Energy Intelligence

PETROLEUM INTELLIGENCE WEEKLY®

Vol. 61, No. 41 www.energyintel.com October 13, 2022

Opec-Plus Cut Restores Spare Capacity Cushion

Energy Intelligence estimates that Opec-plus' spare capacity — excluding Iran — will increase to nearly 3.1 million barrels per day in November when its headline 2 million b/d production cut takes effect. The nearly 700,000 b/d boost to spare capacity — up from about 2.4 million b/d now — will give the group more flexibility to cope with potential losses to Russian production as an EU embargo and G7 price cap kick in and as global demand picks up from the Northern Hemisphere winter. Opec-plus has hinted that it could still increase its production in coming months if needed, although the extent is unclear. Opec-plus cited the weakening global economic outlook, as well as a desire to hold more spare capacity in the face of an uncertain, volatile oil market, as reasons for the cut. The IMF this week lowered its forecast for global GDP growth to 3.2% in 2022 and 2.7% in 2023, saying this is the "weakest growth profile since 2001, except for the global financial crisis and the acute phase of the Covid-19 pandemic." But oil markets did not expect such a large supply cut due to low global inventories for crude oil and refined products and expected losses to Russian output in the coming months. Energy Intelligence reckons the combined effect of looming EU bans on Russian petroleum imports and the price cap could result in the loss of 600,000 b/d of Russian crude and 600,000 b/d of Russian products supply. Opec this week said it expects Russian upstream liquids production to fall by 790,000 b/d in 2023 to 10.08 million b/d.

Concerns about thin spare capacity have supported oil prices for some time — even before Russia's invasion of Ukraine in February. From this perspective, Opec-plus now has more flexibility to cope with whatever supply issues may arise in the near-term — if it chooses so. Most of

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Sanctions to Test Limits of Tanker Fleet

As the market braces for the impacts of both the G7 price cap on Russian petroleum and full implementation of the EU's ban on seaborne Russian oil imports, yet another challenge looms. Some market players say that disruptions to long-established trade flows of oil and products will stretch current shipping capacity to the breaking point. In short, there may not be enough tanker tonnage available to offset the longer voyages that the price cap and embargoes will dictate, as greater Russian volumes are pushed to markets outside Europe. Capacity will fall short as a function of time. Current exports of Russian crude to the EU are 1.6 million barrels per day, but seaborne imports will cease on Dec. 5. Product imports, now estimated at 574,000 b/d, will be banned effective Feb. 5. Technically, all of this displaced oil can be traded to countries that have no embargo on Russian oil provided cooperation with the price cap. But should every single barrel find a home in Asia, Latin America or Africa, voyage length increases dramatically. The journey from Russia's western ports to Western Europe, for example, takes roughly a week. To Asia, that journey can be six weeks. One ship broker explained the impacts on volumes: "Let's say an Aframax [tanker] goes from Russia to Northern Europe, it's delivering 60,000-65,000 b/d. To Ningbo [China], 7,000 b/d. Mumbai [India], 9,000 b/d. It's about an eightfold increase in tonnage required to move the same million b/d" when adjusting for these voyage lengths.

The same dynamic applies to traditional European consumers of Russian oil; as they look for

Global Crude and Product Tanker Fleet			
	# of Vessels	Deadweight* Total Fleet	Deadweight* Per Vessel
VLCCs	859	264,824,237	200,000-plus
Suezmax	664	103,788,482	120-200,000
Aframax/Long Range2	1,080	118,794,869	85-120,000
Panamax/Long Range 1	452	33,060,385	60-85,000
Mid Range	1,656	81,060,284	42-60,000
Handysize Products	522	19,320,087	27-42,000
Small Handy Products	481	7,622,750	10-27,000
Global Tanker Fleet	5,714	628,471,094	

*Deadweight ton capacity. Volumes per end August 2022. *Source: SSY London*

alternative suppliers from further away, voyage length increases and tanker capacity is strained. This applies especially to products, and most critically to diesel. Traders in the region say the diesel market is now in a frenzy in the aftermath of strikes at French refineries, noting extreme backwardation in the fuel's forward curve. The EU needs to displace and find alternatives for almost 250,000 b/d Russian diesel come early February, and some market players are skeptical the logistics can handle that strain. One European trader stated simply: "Are there enough clean product ships to take diesel around the world from Russia while taking Arab Gulf and US diesel to Europe? To me, it looks like there aren't enough ships."

Changing crude flows are already roiling the norm when it comes to dirty tankers. As Europe displaces Russian crude, it is increasing its reliance on other producers in the Atlantic Basin. This has two immediate and interrelated impacts: First, the journey across the Atlantic is longer than from the Baltic or Black Seas. Second, to achieve economies of scale, the tankers chartered must be larger. Both dynamics support higher demand for very large crude carriers (VLCCs), bringing European consumers and Russian exporters into more competition with traditional charterers in that sector, sharply boosting rates. Analysts with BCG's Poten & Partners estimate that Europe has replaced about half a million barrels per day of Russian crude with trans-Atlantic hauls. "The ton-mile demand generated by European imports increased by 32% as a result of replacing 500,000 b/d of Russian crude oil. Finding alternative sources of supply for another 2 [million b/d] will provide another massive stimulus to ton-mile demand (and tanker rates)," they said.

No help will come from newbuild tankers. The pandemic-related demand collapse and uncertain market outlook have dried up the orderbook for 2 million barrel VLCCs beyond 2023 and reduced the volume of newbuilds for smaller tankers. This prospect, along with expectations of rising demand for tankers outside the Western fleet, has pushed up prices for second-hand tankers that are now carrying sanctioned crude from Iran and Venezuela — and probably Russia soon. China is the main buyer of second-hand VLCCs. The price of 15-year-old tankers has been pushed to the highest level in a decade. Shipping firms had expected those tankers to be sold for scrap. Instead, China bought 19 of the 21 second-hand VLCCs sold in the first half of 2022. They can sail under sovereign insurance and financing, outside the reach of the G7 price cap. These VLCCs now go for more than $40 million, 20% more than a year ago when China was also the main buyer. Rising day rates discourage scrapping. Older vessels are now earning money for their new owners. The orderbook for new 1 million bbl Suezmaxes, 800,000 bbl Aframaxes and 600,000 bbl Panamaxes is thinning out as well, as are product tanker newbuilds.

Traders Warn of Liquidity Risks Amid Volatility

The world's top energy traders have made fortunes from the turbulence of the past two years, and the good times are set to roll on as the fallout from the Russia-Ukraine conflict spreads uncertainty across oil and gas markets. But traders are wary of the risks ahead as extreme price swings, especially in European gas, increase the need to make hefty margin calls and threaten a crisis of liquidity in the markets. This was explained in stark terms at last week's Energy Intelligence Forum by TotalEnergies CEO Patrick Pouyanne, who said one evening his trading team had handed him a margin call of $8 billion, which the company was big enough to absorb but reflected the overall frailty of the markets. After the upheavals caused by Russia's invasion of Ukraine on Feb. 24, Pouyanne said more efforts should have been made to stress-test the markets, but he expected the European Central Bank and individual governments to step in to help out the most vulnerable. This has already happened in Germany, where gas utility Uniper, the country's largest importer of Russian gas, received a €15 billion ($15 billion) bailout from the government in July, and is now in the process of being nationalized to stem further losses.

From the traders' perspective, the liquidity crisis is manageable, and the banks that provide them with billions of dollars a year in finance are being more understanding. "People have had time to sort this problem out and I think the larger players in the industry exit this liquidity issue in better shape than before," the co-head of oil trading at Trafigura, Ben Luckock, told the Forum. "It becomes part of their daily risk metrics." He did warn, however, that further price spikes lay ahead that could reach critical mass next year. Russel Hardy, chief executive of the world's large independent energy trader, Vitol, suggested the problem was under control in Europe, with "two or three" companies in Germany having serious financial difficulties, and the rest "doing okay." He also warned of a "spiral" effect, as a lack of liquidity on the exchanges pushes up prices. This sentiment was echoed by the chairman and chief executive of Gunvor, Torbjorn Tornqvist, who said the need to make higher margin calls has created a "vicious circle," with the traders then forced to reduce their volumes, squeezing liquidity and causing more volatility on the exchanges. As a result, he said traders are tending to do less speculative business, like hedging, and sticking to the physical business.

The big traders have taken full advantage of this extended period of price volatility, and recent results speak for themselves. During the six months ending Mar. 31, Trafigura recorded net profits of $2.7 billion, a year-on-year rise of 27%, while Vitol reportedly generated net income of $4.2 billion for the first half of this year, its highest on record. Gunvor, which has a smaller trading portfolio than the other two with fewer fixed assets, saw its first-half net profits soar to $841 million, even though its volumes shrank. As Tornqvist explained to Energy Intelligence in an interview on the sidelines of the Forum, the company has simplified its business model by doing less hedging, especially in gas and LNG, and focusing on the physical business. Price spikes are a trader's best friend: "This kind of volatility creates the profitability," he said. "Our traders are agile and moving quite fast, we are hands-on on ships — we can turn them around just like that." He said Gunvor hopes to keep its gas business, which has skyrocketed volume-wise in recent years, steady in these more challenging market conditions, but described the LNG market as "dysfunctional," with little scope for spot market sales. As for rumors that Gunvor may sell part or all of its shares to Abu Dhabi National Oil Co., Tornqvist was tight-lipped, although trading sources say it may prove to be a good fit.

Africa Keeps Standing as Explorer Hotspot

African oil production south of the Sahara has long been declining, but ongoing discoveries like Venus and Graff in southern Africa's Orange Basin and Baleine in West Africa's Tano basin have sustained the region as a hotspot at a time when energy security fears are trumping calls to halt new exploration. While investment is recovering and hardy independents continue to derisk acreage, investors remain selective the world over. International oil companies (IOCs) are focusing on frontier countries along the Atlantic margins with big new discoveries while sustaining production from near-term discoveries in mature producing countries with improved terms like Angola. And while some discoveries are expected to be massive —and IOCs continue to fast track developments— output from the new discoveries will come too late to put a large dent in the West's oil shortages before 2025. Development of Cote d'Ivoire's Baleine and Senegal's Sangomar could together deliver 250,000 barrels per day next year if projects perform to schedule. Venus and Graaf could potentially double that contribution, with accelerated fast tracking, though plans have yet to be unveiled. While oil output south of the Sahara has fallen sharply from 5.38 million b/d a decade ago to 3.86 million b/d in 2021, exploration has continued to outperform other regions. The handful of recent giant finds since 2021 could deliver as much as 15 billion barrels according to some industry insiders. This followed a decade in which sub-Saharan Africa boasted discoveries of some 52 billion bbl of oil equivalent — more than any other region.

Having played blushing wallflower for decades, Namibia and Cote D'Ivoire emerged as star attractions at the annual Africa Oil Week conference in Cape Town last week. South Africa also carried on a wave of optimism around the Orange Basin that spans its border with Namibia. TotalEnergies, the most active wildcatter in the region, appears set to add the largest volume of reserves and future output if informed speculation around Venus is to be believed. US companies, who considered a retreat from African wildcat exploration in recent years, are also muscling back in, with Chevron taking a new license near Total's discoveries and Exxon Mobil set to drill in the frontier Namibe basin on the Angola side of the border. It is too early to gauge the size of Venus. However, Total plans to drill another exploration well in late 2023 on Block 2912 to test the western extent of the field. Expectations for a second well exceed those for Venus itself, and the well has the markings of a "supergiant," Total says. Wood Mackenzie has estimated reserves at 6 billion boe, but the upside could be more than double that if contingent drilling is successful. In South Africa, Total plans to drill two wells to the south of the Namibian discoveries in the same Orange Basin in 2024. In Angola, Total will press ahead exploring more frontier acreage, while also targeting short-cycle exploration including the deeper Cretaceous plays below the producing Girassol and Dalia fields on Block 17.

Eni is accelerating the strategy of infrastructure-led exploration and fast track development that it has followed for several years in Angola, Congo-Brazzaville, Mozambique and now Cote D'Ivoire — with its new corporate business plan focused even more on Africa. Eni's second successful well at Baleine has proven oil reserves up to 2.5 billion bbl of oil. The Italian major, which has fast tracked development to start producing 15,000 b/d in in 2023, could boost output to 150,000 b/d in 2025 if the project is sanctioned next year as planned. In Angola, where Eni formed the Azule joint venture with BP, it has boasted numerous discoveries on Block 15/06 and is convinced that its exploration model will bring a huge upside to blocks formerly under-explored by BP.

The selective retreat from mature areas is most evident in Nigeria, where the majors are trying to divest onshore assets, and in Cameroon and Gabon, which have seen a raft of sales to smaller independents in recent years. That said, greater exploration and development of Nigeria's deepwater could be on the horizon if next year's elections deliver a more competent and investor friendly government in Abuja. While there are still more sellers than buyers, the growing number of companies looking for divested assets to explore and develop was evident in Cape Town. Interested parties included BW Energy, part of the BW shipping and services group, which operates post production exploration in Gabon and is seeking to monetize the Kudu field discovered by Chevron in 1974, as well as Afentra, Africa Oil Corp. and Baobab Energy, which are seeking to monetize discoveries already made.

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the spare capacity — about 2.8 million b/d — will be held by Saudi Arabia and the United Arab Emirates. Energy Intelligence reckons this capacity could be mobilized on short notice — within 30 days' notice. While US-Saudi relations are clearly strained after the Opec-plus decision, Riyadh and the broader group insist that politics are not factoring into their supply decisions. But Saudi Arabia is putting Opec-plus' interests first: "We are concerned first and foremost with the interests of the kingdom of Saudi Arabia and then the interests of the countries that trusted us and are members of Opec and the Opec-plus alliance," Saudi Energy Minister Prince Abdulaziz bin Salman told Saudi TV last week. Even after the decision to cut, Energy Intelligence understands that US officials continued to lobby Opec members to delay implementation to December, after US midterm elections on Nov. 8. An angry White House has threatened "consequences" for Saudi Arabia and said it would "reevaluate" its relationship with Riyadh. The Saudi foreign ministry in a statement on Thursday said that delaying the decision by a month "would have had negative economic consequences."

Spare Capacity Rises After Production Cut

('000 b/d)	Output Capacity	Assessed Spare Sep'22	Assessed Spare Oct'22	Assessed Spare Nov'22
Saudi Arabia	12,250	1,203	1,260	1,772
Iran	3,800	1,230	1,205	1,180
Iraq	4,408	—	—	—
Kuwait	2,829	—	—	88
UAE	4,300	808	840	981
Venezuela	675	—	—	—
Nigeria	1,010	—	—	—
Libya	1,161	—	—	—
Algeria	1,060	4	5	53
Angola	1,235	—	—	—
Congo (Br)	291	—	—	—
Eq Guinea	95	—	—	—
Gabon	193	—	—	—
Total Opec	**33,307**	**3,245**	**3,310**	**4,074**
Opec ex Iran	**29,507**	**2,015**	**2,105**	**2,894**
Russia	10,200	—	—	—
Mexico	1,737	—	—	—
Kazakhstan	1,800	443	286	156
Oman	884	—	14	43
Azerbaijan	560	—	—	—
Malaysia	400	—	—	—
Bahrain	210	—	—	—
South Sudan	179	—	—	—
Brunei	100	—	—	—
Sudan	84	—	—	—
Non-Opec	**16,154**	**443**	**300**	**199**
Total Opec-Plus	**49,461**	**3,688**	**3,610**	**4,273**
Opec-Plus ex Iran	**45,661**	**2,458**	**2,405**	**3,093**

Source: Energy Intelligence

However, global inventories remain critically low. Even if actual Opec-plus cuts amount to only 1 million b/d for all of 2023, stocks would continue draining on a bullish path unless demand growth fully collapses. Benchmark Brent is already back above $90 per barrel despite demand concerns, after dropping near $80 last month. Citigroup analysts warn that the supply cut could backfire on Opec-plus if it hits economic activity and oil demand further. But with more capacity freed up ahead of the winter season, Opec-plus officials have hinted that their deal could be tweaked and not last until the end of 2023, as currently drawn up. "We are agile and we're flexible," Opec's Secretary General Haitham al-Ghais told Energy Intelligence in an interview. He said Opec-plus could call an emergency meeting, if necessary, and "accordingly adjust" its production policy. While Opec this week revised its global oil demand forecast for 2022 and 2023 lower, it remains more bullish than the International Energy Agency and Energy Intelligence. It sees demand this year increasing by 2.64 million b/d, down 460,000 b/d from the previous forecast. Next year, Opec sees oil demand rising by 2.34 million b/d, 360,000 b/d less than previously forecast, to 102.02 million b/d — still above the pre-pandemic rate of 2019.

Few Options for South Asia in Gas Crisis

Sky-high LNG prices are presenting real problems for South Asia, prompting fuel shortages and undermining economic growth. The current energy crisis could prove costly to ruling regimes in Pakistan and Bangladesh, which will hold national elections next year, and in India, which goes to the polls in 2024. Longer term, the role of gas in the energy transition in these emerging markets now faces serious questions, as the region increasingly turns to cheaper, dirtier alternatives like coal and fuel oil to run power plants and industrial facilities. Pakistan and Bangladesh are checking consumption by reducing operating hours at offices, markets and schools. Last week, Bangladesh faced a massive blackout — its worst since 2014 due to grid failure, as it has not been able to buy enough gas to meet demand. Pakistan last week did not get a single bid for a fifth consecutive LNG tender, which sought offers for 72 cargoes spread over six years' delivery. Gas is deeply entrenched in the economies of Bangladesh and Pakistan, accounting for 68% and 42% of their energy mixes, respectively. India is relatively shielded as gas makes up only 6% of its energy mix, but it seeks to expand that to 15% by 2030. High LNG prices have reduced Pakistan's imports by 19%, Bangladesh's by 10% and India's by 14% during the first eight months of 2022, according to the International Energy Agency.

South Asian LNG buyers have been priced out of the spot LNG market by premium-paying European buyers. All three countries have been seeking additional volumes from Qatar, their largest supplier, under their Brent-linked, cheaper term deals, but they have received no assurance for more supplies. Spot prices have ranged between $40-$60 per million Btu in the last few weeks, keeping them unaffordable for the price-sensitive South Asian economies. With LNG markets expected to remain tight at least until the mid-2020s, there is no relief in sight.

India, Pakistan and Bangladesh are seeking to boost domestic gas production to help cope. But their gas output has mostly been declining in recent years due to aging fields and lack of new investment and discoveries amid an exodus of international oil companies (IOCs). Gas reserves in Pakistan and Bangladesh, both of which rely on onshore production, are estimated to last 10-15 years. Pakistan now has just three foreign companies involved in exploration and production activities, down from 22 just a few years ago, according to a study released last month by the Pakistan Institute of Development Economics (Pide). Bangladesh has just Chevron for IOCs, while India has only BP after others like Exxon Mobil and Santos exited over the last decade.

That is not stopping all three countries from trying to become more attractive to foreign investors. However, poor geological prospects, combined with investor mistrust of government policies, make a significant uptick in foreign investment unlikely. It is doubtful that IOCs will change their view of South Asia's upstream, which lacks the free market regime and stable fiscal policy generally needed to make high-risk exploration worthwhile. India's Oil Minister Hardeep Puri this week launched a new auction round for coal seam and oil and gas exploration blocks in Houston. Bangladesh has hired Wood Mackenzie to improve its production-sharing contract ahead of a planned new auction round, local media reports say. Pakistan last week said that it is working on an ambitious policy framework that will help it turn a gas deficit into a surplus. However, South Asian nations have traditionally shielded consumers by keeping domestic gas prices artificially low and not giving remunerative rates to explorers. And there is little sign of major reforms here. India overhauled its exploration policy in 2016, but it continues to keep gas prices under check through a formula that links domestic prices to international hubs that have gas surpluses. As this year's LNG price spike helped formula prices triple year over year to $8.57/MMBtu for the six-month period that began Oct. 1, New Delhi appointed a committee to ensure "fair prices to the end-consumer," upsetting explorers. Of the 134 blocks that India has offered so far under its overhauled exploration policy, BP is in the only IOC to bid for a block — and only through a minority partnership with India's Reliance Industries. In Pakistan, political instability, in addition to policy uncertainty, is keeping investors away. Pide says that large areas in Pakistan remain unexplored due to law-and-order issues. Investors also remain wary of the bureaucracy, corruption and dominance of state firms.

Nigerian Refinery to Debut Amid Product Crunch

Nigerian industrialist Aliko Dangote's giant complex refinery scheduled to go on stream early next year looks like a potential savior for Nigeria, whose state refineries have manufactured no product in recent years and left the country bartering away its diminishing crude output for imported products. But could the 650,000 barrel per day plant also assist Europe at a time when the EU is about to embargo Russian petroleum? In theory, yes — Dangote will need to find another home for a large portion of the refinery's output, which will comply with Euro V specifications for low-sulfur products. If Dangote sends the surplus barrels into the Atlantic

Basin, it could boost diesel availability and help lower diesel prices in Europe, says African downstream consultancy Citac. The refinery is configured to produce just over 10 million tons per year of gasoil and 11.6 million tons/yr of gasoline, assuming 90% capacity utilization. Citac tallies Nigeria's domestic demand at just 3.76 million tons of gasoil and 17.8 million tons of diesel. This would imply a surplus of at least 6 million tons/yr going to other markets. Even if this surplus went to Latin America, it could still take some steam out of global product prices.

However, there are so many caveats and variables around the refinery, its schedule, and Nigerian politics that it is not clear when, what form, and how much assistance could be provided. Nigerian National Petroleum Corp. (NNPC) Managing Director Mele Kyari insists the refinery will go on stream in the first quarter of 2023. However, it has been delayed several times. Experts doubt it will come on stream until later in 2023 and say it won't run at full capacity before 2024 or even 2025. As the largest single train refinery in the world, it faces unique technical challenges not to mention a raft of logistical hurdles due to inadequate infrastructure.

With Nigerian elections set for February 2023, the next government has yet to be chosen, but its decisions will have bearing on the refinery's operations and profitability — and determine where Dangote sources his crude and sells his products. Key areas to watch range from NNPC practices on allocating crude, to broader policies on exchange rates, gasoline subsidies and trade protection — which Dangote is also expected to seek. Unless the next government acts to cut crude theft, which has dropped output to lows of around 1.1 million b/d in recent months, NNPC, which is entitled to half of Nigeria's crude output, won't be able to supply sufficient feedstock, let alone the crudes Dangote deems optimal for the refinery. The plant would work optimally on Nigerian Bonny Light, Brass and Forcados, as well light, sweet crude from Libya and Algeria. Theft has cut Bonny to a trickle this past year and has limited Brass for more than a decade. Gasoline subsidies — which successive governments have pledged but failed to eliminate — have eroded the state refineries' economics and caused liquidity problems for Nigerian oil product marketers for decades. Thus, Dangote would need to be paid the full market price for his products up-front if he's to function profitably and repay the refinery's vast debts.

The refinery will produce clean fuels with 10 parts per million sulfur in diesel and gasoline. This means its products will likely exceed the price of what Nigeria imports now, even allowing for arbitrage and freight costs. Right now Nigeria's imports are cheaper for NNPC, as a significant chunk of the imported gasoil is blended from Russian origin components now trading at a discount to market prices. Despite pressure from the African Refiners and Distributors Association and other regional institutions to adopt cleaner fuels, NNPC has shown little regard for tightening specifications. it continues to allow suppliers to deliver 500 ppm sulfur gasoline and 5,000 ppm diesel under its Direct Sale Direct Purchase crude for product swaps. As Nigeria's exchequer will continue to reel from the impact of lower revenues and soaring subsidy costs, it will have to weigh the cost of paying market prices to Dangote versus allowing high-sulfur specification imports to compete.

Dangote will need to export more products if the refinery has to pay for crude. This would also be the case if the next government limits access to dollars at the official (cheaper) exchange rate that Dangote would rely on to cover the refinery's costs, or denies protection from cheaper imports, says Jeremy Parker, Citac's head of business development. With astute cultivation of each incoming regime, Dangote has generally proved adept at negotiating terms which tilt the playing field in his favor — but he won't know for sure until February.

Shell CEO: 'Paradigm Shift' for Sustainability and Security

Energy Intelligence's 2019 Energy Executive of the Year, Ben van Beurden, CEO of European major Shell, spoke to last week's Energy Intelligence Forum in London on the unprecedented risks and mixed signals the oil and gas industry is having to navigate — but also why the European major remains committed to its low-carbon energy strategy. Edited highlights follow.

Q: In the wake of the apparent attacks on the Nord Stream pipelines, is Europe prepared for increased risk to energy infrastructure? Is it more difficult to defend infrastructure that is spread out over such a large area and that is held in the hands of private companies rather than a state energy champion?

A: I think at the time [of the 2019 attacks on Abqaiq], we said that, if that were to ever happen, that will be a Black Swan event. Oil prices could go to $200, and it would be quite a task for Aramco to respond. And then of course, [Aramco CEO] Amin [Nasser] turned it into a very Small Swan event. But the point is, we can't rely on that sort of response, that sort of containment, that sort of recovery if energy infrastructure in the North Sea got attacked, or anywhere else in the world.

So, I do think that we cannot be complacent about this, and I also don't think we can rely on there being a sort of obvious and logical entity to respond to events, if they were to happen. So, prevention here is going to be absolutely essential. And I hope it won't come to it, but we'd better be ready for situations where a significant amount of infrastructure is out of commission.

Q: Should people get used to paying more for their energy if there is going to be a security component there as well?

A: I think what we are seeing at the moment is at least two aspects of the energy trilemma play out. We've always said energy is caught in a trilemma: it needs to be more sustainable, it needs to be affordable, and it needs to be available.

There was a time that the only focus was on sustainability of energy and nobody really cared about the availability or the affordability — that was sort of taken for granted. Now, we are seeing that you can't take the affordability for granted, and it is therefore something that we have to manage — particularly in gas, particularly in Europe. And now you see that actually governments are obsessed with affordability of energy. But we haven't really seen energy security issues yet. And therefore I really fear that if that were to happen, that nobody will worry about sustainability, and might not even worry about affordability.

Now, can you solve it by a premium? No, I don't think it works that way. I think you solve this by good policy and by making sure that we understand that this is a very volatile market [and] that you cannot afford spare capacity to run very, very small. … But you don't get it by paying a little bit more for Saudi crude. You get there by a deliberate policy. And I think and hope at least that the events that we are experiencing today are a bit of a wake-up call for governments to say, 'Oh, hold on, it is, it is actually a trilemma, and we should manage the other aspects of the trilemma as well.'

Q: We're seeing really unprecedented levels of market intervention — windfall taxes, price caps, multibillion-dollar bailout packages. Do you see any of these being effective? Are there any you are particularly worried about?

A: First of all, indeed, it's unprecedented what is happening. I know there are quite a few voices out there that say, "Let the market take care of it. It's the best way. The best remedy against high energy prices is high energy prices, so it will all be fine at the end of the day." I'm afraid I don't subscribe to that logic entirely. Sure, the market needs to do its work and therefore we need to have market signals in there. But you cannot have a market that behaves in such a way … that is going to damage a significant part of society. You simply cannot have that. Governments cannot have that, and I think many of us in this room wouldn't stand for that either. So, one way or another, there needs to be government intervention, and I think government intervention that somehow results in protecting the poorest. That probably may then mean that governments need to tax people in this room to pay for it. I think we just have to accept [that] as a societal reality. It can be done smartly and not so smartly, and I think there is a discussion to be had about it. But I think it's inevitable.

Intervening in markets, capping prices, particularly on exchanges, etc. — I think that is going to be a real issue because it's very difficult to really understand the unintended consequences of market interventions, particularly when they are on exchanges. It's been said before, but one of the challenges is governments don't pay too much attention to this industry in the first place, and then with a lack of understanding, to intervene in very sophisticated markets, is, in my mind, one of the biggest risks that we are facing as an industry. And therefore I hope that governments will think twice, or at least consult very broadly with the big players in the industry, with experts in capital markets, to understand what I can and can't do and what the consequences might be.

Q: One of the most complex interventions that's being contemplated is the G7's proposed cap on Russian oil prices. Many are struggling to understand how it could be enacted and what the consequences might be. Do you see a way it could work?

A: I struggle with it as well, to be perfectly honest. I'm sure you can make it work in certain ways, but how effective would it be? I have my doubts. And what sort of instruments would you need for that? People have talked about, well, we need the insurance industry to come along to make sure that ships can't transport oil that is priced above the cap anymore. It's easily said, but not so easily done. And so I see that as a real implementation challenge. There may well be some people that think well, maybe it's better if it doesn't work very well because otherwise we may see oil prices going through the roof, but that's another matter.

I think the bigger challenge in my mind is not so much can somehow governments of the world figure out how to cap Russian oil prices, but actually can we make a meaningful intervention on gas markets here in Europe? Can we somehow intervene on the [Dutch] TTF or something else? I think that is a much more challenging prospect. I would say if you really want to protect consumers, that is probably an area that governments are going to look at first and foremost, rather than oil prices. I mean, we've lived through oil prices above $100, and it's less than $90 today. But we haven't lived too long through gas prices that are above the equivalent of $300 a barrel. So if I was a government, inevitably you'll be drawn to the challenge of how do I contain gas prices? And then I think is a much more challenging thing.

Q: How has your engagement with investors changed through the course of this unprecedented year?

A: It has changed, but I would say that it's still early days in this. It has definitely improved. I think there's a certain segment of the investment community that is rediscovering that this is actually quite a valuable and useful segment of the capital markets to invest in. We can produce a lot of cash and a lot of it actually comes to our investors. So, we are, in a way, harder to resist. But I think there's also a little bit of a re-appreciation that maybe indeed this wasn't so simple. Maybe this wasn't a sort of one-track mind problem where we just get out of oil and gas because we don't need it anymore anyway and we should focus on other forms of energy. I think there is a little bit more balance, a little bit more understanding.

Also, by the way, more understanding on the business models of new energies, which are quite often looked at in a relatively simplistic way. Like, why would you produce a commodity that comes with the utility-type return? And of course our answer is well, you know, that's not our strategy. Our strategy is to work from the customer back, where the returns are much better. But I think at this point in time, there is more appetite from investors to really listen to what it is that we have to say — because I think deep down, everybody understands that this is a moment when the whole paradigm shifts, particularly in Europe, where we can see that we have to go onto this decarbonization journey, not because it is the right thing for the climate, which is one, but it's also something that has to do with energy security. And therefore, how can companies like us not only do that, but benefit from it? I think is much more topical with investors than it has been for many years.

Q: Are investors saying, look, markets are telling us, high prices are telling us that it's okay to spend a bit more on oil and gas in the near-term, as this is what the world needs right now?

A: Yes, we hear that as well. But then I have to sometimes remind our investors that we are still investing a very significant amount of money in in oil and gas. It's less than what we used to, absolutely. But you know, as we sit here, we spend about $8 billion a year in oil, and we spend about $4 billion to $5 billion in LNG. That's a very significant quantum of money. Now, you can say, "But you used to do more, so why don't you just quickly ramp it up at $5 billion a year?" No, you can't, really. It takes a long time for these projects to come on stream. If you really want to work on spending $5 billion for next year, you should have started years ago. So, it's not a quick response. Can we do more short-term projects? Do they make more sense? Absolutely. Do some projects that are a little bit on the cusp all of the sudden look a little bit better? Sure. We'll do that as well. But you cannot have a quick response to the market signals that we are seeing today in the sort of multiple-billions-a-year spend level.

Q: But do these changes that we're seeing — whether it's government market interventions, whether it's changing attitudes of investors — change where you spend the capital that you choose to put to work?

A: There is always flexibility in the strategy we have. Our strategy is a business strategy where we want to pivot into the energy system of the future, which we believe is built from the customer back, with new supply chains in these customer domains. And yes, we can flex that. We can say, well, it looks as if [biofuels] can go faster, or hydrogen can go faster, or power can go faster, or maybe a little bit more nature [based solutions]. And we will continuously readjust our spending to where to where it makes more sense.

But the strategy is very much indeed that — pivot away from the traditional legacy investments that we had in commodity-based oil and gas products. Now, can we go faster? Can we go slower? Sure, we can. And that's what we do. Probably you will see us doing even more in customer-backed strategies in Europe because that is where this is more needed today and also more welcome today. And you will probably see that the investment levels that we are maintaining for oil and gas are in those countries, those resource holders where that is being seen as useful, meaningful, welcome and everything else. But if you say, "If I gave you an extra billion [dollars] to play with, where would you be inclined to spend it? Well, I would be inclined to spend it in the energy system of the future, because that, I think, is where most of the future value is going to be.

Baker Hughes CEO: Energy Market 'Trilemma' to Test Industry

Lorenzo Simonelli has overseen several shifts in corporate structure and strategy in his time as CEO of Baker Hughes, including its transformation into an "energy services" company. Unique among its traditional peers in the oil-field services sector, Baker Hughes is a key supplier to LNG and other hydrocarbon producers, with a focus on developing and scaling emerging technologies. We spoke to him last week on the sidelines of the Energy Intelligence Forum in London about how the world has changed and the "trilemma" now facing the global energy sector.

Q: You've talked about the redrawn map of the global energy landscape, so how are you looking at it now compared to maybe a year or two ago? What does that map look like?

A: I think the aspect of there being a shortage of supply from the underinvestment was known clearly some time ago, and you could actually foresee, just given some of the trends and also post-pandemic, the increase in demand, that we needed more investment into the sector. With the conflict, Russia-Ukraine, clearly there is now an enhanced element of energy security. And so what used to be known as the dual dilemma of affordability and sustainability has now become the trilemma of affordability, sustainability and security. And I think what's been seen in the last year is really that presence of how do we drive an abundance of energy, but also with the security of that abundance from varying sources and continue to expand the energy mix, but make it affordable, and also make it sustainable because there's been no change in the view that we've got to continue to address climate change by really reducing emissions. Not eliminating fuel sources, but by reducing emissions.

Q: To that end, let's talk about LNG. Despite this kind of insatiable demand from Europe and elsewhere, we've seen signs that some of these new projects might be slowing down, for various reasons. As a supplier for many of these projects, how do you think the outlook for LNG development has changed over just the past four, six or 12 months from a project development perspective?

A: We've been positive on LNG for some time, and we've always said that by 2030 there needs to be an installed capacity of 800 million tons of LNG. If you look at the steady progression, today you've got an installed capacity of about 460 million tons and you've got construction on about 160 million tons. So there's a number of projects that need to go forward. And we've always seen those projects in the pipeline, and we've always been very positive with regards to the activity levels continuing to be there through the course of the next few years. What's been highlighted — and again, I think, as you said, Europe has this insatiable need for LNG — is an acceleration of those projects. And what we said would be between 100 million and 150 million tons of FIDs [final investment decisions] in the next two to three years, we now see that really being within two years. And if you look at the offtake agreements that have been signed, if you look at the pipeline of activity, we still feel solid that over the course of the next two years, that's going to be a reality. There are aspects of commercial and financing that need to be sorted out, and that's what's happening. But I think, again, the need for the LNG to come on stream has not changed. But the LNG business has always been lumpy.

Q: So, some of the recent news, not to name specific projects, but do you see those more like speed bumps, part of that lumpy trajectory, but still going in the same direction?

A: Still going in the same direction and, I think, if anything, from an energy security perspective, what you're going to see is the continued build-out of incremental capacity. And again, it comes in lumps, so I wouldn't be surprised if, as we get to 2030 you see additional projects that even take you above the 100 million tons from an energy security perspective.

Q: In terms of the supply chain for LNG and some of these other emerging technologies, again as an equipment provider, where are you seeing some of the biggest bottlenecks right now?

A: Clearly there are some constraints on supply chain. From a shutdown perspective … supply isn't as continuous as it used to be. Also, as you look at some of the chips, the electronics, there's clearly an impact there from some of the China policies of zero-Covid. The other element is when you look at manpower, in the field, from a construction and installation perspective, there's a lot of activity, and we've got to bring the people back in and into the field. From a Baker Hughes standpoint, we feel that we can manage through those supply chain risks and actually work with our customers accordingly. We've got the capacity in place to make sure that we fulfill our commitments.

Q: Do you think these supply chain issues are temporary? Or is this just something the industry is going to have to figure out and or just learn to live with?

A: So, they're temporary. The question is, how long is temporary? I think, where people anticipated that it would be very short term, I think we have a longer term of supply chain bottlenecks that are being cleared through and we'll continue to face them in the second half of 2022, as well as at the beginning of 2023. Over time, everybody's working to clear those bottlenecks, and my expectation is we've gone through instances before where we've had bottlenecks. They will be cleared. But all in all, it will take some time, anywhere between 12 to 18 months to see a full clean-up of the bottlenecks.

Q: Baker Hughes is obviously one of the many companies to have exited Russia, and this could have a big implication on the country's ability to develop some of these LNG projects. What is the state of LNG technology in Russia?

A: So, as you know, the LNG technology has been around — we've helped to develop it, and I think as you look at existing projects, they're continuing to produce. Clearly, we're abiding by the sanctions that are in place, and we'll continue to do that. And it's something that they'll have to understand and contemplate as they go through their outages and maintenance, as well as any new projects that are starting.

Q: Baker Hughes has its hand in a lot of really interesting emerging technologies. Carbon capture, carbon utilization,

clean hydrogen, clean power, geothermal, and probably a bunch that we don't even know about yet. When you're evaluating these potential investments and opportunities, what are you looking for exactly?

A: Running a company, you've got to actually look at all facets of longer term technology and moonshots, as well as shorter term and medium term. And so, as a company, we have core competence when it comes to engineering, when it comes to compression, when it comes to knowledge of dealing with reservoirs and dealing with hydrocarbons. So, we have an incubator approach. We scale new technologies that we think are interesting. And we'll take risks on early technologies and progress those to scalability … What we always look to do is be a technology company that's focused on differentiation, not commoditization, and that's what we look to allocate capital into.

Q: What are some of the new technologies that you think are particularly cool or interesting?

A: Look, I think there's a lot of technologies that are ready for prime time today because they're already commercialized, and there's ways to drive upgrades. There's ways to reduce flaring, through Flare IQ, a product we offer, which is really to reduce the aspect of flaring and then the re-utilization of the gas. So, we've got a lot of capabilities today to actually drive reductions in emissions and drive efficiencies within the operations — our in-line compressor, our zero-leak valves — so there's a lot that can be utilized and we need to continue to go to that as the first pillar. Secondly, as you look at new areas, we're very excited by the continued growth in LNG. We're continuing to develop new turbines and compressors that are more efficient. And then, going forward, CCS, CCUS, modular. Compact Carbon Capture is very interesting. We think the new commercial models around industrial clusters and being able to take that CO2 and emissions into reservoirs. You go into hydrogen, both blue and green, ammonia. And then direct air capture. We think direct air capture is going to be necessary to meet the Paris accord pledge, and we think there's a lot of interesting technologies around really taking CO2 from the atmosphere, and then starting to develop the circular economy, and that's the next forefront.

Q: Is direct air capture (DAC) something that you are working on internally, or something you have invested in?

A: We've made several investments in different technologies. Mosaic, is one [DAC investment]) that we've announced. There's NET Power. So, we see, across the board, different elements of technology. We have an association also with turquoise hydrogen, which is an investment we made in Ekona.

Q: So, what are some of the challenges in scaling these technologies, or getting them to the next level? Is it financial? Is it regulatory? Is it just technology readiness?

A: It's a blend and nothing's always just one thing. From a technology readiness perspective, we need to continue to move up the technology readiness curve. That's something we've always done, and so I feel very confident that we'll be able to do that going forward. Then it's the right congruence of factors from government policy, from collaborations with customers from different partnerships, different ecosystems being created. And, look, there is no one solution. It does require collaboration. And at the end of the day, collaboration is essential as we go and address the need to reduce emissions, and all of the technologies are necessary to be able to do that. So we're working very closely with some of our partners, and being able to develop pilots to be able to introduce and then drive to scale. Ultimately, to bring the cost down of many of these technologies. It's going to require scale and to get that you need a blend of policymakers, customers, partners, financing, etc.

Q: So, I was speaking with one of your colleagues not too long ago about the difficulties associated with both old and new technologies and just getting the facilities and infrastructure built, and he mentioned a term that I had not heard before: Banana — "build absolutely nothing anywhere near anything." It's kind of an extreme version of NIMBYism (not my backyard). So, what is it going to take to implement this technology and get it operational and how much of a headwind do you think this sort of "Banana" mentality is?

A: I haven't discussed this "Banana" idea with [him], but I think what he is referring to is that it really takes a collaboration and an approach toward government, customers, policymakers, financing. And you look at some of the actions that have taken place, which are gamechangers, if you look at the Inflation Reduction Act, that is a significant stimulus to green hydrogen. It's a significant stimulus to carbon capture, utilization and storage. When you look at some of the European legislation, policies being put in place to help invest in introduction technologies. So, I think you are starting to see the right signs. Clearly, it takes some time to mature. But I've been pleasantly surprised with the progress, so continued progression in areas like that is going to be very beneficial.

Q: So, you've spoken about the need, first and foremost, for improvements in energy efficiency. Where are we on that journey and why do you think we're not moving on it as fast as possible?

A: I think we are commercializing and making the technology available. Now, there's also the complexity of putting in the upgrades, being able to have the maintenance and the interval when you've got hydrocarbons that are priced very high. So, we've got to continue to build on the momentum of the efficiencies that we can drive. With anything, it takes some time. But we've seen a steady increase inbounds on digital requests for data to be used in reducing nonproductive time across operations which drives optimization. We've seen an increasing interest in the upgrades that helped to improve the efficiency of current running operations. It's then how does it all flow through at the right time that makes sense also for the operations in place?

Q: Is there something that can be done to stimulate that or push that faster? From a policy level, or from a strategic level? Is there a way to accelerate that?

A: I think, again, it's the continued dialogue. Also, there's the reality of just what's feasible in the timeframe that's available. So, I would say, dialogue is important, and then also ascertaining when we can take the appropriate action. I wouldn't change the dialogue that's happening.

What's New Around the World

GENERAL

CORPORATE — Exxon Mobil is reportedly exploring the potential acquisition of Texas-based independent Denbury Resources, a specialist in CO2 management with extensive assets on the US Gulf Coast. According to a Bloomberg report, Exxon has expressed "preliminary interest" in acquiring Denbury. No final decision has been made, however, sources report. Denbury specializes in enhanced oil recovery (EOR), employing so-called "CO2 floods" to squeeze marginal barrels out of mature oil fields. The company reported sales volumes of 46,561 boe/d in the second quarter of this year, 97% of which was oil. However, the Denbury assets that would likely be the most attractive to Exxon are its massive CO2 pipeline network and growing footprint of leased acreage suitable for sequestering captured CO2. Exxon has identified carbon capture and storage (CCS) as a key pillar of its energy transition and net zero strategies. It has announced plans to build a massive CCS hub near the Houston Ship Channel, an ambitious project that would partner the area's 50 largest emitters. Denbury claims to own and operate the largest CO2 pipeline network in the US, with more than 1,300 miles of pipe to its name, much of it concentrated on the US Gulf Coast.

COUNTRIES

AUSTRALIA — Tokyo Gas has signed a deal to sell its equity stakes in four integrated Australian LNG projects to a unit of US infrastructure fund EIG Global Energy Partners. The US$2.15 billion cash transaction marks the first major sale of equity stakes held by a Japanese utility in LNG projects. The deal would see Tokyo Gas sell its equity interests in Pluto, Gorgon, Queensland Curtis LNG (QCLNG) and Ichthys, all of which are mostly contracted to Asian markets. Japanese utilities have historically held minority stakes in LNG producing projects as a way to gain information about project operations. Tokyo Gas said the sale fits with its 2030 strategic plan, which includes reviewing its asset portfolio to allocate resources to growth areas. The sale would not affect Tokyo Gas' existing offtake contracts with the four projects totaling 5 million tons/yr. The deal marks another attempt by EIG to enter Australia's LNG sector, underlining its broader LNG ambitions. Last year, it signed a deal to buy Origin Energy's 10% stake in Australia Pacific LNG (APLNG) in Queensland, but the deal was eventually pre-empted by Origin's partner ConocoPhillips, which purchased the additional equity in the 9 million ton/yr facility.

CHINA — China's Ministry of Commerce (Mofcom) has announced the first batch of crude oil import quotas for 2023 ahead of schedule, a move that sources say could support demand this quarter in the world's most important oil market. Chinese crude oil traders said the 2023 quotas can be used to buy crude oil during this quarter, but the crude will have to be delivered next year. Chinese refiners buy long-haul crude up to two to three months in advance while purchases of crude in the Asia-Pacific region — including Russia's Espo grade — are made a month in advance. The early allocation came just a week after Mofcom allocated 13.25 million tons of additional export quotas for refined products to be used this quarter or in 2023. The issuance of both types of quotas may be a way to encourage refiners to ramp up their production at a time when Beijing is struggling to re-ignite the nation's economy. In total, 21 refiners received crude oil import quotas totaling 19.93 million tons (146 million barrels) in the first batch of 2023, sources said.

COLOMBIA — Colombian President Gustavo Petro has submitted a watered-down tax proposal on oil company profits amid strong resistance from industry interests. Petro assumed the presidency of Colombia in August with an ambitious energy agenda, but two months later those lofty aspirations are already being tempered by political and economic realities. The Petro administration came roaring out of the gates with a tax reform proposal that it said would raise 25 trillion pesos ($5.4 billion) in 2023 that would be used to fund expanded social programs and reduce the nation's deficit. A major plank of that proposal was a 10% tax on oil exports when crude prices exceeded $48/bbl — roughly half of the average price for global oil benchmark Brent this year. The proposal received fierce pushback from the industry, including state oil company Ecopetrol, which warned that the tax would kill much-needed investment in the country's energy sector. That export tax proposal was soon scaled back to kick in when oil prices exceeded $71/bbl, then replaced altogether in the latest reform package submitted last week. This package would see a diminishing income tax surcharge of 10% in 2023, 7.5% in 2024 and 5% in 2025.

FRANCE — More than half of France's oil refining capacity is either offline or unable to supply the domestic market after workers at refineries and fuel depots owned by Exxon Mobil and TotalEnergies went on strike for better pay and working conditions. The outages have coincided with a Europe-wide energy crisis and are also occurring during a seasonal trough in refinery throughput as plants undergo maintenance. Around 1.5 million b/d of refining capacity is expected to be offline across Europe in October, according to Refinitiv data. The strikes started on Sep. 20 at Exxon's 240,000 b/d Gravenchon Le Havre refinery and its 235,000 b/d Fos-sur-Mer plant on Sep. 21. They have since spread to Total's 240,000 b/d Gonfreville and 109,000 b/d Feyzin refineries after trade unions called for an extension of the protests. The 230,000 b/d Donges refinery was set to join the protests on Oct. 12 after Prime Minister Elisabeth Borne threatened to use the government's authority to order some workers to return to work to safeguard fuel supplies. In all, around 800,000 b/d of France's overall refining capacity 1.3 million b/d of has been targeted by the strikes.

JAPAN — Japan's imports of Saudi crude spiked by 272,000 b/d from July to 1.19 million b/d in August, according to data from the Ministry of Economy, Trade and Industry (Meti). This lifted the Saudi share of total Japanese imports to 40% in August, up from 35% in July. The average in 2021 was 39%. The August increase in Saudi volumes likely came at the expense of reduced imports of Murban crude from Abu Dhabi, which was was priced at comparatively stronger levels. Japanese imports of Murban crude dropped by 107,000 b/d from July to 432,000 b/d in August, while inflows of Saudi Arab Extra Light rose by 17,000 b/d to 425,000 b/d. Japanese refiners also took a lot more Arab Light, with landed volumes up 180,000 b/d to 502,000 b/d in August.

RUSSIA — President Vladimir Putin has signed an order that transfers management of the Sakhalin-1 project in Russia's Far East from Exxon Mobil to Russian oil giant Rosneft, raising the likelihood of a legal row between Moscow and Exxon. The order also provides for the creation of a new Russian-registered operating company for the Sakhalin-1 production sharing agreement (PSA) — a step that was previously taken at the Sakhalin-2 project. Up to now, Exxon had been the sole operator of Sakhalin-1 — via a Bermuda-based operating company — with a 30% stake in the project. The move signals a clear impasse between Moscow and Exxon over the management of the strategic Russian asset. The two have been at loggerheads over the past several months as production at Sakhalin-1 fell to minimal levels of around 5,000-10,000 b/d from more than 200,000 b/d in April. Sources say Exxon insisted the winding down of operations was necessary after Western sanctions forced it to declare force majeure in May. However, its Russian partners have questioned Exxon's inability to market and place Sakhalin crude despite these challenges. There has been a strong push by Russian authorities to increase production at Sakhalin-1, which is important for the Sakhalin region's budget revenues and as a source of associated gas.

Marketview

House of Cards

Oil demand is taking a beating, and some now see Opec-plus as the main culprit rather than the market savior after its decision last week to cut production by 2 million barrels per day.

The International Energy Agency (IEA) is blaming further energy inflation and demand destruction on Opec's "ostensible 'pre-emptive' bid to support oil markets."

The Paris-based agency has cut it demand growth forecast by 470,000 barrels per day in 2023, to 1.7 million b/d, following similar revisions by other forecasters. World oil demand will average 101.3 million b/d in 2023, the IEA reckons.

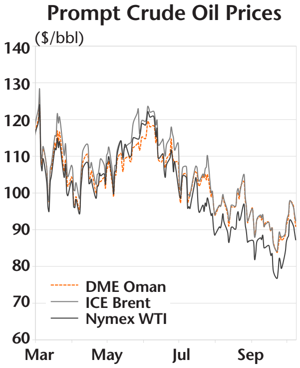
But the finger pointing at the producer group, especially from a very irked US, has distracted the market from a dire demand outlook.

From the trading side, Opec's decision is still seen as an effort to rebalance the market, even if it points to a gradual loss of control over the market. There is a general feeling that Opec-plus has to make increasingly larger headline cuts to realign market fundamentals — or, cynics will argue, to pump up prices — and a fear that the effect of this bailout strategy may rapidly fade.

"The oil market may rally some more, get to $100-$105/bbl, but then fall off a cliff and lose 50% of value," said Omar Najia, global head of derivatives at BB Energy. The same bearish outlook is shared by other traders, who see the economic slowdown as a major hurdle heading into 2023, somehow vindicating the cut.

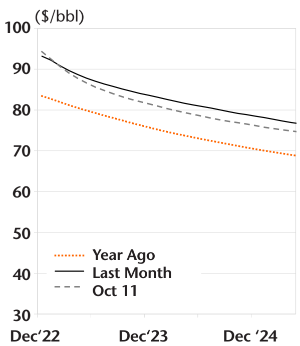
Despite a more buoyant prompt market, Brent is indeed struggling to break through $100/bbl. The benchmark deflated by more than $6/bbl from its previous week's high of $97.92/bbl. Crude differentials in the North Sea have firmed up by about 50¢-70¢, reflecting higher spot demand now that refiners have come out of their seasonal turnarounds and pushing up the Brent front future spreads.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

ICE Brent Forward Curves



Contract Delivery Month

But traders see an increasing disconnect between those spreads and the flat price, suggesting that the current strength at the prompt is not a good yardstick of short-term demand.

The elephant in the room is China, whose strict Covid-19 restrictions have been a key driver of demand erosion in 2022. China's age pyramid is heavily weighted towards the elderly, and the country doesn't have the hospital beds per capita that it would require to let Covid-19 run through the system. Nor has the government been able to deliver the elderly the Covid-19 vaccine booster shots at a scale that would allow the economy to reopen.

Add to that the high energy prices and the tricky mandate of central banks to slay inflation without sparking or aggravating a recession, and it makes a perfect cocktail for further demand erosion.

"The worst is yet to come," said the IMF, which cut its 2023 GDP growth forecast from 2.9% to 2.7%.

For now, governments in the OECD have been actively dolling out fuel subsidies, while large non-OECD are trying to control prices. But if supply keeps running away and prices stay elevated, supporting demand with band-aid fixes may not last very long. Soon or later, it will fall regardless.

Indian Fuel Consumption Edges Up

India's refined product consumption increased in September after contracting in the previous two months, as monsoon rains receded and the month-long Hindu festival season started.

Diesel consumption, which accounts for 38% of total product sales, rose 1.5% in September from August to 1.52 million b/d, according to preliminary sales data of state-owned firms that dominate India's product market. Gasoline sales, however, contracted 2% to 787,000 b/d. Jet fuel sales were up 3.5% to 147,000 b/d, with liquified petroleum gas—used for cooking— up 4.3% to 963,000 b/d, the data showed. Analysts expect product demand in the world's third-largest oil consuming nation to remain robust as the Oct.-Dec. quarter is seasonally the strongest.

PIW Market Indicators

($/barrel)	Oct 10-Oct 12	Oct 3-Oct 7	Sep 12-Sep 16
Spot Crude			
Opec Basket	$96.76	$94.02	$97.13
UK Brent (Dtd.)	95.77	94.95	91.65
US WTI (Cushing)	89.58	88.19	87.24
Nigeria Bonny Lt.	99.68	98.07	94.48
Dubai Fateh	94.38	91.17	92.83
US Mars	86.17	87.01	86.61
Russia Urals (NWE)	72.01	70.96	68.10
Crude Futures			
Brent 1st (ICE)	94.31	93.27	92.69
Brent 2nd (ICE)	92.56	91.39	91.59
B-wave (ICE)	95.03	92.48	93.00
WTI 1st (Nymex)	89.25	87.80	86.76
WTI 2nd (Nymex)	87.96	86.80	86.35
Oman 1st (DME)	93.22	92.58	92.54
Oman 2nd (DME)	91.15	90.17	89.77
Murban 1st (ICE)	95.67	94.89	94.23
Murban 2nd (ICE)	93.40	92.27	91.98
Forward Spreads			
Brent (1st-Dtd.)	-$1.46	-$1.68	+$1.04
Brent (2nd-1st)	-1.75	-1.89	-1.11
WTI (2nd-1st)	-1.29	-1.00	-0.40
WTI (3rd-2nd)	-1.39	-1.27	-0.66
Oman (2nd-1st)	-2.07	-2.42	-2.77
Oman (3rd-2nd)	-1.61	-2.53	-2.52
Murban (2nd-1st)	-2.27	-2.61	-2.25
Murban (3rd-2nd)	-2.32	-2.40	-2.49
Grade Differentials			
WTI-Brent (1st)	-$6.35	-$6.48	-$6.34
WTI-LLS	-2.04	-2.67	-2.15
WTI-Mars	+3.41	+1.18	+0.63
Brent(Dtd)-Dubai	+1.39	+3.78	-1.18
Brent(Dtd.)-Urals	+23.76	+23.99	+23.54
Brent(Dtd.)-Bonny Lt.	-3.91	-3.11	-2.84
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$93.80	$94.64	$94.24
Arab Lt.-Europe (Med)	95.03	92.48	97.70
Arab Lt.-Far East (f.o.b.)	100.83	97.84	104.30
Nigeria Bonny Lt.	97.68	96.86	97.56
Arab Light Gross Product Worth			
Rotterdam	$109.51	$108.37	$99.18
US Gulf Coast	107.28	109.66	100.50
Singapore	94.58	92.65	93.56
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$122.49	$120.59	$100.52
UK Brent Margin	+25.04	+24.40	+7.93
US Gulf Coast			
Mars GPW	99.66	102.70	95.35
Mars Margin	+13.40	+15.58	+8.64
Singapore			
Oman GPW	93.05	91.45	93.33
Oman Margin	-3.49	-2.42	-3.96
US Nymex			
WTI 3-2-1 Crack	+$39.27	+$38.30	+$29.41
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$941.70	$922.82	$832.46
Gasoil (0.1%)	1121.33	1092.05	1008.00
Fuel Oil (0.5%)*	610.00	610.05	640.95
US Gulf Coast (¢/gal)			
RBOB Gasoline	257.60¢	271.24¢	241.13¢
ULS Diesel	390.75	373.70	332.41
Fuel Oil (0.5%, $/ton)	$681.00	$653.60	$678.60
Singapore ($/bbl)			
Naphtha	$74.62	$74.87	$72.02
Gasoil (0.05%)	136.14	130.56	123.63
Fuel Oil (0.5%, $/ton)	753.67	726.40	693.60

*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.