Independent Statistics & Analysis
U.S. Energy Information Administration

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Short-Term Energy Outlook (STEO)

Forecast highlights

- Benchmark North Sea Brent crude oil spot prices averaged $46 per barrel (b) in June, a $4/b decrease from the May average and the lowest monthly average since November of last year when prices averaged $45/b.

- Brent crude oil prices are forecast to average $51/b in 2017 and $52/b in 2018, $2/b and $4/b lower than projected in last month's STEO, respectively. Average West Texas Intermediate (WTI) crude oil prices are forecast to be $2/b lower than the Brent price in both 2017 and 2018. NYMEX contract values for October 2017 delivery that traded during the five-day period ending July 6 suggest that a range of $36/b to $60/b encompasses the market expectation for WTI prices in October 2017 at the 95% confidence level.

- U.S. regular gasoline retail prices averaged $2.35 per gallon (gal) in June, down 4 cents/gal from the average in May. During the April-through-September summer driving season of 2017, U.S. regular gasoline retail prices are forecast to average $2.38/gal, 15 cents/gal higher than last summer. U.S. regular gasoline retail prices are forecast to average $2.32/gal in 2017 and $2.33/gal in 2018.

- U.S. crude oil production averaged an estimated 8.9 million barrels per day (b/d) in 2016 and is forecast to average 9.3 million b/d in 2017. EIA forecasts production to average 9.9 million b/d in 2018, which would mark the highest annual average production in U.S. history, surpassing the previous record of 9.6 million b/d set in 1970.

- Dry natural gas production is forecast to average 73.3 billion cubic feet per day (Bcf/d) in 2017, a 1.0 Bcf/d increase from the 2016 level. Forecast dry natural gas production increases by an average of 3.1 Bcf/d in 2018.

- Natural gas storage injections typically occur from April through the first half of November. EIA projects that natural gas inventories will be 3,940 Bcf at the end of October 2017, which would be 2% higher than the five-year average but 2% lower than the record high end-of-October level from 2016.

- Henry Hub natural gas spot prices are forecast to average $3.10 per million British thermal units (MMBtu) in 2017 and $3.40/MMBtu in 2018, compared with a 2016 average of $2.51/MMBtu, which was the lowest annual average price since 1999.

- EIA expects the share of U.S. total utility-scale electricity generation from natural gas to fall from 34% in 2016 to 31% in both 2017 and 2018 as a result of higher expected natural gas prices and higher electricity generation from renewable sources. Coal's forecast generation share rises from 30% in 2016 to 31% in both 2017 and 2018. Nonhydropower renewables are forecast to provide 9% of electricity generation in 2017 and nearly 10% in 2018. The generation share of hydropower is forecast to be about 7% in both 2017 and 2018. The nuclear share of generation remains just under 20% in both 2017 and 2018.

- After declining by 1.7% in 2016, energy-related carbon dioxide ($CO2$) emissions are forecast to decrease by 0.6% in 2017 and increase by 1.7% in 2018. Energy-related $CO2$ emissions are sensitive to changes in weather, economic growth, and energy prices.

Global Liquid Fuels

EIA estimates that global petroleum and other liquid fuels inventory builds averaged 0.3 million barrels per day (b/d) in 2016, marking the third consecutive year of inventory builds. However, global oil markets are expected to be in closer balance during the next 18 months. Global liquid fuels inventories are expected to decline by an average of 0.1 million b/d in 2017 and to increase by an average of 0.2 million b/d in 2018.

Global Petroleum and Other Liquid Fuels Consumption. Global consumption of petroleum and other liquid fuels averaged 96.9 million b/d in 2016, an increase of 1.5 million b/d from the 2015 level. Consumption growth is expected to be 1.5 million b/d in 2017 and 1.6 million b/d in 2018, with 1.2 million b/d of the growth in both years coming from countries outside of the Organization for Economic Cooperation and Development (OECD). Forecast growth in the consumption of hydrocarbon gas liquids (HGL) is an important driver of overall growth in global liquid fuels consumption.

China and India are expected to be the largest contributors to non-OECD liquid fuels consumption growth. China's consumption growth is forecast to average more than 0.3 million b/d in both 2017 and 2018, and it is driven by increased use of gasoline, jet fuel, and HGL. Last year's significant rise in the use of HGL in China will continue through 2017 and 2018, albeit at a reduced pace, as new propane dehydrogenation (PDH) plants contribute to rising propane use. Diesel consumption, which declined in 2016 as a result of a slowdown in industrial activity, is expected to be largely unchanged in the forecast.

In India, liquid fuels consumption is forecast to grow by 0.2 million b/d in 2017 and by almost 0.3 million b/d in 2018. The growth is expected to result from increased use of transportation fuels, of naphtha and ethane feedstock for new petrochemical projects, and of propane for residential purposes. The Indian government's currency demonetization program in late 2016 contributed to declines in India's oil consumption in the first quarter of 2017. However, as India's oil consumers adjusted to the currency changes, liquid fuels consumption began growing again in the second quarter of 2017.

For non-OECD countries excluding China and India, liquid fuels consumption is forecast to increase by about 0.6 million b/d in both 2017 and 2018. The Middle East and Africa are expected to account for most of this growth, which is expected to be partially offset by declining liquid fuels consumption in Brazil.

OECD petroleum and other liquid fuels consumption rose by 0.4 million b/d in 2016. In 2017, EIA forecasts OECD consumption growth to average 0.3 million b/d, as consumption growth in Europe slows. For 2017, forecast liquid fuels consumption growth of 0.3 million b/d in the United States, including 0.1 million b/d of HGL, and 0.1 million b/d in Europe is partially offset by declining consumption in Japan.

In 2018, OECD consumption growth is expected to return to 0.4 million b/d, with the United States accounting for nearly all of this increase. Forecast U.S. growth is mainly the result of increased use of HGL, which is expected to increase by almost 0.3 million b/d. Rising ethane consumption accounts for almost all of this increase, as new ethane crackers are expected to come online during the forecast period.

Non-OPEC Petroleum and Other Liquid Fuels Supply. EIA estimates that petroleum and other liquid fuels production in countries outside of the Organization of the Petroleum Exporting Countries (OPEC) decreased by 0.6 million b/d in 2016, with more than half of the decrease occurring in North America. However, EIA expects non-OPEC production to rise by 1.0 million b/d in 2017 and by 1.2 million b/d in 2018, as total U.S. liquid fuels production increases by 0.8 million b/d and by 1.0 million b/d, in those respective years, in response to rising oil prices and increases in drilling productivity.

Among non-OPEC producers, other than the United States, declining liquids production in some areas is expected to be countered by rising production in other areas, with total liquid fuels production rising by 0.2 million b/d in both 2017 and 2018. Some of the largest declines are expected to be in Mexico and in China. However, EIA expects production growth in Canada, Brazil, and Kazakhstan to contribute to overall non-OPEC increases.

Growth in Canada's total liquid fuels production is expected to average 0.2 million b/d in 2017 and 0.1 million b/d in 2018. This growth reflects new oil sands projects beginning operation at Meadow Creek and Kirby North and the expansion of oil sands operations at several other projects.

Growth in Brazil's total liquid fuels production is expected to average 0.2 million b/d in 2017 and 0.1 million b/d in 2018. Brazil's production growth is expected to be driven by the commissioning of a number of floating production, storage, and offloading (FPSO) facilities in the presalt fields in the Santos basin. In May, Petrobras began operations at the P-66 FPSO, which added 150,000 b/d of production capacity at the Lula South presalt field. In addition, Petrobras plans to start production at the P-67 FPSO at the Lula North field in the third quarter of 2017, and several other FPSO facilities are expected to come online in 2018.

Kazakhstan is expected to be a notable source of non-OPEC production growth throughout the forecast period, with increases in annual average production projected to be 0.2 million b/d and 0.1 million b/d in 2017 and 2018, respectively. The increase in output is the result of rising production at the giant Kashagan field.

Non-OPEC unplanned production outages in June were about 0.6 million b/d, which is 0.1 million b/d lower than the May level, as Canadian oil production returned following fire-related outages at a Syncrude oil production facility in Alberta. Outages during the first half of 2017 averaged almost 0.6 million b/d, about 0.1 million b/d higher than the 2016 average.

OPEC Petroleum and Other Liquid Fuels Supply. Starting with this STEO, both historical and forecast OPEC production values include Equatorial Guinea. In the first half of 2017, Equatorial Guinea produced about 130,000 b/d of crude oil on average.

OPEC crude oil production averaged 32.7 million b/d in 2016, an increase of 1.0 million b/d from 2015, led by rising production in Iran, Iraq, and, to a lesser extent, Saudi Arabia. OPEC crude oil production is expected to fall by 0.2 million b/d in 2017, as OPEC members have limited production based on the November 2016 agreement. In May 2017, this agreement was extended through the first quarter of 2018. EIA's forecast assumes a further extension of the agreement in 2018 but with lesser compliance. Without a further extension of the agreement, EIA would expect larger inventory builds in 2018 than are included in this forecast.

EIA expects that OPEC crude oil output will rise by 0.5 million b/d in 2018, driven by an increase in output in Iraq. The increase in Iraq's production in 2018 is expected to result from production coming online that was previously scheduled for 2017.

In both 2017 and 2018, EIA expects crude oil production to increase in Libya and Nigeria, which are countries not covered by the supply reduction agreement. In Libya, previously shut-in fields have seen rapid increases in output since the third quarter of 2016. Libya's production reached more than 1.0 million b/d in early July.

OPEC noncrude liquids production averaged 6.6 million b/d in 2016 and is forecast to increase by 0.4 million b/d in 2017 and by 0.2 million b/d in 2018, led by increases in Iran and Qatar.

OPEC unplanned crude oil supply disruptions averaged nearly 1.4 million b/d in June, down almost 0.2 million b/d from the May level. Outages in Libya decreased in June because of the reopening and continued ramp-up of the oil fields in the country. Although Libya's production trajectory has been mostly upward, output during May and June were volatile, with unplanned maintenance, industrial action, and power failures all contributing to outages. Nonetheless, Libya's crude oil production averaged 0.9 million b/d in June, the highest level since October 2014.

Unplanned oil production outages in Nigeria also decreased in June, as Forcados crude oil resumed production following nearly six months offline. Forcados production is typically about 0.2 million b/d, and although cargoes have begun loading Forcados crude oil, EIA expects the full return of the stream to occur sometime in the fourth quarter of 2017. For June 2017, EIA estimates that roughly half of the Forcados volume resumed production.

Average OPEC surplus crude oil production capacity is expected to be 2.1 million b/d in 2017 and 1.4 million b/d in 2018. Surplus capacity is typically an indicator of market conditions, and surplus capacity below 2.5 million b/d indicates a relatively tight oil market. However, high current and forecast levels of global oil inventories make the forecast low surplus capacity less significant.

OECD Petroleum Inventories. EIA estimates that OECD commercial crude oil and other liquid fuels inventories were 2.97 billion barrels at the end of 2016, equivalent to roughly 65 days of consumption.

Forecast OECD inventories rise to 2.99 billion barrels at the end of 2017 and to 3.03 billion barrels at the end of 2018.

Crude Oil Prices. The monthly average spot price of Brent crude oil decreased by $4 per barrel (b) in June to $46/b, marking the first month of 2017 in which Brent crude oil spot prices averaged below $50/b. The return of 0.1 million b/d of combined crude oil production in Libya and Nigeria contributed to lower oil prices in June, as did builds in total U.S. crude oil and petroleum products inventories that were above the five-year average during the weeks ending June 2 and June 9. Also, Brent crude oil spot prices declined by nearly 5% in late May following the news of the OPEC agreement that extended production cuts through the first quarter of 2018, as some market participants had anticipated more aggressive cuts.

EIA forecasts the annual average Brent crude oil spot price to be $51/b in 2017 and $52/b in 2018. Global oil inventories are forecast to be relatively unchanged in the second half of 2017 before returning to average inventory builds of 0.2 million b/d in 2018. Given this expectation of relative balance in the global oil market through the forecast period, Brent crude oil spot prices are expected to remain fairly flat in the coming months.

EIA forecasts the Brent price to average $50/b during the second half of 2017 and first half of 2018. Daily and monthly average prices could vary significantly from this target, because global economic developments and geopolitical events in the coming months have the potential to push oil prices higher or lower than the current STEO price forecast. Uncertainty remains regarding the duration of, and adherence to, the current OPEC production cuts, which could influence prices in either direction. Also, the U.S. tight oil sector continues to be dynamic, and quickly evolving trends in this sector could affect both current prices and expectations for future prices. However, lasting upward and downward price movements could be limited over the next year because U.S. tight oil producers have locked in higher production levels at the higher oil prices seen in early 2017.

Some upward price pressures could emerge in the second half of 2018 if global oil inventories decline during that period and if the market expects global oil inventory withdrawals heading into 2019. EIA forecasts Brent crude oil prices to average $53/b during the second half of 2018, with prices rising to $55/b by the end of 2018.

Average West Texas Intermediate (WTI) crude oil prices are forecast to be $2/b lower than Brent prices in 2017 and in 2018. The slight price discount of WTI to Brent in the forecast is based on the assumption that rising U.S. crude oil production will result in WTI-priced U.S. crude oil exports competing with international volumes priced off of Brent in global crude oil markets.

The current values of futures and options contracts suggest uncertainty in the oil price outlook. WTI futures contracts for October 2017 delivery that were traded during the five-day period ending July 6 averaged $46/b, and implied volatility averaged 29%. These levels established the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in October 2017 at $36/b and $60/b, respectively. The 95% confidence interval for market expectations widens slightly over time, with lower and upper limits of $32/b and $67/b for prices in December 2017.

In July 2016, WTI for October 2016 delivery averaged $49/b, and implied volatility averaged 37%, with the corresponding lower and upper limits of the 95% confidence interval at $35/b and $67/b.

U.S. Liquid Fuels

Consumption. Total U.S. petroleum and other liquid fuels consumption is forecast to average 19.9 million barrels per day (b/d) in 2017, which would be an increase of 310,000 b/d (1.6%) compared with the 2016 level. Consumption is then forecast to grow by 360,000 b/d (1.8%) in 2018. The growth in both years is expected to be led by higher consumption of hydrocarbon gas liquids (HGL) and distillate fuel.

EIA forecasts HGL consumption growth to be the strongest among the liquid fuels. HGL consumption is expected to increase by 120,000 b/d (4.9%) in 2017 and by 250,000 b/d (9.6%) in 2018. This growth reflects an increase in ethylene-producing petrochemical plants that use ethane as their feedstock. Two new plants came online in the first half of 2017, and five more are expected to begin operating by the end of 2018.

After a decline in 2016, distillate consumption averaged 3.9 million b/d during the first half of 2017, an increase of 80,000 b/d from the same period a year earlier. The growth stemmed from an increase in on-road fuel use, oil and gas drilling activity fuel use, and industrial fuel use that was partially offset by a decrease in distillate use for home heating. Overall, distillate fuel consumption growth is forecast to accelerate in the second half of 2017, contributing to expected annual average growth of 90,000 b/d (2.2%) in 2017 followed by growth of 100,000 b/d (2.6%) in 2018.

Motor gasoline consumption is forecast to increase by 10,000 b/d (0.2%) in 2017, resulting in average consumption of slightly more than 9.3 million b/d for the year. In 2016, gasoline consumption increased by 1.6%. The slower forecast growth in gasoline consumption reflects slower expected growth in non-farm employment and disposable income and an expected increase in the retail price of gasoline. Gasoline consumption in 2018 is forecast to grow by 50,000 b/d (0.5%) from 2017 levels.

Jet fuel consumption increased by 100,000 b/d in the first quarter of 2017 compared with the same quarter in 2016, averaging 1.6 million b/d. However, year-over-year growth in jet fuel consumption is expected to slow heading into the summer travel season, resulting in overall growth of 40,000 b/d (2.4%) for 2017 followed by a decrease of 20,000 b/d (1.3%) in 2018. The expected slowing and subsequent decrease in jet fuel consumption is partially because of increases in the price of airline tickets and improvements in fuel efficiency.

Supply. EIA forecasts total U.S. crude oil production to average 9.3 million b/d in 2017, up 0.5 million b/d from 2016. In 2018, crude oil production is forecast to rise to an average of 9.9 million b/d. If achieved, forecast 2018 production would be the highest on record, surpassing the previous record of 9.6 million b/d set in 1970. The 2018 forecast is 0.1 million b/d lower than in last month's STEO because of lower forecast crude oil prices in late 2017 and in 2018.

U.S. crude oil production is forecast to reach 10.1 million b/d in December 2018, which would be 0.9 million b/d higher than the June 2017 level and a 1.4 million b/d increase since the end of 2016. Increased production from tight rock formations within the Permian and Eagle Ford regions in Texas and the Bakken region in North Dakota accounts for 1.1 million b/d of the expected 1.4 million b/d of crude oil production growth from the end of 2016 through the end of 2018. Most of the remaining 0.3 million b/d increase is expected to come from the Federal Gulf of Mexico, as seven new projects are expected to come online by the end of 2018.

The Permian region is expected to produce 2.9 million b/d of crude oil by the end of 2018, which is roughly a 0.5 million b/d increase from estimated June 2017 levels, and would represent about 30% of total U.S. crude oil production in 2018. The Permian region is the geographic area that predominately spans the Permian Basin of western Texas and southeastern New Mexico and covers 53 million acres. Within the Permian Basin are smaller sub-basins, including the Midland Basin and the Delaware Basin, all of which contain historically prolific non-tight formations as well as multiple prolific tight formations such as the Wolfcamp, Spraberry, and Bonespring. With the large geographic area of the Permian region and stacked plays, operators can continue to drill through several tight oil layers and increase production even with sustained WTI prices below $50/b.

The Eagle Ford region is expected to produce an average of 1.3 million b/d in both 2017 and 2018, up from 1.2 million b/d in late 2016. Crude oil production in this region had been generally declining since early 2015, dropping from an average of 1.7 million b/d to less than 1.2 million b/d by November 2016. Similar to the Permian, Eagle Ford wells have high initial production rates and fast decline rates, requiring the continuous drilling of new wells to maintain production levels. Crude oil production growth in the Eagle Ford region is expected to be fairly limited for most of the next year because WTI crude oil prices are forecast to average below $50/b until the second half of 2018.

The Bakken region is expected to produce an average of 1.1 million b/d in 2017 and 2018, slightly lower than the 1.2 million b/d produced in 2015. The Bakken region predominately spans the Williston Basin that contains the Bakken and Three Forks formations. Although the Bakken region is geographically large (23 million acres), it contains fewer identified prolific formations than the Permian region. Operators in this region also are affected by winter weather and have much greater transportation constraints in moving oil to refineries and markets. Some of these transportation constraints are expected to be resolved by the recent completion of the Dakota Access Pipeline. Bakken production has been generally decreasing since early 2015, but recent drilling activity suggests that this has already begun to turn around. With the WTI price expected to remain below $50/b until the second half of 2018, crude oil production from the Bakken region is forecast to remain relatively stable near 1.1 million b/d through 2018.

Gulf of Mexico production is forecast to average 1.7 million b/d in 2017, an increase of 0.1 million b/d from 2016, and then increase to 1.9 million b/d in 2018. The anticipated expansion of the Tahiti field and the start of production from the Horn Mountain Deep field in 2017 and the Big Foot and Stampede projects in 2018, along with other projects that will begin operations in 2017 and 2018, are expected to contribute to increases in production from the Gulf of Mexico.

Crude oil production in Alaska is expected to be unchanged in both 2017 and 2018 at almost 0.5 million b/d.

EIA projects HGL production at natural gas processing plants will increase by 0.3 million b/d in 2017 and by 0.4 million b/d in 2018. EIA expects higher ethane recovery rates in 2017 and 2018, following planned increases in demand for petrochemical plant feedstock in the United States and abroad. Recently opened terminals, a growing ship fleet, and pipeline expansions allow more U.S. ethane, propane, and butanes to reach international markets, with HGL net exports expected to increase by nearly 0.3 million b/d in 2017 and by 0.1 million b/d in 2018.

Product Prices. EIA expects the retail price of regular gasoline to average $2.38 per gallon (gal) during the 2017 summer driving season (April through September), 8 cents/gal lower than projected in last month's STEO, primarily as a result of lower crude oil prices. EIA expects that the U.S. monthly average retail price of regular gasoline decreased from an unseasonably early summer peak of $2.42/gal in April 2017 to $2.35/gal in June. Following an increase to an average of $2.38/gal in the third quarter, EIA expects retail gasoline prices to fall to $2.13/gal in December. The U.S. regular gasoline retail price, which averaged $2.15/gal in 2016, is forecast to average $2.32/gal in 2017 and $2.33 /gal in 2018.

Among the regions, annual average forecast prices for 2017 range from a low of $2.08/gal in the Gulf Coast—Petroleum Administration for Defense District (PADD) 3—to a high of $2.75/gal in the West Coast (PADD 5).

The diesel fuel retail price averaged $2.31/gal in 2016, which was the lowest annual average since 2004. The diesel price is forecast to average $2.59/gal in 2017 and $2.71/gal in 2018, driven higher primarily by higher crude oil prices and growing diesel consumption. Rising diesel consumption is expected to contribute to gradually increasing diesel refinery margins. Diesel refinery margins based on Brent crude oil are expected to average 39 cents/gal in 2017 and 43 cents/gal in 2018, compared with an average of 34 cents/gal in 2016.

Natural Gas

Natural Gas Consumption. Total U.S. natural gas consumption averaged 75.1 billion cubic feet per day (Bcf/d) in 2016. It is forecast to decrease by 2.3 Bcf/d in 2017 and then increase by 2.7 Bcf/d in 2018. In 2017, decreases in total natural gas consumption are mainly attributable to lower electric power sector use, which is forecast to decrease by 2.6 Bcf/d (9.4%) in 2017 and then increase by 0.6 Bcf/d (2.4%) in 2018. The 2017 decline reflects competition from increasing renewable use (particularly hydropower) and competitive coal prices, along with overall lower electricity generation.

Based on forecasts by the National Oceanic and Atmospheric Administration (NOAA), EIA projects 2017 heating degree days (HDD) to be similar to 2016 levels. The first quarters of both years were warmer than normal. EIA expects combined residential and commercial natural gas consumption to be almost unchanged in 2017 compared with 2016 levels and then rise by 1.2 Bcf/d in 2018. Growth in 2018 is largely because of a forecast 8% increase in HDD, based on the NOAA forecast of a return to relatively normal temperatures.

Industrial sector consumption of natural gas increased by 2.2% in 2016, and it is forecast to increase by 1.4% in 2017 and by 2.6% in 2018. Most of the increase in the forecast is attributable to new chemical projects expected to come online. Low natural gas prices in recent years have made it economical to increase the use of natural gas as feedstock in ammonia for nitrogenous fertilizer and methanol manufacturers.

Natural Gas Production and Trade. EIA estimates that dry natural gas production averaged 72.5 Bcf/d in June, which is up 0.9 Bcf/d from the year-ago level. EIA expects production to rise through 2017 and 2018 in response to forecast price increases and large increases in liquefied natural gas (LNG) exports. Overall, EIA expects dry natural gas production to rise by 1.0 Bcf/d in 2017 and by 3.1 Bcf/d in 2018, annual increases of 1.4% and 4.3%, respectively.

Natural gas pipeline exports to Mexico have risen this year, and EIA expects that growth to continue as Mexico undergoes energy market reform. A relatively cheap natural gas export price, rising demand from Mexico, and increased pipeline takeaway capacity in both in the United States and Mexico have led to higher exports. Gross pipeline exports are expected to increase by 0.9 Bcf/d in 2017 and by 0.5 Bcf/d in 2018 to an average of 7.3 Bcf/d.

EIA projects LNG gross exports will average 1.9 Bcf/d in 2017, up from 0.5 Bcf/d in 2016. By the end of 2017, Trains 1 through 4 at Cheniere's Sabine Pass facility in Louisiana are expected to be fully operational, and Cove Point LNG in Maryland is expected to come online. EIA projects gross LNG exports to average 2.8 Bcf/d in 2018, as Sabine Pass and Cove Point ramp up capacity and two new LNG facilities come online. Cameron LNG Train 1 is scheduled to come online in July, followed by Train 2 in November, and Freeport LNG is scheduled to come online in November. Both facilities are along the U.S. Gulf Coast. Cameron LNG Trains 1 and 2 will add 1.1 Bcf/d of new liquefaction capacity, and Freeport Train 1 will add 0.7 Bcf/d of new capacity. The new Cameron and Freeport liquefaction facilities will require a few months to ramp up and are projected to operate below nameplate capacity in 2018.

Total U.S. natural gas imports averaged 8.2 Bcf/d in 2016, and they are expected to average 8.3 Bcf/d in 2017 and 8.8 Bcf/d in 2018.

EIA projects that the United States will become a net exporter of natural gas on average in 2017, with net exports expected to average 0.4 Bcf/d. As LNG exports increase, 2018 net exports are forecast to be 1.3 Bcf/d.

Natural Gas Inventories. Natural gas inventories reached a record high of 4,047 Bcf on November 11, 2016, and inventories ended the winter heating season at 2,072 Bcf in March 2017. Inventory builds have been slightly below average thus far during the injection season, and EIA expects inventories to be 3,940 Bcf at the end of October 2017, which would be 2% higher than the five-year average level for the end of October but 2% lower than the 2016 end-of-October level.

Natural Gas Prices. Henry Hub spot prices have been relatively flat in 2017, averaging \$3.04 per million British thermal units (MMBtu) during the first half of the year, which is the same as the fourth quarter of 2016 average price. Prices averaged \$2.98/MMBtu in June. Closer-to-normal winter temperatures are expected this winter following last year's warm winter, which contributes to growth in residential and commercial consumption. Also, export growth is forecast to increase in the second half of 2017 and in 2018. Both factors could contribute to modest upward price pressure. Forecast Henry Hub natural gas spot prices average \$3.10/MMBtu in 2017 and \$3.40/MMBtu in 2018.

Natural gas futures contracts for October 2017 delivery that were traded during the five-day period ending July 6 averaged $2.98/MMBtu. Current options and futures prices indicate that market participants place the lower and upper bounds for the 95% confidence interval for October 2017 contracts at $2.17/MMBtu and $4.08/MMBtu, respectively. Last year at this time, the natural gas futures contracts for October 2016 delivery averaged $2.88/MMBtu, and the corresponding lower and upper limits of the 95% confidence interval were $2.00/MMBtu and $4.14/MMBtu, respectively.

Coal

Coal Supply. EIA estimates that coal production declined by 169 million short tons (MMst) (19%) in 2016 to 728 MMst, the lowest level of coal production since 1978. In 2017, growth in coal-fired electricity generation and exports is expected to lead to an increase of 57 MMst (8%) in total U.S. coal production. Production in the Western region is forecast to increase by 26 MMst. Increases in production from the Appalachian region and the Interior region are expected to be 16 MMst and 15 MMst, respectively. In 2018, total coal production is expected to remain relatively unchanged, with declines in Appalachian region production offset by increases in Interior region and Western region production.

Electric power sector coal stockpiles were 166 million tons in April 2017 (the last actual data point), up 1% from the previous month. This increase in total coal stockpiles is normal during the spring when the power sector builds coal stockpiles for use during the summer months when demand for electricity is greater.

Coal Consumption. Electric power sector coal consumption is forecast to increase by 9 MMst (1%) in 2017, mostly because of rising natural gas prices. In 2018, demand for coal in the power sector is expected to increase by 2 MMst.

Coal Trade. Coal exports for the first quarter of 2017 were 58% higher than in the same quarter last year, with steam coal exports increasing by 6 MMst. The trend continued in April, with exports 58% higher than in April 2016. EIA expects growth in coal exports to slow in the coming months, with exports for all of 2017 forecast at 72 MMst, 12 MMst (19%) above the 2016 level. Exports are expected to be 63 MMst in 2018.

Atlantic and Gulf Coast electric power generators are forecast to generally maintain their current levels of coal imports, which are primarily from Latin America. Total U.S. imports are estimated to have been 10 MMst in 2016 and are forecast to remain between 9 MMst and 10 MMst in 2017 and 2018.

Coal Prices. EIA estimates the delivered coal price averaged $2.11 per million British thermal units (MMBtu) in 2016, which is 5% lower than the 2015 price. Coal prices are forecast to increase in 2017 and in 2018 to $2.15/MMBtu and $2.21/MMBtu, respectively.

Electricity

Electricity Consumption. According to the National Oceanic and Atmospheric Administration (NOAA), total U.S. cooling degree days (CDD) in the summer of 2016 (June, July, and August) surpassed the record set in the summer of 2011. NOAA projects U.S. CDD for the summer of 2017 will be about 9% lower than last summer, although still slightly above the average of the previous 10 summers.

Milder summer temperatures, which reduce the need for air conditioning, drive EIA's forecast that the average U.S. residential customer will consume 5% less electricity this summer compared with the same period last year. Forecast average residential electricity sales between June and August range from about 2,000 kilowatthours (kWh) per customer in the Pacific census division to about 4,400 kWh per customer in the West South Central division.

EIA expects annual retail sales of electricity to the residential sector in 2017 will be 2.3% lower than sales in 2016 as a result of lower electricity consumption in the first and third quarters. Forecast annual electricity sales to the commercial sector are relatively unchanged this year from the 2016 level, because the effect of lower electricity consumption from milder weather offsets increased sales resulting from economic growth. Industrial sector electricity sales are expected to grow by 1.1% in 2017 after declining by 5.4% last year.

Electricity Generation. In 2016, annual U.S. electricity generation from natural gas surpassed generation from coal-fired power plants, the first time this has happened based on data going back to 1949. Natural gas supplied an estimated 34% of total U.S. electricity generation in 2016 compared with 30% for coal. The increase in the share of generation fueled by natural gas last year was driven by sustained low prices for natural gas. The U.S. average price for natural gas delivered to electric generators was $2.88/million British thermal units (MMBtu) in 2016.

Natural gas prices have risen since last year, with the delivered price to electric generators averaging $3.58/MMBtu during the first half of 2017. EIA estimates that the share of total U.S. generation fueled by natural gas during the first half of this year averaged 29%, down from nearly 34% during the same period last year. In contrast, coal's share of generation rose from 28% in the first half of 2016 to 30% in first half of 2017. Another reason for the decline in natural gas generation so far this year is the strong increase in conventional hydroelectric generation, particularly in the western states. The share of total generation in the West census division supplied from hydropower averaged an estimated 32% in the first half of 2017, compared with 27% during the first half of last year.

EIA expects a less pronounced change in generation shares during the second half of 2017. Natural gas is expected fuel 33% of total U.S. generation in the second half of 2017, compared with 34% during the second half of 2016. The delivered natural gas price to electric generators is expected to average $3.60/MMBtu between July and December 2017, up 46 cents from the same period in 2016. Coal's share of generation in the second half of 2017 is relatively unchanged from the second half last year at 32%.

Natural gas and coal are expected to fuel about the same amount of generation in 2018, with each providing slightly more than 31% of total U.S. generation. Renewable energy sources other than hydropower are forecast to supply nearly 10% of U.S. generation in 2018, up from slightly more than 8% in 2016.

Electricity Retail Prices. EIA forecasts that the U.S. retail electricity price paid by residential customers will average 13.2 cents per kWh this summer, up 3.7% from last summer, reflecting the increase in cost of fuels for generating electricity, particularly natural gas. This increase in prices mostly offsets the expected decline in summer electricity consumption, so that the average residential customer's electricity bill this summer is forecast to be 1.3% lower than last year.

Renewables and Carbon Dioxide Emissions

Electricity Renewables Generation and Capacity. EIA expects total generation from renewables in the electric power sector to increase by 11% in 2017 and then remain relatively unchanged in 2018. Forecast electricity generation from hydropower increases by 13% in 2017 and decreases by 9% in 2018. This change in hydropower generation is the driver for the absence of overall renewable generation growth in 2018. Generation from renewable energy other than hydropower in the electric power sector is forecast to grow by 10% in 2017 and by 6% in 2018.

Beginning in this STEO, EIA is expanding its presentation of data and forecasts for renewable energy sources to include new forecasts of capacity and electricity generation from small-scale solar photovoltaic (PV) systems. Small-scale solar PV systems are defined in EIA publications as those smaller than 1 megawatt in size (as measured in alternating current) and are typically of the type installed on the rooftops of residences or businesses. The new small-scale solar PV forecasts are presented in a new table (Table 8b). This table also shows capacity and electricity generation estimates for large-scale power plants from all renewable technologies.

EIA estimates that total U.S. small-scale solar capacity was 13 gigawatts (GW) at the end of 2016. EIA expects that capacity to be 17 GW at the end of 2017 and to be 22 GW at the end of 2018.

EIA estimates that U.S. large-scale solar capacity totaled almost 22 GW at the end of 2016 and forecasts that by the end of 2018 that capacity is projected to rise to 32 GW. States leading in large-scale solar capacity additions are California, Nevada, North Carolina, and Texas. Forecast large-scale solar generation averages 1.5% of total U.S. electricity generation in 2018.

EIA estimates that U.S. large-scale wind capacity totaled 81 GW at the end of 2016, and by the end of 2018 that capacity is expected to rise to 102 GW. Forecast wind generation accounts for 6.4% of total generation in 2018.

Liquid Biofuels. In November 2016, the U.S. Environmental Protection Agency (EPA) finalized a rule setting Renewable Fuel Standard (RFS) volumes for 2017, and earlier this month released their proposed RFS volumes for 2018 and a proposed biomass-based diesel volume for 2019. EIA used both the final and proposed volumes to develop the current STEO forecast for 2017 and 2018. EIA expects that the largest effect of the current RFS targets will continue to be on biomass-based diesel consumption, which includes both biodiesel and renewable diesel and helps to meet the RFS targets for use of biomass-based diesel, advanced biofuel, and total renewable fuel. Biodiesel production averaged 101,000 barrels per day (b/d) in 2016, and it is forecast to increase to an average of 105,000 b/d in 2017 and to 109,000 b/d in 2018. Net imports of biomass-based diesel are expected to fall from 54,000 b/d in 2016 to 53,000 b/d in 2017 and then rise to 59,000 b/d in 2018.

Ethanol production averaged 1.0 million b/d in 2016 and is forecast to average slightly above 1.0 million b/d in 2017, which would be a record, before declining slightly in 2018. Ethanol consumption averaged about 940,000 b/d in 2016 and is forecast to increase slightly in both 2017 and 2018. This level of consumption results in the ethanol share of the total gasoline pool increasing to nearly 10.1% in both 2017 and 2018. Only marginal increases in higher-level ethanol blends are assumed to occur during the STEO forecast period.

Energy-Related Carbon Dioxide Emissions. EIA estimates that energy-related emissions of carbon dioxide decreased by 1.7% in 2016. Emissions are forecast to decrease by 0.6% in 2017 and increase by 1.7% in 2018. These forecasts are sensitive to assumptions about weather, economic growth, and fuel prices.

U.S. Economic Assumptions

Recent Economic Indicators. Real gross domestic product (GDP) increased at an annual rate of 2.1% in the fourth quarter of 2016 and 1.4% in the first quarter of 2017, according to the recent estimates released by the Bureau of Economic Analysis. The deceleration in real GDP in the first quarter primarily reflected a downturn in private inventory investment and a deceleration in personal consumption expenditures that were partly offset by an upturn in exports and an acceleration in nonresidential fixed investment.

Production, Income, and Employment. EIA used the June 2017 version of the IHS Markit macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

Real GDP is projected to increase 2.3% in 2017 and 2.6% in 2018 compared with the 1.6% increase in 2016. Real disposable income is projected to grow by 2.1% in 2017 and by 3.6% in 2018 compared with a 2.6% increase in 2016. Total industrial production is projected to increase by 2.2% in 2017 and by 2.8% in 2018, compared with a 1.2% decline in 2016. Projected growth in nonfarm employment averages 1.4% in 2017 and 1.1% in 2018, compared with growth of 1.8% in 2016.

Expenditures. Private real fixed investment is projected to grow by 5.2% in 2017 and by 4.3% in 2018, compared with 0.7% growth in 2016. Real consumption expenditures are projected to grow by 2.5% in 2017 and by 3.0% in 2018, compared with a 2.7% increase in 2016.

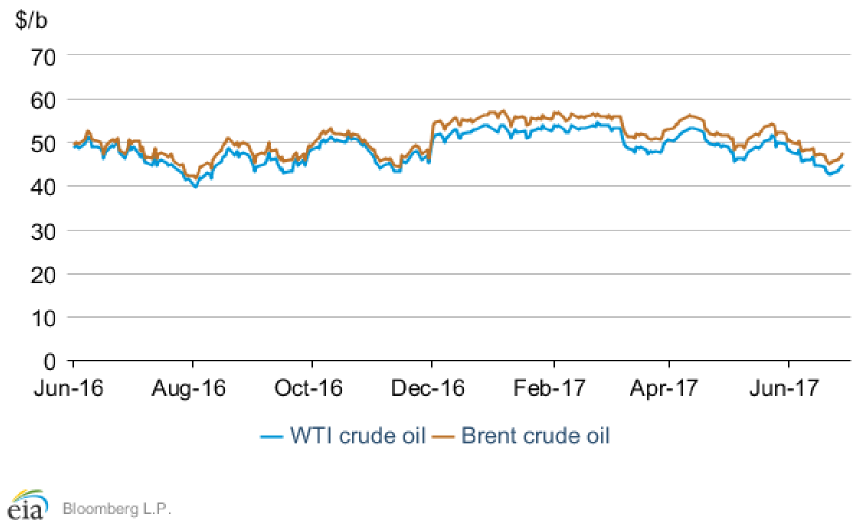
Exports are projected to grow by 2.4% in 2017 and by 2.1% in 2018, compared with 0.4% growth in 2016. Imports are projected to grow by 3.8% in 2017 and by 5.5% in 2018, compared with 1.1% growth in 2016. Total government expenditures are projected to increase by 0.1% in 2017 and by 0.9% in 2018, compared with 0.8% growth in 2016.

Petroleum and natural gas markets review

Crude oil

Prices: Brent and West Texas Intermediate (WTI) crude oil prices declined by $2.52 per barrel (b) and by $2.84/b, respectively, since June 1, with Brent front-month futures prices settling at $48.11/b and WTI settling at $45.52/b on July 6 **(Figure 1)**. June Brent and WTI monthly average spot prices were $3.96/b and $3.34/b lower, respectively, than the May averages.

Figure 1. Crude oil front-month futures prices



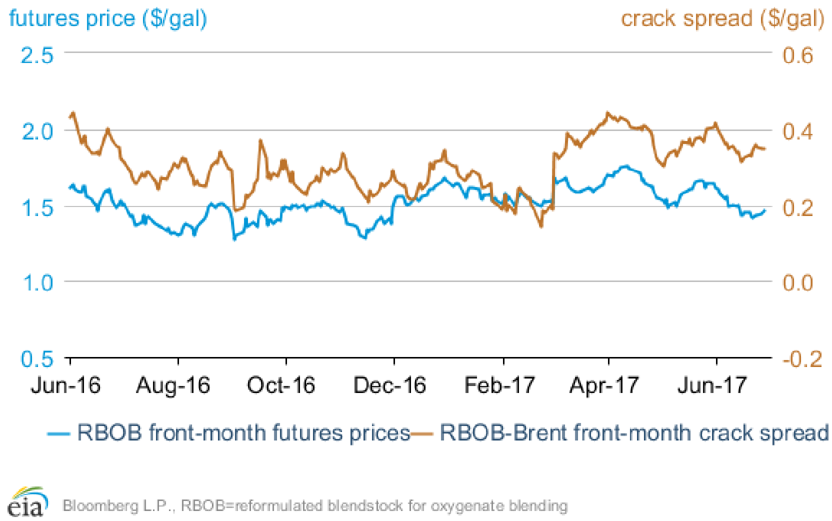
Crude oil prices reached their lowest levels year-to-date in late June. Prices fell after EIA's *Weekly Petroleum Status Report (*WPSR*)* reported builds in total U.S. crude oil and petroleum products inventories that were above the five-year average during the weeks ending June 2 and June 9. The build in total petroleum inventories for the week ending June 2 was the largest for any week since 2008. Also, rising Libyan and Nigerian production in June put downward pressure on prices. With production continuing to increase in the United States, total petroleum inventories in the Organization for Economic Cooperation and Development remained 9% above the previous five-year average at the end of June, despite the ongoing voluntary production cuts made by the Organization of the Petroleum Exporting Countries (OPEC).

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) declined by 7 cents per gallon (gal) from June 1, settling at $1.53/gal on July 6 **(Figure 2)**. The RBOB-Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) declined by 1 cent/gal over the same period, settling at 38 cents/gal on July 6.

Lower gasoline futures prices reflected lower crude oil prices, and crack spreads likely declined because of persistently high levels inventories during June. U.S. total motor gasoline inventories stood at 237.3 million barrels on June 30, according to the WPSR, which is near the five-year high for the last week of June.

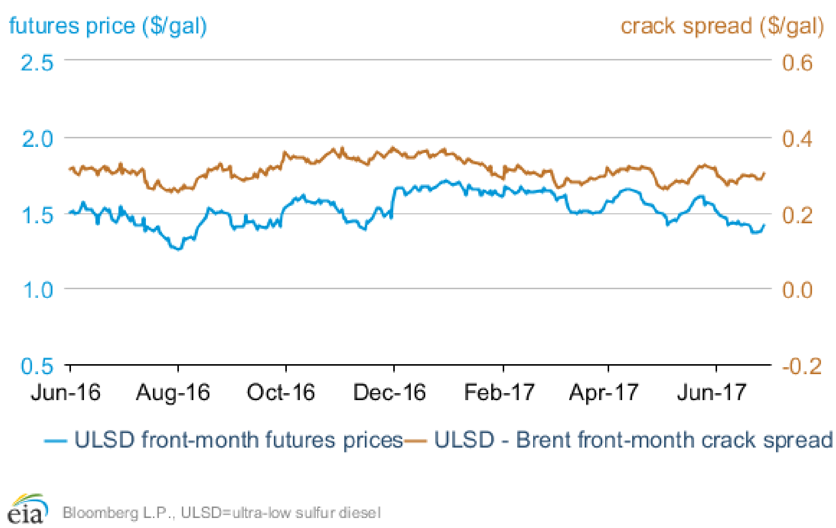
Figure 2. Historical RBOB futures prices and crack spread



Ultra-low sulfur diesel prices: The ultra-low sulfur diesel (ULSD) futures price declined by 2 cents/gal since June 1, settling at $1.48/gal on July 6. The ULSD-Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) rose by 4 cents/gal, settling at 34 cents/gal over the same period **(Figure 3)**.

Distillate crack spreads have been supported in part by an increase in U.S. distillate consumption in 2017 because of increased U.S. industrial activity. However, U.S. distillate consumption declined by about 50,000 b/d from May to June, according to the WPSR, but distillate consumption in June remained higher than year-ago levels.

Figure 3. Historical ULSD futures price and crack spread

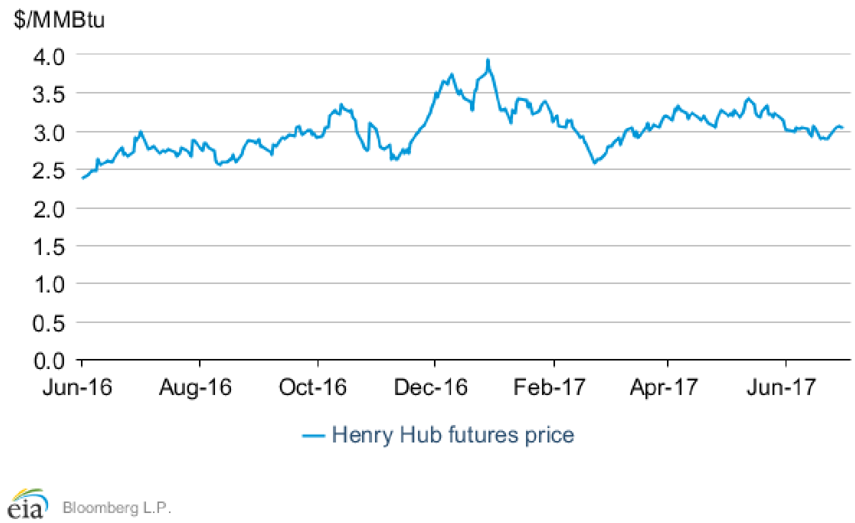


Natural Gas

Prices: The front-month natural gas futures contract for delivery at Henry Hub settled at $2.89/MMBtu on July 6, a decrease of 12 cents/MMBtu from June 1 **(Figure 4)**. The Henry Hub natural gas spot price averaged $2.98/MMBtu in June, which is 17 cents/MMBtu lower than the May average.

In mid-June, natural gas futures prices fell to the lowest level in three months after the release of National Oceanic and Atmospheric Administration (NOAA) projections indicating moderate temperatures for late June. For the week ending June 30, natural gas inventories were 7% above the five-year average.

Figure 4. Historical front month U.S. natural gas prices



Notable forecast changes

- U.S. crude oil production is forecast to average 9.9 million b/d in 2018, which is 0.1 million b/d below last month's forecast. The lower crude oil production forecast for 2018 reflects lower forecast crude oil prices compared with last month's STEO.
- EIA forecasts Brent crude oil prices to average $51/b in 2017 and $52/b in 2018. These prices are $2/b and $4/b lower, respectively, than forecast in last month's STEO.
- For more information, see the detailed table of forecast changes

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.