Forecast highlights

**Global liquid fuels**

- The Brent crude oil spot price in our forecast averages $98 per barrel (b) in the fourth quarter of 2022 (4Q22) and $97/b in 2023. The possibility of petroleum supply disruptions and slower-than-expected crude oil production growth continues to create the potential for higher oil prices, while the possibility of slower-than-forecast economic growth creates the potential for lower prices.

- U.S. crude oil production in our forecast averages 11.8 million barrels per day (b/d) in 2022 and 12.6 million b/d in 2023, which would set a record for the most U.S. crude oil production during a year. The current record is 12.3 million b/d, set in 2019.

- We estimate that 99.4 million b/d of petroleum and liquid fuels was consumed globally in August 2022, up by 1.6 million b/d from August 2021. We forecast that global consumption will rise by an average of 2.1 million b/d for all of 2022 and by an average of 2.0 million b/d in 2023. As a result of high natural gas prices globally, we increased our forecast for oil consumption in 4Q22 and 1Q23 as electricity providers, particularly in Europe, may switch to oil-based generating fuels.

- We expect retail gasoline prices will average $3.60 per gallon (gal) in 4Q22 and $3.61/gal in 2023. Retail diesel prices in our forecast average $4.90/gal in 4Q22 and $4.28/gal in 2023.

**Natural gas**

- In August, the Henry Hub spot price averaged $8.80 per million British thermal units (MMBtu), up from $7.28/MMBtu in July. Natural gas prices rose in August because of continued strong demand for natural gas in the electric power sector, which has kept natural gas inventories below their five-year (2017–2021) average. We expect the Henry Hub price to average about $9/MMBtu in 4Q22 and then fall to an average of about $6/MMBtu in 2023 as U.S. natural gas production rises.

- U.S. natural gas inventories ended August at 2.7 trillion cubic feet (Tcf), which was 12% below the five-year average. We forecast that inventories will end the injection season (April through October) at more than 3.4 Tcf, which would be 7% below the five-year average.
• U.S. LNG exports in our forecast average 11.7 billion cubic feet per day (Bcf/d) in 4Q22, up 1.7 Bcf/d from 3Q22. Factors that will affect the volume of LNG exports in the coming months include the planned outage at Cove Point in October and Freeport LNG resuming partial operations by mid- to late-November. We forecast LNG exports will average 12.3 Bcf/d in 2023.

• U.S. consumption of natural gas in our forecast averages 86.6 Bcf/d in 2022, up 3.6 Bcf/d from 2021, driven by increases across all consuming sectors. We expect consumption to fall by 1.9 Bcf/d in 2023 because of declines in consumption in the industrial and electric power sectors.

• Dry natural gas production has been rising relatively steadily since 1Q22, when it averaged 94.6 Bcf/d. We forecast U.S. dry natural gas production to average 99.0 Bcf/d in 4Q22 and then rise to 100.4 Bcf/d for 2023.

Electricity, coal, renewables, and emissions

• We expect U.S. sales of electricity to ultimate customers to rise by 2.6% in 2022, mostly because of more economic activity but also because of slightly hotter summer weather in than last year much of the country. We forecast U.S. sales of electricity to fall by 0.4% in 2023.

• The largest increases in U.S. electricity generation in our forecast come from renewable energy sources, mostly solar and wind. We expect renewable sources will provide 22% of U.S. generation in 2022 and 24% in 2023, up from 20% in 2021.

• Natural gas fuels 37% of U.S. electricity generation in 2022, a share similar to 2021, and we forecast it to fall to 36% in 2023. Coal-fired electricity generation in our forecast provides 21% of the U.S. total in 2022 and 19% in 2023. Growing generation from renewable sources limits growth in natural gas generation while coal’s generation share declines due to the expected retirement of coal-fired capacity.

• We forecast the U.S. residential price of electricity will average 14.8 cents per kilowatthour in 2022, up 7.5% from 2021. Higher retail electricity prices largely reflect an increase in wholesale power prices driven by rising natural gas prices. The Southwest region has the lowest forecast wholesale prices in 2022, averaging $69 per megawatthour (MWh), up 25% from 2021. The highest forecast wholesale prices are at more than $100/MWh in ISO New England (up 96% from 2021) and New York ISO (up 124% from 2021).

• U.S. coal production in the forecast increases by 22 million short tons (MMst) in 2022 to total 600 MMst for the year. We expect production will total 590 MMst in 2023.
• We expect energy-related carbon dioxide (CO₂) emissions in the United States to increase by 1.7% in 2022 and then to decrease 1.8% back to around 2021 levels in 2023.

**Petroleum and Natural Gas Markets Review**

**Crude oil**

**Prices:** The front-month futures price for Brent crude oil settled at $92.36 per barrel (b) on September 1, a decrease of $7.67/b from the August 1 price of $100.03/b. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, decreased by $7.28/b during the same period, settling at $86.61/b on September 1 (Figure 1).

![Figure 1. Crude oil front-month futures prices](image)

Crude oil prices were lower on average in August than they were in July before ending with a rapid decrease in the week before Labor Day. From August 29 through September 1, the Brent crude oil price decreased $13/b and the WTI price decreased $10/b. The monthly average Brent front-month futures price was $98/b in August, about $7/b lower than in July, and the WTI price was $91/b, $8/b lower than in July. The lower prices in August likely reflected overall increases in global petroleum inventories. The increase in inventories came with ongoing growth in global production of crude oil and other liquid fuels, which we estimate reached 101 million barrels per day (b/d) in August, the highest global production since December 2019.

We estimate that crude oil prices will generally remain near August average levels through the end of 2023. Although we expect average crude oil prices to mostly remain between $90/b–$100/b through next year, the possibility for significant volatility around those averages is high. Recent events contributing to increased uncertainty in the crude oil market and in our forecast include:
• The impact of the recent OPEC decision to reduce crude oil production by 0.1 million b/d in October and whether there will be further production cuts in the future
• The threat of increasing conflict following the outbreak of violent clashes in the Libyan capital of Tripoli
• Uncertainty around the potential expiration of the current coordinated petroleum release from strategic reserves in November
• The potential return to an Iran nuclear deal that could lift sanctions on the country and allow Iran’s crude oil exports into the market
• The risk of hurricanes that could result in potential production outages and limited export traffic along the U.S. Gulf Coast

**Crude oil front-month to third-month futures price spread:** The front-month to third-month crude oil futures price spread (1-3 spread) is a measure of market backwardation, a market environment that encourages crude oil to flow out of inventories and into the market ([Figure 2](#)). Backwardation occurs when crude oil futures contract prices in the near term are higher than crude oil prices in the long term. In response to Russia’s full-scale invasion of Ukraine in the spring, the 1-3 spread for Brent increased from an average of $1/b in January to nearly $7/b in March. Following a decline in April, it returned to near $7/b levels in July. In August, the spread narrowed to $3/b, the narrowest spread since April. The decrease in backwardation in August suggests that the market call to draw oil from inventories has decreased since midsummer, indicating market conditions that are more balanced between supply and demand than earlier this year.

![Figure 2. Crude oil front-month to third-month futures price spread](image)

Data sources: CME Group, Intercontinental Exchange, and Bloomberg L.P.
Note: WTI-West Texas Intermediate
Manufacturing Purchasing Managers’ Index: Regional Purchasing Managers’ Indexes (PMIs) for manufacturing in July decreased in the United States, Europe, and China (Figure 3). A PMI serves as an indicator of increasing or decreasing manufacturing activities. An index rating above 50 represents growth in activity while a rating below 50 indicates a contraction. The U.S. manufacturing PMI decreased in July to 52.8, its lowest rating since June 2020, suggesting a slowing rate of growth. In Europe, the PMI value dropped to 49.8, also its lowest rating since June 2020, while the drop below 50 also suggests market contraction. The latest Europe and U.S. PMIs suggest that these conditions have continued into August, contributing to further concerns about economic conditions and petroleum demand. The low PMI signals a weakening economic environment in Europe, further exacerbated by the decreasing value of the euro, which fell to parity with the U.S. dollar in late August.

Figure 3. Regional Manufacturing Purchasing Managers’ Index (PMI) index

![Graph showing regional manufacturing purchasing managers' index values](image)

Data source: Bloomberg L.P., IHS Markit, and the Institute for Supply Management

U.S. drilled but uncompleted wells and rig count: Since July 2020, the number of U.S. wells that are drilled but uncompleted (DUCs) has been decreasing and has fallen below the number in 2014 (the earliest year in our dataset) in 2022 (Figure 4). DUCs are oil and natural gas wells that have undergone their drilling phase but have not yet undergone casing, cementing, and other procedures that are necessary to establish a fully operational well. Prior to the onset of the COVID-19 pandemic, the number of DUCs had been steadily growing since 2017 in the United States, driven primarily by new production in the Permian Basin. Since July 2020, however, the number of DUCs has been decreasing at a relatively steady pace. At the same time, the Baker Hughes rotary rig count for oil producing wells has been increasing, rising above 600 rigs in July, the highest it has been since March 2020.
The number of DUCs serves as an indicator of the relative supply of wells that may be transitioned to operational status, and the increasing rig count reflects the higher number of wells being drilled. Growth in crude oil production in the United States since 2021 has largely consisted of completing wells from the available DUCs, while new drilling in response to high crude oil prices appears to be lagging the rate of completion. Continued U.S. production increases are likely to continue drawing on available DUCs that are viable candidates for completion at current prices. Continued increases in rig counts will contribute to more drilled wells, which could soon outpace well completions and increase the number of DUCs. However, on September 2, the latest weekly rig count indicated a decrease in 9 rigs from the previous week, down to 596, the largest week-on-week decrease since September 2021.

Our August Drilling Productivity Report showed the smallest monthly percentage decline in DUCs since July 2020. We currently forecast that U.S. crude oil production will increase to 12.2 million b/d in the fourth quarter and will rise to an average of 12.6 million b/d in 2023. This increase would constitute an annual increase of 0.5 million b/d in 2022 and an additional increase of 0.9 million b/d in 2023.

Petroleum products

Gasoline prices: The front-month futures price of RBOB (the petroleum component of gasoline used in many parts of the country) settled at $2.39 per gallon (gal) on September 1, down 61 cents/gal from August 1 (Figure 5). The RBOB-Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) settled at $0.19/gal on September 1, down 43 cents/gal during the same period. The RBOB–Brent crack spread declined by 12 cents/gal on September 1 when the front-month RBOB contract rolled over to October delivery, which reflects winter grade gasoline that is cheaper for refineries to produce. Before the contract roll over, the RBOB–Brent crack spread had already decreased from an average of 85 cents/gal in
July to an average of 58 cents/gal in August, which could be the result of less-than-average seasonal demand and anticipation of the contract roll-over.

The front-month RBOB contract for September delivery sold at an average premium of 22 cents/gal to the second-month contract for October delivery during August trading. This price spread was the second-highest inflation-adjusted price spread since 2006, when the RBOB futures contract began trading (Figure 6). Most of this premium was due to the difference between winter and summer grade gasoline, but market fundamentals also affected the spread. Typically, when inventories are lower, this premium is greater because low inventories add more pressure to prices in near-term contracts than long-term contracts. This dynamic occurs because low inventories occur during tight market conditions in which demand must be met from inventories, and, under these conditions, purchasers are willing to pay a premium to secure needed supply. We estimate that gasoline inventories in the East Coast (PADD 1) were 16% below their five-year (2017–2021) average at the end of August. In 2012, the year with the highest average front-month to second-month price spread, inventories were also below their five-year average, albeit by not as much as this year.
Ultra-low sulfur diesel prices: The front-month futures price for ultra-low sulfur diesel (ULSD) for delivery in New York Harbor settled at $3.56/gal on September 1, a 12 cents/gal (4%) increase from August 1 (Figure 7). The ULSD-Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) increased 30 cents/gal (29%) during the same period and settled at $1.36/gal on September 1.

ULSD prices increased this month as rapidly increasing natural gas prices in Europe and Asia increased demand for distillate fuel as a substitute fuel for power generation in those markets amid low distillate stocks globally. From August 8 to August 26, ULSD prices increased by 83 cents/gal (26%). This increase in ULSD prices occurred despite slowing economic and trucking activity in the United States. A recent decline in the American Trucking Association’s Truck Tonnage Index suggests less consumption of goods, less home construction, and slower...
manufacturing activity contributed to a slight decline in diesel fuel demand. Although changes in crude oil prices normally account for most changes in ULSD prices, as crude oil is the single largest input cost for producing ULSD, the Brent crude oil price increased only 4% between August 8 and August 26. Because ULSD prices increased by more than crude oil prices, it resulted in the ULSD-Brent crack spread increasing by 73 cents/gal (83%) over the same period.

ULSD prices rose in August primarily due to increased interest in fuel switching from natural gas to distillate fuel oil caused by rising natural gas prices in Europe. From August 8 to August 26, front-month natural gas prices at the Dutch Title Transfer Facility (TTF) increased by 72%, reaching a record high. High natural gas prices are making it economical for European operators to switch from natural gas to distillate fuel oil in electricity generation. From August 26 to September 1, ULSD prices declined by 45 cents/gal (11%) as natural gas prices declined and concerns around an economic slowdown that could reduce distillate demand regained the focus of the market.

**U.S. distillate inventories:** Inventories in the United States began the year at 130 million barrels, 14% less than their five-year average (Figure 8). As of June 2022, inventories decreased to 111 million barrels or 23% below the five-year average. We forecast U.S. distillate inventories will build to 118 million barrels or 17% below the five-year average by the end of this year, and will remain below their previous five-year low.

![Figure 8. U.S. distillate inventory thousand barrels](image)

Western sanctions against Russia’s petroleum product exports following its full-scale invasion of Ukraine in February have been a major driver of global distillate markets and subsequent inventory draws this year. Low inventories in New England (PADD 1A), the Central Atlantic (PADD 1B), and the Midwest (PADD 2) suggest both higher and more volatile ULSD prices in the coming months. In the Midwest, where distillate fuel is widely used for harvesting crops, *Weekly Petroleum Status Report* data for the week ending August 26 shows distillate inventories are
17% below the five-year average. In New England and the Central Atlantic, where heating oil is used as a primary source of heat in some homes, inventories are 56% below the five-year average.

**ULSD-RBOB future price spread:** ULSD front-month futures prices traded at an average monthly premium to RBOB of 68 cents/gal in August, the highest premium in real terms since November 2008 ([Figure 9](#)). Although front-month ULSD and RBOB futures typically follow seasonal trends (RBOB trades at a premium in the summer, and ULSD trades at a premium in the winter), global demand for distillate and reduced exports from Russia, a major supplier of distillate fuel and natural gas to Europe, have disrupted this trend. This increased demand for distillate, as well as a concurrent decline in gasoline demand, has encouraged refiners to maximize distillate production. The monthly ULSD-Brent crack spread this August of $1.27/gal is 87 cents/gal (222%) higher than last August while the RBOB-Brent crack spread of 58 cents/gal is only 3 cents/gal (6%) higher compared with last year. Looking forward, we forecast that the combination of the upcoming switch to winter grade gasoline, which is less expensive for refiners to produce, and the typical decline in gasoline demand after the summer driving season will contribute to declining refiner margins for gasoline. We forecast diesel fuel refiner margins will remain above August levels through the end of the year.

![Figure 9. ULSD-RBOB front-month futures price spread](image)

Natural Gas

**Prices:** The front-month natural gas futures contract for delivery at the Henry Hub closed at $9.26 per million British thermal units (MMBtu) on September 1, 2022, which was up 12% (98 cents/MMBtu) from August 1, 2022 ([Figure 10](#)). Closing prices for front-month natural gas futures averaged $8.78/MMBtu during August, the highest August monthly average in real terms since 2008. Natural gas prices remained elevated throughout August as inventories remained below the five-year (2017–2021) average, and consumption in the electric power
sector remained strong. Hotter-than-normal temperatures in much of the country increased demand for air conditioning, and constraints in the coal market limited coal-fired electricity generation, both increasing consumption of natural gas to produce electricity.

The United States generates more electricity during the summer compared with other times of the year. This summer, the percentage share of electricity generation from natural gas has been similar to previous years, despite high natural gas prices that have more than doubled from the same time last year (Figure 11). Previously, high natural gas prices would have resulted in more coal-fired electricity generation. However, coal-fired power plants have been limited in their ability to increase power generation due to historically low inventories, constraints in fuel delivery to coal plants, and continued coal capacity retirements. Even as the capacity for renewable electricity generation has increased over recent years, power providers continue to use natural gas-fired electricity generation most often to meet fluctuations in electricity demand.
In the United States, natural gas is the most common fuel source used by power providers to quickly increase or decrease power supply to meet electricity demand from moment to moment. This instantaneous balance is crucial in U.S. power markets due to the lack of large-scale electricity storage. Most natural gas-fired turbine power plants can increase or decrease their electricity generation in a matter of minutes. In contrast, other sources of generation, such as nuclear power plants, generally provide a stable amount of electricity at all hours of the day, while renewable sources such as wind turbines and solar power facilities provide a fluctuating amount of electricity based on weather conditions. Natural gas was key to meeting electricity demand peaks throughout the country during the hot July, especially in Texas, where several records were set for daily peak electricity demand.

**International natural gas prices:** Real prices for natural gas futures for delivery at the Title Transfer Facility (TTF) in the Netherlands set a record high at more than $99/MMBtu in late August (Figure 12). Prices in East Asia reached a record high of more than $69/MMBtu in August. International natural gas prices have been rising since June amid several factors:

- The June shutdown of the Freeport LNG facility in South Texas reduced global supply of liquefied natural gas (LNG) by about 2 billion cubic feet per day (Bcf/d). Prior to the shutdown, LNG exports from Freeport in the first five months of 2022 accounted for approximately 17% of total U.S. LNG exports.

- **Natural gas pipeline exports from Russia to Europe have declined in 2022,** reaching 1.2 Bcf/d in mid-July, the least in nearly 40 years.

- On August 19, Gazprom announced the Nord Stream 1 pipeline (which delivers natural gas from Russia to Europe) would be offline for three days for unplanned maintenance from August 31 to September 2.
Europe finished the 2021–2022 winter heating season with natural gas inventories at 26% full compared with the five-year average of 34%, according to data from Gas Infrastructure Europe’s (GIE) Aggregated Gas Storage Inventory (AGSI+). Because of limitations in and uncertainty about natural gas pipeline imports from Russia, Europe has been importing record amounts of LNG in 2022 to refill inventory before the upcoming winter. The recent supply constraints affecting the global LNG market and the reduced pipeline flows into Europe have contributed to the increase in the TTF futures price and the increase in the price premium for LNG cargoes delivered to Europe relative to LNG cargoes delivered to East Asia.

**Strong demand for LNG in Europe** continues to drive high international natural gas prices. The percentage of U.S. LNG exports to Europe has **increased in 2022**, averaging 69% in the first half of 2022 compared with 32% in the first half of 2021. U.S. facilities exported LNG at close to their combined capacity in August (excluding the offline Freeport LNG facility), with capacity utilization averaging 93% across all operating facilities.

**Notable forecast changes**

- We have updated several of the equations in the natural gas model, including those that forecast residential and commercial consumption of natural gas, natural gas pipeline imports and exports, and natural gas production in Alaska. The changes include updating the variables and sample periods on which these regression equations are evaluated. We also updated the liquefied natural gas imports forecast to better reflect recent trends. These changes contributed to 1.4 billion cubic feet per day (Bcf/d) more forecast consumption of natural gas in 2022 and 0.8 Bcf/d more consumption in 2023. In addition, we have increased our forecast for production of natural gas in Alaska by just under 0.1 Bcf/d in both years, and we have lowered our forecast of net exports of...
natural gas by 0.7 Bcf/d in 2022 and by 0.5 Bcf/d in 2023, mostly because of more expected pipeline imports.

- You can find more information in the detailed table of forecast changes.