



Short-Term Energy Outlook

Forecast highlights

Global liquid fuels

- The November *Short-Term Energy Outlook* (STEO) remains subject to heightened levels of uncertainty because responses to COVID-19 continue to evolve. Reduced economic activity related to the COVID-19 pandemic has caused changes in energy demand and supply patterns in 2020 and will continue to affect these patterns in the future. U.S. gross domestic product (GDP) declined by 4.4% in the first half of 2020 compared with the same period a year ago. GDP began rising in the third quarter of 2020, and this STEO assumes it will grow by 3.7% from 2020 to 2021. The U.S. macroeconomic assumptions in this outlook are based on forecasts by IHS Markit.
- Brent crude oil spot prices averaged \$40 per barrel (b) in October, down \$1/b from the average in September. Brent prices fell in October as previously disrupted crude oil production in Libya came back online and as COVID-19 cases began increasing in many countries, which could reduce oil demand in the coming months. Despite these developments, the U.S. Energy Information Administration (EIA) expects global oil inventories to continue falling in the coming months. However, EIA expects high global oil inventory levels and surplus crude oil production capacity will limit upward pressure on oil prices and that Brent prices will remain near \$40/b through the end of 2020. EIA expects that as global oil demand rises, forecast inventory draws in 2021 will cause some upward oil price pressures. EIA forecasts Brent crude oil prices will average \$47/b in 2021.
- EIA estimates that an average of 95.3 million barrels per day (b/d) of petroleum and liquid fuels was consumed globally in October. Liquid fuels consumption was down 5.9 million b/d from October 2019, but it was up from both the third-quarter 2020 average of 94.1 million b/d and the second-quarter 2020 average of 85.3 million b/d. EIA forecasts that global consumption of petroleum and liquid fuels will average 92.9 million b/d for all of 2020, down by 8.6 million b/d from 2019, before increasing by 5.9 million b/d in 2021.
- EIA reported that 10.6 million b/d of crude oil was produced in the United States in August (the most recent month for which historical data are available), down 0.4 million b/d from July. Production fell in August mainly because hurricanes disrupted production from the U.S. Gulf of Mexico. EIA reported that U.S. crude oil production in the Gulf of

Mexico averaged 1.2 million b/d in August, down 0.5 million b/d from July. Since reaching a two-and-a-half year low of 10.0 million b/d in May, when producers curtailed wells, U.S. crude oil production has increased mainly because tight oil operators have brought wells back online in response to rising prices. EIA estimates that production will rise to 11.2 million b/d in November. However, EIA expects U.S. crude oil production to generally decline to an average of 11.0 million b/d in the second quarter of 2021 because new drilling activity will not generate enough production to offset declines from existing wells. EIA expects drilling activity to rise later in 2021, contributing to U.S. crude oil production reaching 11.3 million b/d in the fourth quarter of 2021. On an annual average basis, EIA expects U.S. crude oil production to fall from 12.2 million b/d in 2019 to 11.4 million b/d in 2020 and 11.1 million b/d in 2021.

Natural Gas

- In October, the Henry Hub natural gas spot price averaged \$2.39 per million British thermal units (MMBtu), up from an average of \$1.92/MMBtu in September. Higher natural gas spot prices reflected stronger demand for liquefied natural gas (LNG) exports as LNG terminals increased liquefaction following hurricane-related disruptions in August and September. EIA expects Henry Hub spot prices to rise to a monthly average of \$3.42/MMBtu in January 2021 because of rising domestic demand for natural gas for space heating, rising U.S. LNG exports, and reduced production. EIA expects that monthly average spot prices will remain higher than \$3.00/MMBtu throughout 2021, averaging \$3.14/MMBtu for the year, up from a forecast average of \$2.14/MMBtu in 2020.
- EIA estimates that total U.S. working natural gas in storage ended October at almost 4.0 trillion cubic feet (Tcf), 5% more than the five-year (2015–19) average and the second-highest end-of-October level on record. However, because EIA forecasts less U.S. natural gas production this winter than last winter, EIA forecasts that inventory draws will outpace the five-year average during the heating season (October–March) and end March 2021 at 1.5 Tcf, which would be 16% lower than the 2016–20 average.
- EIA expects that total U.S. consumption of natural gas will average 83.7 billion cubic feet per day (Bcf/d) in 2020, down 1.7% from 2019. The decline in total U.S. consumption reflects less heating demand in early 2020, contributing to residential demand in 2020 averaging 13.2 Bcf/d (down 0.6 Bcf/d from 2019) and commercial demand in 2020 averaging 8.8 Bcf/d (down 0.9 Bcf/d from 2019). EIA forecasts industrial consumption will average 22.5 Bcf/d in 2020, down 0.6 Bcf/d from 2019 as a result of reduced manufacturing activity. EIA expects total U.S. natural gas consumption will average 79.4 Bcf/d in 2021, a 5.2% decline from 2020. The expected decline in 2021 is the result of rising natural gas prices that will reduce demand for natural gas in the electric power sector.

- EIA forecasts U.S. dry natural gas production will average 91.0 Bcf/d in 2020, down from an average of 93.1 Bcf/d in 2019. In the forecast, monthly average production falls from a record 97.0 Bcf/d in December 2019 to 87.0 Bcf/d in April 2021 before increasing slightly. EIA forecasts dry natural gas production in the United States to average 87.9 Bcf/d in 2021. EIA expects production to begin rising in the second quarter of 2021 in response to higher natural gas and crude oil prices. The increase in crude oil prices is expected to raise associated gas production from oil-directed wells in late-2021, especially in the Permian region.
- EIA estimates that the United States exported 7.2 Bcf/d of LNG in October, an increase of 2.3 Bcf/d from September—the largest month-on-month increase since U.S. LNG exports began in 2016. Cameron LNG resumed LNG exports in October after being shut down following [Hurricane Laura](#) and [Hurricane Delta](#). Cove Point LNG completed its scheduled three-week annual maintenance and resumed LNG exports in mid-October. Higher global forward prices for LNG indicate improving netbacks for buyers of U.S. LNG in European and Asian markets for the upcoming winter season. The increased prices come amid expectations of natural gas demand recovery in those markets and potential LNG supply reductions because of outages at several LNG export facilities in the Pacific Basin and Atlantic Basin. EIA forecasts that U.S. LNG exports will be above pre-COVID levels in November 2020, averaging 8.5 Bcf/d, and will average 8.4 Bcf/d in 2021, a 31% increase from 2020.

Electricity, coal, renewables, and emissions

- EIA forecasts that the consumption of electricity in the United States will decrease by 3.6% in 2020. EIA expects retail sales of electricity to fall by 6.4% this year in the commercial sector and by 8.8% in the industrial sector. EIA forecasts residential sector retail sales will increase by 2.5% in 2020. Milder winter temperatures earlier this year led to less residential consumption for space heating, offset by increased summer cooling demand and increased electricity use by more people working and attending classes from home. In 2021, EIA forecasts total U.S. electricity consumption will increase by 0.9%. Higher forecast electricity consumption in the first half of 2021 because of increased demand for space heating will be offset slightly by less forecast electricity consumption in the third quarter of 2021 because of less cooling demand based on the NOAA forecast of fewer cooling degree days.
- EIA expects the share of U.S. electric power sector generation from natural gas-fired power plants will increase from 37% in 2019 to 39% this year. In 2021, the forecast natural gas share declines to 33% in response to higher natural gas prices. Coal's forecast share of electricity generation falls from 24% in 2019 to 20% in 2020 and then increases to 25% in 2021. Electricity generation from renewable energy sources rises from 18% in 2019 to 20% in 2020 and to 22% in 2021. The increase in renewables' share is the result of planned additions to wind and solar generating capacity. EIA expects nuclear generation to decline by about 2% in both 2020 and 2021, reflecting recent and

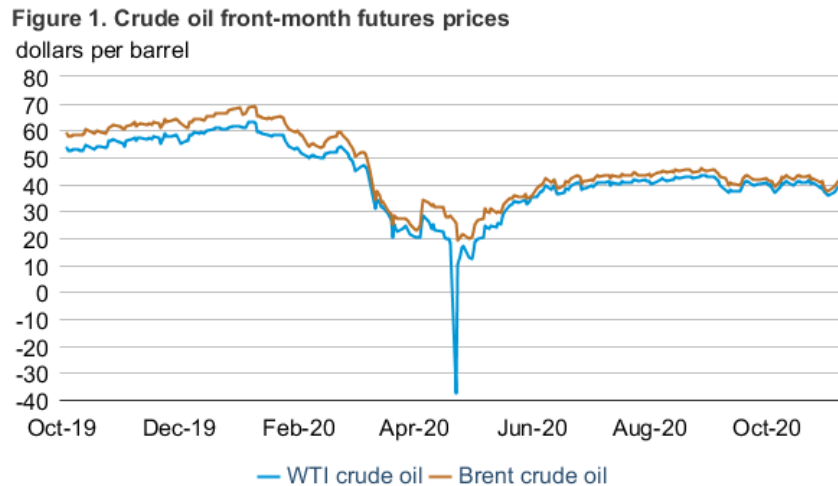
planned retirements of nuclear generating capacity. The nuclear share of U.S. generation remains close to 20% in these years.

- In 2020, EIA expects U.S. residential electricity prices to average 13.1 cents per kilowatt-hour, which is 0.7% higher than the average electricity price was in 2019. Annual changes in regional residential electricity prices this year range from 0.8% lower in the South Atlantic region to 4.0% higher in the Pacific region.
- EIA forecasts that renewable energy will be the fastest-growing source of electricity generation in 2020. EIA expects the U.S. electric power sector will add 23.2 gigawatts (GW) of new wind capacity in 2020 and 7.9 GW of new capacity in 2021. Expected utility-scale solar capacity rises by 12.8 GW in 2020 and by 13.0 GW in 2021.
- EIA expects U.S. coal production to be 521 million short tons (MMst) in 2020, a decline of 26% compared with 2019 levels. EIA forecasts production to rise to 627 MMst in 2021, an increase of 20%. EIA expects coal production to increase in 2021 in response to increased natural gas prices and increased demand in electric power consumption because of lower-than-average winter temperatures, especially in the Upper Midwest and Northwest regions of the United States. EIA expects that an 18% decline in U.S. coal consumption from the electric power sector in 2020 will be followed by a 23% increase in 2021.
- EIA forecasts that U.S. energy-related carbon dioxide (CO₂) emissions, after [decreasing by 2.6% in 2019](#) from the previous year's level, will decrease by 10% in 2020 as a result of reduced consumption of all fossil fuels. EIA expects emissions from coal will be down 18% from 2019 and emissions from petroleum will be down 13% from 2019. This decline in emissions is the result of less energy consumption related to slowing economic growth in response to the COVID-19 pandemic. In 2021, EIA forecasts that energy-related CO₂ emissions will increase by 6% from the 2020 level as the economy recovers and energy use increases.

Petroleum and natural gas markets review

Crude oil

Prices: The front-month futures price for Brent crude oil settled at \$40.93 per barrel (b) on November 5, 2020, unchanged from October 1, 2020. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, increased by 7 cents/b during the same period, settling at \$38.79/b on November 5 (Figure 1).



Source: CME Group and Intercontinental Exchange, as compiled by Bloomberg L.P.
Note: WTI=West Texas Intermediate.

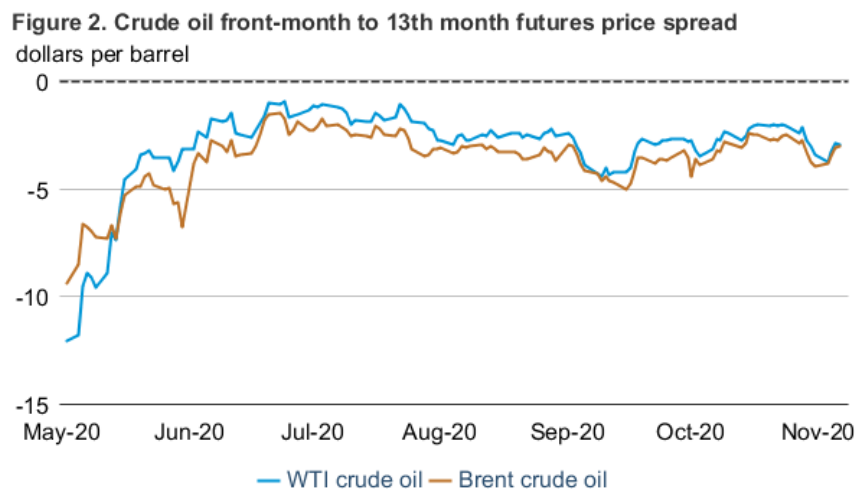
Crude oil price pressures were mostly downward in October, pushing Brent to less than \$38/b late in the month. However, prices increased during the first week of November to about \$40/b. The general downward price pressures came amid renewed crude oil price volatility that was primarily the result of a supply increase from Libya that came sooner than many market participants expected as well as responses to increasing COVID-19 cases.

Rapid increases in crude oil production in Libya likely magnified the downside price effects of reduced demand. EIA estimates that Libya's crude oil production increased to 0.4 million barrels per day (b/d) in October 2020 from 0.1 million b/d in September. In addition, trade press reports indicate that production had increased to more than 0.5 million b/d by the end of October, a level EIA had previously forecast would not be reached until the middle of 2021. The increase in crude oil production adds supply to the current market where petroleum inventories remain high, crude oil refinery runs are subdued, and the rate of increase in global oil demand growth is slowing.

Globally, daily cases of COVID-19 increased to a record high in late October, leading to renewed economic pressure. Uncertainty about responses to increasing COVID-19 cases presents downside risk to EIA's global oil demand forecast for the fourth quarter of 2020 and first half of 2021. EIA now expects global oil consumption will average 97.3 million b/d from the fourth quarter of 2020 through the first half of 2021, which is 0.4 million b/d lower than forecast in the

October *Short-Term Energy Outlook* (STEO). The pace of oil demand recovery will affect not only expectations of petroleum inventory withdrawals but also could affect planned oil supply increases from members of the Organization of the Petroleum Exporting Countries (OPEC) and partner countries (OPEC+), who are scheduled to meet on November 30. OPEC+ members currently plan to increase crude oil production by nearly 2.0 million b/d in January 2021. EIA forecasts that OPEC+ production will generally be tailored to match the pace of global oil demand recovery. As a result of EIA’s reduced demand growth expectations, EIA forecasts closer adherence to announced production targets from OPEC. For OPEC, EIA forecasts first-half 2021 crude oil production will be 27.9 million b/d, 0.5 million b/d lower than the October STEO. The lower forecast comes despite EIA’s assumption of higher production in Libya during early-2021.

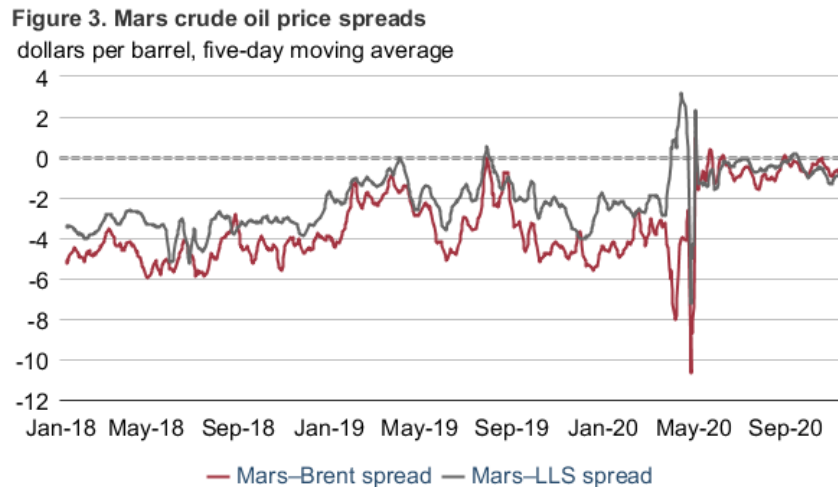
These supply and demand developments have primarily affected the front-month contracts for both Brent and WTI, initially contributing to a wider contango (when near-month prices are lower than longer-dated ones) in mid-October before narrowing slightly on the month. The 1st–13th spread for Brent narrowed to $-\$3.04/\text{b}$ on November 5 from $-\$3.64/\text{b}$ on October 1, and the WTI 1st–13th spread narrowed to $-\$2.95/\text{b}$ from $-\$3.27/\text{b}$ on October 1 (**Figure 2**). Although increases in Libya’s crude oil production may be adding supply to a market with relatively high inventory levels, increased tropical storm and hurricane activity in the U.S. Gulf Coast contributed to significant inventory withdrawals in the United States and is contributing to a narrower contango. In October, rising U.S. petroleum consumption, shutdowns on offshore crude oil production platforms, and lower refinery output in the U.S. Gulf Coast contributed to total U.S. commercial crude oil and petroleum products inventories drawing at a rate of more than 1.3 million b/d, the largest withdrawal rate for any month since February 2007.



Source: CME Group and Intercontinental Exchange, as compiled by Bloomberg L.P.
Note: WTI=West Texas Intermediate.

Crude oil price spreads: A combination of crude oil supply disruptions in the U.S. Gulf Coast and voluntary production reductions from OPEC+ producers of primarily medium-sour crude oils have contributed to higher price spreads for Mars (a medium-sour U.S. Gulf Coast crude oil) compared with light-sweet crude oils in recent months. Mars and other medium-sour crude oils

are popular with complex refiners along the U.S. Gulf Coast, and its price spread with light-sweet crude oils (such as Light Louisiana Sweet (LLS) and Brent) can affect crack spreads and refinery purchasing decisions. The five-day moving average of the Mars-LLS price spread has traded at a premium several times in 2020 and settled at -95 cents/b on November 5, and the Mars-Brent spread settled at -80 cents/b (Figure 3).

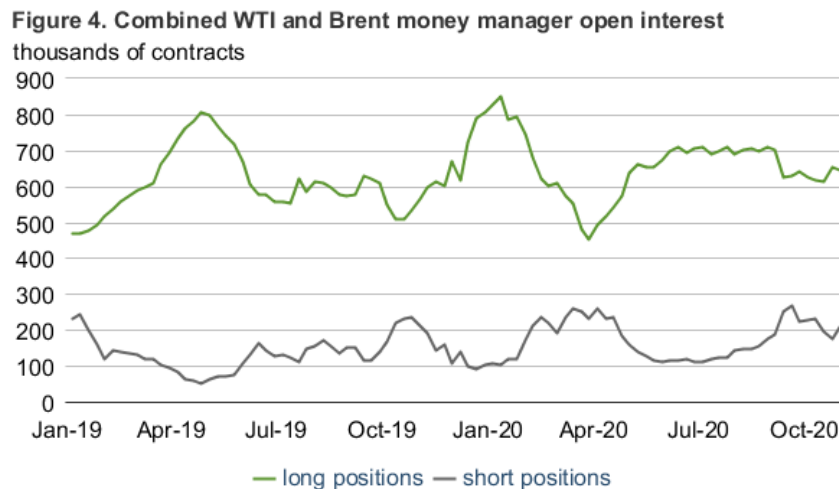


Source: Bloomberg L.P.
Note: LLS=Light Louisiana Sweet.

An active [tropical storm and hurricane](#) season in the U.S. Gulf Coast has contributed to several personnel evacuations and well shut-ins on offshore platforms, which continued into October following Hurricanes Delta and Zeta. Aside from these supply disruptions, Mars and other medium-sour crude oil prices have increased relative to light-sweet crude oils more broadly since 2018. The largest voluntary [production reductions](#) from OPEC+ members have been from countries that produce mainly medium-sour crude oil, including Saudi Arabia and Russia. In addition, lower production from Iran and Venezuela since 2019 have contributed to the loss of medium and heavy crude oil production in those countries, adding further upward price premiums on available medium-sour crude oils like Mars. Year-to-date through November 5, 2020, the Mars-LLS spread averaged -98 cents/b, up from -\$3.35/b in 2018 and from -\$1.89/b in 2019, and the Mars-Brent spread has averaged -\$2.04/b year-to-date, up from -\$4.64/b in 2018 and from -\$3.24/b in 2019. Aside from the various supply-side factors contributing to higher medium-sour crude oil price spreads, increased [refining capacity](#) in Asia in recent years has also contributed to higher medium-sour crude oil prices because the capacity has broadly been designed to process medium-sour crude oil.

Money manager positions: Money managers that hold long positions in Brent and WTI futures contracts can often be an important source of liquidity in the futures market and can often trade indirectly with producers that short crude oil futures. As of October 2020, total open interest in Brent and WTI futures contracts has declined since each of their respective 2020 highs in April, and it is at about the same level as in October 2019. Among the various [trader classifications](#) the Commodity Futures Trading Commission (CFTC) determines, WTI long positions held by money

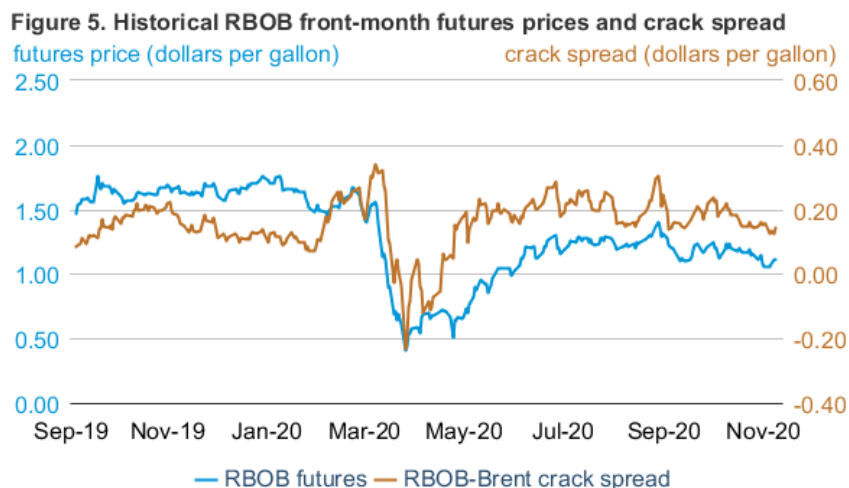
managers increased by more than any other trader’s position from the last week in October 2019 through October 27, 2020, increasing by more than 169,000 contracts (**Figure 4**). Brent money manager long positions, on the other hand, decreased by 86,000 contracts during the same period. The combined contracts’ money manager short positions nearly offset each other. WTI short positions decreased by 20,000 contracts, and Brent short positions increased by 19,000 contracts during the year. Money flowing into [exchange-traded funds](#) that hold WTI futures contracts reached record highs in the first quarter of 2020, and total assets under management remained at elevated levels, which partially explains the large increase in money manager WTI long positions.



Source: U.S. Commodity Futures Trading Commission, Intercontinental Exchange, as compiled by Bloomberg L.P.
Note: WTI=West Texas Intermediate.

Petroleum products

Gasoline prices: The front-month futures price of reformulated blendstock for oxygenate blending (RBOB, the petroleum component of gasoline used in many parts of the country) settled at \$1.12 per gallon (gal) on November 5, down 4 cents/gal from October 1, 2020 (**Figure 5**). The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) decreased by 4 cents/gal to settle at 14 cents/gal during the same period. The crack spread peaked on October 6 at 22 cents/gal and fell to 12 cents/gal on November 2.



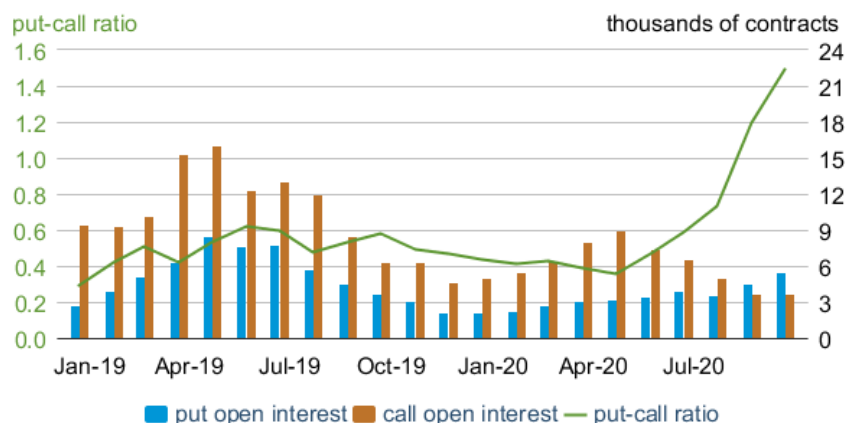
Source: CME Group, as compiled by Bloomberg L.P.
 Note: RBOB=reformulated blendstock for oxygenate blending

Despite the futures price falling as low as \$1.05/gal on October 30, the lowest since May 29, and the crack spread decreasing throughout the month, the average crack spread in October remained within the five-year (2015–19) monthly range for the second consecutive month. One factor that likely supported gasoline crack spreads was reduced production due to temporary disruptions to refineries from Hurricanes [Delta](#), which shut in 62% of gasoline production at U.S. Gulf Coast refiners at its peak on October 9, and [Zeta](#), which shut in 58% of gasoline production at U.S. Gulf Coast refiners at its peak on October 28.

RBOB put-call ratio: The put-call ratio can provide insight into the expectations of market participants. Changes in the relationships between put and call options for RBOB contracts may indicate that market participants are concerned about the continuing economic effects of COVID-19. A put option increases in value when the underlying commodity price declines, and a call option increases in value when the underlying commodity price increases. The put-call ratio is calculated by dividing the open interest (number of contracts outstanding) of put options by the open interest of call options. Put and call options can be used for hedging or mitigating price risk among refiners or other traders.

The average monthly put-call ratio for all RBOB contracts from 2015 to 2019 was 0.53, meaning market participants held almost twice as many calls as puts. After eight consecutive months of ratios that were lower than the average, the ratio increased to higher than the average in July 2020 and has increased since. In September 2020, the ratio increased to 1.20, the first time since January 2018 that the ratio was higher than 1.0 and the highest ratio since April 2012. In October, the ratio increased further to a 10-year record of 1.49. Although overall open interest for both put options and call options are down in 2020, put option open interest has generally increased since May 2020, whereas call options have generally decreased during the same period (**Figure 6**).

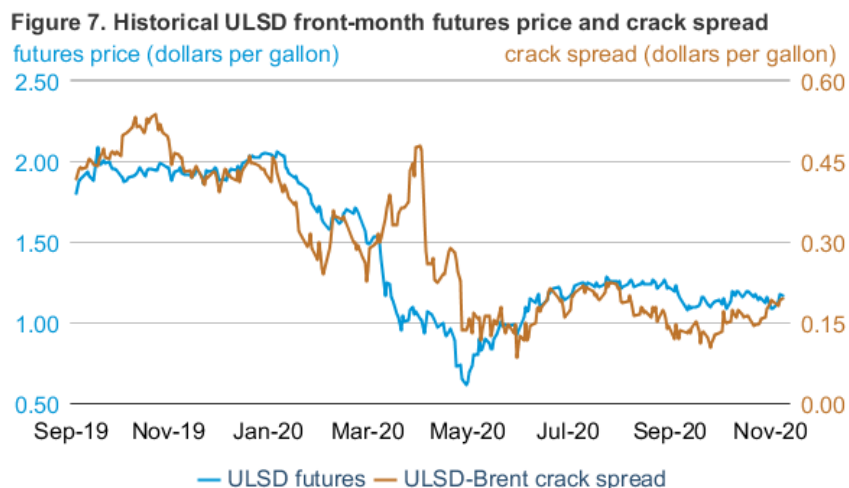
Figure 6. Put-call ratio on open interest for all RBOB contracts, monthly average



Source: CME Group, Bloomberg L.P.
 Note: RBOB=reformulated blendstock for oxygenate blending

For RBOB options as of October 2020, 61% of the put options and 78% of the call options were for the November and December 2020 contracts. The put-call ratio in October for November contracts was 0.90, and the ratio for December contracts was 1.32. In addition, 33% of the open interest on put options was for April contracts, the first contract for delivery of summer-grade gasoline. The put-call ratio of 21.46 for April RBOB contracts drove October’s put-call ratio to 1.49. A possible explanation for this phenomenon is that market participants are hedging against a potential continuation of economic effects of COVID-19 into the 2021 summer driving season. This trend of buying or holding April puts in October is not customary. In the previous three years, the open interest for April puts in October was 0.

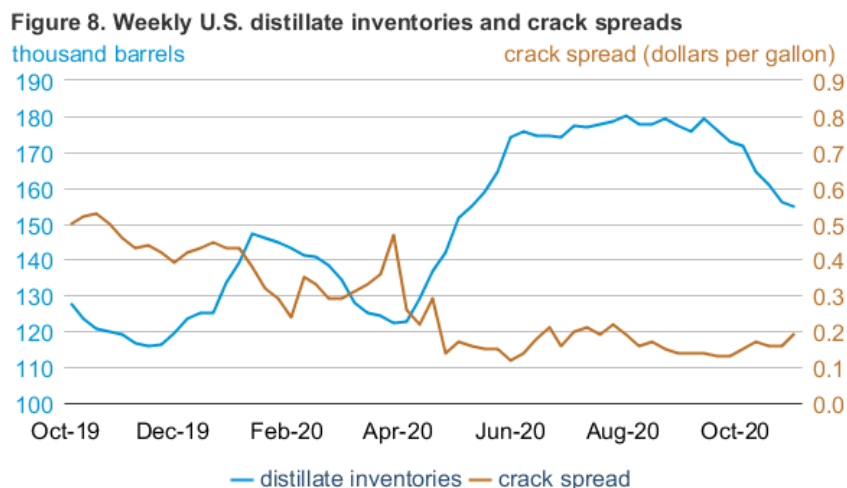
Ultra-low sulfur diesel prices: The ultra-low sulfur diesel (ULSD) front-month futures price for delivery in New York Harbor settled at \$1.17/gal on November 5, 2020, up 4 cents/gal from October 1, 2020 (Figure 7). The ULSD–Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) increased by 4 cents/gal to settle at 20 cents/gal during the same period.



Source: CME Group, as compiled by Bloomberg L.P.
 Note: ULSD=ultra-low sulfur diesel

Inventories of distillate fuel typically decline in the United States during October because U.S. distillate demand typically increases during the fall when diesel-powered agricultural equipment is used to harvest crops, the winter heating season begins, and many refineries reduce crude oil runs to perform maintenance. This year, U.S. distillate consumption increased by 0.4 million barrels per day (b/d) from September to 3.9 million b/d in October, which is more than the five-year (2015–19) average increase of 0.1 million b/d. Whereas in the past five years, the increase in consumption and decrease in inventories led to an average September to October increase of 1 cent/gal on the ULSD–Brent crack spread, this year the average crack spread increased by 3 cents/gal.

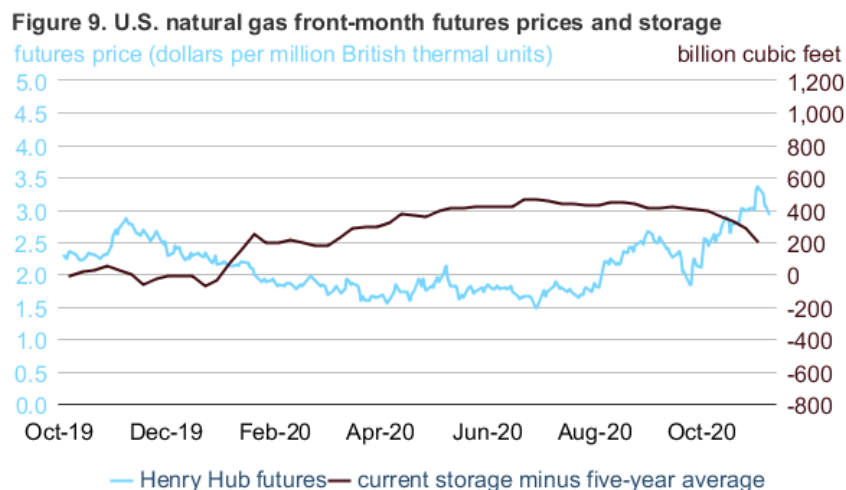
From the week ending October 4, 2019, to the week ending October 2, 2020, distillate inventories increased 44 million barrels (35%), contributing to a decrease in the monthly average crack spread from 51 cents/gal in October 2019 to 13 cents/gal in September 2020, a decrease of 38 cents/gal (Figure 8). Although the month-over-month withdrawal from September to October is typically high, averaging 8.7 million barrels the past five years, this October saw a monthly draw of 17.6 million barrels, which was the largest draw of any month since January 2003. These inventory draws can partially be explained by the decrease in distillate production because of refinery closures in response to Hurricanes Delta and Zeta. If confirmed by monthly data, October’s distillate production of 4.1 million b/d would be the lowest since February 2011. October’s decrease in distillate inventory was met with an increase in the ULSD–Brent crack spread from 15 cents/gal on October 1 to 19 cents/gal on October 30. EIA expects further inventory decreases in the winter and spring because of lower-than-average refinery distillate production and the U.S. Department of Agriculture’s forecast of a larger-than-usual harvest season this year for corn and soybeans.



eia Source: U.S. Energy Information Administration

Natural Gas

Prices: The front-month natural gas futures contract for delivery at the Henry Hub settled at \$2.94 per million British thermal units (MMBtu) on November 5, up 42 cents/MMBtu from October 1 (**Figure 9**). The front-month contract changed from November to December delivery on October 29, 2020, and that change contributed 30 cents/MMBtu to the front-month price increase. When the front-month futures price settled at \$3.02/MMBtu on October 21, 2020, it was the first time that the front-month price had risen higher than \$3.00/MMBtu since January 25, 2019.

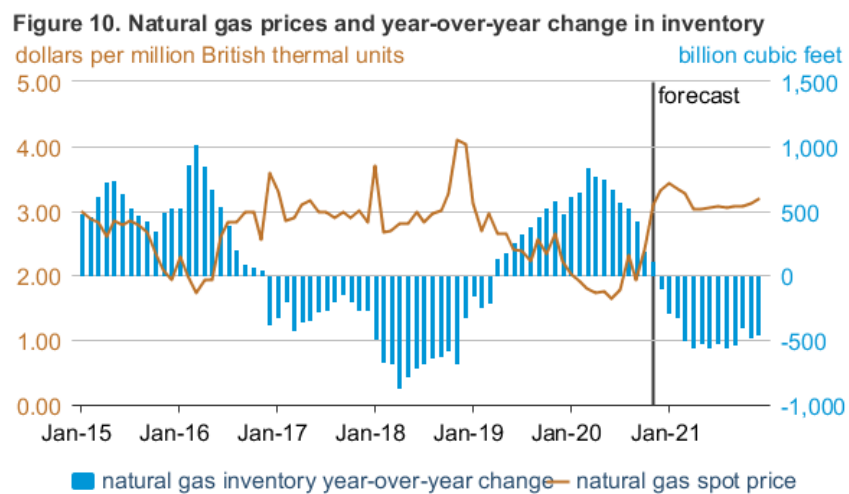


eia Source: U.S. Energy Information Administration, CME Group, as compiled by Bloomberg L.P.

Natural gas prices received support from higher U.S. LNG exports and lower natural gas production. EIA estimates that LNG exports rose to 7.2 billion cubic feet per day (Bcf/d) in October, an increase of 2.3 Bcf/d from the previous month and 1.5 Bcf/d from October 2019.

U.S. natural gas production decreased 0.7 Bcf/d in October from September, and it was 6.6 Bcf/d lower than October 2019 production. The reduction in year-on-year production in October 2020 contributed to the smallest increase in U.S. natural gas inventories in the month of October since 2002. Despite the decreased additions to storage, EIA estimates the level of natural gas inventories increased to the second-highest level on record at the end of October. Although high inventories tend to push prices lower, market participants appear to be focusing on expected changes in market balances over the next several months.

Natural gas prices and changes in inventory: EIA forecasts that natural gas inventories will decline by 2,419 Bcf from the end of October 2020 to the end of March 2021, which would be the third-largest decrease recorded during those months, and that monthly inventories will fall below the previous year’s levels by December 2020 (**Figure 10**). Decreasing natural gas production, which EIA forecasts will fall from November 2020 until May 2021, is one key factor affecting the decline in inventories, but EIA also forecasts that LNG exports will increase, rising to a record high in November 2020. Higher prices for natural gas and LNG in Europe and Asia are helping to boost U.S. LNG exports. Lower production and higher exports, combined with the usual seasonal increase in natural gas consumption, will contribute to the rapid decline in inventories during the winter. This expected change in market fundamentals contributed to the large increase in natural gas prices in October and contributed to EIA’s forecast of higher natural gas prices in 2021 compared with 2020.



 Source: U.S. Energy Information Administration and Refinitiv

Notable forecast changes

- EIA forecasts U.S. gasoline consumption will average 8.4 million barrels per day (b/d) in the fourth quarter of 2020 and 8.7 million b/d in the first half of 2021. Those forecasts are 0.3 and 0.2 million b/d less, respectively, than forecast in the October STEO.
- EIA forecasts OPEC crude oil production will average 25.4 million b/d in the fourth quarter of 2020 and 27.9 million b/d in the first half of 2021, which are 0.3 million b/d and 0.5 million b/d lower than previously forecast. The reduced forecast reflects less production in response to lower forecast global oil consumption, as EIA forecasts closer adherence to announced production targets from OPEC.
- This edition of the STEO incorporates revised historical data for electricity consumption and supply in 2019 and in 2020. Most of these data are relatively similar to the data published in the October STEO. However, retail sales of electricity to the industrial sector for 2019 are about 5% higher than previously estimated, and 2020 retail sales are about 2% higher. As a result, the current STEO forecasts industrial electricity use will fall by 9% between 2019 and 2020 compared with a forecast decline of 6% in the previous 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 United States 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.