



Short-Term Energy Outlook (STEO)

Forecast highlights

Global liquid fuels

- Brent crude oil spot prices averaged \$59 per barrel (b) in January, up \$2/b from December 2018 but \$10/b lower than the average in January of last year. EIA forecasts Brent spot prices will average \$61/b in 2019 and \$62/b in 2020, compared with an average of \$71/b in 2018. EIA expects that West Texas Intermediate (WTI) crude oil prices will average \$8/b lower than Brent prices in the first quarter of 2019 before the discount gradually falls to \$4/b in the fourth quarter of 2019 and through 2020.
- EIA estimates that U.S. crude oil production averaged 12.0 million barrels per day (b/d) in January, up 90,000 b/d from December. EIA forecasts U.S. crude oil production to average 12.4 million b/d in 2019 and 13.2 million b/d in 2020, with most of the growth coming from the Permian region of Texas and New Mexico.
- Global liquid fuels inventories grew by an estimated 0.5 million b/d in 2018, and EIA expects they will grow by 0.4 million b/d in 2019 and by 0.6 million b/d in 2020.
- U.S. crude oil and petroleum product net imports are estimated to have fallen from an average of 3.8 million b/d in 2017 to an average of 2.4 million b/d in 2018. EIA forecasts that net imports will continue to fall to an average of 0.9 million b/d in 2019 and to an average net export level of 0.3 million b/d in 2020. In the fourth quarter of 2020, EIA forecasts the United States will be a net exporter of crude oil and petroleum products by about 1.1 million b/d.

Natural gas

- The Henry Hub natural gas spot price averaged \$3.13/million British thermal units (MMBtu) in January, down 91 cents/MMBtu from December. Despite a cold snap in late January, average temperatures for the month were milder than normal in much of the country, which contributed to lower prices. EIA expects strong growth in U.S. natural gas production to put downward pressure on prices in 2019. EIA expects Henry Hub natural gas spot prices to average \$2.83/MMBtu in 2019, down 32 cents/MMBtu from the 2018 average. NYMEX futures and options contract values for May 2019 delivery traded during the five-day period ending February 7, 2019, suggest a range of \$2.15/MMBtu to \$3.30/MMBtu encompasses the market expectation for May 2019 Henry Hub natural gas prices at the 95% confidence level.

- EIA forecasts that dry natural gas production will average 90.2 billion cubic feet per day (Bcf/d) in 2019, up 6.9 Bcf/d from 2018. EIA expects natural gas production will continue to rise in 2020 to an average of 92.1 Bcf/d.

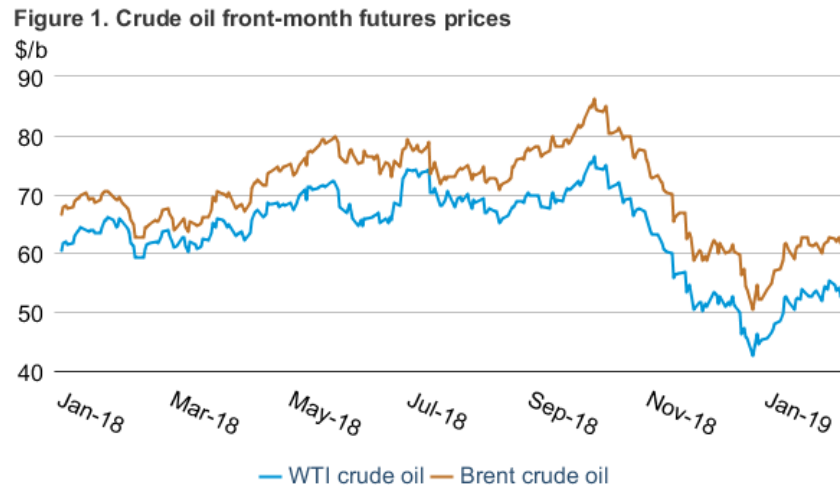
Electricity, coal, renewables, and emissions

- EIA expects the share of U.S. total utility-scale electricity generation from natural gas-fired power plants to rise from 35% in 2018 to 36% in 2019 and to 37% in 2020. EIA forecasts that the electricity generation share from coal will average 26% in 2019 and 24% in 2020, down from 28% in 2018. The nuclear share of generation was 19% in 2018 and EIA forecasts that it will stay near that level in 2019 and in 2020. The generation share of hydropower is forecast to average slightly less than 7% of total generation in 2019 and 2020, similar to last year. Wind, solar, and other nonhydropower renewables together provided about 10% of electricity generation in 2018. EIA expects them to provide 11% in 2019 and 13% in 2020.
- EIA expects average U.S. solar generation will rise from 265,000 megawatt-hours per day (MWh/d) in 2018 to 301,000 MWh/d in 2019 (an increase of 14%) and to 358,000 MWh/d in 2020 (an increase of 19%). These forecasts of solar generation include large-scale facilities as well as small-scale distributed solar generators, primarily on residential and commercial buildings.
- In 2019, EIA expects wind's annual share of generation will exceed hydropower's share for the first time. EIA forecasts that wind generation will rise from 756,000 MWh/d in 2018 to 859,000 MWh/d in 2019 (a share of 8%). Wind generation is further projected to rise to 964,000 MWh/d (a share of 9%) by 2020.
- EIA estimates that U.S. coal production declined by 21 million short tons (MMst) (3%) in 2018, totaling 754 MMst. EIA expects further declines in coal production of 4% in 2019 and 6% in 2020 because of falling power sector consumption and declines in coal exports. Coal consumed for electricity generation declined by an estimated 4% (27 MMst) in 2018. EIA expects that lower electricity demand, lower natural gas prices, and further [retirements of coal-fired capacity](#) will reduce coal consumed for electricity generation by 8% in 2019 and by a further 6% in 2020. [Coal exports](#), which increased by 20% (19 MMst) in 2018, decline by 13% and 8% in 2019 and 2020, respectively, in the forecast.
- After rising by 2.8% in 2018, EIA forecasts that U.S. energy-related carbon dioxide (CO₂) emissions will decline by 1.3% in 2019 and by 0.5% in 2020. The 2018 increase largely reflects increased weather-related natural gas consumption because of additional heating needs during a colder winter and for additional electric generation to support more cooling during a warmer summer than in 2017. EIA expects emissions to decline in 2019 and 2020 because of forecasted temperatures that will return to near normal. Energy-related CO₂ emissions are sensitive to changes in weather, economic growth, energy prices, and fuel mix.

Petroleum and natural gas markets review

Crude oil

Prices: The front-month futures price for Brent crude oil settled at \$61.63 per barrel (b) on February 7, an increase of \$6.72/b from January 2. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, increased by \$6.10/b during the same period, settling at \$52.64/b on February 7 (**Figure 1**).

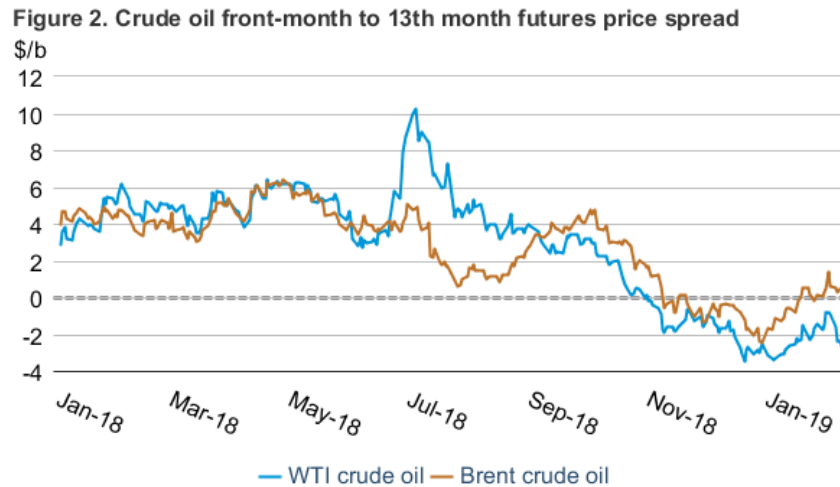


eia CME Group and Intercontinental Exchange, as compiled by Bloomberg L.P.

After two consecutive months of price declines, crude oil prices increased throughout January and into February as global oil supplies declined relatively quickly. The [agreement](#) among members of the Organization of the Petroleum Exporting Countries (OPEC) and several non-OPEC countries to reduce production by 1.2 million barrels per day (b/d) began in January. Saudi Arabia announced it was reducing production by more than it initially agreed, and unplanned supply outages have reduced production in Libya to about 0.8 million b/d, down from 1.2 million b/d in November. The province of Alberta also instituted its own production restraints, which EIA estimates contributed to a decline in Canada's supply of about 0.4 million b/d from December to January, adding further tightness to global oil supply. Although it did not cause any immediate loss to global oil availability, the United States [imposed sanctions](#) on Venezuela's state-owned oil company, PDVSA, in late January, which may disrupt regular trade flows and increase the risk for an oil supply outage.

The expectations for lower demand that contributed to falling prices in December may have ebbed slightly in January and provided some support to oil prices. The Bureau of Labor Statistics reported that [the United States added 304,000](#) jobs in January, which was larger than expected, and the Institute for Supply Management's (ISM) manufacturing Purchasing Managers' Index (PMI) increased to 56.6, signifying expansion in U.S. manufacturing activity.

STEO estimates that in February, total global petroleum inventories will fall by 1.3 million b/d, the largest drop since November 2017. Because of the increased short-term risks related to global crude oil supply, the Brent crude oil futures curve developed a slight backwardation (when near-term futures contracts are higher than longer dated ones) in January. The Brent and WTI 1st–13th futures contract price spread settled at 48 cents/b and $-\$2.65/b$, respectively, on February 7, an increase of $\$2.21/b$ and 69 cents/b since January 2, respectively (**Figure 2**).

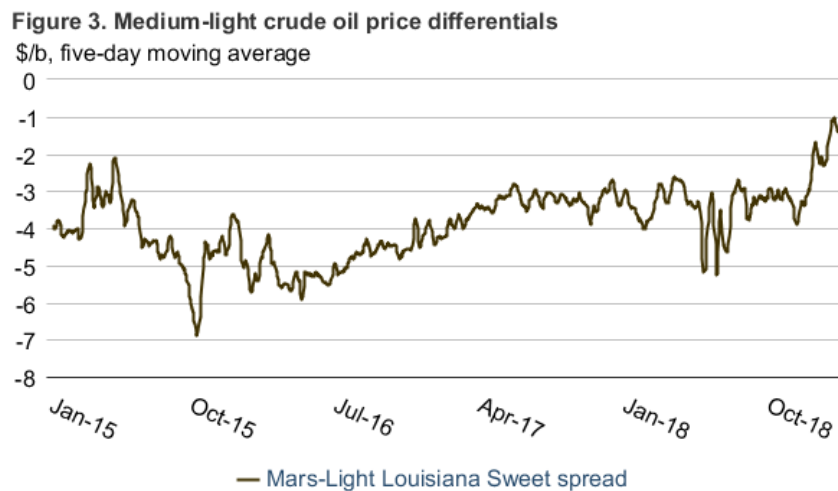


 CME Group and Intercontinental Exchange, as compiled by Bloomberg L.P.

Despite the forecast global oil inventory draws in February and lower forecast OPEC crude oil production in 2019 compared with the January STEO, EIA forecasts that U.S. crude oil production growth will offset decreases in OPEC production throughout the forecast. Even though recent economic data from the United States was positive, EIA (based on data from Oxford Economics) revised its forecast for global oil-weighted GDP growth down slightly from the January STEO. This revision, along with revisions to historical demand estimates that carried through to the forecast, contributed to a slight downward revision in the global oil consumption forecast. Given this forecast, EIA expects global petroleum stocks will build through 2019 and 2020 at a rate of 0.4 million b/d and 0.6 million b/d, respectively. Those builds are larger than forecast last month. As a result, EIA now forecasts Brent crude oil prices will average $\$61/b$ in 2019 and $\$62/b$ in 2020. The 2020 forecast is $\$3/b$ lower than in the January STEO.

Crude oil quality spreads: The reductions in oil production from OPEC countries and Canada and the threat of disruptions in Venezuela are likely increasing the price of medium and heavy crude oils compared with light crude oils. These countries tend to produce [medium and heavy grades of crude oil with higher sulfur content](#), so a large share of the global oil supply reductions in January has been of this quality. The price of Mars—a medium, sour crude oil produced in the U.S. Gulf of Mexico—has increased compared with light, sweet crude oils. The five-day moving average of the Mars–Light Louisiana Sweet (LLS) crude oil price spread narrowed to nearly $-\$1/b$ on January 29 and settled at $-\$1.38/b$ on February 7 (**Figure 3**). Mars traded on average at $\$3$ – $\$4/b$ lower than LLS throughout 2017–18. Typically, medium, sour crude oils like Mars sell at

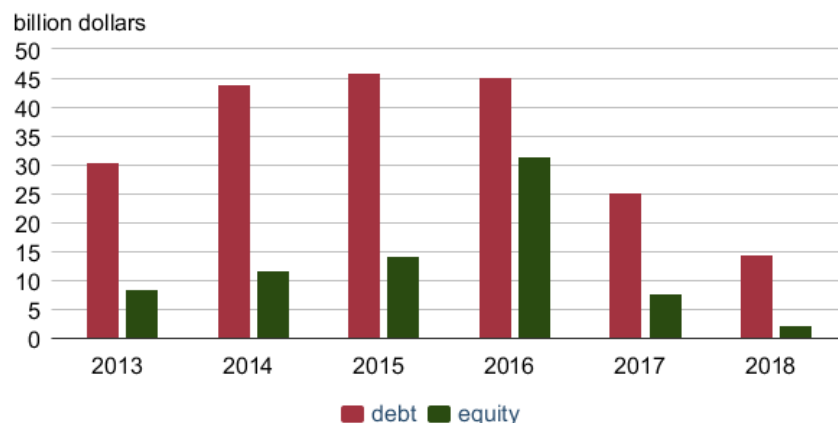
lower prices than light, sweet crude oils like LLS because they require more expensive refining equipment and operations to convert the oil into finished petroleum products.



eia Bloomberg L.P.

U.S. oil company debt and equity issuance: In 2018, publicly traded U.S. oil exploration and production companies issued the lowest amount of new funding since at least 2013, raising \$14 billion in debt and \$2 billion from public equity markets (**Figure 4**). Several factors likely contributed to reduced financing activity in 2018 compared with previous years. First, the relatively higher level of interest rates in 2018 contributed to a higher cost of issuing debt or equity for all companies, including oil companies. The U.S. Federal Funds rate averaged 1.8% in 2018, the [highest since 2008](#), and [energy sector bond yields](#) increased in the fourth quarter as crude oil prices declined. In addition to higher interest rates, oil companies may have needed less outside sources of capital than in previous years. Through third-quarter 2018, a group of 46 U.S. oil producers generated \$56 billion in cash flow from operating activities. The amount of cash flow from operations through the first three quarters of 2018 was higher than full-year amounts from 2015–17. As a result, full-year 2018 cash flow will likely be the highest annual total since 2014 for these companies. Collectively, they spent \$60 billion in capital expenditures and generated a net \$8 billion from asset sales. Because cash from operations plus asset sales exceeded capital expenditures, many companies may have had enough cash to fund their investing activities without the need to issue debt or equity.

Figure 4. U.S. exploration and production company debt and equity issuance

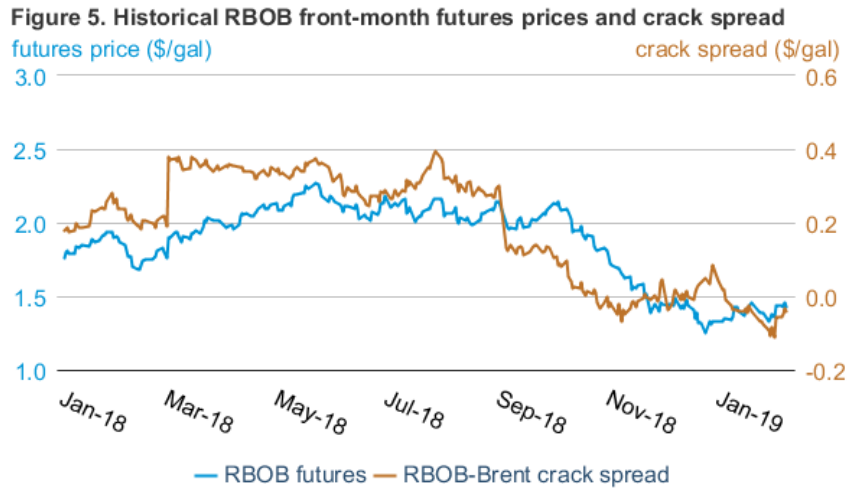


 U.S. Energy Information Administration, based on Evaluate Energy

Petroleum products

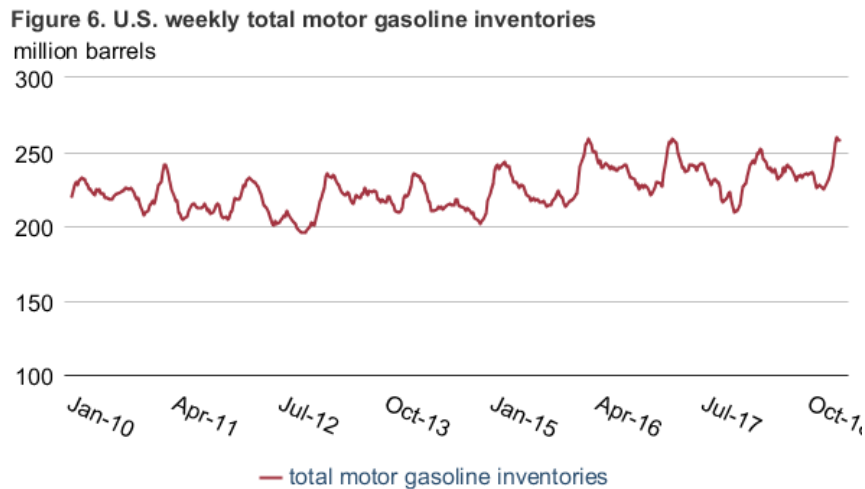
Gasoline prices: The front-month futures price of reformulated blendstock for oxygenate blending (RBOB, the petroleum component of gasoline used in many parts of the country) settled at \$1.43 per gallon (gal) on February 7 (**Figure 5**), an increase of 10 cents/gal from January 2. The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) decreased by 6 cents/gal to settle at -4 cents/gal during the same period.

From November through January, the RBOB–Brent crack spread was negative for 43 of the 62 trading days, a record amount of time the crack spread was negative for any three-month period since RBOB began trading in 2005. The low cracks spreads reflect relatively flat gasoline demand growth relative to strong supply globally, resulting in elevated inventory levels. Although gasoline crack spreads typically decline seasonally to the [lowest levels of the year](#) in the winter months, they tend to begin increasing in January. This year, however, the decline in the monthly average RBOB crack spread from December to January was the largest for that period since the RBOB contract began trading, falling by 7 cents/gal.



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

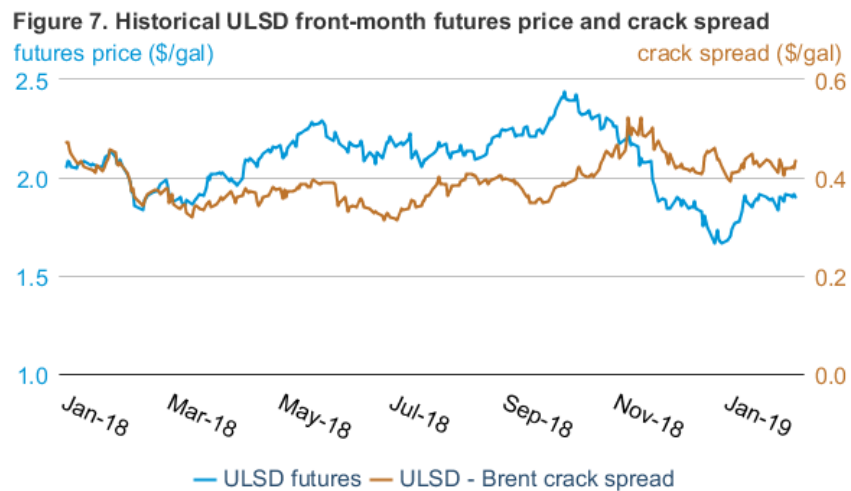
Gasoline inventories are high in every major storage hub globally and are likely contributing to low crack spreads. As of the first week of February, inventories were 15% and 24% higher than their five-year (2014–18) averages in Singapore and the Amsterdam, Rotterdam, and Antwerp (ARA) hubs, respectively. In the United States, gasoline inventories **reached an all-time high of nearly 260 million barrels** for the week ending January 18 (**Figure 6**), declining to 5% higher than the five-year average by February 1. Gasoline inventories and crack spreads could reverse in the coming months as refiners enter maintenance season and seasonal strength in gasoline consumption draws inventories.



eia U.S. Energy Information Administration, Weekly Petroleum Status Report

Ultra-low sulfur diesel prices: The ultra-low sulfur diesel (ULSD) front-month futures price for delivery in New York Harbor settled at \$1.90/gal on February 7 (**Figure 7**), an increase of 20 cents/gal from January 2. 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 43 cents/gal during the same period.

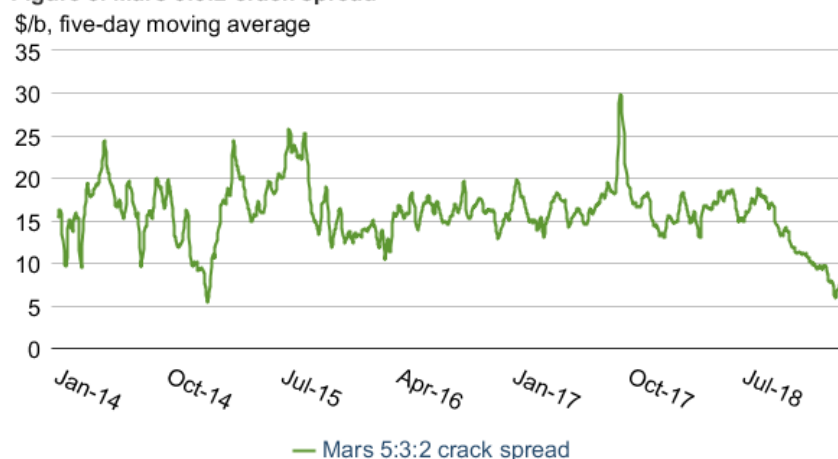


eia CME Group, as compiled by Bloomberg L.P., ULSD=ultra-low sulfur diesel

In contrast to gasoline inventories, distillate inventories remain comparatively low in global trading hubs, and low inventory levels are likely contributing to ULSD crack spreads remaining higher than the five-year average for January. In Singapore, ARA, and the United States, distillate inventories were 2%, 19%, and 4% lower than their five-year average levels, respectively, as of the first week of February. EIA estimates that U.S. distillate consumption was 4.3 million barrels per day (b/d) in January, 4% higher than the five-year average for the month.

U.S. Gulf Coast refinery margins: The recent increase in medium and heavy crude oil prices combined with low gasoline crack spreads is contributing to the lowest refinery margins for complex refiners in years. The five-day moving average of a 5:3:2 crack spread—refining three barrels of gasoline and two barrels of distillate from five barrels of Mars crude oil, which exemplifies a [complex](#) U.S. Gulf Coast refinery margin—reached \$5.89/b on January 29, the lowest price since December 2014 (**Figure 8**). The narrowing spreads of medium, sour crude oils with light, sweet crude oils—discussed in the crude oil section above—have increased the feedstock costs of some refiners, whereas negative gasoline crack spreads are also contributing to low refining margins. Comparatively high distillate crack spreads have supported total refinery margins. Individual refiners can, over time, adjust their feedstock slate and refinery output through operational changes in response to crude oil and petroleum product prices. Refining margins in the U.S. Gulf Coast are typically some of the highest in the world because they have [upgraded equipment](#) to refine lower-cost heavy crude oils into valuable refined products, among other factors.

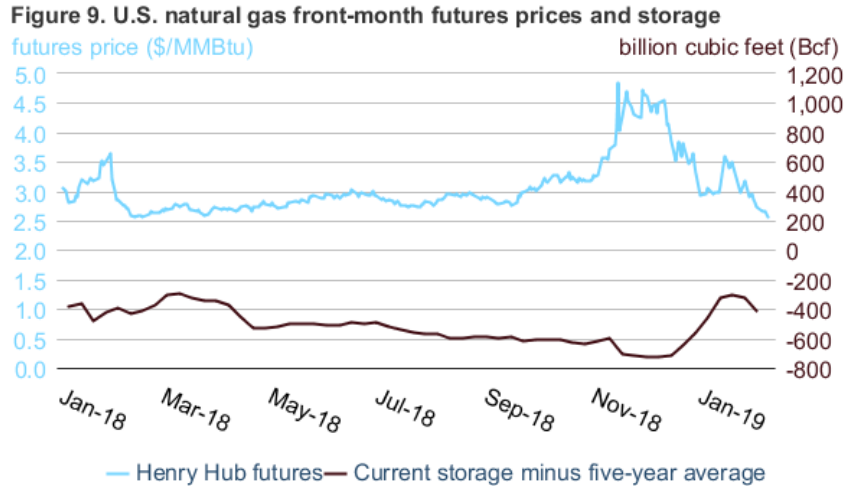
Figure 8. Mars 5:3:2 crack spread



eia Bloomberg L.P.

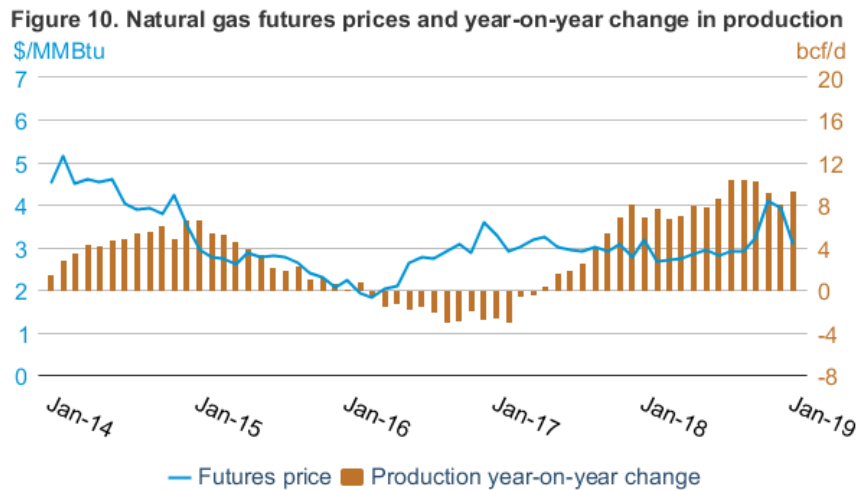
Natural Gas

Prices: The front-month natural gas futures contract for delivery at the Henry Hub settled at \$2.55/million British thermal units (MMBtu) on February 7, a decrease of 41 cents/MMBtu from January 2 (**Figure 9**). Temperatures were much warmer than normal across the Lower 48 states for the first three weeks of January, resulting in lower-than-normal heating degree days (HDD) and withdrawals from natural gas storage. The natural gas inventory deficit to the five-year (2014–18) average narrowed from 560 billion cubic feet (Bcf) on December 28, 2018, to 305 Bcf on January 18, 2019. A polar vortex during the last few days of January in the Midwest and Northeast significantly increased HDD and natural gas demand in residential and commercial sectors. PointLogic Energy estimated that U.S. residential and commercial sector natural gas consumption on January 30 was the [second-highest amount](#) ever recorded. The colder weather prompted higher-than-normal withdrawals from natural gas underground storage at the end of January. This change contributed to a sharp, but relatively brief, increase in natural gas futures prices in the second half of January. By the first week of February, prices had returned to levels last seen in February 2018.



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

U.S. natural gas production: Total U.S. dry natural gas production reached an estimated 87 billion cubic feet per day (Bcf/d) in January, 9.4 Bcf/d higher than year-ago levels. Front-month natural gas futures prices during this period of production growth have not experienced a decline with increased production, as occurred in 2014 and 2015 (**Figure 10**), most likely because of lower-than-average inventory levels. Higher domestic and international demand helped to keep inventories well below the five-year average for the past year.



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

Notable forecast changes

- EIA forecasts Brent and West Texas Intermediate crude oil spot prices will average \$62 per barrel (b) and \$58/b, respectively, in 2020, which are both \$3/b lower than in the January STEO. The lower price reflects the expectation of looser global oil market balances in 2020 compared with last month's outlook. Global oil supply was revised up for 2020, largely as a result of higher forecast crude oil production in the United States. At the same time, global oil demand for 2020 is slightly lower than previously forecast because of lower forecast global GDP growth.
- EIA forecasts U.S. crude oil production to average 12.4 million barrels per day (b/d) in 2019 and 13.2 million b/d in 2020, which are both more than 0.3 million b/d higher than in the January forecast. The forecast reflects an assumption of more productive wells both in the Permian Basin and in the Gulf of Mexico. The updated well productivity resulted from adjustments made because of incoming data during the month. In addition, EIA's assumptions of pipeline constraints in the Permian Basin do not moderate production growth in that area as much as previously forecast.
- For more information, see the [detailed table of STEO forecast changes](#).

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