d by 2027. Despite greater uncertainty around the global economy and fears of a recession, Nasser was confident that China's reopening and return of air travel will sustain oil demand in the short term, with 2023 expected to exceed pre-pandemic levels. Longer term, he also expressed optimism that demand will remain strong.

Aramco is simultaneously seeking to boost its gas production for domestic consumption, which would help free up around 1 million b/d of liquid hydrocarbons that are currently being used for power generation. Energy Intelligence also understands that the Saudi leadership is seeking to expand Aramco's downstream footprint in India and China over the coming years, believing this will further boost the company's valuation. For now, there are no immediate plans to list more of Aramco given the current volatile environment. In gas, increasing output from the Jafurah field is key. According to Aramco's management, the project has started its development phase, targeting the start-up of the first phase in 2025, the second phase in 2027 and plateau in 2030. Aramco management said this week that drilling and fracturing costs were down 68% and 95%, respectively, against a pilot phase in 2015. Some 500 million cubic feet per day of ethane and high levels of condensate will be generated as Jafurah, which is expected to produce 2 billion cubic feet per day of gas by 2030, is completed.

Public E&Ps Weigh Merits of Private Life

A number of US independent E&Ps are exploring taking their businesses private. Investor pressure has built over the past few years for independents to stem growth, return massive amounts of cash to shareholders and improve their environmental credentials. While many have succeeded in meeting investors at least halfway, some are not content to sit on curbed production in the current commodity price boom. Continental Resources founder and chairman Harold Hamm launched a $25.4 billion take-private offer for the company recently, citing the "freedom" privates have to operate without the limits of the public markets. Indeed, privately owned oil and gas producers, which do not face the same shareholder demands for capital discipline as their publicly traded peers, have been most responsible for driving up the US rig count over the past year. Meanwhile, billionaire Warren Buffett's Berkshire Hathaway has increased its stake in Occidental Petroleum to over 20%, not including preferred shares and warrants, fueling speculation he may take the large Permian operator private.

Further, public operators have been vocal about their belief that their stocks are undervalued by the market. Many believe that oil and gas markets have entered a multiyear upcycle due to chronic underinvestment in upstream supplies in recent years. They have responded by stepping up share buyback programs, effectively reducing the amount of public stakes, to demonstrate their faith that share prices will rise and keep investors interested. Buffett's bet on Oxy, even if he doesn't buy up the rest of the company, is still a big one; it also demonstrates the magnate's faith in oil's future. The purchases also give him a toehold in Oxy's Low-Carbon Ventures business, which could be a target for additional investment in the years to come — particularly with federal support for technologies like carbon capture and storage and hydrogen now a certainty with the passage of a US tax and climate law this week. Meanwhile, Hamm's $70 per share offer may represent a premium to Continental's current price, but market watchers say it also takes advantage of the stock's undervaluation and may, in the end, attract a bigger buyer.

Whether a company's strategy would change if taken private would depend on the acquirer. But it would likely shift a firm's business plan from a cyclical strategy to a permanent one. That could be, in Hamm's case, bucking the public market and chasing growth while commodity prices are high. Oxy, meanwhile, would likely remain in cash-machine mode for a number of years regardless of prices, with the Low-Carbon Ventures unit providing some optionality.

But going private is not a cure-all for a company's woes. Private operators may not be beholden to public markets, but they cannot escape wild swings in commodity prices. Nor can they entirely escape environmental, social and governance (ESG) pressures, as more banks, creditors and lenders seek to mitigate their risks here. A number of private independents filed for bankruptcy in the last downturn as oil prices cratered. And while a private investor could be more lax about environmental policies than a horde of public shareholders, they must still meet environmental standards at the regulatory level and could face issues about climate and energy transition risks in wider capital markets. More immediately, as more public E&Ps explore their options, the window for action is starting to close amid rising interest rates, which would increase the cost of taking a public company private.

What's New Around the World

GENERAL

GAS — European spot gas prices could exceed $4,000/Mcm this winter — or more than $110/MMBtu — Russian gas giant Gazprom said. Spot prices hit new highs of more than $2,500/Mcm this week and could rise at least another $1,500/Mcm, if the current trend continues, Gazprom said in a statement that described its price outlook as "conservative." The company said Europe still needs to inject 23.8 Bcm of gas into storage if it wants to match the stockpile it had at the start of the 2019-20 winter heating season, which equated to 97% of storage capacity. Meanwhile, EU data shows that the 27-nation bloc is on track to reach its 80% storage target by November, as injections into storage continue despite the current tight market. EU gas stocks are currently just under 75% full. Gazprom has helped drive gas prices up by delivering less gas to Europe. The government-controlled company denies that it is deliberately withholding supply and says the reduced flows are a consequence of European sanctions against Russia. Some observers have suggested Gazprom might be trying to sabotage the EU's storage injection campaign to persuade European governments to ease sanctions against Russia and dial down their support for Ukraine.

UPSTREAM — Australian independent Santos has sanctioned the first phase of the Pikka oil project in Alaska but has put the Dorado oil project in Australia on hold because of inflation and supply chain concerns. The $2.6 billion first phase of the Pikka project on Alaska's North Slope consists of a single drill site and a production facility with a capacity of 80,000 b/d. Existing infrastructure, including the Kuparuk and Trans-Alaska pipelines will be utilized to limit the project's environmental footprint. Santos says the final investment decision on Pikka Phase 1 is consistent with its goal of achieving net-zero emissions from its own operations (Scope 1 and 2) by 2040. The company has entered into memorandums of understanding with Alaska Native Corporations to deliver carbon offset projects, including a strategic alliance with ASRC Energy Services. First oil is planned for 2026, with an estimated break-even cost of supply of around $40/bbl, including carbon pricing. Santos said it still plans to sell down its 51% interest in Pikka that it inherited as a result of its acquisition of Oil Search. The remaining 49% is held by Spain's Repsol. Dorado was previously expected to be sanctioned in the second half of this year.

COUNTRIES

AZERBAIJAN — Azerbaijan is ramping up sales of gas to Europe from the giant BP-operated Shah Deniz field in the Caspian Sea as it looks at expanding the capacity of the Transadriatic Pipeline (TAP). According to the Azeri energy ministry, gas exports to Europe amounted to 6.5 billion cubic meters in the first seven months of this year. An additional 4.8 Bcm went to Turkey and 1.6 Bcm to Georgia. That represents a 24% increase in overall exports compared to the same period last year and bolsters Azerbaijan's position as an important regional gas player. The European Union has identified the Caspian nation as a key long-term alternative to Russian gas, as the 27-member bloc scours the globe for new sources of supply. During a trip to Baku in July, European Commission President Ursula Von der Leyen, signed a memorandum of understanding with Azeri president Ilham Aliev, to increase Azeri gas imports to 20 Bcm/yr by 2027 — all of which would come from an expanded TAP line. TAP runs from the Greek-Turkish border, across Albania, to Melendugno in southern Italy. It has a current capacity of 10 Bcm/yr, but Azerbaijan has talked about expanding that to 20 Bcm/yr.

INDIA — India's fuel demand weakened in the first half of August as monsoon rains hit demand for transportation fuels and impacted consumption of diesel in the construction, mining and agriculture sectors. While gasoline sales marginally rose 0.8% during the first 15 days of August compared with same period in July to 765,000 b/d, diesel consumption contracted 11% during the same period to 1.43 million b/d, preliminary sales data of state-owned refiners showed. Jet fuel consumption contracted 0.7% during the first half of August compared with same period in July to 134,000 b/d, while liquified petroleum gas consumption shrank 8% to 889,000 b/d, the data showed. Fuel demand is likely to pick up pace as monsoon rains weaken going forward this month and with the advent of Hindu festival season in October.

NIGERIA — Nigeria National Petroleum Corp. (NNPC) has renewed five deepwater oil leases with industry heavyweights such as Exxon Mobil, Chevron, TotalEnergies, Shell and Equinor. NNPC says the extended deals could generate an additional $500 billion in revenues for the country over the long term. The renewal of the leases is an important step for Nigeria's oil sector since the long-awaited Petroleum Industry Act (PIA) was signed by President Muhammadu Buhari a year ago, setting down a new set of rules and guidelines for foreign investors. NNPC's managing director, Mele Kyari, said the new lease agreements create "a great deal of clarity between NNPC and its partners in the deepwater space." The deepwater license renewals are a welcome distraction for Nigeria from the recent debacle over the $1.3 billion sale of Exxon's shallow-water assets in Nigeria to UK-listed independent Seplat Energy. That deal — agreed earlier this year by the two companies — was approved by Buhari, before he reversed his decision to align himself with the country's newly created oil industry regulator. This has created considerable uncertainty, with Seplat claiming it had not received official notification that Buhari's earlier decision had been reversed.

UNITED STATES — European majors Shell and Equinor are partnering to pursue a "collaborative clean energy hub" concept in the US Northeast with manufacturer US Steel. The hub would focus on carbon capture and hydrogen technology in Ohio, West Virginia and Pennsylvania, the companies said Tuesday. The area is home to the prolific Marcellus Shale gas play, where Equinor operates. Shell, meanwhile, is constructing a petrochemical complex in Pennsylvania that will use shale gas as feedstock. The non-exclusive cooperation agreement calls on Equinor and Shell to jointly apply for US Department of Energy funding designated for the creation of regional clean energy hubs. US Steel is evaluating the role it may play in the hub, including as a potential funding participant, customer, supplier or partner. The news follows a similar but separate agreement announced in February to develop a CCS and hydrogen hub in the region. Shell, Equinor and US Steel were partners in that agreement, along with EQT Corp., Marathon Petroleum, GE Gas Power and Mitsubishi Power. Equinor also announced a collaboration with technology firm Battelle earlier this year to explore CCS development near its Marcellus Shale operations. Equinor says it has captured and safely stored more than 23 million tons of CO2 since 1996.

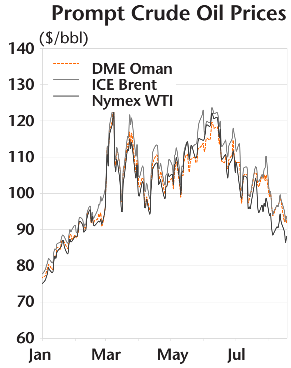
UNITED STATES — Refining capacity in the US is set to grow next year, but not nearly enough to offset the dramatic rationalization that started in the middle of 2019. Chief among the projects adding downstream capacity in 2023 is Exxon Mobil's expansion of its Beaumont, Texas facility, where the integrated major expects an incremental 250,000 b/d in throughput to come into service midyear. Valero Energy, meanwhile, is constructing a 55,000 b/d coker at its facility in Port Arthur, Texas. In addition, the former Hovensa refinery in St. Croix in the US Virgin Islands is working toward a restart, a development that would add roughly 200,000 b/d in capacity. The timeline for the restoration of the refinery is uncertain, however, and previous attempts to restart have fallen apart. However, the additional capacity due to come on line in the next year-plus is a drop in the bucket compared to recent losses. Starting in 2019 with the explosion of the Philadelphia Energy Solutions refinery, the US downstream has lost over 1 million b/d of throughput capacity to closures, accidents and conversions to produce renewable fuels.

Marketview

Let Down

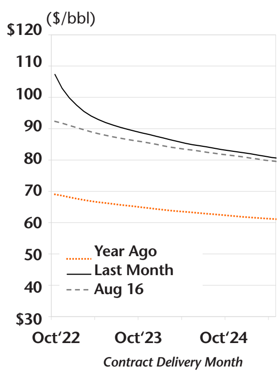
Oil prices have see-sawed over the course of the week, experiencing heavy losses at the start but clawing back lost ground over the past two sessions. There are two main bearish factors weighing on crude: flagging demand in China and the possibility of a nuclear deal with Iran that would see more oil coming to market. Both come amid worries about broader economic growth. However, most trading action in futures remains concentrated at the front of the curve and takes place against a backdrop of low liquidity. From a physical perspective, oil remains better supported.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

ICE Brent Forward Curves



At the start of the week, China's central bank cut interest rates in response to economic wobbles. Some analysts attribute the country's slowing growth to Covid-19 response policies. Both the lockdowns and the fiscal moves hurt oil consumption. For one thing, a weaker Chinese currency versus the dollar makes oil, which is priced in greenbacks, more expensive. And quarantine measures naturally impede road fuel consumption. Market players also noted that imports of crude to China have been lackluster, with current levels flat with late 2019.

Adding to bearish sentiment is developments in the pursuit of a deal with Iran that would allow the Islamic Republic to export more oil in return for nuclear concessions. A deal would bring an incremental 1 million barrels per day of supply to market, just as the EU intensifies implementation of its embargo on seaborne Russian oil and massive sales from US strategic reserves draw to a close. Some analysts have said the return of Iranian barrels could send crude to the low $80s. Others, such as Goldman Sachs, see a return as having a $5-$10 per barrel effect.

There are signs that selling has been exaggerated, however. Physical markets for crude and products are tighter than suggested in the so-called paper market, and dated Brent has maintained a premium to its derivative futures contract on London's Intercontinental Exchange.

Even if Iran returns fully to market, the world must still cope with disruptions of Russian flows of crude and product, particularly to Europe. Not only do sanctions and embargos tighten the market, the West's price cap plan and means of enforcement via shipping insurance could exacerbate the pain.

Surging natural gas prices and the approach of harvest season and winter in the Northern Hemisphere will ratchet up the tightness in products, particularly diesel and heating oil. Iranian crude contributions cannot do much to alleviate fuel tightness, especially as Europe's downstream is hampered by high gas and feedstock prices.

A late-year crunch could be in the offing. To wit, US exports continue to climb higher; crude shipments recently hit a record 5 million b/d, while diesel exports remain well above 1 million b/d. But portions of the US downstream are in maintenance, and refiners there have been running so hard that turnaround projects cannot be postponed without increasing the risk of unplanned outages.

Meanwhile, trading volumes remain relatively anemic. This both results from and contributes to recent volatility that has seen exaggerated price swings in both directions; volatility makes it more expensive to trade, prompting players to exit, resulting in thinner volumes that amplify price movements.

Murban Export Disruption Starts to Ease

A two-week outage at the key export terminal for Abu Dhabi's light, sour Murban crude grade is gradually easing, with at least one of the three single point mooring buoys understood to have resumed loading operations recently.

The Abu Dhabi National Oil Co. (Adnoc) terminal at Fujairah — located outside the Strait of Hormuz shipping lane — is the key export outlet for Murban crude. Murban is the Mideast's most important light, sour grade and physically underpins the ICE Futures Abu Dhabi Murban futures contract. Floods struck the United Arab Emirates in late July, and the emirate of Fujairah on the Arabian Sea was hit particularly hard, forcing the closure of the Adnoc terminal, said a source at a Mideast market player.

PIW Market Indicators

($/barrel)	Aug 15-Aug 17	Aug 8-Aug 12	Jul 18-Jul 22
Spot Crude			
Opec Basket	$97.74	$101.55	$108.82
UK Brent (Dtd.)	96.14	104.57	113.39
US WTI (Cushing)	90.52	94.60	102.24
Nigeria Bonny Lt.	102.01	110.95	123.52
Dubai Fateh	92.32	95.85	103.31
US Mars	88.81	93.13	99.22
Russia Urals (NWE)	67.01	71.75	81.02
Crude Futures			
Brent 1st (ICE)	93.70	97.62	105.52
Brent 2nd (ICE)	93.01	96.28	100.99
B-wave (ICE)	93.61	97.00	104.94
WTI 1st (Nymex)	88.02	91.92	100.03
WTI 2nd (Nymex)	87.57	91.16	97.25
Oman 1st (DME)	92.85	97.45	104.24
Oman 2nd (DME)	90.07	93.83	99.15
Murban 1st (ICE)	94.27	98.12	107.52
Murban 2nd (ICE)	91.94	95.23	101.39
Forward Spreads			
Brent (1st-Dtd.)	-$2.44	-$6.95	-$7.87
Brent (2nd-1st)	-0.68	-1.34	-4.53
WTI (2nd-1st)	-0.45	-0.77	-2.78
WTI (3rd-2nd)	-0.38	-0.74	-2.65
Oman (2nd-1st)	-2.78	-3.62	-5.09
Oman (3rd-2nd)	-1.96	-2.37	-3.79
Murban (2nd-1st)	-2.33	-2.89	-6.13
Murban (3rd-2nd)	-1.27	-1.52	-4.10
Grade Differentials			
WTI-Brent (1st)	-$6.13	-$6.46	-$7.30
WTI-LLS	-2.62	-2.55	-2.86
WTI-Mars	+1.72	+1.47	+3.02
Brent(Dtd)-Dubai	+3.82	+8.72	+10.08
Brent(Dtd.)-Urals	+29.13	+32.82	+32.36
Brent(Dtd.)-Bonny Lt.	-5.87	-6.38	-10.14
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$95.94	$100.26	$106.35
Arab Lt.-Europe (Med)	98.71	102.10	108.84
Arab Lt.-Far East (f.o.b.)	103.80	107.20	110.79
Nigeria Bonny Lt.	102.60	111.03	118.34
Arab Light Gross Product Worth			
Rotterdam	$101.97	$102.32	$113.54
US Gulf Coast	107.52	109.99	116.61
Singapore	100.04	99.31	104.27
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$112.76	$113.04	$114.42
UK Brent Margin	+13.62	+6.95	-0.63
US Gulf Coast			
Mars GPW	102.67	106.07	111.79
Mars Margin	+13.76	+12.83	+12.47
Singapore			
Oman GPW	98.46	98.79	104.13
Oman Margin	+0.81	-1.93	-1.73
US Nymex			
WTI 3-2-1 Crack	+$43.17	+$39.66	+$41.01
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$917.33	$939.56	$1046.08
Gasoil (0.1%)	1056.25	1032.90	1100.60
Fuel Oil (0.5%)*	675.42	696.40	742.60
US Gulf Coast (¢/gal)			
RBOB Gasoline	269.83¢	277.56¢	308.55¢
ULS Diesel	344.89	331.75	355.84
Fuel Oil (0.5%, $/ton)	$713.33	$744.60	$821.60
Singapore ($/bbl)			
Naphtha	$71.78	$76.61	$83.79
Gasoil (0.05%)	128.90	123.85	131.11
Fuel Oil (0.5%, $/ton)	746.00	758.40	950.80

*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.