Forecast highlights

Global liquid fuels

- The August Short-Term Energy Outlook (STEO) is subject to heightened uncertainty resulting from Russia’s full-scale invasion of Ukraine, how sanctions affect Russia’s oil production, the production decisions of OPEC+, the rate at which U.S. oil and natural gas production rises, and other contributing factors. Less robust economic activity in our forecast could result in lower-than-forecast energy consumption.

- We forecast the spot price of Brent crude oil will average $105 per barrel (b) in 2022 and $95/b in 2023.

- U.S. crude oil production in our forecast averages 11.9 million barrels per day (b/d) in 2022 and 12.7 million b/d in 2023, which would set a record for most U.S. crude oil production in a year. The current record is 12.3 million b/d, set in 2019.

- We estimate that 98.8 million b/d of petroleum and liquid fuels was consumed globally in July 2022, an increase of 0.9 million b/d from July 2021. We forecast that global consumption of petroleum and liquid fuels will average 99.4 million b/d for all of 2022, which is a 2.1 million b/d increase from 2021. We forecast that global consumption of petroleum and liquid fuels will increase by another 2.1 million b/d in 2023 to average 101.5 million b/d.

- The U.S. retail price for regular grade gasoline averaged $4.56 per gallon (gal) in July, and the average retail diesel price was $5.49/gal. We expect retail gasoline prices to average $4.29/gal in the third quarter of 2022 (3Q22) and fall to an average of $3.78/gal in 4Q22. Retail diesel prices in our forecast average $5.02/gal in 3Q22 and $4.39/gal in 4Q22.

- U.S. refineries average 93% utilization in 3Q22 in our forecast, as a result of high wholesale product margins. Elevated prices for gasoline and diesel reflect refining margins for those products that are at or near record highs amid low inventory levels.

Natural gas

- In July, the Henry Hub spot price averaged $7.28 per million British thermal units (MMBtu), down from $7.70/MMBtu in June and $8.14/MMBtu in May. Average natural
gas prices fell over the last two months primarily because of additional supply in the domestic market following the shutdown of the Freeport LNG export terminal on June 8. However, prices increased by almost 50%, from $5.73/MMBtu on July 1 to $8.37/MMBtu on July 29, because of continued high demand for natural gas from the electric power sector. We expect the Henry Hub price to average $7.54/MMBtu in the second half of 2022 and then fall to an average of $5.10/MMBtu in 2023 amid rising natural gas production.

- U.S. natural gas inventories ended July at 2.5 trillion cubic feet (Tcf), which was 12% below the 2017–2021 average. We forecast that natural gas inventories will end the 2022 injection season (end of October) at close to 3.5 Tcf, which would be 6% below the five-year average.

- We forecast that U.S. LNG exports will average 10.0 Bcf/d in 3Q22 and 11.2 Bcf/d for all of 2022, a 14% increase from 2021. This increase is the result of additional U.S. LNG export capacity that has come online and Freeport LNG resuming operations sooner than we had initially expected. In the first half of 2022, the United States became the largest LNG exporter in the world. We forecast LNG exports will average 12.7 Bcf/d in 2023.

- U.S. consumption of natural gas in our forecast averages 85.2 Bcf/d in 2022, up 3% from 2021. Consumption in the electric power sector continues to increase as a result of limited switching from natural gas-fired generators to coal-fired generators for power generation, despite elevated natural gas prices. In addition, rising U.S. natural gas consumption reflects increased consumption in the residential and commercial sectors as a result of colder temperatures on average in 2022 than in 2021. We forecast that natural gas consumption will average 83.8 Bcf/d in 2023, about 1.3 Bcf/d (2%) lower than in 2022.

- We forecast U.S. dry natural gas production to average 97.1 Bcf/d in August and 96.6 Bcf/d during all of 2022, which would be 3.0 Bcf/d (3%) more than in 2021. We expect dry natural gas production to average 100.0 Bcf/d in 2023.

**Electricity, coal, renewables, and emissions**

- We expect U.S. sales of electricity to ultimate customers to increase in the forecast by 2.5% in 2022, mostly because of rising economic activity but also because of hot summer weather in much of the country. Forecast U.S. sales of electricity decline by 0.3% 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.
• We forecast the U.S. residential electricity price will average 14.6 cents per kilowatthour (kWh) in 2022, up 6.1% from 2021. Higher retail electricity prices largely reflect an increase in wholesale power prices driven by rising natural gas prices. Annual average wholesale prices for 2022 range from an average of $62 per megawatthour (MWh) in Florida to $95/MWh in the ISO New England and New York ISO markets.

• The U.S. electric power sector added 13 gigawatts (GW) of utility-scale solar photovoltaic (PV) capacity in 2021. Solar capacity additions in the forecast period total 20 GW for 2022 and 24 GW for 2023, and they represent an addition of 31 billion kWh of electric power generation in 2022 and 41 billion kWh in 2023.

• U.S. coal production is forecast to increase by 21 million short tons (MMst) to 599 MMst in 2022 and to 601 MMst in 2023. We expect coal consumption to be slightly lower in 2022 at 541 MMst, relative to 546 MMst in 2021. This forecast decline is a result of constraints on coal generation and mine shutdowns as well as coal transportation limitations. As coal plant shutdowns continue and natural gas prices fall, coal consumption is expected to decline by 9% to 493 MMst in 2023. Coal exports increase from 85 MMst in 2021 to 87 MMst in 2022 and to 98 MMst in 2023.

Petroleum and Natural Gas Markets Review

Crude oil

Prices: The front-month futures price for Brent crude oil settled at $94.12 per barrel (b) on August 4, a decrease of $17.51/b from the July 1 price of $111.63/b. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, decreased by $19.89/b during the same period, settling at $88.54/b on August 4 (Figure 1).

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

Data source: CME Group, Intercontinental Exchange, and Bloomberg L.P.
Note: WTI = West Texas Intermediate
Crude oil prices generally decreased in July, and the price of WTI decreased by more than Brent. The price spread between Brent and WTI increased to a high of $13.26/b on July 29, the highest price spread since January 14, 2014 (Figure 2). This wide Brent-WTI spread, which reflects supply and demand dynamics in Northwest Europe, has come down in the first few trading days of August but remains high.

Russia’s full-scale invasion of Ukraine has resulted in shifting trade patterns, leaving Europe to find substitutes for Russia’s oil. This change has driven up the price of Brent contracts to a level high enough to reduce Asia’s imports of Brent crude oil and to retain more oil in Europe. The Brent-WTI spread has also increased enough to attract more imports of crude oil from the United States into Europe. From March through July, the Brent-WTI spread averaged $6.05/b, an almost $2.50/b increase from the first two months of the year. We forecast the Brent-WTI spread will average $6/b in 2023, up $2/b from the July STEO. This high spread will keep exports from Europe to Asia subdued and encourage higher imports from the United States, both of which will likely be necessary as the EU reduces crude oil imports from Russia by 90% by the end of the year.

Although supply disruptions have kept crude oil prices around $100/b, crude oil prices have come down slightly in July as concerns of slower economic growth or a recession become more prevalent. These concerns are reflected in the University of Michigan’s survey of consumer sentiment, which recorded its lowest reading on record in June, with data going back to November 1952 (Figure 3). Likewise, consumer sentiment in the Euro Area has decreased, reaching record lows in July.
Consumer sentiment has been decreasing as inflation continues to be strong, borrowing costs increase with higher interest rates, and economic growth shows signs of slowing. Data points reflecting these trends include:


- Inflationary concerns have led to the Federal Reserve increasing interest rates, which increases borrowing costs and could also be affecting consumer sentiment.

- As prices have risen, U.S. manufacturing, as measured by the manufacturing Purchasing Manager Index (PMI), decreased in July to its lowest levels since July 2020.

- The Bureau of Economic Analysis’s gross domestic product report released in July showed U.S. real gross domestic product contracting by an estimated 0.9% in 2Q22, making it the second consecutive quarter of economic contraction.

Consumer sentiment has often declined in response to high crude oil prices. This trend likely reflects the effects of higher crude oil prices on consumer budgets. Higher crude oil prices lead directly to increased costs for fuel that consumers purchase for transportation. Additionally, rising crude oil prices can create inflationary pressures throughout the economy by raising input costs of goods. Because inflation has been affecting consumers’ budgets for an extended time now, it is likely that some consumers have begun to make lifestyle adjustments that are reducing petroleum product consumption in the third quarter, which we have reflected as reductions in our forecast.

**Price of Brent crude oil in U.S. dollars and euros:** As U.S. interest rates rise and concerns of a recession increase, demand for U.S. dollars has increased, strengthening its value relative to other currencies. For countries using a currency other than the U.S. dollar, a strengthening
dollar could make the imported cost of a barrel of crude oil more expensive. For example, recently the dollar has been trading close to the euro for the first time since 2002. Whereas the inflation-adjusted price of a barrel of crude oil in U.S. dollars is not as high as the levels seen from 2011–2014 or in 2008, the real price of a barrel of crude oil in euros has surpassed those highs (Figure 4). The relatively higher prices have further contributed to slowing growth in petroleum and other liquids consumption in the second half of 2022 (2H22).

**Figure 4. Real Brent crude oil price in U.S. dollars and euros**

![Graph showing real Brent crude oil price in U.S. dollars and euros from January 2002 to January 2022.](image)

Data source: CME Group, ICE, and Bloomberg L.P. for crude oil prices; Bureau of Labor Statistics and Organization for Economic Cooperation and Development CPIs for inflation adjustments.

**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 $2.79 per gallon (gal) on August 4, down 89 cents/gal from July 1 (Figure 5). The RBOB-Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) settled at $0.55/gal on August 4, down 48 cents/gal during the same period.
Lower crude oil prices and a narrowing gasoline crack spread both contributed to an overall decrease in RBOB prices in July. The monthly average RBOB price in July was $3.34/gal, a decrease of 65 cents/gal compared with June. Just over half of this decrease was in the gasoline crack spread, which decreased to a monthly average of 85 cents/gal, down 34 cents/gal compared with June. The gasoline crack spread has remained below $1/gal since July 1.

Gasoline inventories in the United States increased by 7.8 million barrels in July compared with June. Increased gasoline production as a result of high refinery utilization has filled inventories amid relatively lower gasoline demand compared with 2021. We estimate that refinery utilization and gasoline production will rise in August before decreasing in September, in line with normal seasonal trends for fall maintenance. We estimate that less gasoline demand in the fall and winter will partially offset lower refinery production during the fall maintenance season, though this will lead to normal seasonal draws on inventories until November. From September through the end of 2022, we expect end-of-month motor gasoline inventories to be within 10 million barrels of the five-year average. As inventories grow closer to typical seasonal levels, we expect monthly average gasoline prices to continue decreasing. However, unexpected reductions in refinery operations because of unplanned outages—particularly those related to hurricanes on the Gulf Coast—as well as potential increases in driving activity in response to lower retail gasoline prices both present upside risks to gasoline prices and crack spreads.

**New York Harbor-Gulf Coast price differential:** The price differential for conventional gasoline between the New York Harbor and U.S. Gulf Coast spot markets increased substantially in July. On July 29, the price spread widened to 59 cents/gal, the widest spread in real terms since September 2012 (Figure 6). The average price spread in July was 27 cents/gal, the widest monthly average price spread in real terms since 2014.
The wide price spread reflects substantially lower gasoline inventories at New York Harbor and along the East Coast than on the Gulf Coast. East Coast weekly motor gasoline inventories have averaged 21% less than the five-year average since May. In contrast, Gulf Coast weekly motor gasoline inventories have averaged slightly more than the five-year average since May. East Coast refineries produce a relatively small share of the overall volume of gasoline that is consumed in the region. The East Coast has historically imported gasoline from Europe and Canada and received transfers from the U.S. Gulf Coast to meet its consumption needs. Lower gasoline inventories along the East Coast reflect the impact of not only reduced imports of gasoline from Europe but also the closure of what had been the East Coast’s largest refinery in 2019, as well as the closure of the export-oriented Canadian Come-by-Chance refinery in 2020. With these lost sources of supply, Gulf Coast refiners have increased refinery utilization and gasoline production in response to the high prices, but logistical capacity constraints limit the volume of gasoline that can be moved to East Coast markets, accounting for the wide regional discrepancy in inventory levels.

Trade press reports have suggested that line space along the Colonial Pipeline (the largest petroleum product pipeline connecting the Gulf Coast to the East Coast), which is traded on secondary markets, was pricing at its highest premium to the pipeline’s tariff rate since 2015. Gasoline that cannot be moved along the Colonial Pipeline or the smaller Products SE Pipeline must instead be moved from the Gulf Coast to the East Coast by rail or Jones Act compliant tanker. The current level of the regional price spread suggests that even capacity on more expensive modes of transit between the Gulf Coast to the East Coast, such as rail or tanker, are being used to their current capacity. Increased tanker traffic, more available space on rail lines, or even increased long distance trucking traffic to certain regions may become temporarily viable at current price spreads if market participants believe the price spreads will last long enough to justify the diversion of resources.
Ultra-low sulfur diesel prices: The front-month futures price for ultra-low sulfur diesel (ULSD) for delivery in New York Harbor settled at $3.34/gal on August 4, a 60 cents/gal decrease from July 1 (Figure 7). The ULSD-Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) decreased 18 cents/gal during the same period and settled at $1.10/gal on August 4.

ULSD prices and crack spreads decreased this month to levels not seen since early April, as concerns about a potential recession weighed on the economic outlook. Compared with June, July ULSD prices were 15% lower, and crack spreads were 24% narrower, marking the first decline in ULSD prices since the beginning of the year. However, ULSD prices in July were still 71% higher than in July 2021, and ULSD crack spreads for July were three times wider than in July 2021.

Declining crude oil prices and less domestic consumption of distillate contributed to lower distillate prices. We estimate distillate consumption decreased by 0.2 million b/d (4%) from June to 3.7 million b/d in July. Consumption typically declines in July as stocks rebuild to prepare for higher demand during the fall harvest season and winter heating season. However, we estimate U.S. distillate inventories decreased 1.8 million barrels (2%) in July to reach 109 million barrels, or 26% below the five-year average. We estimate U.S. distillate production averaged 5.1 million b/d in July, slightly below June, which had seen the most production since December 2019. Strong global distillate demand continues to support higher production and, with lower domestic consumption, higher-than-average exports in July. We forecast production will remain above 2021 levels through the rest of the year.

International distillate inventories: 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 prices this year. Even before the sanctions, however, distillate inventories at all three
major trading hubs (New York Harbor, Amsterdam-Rotterdam-Antwerp, and Singapore) started the year below their respective five-year averages (Figure 8). U.S. distillate inventories increased to record highs in 2020 when the COVID-19 pandemic resulted in historically low consumption of petroleum products. As demand returned, inventory drawdowns began in the United States and followed overseas by the beginning of 2021. As of July 29, 2022, combined distillate inventories in the East Coast and the Gulf Coast (PADD 1 and PADD 3) were 31% below the five-year average, and inventories at Amsterdam-Rotterdam-Antwerp and Singapore were around 40% below their five-year averages. In addition to sanctions on Russia’s exports, reduced refinery capacity in the United States and lower quotas for exports from China contributed to distillate inventory draws. Low inventories globally have put sustained upward pressure on distillate prices. We forecast higher-than-average domestic distillate production will begin contributing to building inventories in August with overall domestic stocks reaching 119 million barrels, or 17% short of the five-year average, by the end of this year.

Natural gas

Prices: The front-month natural gas futures contract for delivery at the Henry Hub settled at $8.12 per million British thermal units (MMBtu) on August 4, up $2.39/MMBtu from July 1, 2022 (Figure 9). The average price for front-month natural gas futures contracts in July was $7.19/MMBtu, down 41 cents/MMBtu from June’s average of $7.60/MMBtu when the front-month natural gas futures price topped $9.00/MMBtu on two days.
Natural gas injections into storage in June were 2% higher than the five-year (2017–2021) average. That trend reversed in July as 10% less natural gas was injected into storage than the five-year average. We estimate that storage inventories ended July at 2,493 billion cubic feet (Bcf), 12% less than the five-year average level.

The front-month Henry Hub futures price fell from $9.29/MMBtu on June 7, the day before the outage at Freeport LNG, to $5.42/MMBtu on June 30, likely because of market anticipation that the decrease in natural gas available for export would lead to an increase in natural gas supply available in the U.S. market. With more natural gas supply available, market participants may have anticipated more natural gas injections into storage. However, higher-than-normal temperatures in July increased consumption of natural gas for electric power generation to meet air-conditioning demand. We estimate that an average of 41.8 billion cubic feet per day (Bcf/d) of natural gas was consumed in the electric power sector during July, 2.2 Bcf/d more than the five-year average and 5.0 Bcf/d more than in June. At the same time, we estimate that dry natural gas production averaged 96.4 Bcf/d in July, down 0.6 Bcf/d from June.

**Summer space cooling:** During May, June, and July, the United States experienced 800 cumulative cooling degree days (CDD), or 69 (9%) more than the prior 10-year (2011–2020) average (Figure 10), and the most CDDs for this time period since 2018. Higher-than-normal temperatures led to more consumption of natural gas for electric power generation to meet air-conditioning demand. We estimate that natural gas consumption in the electric power sector averaged 36.2 Bcf/d from May through July, 2.1 Bcf/d more than the same time period in 2021 and 3.4 Bcf/d more than the five-year average. The strong demand has led to lower-than-average injections into natural gas storage for three of the four months so far during this injection season (April–October) and has contributed to the deficit in the storage inventory compared with the five-year average. The sustained lower-than-average storage inventories have put upward pressure on the Henry Hub spot natural gas price.
Natural gas share of electricity generation: In recent years, the electric power sector substituted natural gas-fired generation with coal-fired generation when natural gas prices rose. However, in recent months, coal power plants have responded less to price than in the past, most likely as a result of continued coal capacity retirements, constraints in fuel delivery to coal plants, and lower-than-average stocks at coal plants. Additionally, growth in electricity generation capacity from renewable sources is limiting the dispatch of both coal and natural gas. The Henry Hub spot natural gas price has remained elevated since the beginning of the year, but natural gas has maintained a more than 60% share of fossil-fuel sourced electricity generation (Figure 11). The Henry Hub spot price increased $3.76/MMBtu from January to May, but the natural gas share of fossil-fuel sourced electricity generation also increased from 60% in January to 67% in May despite the higher fuel cost.
Notable forecast changes

• This STEO incorporates our changed forecast for the Brent and WTI crude oil price spread. Changes to sources of Europe’s crude oil imports following Russia’s full-scale invasion of Ukraine and the EU’s subsequent petroleum import ban have contributed to redirections in oil trade flows. European countries are importing more crude oil from the United States and exporting less crude oil to countries in Asia, contributing to the development of a crude oil import price premium in Europe. As a result, we anticipate this trend will maintain a wider price spread between Brent and WTI crude oil of $6/b in 2023, which is $2/b wider than in the July STEO.

• Natural gas prices have risen in recent weeks in response to the sooner-than-expected re-opening of the Freeport LNG export terminal and ongoing hot weather. As a result, we have increased our forecast for natural gas prices. We now forecast that the Henry Hub price will average $7.54/MBtu during the second half of 2022 compared with a forecast of $5.97/MBtu in the last STEO. We have also raised our forecast average price for 2023 from $4.76/MBtu to $5.10/MBtu.

• We have revised our modeling of electricity supply to better reflect regional differences in fuel costs. This change, along with a higher forecast natural gas price, has contributed to some significant increases in our forecast for wholesale electricity prices, particularly in the Northeast. In the current STEO, we forecast winter wholesale prices in ISO New England will average $176 per megawatthour (MWh) between December and February compared with $57/MWh in the previous STEO. The large increase in forecast prices reflects updates to our assumption about that region’s natural gas costs for this winter. We also raised our forecast electricity prices in Texas’s ERCOT market.

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

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