Forecast highlights

Global liquid fuels

- The August *Short-Term Energy Outlook* (STEO) remains subject to heightened levels of uncertainty related to the ongoing recovery from the COVID-19 pandemic. U.S. economic activity continues to rise after reaching multiyear lows in the second quarter of 2020 (2Q20). U.S. gross domestic product (GDP) declined by 3.5% in 2020 from 2019 levels. This STEO assumes U.S. GDP will grow by 6.6% in 2021 and by 5.0% in 2022. The U.S. macroeconomic assumptions in this outlook are based on forecasts by IHS Markit. Our forecast assumes continuing economic growth and increasing mobility. Any developments that would cause deviations from these assumptions would likely cause energy consumption and prices to deviate from our forecast.

- Brent crude oil spot prices averaged $75 per barrel (b) in July, up $2/b from June and up $25/b from the end of 2020. Brent prices have been rising this year as result of steady draws on global oil inventories, which averaged 1.8 million barrels per day (b/d) during the first half of 2021 (1H21) and remained at almost 1.4 million b/d in July. We expect Brent prices will remain near current levels for the remainder of 2021, averaging $72/b from August through November. However, in 2022, we expect that continuing growth in production from OPEC+ and accelerating growth in U.S. tight oil production—along with other supply growth—will outpace decelerating growth in global oil consumption and contribute to Brent prices declining to an average of $66/b in 2022.

- We estimate that 98.8 million b/d of petroleum and liquid fuels were consumed globally in July, an increase of 6.0 million b/d from July 2020 but 3.4 million b/d less than in July 2019. We forecast that global consumption of petroleum and liquid fuels will average 97.6 million b/d for all of 2021, which is a 5.3 million b/d increase from 2020. We forecast that global consumption of petroleum and liquid fuels will increase by 3.6 million b/d in 2022 to average 101.2 million b/d.

- U.S. gasoline consumption averaged 8.6 million b/d in 1H21, up from 8.3 million b/d in 2H20 but below the 9.3 million b/d in 2H19. Our latest estimates show that gasoline consumption in May through July was higher than we had previously expected. Growth in employment and increasing mobility have led to rising gasoline consumption so far in 2021. In this STEO, forecast U.S. gasoline consumption averages 8.8 million b/d in 2021, up from 8.0 million b/d in 2020. We expect the trend of rising employment and mobility
to continue into next year, and as a result, we forecast gasoline consumption to average almost 9.0 million b/d in 2022. However, our assumption that a relatively high share of the workforce will continue working from home next year compared with before the pandemic keeps our forecast gasoline consumption below the 2019 level of 9.3 million b/d.

- U.S. regular gasoline retail prices averaged $3.14 per gallon (gal) in July, the highest monthly average price since October 2014. Recent gasoline price increases reflect rising crude oil prices and rising wholesale gasoline margins, amid relatively low gasoline inventories. We expect that prices will average $3.12/gal in August before falling to $2.82/gal, on average, in 4Q21. The expected drop in retail gasoline prices reflects our forecast that gasoline margins will decline from elevated levels, as is typical in the United States during the second half of the year.

- We forecast OPEC crude oil production will average 26.5 million b/d in 2021, up from 25.6 million b/d in 2020. OPEC crude oil production in the forecast rises from 25.0 million b/d in April to an average of 27.1 million b/d in 3Q21. Our expectation of rising OPEC production is primarily based on our assumption that OPEC will raise production through the end of 2021 in line with targets it announced on July 18. We expect OPEC crude oil production will rise to an average of 28.7 million b/d in 2022.

- EIA’s most recent monthly data show U.S. crude oil production was 11.2 million b/d in May. We expect production to be relatively flat through October before it starts rising in November and December and throughout 2022. Forecast U.S. crude oil production for 2022 averages 11.8 million b/d, up from 11.1 million b/d in 2021.

**Natural Gas**

- In July, the natural gas spot price at Henry Hub averaged $3.84 per million British thermal units (MMBtu), which is up from the June average of $3.26/MMBtu. We expect the Henry Hub spot price will average $3.71/MMBtu in 3Q21 and $3.42/MMBtu for all of 2021, which is up from the 2020 average of $2.03/MMBtu. Higher natural gas prices this year primarily reflect two factors: growth in liquefied natural gas (LNG) exports and rising domestic natural gas consumption for sectors other than electric power. In 2022, we expect the Henry Hub price will average $3.08/MMBtu amid rising U.S. natural gas production.

- We expect that U.S. consumption of natural gas will average 82.5 billion cubic feet per day (Bcf/d) in 2021, down 1.0% from 2020. U.S. natural gas consumption declines in the forecast, in part, because electric power generators switch to coal from natural gas as a result of rising natural gas prices. In 2021, we expect residential and commercial natural gas consumption combined will rise by 1.2 Bcf/d from 2020 and industrial consumption will rise by 0.2 Bcf/d from 2020. Rising natural gas consumption in sectors other than
the electric power results from expanding economic activity and colder winter temperatures in 2021 compared with 2020. We expect U.S. natural gas consumption will average 83.8 Bcf/d in 2022.

- We estimate that U.S. natural gas inventories ended July 2021 at almost 2.8 trillion cubic feet (Tcf), which is 6% lower than the five-year (2016–20) average for this time of year. More natural gas was withdrawn from storage during the winter of 2020–21 than the previous five-year average, largely as a result of the colder-than-average February temperatures that constrained natural gas production while it increased consumption. We forecast that inventories will end the 2021 injection season (end of October) at 3.6 Tcf, which would be 4% below the five-year average.

- We expect dry natural gas production will average 92.9 Bcf/d in the United States during 2H21—up from 91.4 Bcf/d in 1H21—and then rise to 94.9 Bcf/d in 2022, driven by natural gas and crude oil prices, which we expect to remain at levels that will support enough drilling to sustain production growth.

Electricity, coal, renewables, and emissions

- We forecast that U.S. retail sales of electricity will increase by 2.7% in 2021 after falling by 3.9% in 2020. The largest forecast increase in electricity consumption occurs in the industrial sector, driven by rising levels of economic output. We forecast U.S. retail sales of electricity to the industrial sector will grow by 5.3% this year. Retail sales of electricity to the commercial sector also grow in the forecast, but they grow at the slightly slower pace of 2.2% in 2021 because some workers will continue working from home instead of in office buildings. We forecast U.S. residential electricity sales will grow by 1.5% in 2021 as a result of colder temperatures in 1Q21 compared with 1Q20 and because of hot temperatures in June.

- We expect the share of electric power generation produced by natural gas in the United States will average 36% in 2021 and 37% in 2022, down from 39% in 2020. The forecast share for natural gas as a generation fuel declines in response to our expectation of a higher delivered natural gas price for electricity generators, which we forecast will average $4.46/MMBtu in 2021 compared with an average of $2.39/MMBtu in 2020. As a result of the higher expected natural gas prices, the forecast share of generation from coal rises from 20% in 2020 to 23% this year but falls to 21% next year. New additions of solar and wind generating capacity are offset somewhat by reduced generation from hydropower this year, resulting in the forecast share of all renewables in U.S. generation to average 20% in 2021, about the same as last year, before rising to nearly 23% in 2022. The nuclear share of U.S. electricity generation declines from 21% in 2020 to 20% in 2021 and to 19% in 2022 as a result of retiring capacity at some nuclear power plants.
• We forecast that planned additions to U.S. wind and solar generating capacity in 2021 and 2022 will increase electricity generation from those sources. We estimate that the U.S. electric power sector added 14.7 gigawatts (GW) of new wind capacity in 2020. We expect 17.6 GW of new wind capacity will come online in 2021 and 6.3 GW in 2022. Utility-scale solar capacity rose by an estimated 10.6 GW in 2020. Our forecast for added utility-scale solar capacity is 16.2 GW in 2021 and 16.6 GW for 2022. We expect significant solar capacity additions in Texas during the forecast period. In addition, about 5 GW of small-scale solar capacity (systems less than 1 megawatt) will come online each year during 2021–22 in the STEO forecast.

• Coal production in our forecast totals 607 million short tons (MMst) in 2021, an increase of 13% over 2020. We expect total consumption of coal to be 33 MMst greater than primary coal supply in 2021, contributing to significant inventory draws. In 2022, we expect coal production to decline by 7 MMst (1%).

• We expect coal consumption for electricity generation to grow by 75 MMst (17%) in 2021 as a result of relatively high natural gas prices that make coal more competitive for dispatch in the electric power sector. Forecast electric power sector demand for coal then falls by 47 MMst (9%) in 2022. We expect demand for coal for other uses to rise by 5 MMst (13%) in 2021 and by 3 MMst (7%) in 2022. This increase is mostly for coking coal, which is used in steelmaking.

• We expect coal exports to total 90 MMst in 2021, a 21 MMst (30%) increase from 2020. In 2022, forecast coal exports rise an additional 16 MMst to 106 MMst. High global steel prices are driving these increases in coal exports, and trade tensions between China and Australia continue to support U.S. thermal coal exports.

• We estimate that U.S. energy-related carbon dioxide (CO\textsubscript{2}) emissions decreased by 11% in 2020 as a result of less energy consumption related to reduced economic activity and responses to COVID-19. For 2021, we forecast energy-related CO\textsubscript{2} emissions will increase about 7% from the 2020 level as economic activity increases and leads to rising energy use. We also expect energy-related CO\textsubscript{2} emissions to rise in 2022 but by a slower rate, 1%. We forecast that after declining by 19% in 2020, coal-related CO\textsubscript{2} emissions will rise by 17% in 2021 and then decrease by 7% in 2022. Short-term changes in energy-related CO\textsubscript{2} can be affected by temperature. A recent STEO supplement examines these dynamics.
Petroleum and natural gas markets review

Crude oil

**Prices:** The front month futures price for Brent crude oil settled at $71.29 per barrel (b) on August 5, 2021, down $4.55/b from $75.84/b on July 1. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, decreased by $6.14/b during the same period, settling at $69.09/b on August 5 (Figure 1).

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

Sources: Graph by EIA, based on CME Group and Intercontinental Exchange, compiled by Bloomberg L.P.
Note: WTI = West Texas Intermediate

After several months of steadily increasing crude oil prices, price volatility increased in July when members of OPEC+ concluded their ministerial meeting on July 5 without reaching an agreement on future production cuts and adjustments to baseline production levels. On Sunday, July 18, the OPEC+ members met again and announced they had reached an agreement after concluding another round of discussion. They decided to ease production cuts by 400,000 barrels per day (b/d) each month, beginning in August 2021. The agreement also included adjustments to the baseline crude production levels of some OPEC+ members, including Saudi Arabia, Russia, and the United Arab Emirates, to take effect in May 2022, though more specific details of the implementation have not been announced. Rising cases of the Delta variant of the COVID-19 virus present an additional downside price risk because of potentially lower demand for petroleum, which add to the volatility. Potential increases in crude oil supply, combined with the risk of lower demand contributed to lower prices in late July and early August, with prices decreasing to their monthly lows of $69/b for Brent and $66/b for WTI on July 19, the first trading day after the OPEC+ deal was announced, and a $5/b decrease compared with their closing price from the previous trading day.

Our Brent crude oil price outlook for the 2021 average has increased to $68.71/b, $0.07/b (0.1%) lower than the July STEO, while the price forecast for 2022 is $0.60/b (0.9%) lower at
$66.04/b, based on concerns about future demand and lower crude oil prices in late July and early August. In our July STEO, we anticipated a larger increase in OPEC production levels than the organization announced, as well as some degree of new crude oil production in response to rising crude oil demand globally. In this month’s STEO we have adjusted OPEC crude production in 2021 down by 300,000 b/d (0.9%) and production in 2022 up by 40,000 b/d (0.1%) in response to the final OPEC+ announcement, while global production has been reduced by 290,000 b/d (0.3%) in 2021 and by 20,000 b/d (less than 0.1%) in 2022.

**Calls on OPEC and OPEC production:** In the August STEO, we expect increased crude oil production by OPEC members is happening within the context of a broad trend of increasing global petroleum consumption. To estimate how much crude oil the global market will need from OPEC member states, we calculate the call on OPEC crude oil production by subtracting non-OPEC production of petroleum and other liquids and OPEC production of non-crude oil liquids from our forecast of global consumption of crude oil and other liquids. This metric assumes that petroleum production from non-OPEC countries is at its maximum level, leaving OPEC or available petroleum inventories to fill the gap between supply and demand. This metric does not account for spare production capacity from non-OPEC members of the OPEC+ agreement, most notably, Russia. Nonetheless, calls on OPEC can serve as one measure of whether OPEC crude oil production is less than or greater than global markets would otherwise demand. If calls on OPEC are greater than forecast OPEC crude oil production, it implies that the market will be short crude oil, and conversely, if calls on OPEC are less than expected OPEC crude oil production, it implies that the market will build crude oil inventories.

In the August STEO, we estimate that OPEC crude oil production will remain lower than calls on OPEC through the third quarter (3Q) and fourth quarter (4Q) of 2021 (Figure 2). In 3Q21, we estimate calls on OPEC will exceed OPEC production by 1.0 million b/d, and this difference will drop to 0.3 million b/d in 4Q21. However, beginning in 1Q22, we forecast OPEC crude oil production will outpace calls on OPEC production, contributing to increased crude oil inventories and lower crude oil prices. OPEC+ leaders are expected to reconvene in December 2021, when we expect some adjustments to their curtailment plan. Any significant changes in future OPEC+ production decisions would present noteworthy uncertainty for our forecast.
Crude oil historical volatility: July’s OPEC+ announcements and heightened uncertainty in the COVID-19 outlook with rising cases of new viral variants have likely contributed to heightened uncertainty and price volatility. The 30-day historical volatility for WTI crude oil futures prices rose above 30% on July 19, and volatility for Brent crude oil followed suit the following day, on July 20. Both benchmarks had historical volatility less than 30% throughout June and most of May (Figure 3). As of August 5, WTI 30-day historical volatility was 38%, and Brent 30-day historical volatility was 36%, up 18 percentage points and 23 percentage points, respectively, compared with the beginning of July. The increasing volatility coincides with the substantial drop in crude oil prices on July 19, before they returned to the previous week’s levels by the end of the week. The drop in crude oil prices on August 2 contributed to additional volatility, as the rolling 30-day historical volatility for Brent crude oil moved higher than 35% and WTI increased to higher than 36% (its highest level since early May, 2021). So far, volatility remains below its 2021 peak in early April, when it was just over 51% for WTI and just under 49% for Brent. Volatility in early April was lower than the high volatility in early November 2020, at just under 54% for WTI and just over 49% for Brent.
Money Manager open interest in WTI futures: Some of the factors that contributed to price declines in late July may also be affecting long positions held by Money Managers, particularly the risk of lower demand as a result of increases in COVID-19 cases. On July 20, 2021, open interest long positions held by Money Managers in the WTI futures contract decreased to 344,000 contracts, their lowest level since April 2020 (Figure 4). 2020 and 2021 have seen a greater-than-average volume of Money Managers’ long positions, according to the weekly Commitments of Traders report from the Commodity Futures Trading Commission (CFTC). Although open interest long positions held by Money Managers have been generally declining since late June, they remain elevated compared with contract open interest prior to the onset of the COVID-19 pandemic. For comparison, the average number of long positions during 2019 was 256,000. The recent decrease in long positions was matched by an increase in short positions to 76,000 contracts, the largest volume of short positions since February 2, 2021. Increased short positions and lower long positions both contributed to a decrease in net long open interest, which totaled 278,000 contracts on July 27, down from 383,000 contracts at the previous month’s high on June 21.
Petroleum products

Gasoline prices: The front-month futures price of RBOB (the petroleum component of gasoline used in many parts of the country) settled at $2.29 per gallon (gal) on August 5, up 3 cents/gal from July 1 (Figure 5). The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) increased by 13 cents/gal to settle at 60 cents/gal during the same period. The crack spread on July 30 of 55 cents/gal was the highest July crack spread since July 31, 2015.

July’s high RBOB–Brent crack spread reflected increasing demand and decreasing inventories. We estimate U.S. gasoline consumption averaged 9.4 million barrels per day (b/d) in July, which is 0.9 million b/d (11%) higher than in July 2020, and only 0.2 million b/d (2%) lower than the

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**Figure 4. Money Manager open interest in WTI futures contracts**

<table>
<thead>
<tr>
<th>Thousands of Contracts</th>
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<tr>
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</tr>
<tr>
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</tr>
<tr>
<td>-250</td>
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<tr>
<td>-500</td>
</tr>
</tbody>
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Jan-19 | Jul-19 | Jan-20 | Jul-20 | Jan-21 | Jul-21 |

- money managers long
- money managers short
- money managers net

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**Figure 4. Historical RBOB front-month futures prices and crack spreads**

<table>
<thead>
<tr>
<th>Futures Price (dollars per gallon)</th>
<th>Crack Spread (dollars per gallon)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.50</td>
<td>0.60</td>
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<tr>
<td>2.00</td>
<td>0.40</td>
</tr>
<tr>
<td>1.50</td>
<td>0.20</td>
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<td>1.00</td>
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<tr>
<td>0.50</td>
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<td>-0.20</td>
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<tr>
<td>-0.00</td>
<td>-0.40</td>
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</table>

Source: Graph by EIA, based on data from CME Group, as compiled by Bloomberg L.P.

Note: RBOB is the petroleum component of gasoline used in many parts of the country.
pre-COVID-19 July 2019 level. The increase in gasoline demand likely reflects typical seasonal factors such as increased summer driving demand, especially around the July 4th holiday weekend. For the week ending July 2, we reported in our Weekly Petroleum Status Report that gasoline product supplied was 10.0 million b/d, a record high in our data, which goes back to 1991. Product supplied is the volume of petroleum products delivered out of the primary supply chain, rather than the actual amount of gasoline consumed by end users that week. An individual week’s amount of product supplied could be affected by a number of factors, such as the timing of when import or export cargoes clear customs. Nevertheless, this record product supplied level likely indicates that driving demand was high in late June and early July. Although gasoline consumption remains below 2019 levels, the July 2021 estimate is the closest gasoline consumption has been to its corresponding 2019 level so far in 2021 (Figure 6). The relatively high consumption has contributed to gasoline stocks decreasing to 228.5 million barrels in July, the lowest July level since 2015. We forecast lower gasoline stocks between August and November, which will likely continue to support relatively high crack spreads.

![Figure 6. U.S. gasoline consumption million barrels per day](image)

Source: U.S. Energy Information Administration, Short-Term Energy Outlook

**RBOB 1st to 13th contract spread:** The RBOB 1st to 13th futures price spread settled at 25 cents/gal on August 5, the highest level of backwardation (when near-term contract prices are higher than farther-dated ones) since August 31, 2017, which was when Hurricane Harvey disrupted U.S. Gulf Coast refineries. The 1st to 13th futures price spread for ULSD has also been increasing but is not at multiyear highs like the RBOB spread (Figure 7).
Recent inventory draws for gasoline have contributed to the high 1st to 13th futures price spread. We estimate that gasoline inventories in July were 228.5 million barrels, which is the lowest they have been since October 2020 and is 4% lower than the five-year (2016–2020) average for the month of July. Expectations of continued strong gasoline demand through August and lower gasoline production in the fall are contributing to our expectations of low gasoline stocks in the short term. Distillate stocks are also lower than average, but they have been relatively flat in the summer and we expect them to increase in August in advance of growth in demand in the fall and winter, when diesel-powered agricultural equipment is used to harvest crops and the winter heating season begins. The futures price spread is likely lower for distillate than gasoline because distillate stocks are relatively flat, whereas gasoline stocks have been decreasing due to high summer demand.

**Ultra-low sulfur diesel prices:** The front-month futures price for ultra-low sulfur diesel (ULSD) for delivery in New York Harbor settled at $2.11/gal on August 5, down 5 cent/gal from July 1 (Figure 8). The ULSD–Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) increased 6 cents/gal, settling at 41 cents/gal during the same period.
Seasonally low production has not kept up with distillate demand and has likely helped sustain the above-average ULSD–Brent crack spread. We estimate distillate production was 4.8 million b/d in July, which would be the lowest for that month since 2012. In contrast, our distillate consumption estimate of 3.8 million b/d is 2% higher than the five-year average. Several months of seasonally low production and relatively average demand has led to low distillate stocks. We estimate distillate stocks of 138.9 million barrels in July, which is 7% lower than the five-year average.

**Natural Gas**

*Prices:* The front-month natural gas futures contract for delivery at the Henry Hub settled at $4.14 per million British thermal units (MMBtu) on August 5, 2021, which was up 48 cents/MMBtu from July 1, 2021 (Figure 9). The average price for front-month natural gas futures contracts in July was $3.82/MMBtu, the highest July average since 2014.
Henry Hub natural gas futures prices increased in July as cooling demand increased, especially in the western United States. We estimate that U.S. consumption of natural gas in July increased by 3.9 billion cubic feet per day (Bcf/d) from June to 75.8 Bcf/d, driven by an increase in consumption in the electric power sector. Cooling demand was particularly strong in the western United States (Pacific and Mountain regions) which had 684 cooling degree days in July, 9% more than the 10-year average. Regional prices in the West increased along with the demand increase. The price at PG&E Citygate in California increased 16% from June to July to $5.16/MMBtu, a 107% increase over the July 2020 price, according to data from Natural Gas Intelligence.

Natural gas exports (pipeline and LNG) also increased in July from 17.8 Bcf/d in June to 18.2 Bcf/d in July. At the same time, dry production of natural gas declined slightly from 92.7 Bcf/d in June to 92.5 Bcf/d in July, prompting an increase in the Henry Hub price. The 17.9% increase in the Henry Hub price from June to July is the largest month-on-month percentage change for June to July since 2012, when the price increased 20.3%.

**Natural gas consumption amid high prices:** The relative share of fossil-fuel electricity generation from natural gas was greater than coal in the eastern United States (United States excluding the Pacific and Mountain regions) in July despite relatively high natural gas prices (Figure 10). Typically, higher natural gas prices will prompt gas-to-coal switching for electricity generation. For example, in February–September 2018, when the Henry Hub price was less than $3.00/MMBtu, natural gas made up an average of 56% of the share of fossil-fuel generation. In November and December of the same year, when the price increased to more than $4.00/MMBtu, the natural gas share of fossil-fuel generation decreased to 51%.
In the first half of 2020, natural gas made up a 69% share of fossil-fuel generation and Henry Hub prices averaged $1.81/MMBtu. For the same period in 2021, natural gas made up a 60% share of fossil fuel generation, and Henry Hub prices averaged $3.25/MMBtu. Since March 2021, the Henry Hub price has steadily increased, approaching $4.00/MMBtu, yet the natural gas share of fossil-fuel generation has remained higher than 60%. Except for the February price spike as a result of extremely cold weather, July Henry Hub prices were at their highest this year. Natural gas made up a 61% share of fossil-fuel generation and coal made up 39%. This difference is partially because of a longer-term trend of decreasing capacity for coal-fired electricity generation and increasing natural gas-fired capacity. Capacity for coal-fired electricity generation has decreased every year since 2011, and natural gas-fired capacity has increased every year since at least 2009.
Notable forecast changes

- We expect OPEC crude oil production to average 27.6 million barrels per day (b/d) in the second half of 2021 (2H21), about 0.6 million b/d lower compared with our previous forecast. Our forecast of lower OPEC crude oil production reflects the July 18 OPEC+ announcement that calls for participating countries to collectively increase supply by 0.4 million b/d per month from August to December 2021, a production increase that is lower than we previously anticipated. Forecast OPEC crude oil production in 2022 is about the same as our July forecast, with higher-than-expected output in the second half of the year offsetting lower forecast production in 1Q22, which is consistent with higher OPEC production baselines that were also announced on July 18.

- In our August STEO, we revised down our 2022 jet fuel consumption forecast by 80,000 b/d to 1.6 million b/d. The lower jet fuel forecast reflects a lower GDP forecast by IHS Markit. It also reflects our assumption that increases in jet fuel consumption will occur more slowly than we has previously forecast. The largest downward revision is for 2H22, when we forecast jet fuel consumption will average 1.7 million b/d, down from 1.8 million b/d in the July forecast.

- We forecast Henry Hub spot prices will average $3.59 per million British thermal unit (MMBtu) in 2H21, an increase of 40 cents/MMBtu from last month’s STEO. High demand for electricity generation because of record-high temperatures in June led to strong consumption of natural gas in the electric power sector, supporting higher prices into July and August. We expect Henry Hub spot prices to decline over the forecast period as temperatures return closer to historical averages, U.S. dry natural gas production increases, and growth in liquefied natural gas export growth slows.

- We have updated our modeling of electricity generation to better account for regional emissions restrictions and fuel contracts. These changes have the general effect of limiting future growth in coal-fired generation. As a result, the impact on forecast coal-fired generation in 2021 from our increased forecast for natural gas prices is generally offset by the effect of the new model constraints that limit growth in coal-fired generation. Thus, our forecast for U.S. coal and natural gas generation are relatively unchanged from last STEO.

- We corrected calculations for several of the industrial production indexes in tables 9a and 9b. Most of the changes were minor. For more information on these corrections please contact us.