Short-Term Energy Outlook

Forecast highlights

Winter Fuels Outlook

- We forecast that average U.S. household expenditures for all major home heating fuels will increase significantly this winter primarily because of higher expected fuel costs as well as more consumption of energy due to a colder winter. Average increases vary by fuel, region, and weather assumptions. Compared with last winter, we forecast propane expenditures will rise by 54%, heating oil by 43%, natural gas by 30%, and electricity by 6%. We expect space heating demand to generally be higher this winter based on forecasts from the National Oceanic and Atmospheric Administration (NOAA) that U.S. average heating degree days will be 3% higher than last winter (Winter Fuels Outlook). Altering our assumptions for a 10% colder-than-expected winter significantly increases forecast expenditures, while a 10% warmer-than-expected winter still results in increased expenditures, because of price increases.

Global liquid fuels

- The October Short-Term Energy Outlook (STEO) remains subject to heightened levels of uncertainty related to the ongoing recovery from the COVID-19 pandemic. U.S. economic activity continues to rise after reaching multiyear lows in the second quarter of 2020 (2Q20). U.S. gross domestic product (GDP) declined by 3.4% in 2020 from 2019 levels. This STEO assumes U.S. GDP will grow by 5.7% in 2021 and by 4.5% in 2022. The U.S. macroeconomic assumptions in this outlook are based on forecasts by IHS Markit. Our forecast assumes continuing economic growth and increasing mobility. Any developments that would cause deviations from these assumptions would likely cause energy consumption and prices to deviate from our forecast.

- Brent crude oil spot prices averaged $74 per barrel (b) in September, up $4/b from August and up $34/b from September 2020. Brent spot prices have risen from their September average to more than $80/b in early October. Oil prices have increased over the past year as result of steady draws on global oil inventories, which averaged 1.9 million barrels per day (b/d) during the first three quarters of 2021. In addition to sustained inventory draws, prices increased after the October 4 announcement by OPEC+ that the group would keep current production targets unchanged.
• We expect Brent prices will remain near current levels for the remainder of 2021, averaging $81/b during the fourth quarter of 2021, which is $10/b higher than our previous forecast. The higher forecast reflects our expectation that global oil inventories will fall at a faster rate than we had previously expected owing largely to lower global oil supply in late 2021 across a range of producers. In 2022, we expect that growth in production from OPEC+, U.S. tight oil, and other non-OPEC countries will outpace slowing growth in global oil consumption and contribute to Brent prices declining from current levels to an annual average of $72/b.

• U.S. regular gasoline retail prices averaged $3.18 per gallon (gal) in September, up 2 cents/gal from August and almost $1/gal higher than in September 2020. Recent gasoline price increases reflect increasing crude oil prices outweighing falling gasoline wholesale margins. We forecast that retail gasoline prices will average $3.21/gal in October before falling to $3.05/gal in December.

• Total U.S. crude oil production averaged 11.3 million b/d in July —the most recent monthly historical data point. We estimate that domestic production fell to 10.6 million b/d in September because of disruptions from Hurricane Ida. We forecast production will be 11.0 million b/d in October and rise to 11.3 million b/d in December. We forecast 2021 production will average 11.0 million b/d, increasing to 11.7 million b/d in 2022 as tight oil production rises in the United States. Growth will come as a result of operators increasing rig counts, which we expect will offset production decline rates.

Natural Gas

• In September, the natural gas spot price at Henry Hub averaged $5.16 per million British thermal units (MMBtu), which was up from the August average of $4.07/MMBtu and up from an average of $3.25/MMBtu in the first half of 2021. The rising prices in recent months reflect U.S. natural gas inventory levels that are below the five-year average and continuing demand for natural gas for power generation use at relatively high prices.

• We expect the Henry Hub spot price will average $5.80/MMBtu in fourth-quarter 2021, which is $1.80/MMBtu higher than we forecast in the September STEO. In the current forecast, Henry Hub prices reach a monthly average peak of $5.90/MMBtu in January and generally decline through 2022, averaging $4.01/MMBtu for the year amid rising U.S. natural gas production and slowing growth in LNG exports. We raised our Henry Hub price forecast through the end of 2022 compared with last month. The increase reflects a higher starting point for our price forecast that incorporates recent developments in U.S. and global natural gas markets. We forecast that U.S. inventory draws will be slightly more than the five-year average this winter, and we expect that factor, along with rising U.S. natural gas exports and relatively flat production through January will keep U.S. natural gas prices near recent levels before downward pressures emerge. Given low natural gas inventories in both U.S. and European natural gas
storage facilities and uncertainty around seasonal demand, we expect natural gas prices to remain volatile over the coming months, with winter temperatures being a key driver of demand and prices.

- We estimate that U.S. LNG exports averaged 9.3 billion cubic feet per day (Bcf/d) in September 2021, down 4% from August. Despite the recent monthly decline, these were the most U.S. LNG exports for September since the United States began exporting LNG from the Lower 48 states in February 2016. Even though September exports were a record for the month, they were limited by weather conditions, which led to the suspension of piloting services for several days at Sabine Pass, Cameron, and Corpus Christi. We expect that LNG exports will average 9.1 Bcf/d in October and then increase in the coming months. Cove Point LNG terminal is scheduled to complete its annual maintenance by mid-October and resume exports this month. Through this winter, LNG exports in the forecast average 10.7 Bcf/d as global natural gas demand remains high and several new LNG export trains—the sixth train at Sabine Pass LNG and the first trains at the new LNG export facility Calcasieu Pass LNG—enter service.

- We estimate that U.S. natural gas inventories ended September 2021 at about 3.3 trillion cubic feet (Tcf), 5% less than the five-year (2016–20) average for this time of year. Injections into storage this summer have been below the previous five-year average, largely as a result of more electricity consumption in June due to hot weather, and increased exports even as domestic natural gas production has remained flat. We forecast that inventories will end the 2021 injection season (at the end of October) at almost 3.6 Tcf, which would be 5% less than the previous five-year average. We expect natural gas inventories to fall by 2.1 Tcf this winter, ending March at less than 1.5 Tcf, which would be 12% less than the 2017–21 average for that time of year.

- We estimate dry natural gas production averaged 93.3 Bcf/d in the United States during the third quarter of 2021—up from 91.6 Bcf/d in in the first half of 2021. Production in the forecast rises to an average of 94.0 Bcf/d during the winter, and averages 96.4 Bcf/d during 2022, driven by natural gas and crude oil prices, which we expect to remain at levels that will support enough drilling to sustain production growth.

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

- We expect the share of electricity generation produced by natural gas in the United States will average 36% in 2021 and 35% in 2022, down from 39% in 2020. In 2021, our forecast share for natural gas as a generation fuel declines in response to our expectation of a higher delivered natural gas price for electricity generators, which we forecast will average $5.15/MMBtu compared with $2.39/MMBtu in 2020. As a result of the higher expected natural gas prices, the forecast share of electricity generation from coal rises from 20% in 2020 to about 24% in 2021 and 23% in 2022. For renewable energy sources, new additions of solar and wind generating capacity are offset
somewhat by reduced generation from hydropower this year, resulting in the forecast share of all renewables in U.S. electricity generation to average 20% in 2021, about the same as last year, before rising to 22% in 2022. The nuclear share of U.S. electricity generation declines from 21% in 2020 to 20% in 2021 and 2022.

- Electricity generation from coal-fired power plants has not increased as much in response to rising natural gas prices as it has in the past, or by as much as our models forecasted in recent STEOs. The lower price responsiveness of coal for electricity generation, which is likely the result of constraints on coal supply and low coal stocks, is contributing to upward pressure on natural gas prices. To reflect the lower price responsiveness of coal-fired electricity generation, we have lowered our forecast for U.S. coal generation for the fourth quarter of 2021 and the first half of 2022 by an average of 7 billion kWh (9%) each month, and we have raised our forecast for natural gas generation 5 billion kWh (5%) each month.

- We forecast that planned additions to U.S. wind and solar capacity in 2021 and 2022 will increase electricity generation from those sources. We estimate that the U.S. electric power sector added 14.6 gigawatts (GW) of new wind capacity in 2020. We expect 17.1 GW of new wind capacity will come online in 2021 and 6.5 GW in 2022. Utility-scale solar capacity rose by an estimated 10.5 GW in 2020. Our forecast for added utility-scale solar capacity is 16.0 GW for 2021 and 18.3 GW for 2022. We expect significant solar capacity additions in Texas during the forecast period. In addition, we project that after increasing by 4.5 GW in 2020, small-scale solar capacity (systems less than 1 megawatt) will grow 5.8 GW and 7.8 GW in 2021 and 2022, respectively.

- Coal production in our forecast totals 588 million short tons (MMst) in 2021, 53 MMst more than in 2020. We expect demand for coal from the electric power sector to increase by 84 MMst in 2021. Production growth is unlikely to match the increases in demand in the near term due to many coal mines operating at a reduced capacity and limited available transportation. In 2022, we expect coal production to increase by 34 MMst to 622 MMst, as the production and transportation constraints experienced in 2021 ease. Secondary inventories of coal at electric utilities decreased in the first half of 2021, and we forecast this trend will continue into the second half of 2021 and 2022.

- We estimate that U.S. energy-related carbon dioxide (CO2) emissions decreased by 11% in 2020 as a result of less energy consumption related to reduced economic activity and responses to COVID-19. For 2021, we forecast energy-related CO2 emissions will increase about 8% from the 2020 level as economic activity increases and leads to rising energy use. We expect almost no change in energy-related CO2 emissions in 2022. We forecast that after declining by 19% in 2020, coal-related CO2 emissions will rise by 20% in 2021 and then fall by 5% in 2022. Short-term changes in energy-related CO2 can be affected by temperature. A recent STEO supplement examines these dynamics.
Petroleum and natural gas markets review

Crude oil

**Prices:** The front-month futures price for Brent crude oil settled at $81.95 per barrel (b) on October 7, 2021, up $10.36/b from $71.59/b on September 1. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, increased by $9.71/b during the same period, settling at $78.30/b on October 7 (Figure 1).

WTI crude oil prices reached nearly seven-year highs on October 5 after gradually increasing throughout September and the first few trading days of October. Several developments during the past month are contributing to higher oil prices. First, U.S. crude oil inventories have decreased because of Hurricane Ida’s impact on crude oil production in the Gulf of Mexico. Second, OPEC+ members decided to follow their scheduled crude oil production increase of 400,000 barrels per day (b/d) in November rather than increase production by more, like some market participants expected based on recent price movements. Third, trade press reports increased purchases of oil and petroleum products as a result of high natural gas prices because electric power generators in parts of Asia and Europe may implement natural gas-to-oil fuel switching to decrease fuel costs. Lastly, crude oil prices continue to rise due to steady and sizable global oil inventory draws. We estimate that global inventories fell by 1.9 million b/d in third-quarter 2021 (3Q21), marking the fifth consecutive quarter of draws; quarterly draws averaged 2.2 million b/d over those five quarters.

We estimate U.S. crude oil inventories ended September at 420.9 million barrels, the lowest level since September 2018 (Figure 2). U.S. crude oil stocks have decreased each of the past six months, decreasing by 81.0 million barrels (16%) since March, the largest six-month withdrawal on record in our crude oil data for all inventories outside of the Strategic Petroleum Reserve,
which go back to 1973. Furthermore, according to weekly data in our *Weekly Petroleum Status Report*, crude oil stocks on September 17 were 37.0 million barrels (8.2%) below the five-year average for that time of year, the largest percentage below the five-year average since July 4, 2008. Like domestic stocks, we estimate OECD commercial petroleum stocks at the end of September to be at their lowest levels in more than three years.

A major factor contributing to the stock draws has been low crude oil production, which has been outpaced by increases in demand. U.S. oil production averaged 11.0 million b/d from January through August (compared with 12.0 million b/d in the same months in 2019) and decreased to 10.6 million b/d in September because of lower U.S. offshore oil production in the Gulf of Mexico after Hurricane Ida. According to the Bureau of Safety and Environmental Enforcement (BSEE), from August 28 through September 6, more than 80% of oil production in the Gulf of Mexico was shut in, and more than 15% of Gulf of Mexico oil remained shut in through September 23, when BSEE issued its final outage report for Hurricane Ida. In total, disruptions in the Gulf of Mexico reduced crude oil production by about 30 million barrels since Hurricane Ida formed in late August.

Global liquid fuels production has also risen more slowly than global demand this year. Production increased by 2.7 million b/d (3%) from January to September, whereas global consumption increased by 6.3 million b/d (7%) during the same period. Despite relatively low global production and rising crude oil prices, OPEC+ members reaffirmed a previously agreed on production increase of 400,000 b/d in November, as opposed to a higher production increase for the month. Following this announcement on October 4, the price of Brent crude oil settled at $81.26, after beginning the day at $79.28.

In this forecast, we now expect that global oil inventories in 4Q21 and 1Q22 will fall at a faster rate than we had previously expected, which largely reflects lower global oil supply during this
period across a range of producers. We have also raised our expectations for global oil demand during winter 2021–22. In the October STEO, we have increased our forecast for Brent crude oil prices. We now expect falling global oil inventories will keep Brent prices near $80/b this winter, averaging $81/b in 4Q21 and $78/b in 1Q21, both of which are $10/b higher than forecast last month.

**Market-derived probabilities:** In our most recent forecast, we expect WTI prices to average $78/b in 4Q21. The upward price pressure and market uncertainties are apparent in market-derived price probabilities that are based on futures and options prices. The market-derived probability of the December WTI futures contract expiring higher than $70/b was 77% on October 7, and the probability of the contract expiring higher than $80/b was 37% (Figure 3). On September 1, the market-derived probability of the December WTI futures contract expiring higher than $70/b had been 39%, and the probability of the contract expiring higher than $80/b was 12%. The increase in market-derived price expectations for the December WTI contract from September 1 to October 7 conveys the market’s reaction to factors such as decreasing stocks and the potential for natural gas-to-oil switching. The December WTI contract has not expired at more than $70/b since 2014 and has not expired at more than $80/b since 2013.

![Figure 3. Probability of the December WTI futures contracts expiring above different price levels](image)

**Commodity Prices:** In 2021, energy commodity prices have increased more than other commodities and asset classes, especially since May, primarily as a result of production and supply developments specific to energy markets. The S&P GSCI (formerly the Goldman Sachs Commodity Index) is an index comprising 24 individual weighted commodity price contracts organized into 5 subindexes, and we use it for comparing energy commodities to other categories of commodities.

As of October 7, the non-energy index (an index consisting of agricultural, livestock, precious metal, and industrial metal commodities) was up 14% from the beginning of 2021 but down 5%
from its peak on May 7. Energy commodities, on the other hand, have increased 27% since May 7 and are up 72% from January 1. The S&P 500, which is up by 19% from January 1, has also increased since May 7, but only by 4% (Figure 4).

Whereas general economic growth likely explained a portion of the increase in energy prices from January 1 through May 7, the growth in energy commodities since then has mostly been a result of factors specific to petroleum markets, such as production increases lagging demand increases. Brent and WTI make up 70% of the energy sub-index’s weight. Thus, the price increases from around $50/b for Brent and WTI at the beginning of the year to around $80/b in early October explains a significant portion of the increase in the energy sub-index. Higher prices for petroleum products, which make up 25% of the index, and for Henry Hub natural gas, which makes up the remaining 5% of the index, have also contributed to the rest of the growth in the energy sub-index.

**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 $2.33 per gallon (gal) on October 7, up 22 cents/gal from September 1 (Figure 5). The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) decreased by 2 cents/gal to settle at 38 cents/gal during the same period. The average RBOB–Brent crack spread in September was 38 cents/gal, an increase of 20 cents/gal compared with September 2020.
After the RBOB–Brent crack spread averaged 55 cents/gal in August, it fell in September because of rising crude oil prices and lower gasoline prices. Lower gasoline prices compared with August reflect expected lower seasonal demand for gasoline as well as the price decrease for winter grade gasoline, which is relatively less expensive for refiners to produce because of less stringent Reid Vapor Pressure (RVP) requirements. The shift from summer to winter grade gasoline primarily takes place in September, putting downward pressure on the futures contract price in September onward. Temporary weather-related refinery outages along the U.S. Gulf Coast contributed to reduced production and draws on gasoline inventories earlier in September and limited some of the downward pressure on crack spreads. Compared with August 2021, U.S. demand for gasoline in September was an estimated 0.4 million barrels per day (b/d) lower. We estimate U.S. gasoline consumption averaged 9.1 million b/d in September, which is 0.5 million b/d (6%) higher than in September 2020 but also 0.1 million b/d (1%) lower than September 2019 level. We expect gasoline consumption to remain just below 2019 levels through the end of 2022. Combined with high net imports and lower demand, inventories increased during the second half of September; however, lost production from earlier in the month resulted in gasoline stocks ending September at 225.1 million barrels, the lowest end-of-September inventory level since 2017. Overall lower inventories may also have contributed to increasing gasoline crack spreads from October 4 through October 7.

***Ultra-low sulfur diesel prices***: The front-month futures price for ultra-low sulfur diesel (ULSD) for delivery in New York Harbor settled at $2.46/gal on October 7, up 33 cents/gal from September 1 (*Figure 6*). The ULSD-Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) increased 8 cents/gal during the same period and settled at 51 cents/gal on October 7. The ULSD–Brent crack spread averaged 41 cents/gal in September.
High distillate demand and low distillate production resulted in the highest ULSD-Brent crack spreads seen this year, continuing a trend of rising ULSD crack spreads in recent months. We estimate that distillate consumption was 4 million b/d in September—the highest September level since 2018. Hurricane-related disruptions, including refinery shutdowns and brief closures of Colonial Pipeline Line 2, contributed to reduced production and higher inventory withdrawals. Also, increases in the American Trucking Associations’ Truck Tonnage Index and the Cass Freight Index suggest trucking demand remains high as supply chains continue to navigate a backlog of shipping orders. Rapidly rising shipping activity will likely contribute to high distillate demand. While we forecast gasoline demand to remain below 2019 levels throughout 2022, we forecast distillate demand to increase next year to its highest level since 2018.

Rising crack spreads also likely reflect relatively low distillate fuel inventories. Distillate inventories typically increase in the summer to prepare for growth in demand in the fall and winter, when diesel-powered agricultural equipment is used to harvest crops and the winter heating season begins. This year, distillate inventories did not build as much as usual due to high distillate demand and relatively low production. Second- and third-quarter distillate production was 5.5% and 5.1% below the five-year (2016–20) average, respectively. Our estimate of 4.5 million b/d for production this September is 6.9% below the five-year average. As a result, U.S. distillate stocks are below average for this time of year. In the Northeast, where 4.14 million households will use heating oil as their primary source of heat this winter, distillate inventories declined to 27.4 million barrels (30% below the five-year average), according to the latest Weekly Petroleum Status Report (Figure 7). Our Winter Fuels Outlook forecasts a 43% increase in heating oil expenditure over last year and the highest price per gallon for heating oil since the 2012–13 winter.
The Mars crude oil 5:3:2 crack spread at the U.S. Gulf Coast is an indicator of profitability of gasoline and diesel-producing refinery operations for high-conversion refineries along the U.S. Gulf Coast that are able to process denser, more sour crude oil grades, such as Mars. On August 31, the five-day moving average crack spread reached 56 cents/gal, its highest point in 2021 (Figure 8). The high overall crack spread primarily reflects increased gasoline cracks, which also reached an annual high in August. Gasoline crack spreads in the first half of September were elevated because of temporary hurricane outages, which supported the 5:3:2 crack through the middle of the month, continuing the trend from August, as well as increasing distillate crack spreads as the outages resulted in distillate inventory withdrawals. As supply constraints were resolved and refineries came back online, gasoline cracks decreased while distillate cracks continued to increase.
Higher crude oil costs, pressure on gasoline prices from the shift to winter grade, decreasing prices for renewable identification numbers (RINs), and seasonally lower demand has contributed to decreases in gasoline crack spreads in the latter half of September, while lower inventories and increasing seasonal demand continued to contribute to increasing diesel cracks. In addition to elevated crude oil prices globally, production outages in the Gulf Coast limited heavy sour crude oil production in August, and Mars grade in particular has faced extended production outages. As gasoline cracks decreased and distillate cracks increased, the distillate crack spread overtook the gasoline crack spread on September 23 and has remained higher so far into October. The relatively larger reduction in gasoline cracks compared with increasing distillate cracks contributed to decreases in the Mars 5:3:2 crack, which fell from 49 cents/gal on September 15 to 45 cents/gal on September 30. Since October 1, the gasoline and diesel crack five-day average crack spreads have both been increasing, contributing to increases in the Mars 5:3:2 crack as well.

**Natural Gas**

*Prices:* The front-month natural gas futures contract for delivery at the Henry Hub settled at $5.68 per million British thermal units (MMBtu) on October 7, 2021, which was up $1.06/MMBtu from September 1, 2021 (Figure 9). The average price for front-month natural gas futures contracts in September was $5.11/MMBtu, the highest monthly average since February 2014. Henry Hub natural gas prices during much of the summer were supported by inventory builds that were below the previous five-year (2016–20) averages. Over the past month, increases in Henry Hub prices have coincided with sharp increases in international prices for natural gas, especially in Europe and Asia, and high international prices have contributed to strong demand for more U.S. liquefied natural gas (LNG) cargoes.

![Figure 9. U.S. natural gas front-month futures prices and storage deviation from five-year average](source: Graph by EIA, based on data from CME Group, as compiled by Bloomberg L.P.)
**International natural gas prices:** LNG spot and forward prices in Europe and Northern Asia ended September at record-high levels. On September 30, 2021, LNG spot prices for Japan/Korea reached $31.10/MMBtu, and the price at the European natural gas benchmark, Title Transfer Facility (TTF), reached $33.20/MMBtu (Figure 10). From the end of January to the end of September, the price spread between LNG prices in Asia and Henry Hub has increased from $6.31/MMBtu to $25.23/MMBtu. The price spread between European spot natural gas prices at TTF and Henry Hub increased from $4.49/MMBtu to $27.34/MMBtu over the same period. These large price differences have supported record LNG exports from the United States to Europe and Asia. U.S. LNG exports also increased because of new export capacity added in 2020. The final liquefaction units were commissioned at Freeport, Cameron, and Corpus Christi LNG, and the remaining small-scale units were placed in service at Elba Island LNG. Additionally, we expect Sabine Pass train 6 and Calcasieu Pass LNG facility to begin exporting by the end of the year.

High natural gas demand in Asia, particularly in China because of disruptions in coal availability, contributed to increased demand for spot LNG shipments in addition to volumes supplied under long-term contracts. U.S. exports of LNG to China nearly quadrupled, increasing from 0.3 billion cubic feet per day (Bcf/d) for the first seven months of 2020 to 1.1 Bcf/d for the same period in 2021. U.S. LNG exports to Japan and South Korea increased by 64% and 62%, respectively, over the same period.

Low European natural gas storage inventories this year have led to high natural gas spot prices in that region as well. According to data from Gas Infrastructure Europe’s (GIE) Aggregated Gas Storage Inventory (AGSI+), natural gas stocks in Europe ended September at 2.7 trillion cubic feet, 16% below the five-year average and 8% below the five-year minimum. Colder-than-normal weather late in the 2020–21 heating season and a cold spell in April led to rapid...
drawdowns of natural gas inventories early in 2021, contributing to the low inventory levels that are putting upward pressure on prices.

**U.S. consumption and price outlook:** Consumption of natural gas in the United States tends to decrease in September and October as temperatures are mild. U.S. consumption of natural gas decreased in September by 6.1 billion cubic feet per day (Bcf/d), or 7.9%, compared with August. This decrease was driven by a 6.7 Bcf/d decrease in natural gas consumption in the electric power sector that was partially offset by increases in the commercial, residential, and industrial sectors. U.S. exports of LNG also decreased in September, averaging 9.3 Bcf/d for the month, down from 9.7 Bcf/d in August. Annual maintenance at the Cove Point LNG facility in Maryland began in mid-September, and a power outage in Houston following Hurricane Nicholas resulted in the Freeport LNG terminal shutting down for a few days. Both of these events contributed to lower LNG exports in September. We expect LNG exports to average 10.7 Bcf/d this winter (October–March), a record high for that time period.

We estimate that U.S. working natural gas inventories ended September at 3,304 Bcf, 5.5% below the 2016–2020 average. This level is a decrease in the deficit to the 2016–2020 average when compared with August, which ended the month at 7.4% below the 2016–2020 average.

We expect that Henry Hub prices will remain high this winter, averaging $5.67/MMBtu in the forecast for October through March, which would be the highest winter average since winter 2007–08. However, the price outlook for this winter is very uncertain. Given that natural gas inventories in the United States are below average levels from recent years, the possibility that prices could be volatile is high, particularly if any area in the United States experiences a severe cold snap. Uncertainty in the price forecast also results from linkages between U.S. natural gas markets and global markets. With high demand for U.S. natural gas exports, increases in global natural gas prices have coincided with smaller price increases at Henry Hub.

Given the uncertainty surrounding natural gas prices, market-derived probabilities based on futures and options contracts are showing very wide range of market-implied price outcomes for the January Henry Hub futures contract (Figure11). As of October 7, the market-derived probabilities implied that the January contract had about a 10% chance of expiring below $2.70/MMBtu and an equal chance of expiring above $10.25/MMBtu. A month earlier that probability range was bounded by $3.00/MMBtu on the low end and about $6.25/MMBtu on the high end. This shift shows that the market is increasingly pricing in the possibility of large price shifts in the coming months.
Notable forecast changes

- We forecast Brent crude oil prices will average $81 per barrel (b) during the fourth quarter of 2021 (4Q21) and $78/b during 1Q22, both of which are $10/b higher than our previous forecast. The higher forecast reflects much tighter oil markets during this period than we previously expected. We now expect that global oil inventories in 4Q21 and 1Q22 will decline at an average rate of 0.5 million barrels per day (b/d), compared with a forecast of mostly unchanged inventories during that period in last month’s STEO.

- We expect crude oil production in the Federal Offshore Gulf of Mexico will average 1.5 million b/d in 4Q21, more than 0.2 million b/d lower than forecast last month. The lower forecast is mostly the result of Shell’s announcement that platforms damaged by Hurricane Ida would remain offline through the end of the year.

- We forecast Henry Hub spot prices will average $5.80 per million British thermal units (MMBtu) in 4Q21, an increase of $1.80/MMBtu from last month’s STEO. In this outlook, we expect prices to remain elevated through the first quarter of 2022. Forecast Henry Hub prices for 2022 average $4.01/MMBtu, up 54 cents/MMBtu from last month’s STEO.

- In mid-September, Exelon announced that it will continue operating its nuclear reactors at the Byron and Dresden power plants in Illinois. These nuclear plants were previously scheduled to be retired next year. As a result of this decision, we raised our forecast for U.S. nuclear generation in 2022 by 4% above the level forecast in last month’s STEO.
This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.