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Traders Brace for Losses to Russian Exports

Market players increasingly believe Russia will fail to keep all its oil flowing once EU import bans take effect. Asian traders think China and India cannot absorb all of the 1.2 million barrels per day of crude oil that Russia still must redirect away from Europe, and it will be even harder to find non-EU buyers for an additional 1 million b/d of Russian refined products, since Asia does not need these. With the ban deadlines looming and the December trading cycle starting, traders are also eagerly awaiting details of the G7 price cap on Russian crude and products. Trading sources in Singapore think Russia will only manage to place roughly half of the additional crude and products in Asia that will be displaced by the EU bans, which take effect on Dec. 5 for crude and Feb. 5 for products. They note that China is reluctant to buy much more than the current 2 million b/d of Russian crude — already 400,000 b/d more than average 2021 levels. "China wants to keep Russian buying at current proportionate levels," one analyst noted. If China would increase crude imports by 1 million b/d to ramp up refinery runs, Russia's share would just be 20% of that, the analyst said. Likewise, Indian refiners are close to maxing out their Russian intake, traders said. All of Asia could perhaps take another 600,000 b/d more, with perhaps some going to the Mideast. Finding new markets for Russian products is even harder, as both India and China are long diesel, while most OECD countries are banning the imports. That leaves Africa, Latin America and the Mideast as remaining outlets. Moscow may recognize the potential problem. Reuters reported this week that Russia is likely to propose that Opec-plus reduce oil output by around 1 million b/d at its next meeting on Oct. 5, a move that would provide price support if its exports fell.

The G7 price cap system is designed to keep Russian crude and products flowing — to avoid

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Price Cap Response in Moscow's Hands

The Kremlin will dictate how Russian oil companies deal with the G7's price cap on Russian oil exports. Political factors will outweigh everything else, even if there is an economic case for Russian producers to sell their oil under the parameters of the cap. It is important not to give in to pressure from the West, since concessions could encourage more Western sanctions and restrictions in the future, Russian market players believe. Details of the cap have been slow to emerge, but the idea is to set Russian export prices below market levels to restrict Moscow's income but above its production costs to keep Russian oil flowing — and hopefully avoid a global price spike. Traders see flaws in the system though and say it will be easy to evade and difficult to enforce. Yevgeny Tolochek, CEO of midsized Russian independent producer Russneft, does not rule out that the cap could work in favor of Russian exporters — if it is set at an acceptable level and if the ruble/dollar exchange rate improves. In what could be an indicator of an acceptable level, Russneft's 2023 budget is based on a $69/bbl Urals price, while benchmark Brent crude now trades near $90/bbl. Tolochek said Russneft would like to see an exchange rate of 80 rubles to one US dollar, compared to 58 rubles now. But he emphasized that Moscow would have the final say on how firms proceed.

A price cap of $70/bbl could just formalize the discount that Russia now offers to buyers of its oil from "friendly" countries. But Russian President Vladimir Putin and other officials have repeatedly said Russia would stop supplies to those countries that use the price cap. Indeed, it is

doubtful Moscow would accept any price mechanism designed to reduce its income and ability to finance the war in Ukraine. Reports suggest the price cap under consideration is in the range of $40-$60/bbl. Russia's production costs stand at $15-$40/bbl, depending on the field. The draft of the 2023 state budget now under consideration in Russia's parliament is based on $70/bbl. Igor Sechin, CEO of state-controlled Rosneft, said earlier this year that Moscow offers discounts to friendly countries, while unfriendly countries should pay a premium for Russian oil — more evidence that decisions on pricing will be politically motivated. According to an executive at a major Russian oil producer, Moscow should not agree to any compromise on the price cap because it is a violation of market principles, and concessions now could lead to new problems in the future. The decision should be unanimous, and all exporters should follow it — otherwise it won't work, the deputy governor of the Tyumen region, Andrei Panteleyev, said last week.

Still, Russian companies refuse to talk about their plans following the EU's embargo on Russian crude imports, which takes effect on Dec. 5 along with the price cap. They already admit that oil sales are a big challenge now, with September export figures showing some weakness. However, official plans indicate that Moscow remains optimistic about its crude exports next year. The draft of the state budget approved by the government envisages 2023 exports at 250 million metric tons (5.013 million b/d), up from 243.1 million tons (4.875 million b/d) in 2022. This could be too ambitious. Indeed, Russia's September oil exports are set to show the largest monthly decline so far this year, to 4.53 million b/d, down by around 385,000 b/d compared with August, according to Energy Intelligence calculations. Crude oil and gas condensate production is expected to fall in 2023, according to the state document, to 490 million tons (9.827 million b/d), from 515 million tons (10.328 million b/d) expected this year, although Russian was producing more — 10.68 million b/d — in January-August 2022. A Reuters report this week suggested Russia is likely to suggest a cut in Opec-plus output of around 1 million b/d at the group's next meeting on Oct. 5. Energy Intelligence understands that Russian oil company executives would like to see a cut in Opec-plus production to bolster prices — especially ahead of the EU ban and price cap — but Russia has not publicly called for a reduction in output so far, and officials in Moscow have not communicated such a proposal to other Opec-plus members, according to delegates.

Oil Plays Big Role in Galp Transition Plan

Portugal's Galp is ramping up volumes across its diversified energy portfolio as it looks to sector-leading oil growth as well as significant increases in its capacity to produce renewable power, renewable fuels and potentially lithium for batteries. CEO Andy Brown, who came to Galp last year after a long career at Shell, told Energy Intelligence in an exclusive interview that the world needs to transition to clean energy, but cutting off all oil growth does not make sense. "I am worried about how the world can satisfy both what is a very clear and urgent climate objective," Brown said, "but secondly to make sure that energy is delivered as abundantly and affordably to consumers around the world." Even with the planned expansion, Galp forecasts spending to decrease by 20% relative to its historical average to between €800 million-€1 billion ($783 million-$979 million) through 2025, as it balances its production growth with returns to shareholders.

Galp is planning to boost hydrocarbon production by at least 25% by 2025. This compares with plans from European majors like TotalEnergies, Shell and BP for modest growth in the low-single digits in the medium-term and expectations for later declines as they shift attention to transition businesses. Galp's growth will come despite it allocating just 50% of its capital budget to hydrocarbons — a lower percentage than other European companies, which commonly allocate at least two-third of their budget to traditional oil and gas investments. By 2025, Galp's total production should reach well over 150,000 barrels of oil equivalent per day, driven by growth from its non-operated holdings offshore Brazil. It also owns a slice of Area 4 off Mozambique, where the Coral FLNG project is about to come onstream, and exploration acreage in Namibia, where Total and Shell have reported potentially massive discoveries. The portfolio has the advantage of both low costs, with an estimated breakeven for new projects of $25 per barrel, and low carbon intensity of 10.2 kilograms per barrel, compared to an industry average of 17.4 kg/bbl.

Galp's plans to build its renewable power portfolio are similarly ambitious. It has 1.2 gigawatts in operation and another 7.8 GW in its project pipeline, with a focus on solar. Brown is looking to expand outside of Galp's Iberian stronghold—again focusing on the potential of Brazil—to grow renewable capacity to more than 4 GW by 2025 and 12 GW by 2030. Some of that additional capacity will be directed to green hydrogen production starting with a modest 2-megawatt electrolyzer to supply the needs of its 220,000 b/d Sines refinery in Portugal. Galp is targeting returns of at least 9% from its renewable power investments, and Brown sees the potential for even higher margins by increasing exposure to the currently high-priced merchant power market. Beyond its initial hydrogen needs, Galp is studying investment in two 100 MW electrolyzers and future electrolyzer capacity of as much as 1 GW as the market for hydrogen grows. "We believe that getting ourselves going at the 100 megawatt level is probably an important thing for Galp to do because we do believe in the long-term value of this market," he said.

Galp's foray into lithium processing is unique among its peers, which have looked to grab a piece of the electric vehicle (EV) revolution through charging, convenience store sales or lubricants rather than the EV manufacturing process. The company's proposed Aurora lithium processing joint venture with battery giant Northvolt seeks to leverage its unique location—Portugal has the largest lithium reserves in Europe—with a growing fear among policymakers that the continent could be trading its dependence on Russian gas for a dependence China's dominance of renewables technology. Mooted for Setubal, Portugal, Aurora would have capacity to produce up to 35,000 tons of lithium hydroxide using green power, enough to produce about 700,000 EVs. Northvolt has signed up to take up to half the production volume for its own battery manufacturing operations that will supply carmakers like BMW, Volkswagon and Volvo. The business could have "an extraordinary growth trajectory," Brown said, adding the plant could leverage the "cheapest renewable energy sources in Europe."

Gas Crisis Threatens LNG's Future in Asia

Persistent sky-high LNG prices and new competition from Europe are prompting Asia to rethink the role of gas and LNG in its energy future. As the world's fastest-growing LNG market, Asia had hoped to lean on LNG heavily to achieve carbon-neutrality goals, offset declining domestic production and complement renewables in power generation. But LNG's future role in Asia appears less secure today as policymakers and consumers respond to the current energy crisis. Soaring European gas prices have hoisted Asian spot LNG prices and led to demand destruction. Asian LNG demand was down nearly 8% in the first half of 2022, and weakness is expected to persist in the near term. China will likely record an annual decline in LNG demand this year due to high spot prices and Covid-19-induced economic slowdowns. China's attention has shifted to cheaper coal, domestic gas supplies and Russian pipeline gas. The crisis, meanwhile, has emboldened Japan and South Korea to push for a revival of nuclear power, while Southeast Asia is also studying its nuclear options.

The Ukraine war and high prices are encouraging Beijing to reconsider the significance of gas and LNG in its energy mix, Chinese sources say. Energy security and self-sufficiency have gained renewed importance. This has prompted Beijing to retain flexibility to turn to coal as a last resort in its latest five-year energy plan (2021-25), which made no mention of coal-to-gas switching and did not state any gas targets. China has also approved more new coal capacity and 10 new nuclear reactors — the most since 2008 — suggesting doubts over gas as a transition fuel. Gas is closely linked to people's livelihoods, so affordability is critical, giving domestic gas and pipeline gas an advantage over LNG. Sources say price and policy will determine China's gas and LNG consumption. They peg China's threshold for LNG spot prices at up to $15 per million Btu — much lower than current prices around $40/MMBtu. Chinese buyers signed a flurry of new long-term LNG deals earlier this year, but momentum has since eased as sellers seek higher prices. Since LNG prices are expected to remain elevated until new supply comes on line in the mid-2020s, Chinese gas consumption could decline in the next three to five years, particularly given China's uncertain economic outlook.

While Russia's accelerated pivot to Asia gives China leverage for additional Russian supplies, sources believe China will tread carefully due to concerns about sanctions and Russia's reputation as an unreliable supplier. The lack of details in a February agreement to import an additional 10 billion cubic meters per year from Gazprom showed that the deal holds greater political significance than commercial viability, while a recent meeting between Russian leader Vladimir Putin and his Chinese counterpart, Xi Jinping, in Uzbekistan failed to shed light on the proposed Power of Siberia 2 gas pipeline via Mongolia to China. Some observers argue it is not urgent for China to buy new Russian gas before 2030 given that it is already planning to boost gas supplies from Turkmenistan by 30 Bcm/yr via a new Central Asia Pipeline D now under construction. Chinese buyers have also committed to around 40 million tons per year of LNG in new term contracts, most of which would start from mid-2020s.

The rerouting of LNG flows to Europe is hurting plans by Asian emerging markets that are on the cusp of importing LNG to support power generation. New regasification projects in Vietnam and the Philippines, due to start up this year, are facing delays because of high spot prices and the inability to secure LNG supplies. Vietnam has delayed releasing its new long-term power plan through 2030, with a vision to 2045, as it ponders the implications of Europe's gas crisis and the feasibility of developing offshore wind as an alternative. "Global spot market competition for LNG, exacerbated by ongoing events in Ukraine, have raised questions over whether Vietnam, a developing market, can compete with traditional European and East Asian buyers who are racing to stockpile supplies to meet national energy security interests," says Daniel Haberfield, an Australian lawyer based in Ho Chi Minh with Mayer Brown.

Traders Brace for Losses to Russian Exports

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a price spike — while reducing Moscow's income. However, this may be impossible. Even if all Russian oil is sold under the price cap, some believe the world lacks the necessary tankers to transport all the Russian oil to new markets, since this trade realignment would extend tanker routes. This realization could prompt the EU to alter the terms of its ban. The price cap is designed to work with another EU policy that bans tankers from using Western insurance and financing services for transporting Russian oil. Firms can use these services only if Russian oil is sold under the price cap. However, Indian state-owned refiner Bharat Petroleum calculates it would take an additional 100 million barrels in tanker capacity to bring displaced Russian crude from the EU ban — which it estimates at 1.2 million-1.5 million b/d — because travel times will be much longer if it all goes to Asia. That tanker capacity is not available even if Russia finds willing buyers, Bharat Deputy General Manager Amit Bilolikar told the S&P Global Appec 2022 conference in Singapore this week. International trader Vitol came to a similar conclusion. Vitol CEO Russell Hardy suggested the EU could alter the terms of its ban and allow Russian oil to keep shipping to Europe — so long as it is under the price cap — to keep oil markets stable. Moscow, however, says it will not sell oil to any countries imposing the price cap.

Traders are also calculating the risk that Russia might decide to cut oil flows to drive up the oil price and punish the West for its political and military support of Ukraine — as it has with the natural gas flows to Europe. Consensus seems to converge around the Energy Intelligence view that the world could handle the loss of some 500,000 b/d of Russian crude but not the loss of a similar volume of refined products. The global diesel market is already critically tight, and Russian diesel exports are crucial to preventing the market from running even shorter. China is considering allowing its refiners to export more products like diesel. Traders initially thought China might buy more discounted Russian Urals to do that — which would see them earn fat refining margins — but now are less certain.

Refining Capacity Living on Razor's Edge

Oil's dramatic price slide during the third quarter obscures a major challenge facing the market as winter approaches — strained refinery capacity. While crude prices have fallen substantially amid intensifying recession fears, with global benchmark Brent now below $90 per barrel, product prices have held up relatively well and refinery margins remain robust. US Gulf Coast margins of $29/bbl per Energy Intelligence's model serve as a testament to product market tightness. A confluence of structural and acute factors mean the market will be walking a tightrope, with virtually no room for refinery outages. Put simply, supply of refined fuels is under pressure. In the Western Hemisphere, downstream capacity has dropped considerably since the start of the pandemic. Covid-19's destructive demand impacts not only caused utilization to plunge, which lowered inventories, it also accelerated closure and conversion of existing facilities, removing over 1 million barrels per day of throughput capacity in North America alone. Russia's invasion of Ukraine prompted embargoes on Russian crude and products, resulting in Russian refiners lowering utilization as well; Energy Intelligence estimates throughputs are down some 6% from prewar levels. Meanwhile, Chinese refiners have been keeping a tight leash on product exports, although August volumes jumped. European refiners are under pressure from skyrocketing natural gas prices; gas is a key component of desulfurization, and in the wake of explosions on the Nord Stream pipeline system, the price pain is becoming even more acute.

Recent developments in North America have illuminated just how stretched downstream capacity is. The US downstream has been running flat out to not only supply domestic markets but also export more product, especially to Europe as the EU looks to replace Russian volumes ahead of looming embargoes. But a series of unplanned outages, as well as seasonal maintenance, is now roiling regional markets and could have cascading effects abroad, all as a storm hit Florida this week, serving as a reminder that hurricane season remains a threat. BP has experienced fires at two plants recently. The first, at the Whiting refinery in Indiana, did not result in long downtime. But the second killed two employees at the 160,000 b/d Toledo, Ohio, plant. The entire facility is now off line with no timeline for restart. On the West Coast, meanwhile, four facilities are either undergoing or set to undergo maintenance. Product cracks in both regions are up, but the outages in the Midwest in particular mean East Coast markets will need to import more, competing with Europe for barrels. Meanwhile, Hurricane Ian made landfall in Florida Wednesday as a Category 4 storm. While it will not impact Gulf Coast refining capacity, it will roil shipping, interfering with product flows at a vulnerable time.

As the downstream walks a tightrope, oil demand is seeing support heading into winter. Even before this week's Nord Stream incident, market watchers like the International Energy Agency saw the prospect of an incremental 700,000 b/d in demand for oil via fuel switching from more expensive natural gas. Seasonal consumption patterns are at play as well, and a cold winter would amplify the need for heating fuel. Against a backdrop of costly gas, that heating fuel is likely to be petroleum. Such developments could offset slowing economic growth and lower industrial consumption of diesel. Not only will downstream players struggle to meet demand, but there is also little inventory cushion. In the US, stocks of distillate fuels like diesel and heating oil are 15.4 million barrels below 2021 levels. In Europe, stocks of middle distillates were almost 53 million bbl lower year on year in August.

The market recently got some relief from a surge in Chinese exports in August, which helped cut the legs out from under diesel prices. Many analysts also expect China to grant licenses to refiners for more exports going forward. In addition, some more refining capacity is set to come on line during the first part of 2023 in the US. But it will not be enough to offset current supply concerns unless demand slumps. China's product exports were up some 330,000 b/d in August amid weak domestic demand. Citi analysts suggest that even with new permits, Chinese exports would remain roughly 9.6% below 2021 levels. Indeed, diesel futures have rallied hard after their initial plunge. Incremental downstream capacity in North America will be offset by the impending closure of LyondellBasell's Houston refinery.

Despite Crisis, Banks Stay on Net-Zero Path

Large US banks including Bank of America, JPMorgan and Morgan Stanley are reportedly feeling increasingly uncomfortable about their membership in the UN-convened Net-Zero Banking Alliance (NZBA), a component of the Glasgow Financial Alliance for Net Zero (Gfanz). Amid political pressure over the legitimacy of environmental, social and governance (ESG) considerations, they fear being sued over explicit commitments to phase out fossil fuels. However, beyond local issues in the US, evidence shows that pledges under NZBA are progressing steadily, even if this is slower and less ambitious than climate activists would expect. The issue relates to updated guidelines released in June by the UN Race to Zero campaign, Gfanz's key conceptual source. The new guidelines make explicit the obligation for signatories to restrict fossil fuel financing. "The exact pathways and timelines naturally differ across regions and sectors," Race to Zero insists. But even with this provision, "the explicit phase down and out of all unabated fossil fuels is a bridge too far for many US banks," nonprofit BankTrack's Johan Frijns tells Energy Intelligence. Over the past year, there has been backlash toward ESG investing in some Republican-leaning, fossil-fuel producing US states like Texas, Oklahoma and West Virginia. These states have threatened to cut ties with certain ESG-focused financiers, prompting some firms to promote their commitments to fossil fuel investments.

Whereas most North American banks have opted for carbon intensity targets, most European banks have published absolute emissions reduction targets to 2025-30. The latter are roughly in line with the International Energy Agency's (IEA) Net-Zero Emissions (NZE) scenario, in which oil and gas-related emissions drop by almost 30% over 2019-30. NZBA was launched in April last year and has grown to include some 120 banks representing 40% of global banking assets. Half of them are from Europe, 20% from the Asia-Pacific region and 15% each from North America and the rest of the world. NZBA banks commit to align greenhouse gas emissions attributable to their lending and investment portfolios with pathways to net zero by 2050 or sooner. Within 18 months of joining, they are due to set 2030 targets and intermediary goals every five years from 2030 onward. European banks have been engaged in climate action for many years, so complying with NZBA requirements has been a "mere formality" for many of them, Frijns notes. Published targets to 2030 range from minus 19% for oil and gas lending by the Netherlands' ING to minus 50% or more for Germany's Commerzbank, Switzerland's Credit Suisse and UBS, Denmark's Danske Bank and the UK's Lloyds. Instead of absolute targets, most US and Canadian banks have targeted reductions in emissions per unit of energy, which critics say allows them to keep increasing oil and gas financing.

Green activists criticize NZBA banks because very few of them exclude financing any oil and gas expansion. Banks argue that while the IEA's NZE finds that no new oil and gas fields need to be approved for development, other net-zero scenarios allow limited investment in new resources. They insist they also need flexibility to manage their oil and gas exposure, especially in the current geopolitical context and energy crisis. Indeed, Gfanz co-chair and former Bank of England governor Mark Carney recently acknowledged that Russia's invasion of Ukraine will cause emissions and investment in fossil fuels to increase in the near term. But "more assets will become stranded as a consequence of that" because they risk being short-lived, he warned. "Judgements [need to] be appropriately made on whether financing them is okay." BankTrack identified only one NZBA bank — France's Banque Postale, a relatively small one — having decided to stop lending to oil and gas companies developing new supply projects. In some case, banks exclude segments of the fossil fuel industry, notably coal. France's BNP Paribas no longer provides products and services to companies with more than 10% of their business in tar sands and shale oil and gas, or any oil and gas projects and related infrastructure in the Arctic and Amazon regions. The UK's NatWest will only finance upstream oil and gas projects where the majority of assets being financed are based in the UK. In recent years, all major US banks — Goldman Sachs, Morgan Stanley, JP Morgan, Wells Fargo, Citi and Bank of America — committed to ending financing for oil and gas exploration in the Arctic.

Labor, Supply-Chain Woes Dog US Projects

US producers are facing multiple headwinds from labor constraints, equipment shortages and supply squeezes on goods and services. On top of the labor shortages and inflationary pressures oil and gas companies are seeing, there are growing concerns that similar hurdles could hinder the new wave of clean energy projects, spurred by the recently passed Inflation Reduction Act, with its $369 billion in climate provisions. Labor shortages have been well documented, with the Bakken shale in North Dakota having the most visible struggles attracting workers. After years of paring back costs and instituting layoffs, exacerbated by the Covid-19 pandemic, the oil-field labor force of several years ago has dwindled and been dispersed, leaving service firms struggling to keep crews staffed. Smaller E&Ps and private firms have felt the squeeze more than majors, with drilling activity levels affected at some companies; those pressures have made it harder for contractors to invest enough to keep pace with demand. Oil-field service firms have had among the most high-profile constraints in staffing crews, impacting crude production growth projections for the better part of the year, with some companies getting into labor bidding wars.

Supply-chain issues and equipment availability — primarily fracking equipment — have been a sizable constraint. Some top fracking providers like Halliburton have idled or scrapped equipment to reduce their fleets, and companies have generally been reluctant to build new equipment on spec. E&Ps, looking to accelerate activity to keep pace with demand, have also run into supply-chain bottlenecks with steel sourcing for well bores, with inventories reportedly lower than previous years. Given high steel prices, suppliers have been less likely to hold more robust high-cost inventory in case drilling enthusiasm tapers off again amid mounting concerns about a recession, which has weighed on US oil and gas prices recently.

Frack sand availability in key US shale plays has become another thorn in the side of efforts to boost output amid inflationary pressures. Prices since the pandemic started have more than doubled from less than $20 per ton to $50-$70/ton, according to Rystad Energy data, although operators switching to in-basin sand in recent years rather than sourcing it from Wisconsin sand mines has helped defray some of the costs. Antero Resources and Devon Energy recently reported using more locally sourced sand in Appalachia and West Texas, respectively, to bypass high cost and supply-chain issues.

Clean energy projects have not been immune from the labor and supply constraints, especially with a slew of potential new hydrogen, carbon capture and other projects that stand to get a boost from the new US tax incentives. That could help propel a new labor force, because the investments now have a 10-year time horizon compared to the piecemeal, short-term tax credits for clean energy in recent years. "You can't do a lot of workforce training based on a tax credit that has been allowed for one to two years," said David Foster, a former US Department of Energy official now with the Energy Futures Initiative. The crossover with oil and gas workforce skill sets could also minimize the amount of new training infrastructure, although it also adds a layer of competition for skilled workers in some cases. But supply shortages could affect clean energy projects just as heavily, especially factoring in that some of the new tax credits are tied to domestic content requirements. Global demand for electrolyzers, used in green hydrogen production, for example, has been on the rise, raising questions about the equipment sector's ability to source materials and deliver products given ongoing supply-chain challenges.

Galp CEO: Market Upheaval 'Reinforces' New Strategy

Andy Brown took over as CEO of Galp in February 2021 following a long career at Shell and quickly unveiled a new strategy at the Portuguese integrated giant. The plan seeks to balance growth in the upstream sector with rapid expansion of energy transition-focused businesses. Energy Intelligence caught up with Brown to talk about how that strategy will hold up amid recent upheaval in energy markets and how he sees the company capitalizing on transition trends.

Q: You unveiled a new strategy in June 2021, and the world has changed a lot since then. How is it performing in this unprecedented environment?

A: What happened in the last 15 months, or certainly the last six months, kind of reinforces all the things we were saying. If you look at REPowerEU and its ambition to accelerate solar, we are building a big solar portfolio in Iberia, but we're also doing it now in Brazil. So, that was very much spot on to where Europe wants to go. Europe also completely ramped up its ambition for hydrogen. Hydrogen had been a very critical part also of our strategy.

And I think where we've seen a big change is lithium, where we clearly have cemented our relationship with Northvolt, one the biggest independent battery manufacturers in Europe to build a lithium hydroxide facility. So, everything I see that's come out because of the energy crisis and then the war, and I have to be distinct — there was an energy crisis first and then war second — have meant that the regulators and the ambition, particularly in the EU, has very much reinforced the strategy we adopted.

Q: Have the events of the last year changed your thinking at all about how you deal with geopolitical risk in your strategy?

A: I think that geopolitical risk is something that we do manage as part of our business. Brazil is having an election very soon. Brazil has had governments that have been left and right wing, but you know the physical environment for the pre-salt has been very stable through that.

In Mozambique, the security issue is clearly an issue. The good news is that we're just about to produce the first LNG from the Coral floating LNG facility offshore, which is insulated from the onshore insecurities. What I do see is a world where, whether it's the US or it's Europe, has become much more interested in the security of supply of energy and much more interested in making sure they're not solely reliant on a third-party country. I do think that will throw up a lot of opportunity, particularly in Europe and obviously in America for companies like Galp.

Q: What do you think of the proposed cap on Russian oil prices? Can something like this work?

A: I think that all that does is stimulate a further move to a black market for Russian oil, so I don't know if that will in itself be successful. I think there's a big dilemma. The recession is driving demand down, so there's some relief in oil prices. But there isn't a lot of spare capacity in the world. And if [a price cap] ends up taking a lot of volume out of the Russian market, that will have its own impact back in the oil market. So, we'll see. I think it's a very relevant move for the West, the European Union and America, to try and consider how in this era of very high oil and product prices and gas prices, to avoid obviously funding Putin's war effort. But you have to be really careful of the unintended consequences of that. I do think it's a balancing act and a very difficult issue to solve.

Q: In your new strategy, you reduced capital spending by about 20% relative to past levels. Are you tempted at all to invest a little bit more to capture some of these high prices? Isn't that what commodity markets are telling you?

A: I think there's an interesting debate on whether the higher oil prices should stimulate more spending on oil projects. I think you'll find the European international oil companies will maintain capital discipline and will not be tempted. If you look back at history, every time the oil price goes up and the international companies start burning a lot more capex, the costs in the market, for deepwater rigs, for everything, goes up with it, and what we have is a boom and bust situation.

That has been what our industry has been through for the last decades. I think this is different. The reason why the European international companies are not spending more on oil is because basically that ESG [environmental, social and governance] has trumped the pricing. They are determined that they will transition their portfolio over time, so this isn't a moment to do any backsliding. I do think that the world and the regulators need to be very careful about trying to think that they can drive an energy transition by somehow stopping investments in oil. We've seen that in terms of some of the financing undertakings in COP26. I think there's an ESG part of this where the European companies are trying to transition their portfolio.

But there is going too far, which is to try and stop new oil projects — because what's been absolutely clear in the world this year has been underinvestment in oil and gas can create massive distress in the energy markets, which hurts everyone. It hurts consumers, and it doesn't drive the energy transition.

Q: Galp's expected 25% oil production growth by 2025 is the highest of your peers. What is the role of the upstream in the portfolio through 2025 and beyond?

A: Galp's premium in the oil market has been around its upstream growth path. It is predominantly because of the *Bacalhau* FPSO [floating production, storage and offloading vessel] that will come on line at the end of 2024. It's a 220,000 barrel a day capacity. We've got 20% in it. For Galp, that gives us a massive uplift in in our production. What's interesting about Galp is that it is growing its upstream but only allocating 50% of its capital on oil and gas. That means that we can spend 50% more capital on renewable projects, whether renewable energy, hydrogen or lithium. That means that business is growing much, much faster than our upstream business. So, as an average we are decarbonizing but we are growing. We have a pretty strong yield, but we are also decarbonizing, and we are growing. These are the three things I think that investors will look for in a company, and I think we're ticking all three boxes.

Q: Let's talk a bit more about that renewable portfolio. You have a significant amount of exposure to the high power market prices. How are you looking at balancing long-term power sales contracts versus merchant market exposure. What's the right risk-reward balance?

A: I think this is a really interesting debate about which is the best way to maximize returns on renewable investments. Historically the model in the utilities has been to build the renewable projects; sell long-term power purchase agreements [PPAs]; finance [the projects] on those PPAs; sell down to strategic investors to try and eke out a return. Now, financing costs are going up, costs of solar are going up, so some of the fundamentals of that business model have been challenged. The international oil companies [IOCs] have always had full exposure to the merchant risk of the oil price. They come into this electricity world and renewable electricity world and bring a slightly different view. They say I might use my own balance sheet for this and take some merchant risk.

There will be moments when you do lock in PPAs. You may lock in PPAs for your own use with your commercial customers. But I think what happens is that you get many more different models of short-term PPAs or much more merchant (exposure). When you talk to the utilities, they are also talking about increasing their merchant exposure. What I find very interesting about the whole energy system is you have had the oil and gas companies that obviously have been taking commodity risk and living on that commodity risk, and you've had utilities that have basically locked in and not taken the commodity risk, and we're both now engaged in this business.

We're going to meet in the middle and we're going to do all sorts of things like make hydrogen and renewable fuels. So, the energy continuum, I think, will be a lot more homogenized where the utilities and the IOCs start to basically move into each other's businesses. Over time you'll get a blurring of those two sets of companies.

Q: Galp is unique among its peers in pursuing lithium processing. Why is that the right strategy for you? And can you give us an update on the Aurora joint-venture facility?

A: We started thinking about lithium because Portugal was the largest lithium resource holder in Europe. There is a discovered mine in Portugal, and there's a lot of debate on whether it's actually going to be constructed or not.

But for Galp that meant there actually was a lot of interest and then there was interest from companies like Northvolt in Portugal. We are the industrial incumbent in Portugal. We're a company that has built two refineries and operate one large refinery at the moment and is used to building industrial facilities that process raw materials and make finished products. It's not an identical skill set, but it's very similar. We concluded that this would be a good way for using some of our engineering skills and processing skills in a refinery process or a conversion process that is completely entirely aligned with the energy transition.

We also observed the companies like Northvolt and also the EV [electric vehicle] manufacturers were increasingly concerned about the CO_2 footprint of the battery itself. What's the point of an electric vehicle that consumes loads of CO_2 to actually construct it? Then, recently the European Union themselves saying they want 30% of lithium to be sourced locally provides all sorts of additional impetus to say this is very much the right kind of escalator for a company like Galp to jump on.

So, Aurora joint venture has been formed. We're in what's called a definitive feasibility study. We will be looking at an FID [final investment decision] around the end of next year. That would mean that by the end of 2025, early 2026, we'd hope to be on line. That's the first step. I say that because we are quite excited to be involved in that battery value chain. We need to consider whether we extend from that conversion facility into any other parts of the value chain or we just build more of that conversion facility. It gives us optionality for growth. Now if you look at Galp. This is about a €700 million ($684 million) facility. We're 50% — so €350 million, which we will project finance. So, we're not betting the farm on this. But I think that's very appropriate and exciting for us to be in.

Q: Do you have any idea on the returns you might expect from lithium?

A: I think any industrial facility would be looking for a double-digit return. At the moment, lithium hydroxide is sold for extraordinary amounts of money, but also the cost of the raw materials is high as well. We have to again look at those value chains and consider how we get the most value. One of my concerns about the energy transition is the number of different rare earth materials.

There will become bottlenecks in the pace of the transition, and lithium is one of them. I think copper will be another because the transition will require enormous growth of these minerals. The pace and the time to get any mines up and running seems to be extraordinarily long. So, I think we'll go from an energy crisis to a rare earth mineral crisis. I think that's a real concern, which I think governments also need to address.

What's New Around the World

GENERAL

CORPORATE — TotalEnergies has set out plans to grow its business and distributions to shareholders without any future contribution from its Russian assets. Total CEO Patrick Pouyanne this week reaffirmed that "fundamentally, we don't think our future's with Russia" while emphasizing the growing importance of the French major's LNG and renewable power business in the US. The company hopes to add to its US LNG position with an equity stake in the right liquefaction project, preferably a brownfield project, Pouyanne said. He emphasized that Total's LNG business would thrive even without Russia: "I could add that it's less Russia, more US, more Qatar." Unlike its European peers that are exiting Russia, Total still has a 19.4% minority stake in gas producer and LNG developer Novatek, and stakes in the Novatek-led Yamal and Arctic LNG 2 export projects. "As long as Europe does not sanction Russian gas, we have no way to escape from these contracts," Pouyanne said. But the Total CEO said he believed cash flows from the company's Russian holdings could dry up in the coming months, amid escalating tensions between Russia and the West over the war in Ukraine.

M&A — Global upstream M&A deal value has rebounded in the third quarter, with around $32.6 billion worth of assets changing hands so far, according to Enverus. That's already up 47% from the previous quarter and the highest quarterly total since the fourth quarter of 2021. The number of deals announced, at just 106, is a far cry from the 249 transactions agreed during the same three-month period last year, but M&A experts paint a largely bullish outlook for dealmaking going forward. Russia's invasion of Ukraine and the West's resulting aversion to Russian energy supplies has lifted the appeal of oil and gas assets. Investors now recognize that conventional assets have a role to play in the energy transition for years to come, and there is a substantial return to be made from investing in them now given the bullish near-term oil and gas price outlook. Even companies with a clear focus on renewables are being tempted to make forays into fossil fuels. Germany-based asset manager IKAV, which built a portfolio around solar power following its launch in 2010, this month agreed to buy Shell and Exxon Mobil's stakes in their Aera Energy oil and gas joint venture in California.

PIPELINES — Damage from alleged explosions at the Nord Stream and Nord Stream 2 pipelines in the Baltic Sea could be difficult to repair and will be complicated by growing Western sanctions against working with Russia, according to an industry source. Danish and Swedish investigators continue their work at two leaks on the Nord Stream pipeline and another leak on Nord Stream 2, believed to have been caused by sabotage. The industry source, who is close to the projects, stressed the complication of repairing such damage to undersea pipelines, and predicted that Nord Stream is likely to remain out of action throughout this winter and potentially longer. The two pipes were each designed to bring 55 Bcm/yr of gas from Russia to Germany, although neither was flowing at the time of this week's incident — Moscow had suspended flows through Nord Stream and the Ukraine crisis prevented the start of Nord Stream 2. It is currently impossible to know how hard it might be to repair either of the lines, a process that Russian officials have said must include Gazprom as the outright or majority owner of the two pipes. The extent of damage remains unknown for now, and the potential for seawater to corrode the line could complicate the operation, the source said.

COUNTRIES

GERMANY — Germany struck an LNG supply deal and several other energy agreements with the United Arab Emirates during a Mideast Gulf trip by Chancellor Olaf Scholz, as Europe's largest economy continues to seek alternatives to Russian oil and gas. Under a deal signed at the weekend between Germany's RWE and Abu Dhabi National Oil Co. (Adnoc), the latter will supply one 137,000 cubic meter cargo of LNG for delivery in December. This will be used in the commissioning of the Elbehafen LNG import terminal at Brunsbuttel near Hamburg, which is on track to become the country's first floating storage and regasification unit. A person familiar with the matter told Energy Intelligence that a total of six LNG cargoes of "significant" size would also be delivered by Adnoc next year, in addition to the one scheduled for December. The cargoes will be supplied as part of a memorandum of understanding (MOU) for "multiyear LNG supplies" signed by Adnoc and RWE. For the UAE, the deal is a foray into an emerging LNG market as it ramps up its natural gas output and liquefaction capacity, including a new export terminal in the emirate of Fujairah outside the strategic Strait of Hormuz waterway.

INDIA — India's state-run refiner Bharat Petroleum (BPCL) has signed a preliminary agreement with Brazilian state oil firm Petrobras aimed at developing long-term oil supply contracts and diversifying both countries' oil flows. BCPL said the memorandum of understanding (MOU) between it and Petrobras will "strengthen future crude oil trade relations between the two companies" as well as "explore potential crude import opportunities ... on a long-term basis, especially considering the current geopolitical situations." The MOU is the latest sign of how Brazil is looking to expand its presence in key Asian growth markets, while India works to diversify its sources of crude oil. Petrobras has viewed Asian exports as a potentially lucrative market for its low-sulfur crude oil production from its prolific pre-salt region for years. Chinese refiners in particular have exhibited strong demand for Brazil's oil, at times accounting for nearly 90% of Petrobras' exports abroad. However, China has increasingly turned toward cheap Russian crude since Russia's invasion of Ukraine in February pushed discounted barrels east, forcing Petrobras to look to diversify its export markets. Last year, 50% of India's crude imports came from Iraq, Saudi Arabia and the United Arab Emirates, according to trade data released by India's Ministry of Commerce and Industry, while only 1% came from Brazil.

IRAQ — The commissioning of Iraq's new 140,000 b/d Karbala refinery began at the weekend, with oil ministry officials saying this should allow Baghdad to slash its costly gasoline imports bill by about a third. "We've started pumping crude oil in preparation for … beginning the plant's actual refining and production operations before the end of this year," the oil ministry's head of refining, Hamid Younis, said. Production of "high-quality oil products" should rise in the first quarter of 2023 to cover a large part of domestic consumption, he added. Despite being Opec's second-largest producer, the poor state of Iraq's refineries means it currently needs to import about 101,000 b/d of gasoline and 26,000 b/d of gasoil, another senior oil ministry official told Energy Intelligence. That equates to an annual imports bill for gasoline alone of well over $3 billion at today's prices. The $6.4 billion construction contract for the project was awarded in 2014 to a South Korean consortium led by Hyundai and was supposed to take four and half years to complete. But mismanagement, late payments and the Covid-19 pandemic all contributed to delays in Iraq's biggest ever downstream project.

QATAR — TotalEnergies has won the first of the equity stakes for Phase 2 of Qatar's 48 million tons/yr LNG mega-expansion, state-owned QatarEnergy announced. The French major's selection as a 9.375% partner in the 16 million ton/yr Phase 2, also known as North Field South (NFS), comes as no surprise, confirming an earlier exclusive report by Energy Intelligence. The award gives Total an outsized share of the 25% of NFS that QatarEnergy will make available to international partners. "The timing is perfect because, as you know, most of the leaders of the world have discovered this year the word LNG," Total CEO Patrick Pouyanne told a press conference in Doha, noting new demand in Europe. Total had previously won a 6.25% stake in the larger Phase 1 of the expansion, which was awarded earlier this summer. The stakes in both phases will add about 3.5 million tons/yr of LNG to Total's portfolio, the company said. Partner selection for NFS is expected to be based on the pool of Phase 1 winners. In addition to Total, these include Exxon Mobil, Shell, ConocoPhillips and Eni. More than any of its peers, Total is committed to the Middle East and sees the region's low-cost oil and gas as a key competitive advantage.

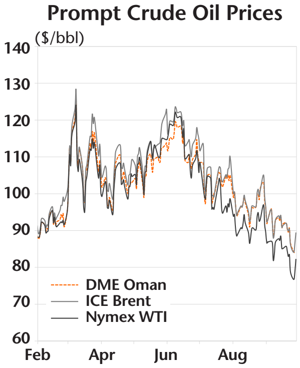
Marketview

Bundled Up Tight for Winter

The third quarter is drawing to a close with oil on the back foot, but as year-end approaches prices could easily take back lost ground as tightness in the product market intensifies.

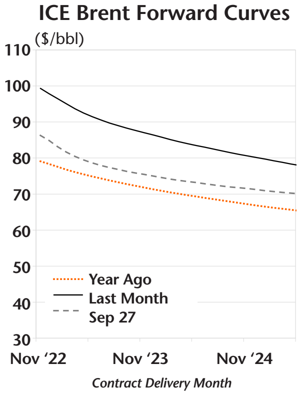
Global benchmark Brent crude is trading below $90 per barrel, a far cry from the almost $120/bbl posted at the end of the second quarter and well below its year-to-date high of over $133/bbl. Underlying dated Brent has shifted from a premium to the derivative to a discount, which usually signals a looser physical market than accounted for in futures.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

ICE Brent Forward Curves



Sentiment has been a major driver for oil's slide. High inflation and central banks' attempts to curb it have intensified fears of a recession, which would have a negative impact on oil demand growth. A strong dollar is also weighing on prices. The macroeconomic environment looks decidedly bearish.

Meanwhile, oil demand had to recover from price shocks experienced during the second quarter — Energy Intelligence balances in August showed the oil market at a 1 million barrel-per-day surplus for the third quarter. The situation has spooked producers; A Reuters report suggests Russia is likely to ask Opec-plus to implement a 1 million b/d cut at its Oct. 5 meeting, and some Opec watchers suggest the group is likely to slash quotas by a considerable amount. The goal may not be so much to reinvigorate prices, but rather provide some stability to an extremely volatile market and stop some of the recent bleeding.

An Opec cut alongside slowing production growth in the US Permian Basin would help to limit supply, but these affect crude at a time of stretched refinery capacity. Refined products and inventories are better indicators for demand. And both suggest prices could see significant support during the fourth quarter.

Oil consumption typically ebbs during the winter, with the exception of heating fuels such as diesel. This year, however, Europe needs to contend with several challenges that could make securing enough fuel difficult, if not impossible, and drive prices higher. The fast-approaching EU embargo on Russian products means the bloc needs to scramble for alternative suppliers such as the US and India, just as refinery maintenance in North America is in full swing and global capacity is under pressure.

Meanwhile, sky-high natural gas costs are likely to boost oil demand via fuel switching. Energy Intelligence forecasts suggest substituting oil products for natural gas, mostly for heating purposes, could create roughly 1 million b/d in demand. That suggests demand could surprise to the upside against a backdrop of strained refineries, top producers easing back on the throttle, and paper-thin inventories.

While these concerns have not managed to overwhelm bearish sentiment in oil futures markets, the structure of oil's forward curve signals tightness. Brent's backwardation has held up well relative to the outright price's fate, with front-month barrels maintaining a significant premium to later-dated contracts.

Refinery margins also suggest tightness. Gulf Coast profits of $29/bbl in a complex refinery belie the bearishness of headline price movement. Even in Europe, whose downstream faces significant headwinds, more sophisticated refiners realize margins of almost $11/bbl against incremental spot Brent.

Chinese Oil Demand to Pick Up

Chinese energy industry players say the country's strict zero-Covid-19 policy, which has stifled oil demand this year, is on its way out. However, a full return to freedom of movement and strong oil demand in China will take time, and 2022 looks set to end with China's oil demand falling for the first time since 2002. "The direction is very clear. We will see China opening up […]. We know the destination. But the process will not be very fast," Rongsheng PetroChemical's Singapore deputy manager Chen Hongbing told the Appec conference in Singapore. China's apparent oil demand fell by around 3.3%, or 460,000 b/d, in the first eight months of this year versus the same period of 2021, according to Energy Intelligence's preliminary calculations.

PIW Market Indicators

($/barrel)	Sep 26-Sep 28	Sep 19-Sep 23	Aug 29-Sep 2
Spot Crude			
Opec Basket	$89.86	$95.25	$101.96
UK Brent (Dtd.)	85.82	88.97	96.54
US WTI (Cushing)	79.41	83.44	90.79
Nigeria Bonny Lt.	89.85	91.98	100.83
Dubai Fateh	84.57	91.12	98.00
US Mars	78.71	82.28	89.29
Russia Urals (NWE)	62.68	65.44	73.03
Crude Futures			
Brent 1st (ICE)	86.55	89.81	97.25
Brent 2nd (ICE)	85.26	88.68	95.91
B-wave (ICE)	86.22	90.24	97.86
WTI 1st (Nymex)	79.12	83.07	90.34
WTI 2nd (Nymex)	78.41	82.60	89.82
Oman 1st (DME)	85.38	89.86	96.47
Oman 2nd (DME)	84.64	87.46	94.81
Murban 1st (ICE)	87.79	91.51	98.16
Murban 2nd (ICE)	86.22	89.45	95.89
Forward Spreads			
Brent (1st-Dtd.)	+$0.73	+$0.84	+$0.71
Brent (2nd-1st)	-1.29	-1.13	-1.35
WTI (2nd-1st)	-0.71	-0.47	-0.52
WTI (3rd-2nd)	-0.88	-0.74	-0.75
Oman (2nd-1st)	-0.74	-2.40	-1.66
Oman (3rd-2nd)	-4.18	-2.75	-2.47
Murban (2nd-1st)	-1.57	-2.06	-2.27
Murban (3rd-2nd)	-3.01	-2.56	-2.10
Grade Differentials			
WTI-Brent (1st)	-$7.43	-$6.92	-$7.07
WTI-LLS	-2.75	-2.40	-2.38
WTI-Mars	+0.70	+1.16	+1.50
Brent(Dtd)-Dubai	+1.25	-2.15	-1.45
Brent(Dtd.)-Urals	+23.13	+23.54	+23.51
Brent(Dtd.)-Bonny Lt.	-4.03	-3.00	-4.29
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$86.34	$89.91	$96.92
Arab Lt.-Europe (Med)	90.92	94.94	102.56
Arab Lt.-Far East (f.o.b.)	95.91	102.05	108.73
Nigeria Bonny Lt.	91.73	94.88	102.45
Arab Light Gross Product Worth			
Rotterdam	$94.20	$94.13	$106.51
US Gulf Coast	100.25	99.18	108.36
Singapore	85.21	90.05	102.48
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$104.39	$104.67	$107.92
UK Brent Margin	+16.04	+14.71	+9.97
US Gulf Coast			
Mars GPW	94.46	93.74	102.75
Mars Margin	+15.65	+11.36	+13.36
Singapore			
Oman GPW	85.25	90.32	101.14
Oman Margin	-3.64	-4.36	+0.28
US Nymex			
WTI 3-2-1 Crack	+$36.37	+$32.46	+$34.64
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$803.87	$820.90	$832.15
Gasoil (0.1%)	975.33	977.35	1110.10
Fuel Oil (0.5%)*	581.08	597.75	657.75
US Gulf Coast (¢/gal)			
RBOB Gasoline	254.30¢	244.97¢	248.90¢
ULS Diesel	326.45	326.49	363.54
Fuel Oil (0.5%, $/ton)	$614.33	$649.20	$724.20
Singapore ($/bbl)			
Naphtha	$69.63	$73.14	$71.55
Gasoil (0.05%)	115.01	119.93	140.67
Fuel Oil (0.5%, $/ton)	664.33	692.40	733.00

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