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No Quick Fixes for Europe's Energy Shortages

Energy costs in Europe are skyrocketing, with prices for natural gas and electricity hitting a series of record highs and those for liquids fuels little better — even before tougher sanctions on Russian oil and products come into effect. The toxic mix is driving inflation up on the continent and economic activity down. Calls abound for Europe to become more self-sufficient but — at least when it comes to oil and gas — it has few options to alleviate near-term pressures and may not have the appetite to undertake medium-term developments due to its bold climate ambitions. In short, there is no sleeping giant to awaken in Europe's energy supply landscape, meaning demand destruction may be the primary mechanism to balance markets. A quick look at the top holders of oil and gas reserves shows the most resource-rich country — Norway — barely makes the top 20 globally. Norway's Equinor increased gas production 18% in the second quarter through a mix of drilling, optimization and deferred maintenance. "We will continue to try to sustain as much of the gas production as we can," CFO Ulrica Fearn told investors on a second quarter call. But the need for maintenance outages at key hubs has left Norway's exports at 314 million cubic meters per day on Aug. 25, down from 334 Mcm/d a month earlier. UK gas production rose 26% to 16.8 billion cubic meters in the first half of 2022, but the boost came against historically low 2021 volumes and was down 10% against 2020 levels. The total covered about half of the UK's demand.

Companies are doing infill drilling and optimizing facilities where they have opportunities in places like the North Sea and the handful of remaining legacy onshore fields. But most

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Saudis Warn of Risks From Volatile Market

Frustration is mounting in corners of the industry about government intervention in oil markets, which some think is undermining efficient price discovery. Saudi Energy Minister Prince Abdulaziz bin Salman expressed concern that the physical and paper markets have become disconnected, in turn prompting extreme volatility in oil futures. Some might argue that he was merely trying to talk up oil prices, which have been sliding since June — taking Brent below $90 per barrel earlier this month. But high volatility and breaks between fundamentals and price movements can pose a risk to commodity markets by creating insecurities and difficulties for traders and industry players seeking to hedge. "The paper oil market is facing a vicious cycle of very thin liquidity and extreme volatility, which in turn is creating a disconnection between the physical market and the futures market," Prince Abdulaziz told Energy Intelligence in an interview. "This vicious circle is being magnified by the constant flow of unsubstantiated stories about demand destruction, news about the return of large volumes of supply, and ambiguity and uncertainty about the potential impacts of price caps, embargoes and sanctions," he added. Oil prices have swung wildly in recent months as the market digests the threat to Russian exports from Western sanctions. Moreover, the Biden administration's market interventions, notably a record release of 1 million barrels per day from US strategic stockpiles from April to October, and a steady stream of news on the revival of the Iran nuclear agreement — which would unleash more

Chairman: Raja W. Sidawi. Vice Chairman: Marcel van Poecke. Chief Strategy Officer & Chairman Executive Committee: Lara Sidawi Moore. President: Alex Schindelar. Editor-in-Chief: David Pike. Executive Editor: Noah Brenner. Contact Us: New York: Tel: +1 212 532 1112. London: +44 (0)20 7518 2200. Sales: sales@energyintel.com. Customer Service: customerservice@energyintel. com. Bureaus: Beirut: +961 3 301278. Dubai: Tel: +971 4 364 2607/2608. Houston: Tel: +1 713 222 9700. Moscow: Tel: +7 495 604 8279/78/77. Singapore: Tel: +65 6538 0363. Washington: Tel: +1 202 662 0700. Other publications: *EI New Energy, Energy Compass, Energy Intelligence Finance, International Oil Daily, Jet Fuel Intelligence, Natural Gas Week, Nefte Compass, NGW's Gas Market Reconaissance, Nuclear Intelligence Weekly, Oil Daily, Oil Markets Briefing, Oil Market Intelligence, World Gas Intelligence.* www.energyintel.com

Iranian oil to the market — have given traders more to think about. The prince stated that energy policy should be long-sighted, and that current distorted market conditions are preventing players from hedging and managing risk — and when this happens, industries can start shutting down. Such an example can be found in Europe, where volatile natural gas prices have made it difficult for industrial users to operate. “In a way the [oil] market is in a state of schizophrenia,” Prince Abdulaziz said in a separate interview with Bloomberg.

Prince Abdulaziz said Opec-plus as a group is capable of handling challenging situations. He referenced the group’s past actions, which include the ability to cut production — comments that surprised the market and pushed Brent back over $100/bbl. “Prince Abdulaziz shook the market up, hit it at a perfect time,” said a US-based oil analyst. Energy Intelligence understands that all options are on the table for Opec-plus with regards to setting oil policy. “Opec-plus has the flexibility and the commitment among members within the Declaration of Cooperation to deal with market challenges and provide guidance including cutting production at any time and in different forms as has been clearly demonstrated in 2020 and 2021,” the prince said, referring to the agreement that created the broad Opec-plus group. Prince Abdulaziz did not say if cuts might be considered or formally discussed at the next Opec-plus meeting. Ministers from Iraq and Kuwait issued statements this week echoing Prince Abdulaziz’s concerns about volatility, while other members agree that the issue merits attention. Opec-plus officials will meet to discuss supply policy on Sep. 5. The last meeting on Aug. 3 resulted in a modest increase in production that helped maintain group cohesion.

While some observers suggested the Saudi comments were aimed at putting a floor under oil prices, Energy Intelligence understands they were designed to reassert control over an oil market that has gyrated with the daily news cycle and to safeguard global economic growth. Saudi-led Opec-plus has stated repeatedly that global upstream investment must increase to avoid an oil market crisis despite concerns about climate change and some countries’ preference for a rapid energy transition. Prince Abdulaziz warned that the “yo-yo” effect in today’s oil market is an unhealthy sign that sends false messages of security at a time when spare capacity remains low. The prince and other Saudi officials have urged global oil producers to increase upstream investment to safeguard energy security on many occasions in recent years. “Truly, you cannot attend to climate change without energy security,” Prince Abdulaziz told a conference earlier this year. He added that energy security is needed to have the economic prosperity necessary to tackle climate change.

One Year On, Total’s Iraq Deal Awaits Liftoff

One year after TotalEnergies signed a $27 billion energy megadeal with Iraq — a project seen as potentially transformational for the country’s upstream fortunes — work has yet to begin. Wrangling over outstanding contract details, including the government’s stake, and a deepening political crisis have prevented the French major from launching what Oil Minister Ihsan Ismael has described as the biggest investment by a Western company in Iraq. Already the timelines are slipping, jeopardizing the Opec country’s plan to phase out gas flaring, while also impairing the positive signals the project appeared to send to foreign investors. Since Total inked the agreement in Baghdad on Sep. 5 last year, dates for its expected “activation” have come and gone, with the ministry unable to get the necessary approvals. This is hardly surprising given the political turmoil in Iraq, whose top court ruled in May that the current caretaker administration does not have the authority to take big decisions, and with powerful political factions likely to resist granting generous concessions to Total. The oil minister has pushed hard for it, meeting Total CEO Patrick Pouyanne in Paris last month and saying afterwards that progress had been made on implementing the four contracts that comprised the deal. Industry sources say the terms of the gas capture, water injection and 1,000 megawatt solar power plant have been agreed, but not the stake allocated to the Iraqi National Oil Co. (INOC). Ismael has said it would be 40%, which seems at odds with Total’s plan to bring in other international oil companies (IOCs). The key oilfield component of the contract is also a sticking point. Total declined to comment.

Until a new government is formed, more drift seems inevitable. And Iraq looks set to remain without a government — and a budget law — in the coming months, deepening doubts about major new investment projects in the oil and gas sector. Fresh elections may be the only way out of the impasse, which would take time to organize. But the massive oil revenues currently replenishing Iraq's coffers ought to facilitate the progress of projects like Total's, if the political crisis is resolved. Contractors are waiting in the wings, and IOCs are watching events unfold closely. Iraq's ongoing failure to advance the Total deal risks turning an opportunity to rekindle the fading interest of Western majors into the bad bet that kills it off. It will also determine the fate of a 5 million barrels-per-day water injection scheme, long planned and increasingly needed, to boost reservoir pressure and output at key southern oil fields. For the moment, preparations continue, with the state-run South Gas Co. in June awarding a front-end engineering and design (Feed) contract to Houston-based KBR, for the Ratawi central gas complex, which the oil minister insists was done "in collaboration with Total." A senior executive at UK-based Wood Group, which like KBR has extensive experience in Iraq, told Energy Intelligence that his company would be keen to participate in the Total project, describing the investment it potentially brings to the region as "hugely exciting." Initial capex in the project is estimated at around $10 billion.

The capture and processing of 600 million cubic feet per day of associated gas that is currently flared in southern Iraq — representing 35% of the total gas flared in the country last year — is a key feature of the Total deal. As its timeframe gets pushed back, so does Iraq's plan to eliminate gas flaring and raise badly needed domestic production. Informed sources say four to five years of intensive work and investment will be needed to get all of the Total project's main components up and running, meaning Iraq will miss the 2025 target to end routine flaring that was announced a month after the deal was signed. The biggest existing flare reduction scheme, the Shell-led Basrah Gas Co. (BGC) joint venture, aims to capture 400 MMcf/d of gas with the addition of two new trains, now due on stream in the second half of 2023 and the first half of 2024. BGC has room to expand further. And Baker Hughes appeared to take a step forward in May with its project to capture 200 MMcf/d of associated gas at the Nasiriyah and Garraf fields, awarding a detailed engineering contract to China's CPECC for the Nasiriyah gas processing plant. Both projects were heavily delayed by Covid-19 and the oil price collapse, which brought Iraq close to bankruptcy and halted work. Now, Iraq's monthly oil revenues are averaging more than $10 billion, but a political crisis stands in the way of progress.

Gas Finds New Ways to Aid Transition

Natural gas already has a critical role to play in the energy transition, but emerging applications are expanding its usefulness further. As a cleaner-burning alternative in power generation and transportation, gas has long been seen as a "bridge" fuel for consumers and industries looking to reduce emissions. But growing interest and investment in known technologies like gas-to-liquids (GTL) and methane pyrolysis, particularly in North America, have gas poised to be a potentially important feedstock for buzzy products like sustainable aviation fuel (SAF), clean hydrogen and renewable diesel and gasoline, even as geopolitical concerns in Europe jack up demand for LNG and goose global gas prices. In the oil field, gas use is already established as a convenient way to lower operational emissions. Interest in electrified drilling rigs and hydraulic fracturing spreads remains high, although equipment is in short supply. While remote locations in the Permian Basin in West Texas and southeastern New Mexico have proven difficult to fully electrify, so-called dual-fuel options have emerged that enable operators to use field gas to displace diesel. Kirk Johnson, ConocoPhillips' head of lower 48 operations, says the deployment of dual-fuel equipment has cut the company's diesel usage by 75% across its Permian operations. That can translate into cost savings as well — Trican Well Services CEO Brad Fedora says his company's dual-fuel frack equipment can save operators more than $50,000 per day per well compared to engines fueled by diesel alone.

Interest in GTL technology has ebbed and flowed over the decades, with a handful of major projects still operating in gas-rich (and some oil-poor) regions around the world. In North America, plans for a couple of massive GTL plants collapsed last decade with the dawn of LNG exports, striking a blow to the technology's reputation in the region. More recently, small-scale GTL has gained traction as developers significantly scale down project scopes with a focus on modular plants that can be deployed quickly, inexpensively and at locations close to both markets

and feedstocks, including biomass and renewable natural gas. Large-scale GTL is inching back into the picture in North America as well, with multibillion-dollar projects under way in the Permian and the Bakken Shale targeting associated gas and stranded supplies. New twists on GTL technology offer promising sources of supply as demand intensifies for SAF and synthetic fuels that have a lower life-cycle emissions profile than conventional products. London-listed Velocys is working with Oxy Low Carbon Ventures to build a 2,000 barrel per day SAF plant in Mississippi, with an off-take agreement in place with Southwest Airlines. Velocys has a separate, 1,100 b/d project in development in the UK that will sell SAF to British Airways. Other GTL projects are even smaller. US-based EN Global sells truckable GTL plants that capture gas that would otherwise be flared and converts it to synthetic crude, diesel or naphtha. It has agreements in place to deploy 50 b/d and 100 b/d units to Iraq, Libya, Algeria, Oman and India. Public investors are starting to take note — renewable gasoline producer Bluescape Clean Fuels this month signed a reverse merger agreement with blank-check outfit Cenaq Energy that attaches a $280 million enterprise value to the combined company.

Hydrogen produced with renewable power and electrolyzers (green) or with steam methane reforming and carbon capture and storage (blue) have received most of the attention at this stage of the transition. But "turquoise" hydrogen, produced through methane pyrolysis, is quietly emerging as another emissions-free option. The process splits methane into hydrogen gas and a solid form of carbon that can be marketed for industrial purposes, or landfilled as non-emitted waste. Nebraska-based Monolith made a splash last year after securing a more than $1 billion conditional loan guarantee from the US Department of Energy to expand the company's hydrogen and ammonia plant, which utilizes proprietary pyrolysis technology. This month, Canada-based Aurora Hydrogen, which has its own unique approach to methane pyrolysis, closed a Series A round that attracted investments from Shell and Chevron. High global gas prices could pose a challenge to many of these emerging technologies, which all rely on cheap feedstock to make the economics work. Leaky upstream and midstream gas infrastructure can also undermine claims of "zero-emissions" product offerings. In the US, the recent Inflation Reduction Act could help on both fronts. The legislation, now law, offers generous tax credits for clean hydrogen and SAF that can help offset further increases in gas prices. And the law's new methane-release penalty and other incentives to fix leaks will help reduce fugitive emissions and increase the overall supply of captured gas. Executives say they are confident demand for their gas-derived products is strong enough to overcome fluctuations in commodity prices.

China Imports More Russian Oil Despite Risks

China's imports of Russian seaborne crude are on the rise this month, but their trajectory going forward remains a mystery as the West seeks to tighten sanctions on Moscow. Seaborne imports of Russian crude are slated to increase by more than 150,000 barrels per day in August from July, with Chinese independent refiners hiking their Urals purchases substantially lately. Roughly 1.3 million b/d of Russian seaborne crude are expected to land at Chinese ports this month after including estimated volumes from ship-to-ship transfers, said Emma Li, a China-focused analyst at Vortexa, up from 1.1 million b/d in July. Kpler projects 1.31 million b/d of Russian seaborne crude arriving in China this month, up from 1.16 million b/d in July. Chinese independent refiners' increasing appetite for Urals is notable. For the first 18 days of August, Vortexa estimates around 500,000 b/d of Urals arrived at Chinese ports for independents, while national oil companies (NOCS) took none. Independents took little to no Urals in 2021 and in the first five months of 2022. In June, they were noticeable in the market, taking around 150,000 b/d, while NOCs landed less than 100,000 b/d, according to Vortexa. Kpler data points to 414,000 b/d of Urals arriving in China in August. As the Ukraine war drags past its sixth month, market players in China and India are getting more comfortable with buying Russian crude. But it is Urals' cheapness that is mostly driving Chinese independents' rising demand, traders say.

Indeed, independent refiners are helping China cement its position as a crucial buyer of Russian crude. They are also an important buyer of East Siberia-Pacific Ocean (Espo), Russia's other top export grade along with Urals. Around 800,000 b/d of seaborne Espo are expected to reach Chinese ports from Aug.1 to Aug. 18, with independents expected to land more than 600,000 b/d of those volumes, according to Vortexa. Kpler estimates 792,000 b/d of seaborne Espo will arrive at Chinese ports in August. Around 80% of August loading Espo is pointed at China, with India snapping up most of the remainder, says a Chinese market source. For the first three weeks of August, China took 22 of the 26 Espo cargoes sailing from the Far East and picked up two Sakhalin Blend cargoes for a combined volume of 813,000 b/d, Kpler reckons.

While the trend has been apparent to outside observers, it is less evident in puzzling official customs data from China. Typically, China imports around 800,000 b/d of Russian crude through pipelines, with 830,000 b/d arriving in July. However, Chinese customs data counted only 1.69 million b/d of total seaborne and pipeline Russian crude imports in July. This implies China only imported less than 600,000 b/d of pipeline Russian crude last month — substantially lower than the norm. Analysts believe that China likely undercounted Russian crude arrivals in June and July, perhaps to avoid political consequences with the West.

Conservatively assuming 800,000 b/d of pipeline Russian crude imports this month, it would point to robust overall Russian crude imports of at least 2.1 million b/d for China. The question is how much more it can or is willing to take. This will be put to the test by the EU's ban on Russian crude imports that will kick in on Dec. 5. The embargo will force Moscow to find markets for an additional 1 million b/d of crude and 1 million b/d of refined products. Even if China or other Asian buyers want to buy more, there could be a shortage of tankers — especially for products — to move the oil due to proposed EU shipping sanctions on finance and insurance. Traders argue these restrictions must be watered down to prevent global supply shortages and price spikes. A waiver on the insurance ban is already being discussed. The US is also promoting a price cap system that would allow tankers to ship Russian oil if buyers can show it was purchased at a price set by the West. But traders think such a plan is impractical and can be circumvented with made-up paperwork by willing buyers.

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volumes that could come to Europe before the end of the coming winter needed to be in the development pipeline long before now. Still, European majors including TotalEnergies, BP and Shell have pledged to find short-term solutions. Total is "accelerating development of short-cycle projects, for example, and notably, to increase gas deliveries to the European market from the North Sea," CEO Patrick Pouyanne told investors. Shell is retrofitting a floating production vessel to wring more gas out of an existing oil field beginning this fall and sanctioned its Jackdaw gas field that will be online in the second half of 2025. Independent Harbour Energy brought on its delayed Tolmount Field in late April, and competitor Neptune Energy has started drilling at its infill project at the Cygnus gas field. Looking further ahead, in the Black Sea, the first phase of Turkey's Sakarya field could be onstream in 2023, producing 3.5 bcm/yr with another 10 Bcm/yr in Phase 2 in 2027. Romania is trying to accelerate its Neptun Deep field, which could cover its own demand and regional exports, but OMV Petrom has yet to sanction it.

More radical options are gaining some traction. Ramping up output from the earthquake plagued Groningen field in the Netherlands remains a stop-gap alternative should continental gas supplies fall short. There are growing calls for countries to rethink their restrictions on hydraulic fracturing, although a host of issues remain. Even conventional offshore gas developments continue to face headwinds from campaigners who see the answer as more renewables, not more oil and gas. "That will be a function of how the Dutch government kind of weighs off the demand for gas versus the supplies," Exxon Mobil CEO Darren Woods said of a possible expansion of Groningen gas production. "But the capacity is there." Drilling has begun at Hungary's Project Corvinus development, which the government calls an "unconventional" gas field, with first production targeted in January. A recent poll found 27% of residents in Germany supported fracking. But after retreating from the promise of large shale gas reserves in places like Poland and Romania, it is not clear that the majors would have any appetite to tackle significant onshore developments in Europe that would be sure to draw controversy. "The equation is as simple as that, even if some people might find it difficult at first to step out of their comfort zone and accept the consequence of the current crisis," Wintershall CEO Mario Mehren said of Europe's need to produce more domestic energy. Meanwhile, Greenpeace is suing to stop Shell's Jackdaw permits.

Peak Demand Still Looms Despite Recovery

The strong rebound in oil demand following the Covid-19 crisis led several energy modelers to postpone the expected date of peak oil demand. Consultancy DNV and BP, which last year considered oil could have peaked in 2019, now see demand peaking respectively in 2024 and 2025. But the desired and likely direction of travel has not changed. In fact, the Intergovernmental Panel on Climate Change's (IPCC) recent warning — that keeping a 1.5ºC or even 2ºC warming limit in sight will require a big strengthening of policies — could mean an even faster phasing

out of fossil fuels than initially envisaged. This year's spike in oil and gas prices could add momentum to these efforts and accelerate the uptake of electric vehicles in transportation and renewables in power generation, despite calls for increased oil and gas supply in the near term. Indeed, Paris-compliant energy scenarios assume oil and gas demand will fall by respectively 40%-80% and 20%-60% between now and 2050. Gas demand would also need to peak only a few years after oil, around 2025-30. Most scenarios, however, even among Paris-compliant ones, do not achieve net-zero — or near net-zero — CO2 emissions by 2050. This would only happen with the International Energy Agency's (IEA) and BP's net-zero scenarios, and the IPCC's 1.5°C group of scenarios with limited warming "overshoot" — in other words, there is a limited degree to which the average temperature increase misses or overshoots what is targeted. In the IPCC's 1.5°C scenarios with high overshoot, reaching net zero would happen five to 10 years later, and only around 2070 in the 2°C scenarios, in line with Shell's Sky 1.5 scenario. Some big oil and gas consuming and producing nations have set net-zero targets beyond 2050. China, Indonesia and Saudi Arabia are targeting net-zero CO2 by 2060, and India by 2070.

Many experts, including Energy Intelligence, now do not see peak oil demand before 2030 and foresee more of a plateau after it occurs rather than a sharp decline. They also emphasize the role carbon capture and storage (CCS) needs to play to keep emissions within budget, based on its ability to limit emissions in hard-to-decarbonize industrial processes, along with its projected ability to achieve negative emissions by removing CO2 from the atmosphere when combined with bioenergy (BECCS). Conservative scenarios such as Equinor's Rivalry, the IEA's Stated Policies and BP's New Momentum only assume limited amounts of CCS of just a few hundred million tons per year of CO2 by 2050. That's a seemingly modest amount, but five to 10 times more than today's installed capacity of 40 million tons/yr. Paris-compliant scenarios assume more substantial amounts of CCS, ranging from 4 billion tons/yr in BP's Accelerated scenario to 8 billion tons/yr in the IEA's net-zero and over 9 billion tons/yr in the IPCC's 1.5°C scenarios. This is considerable — and unrealistic, critics argue — as it more or less matches the current physical size of the oil and gas industry. Building such a big industry from scratch would require some $150 billion per year over 2030-50, according to a recent report from the Energy Transition Commission (ETC), an international think tank. This is huge but amounts to less than a third of today's oil and gas capital expenditure, at around $500 billion/yr, the ETC's Kash Burchett notes. Western majors, and top US oil companies in particular, are keen on CCS in their energy transition strategies. All Paris-compliant pathways involve rapid and deep emissions reductions in all sectors, but also deployment of negative emissions technologies such as afforestation-reforestation, BECCS and direct air capture to counterbalance residual emissions and reduce excess CO2 concentration in the atmosphere. Negative emissions options, while "unavoidable," face substantial "implementation challenges" including technological and social risks, scaling and costs, the IPCC warns.

Natural gas demand increases in most scenarios in the current decade — with the notable exceptions of truly net-zero projections such as the IPCC's 1.5°C and BP's and the IEA's net-zero scenarios. Sharper divergences on gas demand appear after 2030. Paris-compliant projections see it peaking no later than 2030-35, while several scenarios do not foresee a peak at all within their horizons. Those include the notoriously bullish US Energy Information Administration's *International Energy Outlook* and Opec's *World Oil Outlook*, but also Gazprom's and Exxon Mobil's base cases, TotalEnergies' Momentum, BP's New Momentum and the IEA's Stated Policies scenario. The IEA's Announced Pledges scenario, which might replace the Stated Policies as the agency's implicit base case, and the IPCC's 2°C scenarios see gas demand peaking in 2030 at around 150 exajoules, just a few percent higher than today's 145 EJ. It would then decrease by around 0.5% per year to 2050.

Oil Demand to 2050

(million b/d)	Peak	2030	2040	2050	2021-50
Energy Watch Group (0 Gt)	<2021	72	31	0	-100%
UNPRI 1.5 (2 Gt)	2025	88	46	20	-79
IEA Net-Zero (0 Gt)	<2021	72	43	24	-74
BP Net-Zero (2 Gt)	<2021	90	55	24	-74
UNPRI Forecast Policy (9 Gt)	2026	99	63	37	-61
IPCC 1.5°C Low Overshoot (1 Gt)	<2021	86	63	41	-56
Total Rupture	<2021	88	59	41	-56
Equinor Rebalance (9 Gt)	<2021	88	61	46	-51
BP Accelerated (10 Gt)	2025	96	72	47	-50
IPCC 1.5°C High Overshoot (6 Gt)	<2021	99	78	53	-44
DNV (19 Gt)	2024	85	69	49	-48
IEA Sustainable Development (8 Gt)	<2021	88	65	57	-39
Total Momentum	<2021	94	74	63	-33
IPCC 2°C (14 Gt)	2030	100	88	70	-26
IEA Announced Pledges (21 Gt)	2030	96	84	77	-18
BP New Momentum (31 Gt)	2030	101	92	81	-14
Equinor Reform (24 Gt)	2030	100	92	84	-11
Shell Sky 1.5 (18 Gt)	2025	100	94	85	-10
IPCC 2.5°C (29 Gt)	2040	105	107	99	+5
Shell Islands (34 Gt)	2040	102	104	102	+8
IEA Base (34 Gt)	2040	103	104	103	+9
IPCC 3°C (38 Gt)	2040	104	108	106	+13
Exxon	>2040	104	107	107	+14
Opec (34 Gt)	>2045	107	108	108	+15
Equinor Rivalry (32 Gt)	>2050	107	110	110	+17
IPCC 4°C (52 Gt)	2040	107	111	111	+18
Shell Waves (35 Gt)	2040	111	119	111	+18
US EIA (43 Gt)	>2050	109	117	126	+34%

Projected oil demand to 2030-50 in million barrels per day in a range of scenarios. When available, projected CO2 emissions in billion tons are shown in parenthesis (2021: 34 Gt). Source: BP, DNV, Equinor, EWG, Exxon Mobil, IEA, IPCC, Shell, TotalEnergies, UNPRI, US DOE

What's New Around the World

GENERAL

CORPORATE — Dividends and share buybacks by large US E&Ps skyrocketed in the first half of 2022 amid soaring oil and natural gas prices, and the second half of the year could see the same as capital spending plans remain relatively buttoned down. The fifteen largest oil-weighted US E&Ps by market cap reported distributing nearly $13 billion in dividends in the first half of 2022, according to data compiled by Energy Intelligence and Evaluate Energy, well beyond what was distributed in full-year 2021. The 15 firms' share buybacks in the first half of the year also eclipsed the full-year total from 2021 by a significant margin. That trend appears likely to continue in the second half of the year and potentially into 2023 as investors continue to demand that E&Ps prioritize returns and fiscal discipline over production growth, even as elevated oil and natural gas prices inflate revenues and free cash flow. The 15 tracked E&Ps reported more than $25 billion in free cash flow in the first half of 2022, buoyed by massive margins on their oil and gas production after years of improving operational efficiencies and driving down their break-even prices.

COUNTRIES

CANADA — Prime Minister Justin Trudeau stated again that Canada would be willing to consider easing burdensome red tape on new gas export facilities to Europe, though he acknowledged that financing LNG export ventures in Eastern Canada could prove difficult. Speaking at a joint press conference with German Chancellor Olaf Scholz, Trudeau said there is no easy solution to the difficulty of supplying LNG export terminals on Canada's Atlantic coast with gas sourced thousands of miles away in Western Canada. Canada will "explore ways to see if it makes sense to export LNG, and if there's a business case for it to export LNG directly to Europe," Trudeau said. Calgary-based Pieridae Energy, developer of the proposed 10 million ton/yr Goldboro LNG export project in Nova Scotia, reported progress in 2018 in garnering US$1.5 billion in "untied" German federal government loan guarantees to help finance upstream activities within the project. This was in addition to a similar confirmation of eligibility for up to US$3 billion in German financing for construction of Goldboro LNG's first liquefaction train. Earlier this month, Spain's Repsol confirmed that it was in discussions about exporting gas to Europe from its Saint John LNG terminal in eastern Canada, which currently operates as a regasification facility.

CHINA — China's apparent oil demand plunged 7.5% in July versus June to 12.79 million b/d — the lowest monthly tally since April 2020, when China was starting to emerge from its first wave of the Covid-19 pandemic. The unexpectedly low July number — largely the result of collapsing refinery runs — left China's apparent oil demand for January-July 2022 down 2.5% at 13.33 million b/d versus the same period of last year, Energy Intelligence calculates. To surpass the 2021 average of 14.07 million b/d this year, China's apparent oil demand would have to average 14.72 million b/d in August-December, an increase of 1.39 million b/d over the January-July average. Such a strong rebound in China's oil demand seems increasingly unlikely if Covid-19 lockdowns continue, especially given concerns about the possibility of a global recession triggered by runaway inflation and rising interest rates. Crude runs at Chinese refineries fell to a fresh 2-year low of 12.58 million b/d in July. That was down 842,000 b/d from June when runs seemed to be picking up as Covid-19 lockdowns were lifted. Some industry sources believe the low crude runs reflect several months of dismal demand.

CYPRUS — European majors Eni and TotalEnergies have made another large natural gas discovery offshore Cyprus, where development of a series of significant finds is complicated by overlapping claims to offshore acreage. The partners estimate they have hit as much as 2.5 Tcf of natural gas in place with the Cronos-1 well on Block 6 about 160 kilmeters (99 miles) southwest of the Mediterranean island. Block 6 was already home to Eni and Total's 2018 Calypso discovery that is estimated to hold between 2 Tcf and 5 Tcf of gas. Eni and Total pledged to follow up Cronos with an appraisal well on Block 6 to determine the best way to develop the find, which Eni has pledged to "fast-track." However, the technical aspects of the discovery are likely less tricky than the political ones. Including Cronos, operators like Eni, Exxon Mobil and Chevron have discovered as much as 18 Tcf of gas offshore Cyprus and are considering a range of possible development schemes, including floating LNG and sending gas to Egypt by pipeline to take advantage of existing liquefaction capacity there. However, competing claims between Cyprus, Turkey and Israel over portions of the fields have complicated negotiations between partners over how to bring the discoveries into production.

SURINAME — APA Corp. said it has struck oil at its Baja-1 well off Suriname, the US independent's sixth discovery in the country's waters and the first in Block 53. The result further de-risks other prospects in the southern portion of the block, as well as in neighboring Block 58, where APA's previous discoveries lie, CEO John Christmann said. It also strengthens the case for expansion in Block 53 following the drilling of a dry hole at APA's Rasper prospect earlier this year. Rasper was the final of three commitment wells on the license and APA's first in five years and was being closely watched after its initial two wells in the block showed mixed results. The Baja-1 discovery was announced after regulators approved an amendment to the Block 53 production sharing contract that allowed options to extend the agreement's exploration period by up to four years. APA said it was "progressing the formalization of the election of the first one-year extension, for which all work commitments are complete." APA also reported a duster at the Dikkop exploration well in Block 58, which is operated by TotalEnergies. The well encountered water-bearing sandstones in the targeted interval and has been plugged and abandoned, APA said.

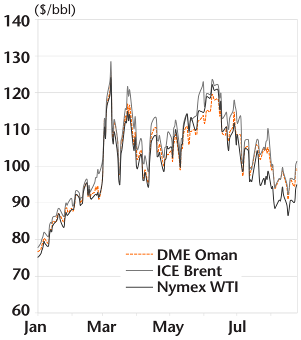
UNITED STATES — Pressure-pumper ProPetro is expanding its fleet of electric-powered hydraulic fracturing units, reflecting the growing demand for low-emissions oil-field equipment. Midland-based ProPetro said Monday that it ordered two electric fracking fleets on long-term lease agreements from a "leading manufacturer." CFO David Schorlemer said its leasing agreement "includes an option to purchase each fleet at the end of its respective lease term." Despite extremely tight supplies of e-frack equipment, most pressure pumpers have said they will not spend capital to add capacity without firm contracts in hand. CEO Sam Sledge said the company is "in discussions with several customers regarding multi-year projects that will use these electric fleets." ProPetro expects the leased e-frack fleets to be delivered in the third quarter of 2023. ProPetro is expanding its fleet as demand for electric fracking booms, particularly in the Permian Basin, its core operating area. The use of more electricity- and natural gas-powered equipment in the oil field has emerged as a key part of many shale players' plans to decarbonize their operations. The electric fleets can also offer lower operating costs. ProFrac estimates that the monthly fuel and equipment costs for one of its new electric fracking fleets can be over 40% lower than a diesel-powered unit.

Marketview

Late Summer Rebound

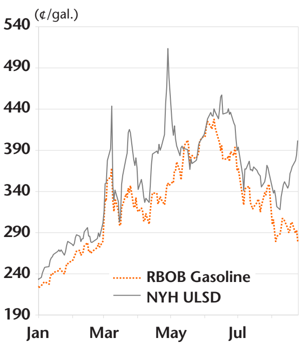
Super-charged by diesel, oil prices staged a late summer rally over the past week and propelled benchmark Brent back over the $100 psychological threshold. The momentum, to be sure, came from petroleum products and not crude oil, despite a warning from the Saudi energy minister that global oil markets may need more tightening.

Prompt Crude Oil Prices



Source: Nymex, ICE, DME

Nymex Prompt Gasoline vs. NYH ULSD



Specifically, heating oil futures on Nymex in New York, a proxy for diesel, mustered gains in seven straight sessions, surging nearly 20% to $4.03 per gallon as of the close of trading on Aug. 24. This price action alone made it abundantly clear that products are driving global markets.

By contrast, the price of dated Brent, a barrel for physical delivery, over the past week fell below the front-month futures contract for the first time since the start Ukraine war. Just five weeks ago, dated Brent enjoyed an almost $8 premium over the front-month contract on the paper market, a reflection of a super-tight market and buyers' insatiable thirst for immediate crude supply. Given that refining cracks for transportation fuels had tread record highs, refiners gobbled up as much feedstock as they could get their hands on, which kept dated Brent on the boil. Over the past week, however, that premium disappeared, at least for now, signaling that the overall supply tightness has cooled a bit.

Still, refiners continue to bask in good times. On Nymex, the heating oil crack for October, or what a refiner can expect to earn on refining a barrel of crude into diesel, was a head-spinning $71 during Aug. 25 trading. On the ICE in Europe, the diesel crack was a much lower $54/bbl but still an attractive level for European refiners.

Gasoline, by contrast, is showing late-summer fatigue, as expected. Over the week, the paper contract for RBOB, a blending component used to make gasoline, has shed 20¢ on the Nymex exchange to $2.85 per gallon. The crack on a barrel of October West Texas Intermediate is now $18, the kind of return that, after the euphoria of recent months, is likely to make a refiner yawn.

But this summer has been exception for the US: record prices torpedoed consumption. The US Energy Information Agency said on Aug. 24 that average gasoline supplies to the market over the four weeks ending Aug. 19 amounted to 8.9 million b/d, down 7% from the same period a year ago — clearly a counter-intuitive data point for an economy that had been expecting a recovery after two years of pandemic.

Looking ahead to the winter, and even beyond, diesel will rule the roost. In Europe, refiners will have to contend with stratospheric prices for natural gas, which is needed to make hydrogen and then scrub the sulfur from the long-chain diesel molecules. Also, draught has lowered river levels and complicated shipping in places like Germany, creating pockets of deficit. And in February, the EU will prohibit imports from Russia, which has been supplying some 500,000 b/d. Where these barrels go, and how Europe will replace them, ensures that both crude and product markets will see price volatility for many months ahead.

US 'Closer' to Nuclear Deal With Iran

The US has responded to Iran's comments on a "final text" for a nuclear agreement tabled by the EU last month, but gaps must be filled before a final deal can be done.

"We are closer now than we were even just a couple of weeks ago because Iran made the decision to make some concessions," US National Security Communications Coordinator John Kirby said Wednesday. But he added that "gaps remain." Negotiators have been working since April 2021 on a possible return to the 2015 deal that saw Iran agree to controls on its nuclear program in exchange for sanctions relief. A straight return to that arrangement could see around 1 million b/d of additional Iranian oil reaching the global market within about 10 months, Energy Intelligence reckons.

PIW Market Indicators

($/barrel)	Aug 22-Aug 24	Aug 15-Aug 19	Jul 25-Jul 29
Spot Crude			
Opec Basket	$101.57	$98.22	$109.09
UK Brent (Dtd.)	98.35	96.25	109.64
US WTI (Cushing)	94.90	91.76	99.60
Nigeria Bonny Lt.	101.27	101.83	119.40
Dubai Fateh	96.60	92.82	103.95
US Mars	93.03	89.57	97.21
Russia Urals (NWE)	73.27	69.33	77.10
Crude Futures			
Brent 1st (ICE)	99.31	94.88	106.66
Brent 2nd (ICE)	98.44	94.18	101.42
B-wave (ICE)	98.09	94.50	106.54
WTI 1st (Nymex)	92.95	89.06	96.80
WTI 2nd (Nymex)	92.67	88.65	94.80
Oman 1st (DME)	98.76	94.20	104.47
Oman 2nd (DME)	96.63	91.46	100.20
Murban 1st (ICE)	99.86	95.48	105.65
Murban 2nd (ICE)	98.24	93.35	101.80
Forward Spreads			
Brent (1st-Dtd.)	+$0.96	-$1.37	-$2.98
Brent (2nd-1st)	-0.87	-0.70	-5.24
WTI (2nd-1st)	-0.28	-0.41	-2.00
WTI (3rd-2nd)	-0.62	-0.38	-1.54
Oman (2nd-1st)	-2.13	-2.74	-4.27
Oman (3rd-2nd)	-2.73	-1.84	-3.56
Murban (2nd-1st)	-1.62	-2.13	-3.85
Murban (3rd-2nd)	-1.96	-1.53	-3.58
Grade Differentials			
WTI-Brent (1st)	-$6.31	-$6.23	-$9.87
WTI-LLS	-2.93	-2.39	-2.73
WTI-Mars	+1.87	+2.19	+2.39
Brent(Dtd)-Dubai	+1.75	+3.43	+5.69
Brent(Dtd.)-Urals	+25.08	+26.93	+32.55
Brent(Dtd.)-Bonny Lt.	-2.92	-5.57	-9.75
Term Crude Formulas			
Arab Lt.-US (c.i.f.)	$100.16	$96.70	$104.34
Arab Lt.-Europe (Med)	103.19	99.60	110.44
Arab Lt.-Far East (f.o.b.)	108.35	104.20	112.54
Nigeria Bonny Lt.	104.81	102.71	114.59
Arab Light Gross Product Worth			
Rotterdam	$108.47	$103.47	$114.10
US Gulf Coast	113.31	109.09	122.61
Singapore	106.71	100.92	104.78
Gross Product Worth & Margins			
Rotterdam			
UK Brent GPW	$120.25	$114.36	$115.06
UK Brent Margin	+19.91	+16.21	+4.36
US Gulf Coast			
Mars GPW	107.52	104.10	117.90
Mars Margin	+14.39	+14.43	+20.59
Singapore			
Oman GPW	105.21	99.15	104.42
Oman Margin	+2.67	+1.16	-4.38
US Nymex			
WTI 3-2-1 Crack	+$41.83	+$44.07	+$49.83
Refined Products			
Rotterdam ($/ton)			
Eurobob Gasoline	$916.70	$926.82	$1051.20
Gasoil (0.1%)	1134.92	1072.05	1103.00
Fuel Oil (0.5%)*	687.25	678.75	720.30
US Gulf Coast (¢/gal)			
RBOB Gasoline	260.60¢	275.05¢	329.03¢
ULS Diesel	380.87	350.94	359.16
Fuel Oil (0.5%, $/ton)	$719.00	$719.60	$809.40
Singapore ($/bbl)			
Naphtha	$74.06	$72.55	$82.83
Gasoil (0.05%)	142.73	131.20	131.12
Fuel Oil (0.5%, $/ton)	766.67	749.40	877.20

*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.