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US Embarks on New SPR Era Under Biden

The US plans to use its massive Strategic Petroleum Reserve (SPR) as a market management tool to control oil prices — not just selling when prices are high, as currently, but also buying when they are low, effectively setting a floor for domestic producers. The Biden administration had some success taming oil prices with SPR sales earlier this year, but the stakes are now higher. Biden's SPR policy risks putting the US, the world's largest liquid hydrocarbons producer — but also its largest consumer — in competition with Opec-plus over oil market control. The problem is that Washington has limited strategic stocks to draw on, cannot control private-sector production, and would like a lower price than Opec-plus. The two sides may be some $20 per barrel apart on where they would like oil prices to be, based on recent actions. Biden's SPR buyback plan would kick in at around $70/bbl for West Texas Intermediate (WTI), or roughly $75 for Brent, while Opec-plus' moves this year suggest it would like a Brent price of $90-$100/bbl. Biden revealed his SPR repurchase plan shortly after Opec-plus' recent decision to cut headline production by 2 million barrels per day — a move that infuriated the White House ahead of Nov. 8 US midterm elections and before new sanctions on Russia take effect. The US has sold more than 200 million barrels from the SPR since May, helping to drive down crude and gasoline prices. US retail gasoline prices hit a record $5 a gallon in mid-June, dropped to around $3.65 by mid-September, but have ticked higher to around $3.80-$3.90 in recent weeks.

The White House hopes its move will stimulate upstream investments in new US oil production by offering to refill the SPR when WTI is "at or below $67-$72." The effort fits a wider

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What Could Spur Opec-Plus to Ease Cuts?

What might it take for Opec-plus to ease its supply cuts in the coming months? It is a critical question for oil markets with prices still elevated and the potential for major disruptions to Russian production ahead. Opec-plus cited the desire to hold more spare capacity to give it greater flexibility to cope with volatile markets in making its Oct. 5 decision to cut headline production by 2 million b/d starting in November. While Opec-plus' actions this year suggest it may be defending a $90 per barrel price, Energy Intelligence understands that, with the oil demand outlook deteriorating, it is more concerned about avoiding a sudden crash that would threaten national budgets and upstream spending plans. Gulf states, particularly Saudi Arabia, want to avoid a situation where they are forced to use all their spare capacity, which they believe would spook markets further and cause a damaging price spike. This could point to a complicated discussion about any easing of cuts, which might require a combination of Russian supply disruptions, better-than-expected demand, higher prices that threaten economic growth and improved Saudi-US relations. Opec-plus has indicated there could be a case to tweak its production policy over the coming months depending on market conditions. A key driver behind the cut decision was to prevent a precipitous price collapse — like those seen in 2008 and 2020 — while keeping the market conducive to new upstream investments, sources say. This could be a difficult balance to strike. Opec-plus for some time has worried about under-investment in upstream supply,

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and this issue has been evident inside the group, as many members are unable to produce at their assigned quotas. In September, this shortfall was 3.4 million b/d. This is why actual Opec-plus production cuts are expected to come in at around 1 million b/d. Prices would need to fall substantially from current levels in the low $90s to threaten national budgets. Energy Intelligence's updated modeling indicates that the 2022 average Opec-plus external break-even is about $72/bbl.

While most oil market watchers — including Opec — anticipate substantial disruption of Russian output due to looming EU bans on imports, a key consideration for Opec-plus will be how this stacks up against demand deterioration amid a looming recession. Observers believe that the recent drop in crude differentials — despite the recent Opec-plus cut decision — signals that demand may be weaker than anticipated. Energy Intelligence thinks the EU ban on Russian seaborne crude imports — which takes effect on Dec. 5 — could result in the loss of 600,000 b/d of crude supply, while acknowledging many uncertainties. Opec in its latest monthly report said it expects Russian upstream liquids production to fall by 790,000 b/d in 2023. Saudi Energy Minister Prince Abdulaziz bin Salman last week reassured top Asian oil importing countries China, India and Japan that their supply needs would continue to be met, which suggests Opec-plus could take action if Russian output plunges and a supply deficit emerges. For now, however, the shaky demand outlook — which has been dominating market headlines recently — may call for a cautious approach. Standard Chartered analysts said that "unusually large" downward demand revisions by top oil market forecasters recently "support the producers' case" for cuts. Not everyone agrees. The International Energy Agency said the cut "increases energy security risks worldwide" and that oil prices "may prove the tipping point for a global economy already on the brink of recession."

Opec-plus will also factor in the impact of further releases from the US Strategic Petroleum Reserve (SPR) as it weighs future supply policy. Prince Abdulaziz this week warned of the dangers of draining the SPR and turning it into a market management tool, which he said would be disruptive to markets. "People are depleting their emergency stocks … as a mechanism to manipulate [oil] markets," he said. "It is my duty to make clear that losing emergency stocks may be painful in the months to come," he added, emphasizing that Saudi Arabia would act in its national interests. US-Saudi relations became strained immediately after the Opec-plus decision, which infuriated the Biden administration ahead of US midterm elections on Nov. 8 and new sanctions on Opec-plus member Russia, but temperatures seemed to cool over the past week. A big test could come from how the White House proceeds with the SPR. It is weighing additional releases beyond the 180 million barrels already authorized in May, which will end in December. The Biden administration has introduced a price component to its SPR strategy, with assurances to fill the reserve when US crude drops to about $70/bbl. Opec-plus is now understood to be watching Washington's next steps closely — given clear tension on the issue, any further SPR releases could make the group less inclined to ease its cut. For now, Energy Intelligence is maintaining its Brent forecast of $95 for fourth-quarter 2022 and $105 for first-quarter 2023. But any unwillingness by Opec-plus to respond to supply outages raises the prospect of $100-plus Brent arriving sooner.

More Progress for EU on Kicking Russian Gas

European natural gas prices are trading at their lowest levels in more than a year. The continent's stressed energy system has won some reprieve from soaring prices due to a variety of positive factors, cutting market rates for gas and corresponding power prices. LNG that was once being soaked up by Europe is now sitting on vessels offshore or rerouting to Asia as demand is low and there is little room in EU storage facilities to accommodate it. The price decline has given EU member states some breathing room as they struggle to align on plans to reorder gas and power markets to prevent another catastrophic round of price increases that many believe could come later this winter. Natural gas traded at the benchmark Dutch TTF hub fell to as little as €24 ($24) per megawatt hour in day-ahead pricing this week from a high of as much as €350/MWh in August. The price drop is directly attributable to a drop in gas demand as electricity from sources like nuclear, hydro and wind all pushed gas-fired power out of the supply stack, while unseasonably warm weather cut heating demand. There was a further drop as many EU countries have filled their available storage capacity and are no longer buying more gas than they can immediately use. The drop put prices well below the levels where any of the proposed EU gas price cap arrangements would have come into effect.

Europe has made significant progress in shifting away from Russian gas due to both voluntary measures and Russia's ratcheting down of export volumes. Currently, LNG is accounting for the largest increase in supplies, but additional non-Russian pipeline volumes are also increasing. Further supply diversification is possible as importing countries — particularly Germany — build out their LNG import infrastructure. All potential supply additions will be needed as countries look to what many believe will be an even tougher winter in 2023-24, when Europe will have to refill its storage capacity with little or no contribution from Russia. Russia accounted for just 9% of EU natural gas imports in August — down from 41% in August 2021. LNG imports now account for 41% of the EU's imported gas supply, up from 19% a year ago, while non-Russian pipeline volumes from countries like Norway have increased from 40% of 2021 imports to 50% today. Europe bought more than 65% of US LNG export cargoes through July 2022, up from 29% last year. Meanwhile, the amount of US LNG going to Asia fell from 50% of total exports in 2021 to just 22% in 2022. Next year, Europe could need to replace much of the 60 billion cubic meters of gas that it received from Russia in the first nine months of 2022, as Russia continues to limit gas exports to the continent.

Significant challenges remain in both commodity markets and the political arena. Differences remain among EU member states and even between member states and European Commission officials on the best way to calm markets without distorting them for years to come. Thus far, Europe has benefited from low demand in China due to Beijing's zero-Covid policy, which has freed up LNG cargoes to flow west. If economic activity or cold weather force China and other large Asian buyers back into the LNG market, Europe could find itself in an expensive global competition for gas volumes that it could not afford to lose. Dutch TTF futures pricing for natural gas in February is trading at more than €140/MWh — some three times today's spot pricing — indicating traders believe the low prices Europe is enjoying today are unlikely to last. EU energy ministers failed to come to an agreement on a preferred method to limit natural gas prices during a meeting in Luxembourg on Tuesday and now say a vote may not come until late November, further delaying implementation of any reforms.

Rerouting Knocks Differentials for Russian Oil

With six weeks remaining until the Dec. 5 EU ban on most Russian crude oil imports, discounts on sour Russian Urals exports have started widening beyond the previously stable $20 per barrel versus sweet dated Brent. Some Indian buyers have halted buying cargoes arriving post-Dec. 5. Both official data from Russia and price assessment agencies indicate the Urals discount has reached $24-$25/bbl in recent days, and observers expect this to grow in the run-up to December. Knowing the sheer volumes at stake and limited time, buyers may hold out for steeper discounts while Russian producers fret in search of new customers and tanker tonnage. Since Russia invaded Ukraine in February, EU buyers have pushed out 1.5 million barrels per day of crude imports, but Russia has managed to place all that in India, China and Turkey — albeit at a discount. Over the next six weeks, Russia needs to find a market for the remaining 1.1 million b/d still flowing to the EU that is not exempt from the import ban. In addition to price, Moscow will need to find sufficient tankers to haul the oil. Another EU directive says that tankers with connections to EU insurance and financing — close to 90% of the global fleet — cannot carry Russian oil. A large non-Western fleet has been put together in recent months. In the first half of 2022 alone, China bought 20 very large crude carriers (VLCCs) that can shuttle Russian crude from the Baltics and Black Sea to Asia under Chinese insurance and financing. India could potentially handle 600,000 b/d more, one Indian trader confirms. But Indian refiners fear the reach of US sanctions. Russia is also trying to rail 200,000 b/d more to China.

A bigger headache for Russia will be maintaining flows of refined products. Until January, or before the EU's Feb. 5 products ban, Russian refiners will try to sell as much as they can in Europe. September exports to the EU are estimated at 700,000 b/d — all of which Russia will be forced to sell further afield starting in January. Refiners will need to find tankers to haul diesel as far away as Brazil, and then swallow the costs. If sales drop, refiners will have to lower runs from the current 5.4 million b/d, and producers will either ramp up exports or shut

in production. For now, the economics do not look appealing. Currently there aren't any market assessment for cargoes hauling diesel from the Russian Baltic to Brazil, which has pledged to buy up to 200,000 b/d of diesel. But as one Russian analyst noted, based on available rates, a Baltic-Brazil cargo would run about $140 per ton, compared to about $30/ton for a 270,000 bbl cargo to Rotterdam. But diesel is in short supply worldwide: discounts for Russian cargoes have narrowed to $8.50/bbl from $14 earlier in October. Naphtha, on the other hand, won't be so easy. Russia typically exports about 500,000 b/d, or about 85% output, and has been selling to Europe at about a $250 per ton ($22.7/bbl) discount, kneecapping margins. Finding buyers and tonnage for this part of the slate will be an extreme challenge, particularly if Moscow sticks to principle and refuses to sell into the G7-imposed price cap allowing the use of Western tankers.

Regardless, rerouting Russian crude and products will warp differentials. Refiners continue to see huge margins for making diesel, ranging from nearly $80/bbl in the US to $50 in Europe. But compared to pre-war, sweet crude is now more expensive in Europe, less expensive in the US and at a traditional premium in Asia. These fresh price patterns can change again with the upcoming crude reshuffling. The widening is not just sour weakness, despite the additional 1 million b/d expected cut in Opec-plus output from November, but also Brent strength. Refiners, especially in Europe, continue to bid up the low-sulfur sweet oil to meet stringent EU product specifications. Sweet Brent is now trading $7.40 over sour Dubai, the benchmark in the Mideast, and again widening but not yet at its peak $12.76 high of July. The change in market dynamic can be seen in term pricing from Saudi Arabia. The premium of Arab Light over Arab Heavy in Europe for November loadings is at $6.40 — more than $3/bbl higher than its long-term average — while the premium for Asia is on a par, and the US about $2.50/bbl below the average.

Russia Charts Course Without Western Majors

Russia continues to come to terms with the exit of Western majors from its oil and gas sector. Moscow believes that development of hard-to-recover oil reserves will be most affected over the long term by the loss of Western technologies. However, more immediately Russia is focused on finding new markets for its crude oil and refined products ahead of looming EU import bans, with an eye on expanding port capacity significantly to accommodate more seaborne exports. The recent annulment of Exxon Mobil's 30% operating stake in the Sakhalin-1 project marks the full departure of the US supermajor from Russia. Moscow left the door open for foreign majors to stay — in the case of the Sakhalin-1 and Sakhalin-2 projects, this meant taking stakes in newly established Russian-registered operators. But both Exxon and Shell, which had a 27.5% minus one share in Sakhalin-2, opted to leave. TotalEnergies, which still has a 19.4% minority stake in gas and LNG developer Novatek and stakes in the Novatek-led Yamal and Arctic LNG 2 export projects, might follow suit. Chairman and CEO Patrick Pouyanne told investors last month that "fundamentally, we don't think our future is with Russia." BP still holds its 19.75% stake in Rosneft. Russian President Vladimir Putin's order preventing any transactions involving strategic companies or assets has put some Western majors' plans in a holding pattern. Nevertheless, Russian companies appear ready to replace foreign majors. Rosneft is expected to take over Exxon's stake in Sakhalin-1, while Novatek is considering taking Shell's Sakhalin-2 stake.

Speaking at the recent Russian Energy Week forum in Moscow, Putin admitted that Russia had become heavily dependent on foreign technologies in recent years. However, he said Russia would be able to develop its own technologies. While such technologies have been key to the development of hard-to-recover reserves, Moscow's tax and fiscal support was also critical, noted Deputy Energy Minister Pavel Sorokin. Experts say the real impact of foreign majors' exodus will only be seen in the next couple of years. This year, Russia still expects its crude production and exports to exceed 2021 levels, Deputy Prime Minister Alexander Novak told the forum.

As Russia seeks to ship more oil to markets outside the EU — particularly Asia — Novak said Russia will expand its export capacity at key ports by 40 million metric tons per year (802,000 barrels per day) at a cost of 150 billion rubles ($2 billion) over three years. However, Russia also must develop new payment systems and insurance services that would enable it to sidestep Western sanctions and remain a major player in international energy markets. According to Gazprom Neft boss Alexander Dyukov, Russia still must reroute about 1 million b/d of the 2.5 million to 3 million b/d of crude and products that it supplied to Europe before the Ukraine war. One step that might attract more customers is Moscow's plan to reduce freight rates for Russian-owned ships transporting crude and products. Continued cooperation with Opec will also be crucial as Moscow seeks to keep its production relatively flat in the coming years despite sanctions and the loss of key markets.

Russia is also taking steps to sustain its leading position on the global gas scene despite the sharp decrease in pipeline shipments to Europe in recent months. Moscow and Ankara recently started working on ways to transform Turkey into a new gas hub, mainly by diverting Russian gas flows that used to be shipped to Europe via the Nord Stream pipeline, shortly after the idea was first muted by Putin in mid-October. Moscow thinks Russian LNG can keep its role in the market, although longer-term LNG ambitions face challenges from sanctions. Russia's LNG production increased 11.9% on the year to 24.1 million tons in the first nine months of 2022, according to the federal state statistics service, which contrasts with a 12.1% decline in natural gas production. Europe might face a LNG deficit of 60 million to 70 million tons/yr in the next several years, if Russian pipeline gas exports fall by 100 billion cubic meters per year from the 2021 levels — compared with a 50 Bcm drop expected this year — Novatek boss Leonid Mikhelson told the Russian Energy Week forum.

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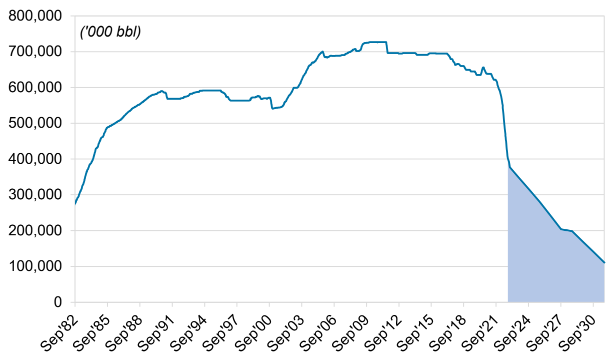
trend of Western governments becoming "more activist and interventionist" in their economies, one analyst notes — the result of extreme price volatility caused by the Covid-19 pandemic, the energy transition and Russia's invasion of Ukraine. The war has triggered import bans, sanctions and price caps. Governments are getting more involved to protect their citizens and economies, and prevent shortages. Price stability is needed for investments to continue, but some executives have warned of damaging effects from too much intervention. Energy economist Philip Verleger says the White House's SPR action could be a big incentive for US producers to invest in new capacity by making the SPR a "buffer stock" that guarantees a floor price for their oil, but producers still face investor pressure demanding capital discipline. John Raymond, managing partner at private equity fund Energy & Minerals Group, told Energy Intelligence that while the SPR move "means oil companies can invest to ramp up production now," it will not be enough to sustain significant growth in volumes as currently the only cash being reinvested in US shale is coming from cash flow remaining after dividends are paid out.

SPR Volumes



Note: Shaded area = reflects future drawdowns from Oct. 21, 2022 based on congressional mandates and announced emergency sales. Source: US Energy Information Administration, US Department of Energy, US Public Laws 114-74; 114-94; 114-255; 115-97; 115-123; 115-141; 115-270; 117-58

The SPR was established in the 1970s to reduce the effects of unexpected oil supply reductions. But some think the shale boom of the last decade has made it less critical to US energy policy. As a net exporter of oil, the US no longer needs to keep massive inventories for emergencies and supply disruptions — production of crude and natural gas liquids (NGLs) from shale operations turned the country from a 12.5 million b/d importer in 2005 to a net 1 million b/d exporter today. This status is also changing the energy dynamic between the US and Saudi Arabia, the largest Opec-plus producer. Biden's SPR releases have irked Opec-plus officials. "People are depleting their emergency stocks … as a mechanism to manipulate [oil] markets," Saudi Energy Minister Prince Abdulaziz bin Salman said this week. "It is my duty to make clear that losing emergency stocks may be painful in the months to come," he added. In the US, meanwhile, the political debate over Opec has flared up — with accusations stating the group is manipulating the oil market by withholding production and keeping prices too high. There are now about 401 million bbl left in the SPR — more than half of its 714 million bbl capacity. Even though levels are at their lowest since 1984, there is more room for sales — assuming the US is willing to risk a response from Opec-plus. The White House plans to decide on future releases — beyond the 180 million bbl already authorized in May, which will end in December — over the next month.

Current mandates from Congress require another 265.6 million bbl to be sold off by the end of 2031, which would bring the SPR to just a bit over 100 million barrels if the US Department of Energy (DOE) does not replenish the reserve. The Biden administration hopes purchases with fixed price — rather than market price — contracts increase the chances of doing so cost effectively. Actual contracts and conditions for sales and purchases still must be worked up for the latest action, the DOE says. Its guidelines say the US plans six-month SPR "requirements" but that it could deviate from a plan if the market changes. Buying or selling could be at fixed prices for a set period of time, also to be adjusted when needed.

Bunker Market Set to Fragment in Green Push

There is surprisingly little clamor for a single-fuel solution to the global shipping industry's carbon problem. Ammonia, biofuels, hydrogen, LNG and methanol are all being discussed as possible replacements for the 300 million metric tons per year (5.8 million barrels per day) of fossil fuel oil and gasoil currently burnt at sea, leaving much to be decided in one of the hardest sectors to decarbonize. The International Maritime Organization (IMO) is still searching for ways to at least halve global greenhouse gas emissions from shipping from 2005 levels by 2050, even as other industries embrace net-zero targets. Shippers are already used to handling multiple bunker grades to meet differing environmental standards around the world and as they come into port. But some of the new low-carbon fuels require completely different engine technologies that will likely require expensive investment decisions before new fuels are widely available.

A highly fragmented bunker pool is expected by 2050, according to the International Energy Agency (IEA), which presented its latest projections at the IMO's second-ever Symposium on Alternative Fuels held in London last week. But Ammonia made from green hydrogen could be powering almost half of the world's shipping fleet by midcentury, according to the IEA. Drop-in biofuels could make up another 20% and hydrogen 15% of the global shipping fuels market by 2050, when fossil-derived fuel oil and marine gasoils will still account for 15% of bunker sales, the IEA thinks. Hydrogen is likely to be used for shorter journeys close to shore but isn't energy dense enough to be practical for long-distance shipping. Liquid ammonia, itself made from green hydrogen, has emerged as the ideal compromise. Ammonia has about half the energy intensity of current bunker fuels but is relatively easy to handle compared to hydrogen. Speakers at the Symposium cautioned that ammonia engines are still at the development stage but that ships would be sailing commercially by 2030.

Clean-burning methanol has already been dropped as a likely future fuel since the IMO's first Symposium last February, while LNG, which is still considered a real contender by some international oil companies like Shell and Total, has also seen its role diminished. Neither fuel is expected to survive IMO plans to measure well-to-wake rather than just engine emissions. Some 20 methanol- powered vessels are already on the water, with at least 70 more on order, according to the Methanol Institute. Methanol production already stands at almost 100 million tons/yr, used in the chemical and fuel-blending industries. Current output is entirely derived from coal and natural gas. The IEA argues it would be too expensive to make methanol from green hydrogen compared to rival ammonia. It also sees LNG peaking at less than 5% of the global bunker market sometime before 2040 then becoming obsolete by 2050.

The UN shipping body is set to agree on a new medium-term greenhouse gas reduction strategy for the sector next July, more than five years after its initial strategy was slammed for setting weak carbon-intensity limits that most shipowners could meet simply by reducing vessel speed. New IMO plans are expected to include much tougher carbon-intensity standards on ships, aimed at incentivizing the use of low- and zero-carbon fuels, as well as a move to measuring full life-cycle well-to-wake emissions. There is also talk of green corridors that could act as a direct catalyst for low-carbon fuels demand.

Recent discussions also seek to ensure a just and inclusive transition to low-carbon shipping. Less developed countries (LDCs), particularly the small island developing states that are a vocal part of IMO's membership, are typically the most affected by climate change but often the least well placed to pay for the huge investments needed in the energy transition. LDCs could be near the forefront of renewable energy and green hydrogen and could play a much bigger part in fueling a greener shipping industry, sources said. The location of bunkering centers could change dramatically by 2050, as well as the types of fuels supplied. Morocco and Chile have already emerged as likely green hydrogen producers.

Exxon Upstream Boss: Efficiency Unlocking More Growth for Less

Exxon Mobil, the largest Western supermajor, has not been immune to the effects of recent market and geopolitical volatility. Upstream President Liam Mallon spoke at the recent Energy Intelligence Forum in London about how the company is navigating these challenges and becoming a more efficient producer. Edited highlights follow.

Q: Upstream underinvestment has been on the industry's radar for years, but it has very different implications when it's against the backdrop of an energy crisis, and also calls for an ever-faster energy transition. So, where do you see things today?

A: From our perspective, we've actually invested more in the last three years, a lot more than we earned. So, we've continued to invest through the cycle, if you like, and been very deliberate about that. And I think it's paying dividends today. We're still growing production, and we intend on continuing to grow production. In many ways, industry is underinvesting, we within the industry are continuing to grow our oil and gas. And we see in almost every scenario, that that is a valid strategy for a long time to come.

But things have changed in some ways … and there's no doubt there's underinvestment relative to the past. But I think you have to put it in the context of what's also changed relative to the past. Technology has advanced dramatically. In my opinion, the industry is adopting innovation far faster than it ever did before. The partnerships and collaboration across all of the relevant stakeholders are very different. So, I think it's a bit misleading to look at absolute numbers and conclude that the productivity of that number is the same today as it was just four years ago.

A great example, in the well-discussed Permian Basin, our and many of our competitors' drilling completion costs are down by a factor of four. So, what was taking 50 rigs to exploit just four years ago, it's now taking in the mid-teens for the same output. Cycle times have reduced as companies have innovated. Our Guyana story is well-talked about, but it's dramatically different than it was. So, I think you've got to look at it in the context of some of those incredible innovation and efficiency gains. We are starting to see some policy innovation, some good, some not so good — in particular, I think what's happening here in Europe, but that has also been part of that changed story. So, we remain confident that with continuing technological evolution, with always driving to the left hand side of the supply curve, and always driving to lower emissions, we can actually continue to grow oil and gas production and lower our emissions responsibly. This whole concept of a responsible operator, that we can do both, has been demonstrated, and I think that's going to accelerate.

Q: Cost inflation, labor shortages and supply-chain issues have hit the US oil patch hard this year. How do you see those problems slowing down those gains?

A: It's a factor. There are many factors. In the nature of our business, we tend to find that there is a responsive price-driven response, albeit maybe not from an activity perspective, to what we've seen in the past. But certainly today there is pretty significant stress on people availability and supply chains. But again, I think what we're finding is different ways to offset those. For example, it is it is rapidly approaching the point where a huge number of our rigs will be fully automated. Remote centers are now the norm, you rarely see people sitting on rigs steering wells. You've got one directional driller drilling 10 wells in a remote center. So I'm not sure it's fully appreciated, the magnitude of the innovation.

Q: One of the areas that has certainly allowed the industry to kind of push out of a potential supply crunch has been US shale overperforming and outperforming expectations. Whether it was ever a true swing supplier is up for debate. But what's not debatable is that the capital framework around shale has fundamentally changed. Can the world count on US shale if markets really do become extremely tight? Do the to the market signals still work?

A: Everybody has a different view on capital framework, but the discipline that appears to be holding in this upcycle appears to be consistent. And I think part of it goes back to my efficiency point: you are getting a lot more. And it is what's enabling the growth. If you look at activity, it's probably three or four times or less of what it was at the peak. When you think about what we were doing, we're early in recovery, particularly in some of the larger basins, many of the technologies that unlocked it in the first place like horizontal drilling, like fracking, are now having significant science applied to them. In the early days, it was more experimentation. So, if you think about it, you could unlock another five to 10% recovery, and do it at a reasonable cost, and do it with net zero, which is what we're proposing to do by 2030, then you have a winning formula. Because you've created an extremely resilient business, an extremely affordable energy supply, an extremely secure energy supply that has and can achieve your net-zero emission.

And it leverages the previous discussion, it's not like these things are disconnected. We will use renewable power as part of that net zero. Whether we build it or not is neither here nor there, but we can use it. So, I think the answer to your question is the pace of growth post-pandemic has been pretty significant. For us, it's been on the order of 25% a year — you would expect that to temper but it will still grow. And as we look at the projections, it continues to be strong, at least through the decade. And I firmly believe even beyond the decade, we will find breakthroughs to drive the recovery factor higher. And if we do that, there's enormous potential for long-term growth.

Q: We've heard in recent months some of these kind of re-emerging conversations around shale, where the industry

has kind of tapped its best inventory. But you really are seeing this as a technological challenge that doesn't necessarily make this as big of a deal as it is.

A: It is a resource that depletes and it is finite. Some basins are more mature than others. But I think the point I'm really trying to make is there is a lot of room. And, of course on the gas side, I think it's well known in the US that the resource has decades of potential that is underexploited today, and with the ability to continue that clean-burning fuel and put some of the energy transition technologies on it, you continue to make that a very secure, reliable source in countries that need it. So, I think it's very easy to generalize on this.

Q: Certainly, one of the things that we have heard in Europe coming out of this energy crisis is these accelerated calls for the low-carbon energy transition as a means to energy security, to lessening import dependency. But at the same time, we've heard fewer calls for an immediate halt to oil and gas. Do you feel like you have more breathing room to take your "all of the above" transition?

A: We don't really think about it, honestly, from a breathing room perspective. Us and many others have made a commitment, and that commitment is rooted in our in our societal obligation and doing everything we can to play our role to reduce emissions consistently, as agreed. And we've talked about net zero in our operations by 2050. And we're partners with others, influencing to the extent that's necessary to achieve similar goals.

If you remember, we talked about an external goal to be achieved by 2025, we actually achieved that in 2021. That gave us the confidence to set another ambition level for 2030. And everything I'm saying today suggests that we will achieve that, including in some huge resources that we've already alluded to. So, I don't think it changes our ambition. And it doesn't change what we're doing in terms of the leadership.

But I want to bridge into the last discussion. We really see our leadership is in the hard to decarbonize sectors, which I think is where we will play — we've been very clear about it. And our new low-carbon business, in CCS (carbon capture and storage), in biofuels, in hydrogen, ammonia. And we will continue to advance that. But at the same time, this whole ecosystem complexity and the assumptions that drive it, I think we all know that they're going to change. And so we have three businesses strategically, that we will measure the pace and rate of the capital allocation and resource allocation to those businesses dependent on the cycles we're seeing as the energy transition progresses.

So, we see growth in our oil and gas business, and we're very focused on exploration, acquisitions, and divestments to continue to provide that growth in a way that is more profitable than before and has the lowest possible emissions. All the things we're investing in are in this cost of supply of less than $3 per barrel. And we are rigorously applying that discipline to make sure that we stay on the left side of the supply curve. And almost regardless of the demand scenario you choose to pick, you will create a resilient business.

At the end of the day, if the pace and rate of the transition is faster, then that means that other products, lower-carbon products, lower-carbon solutions, are penetrating at a rate faster than we thought, which means someone is willing to pay for that at the end of the day. And if that's happening, we can pivot because exactly the same skills we have in the upstream can be applied to storage, to megaproject management, to commercial structures that make sense. So, we're very confident that strategy of being a leader in the energy transition and growing our oil and gas and the products that drive society —our high-end chemicals products, more and more lower-carbon fuel products — is a strategy that will win, albeit it may need to adapt based on milestones and cycles. And if it does, we have a structure that will allow us to resource-optimize across the whole thing.

Q: One of the things that really struck me earlier this year when Exxon put out its latest outlook, was it gave an illustration of how your capex, maybe post-2030, that mix between the oil and gas and low-carbon fuels was materially different, depending on that pace. As head of upstream, how do you keep that flexibility in the upstream portfolio to be able to pull your levers at different rates, depending on how the transition moves forward?

A: I think it's back to a very clear intent and those disciplined investment goals that others also have, and then playing to your capabilities. And we've been very clear in the upstream, that for new things, I'm not talking about the existing base, which is huge and generating the vast majority of cash today, but for new things, we see those capabilities for us in LNG, deepwater, and shale oil or unconventional, as we call it. And exploiting those capabilities to produce resilient investments that will stand the test of high uncertainty and the energy transition.

The questions are always, how much do you pad for certainty? And the LNG business is a highly capital-intensive business. Long-term contracts, very, very low cost of supply, very clean energy. But you have choices to make up front to add CCS, to add E-drives, all of these choices you have to make. And the good news is, you can make those with a fairly good degree of certainty, because of the long-term nature of that business and knowing that that fuel is flexible. And you can make ammonia from it, you can make hydrogen from it. And you can connect to all the economies in the world that use those products.

So, I think it's a question of going where you have your strengths, and leverage those strengths and be very rigorous about not taking on investment risk that's outside those parameters. And that discipline is necessary, I think, to create this strategy that we have that's pretty unique to our company in the upstream, where we believe growth is critically important. And we can do it for net zero in many cases.

Q: We have seen increasing questions in the past few months around gas prices. For the longest time, the industry's argument was that we provide reliable and affordable energy to the world. And $67 per million Btu gas is not really affordable. Do you have concerns about that materially affecting demand for longer term? How do you build that flexibility so that if LNG demand does hit a ceiling? How do you configure assets accordingly?

A: I think we're back to the long-term view again. We fundamentally believe that demand for gas will stay strong can continue to grow, for all the reasons that we've talked about: clean, low costs, plentiful. And you can make it frankly, as low emissions as you want to make it. So, we're pretty resolute in our view of that. And we will do what we can in the short term.

We've got many new investments coming on, and we're trying to accelerate some. Policy holders play a hugely important role in that discussion. We've seen some very positive policy development in the US, for example, recently, and of course, here recently in Europe some pretty negative policy development from the point of view of encouraging investment right when it's needed most. So, I think there are potentially some short-term solutions. But you all know the cycle time in the upstream business, I can say it's typically not something that you can turn the dial on.

So, that whole concept of policy, fiscal stability, incentivizing the nature of this very complex system to progress at a balanced pace, balancing affordability, reliability, and sustainability is key. And I think the narrative on that is changing to a more positive direction. I think that understanding is growing. But your ability to turn the dial and make a difference immediately is challenged. We will do whatever we can. And we have many things that we're in the process of doing that with, and our plans give us another significant growth jump across our business in the next one to two years. And that will help, but it's not going to solve the immediate problem.

Q: One area we have seen upstream capex step up is from [national oil companies] like Aramco and Adnoc. Certainly, Adnoc, one of your long-standing partners, is looking to add material capacity in the next several years, and potentially that could include your project at Upper Zakum. I think that's maybe kind of an overlooked asset these days, because the Permian and Guyana have so much growth. But could you just talk about the competitiveness of the asset and how it fits in your portfolio, given this very rigorous criteria you have for investment?

A: This is probably the second-largest oil field in the world. And we're very proud of being a part of it since 2006, along with our Japanese colleagues, and of course Adnoc. And it's been an extraordinary journey with extraordinary technology and innovation, and unlocking enormous potential on that field. If you want to look at where technology has made a difference, it is a great example. It's not just tight oil or tight gas, so we're very proud of that. The potential exists to expand, which I think I think is your point. And then we honestly would look at it no differently than we looked at those other investments. It has to be competitive. And really, for us, being competitive means it has to lift the average. It has to meet those thresholds we talked about — we have to see that to net zero at some point. And it needs to be something we think our capabilities are relevant to. All of those things are true, and there will have to be a discussion.

Q: Exxon had committed to invest through the cycle, and very much made plans to grow. With that, though, your capex plans are about $10 billion a year less than they were pre-Covid. And I'm just wondering how that feeling influences your priorities, as you look to keep that going through the cycle.

A: I think as innovation has evolved, we're finding that we can do more, with less. So, what I would tell you today is we still feel exceptionally good about the quality of our portfolio. And if anything, with time during the pandemic, in some areas of the world, other above-ground issues impacting the pace, we've used that time to improve almost everything: redesigned concepts, engaging our very best EPC [engineering, procurement and construction] contractors. So, I would say relative to what we want to do, the capital that we have is well balanced. And it is rigorously prioritized based on the objectives I said earlier. So, I think to a large extent, it's balanced. And of course, we have to balance the other three businesses in our broad objective of dividend, buying down shares, and, frankly, being ready for a time when there are maybe other opportunities in the market.

Back to what I said before, if you look at our oil and gas growth strategy, exploration alone will not do. If you look at 6% to 7% depletion per year, and think that you can replace that purely through exploration, that's nothing anybody in the industry has proven to be the case. That's not to say exploration is not highly valued, it is highly valued, and remains a core piece of our strategy. But we feel comfortable in that in that 7-ish billion dollars a year. And in that a significant sum is going to lowering the carbon intensity of our upstream business. So, I don't feel constrained in any way by that. And frankly, it's an opportunity to drive more innovation into the business. And I think you're seeing that from us. You're seeing it from our partners and our peers. And I think the industry, from that perspective, is in a fundamentally different place. If I look through my history of evolutions of revolutions, this whole industrial fourth revolution, whatever people call it, the digital transformation is fundamentally changing things to a degree that will provide for a high degree of flexibility even in a world where we're spending less.

Q: Exxon has been in many ways more efficient and quicker in withdrawing or promising to withdraw from big capital projects in Russia since the invasion, particularly compared to some European IOCs. One bit of Exxon's portfolio that's still a bit risky is its investments in the CPC pipeline. Could you share this view of the risks involved in that part of Exxon's business and where you see it going in the long term?

A: Let me just start with Russia and Asia. We are the operator on the Sakhalin-1 venture on Sakhalin Island, offshore and onshore. What's unique about our position is we are the operator. So it gives us a responsibility for day to day integrity and operations and different things than some of the others who are in partnerships. And we announced pretty early on our intention to discontinue operations and take steps to exit. From the perspective of discontinuing operations, production is largely now shut in, basically driven by a force majeure declaration on our exports due to sanctions. And we're continuing to work very diligently with the Russian Federation and our partners to now progress that exit. So, that's where we're at in that process. And I will just say that that is an intense discussion, but that's pretty much a minute-by-minute day-by-day.

I think for all of us, we were all surprised at the rapidity of what happened here, but it does make you think about things like CPC and the exposure to that. And we're very fortunate to have an outstanding partner with Chevron, who largely laid the influence strategy along with us and the partners of the consortium. And I think we're playing a significant role in making sure that that connectivity is understood. And I think so far, that's been successful, largely speaking. With the exception of some maintenance requirements, it's been undisrupted. I think we've all learned from some of these unexpected events, and we will all look at those single point-type scenarios and look for flexibility. And just like our other investments, make decisions as to whether the chart makes sense or not. But for now, I think it's understood. I think it's a very engaged dialogue. And people understand the risks, and they're being well-managed.

What's New Around the World

GENERAL

IEA — The International Energy Agency (IEA) says the fallout from Russia's war in Ukraine is accelerating the energy transition, prompting it to dramatically increase its estimate of growth in renewable power capacity this year. "We expect this year we will see again a huge growth in renewables, a 20% increase in renewables capacity — solar, wind and others — close to 400 GW of new capacity additions," IEA Executive Director Fatih Birol said. The new numbers compare with the IEA's previous estimate of 340 GW for growth in renewable electricity generation this year, published just last month. Greater penetration of renewables poses a challenge to the role of natural gas in the energy transition. Birol also said electric cars will account for around 15% of all cars sold in the world this year, up from around 4% in 2019, posing a more direct threat to oil demand. He said interest and investment in low-carbon energy has been surging because the world is "in the middle of the first truly global energy crisis." The energy crisis of the 1970s had been limited to a sharp increase in oil prices, whereas the current crisis has resulted in soaring prices for oil, gas, coal and electricity, largely due to Russia's invasion of Ukraine, he said.

CORPORATE — Oil-field services giant Schlumberger is changing its name to SLB, part of a larger restructuring focused on becoming a low-carbon energy technology company. The new name and logo represents another step in Schlumberger's transformation from a traditional oil-field services provider into a technology firm at the forefront of the global energy transition, according to the company's chief strategy and sustainability officer Katharina Beumelburg. Schlumberger began laying the groundwork for its rebrand in 2020 — in the midst of the pandemic oil price crash — with the launch of its New Energy segment focused on carbon capture development as well as hydrogen and geothermal energy. CEO Olivier Le Peuch has worked to streamline the company's 17 product lines into four primary focus areas: new energy, industrial decarbonization, digital services and oil and gas. All four now involve climate mitigation to varying extents, with methane control and carbon capture and sequestration emerging as increasingly important business lines for the firm. Oil and gas still remains central to Schlumberger's balance sheet, however, and comprised the bulk of the company's revenue in the third quarter this year.

COUNTRIES

KAZAKHSTAN — Kazakhstan's national oil company Kazmunaigas is gearing up for the sale of up to 25% of its shares in a long-awaited initial public offering (IPO) in early December that will primarily target local investors. KMG — 90% owned by Kazakhstan's sovereign wealth fund Samruk Kazyna, with the central bank holding 10% — is the country's largest and most profitable company. The IPO was delayed for over three years because of jittery global markets. The company produces around 450,000 b/d of oil and 8 Bcm/yr of gas. It reported net income of $1.5 billion for the first half of this year — roughly the same as for the first half of last year. The IPO is being pitched to Kazakh investors, and in particular to retail investors, although there is nothing to prevent foreigners from taking part. The shares will be traded on the stock exchanges in Almaty and Astana. In the run-up to the IPO, senior KMG executives have set out the company's long-term plans to increase oil production and step up exploration both onshore and offshore, with a focus on the Chevron-operated Tengiz onshore field and the Kashagan offshore field.

OMAN — Oman has committed to reaching net-zero emissions by 2050, in line with the Paris Agreement objective of limiting global warming to 1.5°C. The announcement was made on Sunday ahead of next month's COP27 climate summit in Egypt. Oman is the third Middle East oil and gas producer to make a net-zero pledge. The United Arab Emirates and Saudi Arabia both announced net-zero targets last year. The energy ministry also unveiled a Green Hydrogen Strategy and announced the formation of Hydrogen Oman (Hydrom) — a subsidiary of state-owned Energy Development Oman (EDO — previously known as Petroleum Development Oman). The Sultanate is targeting $140 billion of investment in the green hydrogen industry and hopes to achieve production of 1 million tons/yr by 2030. EDO Chief Executive Mazin al-Lamki said Hydrom will leverage Oman's abundant solar and wind resources to produce green hydrogen and support the government's efforts to reduce the country's carbon footprint and achieve its decarbonization targets. The sultanate is a medium-sized Opec-plus oil producer, with recent crude oil output of around 880,000 b/d. It also has two LNG production facilities and has been looking to expand its natural gas production.

QATAR — Shell has won the second international equity stake in North Field South (NFS) — Phase 2 of Qatar's 48 million ton per year LNG mega-expansion — Shell and QatarEnergy announced on Sunday. The company was awarded a 9.375% interest in the two-train 16 million ton/yr NFS project out of a total 25% interest available to international partners. QatarEnergy will hold the remaining 75%. TotalEnergies was also awarded a 9.375% stake in NFS last month. NFS is known to have slightly higher production costs than Phase 1, "but it is still a world-class asset," Saad al-Kaabi, Qatar's energy minister and CEO of QatarEnergy told Energy Intelligence last month. Completion of the 32 million ton/yr Phase 1 (North Field East) and Phase 2 expansions will raise Qatar's total LNG production capacity to 126 million tons by 2027. The 9.375% stake will give Shell another 1.5 million tons/yr of Qatari LNG when the NFS expansion comes on line, adding to the roughly 2 million tons/yr it will get from its 6.25% stake in North Field East. Shell — the world's top LNG portfolio player — had 31 million tons of liquefaction capacity around the world last year.

SAUDI ARABIA — Saudi Aramco is exploring the option of generating electricity for its largest offshore oil field using wind power, a move that would contribute to the company's net zero by 2050 target, sources said. Australian contractor Worley is working with Aramco on assessing the possibility of installing offshore wind turbines to generate power for operations at the giant Safaniya field, industry sources told Energy Intelligence. "The area is one the windiest in the Arabian Gulf which makes it a good choice for offshore wind power generation," said one industry source. The capacity of any wind turbines to be installed would still have to be determined as well as the project's possible timeline. Safaniya is presently being supplied with electricity generated by hydrocarbons via subsea cables. No one from Aramco or Worley was immediately available to comment. Aramco has begun looking at ways to cut down its operational emissions as it prepares to achieve its net zero by 2050 target set last year. The Saudi oil giant has set a target of 12 gigawatts of solar and wind capacity by 2035, and plans to produce 11 million tons of blue ammonia by 2030 as part of its net-zero drive.

UNITED STATES — Chevron has opted out of the Shell-operated Leopard project in the US Gulf of Mexico, the second time in a year that the US supermajor has exited a significant discovery poised for development in a prolific corner of the Gulf. A Chevron spokesperson confirmed the company has handed its 50% interest in the five blocks associated with Leopard to Shell, including Alaminos Canyon 691, the site of the initial discovery well drilled in 2020. "In exchange, Shell has assigned its 100% and 50% interests to Chevron in Green Canyon Blocks 636 and 505, respectively, in the deepwater US Gulf," the spokesperson told Energy Intelligence. In January, Chevron said it had traded its full 20% interest in Shell's Blacktip discovery, also in Alaminos Canyon, to Shell in exchange for a stake in another Gulf exploration project, led by Chevron, that ultimately proved unsuccessful. Chevron did not provide its strategic rationale for exiting Leopard. In January it said it left Blacktip because the project "did not compete for our capital compared to other opportunities." Chevron still holds a 40% interest in the nearby Whale development, which is operated by Shell and is due to start up in 2024.

Marketview

Diesel and Dust

Brent has traded at an average of $93.58 per barrel since the Oct. 5 decision by Opec-plus to cut its headline production by 2 million barrels per day starting in November.

The price boost from the official news lasted about two days, with the highest close recorded on Oct. 7 at $97.92 per barrel, after which the benchmark started to trade sideways. Prices did make gains ahead of Oct. 5 on reports that Opec-plus was considering a cut, however,

Opec-plus may have reduced output in light of a dire demand outlook, but the group has not helped reduce uncertainty. The lack of direction is what is holding this market more than everything else. Showing how thin physical demand is despite the end of the maintenance turnarounds in Europe and the potential for diesel shortages cargoes of light, sweet Forties Blend offered in the open market have failed to find buyers and are floating without a destination.

On the one hand, middle distillate demand is strong, supply is tight, and global inventories are low, which makes for a perfect cocktail of bullish price drivers. Add an imminent EU ban on Russian refined product imports on Feb. 5, 2023, a lack of refining capacity to make that up, and a lower availability of diesel-rich, medium, sour crude feedstock with Russia's Urals crude off the table and Opec cutting production, and the cocktail becomes potentially explosive. In addition to winter-specification diesel, seasonal demand translates into additional gas-oil demand for heat and power generation.

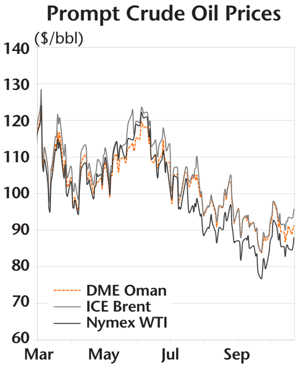
Tightness in global middle distillates has sent refining margins through the roof. At about $75/bbl for ultra-low-sulfur diesel in Europe and about $78/bbl in the US, there is more appetite for heavier, sour barrels susceptible to yield the right mix of winter products, especially gasoil.

Diesel prompt futures spreads in New York and Europe trade sharply higher and underpin the price of crude. At the same time, they also point to the ineffectiveness of releasing strategic reserves of essentially light, sweet crude when what is badly needed is diesel and heating oil — and the heavier crude that yields more of these products.

On the other hand, middle distillates demand is sensitive to business cycles and will take a direct hit when a full-fledge recession materializes. Whatever gains are achieved in the gasoil/diesel market this winter may be lost elsewhere given the dire economic outlook. Naphtha margins are in the doldrums, and with little uses for it in Europe, refiners have started to reduce their intake of crude oil blends that yield too much of it, including North Sea light, sweet crude. This partly explains why the spot prices of grades that do not yield enough middle distillates and/or are not a good match for the lost, heavier Urals barrel have fallen.

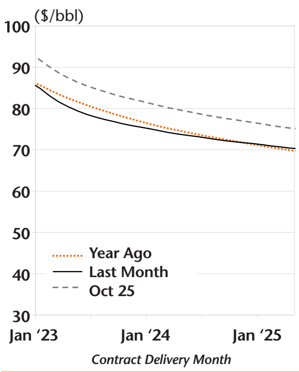
The oil market is almost done with December trading, and refiners are also cautious, for accounting reasons, not to buy crude that won't be processed until next year and will show up in year-end inventories. Pending any visibility on a possible recession timeline, most refiners want to minimize pain on their profit and loss statements.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

ICE Brent Forward Curves



EIA Flags Stagnant US Production

Crude oil production in the US leveled out in mid-October, according to the US Energy Information Administration (EIA), despite a rebound in Alaskan output.

An EIA weekly report showed that US crude output stayed at roughly 12 million b/d in the week ended Oct. 21. US output has hovered in a narrow range of about 11.9 million-12.1 million b/d for six months now as operators grapple with rising costs, supply chain constraints and labor shortages. The EIA also flagged that the number of drilled but uncompleted wells (DUCs) in the US fell to 4,333 as of September 2022 — the fewest since at least December 2013, when it started estimating the number of DUCs. Fewer DUCs, along with natural gas pipeline constraints, could limit future US production growth, it warned.

PIW Market Indicators

($/barrel)	Oct 24-	Oct 17-	Sep 26-
Spot Crude	**Oct 26**	**Oct 21**	**Sep 30**
Opec Basket	$92.75	$91.37	$90.94
UK Brent (Dtd.)	92.17	91.32	87.19
US WTI (Cushing)	87.35	85.33	80.08
Nigeria Bonny Lt.	94.54	93.76	91.00
Dubai Fateh	89.93	88.97	86.11
US Mars	82.83	81.04	79.15
Russia Urals (NWE)	68.46	67.06	63.90
Crude Futures			
Brent 1st (ICE)	94.16	91.99	87.22
Brent 2nd (ICE)	92.25	90.23	85.62
B-wave (ICE)	93.51	91.91	87.17
WTI 1st (Nymex)	85.94	84.97	79.62
WTI 2nd (Nymex)	84.86	83.92	78.87
Oman 1st (DME)	90.09	89.00	86.31
Oman 2nd (DME)	88.02	87.74	85.03
Murban 1st (ICE)	94.01	91.73	88.59
Murban 2nd (ICE)	91.75	89.71	86.64
Forward Spreads			
Brent (1st-Dtd.)	+$1.99	+$0.66	+$0.03
Brent (2nd-1st)	-1.91	-1.76	-1.60
WTI (2nd-1st)	-1.08	-1.06	-0.74
WTI (3rd-2nd)	-1.23	-1.08	-0.92
Oman (2nd-1st)	-2.07	-1.27	-1.28
Oman (3rd-2nd)	-3.21	-2.27	-2.41
Murban (2nd-1st)	-2.26	-2.01	-1.95
Murban (3rd-2nd)	-2.28	-1.96	-2.93
Grade Differentials			
WTI-Brent (1st)	-$8.22	-$7.85	-$7.60
WTI-LLS	-2.22	-3.28	-2.49
WTI-Mars	+4.52	+4.29	+0.93
Brent(Dtd)-Dubai	+2.24	+2.35	+1.08
Brent(Dtd.)-Urals	+23.71	+24.26	+23.29
Brent(Dtd.)-Bonny Lt.	-2.37	-2.44	-3.81
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$90.46	$88.67	$86.78
Arab Lt.-Europe (Med)	96.21	94.61	91.87
Arab Lt.-Far East (f.o.b.)	96.82	95.55	97.12
Nigeria Bonny Lt.	94.08	93.23	93.10
Arab Light Gross Product Worth			
Rotterdam	$104.42	$105.44	$97.94
US Gulf Coast	112.51	104.27	101.10
Singapore	91.62	92.83	86.47
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$118.15	$119.59	$99.68
UK Brent Margin	+23.19	+26.86	+10.85
US Gulf Coast			
Mars GPW	104.22	96.68	95.16
Mars Margin	+21.29	+15.54	+15.91
Singapore			
Oman GPW	91.03	91.82	86.42
Oman Margin	-2.25	+0.06	-3.27
US Nymex			
WTI 3-2-1 Crack	+$49.86	+$43.22	+$36.56
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$917.37	$900.26	$812.02
Gasoil (0.1%)	1112.67	1126.40	977.60
Fuel Oil (0.5%)*	602.67	606.60	585.85
US Gulf Coast (¢/gal)			
RBOB Gasoline	274.67¢	249.04¢	252.53¢
ULS Diesel	407.35	379.03	331.69
Fuel Oil (0.5%, $/ton)	$660.33	$653.00	$612.80
Singapore ($/bbl)			
Naphtha	$74.06	$72.13	$70.38
Gasoil (0.05%)	131.13	133.12	116.80
Fuel Oil (0.5%, $/ton)	703.00	717.80	675.00

*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.