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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' NINTH REQUEST FOR INFORMATION QUESTION NOS. TIEC 9-1 THROUGH TIEC 9-10

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DECEMBER 22, 2021

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APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

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TEXAS INDUSTRIAL ENERGY CONSUMERS'
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QUESTION NOS. TIEC 9-1 THROUGH TIEC 9-10

TIEC 9-1:

On an electronic spreadsheet with all formulas intact, please provide complete copies of all the workpapers used to produce the charts, schedules, and figures included in EPE witness Jennifer Nelson's rebuttal testimony.

RESPONSE:

Please see Ms. Nelson's workpapers filed on the Public Utility Commission of Texas Interchange website on November 22, 2021.

Preparer: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisors

Sponsor: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisors

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TIEC 9-2:

Please provide complete copies of the articles or portions of textbooks, reports or journals cited by Ms. Nelson in her rebuttal testimony.

RESPONSE:

Please see TIEC 9-2 Attachment 1-Voluminous, and Attachment 2-Confidential.

Preparer: Jennifer E. Nelson — Title: Assistant Vice President – Concentric Energy Advisors

Sponsor: Jennifer E. Nelson — Title: Assistant Vice President – Concentric Energy Advisors

COMMENTS — 20 Jan, 2021 | 18:22 —

APAC, United States of America, Latin America, Canada, EMEA, APAC

North American Regulated Utilities' Negative Outlook Could See Modest Improvement

Primary Credit Analyst:	**Gabe Grosberg**
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Sector	Oil & Gas, Oil & Gas, Corporates, Infrastructure & Utilities, Utilities & Power
Tags	Americas, Latin America, APAC, EMEA

View Analyst Contact Information

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Key Takeaways

- Credit quality for the North American regulated utility industry weakened in 2020. At the beginning of the year about 18% of the industry had a negative outlook or ratings on CreditWatch with negative implications. By the end of the year that percentage had doubled, to about 36%.
- For the first time in a decade downgrades outpaced upgrades for the predominately investment-grade industry.
- The industry generally performed well throughout the pandemic and we expect it will continue to mostly manage through the remaining COVID-19-related risks.
- The main causes of weakening credit quality reflected environment, social, and governance (ESG) risks, regulatory issues, and companies' practice of strategically managing financial measures close to their downgrade threshold with little or no cushion.
- Despite our negative 2021 industry outlook, we expect a modest improvement to credit quality over the next 12 months. We believe Congress is more likely to raise the corporate tax rate, which would improve the industry's financial measures, offset in part by a continued focus on ESG risks.

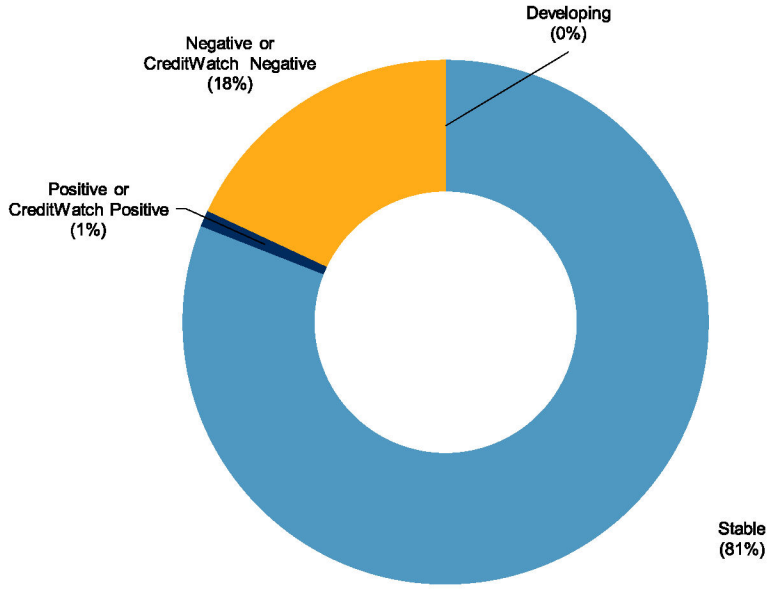
Credit Quality Weakened In 2020

We revised the industry's outlook to negative in the first quarter (**COVID-19: The Outlook For North American Regulated Utilities Turns Negative** , April 2, 2020), citing the already high percentage of companies with a negative outlook or ratings on CreditWatch with negative implications

(18%) and the additional potential credit risks from COVID-19. During the year, the utility industry performed poorly from a credit quality perspective. The negative outlooks or CreditWatch negative listings doubled and downgrades outpaced upgrades for the first time in a decade by about 7 to 1. As a result, while the median rating for the industry remains at 'A-', it is slowly creeping closer to 'BBB+'.

Chart 1

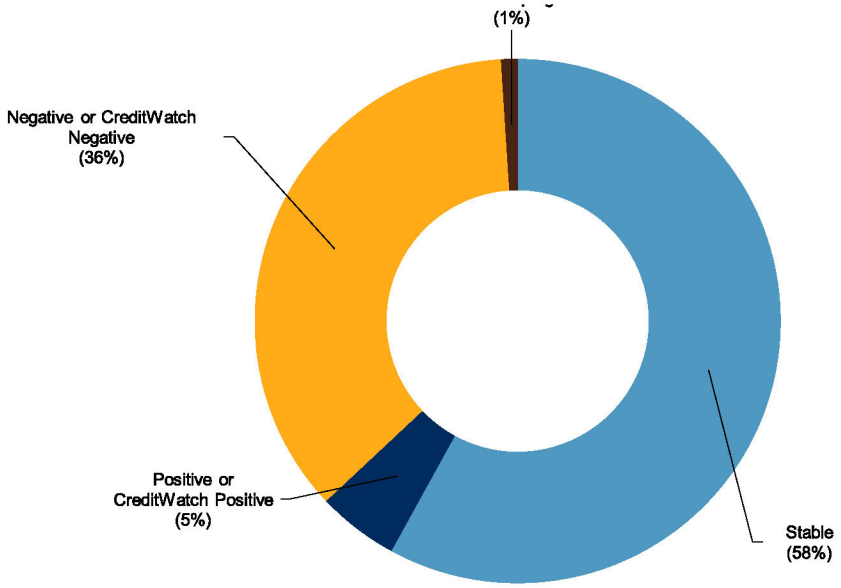
Ratings Outlooks At The Beginning Of 2020



Source: S&P Global Ratings.

Chart 2

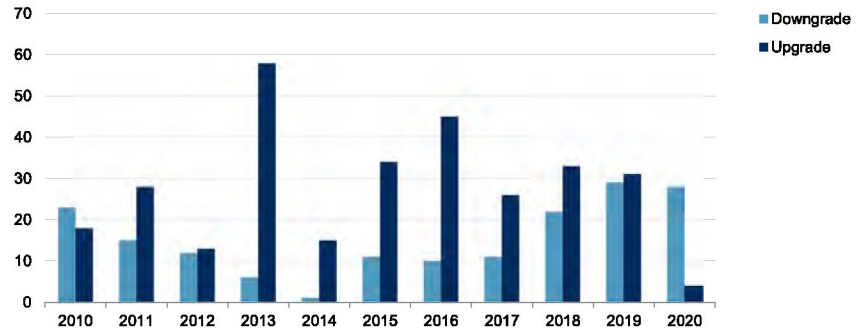
Ratings Outlooks At The End Of 2020



Source: S&P Global Ratings.

Chart 3

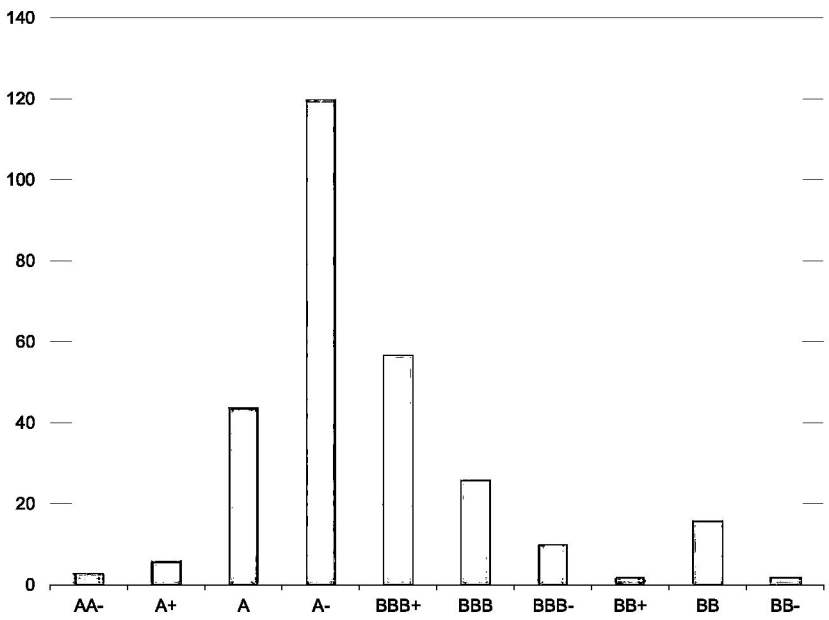
North America Regulated Utilities Upgrades And Downgrades



Source: S&P Global Ratings.

Chart 4

North America Regulated Utilities Rating Distribution



As of Jan. 8, 2021. Source: S&P Global Ratings.

COVID-19 Was Not The Culprit For Weaker Credit Quality

In March 2020, we identified five COVID-19-related risks that could lead to a weakening of the industry's credit quality. We expected that these developments could bring about a deterioration in the industry's 2020 funds from operations (FFO) to debt of about 100 basis points. These risks included the following:

- Lower deliveries to commercial and industrial (C&I) customers;
- Higher bad debt expense;
- Delayed rate case filings, delayed rate case orders, or lower-than-expected rate case outcomes;
- Lack of consistent access to the capital markets; and
- Weaker market returns that could increase postretirement benefit obligations.

Encouragingly, the industry has generally performed well throughout the pandemic. Lower electric and gas deliveries to C&I customers were mostly offset by higher residential deliveries, the industry generally worked well with regulators to defer COVID-19-related costs for future recovery, market returns improved, and the industry generally had consistent access to the capital markets. The one area that we saw some weakness was with regard to rate cases. Many rate case filings were delayed, rate case orders often took longer than expected, and many of the orders were below expectations. This trend generally reflected the weak economy caused by COVID-19 and the difficulties of passing on higher costs to customers during the pandemic. We expect that as vaccines take hold and the pandemic dissipates, the economy will gradually recover, as will the industry's rate case performance.

As vaccine rollouts in several countries continue, S&P Global Ratings believes there remains a high degree of uncertainty about the evolution of the coronavirus pandemic and its economic effects. Widespread immunization, which certain countries might achieve by midyear, will help pave the way for a return to more normal levels of social and economic activity. We use this assumption about vaccine timing in assessing the economic and credit implications associated with the pandemic (see our research here: **www.spglobal.com/ratings**). As the situation evolves, we will update our assumptions and estimates accordingly.

Here's What Happened

The stark weakening of credit quality in 2020 primarily reflected environmental, social, and governance (ESG) factors, regulatory issues, and the industry's practice of continuing to manage its financial measures with little or no financial cushion from the downgrade threshold.

During 2020, we saw a number of ESG-related events that included:

- A bribery charge filed against Exelon Corp.'s subsidiary (**Exelon Corp. Outlook Revised To Negative On Bribery Charge; Subsidiary Commonwealth Edison Co. Downgraded** , July 21, 2020).
- Unprecedented wildfire activity throughout California at the beginning of the wildfire season that could have indicated a worsening environment more susceptible to frequent wildfires. (**Edison International And Subsidiary Outlooks Revised To Negative On Adverse Wildfire Conditions; 'BBB' Ratings Affirmed** , Sept. 16, 2020; **PG&E Corp. And Subsidiary Outlooks Revised To Negative On Adverse Wildfire Conditions; 'BB-' Ratings Affirmed** ; Sept. 16, 2020; **San Diego Gas & Electric Co. Outlook Revised To Negative On Adverse Wildfire Conditions; 'BBB+' Rating Affirmed** , Sept. 16, 2020).
- Climate change risks. **Entergy New Orleans LLC Downgraded To 'BBB' From 'BBB+' On Storm Risks, Outlook Negative** , Oct. 8, 2020.
- FirstEnergy Corp. terminated three executives including its CEO after it determined that they violated company policies and its code of conduct. This followed the U.S. government filing a criminal complaint against the Speaker of the Ohio House of Representatives and four associates for participating in an approximately $60 million racketeering scheme (**FirstEnergy Corp. Downgraded to 'BB+' On Termination Of CEO; Ratings Remain On CreditWatch Negative** , Oct. 30, 2020).
- Duke Energy Corp.'s potentially higher risks regarding its ability to fully and consistently recover coal ash costs (**Duke Energy Corp. And Subsidiaries Outlooks Revised To Negative On Higher Regulatory Risks, Elevated Spending Plan** , Dec. 15, 2020).

Regulatory issues also contributed to a weakening of credit quality and included the following 2020 actions:

- **Puget Energy Inc. And Subsidary Ratings Placed On CreditWatch Negative Over Regulatory Concerns**, July 23, 2020.
- **Consolidated Edison Inc. And Subs Outlooks Revised To Negative Amid Potential Political Headwinds; Ratings Affirmed**, Nov. 24, 2020.
- Following our assessment of a modest weakening of the regulatory environment in Alberta we revised our rating outlook on FortisAlberta Inc. to negative. (**FortisAlberta Inc. Ratings Affirmed; Outlook Negative**, Nov. 24, 2020).

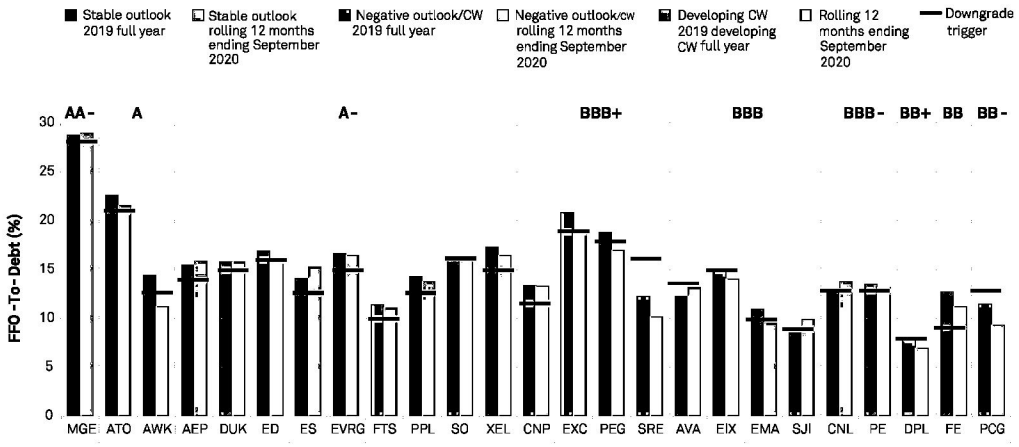
During 2020, we revised the outlook on a number of companies to negative and downgraded other companies, reflecting weak financial measures.

- South Jersey Industries Inc. And Subsidiaries Outlook Revised To Negative On Weaker Financial Results; Ratings Affirmed, March 10, 2020.
- Emera Inc. And TECO Downgraded On Weak Financials, Outlook Stable; Subsidiaries Ratings Affirmed, March 24, 2020.
- ENMAX Corp. Downgraded To 'BBB-'; Off CreditWatch; Outlook Stable, March 24, 2020.
- PNM Resources Inc., Public Service Co. Of New Mexico, Texas-New Mexico Power Co. Downgraded One Notch; Outlook Stable, April 6, 2020.
- ALLETE Inc. Downgraded To 'BBB' On Expected Weaker Financial Measures; Outlook Stable, April 22, 2020.
- CenterPoint Energy Resources Corp. Ratings Affirmed On Completed Sale Of CenterPoint Energy Services, Outlook Negative, June 5, 2020.
- Otter Tail Corp. Outlook Revised To Negative; Ratings Affirmed, Aug. 18, 2020.
- National Grid North America Inc. And Subsidiaries Outlooks Revised To Negative Following Outlook Revision On Parent, Aug. 25, 2020.
- ATCO Ltd. And Canadian Utilities Ltd. Outlooks Revised To Negative; Operating Subsidiary CU Inc. Outlook Remains Stable, Sept. 17, 2020.
- Fortis TCI Ltd. Downgraded To 'BBB-' On Weaker Financial Measures; Outlook Stable, Oct. 21, 2020
- Middlesex Water Co. Outlook Revised To Negative On Weaker Financial Measures; 'A+' Rating Affirmed, Nov. 3, 2020.
- Unitil Corp. And Subsidiaries Outlooks Revised To Negative On Weaker Consolidated Financial Measures; Ratings Affirmed, Nov. 5, 2020.

The industry's credit quality continues to be squeezed by the industry's tendency to strategically manage financial measures with only minimal financial cushion.

Chart 5

Sampling Of Minimal Cushion At Current Rating Level



Note: PE is Puget Energy Inc. Source: S&P Global Ratings and company data.

What will occur in 2021?

We expect a marginal improvement in credit quality in 2021. We think it's likely that Congress will enact a higher corporate tax rate. This will help strengthen the industry's financial measures, partially offset by continued focus on ESG related risks.

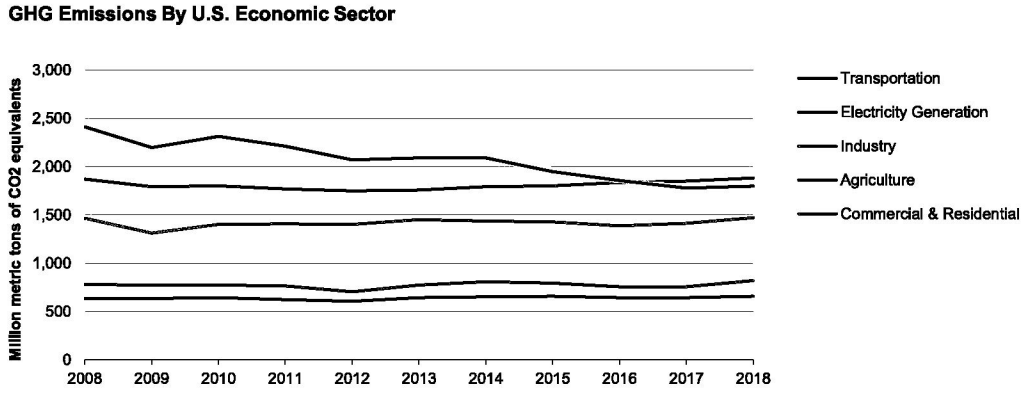
Because President-elect Biden won the U.S. presidency and the democrats have control of the U.S House of Representatives and Senate, we expect Congress will more likely implement a higher corporate tax rate. While details of such a plan are limited, a key element of the proposal would likely call for an increase in the corporate tax rate to 28% from 21%. We estimate that this higher tax rate would improve the industry's funds from operations to debt by about 100 basis points (

U.S. Regulated Utilities' Credit Metrics Could Strengthen Under Proposed Biden Tax Plan

, Oct. 29, 2020). The improving financial measures would likely boost credit quality, enhancing utilities' financial cushions from their downgrade thresholds.

The industry's environmental risks including its exposure to greenhouse gas (GHG) emissions remain a key concern for investors. Despite the industry's enormous progress over the past decade, it has a way to go. Over the past decade, the industry significantly reduced its reliance on coal-fired generation and its associated level of carbon based emissions. The industry is no longer the number one North American emitter of carbon-based pollutants, reducing its carbon emissions by about 25% and has reduced its reliance on coal-fired generation by about 50%.

Chart 6



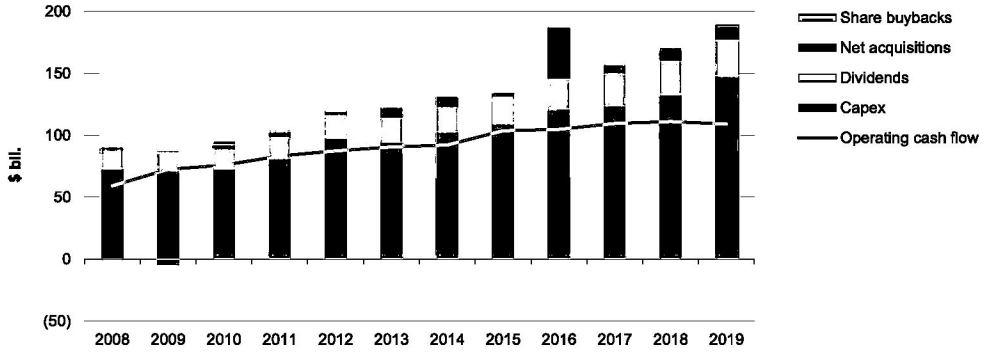
Source: U.S. Environmental Protection Agency.

Still, about 30% of the electric utility industry relies on coal-fired generation for at least 50% of its owned electricity production and about two-thirds of those utilities depend on coal-fired generation for more than 70% of their total generation. Investors are increasingly focused on environmental issues and given that the industry typically operates with negative discretionary cash flow, it relies on consistent access to

reasonably priced capital markets. We expect that the continued focus on these ESG risks will weaken credit quality, offsetting much of the credit benefits from a potentially higher corporate tax rate.

Chart 7

Cash Flow And Primary Uses



Source: S&P Global Ratings and company data.

This report does not constitute a rating action.

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For release at 2:00 p.m., EDT, September 22, 2021

Summary of Economic Projections

In conjunction with the Federal Open Market Committee (FOMC) meeting held on September 21–22, 2021, meeting participants submitted their projections of the most likely outcomes for real gross domestic product (GDP) growth, the unemployment rate, and inflation for each year from 2021 to 2024 and over the longer run. Each participant's projections were based on information available at the time of the meeting, together with her or his assessment of appropriate monetary policy—including a path for the federal funds rate and its longer-run value—and assumptions about other factors likely to affect economic outcomes. The longer-run projections represent each participant's assessment of the value to which each variable would be expected to converge, over time, under appropriate monetary policy and in the absence of further shocks to the economy. "Appropriate monetary policy" is defined as the future path of policy that each participant deems most likely to foster outcomes for economic activity and inflation that best satisfy his or her individual interpretation of the statutory mandate to promote maximum employment and price stability.

For release at 2:00 p.m., EDT, September 22, 2021

Table 1. Economic projections of Federal Reserve Board members and Federal Reserve Bank presidents, under their individual assumptions of projected appropriate monetary policy, September 2021

Percent

Variable	Median[1]					Central Tendency[2]					Range[3]				
	2021	2022	2023	2024	Longer run	2021	2022	2023	2024	Longer run	2021	2022	2023	2024	Longer run
Change in real GDP	5.9	3.8	2.5	2.0	1.8	5.8–6.0	3.4–4.5	2.2–2.5	2.0–2.2	1.8–2.0	5.5–6.3	3.1–4.9	1.8–3.0	1.8–2.5	1.6–2.2
June projection	7.0	3.3	2.4		1.8	6.8–7.3	2.8–3.8	2.0–2.5		1.8–2.0	6.3–7.8	2.6–4.2	1.7–2.7		1.6–2.2
Unemployment rate	4.8	3.8	3.5	3.5	4.0	4.6–4.8	3.6–4.0	3.3–3.7	3.3–3.6	3.8–4.3	4.5–5.1	3.0–4.0	2.8–4.0	3.0–4.0	3.5–4.5
June projection	4.5	3.8	3.5		4.0	4.4–4.8	3.5–4.0	3.2–3.8		3.8–4.3	4.2–5.0	3.2–4.2	3.0–3.9		3.5–4.5
PCE inflation	4.2	2.2	2.2	2.1	2.0	4.0–4.3	2.0–2.5	2.0–2.3	2.0–2.2	2.0	3.4–4.4	1.7–3.0	1.9–2.4	2.0–2.3	2.0
June projection	3.4	2.1	2.2		2.0	3.1–3.5	1.9–2.3	2.0–2.2		2.0	3.0–3.9	1.6–2.5	1.9–2.3		2.0
Core PCE inflation[4]	3.7	2.3	2.2	2.1		3.6–3.8	2.0–2.5	2.0–2.3	2.0–2.2		3.5–4.2	1.9–2.8	2.0–2.3	2.0–2.4	
June projection	3.0	2.1	2.1			2.9–3.1	1.9–2.3	2.0–2.2			2.7–3.3	1.7–2.5	2.0–2.3		
Memo: Projected appropriate policy path															
Federal funds rate	0.1	0.3	1.0	1.8	2.5	0.1	0.1–0.4	0.4–1.1	0.9–2.1	2.3–2.5	0.1	0.1–0.6	0.1–1.6	0.6–2.6	2.0–3.0
June projection	0.1	0.1	0.6		2.5	0.1	0.1–0.4	0.1–1.1		2.3–2.5	0.1	0.1–0.6	0.1–1.6		2.0–3.0

NOTE: Projections of change in real gross domestic product (GDP) and projections for both measures of inflation are percent changes from the fourth quarter of the previous year to the fourth quarter of the year indicated. PCE inflation and core PCE inflation are the percentage rates of change in, respectively, the price index for personal consumption expenditures (PCE) and the price index for PCE excluding food and energy. Projections for the unemployment rate are for the average civilian unemployment rate in the fourth quarter of the year indicated. Each participant's projections are based on his or her assessment of appropriate monetary policy. Longer-run projections represent each participant's assessment of the rate to which each variable would be expected to converge under appropriate monetary policy and in the absence of further shocks to the economy. The projections for the federal funds rate are the value of the midpoint of the projected appropriate target range for the federal funds rate or the projected appropriate target level for the federal funds rate at the end of the specified calendar year or over the longer run. The June projections were made in conjunction with the meeting of the Federal Open Market Committee on June 15–16, 2021. One participant did not submit longer-run projections for the change in real GDP, the unemployment rate, or the federal funds rate in conjunction with the June 15–16, 2021, meeting, and one participant did not submit such projections in conjunction with the September 21–22, 2021, meeting.

1. For each period, the median is the middle projection when the projections are arranged from lowest to highest. When the number of projections is even, the median is the average of the two middle projections.
2. The central tendency excludes the three highest and three lowest projections for each variable in each year.
3. The range for a variable in a given year includes all participants' projections, from lowest to highest, for that variable in that year.
4. Longer-run projections for core PCE inflation are not collected.

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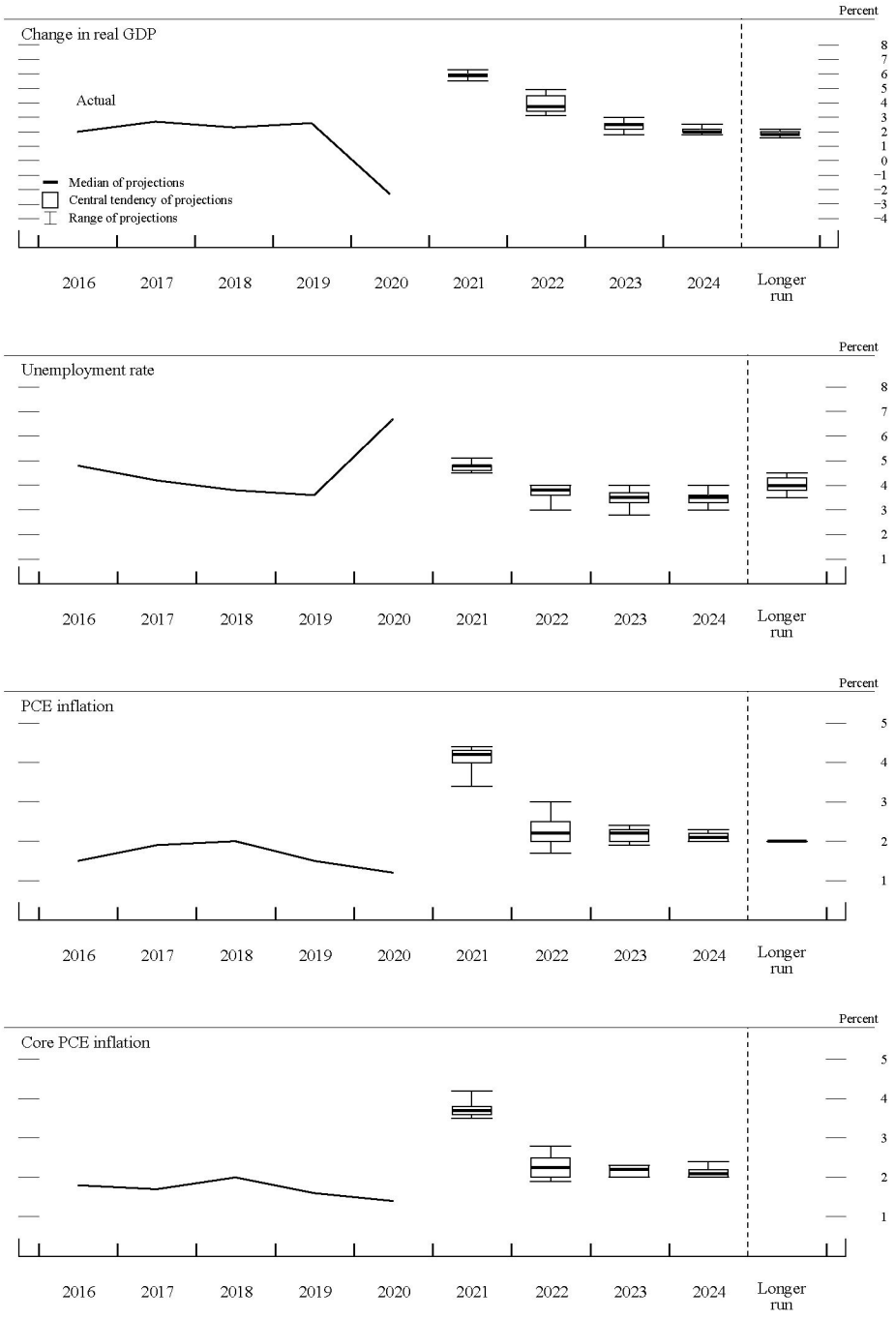
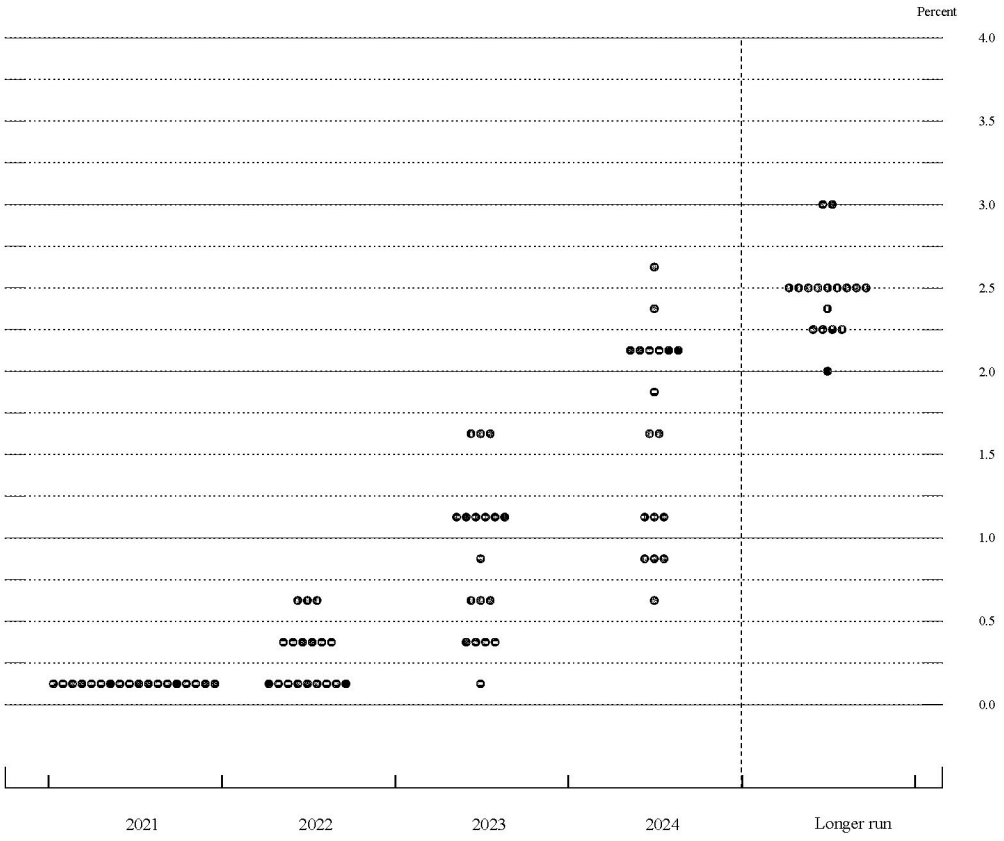
Figure 1. Medians, central tendencies, and ranges of economic projections, 2021–24 and over the longer run



NOTE: Definitions of variables and other explanations are in the notes to table 1. The data for the actual values of the variables are annual.

For release at 2:00 p.m., EDT, September 22, 2021

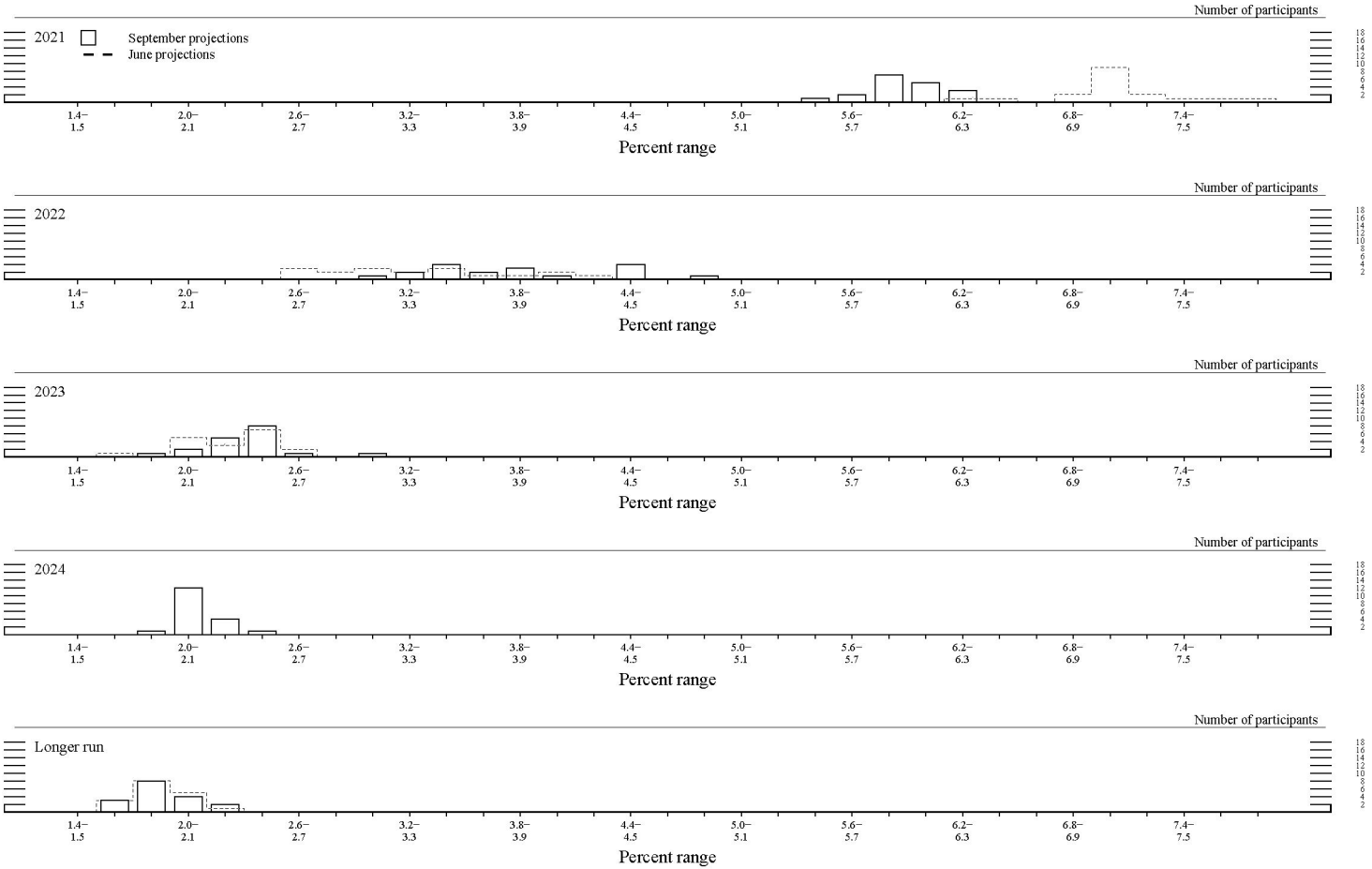
Figure 2. FOMC participants' assessments of appropriate monetary policy: Midpoint of target range or target level for the federal funds rate



NOTE: Each shaded circle indicates the value (rounded to the nearest 1/8 percentage point) of an individual participant's judgment of the midpoint of the appropriate target range for the federal funds rate or the appropriate target level for the federal funds rate at the end of the specified calendar year or over the longer run. One participant did not submit longer-run projections for the federal funds rate.

For release at 2:00 p.m., EDT, September 22, 2021

Figure 3.A. Distribution of participants' projections for the change in real GDP, 2021–24 and over the longer run



NOTE: Definitions of variables and other explanations are in the notes to table 1.

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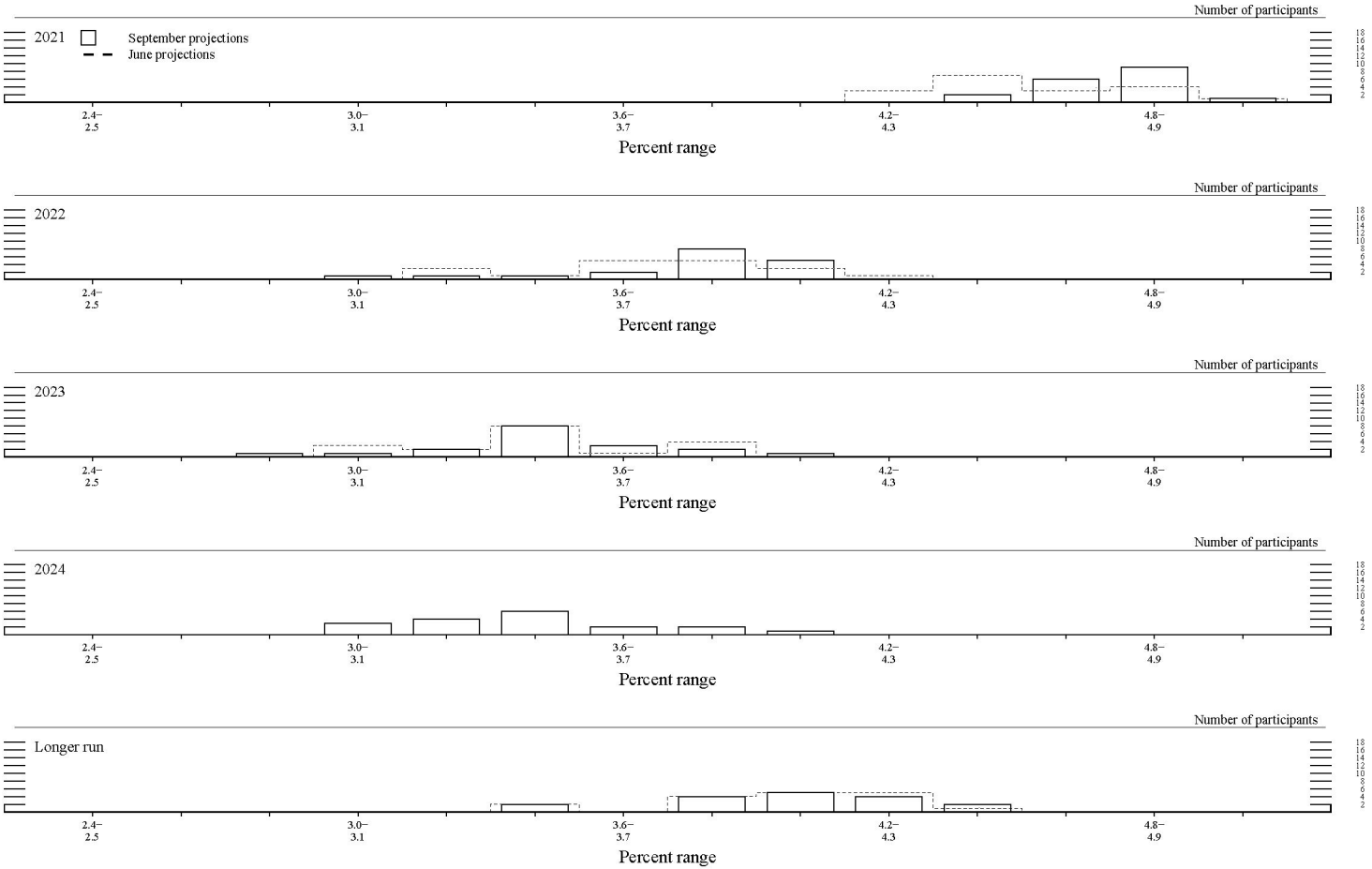
Figure 3.B. Distribution of participants' projections for the unemployment rate, 2021–24 and over the longer run



NOTE: Definitions of variables and other explanations are in the notes to table 1.

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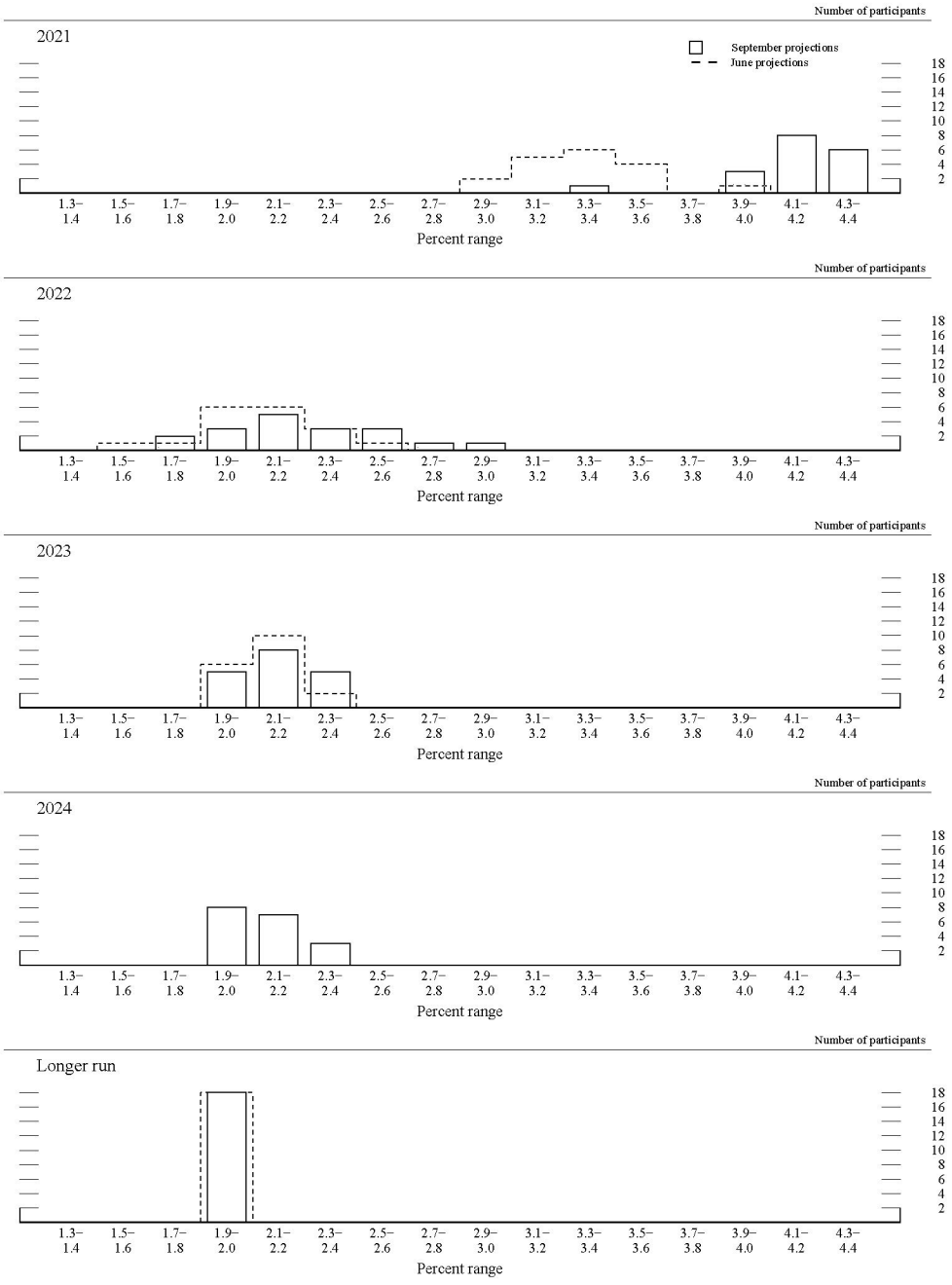
For release at 2:00 p.m., EDT, September 22, 2021

Figure 3.C. Distribution of participants' projections for PCE inflation, 2021–24 and over the longer run



NOTE: Definitions of variables and other explanations are in the notes to table 1.

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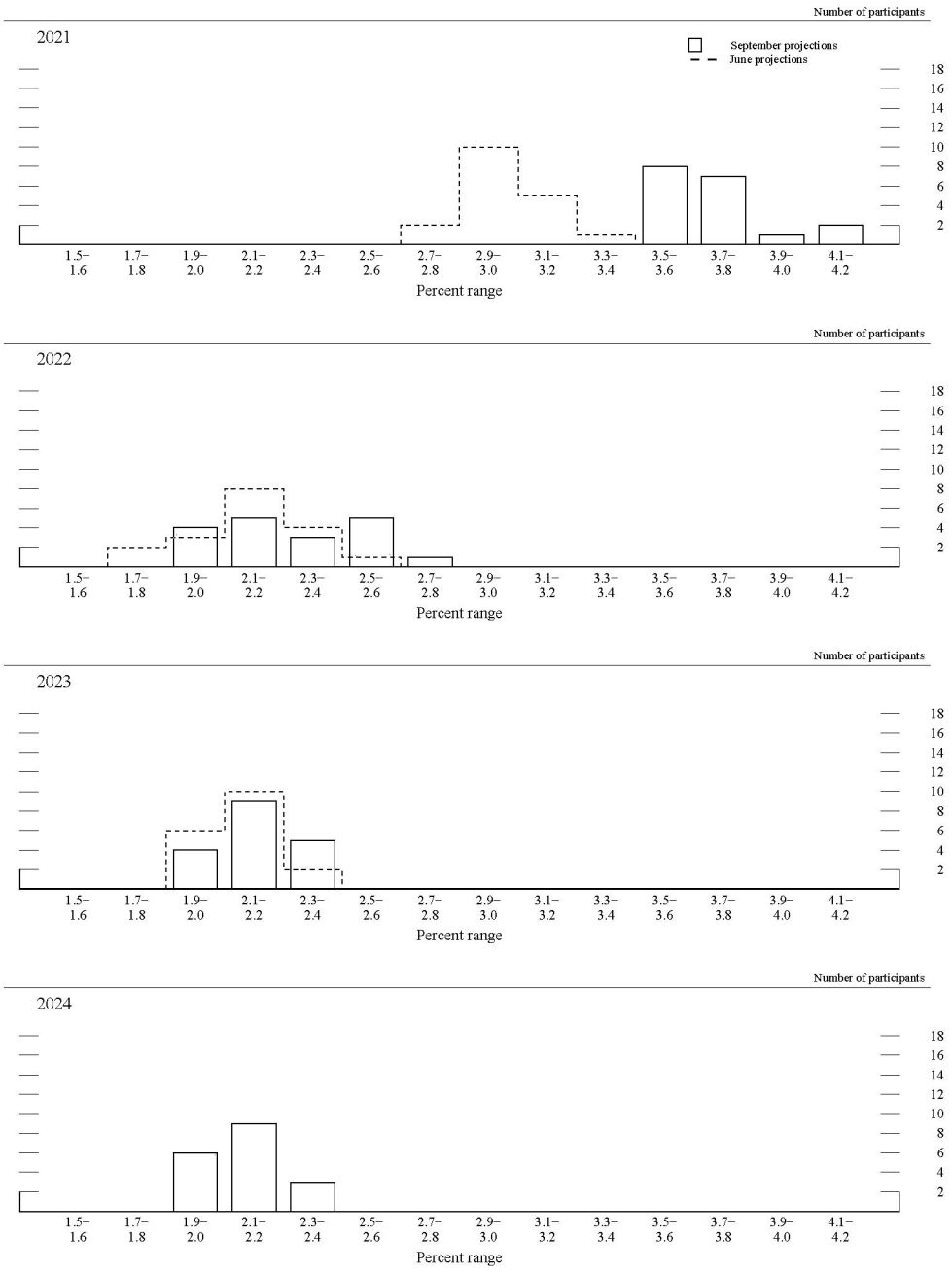
Figure 3.D. Distribution of participants' projections for core PCE inflation, 2021–24



NOTE: Definitions of variables and other explanations are in the notes to table 1.

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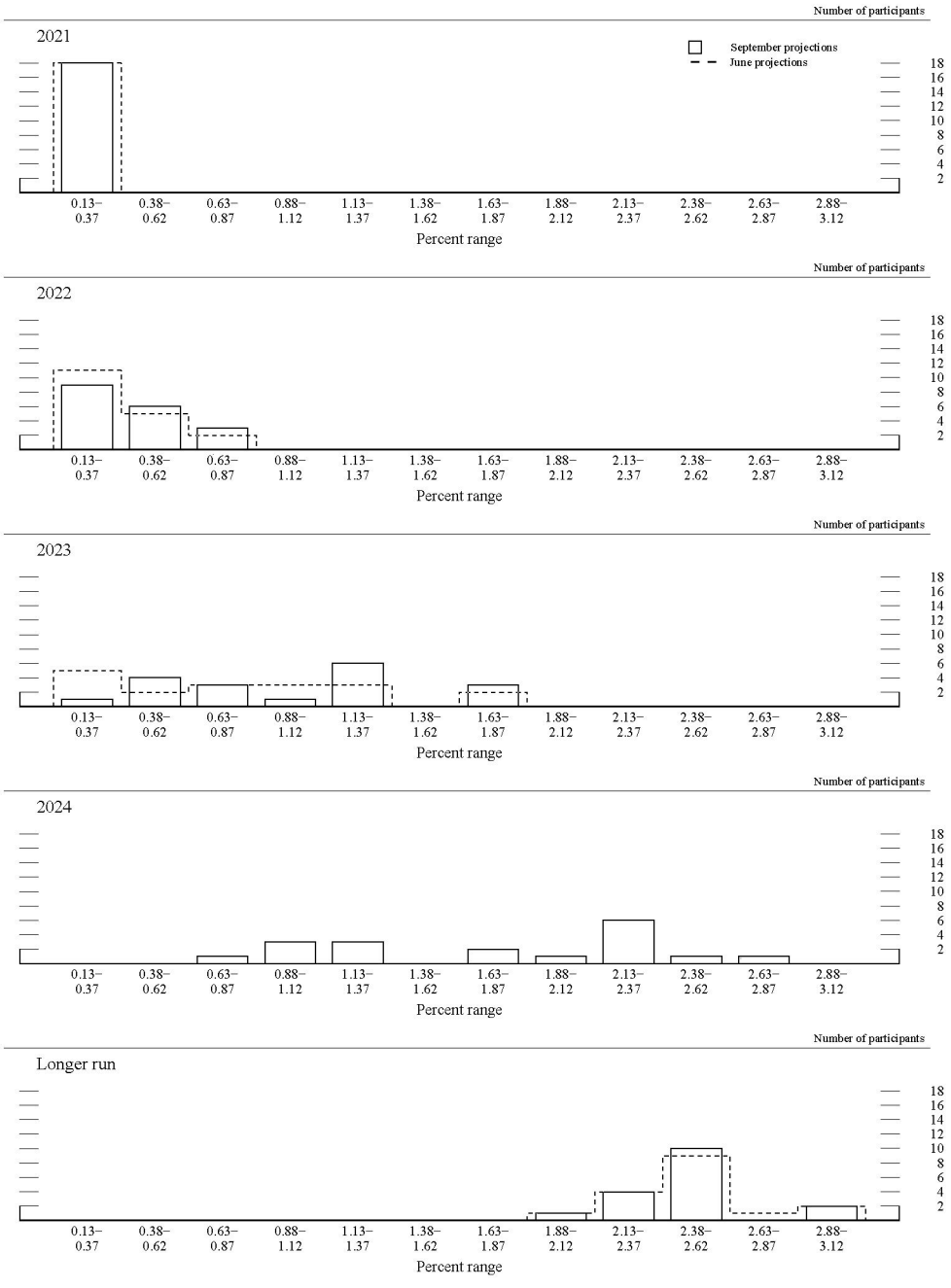
Figure 3.E. Distribution of participants' judgments of the midpoint of the appropriate target range for the federal funds rate or the appropriate target level for the federal funds rate, 2021–24 and over the longer run



NOTE: Definitions of variables and other explanations are in the notes to table 1.

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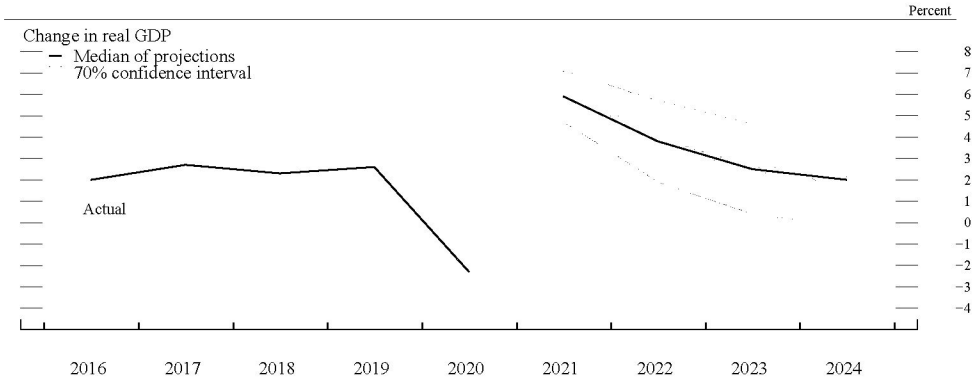
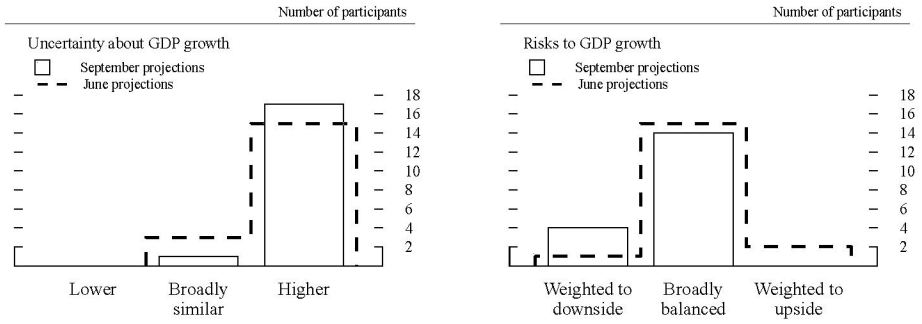
Figure 4.A. Uncertainty and risks in projections of GDP growth

Median projection and confidence interval based on historical forecast errors



FOMC participants' assessments of uncertainty and risks around their economic projections



NOTE: The blue and red lines in the top panel show actual values and median projected values, respectively, of the percent change in real gross domestic product (GDP) from the fourth quarter of the previous year to the fourth quarter of the year indicated. The confidence interval around the median projected values is assumed to be symmetric and is based on root mean squared errors of various private and government forecasts made over the previous 20 years; more information about these data is available in table 2. Because current conditions may differ from those that prevailed, on average, over the previous 20 years, the width and shape of the confidence interval estimated on the basis of the historical forecast errors may not reflect FOMC participants' current assessments of the uncertainty and risks around their projections; these current assessments are summarized in the lower panels. Generally speaking, participants who judge the uncertainty about their projections as "broadly similar" to the average levels of the past 20 years would view the width of the confidence interval shown in the historical fan chart as largely consistent with their assessments of the uncertainty about their projections. Likewise, participants who judge the risks to their projections as "broadly balanced" would view the confidence interval around their projections as approximately symmetric. For definitions of uncertainty and risks in economic projections, see the box "Forecast Uncertainty."

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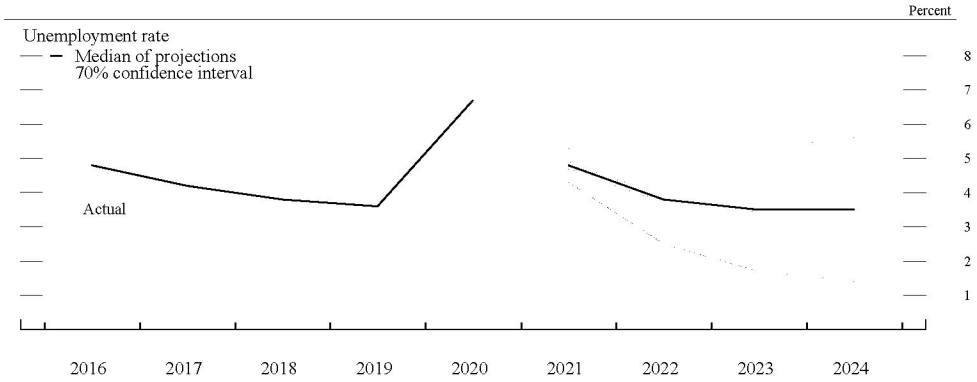
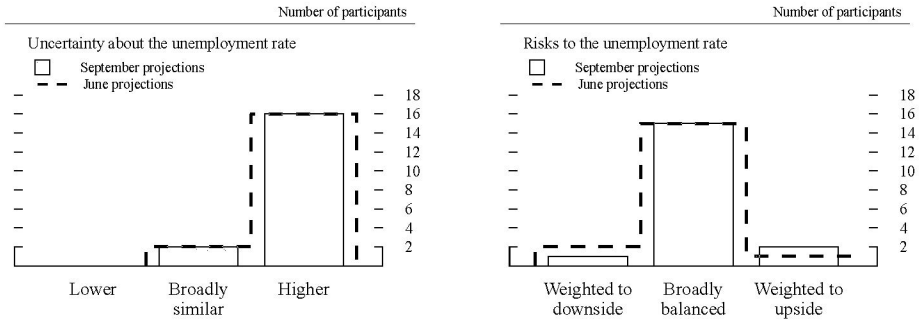
Figure 4.B. Uncertainty and risks in projections of the unemployment rate

Median projection and confidence interval based on historical forecast errors



FOMC participants' assessments of uncertainty and risks around their economic projections



NOTE: The blue and red lines in the top panel show actual values and median projected values, respectively, of the average civilian unemployment rate in the fourth quarter of the year indicated. The confidence interval around the median projected values is assumed to be symmetric and is based on root mean squared errors of various private and government forecasts made over the previous 20 years; more information about these data is available in table 2. Because current conditions may differ from those that prevailed, on average, over the previous 20 years, the width and shape of the confidence interval estimated on the basis of the historical forecast errors may not reflect FOMC participants' current assessments of the uncertainty and risks around their projections; these current assessments are summarized in the lower panels. Generally speaking, participants who judge the uncertainty about their projections as "broadly similar" to the average levels of the past 20 years would view the width of the confidence interval shown in the historical fan chart as largely consistent with their assessments of the uncertainty about their projections. Likewise, participants who judge the risks to their projections as "broadly balanced" would view the confidence interval around their projections as approximately symmetric. For definitions of uncertainty and risks in economic projections, see the box "Forecast Uncertainty."

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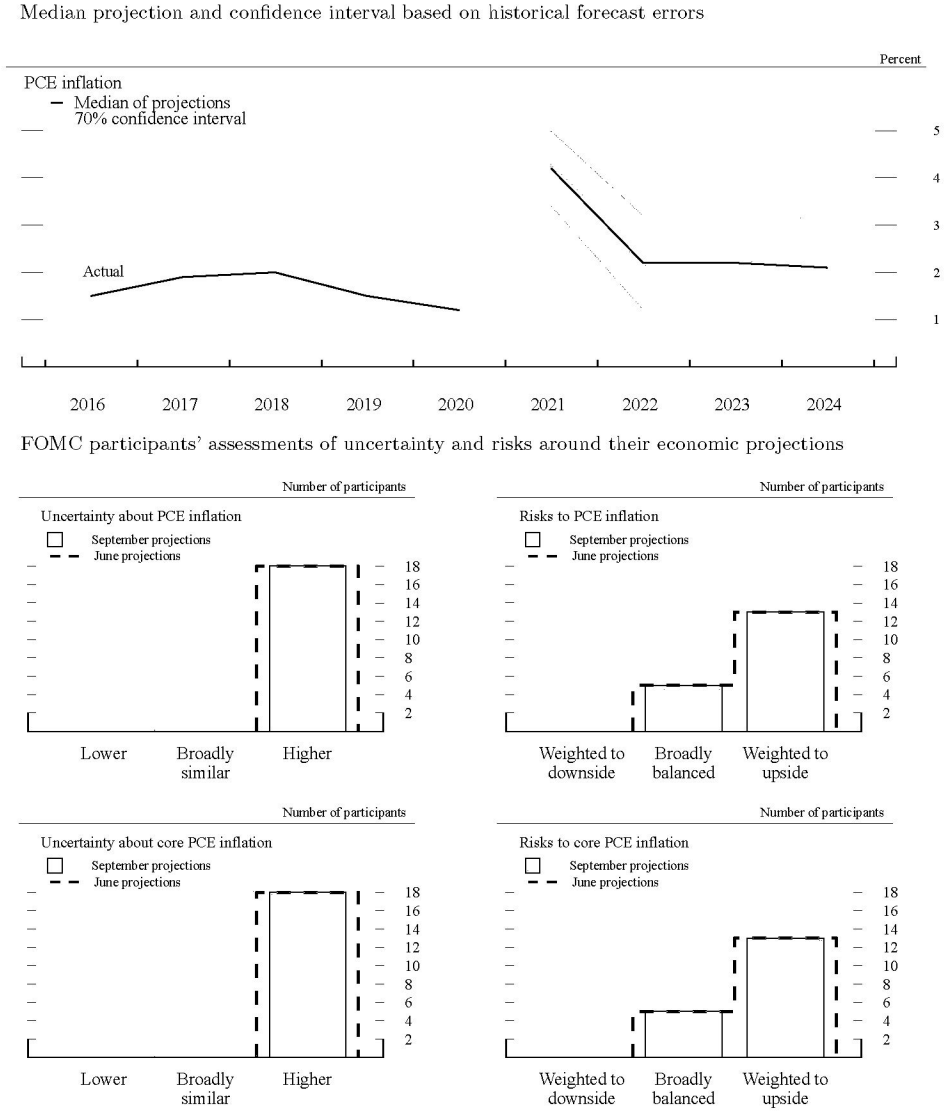
Figure 4.C. Uncertainty and risks in projections of PCE inflation



NOTE: The blue and red lines in the top panel show actual values and median projected values, respectively, of the percent change in the price index for personal consumption expenditures (PCE) from the fourth quarter of the previous year to the fourth quarter of the year indicated. The confidence interval around the median projected values is assumed to be symmetric and is based on root mean squared errors of various private and government forecasts made over the previous 20 years; more information about these data is available in table 2. Because current conditions may differ from those that prevailed, on average, over the previous 20 years, the width and shape of the confidence interval estimated on the basis of the historical forecast errors may not reflect FOMC participants' current assessments of the uncertainty and risks around their projections; these current assessments are summarized in the lower panels. Generally speaking, participants who judge the uncertainty about their projections as "broadly similar" to the average levels of the past 20 years would view the width of the confidence interval shown in the historical fan chart as largely consistent with their assessments of the uncertainty about their projections. Likewise, participants who judge the risks to their projections as "broadly balanced" would view the confidence interval around their projections as approximately symmetric. For definitions of uncertainty and risks in economic projections, see the box "Forecast Uncertainty."

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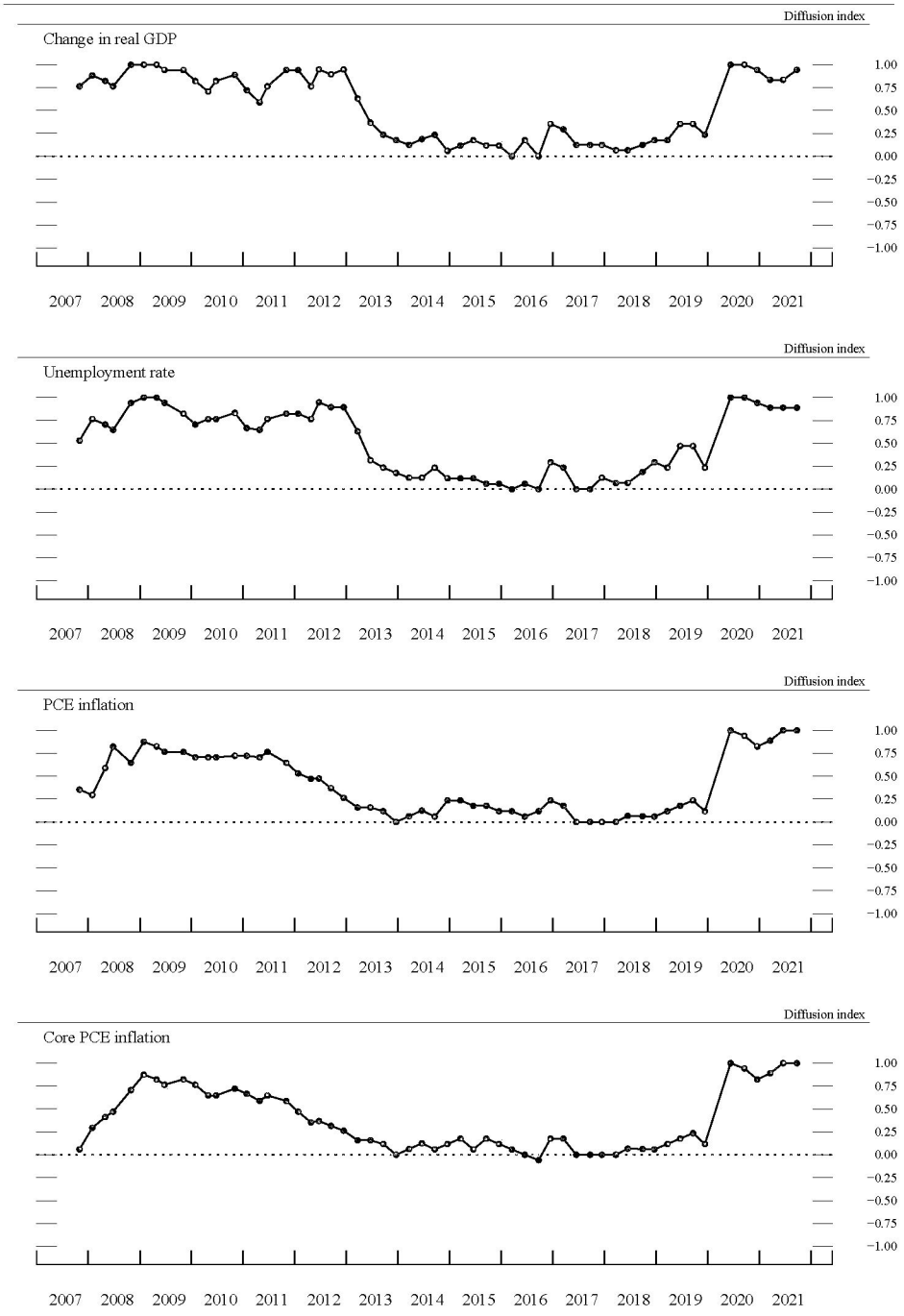
Figure 4.D. Diffusion indexes of participants' uncertainty assessments



NOTE: For each SEP, participants provided responses to the question "Please indicate your judgment of the uncertainty attached to your projections relative to the levels of uncertainty over the past 20 years." Each point in the diffusion indexes represents the number of participants who responded "Higher" minus the number who responded "Lower," divided by the total number of participants. Figure excludes March 2020 when no projections were submitted.

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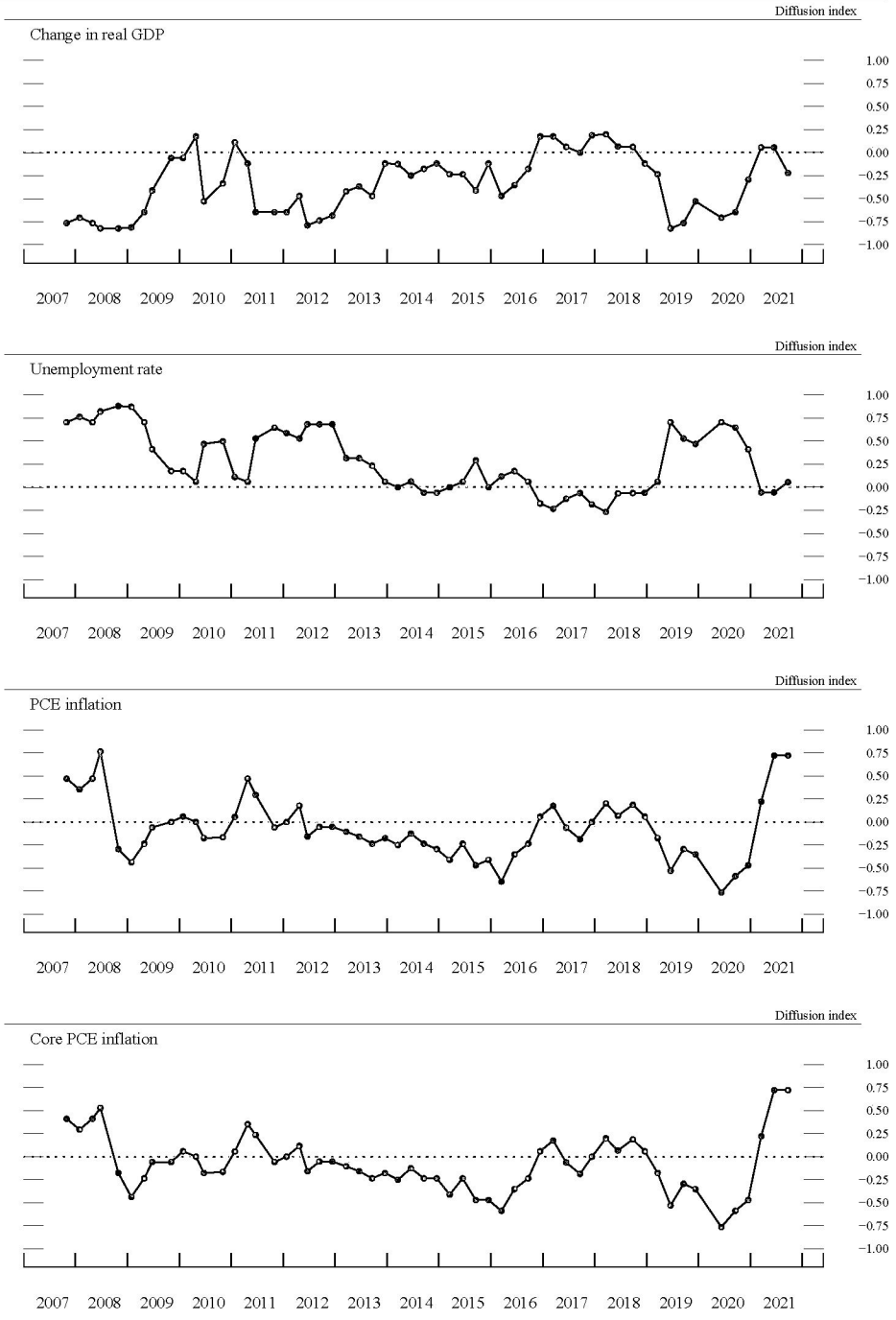
Figure 4.E. Diffusion indexes of participants' risk weightings



NOTE: For each SEP, participants provided responses to the question "Please indicate your judgment of the risk weighting around your projections." Each point in the diffusion indexes represents the number of participants who responded "Weighted to the Upside" minus the number who responded "Weighted to the Downside," divided by the total number of participants. Figure excludes March 2020 when no projections were submitted.

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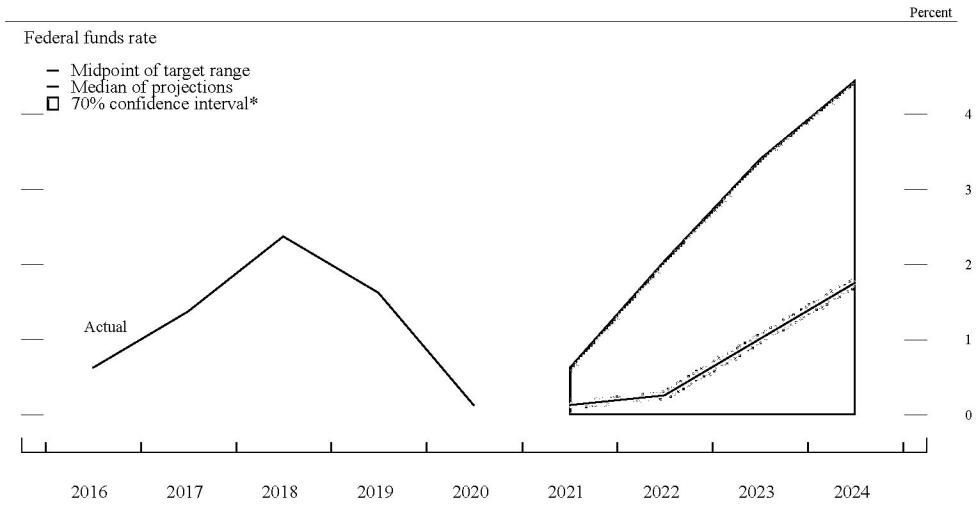
Figure 5. Uncertainty and risks in projections of the federal funds rate



NOTE: The blue and red lines are based on actual values and median projected values, respectively, of the Committee's target for the federal funds rate at the end of the year indicated. The actual values are the midpoint of the target range; the median projected values are based on either the midpoint of the target range or the target level. The confidence interval around the median projected values is based on root mean squared errors of various private and government forecasts made over the previous 20 years. The confidence interval is not strictly consistent with the projections for the federal funds rate, primarily because these projections are not forecasts of the likeliest outcomes for the federal funds rate, but rather projections of participants' individual assessments of appropriate monetary policy. Still, historical forecast errors provide a broad sense of the uncertainty around the future path of the federal funds rate generated by the uncertainty about the macroeconomic variables as well as additional adjustments to monetary policy that may be appropriate to onset the effects of shocks to the economy.

The confidence interval is assumed to be symmetric except when it is truncated at zero - the bottom of the lowest target range for the federal funds rate that has been adopted in the past by the Committee. This truncation would not be intended to indicate the likelihood of the use of negative interest rates to provide additional monetary policy accommodation if doing so was judged appropriate. In such situations, the Committee could also employ other tools, including forward guidance and large-scale asset purchases, to provide additional accommodation. Because current conditions may differ from those that prevailed, on average, over the previous 20 years, the width and shape of the confidence interval estimated on the basis of the historical forecast errors may not reflect FOMC participants' current assessments of the uncertainty and risks around their projections.

* The confidence interval is derived from forecasts of the average level of short-term interest rates in the fourth quarter of the year indicated; more information about these data is available in table 2. The shaded area encompasses less than a 70 percent confidence interval if the confidence interval has been truncated at zero.

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Table 2. Average Historical Projection Error Ranges (Percentage points)

Variable	2021	2022	2023	2024
Change in real GDP[1]	±1.2	±1.9	±2.1	±2.2
Unemployment rate[1]	±0.5	±1.3	±1.8	±2.1
Total consumer prices[2]	±0.8	±1.0	±1.1	±1.0
Short-term interest rates[3]	±0.5	±1.8	±2.4	±2.7

NOTE: Error ranges shown are measured as plus or minus the root mean squared error of projections for 2001 through 2020 that were released in the fall by various private and government forecasters. As described in the box "Forecast Uncertainty," under certain assumptions, there is about a 70 percent probability that actual outcomes for real GDP, unemployment, consumer prices, and the federal funds rate will be in ranges implied by the average size of projection errors made in the past. For more information, see David Reifschneider and Peter Tulip (2017), "Gauging the Uncertainty of the Economic Outlook Using Historical Forecasting Errors: The Federal Reserve's Approach," Finance and Economics Discussion Series 2017-020 (Washington: Board of Governors of the Federal Reserve System, February), https://dx.doi.org/10.17016/FEDS.2017.020.

1. Definitions of variables are in the general note to table 1.

2. Measure is the overall consumer price index, the price measure that has been most widely used in government and private economic forecasts. Projections are percent changes on a fourth quarter to fourth quarter basis.

3. For Federal Reserve staff forecasts, measure is the federal funds rate. For other forecasts, measure is the rate on 3-month Treasury bills. Projection errors are calculated using average levels, in percent, in the fourth quarter.

Forecast Uncertainty

The economic projections provided by the members of the Board of Governors and the presidents of the Federal Reserve Banks inform discussions of monetary policy among policymakers and can aid public understanding of the basis for policy actions. Considerable uncertainty attends these projections, however. The economic and statistical models and relationships used to help produce economic forecasts are necessarily imperfect descriptions of the real world, and the future path of the economy can be affected by myriad unforeseen developments and events. Thus, in setting the stance of monetary policy, participants consider not only what appears to be the most likely economic outcome as embodied in their projections, but also the range of alternative possibilities, the likelihood of their occurring, and the potential costs to the economy should they occur.

Table 2 summarizes the average historical accuracy of a range of forecasts, including those reported in past *Monetary Policy Report*s and those prepared by the Federal Reserve Board's staff in advance of meetings of the Federal Open Market Committee (FOMC). The projection error ranges shown in the table illustrate the considerable uncertainty associated with economic forecasts. For example, suppose a participant projects that real gross domestic product (GDP) and total consumer prices will rise steadily at annual rates of, respectively, 3 percent and 2 percent. If the uncertainty attending those projections is similar to that experienced in the past and the risks around the projections are broadly balanced, the numbers reported in table 2 would imply a probability of about 70 percent that actual GDP would expand within a range of 1.8 to 4.2 percent in the current year, 1.1 to 4.9 percent in the second year, 0.9 to 5.1 percent in the third year, and 0.8 to 5.2 percent in the fourth year. The corresponding 70 percent confidence intervals for overall inflation would be 1.2 to 2.8 percent in the current year, 1.0 to 3.0 percent in the second year, 0.9 to 3.1 percent in the third year, and 1.0 to 3.0 percent in the fourth year. Figures 4.A through 4.C illustrate these confidence bounds in "fan charts" that are symmetric and centered on the medians of FOMC participants' projections for GDP growth, the unemployment rate, and inflation. However, in some instances, the risks around the projections may not be symmetric. In particular, the unemployment rate cannot be negative; furthermore, the risks around a particular projection might be tilted to either the upside or the downside, in which case the corresponding fan chart would be asymmetrically positioned around the median projection.

Because current conditions may differ from those that prevailed, on average, over history, participants provide judgments as to whether the uncertainty attached to their projections of each economic variable is greater than, smaller than, or broadly similar to typical levels of forecast uncertainty seen in the past 20 years, as presented in table 2 and reflected in the widths of the confidence intervals shown in the top panels of figures 4.A through 4.C. Participants' current assessments of the uncertainty surrounding their projections are summarized in the bottom-left panels of those figures. Participants also provide judgments as to whether the risks to their projections are weighted to the upside, are weighted to the downside, or are broadly balanced. That is, while the symmetric historical fan charts shown in the top panels of figures 4.A through 4.C imply that the risks to participants' projections are balanced, participants may judge that there is a greater risk that a given variable will be above rather than below their projections. These judgments are summarized in the lower-right panels of figures 4.A through 4.C.

As with real activity and inflation, the outlook for the future path of the federal funds rate is subject to considerable uncertainty. This uncertainty arises primarily because each participant's assessment of the appropriate stance of monetary policy depends importantly on the evolution of real activity and inflation over time. If economic conditions evolve in an unexpected manner, then assessments of the appropriate setting of the federal funds rate would change from that point forward. The final line in table 2 shows the error ranges for forecasts of short-term interest rates. They suggest that the historical confidence intervals associated with projections of the federal funds rate are quite wide. It should be noted, however, that these confidence intervals are not strictly consistent with the projections for the federal funds rate, as these projections are not forecasts of the most likely quarterly outcomes but rather are projections of participants' individual assessments of appropriate monetary policy and are on an end-of-year basis. However, the forecast errors should provide a sense of the uncertainty around the future path of the federal funds rate generated by the uncertainty about the macroeconomic variables as well as additional adjustments to monetary policy that would be appropriate to offset the effects of shocks to the economy.

If at some point in the future the confidence interval around the federal funds rate were to extend below zero, it would be truncated at zero for purposes of the fan chart shown in figure 5; zero is the bottom of the lowest target range for the federal funds rate that has been adopted by the Committee in the past. This approach to the construction of the federal funds rate fan chart would be merely a convention; it would not have any implications for possible future policy decisions regarding the use of negative interest rates to provide additional monetary policy accommodation if doing so were appropriate. In such situations, the Committee could also employ other tools, including forward guidance and asset purchases, to provide additional accommodation.

While figures 4.A through 4.C provide information on the uncertainty around the economic projections, figure 1 provides information on the range of views across FOMC participants. A comparison of figure 1 with figures 4.A through 4.C shows that the dispersion of the projections across participants is much smaller than the average forecast errors over the past 20 years.

BLOOMBERG NEWS

Nov 10, 2021 15:20:26

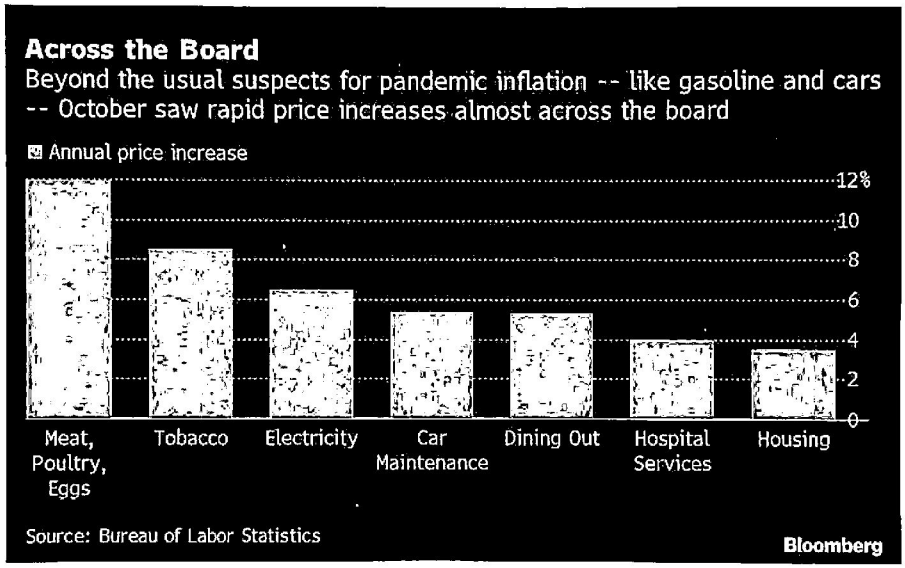
Worst Is Yet to Come for U.S. Inflation as Fed, Biden Feel Heat

- Already at a 30-year high, inflation could approach 7% soon
- Fed faces growing rate pressure: Biden spending plans at risk

By Reade Pickert, Steve Matthews and Katia Dmitrieva

(Bloomberg) -- After U.S. prices climbed by the most in three decades, there's even worse news ahead for households and policy makers: Inflation likely has further to rise before it peaks.

October's annual rate was 6.2%, the highest since 1990, as price increases spread well beyond the parts of the economy most disrupted by pandemic closures. Key drivers, like hot housing markets and a global energy crunch, show few signs of fading away soon -- leading economists to predict even bigger jumps in the coming months.



"We're going to see the inflation picture get worse before it gets better," said Sarah House, senior economist at Wells Fargo & Co. She doesn't expect much relief before next spring.

For the Federal Reserve, and President Joe Biden, that likely seems a long way off -- and pressure for a change of policy course will ratchet up in the meantime, as calls to rein in pandemic support grow louder.

'Tipping Point'

Surging prices are eating into family budgets, wiping out the wage increases that U.S. workers have battled for after last year's jobs wipeout, and squeezing profit margins for small businesses.

The Fed has already begun to back away from the case it's been making since Covid-19 first arrived: that pandemic inflation will be "transitory." It's starting to wind down bond purchases this month, and leaning toward raising interest rates next year instead of waiting until 2023. Wednesday's inflation data could accelerate the timetable.

The U.S. central bank may have arrived at a "tipping point," said James Knightley, chief international economist at ING. "Is it really justifiable to be continuing to stimulate when you've got the economy growing at 6% and inflation increasing at 6% and no sign that there's any loss of momentum in either of those indicators?"

Knightley expects the Fed's so-called taper to be concluded in the first quarter of 2022 -- about three months ahead of the consensus schedule. And he foresees two 25 basis-point rate hikes to follow by the end of the year, with a growing likelihood that could turn into three.

That's roughly what financial markets expect too. Investors have been betting on a speeded-up hiking cycle for nearly two months. After Wednesday's inflation numbers, yields on five-year Treasuries rose more than 10 basis points.

Read More: Breakevens Surge as Traders Bet on Faster Fed Move After CPI

Not the 1970s

An acceleration of the timetable could show up at next month's meeting of the rate-setting Federal Open Market Committee, said Michael Feroli, chief U.S. economist at JPMorgan Chase & Co. Last time the Fed released a so-called "dot-plot" in September, it showed an even split on whether rates will rise next year.

"It is reasonable to suspect you could get the median to move higher," Feroli said.

> **What Bloomberg Economics Says...**
>
> "We expect headline inflation may top 6.8% year on year in November. The main factors would be persistent price gains for energy and shelter and adverse base effects."
>
> "While the bar for accelerating the pace of Fed taper is extremely high and the central bank is unlikely to do so, today's release -- and the readings in the rest of the year --likely would put them in a very hot seat."
>
> Anna Wong, Bloomberg Economics
>
> Click here to read the full note

Fed officials acknowledge that inflation is sticking around longer than they'd expected. They fret that households and businesses may come to expect more of the same, the kind of change in expectations that can prove self-fulfilling. But they still reckon many price increases are essentially a one-off.

There's no reason why the energy spike of 2021, or the big shift in housing markets driven by work-from-home, should repeat themselves in future years, the argument goes. And labor isn't strong enough to keep bidding wages up like it did in the 1970s.

That's why there'll be plenty of resistance inside the Fed to any abrupt shift toward tighter policy.

"Inflation is high, it's eye-popping," Mary Daly, president of the San Francisco Fed and one of the central bank's most dovish officials, told Bloomberg TV on Wednesday. Still, "right now it would be premature to start changing our calculations about raising rates," she said. "Uncertainty requires us to wait and watch with vigilance."

'Tight Spot'

Biden, whose party suffered a reversal in state elections last week and must defend thin Congressional majorities in mid-term voting next year, is in the firing line too. Inflation is high on the list of public grievances, and the president called it a "top priority" after Wednesday's data.

One problem for Biden, as he tries to get a $1.75 trillion social-spending plan through Congress, is that he needs votes from centrists like Senator Joe Manchin of West Virginia -- who's voiced concerns that more public spending could make inflation worse. On Wednesday, Manchin called for action against soaring prices, without saying what kind.

Still, it's the Fed -- which is supposed to be responsible for managing inflation -- that's more directly in the firing line.

In the last couple of years the central bank has come up with a new policy framework, essentially allowing it to keep rates lower even when inflation stays a bit above the 2% target, and rolled out emergency programs to dig the economy out of a deep pandemic hole.

Through all of this, it's stressed the importance of accommodative monetary policy to boost employment and growth, and allow wages -- especially for low-income Americans -- to keep rising. But those arguments, drawn up in a world where inflation rarely got near 3%, are getting harder to sustain at 6% plus.

"The fact that inflation is off the business page and on the front page is a problem for an institution trying to preserve its reputation," said Feroli. "They are in a tough spot."

--With assistance from Alex Tanzi and Craig Torres.

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Understanding the CME Group FedWatch Tool and Fed Funds Futures Probability Tree Calculator

13 Jan 2017 // By CME Group // Topics: #Interest Rates

Fed Watch Tool's Assumption and Interpretations:

- Probability of a rate hike is calculated by adding the probabilities of all target rate levels above the current target rate.
- Probabilities of possible Fed Funds target rates are based on Fed Fund futures contract prices assuming that the rate hike is 0.25% (25 basis points) and that the Fed Funds Effective Rate (FFER) will react by a like amount.
- FOMC meetings probabilities are determined from the corresponding CME Group Fed Fund futures contracts.

Methodology:

The FedWatch tool calculates unconditional probabilities of Federal Open Market Committee (FOMC) meeting outcomes to generate a binary probability tree. CME Group lists 30-Day Federal Funds Futures (FF) futures, prices of which incorporate market expectations of average daily Federal Funds Effective Rate (FFER) levels during futures contract months. (E.g., the market price of FFU5 reflects the market consensus expectation of the average FFER level during the month of September 2015.) The FFER is published by the Federal Reserve Bank of New York each day, and is calculated as a transaction-volume weighted average of the previous day's rates on trades arranged by major brokers in the market for overnight unsecured loans between depository institutions.

In the FedWatch tool's probability analysis, the implementation assumes that the size of a rate change is always 25 basis points and that for a given FOMC meeting month, prior or post FF futures contract prices contain information that either is independent of the outcome of that meeting or is solely dependent on that meeting's outcome. Additionally, the FedWatch tool incorporates the assumption that FFER is bounded below by zero. Because the price of each FF futures contract represents the expected average daily FFER for the contract month, if one were in a FOMC meeting month where there was no FOMC meeting in the prior month, then the FF futures price of the previous month contains information independent of the current month's meeting. Likewise, if one were in a FOMC meeting month such that there was no FOMC meeting scheduled for the next following month, then the FF futures price of the following contains only information about the outcome of the current month's meeting. If one assumes that in its current month meeting the FOMC will decide either to raise its daily FFER target or to maintain the status quo, then the probabilities of a rate hike versus no rate hike would be calculated as:

P(Hike) = [FFER(end of month) – FFER(start of month)] / 25 basis points

P(NoHike) = 1 – P(Hike)

Whether the FOMC sets its target for daily FFER as a level or as a range should not affect either the pricing of FF futures or the calculation of implied probabilities of FOMC meeting outcomes, because calculation is based on a comparison of FFER (end of month) versus FFER (start of month). Provided that changes in the FOMC target levels are of the magnitude of 25 basis points (whether as the change in a given target level or in the location of a target range), the probability of a rate change is relative to the expected End-of-month target versus the expected Start-of-month target.

To calculate unconditional probability of a change in the target at the current month FOMC meeting, the primary consideration is whether there is an FOMC meeting in the month immediately before "meeting" month. If there was no meeting in the month prior, it is categorized as a "Type 2 meeting." Otherwise, it is categorized as a "Type 1 meeting." To see this, consider the following table:

	TYPE 1	TYPE 2
N	Days in Meeting Month	Days in Meeting Month

M	Day(MeetingDate) – 1	Day(MeetingDate) – 1
FFER.Start	(N/M) * [Implied Rate – FFER(end)*((N-M)/N)]	(1 – FF.MonthBefore)
Implied Rate	100 – FF.MeetingMonth	
FFER.End	(1 – FF.MonthAfter)	(N/(N-M)) * [Implied Rate – (M/N)*FFER(start)]

Example, September 17, 2015 FOMC – Type #2

FFQ5 = 99.8675

FFU5 = 99.805

N = 30

M = 16

FFER(start) = 0.1325 (100-99.8675)

ImpliedRate = 0.195 (100-99.805)

FFER(end) = 30/14* [0.195 – (16/30)*0.1325]
= 0.26643

P(Hike) = (0.26643 – 0.1325) / 0.25 = 53.6%

P(NoHike) = 46.4%

After the FedWatch tool computes the unconditional probability for each known meeting date (as published by the Federal Reserve Board of Governors website), it calculates a binary policy decision tree.

For the first node of the tree, there are probabilities for two outcomes: (1) Maintenance of current target or (2) a change to a different target (25 bps higher or 25 bps lower). In the current example and in subsequent examples, there will only be two outcomes, i.e. hike or no hike, cut or no cut[1].

For the second node, assuming that the expectation is for the target rate to be raised or not, then at the second meeting we have the following probabilities: probability of a decreased target rate at the second meeting, probability of an unchanged target rate FFTR at the second meeting, probability of an increased target rate at the second meeting.

The equations are as follows[2]:

P(FFER decreased) = Probability(FFER Decrease previous) * (1-Probability of a rate change)

P(FFER unchanged) = Probability(FFTR increase previous) * (1-Probablity of a rate change)
+ (Probability of a FFTR decrease previous) * (Probability of a rate change)

P(FFER increased) = (Probability FFTR Increase previous)* (Probability of a rate change)

Note 1: Recall that one of the assumptions of this methodology is that the FOMC will always move rates in 25 basis point increments. It is possible for the expected Federal Funds Rate (as implied from futures prices) to be more than 25 basis points above the current effective rate – in this case the market is implying some chance of a rate hike of rate hike greater than 25 basis points.

In such cases, the calculated probability will exceed 100%. To simplify the interpretation, the calculated probability is re-distributed between the probability of a single hike and the probability of two hikes

- The amount that is in excess of 100% will be defined as the probability of a 50 basis point rate hike, to the next target increment, defined as $P_{50bp\ hike}$
- The probability of a single hike is now defined as (1- $P_{50bp\ hike}$)

Example: Due to high implied rate in futures contract, calculated probability is 104% probability of a 25 bps rate hike, with a -4% probability of no change. Using a formula, this will be redistributed and shown as P(NoHike)=0%, P(25bpHike) = 96%, and P(50bpHike) = 4%

Note 2: Based on market commentary and market assumptions the FFER is bounded by zero. As such the scenarios for the second node are as follows: Probability of unchanged FFER at the second meeting, Probability of an increased FFER in the second meeting (or probability of a decrease in the second meeting after an increase in the first), Probability of an increased FFER in the first and second meeting.

The formulas for these probabilities are as follows:

P(FFER unchanged) = Probability(FFER NoHike previous meeting) * (1-Probability of a rate change)

P(FFER first increased on this meeting date, or decreased at second meeting if hike in the first meeting) = Probability(FFTR hike previous meeting) * (1-Probablity of a rate change) + (Probability of a FFTR NoHike previous meeting) * (Probability of a rate change)

P(FFER increased this meeting date as well as previous meeting date) = (Probability FFTR Increase previous meeting)* (Probability of a rate change)

Economic News Release

Consumer Price Index Summary

Transmission of material in this release is embargoed until
8:30 a.m. (ET) November 10, 2021 USDL-21-1973

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CONSUMER PRICE INDEX – OCTOBER 2021

The Consumer Price Index for All Urban Consumers (CPI-U) increased 0.9 percent in October on a seasonally adjusted basis after rising 0.4 percent in September, the U.S. Bureau of Labor Statistics reported today. Over the last 12 months, the all items index increased 6.2 percent before seasonal adjustment.

The monthly all items seasonally adjusted increase was broad-based, with increases in the indexes for energy, shelter, food, used cars and trucks, and new vehicles among the larger contributors. The energy index rose 4.8 percent over the month, as the gasoline index increased 6.1 percent and the other major energy component indexes also rose. The food index increased 0.9 percent as the index for food at home rose 1.0 percent.

The index for all items less food and energy rose 0.6 percent in October after increasing 0.2 percent in September. Most component indexes increased over the month. Along with shelter, used cars and trucks, and new vehicles, the indexes for medical care, for household furnishing and operations, and for recreation all increased in October. The indexes for airline fares and for alcoholic beverages were among the few to decline over the month.

The all items index rose 6.2 percent for the 12 months ending October, the large st 12-month increase since the period ending November 1990. The index for all items less food and energy rose 4.6 percent over the last 12 months, the largest 12-month increase since the period ending August 1991. The energy index rose 30.0 percent over the last 12 months, and the food index increased 5.3 percent.

Table A. Percent changes in CPI for All Urban Consumers (CPI-U): U.S. city average

	Seasonally adjusted changes from preceding month							Un-adjusted 12-mos. ended
	Apr. 2021	May 2021	June 2021	July 2021	Aug. 2021	Sep. 2021	Oct. 2021	Oct. 2021
All items	.8	.6	.9	.5	.3	.4	.9	6.2
Food	.4	.4	.8	.7	.4	.9	.9	5.3
Food at home	.4	.4	.8	.7	.4	1.2	1.0	5.4
Food away from home (1)	.3	.6	.7	.8	.4	.5	.8	5.3
Energy	-.1	.0	1.5	1.6	2.0	1.3	4.8	30.0
Energy commodities	-1.4	-.6	2.6	2.3	2.7	1.3	6.2	49.5
Gasoline (all types)	-1.4	-.7	2.5	2.4	2.8	1.2	6.1	49.6
Fuel oil (1)	-3.2	2.1	2.9	.6	-2.1	3.9	12.3	59.1
Energy services	1.5	.7	.2	.8	1.1	1.2	3.0	11.2
Electricity	1.2	.3	-.3	.4	1.0	.8	1.8	6.5
Utility (piped) gas service	2.4	1.7	1.7	2.2	1.6	2.7	6.6	28.1
All items less food and energy	.9	.7	.9	.3	.1	.2	.6	4.6
Commodities less food and energy commodities	2.0	1.8	2.2	.5	.3	.2	1.0	8.4
New vehicles	.5	1.6	2.0	1.7	1.2	1.3	1.4	9.8
Used cars and trucks	10.0	7.3	10.5	.2	-1.5	-.7	2.5	26.4
Apparel	.3	1.2	.7	.0	.4	-1.1	.0	4.3
Medical care commodities (1)	.6	.0	-.4	.2	-.2	.3	.6	-.4
Services less energy services	.5	.4	.4	.3	.0	.2	.4	3.2
Shelter	.4	.3	.5	.4	.2	.4	.5	3.5
Transportation services	2.9	1.5	1.5	-1.1	-2.3	-.5	.4	4.5
Medical care services	.0	-.1	.0	.3	.3	-.1	.5	1.7

1 Not seasonally adjusted.

Food

The food index increased 0.9 percent in October, the same increase as in September.

The food at home index increased 1.0 percent over the month as all six major grocery store food group indexes continued to rise. The index for meats, poultry, fish, and eggs continued to rise sharply, increasing 1.7 percent following a 2.2-percent increase in September. The index for beef rose 3.1 percent over the month.

The index for other food at home rose 1.2 percent over the month, its largest monthly increase since April 2020, near the onset of the pandemic. The index for cereals and bakery products rose 1.0 percent in October following a 1.1-percent increase the prior month. The index for nonalcoholic beverages rose 0.8 percent in October, the index for dairy and related products rose 0.2 percent, and the index for fruits and vegetables advanced 0.1 percent.

The food away from home index rose 0.8 percent in October after increasing 0.5 percent in September. The index for full service meals rose 0.9 percent and the index for limited service meals increased 0.8 percent over the month.

The food at home index rose 5.4 percent over the past 12 months as all of the six major grocery store food group indexes increased over the period. The index for meats, poultry, fish, and eggs increased 11.9 percent, with the index for beef rising 20.1 percent and the index for pork rising 14.1 percent, its largest 12-month increase since the period ending December 1990. The other major grocery store food group indexes also increased over the last 12 months with increases ranging from 1.8 percent (dairy and related products) to 4.5 percent (nonalcoholic beverages).

The index for food away from home rose 5.3 percent over the last year. The index for limited service meals rose 7.1 percent over the last 12 months, and the index for full service meals rose 5.9 percent, both the largest 12-month increases in the history of the respective series. The index for food at employee sites and schools declined sharply over the past year, falling 45.4 percent.

Energy

The energy index rose 4.8 percent in October after rising 1.3 percent in September. The gasoline index rose 6.1 percent in October, its fifth consecutive monthly increase. (Before seasonal adjustment, gasoline prices rose 3.7 percent in October.) The index for natural gas rose 6.6 percent over the month, its largest monthly increase since March 2014. The electricity index increased 1.8 percent in October, its largest 1-month increase since May 2014, while the fuel oil index also rose sharply, increasing 12.3 percent.

The energy index rose 30.0 percent over the past 12 months, its largest 12-month increase since the period ending September 2005. All the major energy component indexes increased sharply over the last 12 months. The gasoline index rose 49.6 percent over the last year, and is now at its highest level since September 2014. The fuel oil index increased sharply over the year, rising 59.1 percent. The index for natural gas rose 28.1 percent over the last 12 months, and the electricity index rose 6.5 percent.

All items less food and energy

The index for all items less food and energy rose 0.6 percent in October as most major component indexes increased. The shelter index increased 0.5 percent over the month, as the indexes for rent and owners' equivalent rent both rose 0.4 percent and the index for lodging away from home increased 1.4 percent. Major vehicle indexes also rose in October. The index for used cars and trucks rose 2.5 percent after declining in August and September. The index for new vehicles rose 1.4 percent in October, its seventh consecutive monthly increase.

The medical care index increased in October, rising 0.5 percent, its largest monthly increase since May 2020. The index for hospital services rose 0.5 percent, and the index for prescription drugs advanced 0.6 percent; the index for physicians' services was unchanged. The household furnishings and operations index rose 0.8 percent, and the recreation index increased 0.7 percent. Also rising in October were the indexes for personal care (0.6 percent), tobacco (1.9 percent), education (0.2 percent), and communication (0.1 percent).

The motor vehicle insurance index and the apparel index were both unchanged in October. The index for airline fares was one of the few to decline, falling 0.7 percent; the index for alcoholic beverages decreased 0.2 percent.

The index for all items less food and energy rose 4.6 percent over the past 12 months. Component indexes rising more include used cars and trucks (26.4 percent) and new vehicles (9.8 percent, the largest 12-month increase since the period ending May 1975). Indexes rising less than 4.6 percent include shelter (3.5 percent) and medical care (1.3 percent). Few major component indexes declined over the past year; one exception is airline fares (-4.6 percent).

Not seasonally adjusted CPI measures

The Consumer Price Index for All Urban Consumers (CPI-U) increased 6.2 percent over the last 12 months to an index level of 276.589 (1982-84=100). For the month, the index increased 0.8 percent prior to seasonal adjustment.

The Consumer Price Index for Urban Wage Earners and Clerical Workers (CPI-W) increased 6.9 percent over the last 12 months to an index level of 271.552 (1982-84=100). For the month, the index rose 0.9 percent prior to seasonal adjustment.

The Chained Consumer Price Index for All Urban Consumers (C-CPI-U) increased 6.1 percent over the last 12 months. For the month, the index increased 0.8 percent on a not seasonally adjusted basis. Please note that the indexes for the past 10 to

12 months are subject to revision.

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The Consumer Price Index for November 2021 is scheduled to be released on Friday, December 10, 2021 at 8:30 a.m. (ET).

Coronavirus (COVID-19) Pandemic Impact on October 2021 Consumer Price Index Data

Data collection by personal visit for the Consumer Price Index (CPI) program has been suspended almost entirely since March 16, 2020. When possible, data normally collected by personal visit were collected either online or by phone. Additionally, data collection in October was affected by the temporary closing or limited operations of certain types of establishments. These factors resulted in an increase in the number of prices considered temporarily unavailable and imputed. While the CPI program attempted to collect as much data as possible, many indexes are based on smaller amounts of collected prices than usual, and a small number of indexes that are normally published were not published this month. Additional information is available at www.bls.gov/covid19/effects-of-covid-19-pandemic-on-consumer-price-index.htm.

Technical Note

Brief Explanation of the CPI

The Consumer Price Index (CPI) measures the change in prices paid by consumers for goods and services. The CPI reflects spending patterns for each of two population groups: all urban consumers and urban wage earners and clerical workers. The all urban consumer group represents about 93 percent of the total U.S. population. It is based on the expenditures of almost all residents of urban or metropolitan areas, including professionals, the self-employed, the poor, the unemployed, and retired people, as well as urban wage earners and clerical workers. Not included in the CPI are the spending patterns of people living in rural nonmetropolitan areas, farming families, people in the Armed Forces, and those in institutions, such as prisons and mental hospitals. Consumer inflation for all urban consumers is measured by two indexes, namely, the Consumer Price Index for All Urban Consumers (CPI-U) and the Chained Consumer Price Index for All Urban Consumers (C-CPI-U).

The Consumer Price Index for Urban Wage Earners and Clerical Workers (CPI-W) is based on the expenditures of households included in the CPI-U definition that meet two requirements: more than one-half of the household's income must come from clerical or wage occupations, and at least one of the household's earners must have been employed for at least 37 weeks during the previous 12 months. The CPI-W population represents about 29 percent of the total U.S. population and is a subset of the CPI-U population.

The CPIs are based on prices of food, clothing, shelter, fuels, transportation, doctors’ and dentists’ services, drugs, and other goods and services that people buy for day-to-day living. Prices are collected each month in 75 urban areas across the country from about 6,000 housing units and approximately 22,000 retail establishments (department stores, supermarkets, hospitals, filling stations, and other types of stores and service establishments). All taxes directly associated with the purchase and use of items are included in the index. Prices of fuels and a few other items are obtained every month in all 75 locations. Prices of most other commodities and services are collected every month in the three largest geographic areas and every other month in other areas. Prices of most goods and services are obtained by personal visits or telephone calls by the Bureau’s trained representatives.

In calculating the index, price changes for the various items in each location are aggregated using weights, which represent their importance in the spending of the appropriate population group. Local data are then combined to obtain a U.S. city average. For the CPI-U and CPI-W, separate indexes are also published by size of city, by region of the country, for cross-classifications of regions and population-size classes, and for 23 selected local areas. Area indexes do not measure differences in the level of prices among cities; they only measure the average change in prices for each area since the base period. For the C-CPI-U, data are issued only at the national level. The CPI-U and CPI-W are considered final when released, but the C-CPI-U is issued in preliminary form and subject to three subsequent quarterly revisions.

The index measures price change from a designed reference date. For most of the CPI-U and the CPI-W, the reference base is 1982-84 equals 100. The reference base for the C-CPI-U is December 1999 equals 100. An increase of 7 percent from the reference base, for example, is shown as 107.000. Alternatively, that relationship can also be expressed as the price of a base period market basket of goods and services rising from $100 to $107.

Sampling Error in the CPI

The CPI is a statistical estimate that is subject to sampling error because it is based upon a sample of retail prices and not the complete universe of all prices. BLS calculates and publishes estimates of the 1-month, 2-month, 6-month, and 12-month percent change standard errors annually for the CPI-U. These standard error estimates can be used to construct confidence intervals for hypothesis testing. For example, the estimated standard error of the 1-month percent change is 0.03 percent for the U.S. all items CPI. This means that if we repeatedly sample from the universe of all retail prices using the same methodology, and estimate a

percentage change for each sample, then 95 percent of these estimates will be within 0.06 percent of the 1-month percentage change based on all retail prices. For example, for a 1-month change of 0.2 percent in the all items CPI-U, we are 95 percent confident that the actual percent change based on all retail prices would fall between 0.14 and 0.26 percent. For the latest data, including information on how to use the estimates of standard error, see https://www.bls.gov/cpi/tables/variance-estimates/home.htm.

Calculating Index Changes

Movements of the indexes from 1 month to another are usually expressed as percent changes rather than changes in index points, because index point changes are affected by the level of the index in relation to its base period, while percent changes are not. The following table shows an example of using index values to calculate percent changes:

	Item A	Item B	Item C
Year I	112.500	225.000	110.000
Year II	121.500	243.000	128.000
Change in index points	9.000	18.000	18.000
Percent change	9.0/112.500 x 100 = 8.0	18.0/225.000 x 100 = 8.0	18.0/110.000 x 100 = 16.4

Use of Seasonally Adjusted and Unadjusted Data

The Consumer Price Index (CPI) produces both unadjusted and seasonally adjusted data. Seasonally adjusted data are computed using seasonal factors derived by the X-13ARIMA-SEATS seasonal adjustment method. These factors are updated each February, and the new factors are used to revise the previous 5 years of seasonally adjusted data. The factors are available at www.bls.gov/cpi/tables/seasonal-adjustment/seasonal-factors-2021.xlsx. For more information on data revision scheduling, please see the Factsheet on Seasonal Adjustment at www.bls.gov/cpi/seasonal-adjustment/questions-and-answers.htm and the Timeline of Seasonal Adjustment Methodological Changes at www.bls.gov/cpi/seasonal-adjustment/timeline-seasonal-adjustment-methodology-changes.htm.

For analyzing short-term price trends in the economy, seasonally adjusted changes are usually preferred since they eliminate the effect of changes that normally occur at the same time and in about the same magnitude every year—such as price movements resulting from weather events, production cycles, model changeovers, holidays, and sales. This allows data users to focus on changes that are not typical for the time of year. The unadjusted data are of primary interest to consumers concerned about the prices they actually pay. Unadjusted data are also used extensively for escalation purposes. Many collective bargaining contract agreements and pension plans, for example, tie compensation changes to the Consumer Price Index before adjustment for seasonal variation. BLS advises against the use of seasonally adjusted data in escalation agreements because seasonally adjusted series are revised annually.

Intervention Analysis

The Bureau of Labor Statistics uses intervention analysis seasonal adjustment for some CPI series. Sometimes extreme values or sharp movements can distort the underlying seasonal pattern of price change. Intervention analysis seasonal adjustment is a process by which the distortions caused by such unusual events are estimated and removed from the data prior to calculation of seasonal factors. The resulting seasonal factors, which more accurately represent the seasonal pattern, are then applied to the unadjusted data.

For example, this procedure was used for the motor fuel series to offset the effects of the 2009 return to normal pricing after the worldwide economic downturn in 2008. Retaining this outlier data during seasonal factor calculation would distort the computation of the seasonal portion of the time series data for motor fuel, so it was estimated and removed from the data prior to seasonal adjustment. Following that, seasonal factors were calculated based on this “prior adjusted” data. These seasonal factors represent a clearer picture of the seasonal pattern in the data. The last step is for motor fuel seasonal factors to be applied to the unadjusted data.

For the seasonal factors introduced for January 2021, BLS adjusted 72 series using intervention analysis seasonal adjustment, including selected food and beverage items, motor fuels, electricity, and vehicles.

Revision of Seasonally Adjusted Indexes

Seasonally adjusted data, including the U.S. city average all items index levels, are subject to revision for up to 5 years after their original release. Every year, economists in the CPI calculate new seasonal factors for seasonally adjusted series and apply them to the last 5 years of data. Seasonally adjusted indexes beyond the last 5 years of data are considered to be final and not subject to revision. For January 2021, revised seasonal factors and seasonally adjusted indexes for 2016 to 2020 were calculated and published. For series which are directly adjusted using the Census X-13ARIMA-SEATS seasonal adjustment software, the seasonal factors for 2020 will be applied to data for 2021 to produce the seasonally adjusted 2021 indexes. Series which are indirectly seasonally adjusted by summing seasonally adjusted component series have seasonal factors which are derived and are therefore not available in advance.

Determining Seasonal Status

Each year the seasonal status of every series is reevaluated based upon certain statistical criteria. Using these criteria, BLS economists determine whether a series should change its status from "not seasonally adjusted" to "seasonally adjusted", or vice versa. If any of the 81 components of the U.S. city average all items index change their seasonal adjustment status from seasonally adjusted to not seasonally adjusted, not seasonally adjusted data

will be used in the aggregation of the dependent series for the last 5 years, but the seasonally adjusted indexes before that period will not be changed. Thirty-four of the 81 components of the U.S. city average all items index are not seasonally adjusted for 2021.

Contact Information

For additional information about the CPI visit www.bls.gov/cpi or contact the CPI Information and Analysis Section at 202-691-7000 or cpi_info@bls.gov.

For additional information on seasonal adjustment in the CPI visit www.bls.gov/cpi/seasonal-adjustment/home.htm or contact the CPI seasonal adjustment section at 202-691-6968 or cpiseas@bls.gov.

Information from this release will be made available to sensory impaired individuals upon request. Voice phone: 202-691-5200; Federal Relay Service: 1-800-877-8339.

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https://www.wsj.com/articles/global-stock-markets-dow-update-09-28-2021-11632814517

U.S. MARKETS

Stocks Close Sharply Lower as Bond Yields Hit Three-Month High

Tech shares pull S&P 500, Nasdaq down more than 2%, while bond yields rally on inflation concerns

By Akane Otani and Will Horner
Updated Sept. 28, 2021 4:35 pm ET

U.S. stocks tumbled Tuesday, logging their sharpest pullback since May, as rising bond yields deepened a rout in shares of technology companies.

For much of the past decade, many investors had piled into shares of fast-growing technology companies, wagering they would deliver relatively robust profit growth even in a sluggish economic environment. This week, that trade hit a roadblock.

With the economy out of the worst of the pandemic-fueled crisis, the Federal Reserve signaled last week that it could start to reverse its pandemic stimulus programs as soon as November and raise interest rates sometime next year. That appears to have prompted an unwind of some of the market's most enduring trades—pushing Treasury yields to their highest level in months and sending investors out of popular technology stocks.

Investors agree the economic outlook has improved significantly since 2020. But many wonder how well the market will be able to stand on its own once the Fed begins to taper its monthly asset purchases—especially since they credit much of the market's rebound from its pandemic low to extraordinary levels of monetary and fiscal support from Washington. Some investors have also expressed concerns about the economic outlook. Inflation has made a surprising comeback this year, something some worry will start to cut into companies' profit margins. The fast-spreading Delta variant of Covid-19 has also complicated economists' efforts to forecast the global economy's growth outlook.

"People are realizing, or at least remembering, that central banks are going to have to start raising rates," said Altaf Kassam, head of investment strategy for State Street Global

Advisors in Europe. "The patient has become used to being given all these drugs, but soon those drugs are going to have to be reduced."

The S&P 500 fell 90.48 points, or 2%, to 4352.63, marking its second straight day of losses and worst one-day percentage decline since May. The tech-heavy Nasdaq Composite Index slid 423.29 points, or 2.8%, to 14546.68, while the Dow Jones Industrial Average shed 569.38 points, or 1.6%, to 34299.99.

All three major indexes are on course to end the month lower.

Tuesday's market selloff was broad, pulling all but one of the S&P 500's sectors down for the day.

Traders yanked money out of the technology sector. Shares of companies like Facebook, Google parent Alphabet and Microsoft, each of which had vastly outperformed the broader market this year, fell more than 3.5% apiece.

Meanwhile, selling pressure accelerated in the government bond market. The yield on the benchmark 10-year Treasury note rose for a sixth consecutive day Tuesday, climbing from 1.482% Monday to 1.534%, its highest level since late June. Bond yields rise as prices fall.

Shares of energy companies avoided the broader selloff.

Schlumberger added 72 cents, or 2.4%, to $30.91, while ConocoPhillips rose $1.09, or 1.6%, to $67.80. Both stocks benefited from crude oil prices hitting multiyear highs this week, although oil wound up giving up the day's gains to end slightly lower Tuesday. Strategists have attributed the spike to a combination of rising demand and supply shortages.

The jump in commodity prices has ramped up some investors' worries about short-term inflation pressures. Inflation tends to weigh on bond prices, since it erodes the purchasing value of their fixed payments.

Some investors say stocks' recent setbacks aren't surprising after a long period of relative calm. The S&P 500 has risen seven straight months in a row, its longest such streak since the 10 months through January 2018, according to Dow Jones Market Data.

Data suggests investors were heavily positioned in bets on lower interest rates and subdued inflation earlier this month, another factor that might have exacerbated the speed and scale of Tuesday's pullback. In a survey of global fund managers conducted

Sept. 3-9, Bank of America found investors were generally betting on stock prices rising and inflation pressures easing.

"That's often how it happens—you have quiet and complacent markets and then a gut check," said Keith Lerner, co-chief investment officer of Truist Advisory Services. Mr. Lerner added that he is still optimistic about the market's outlook over the longer term.

Elsewhere, European markets slumped, while Asian indexes were mixed.

The pan-continental Stoxx Europe 600 fell 2.2% for its third straight session of losses.

Hong Kong's Hang Seng Index rose 1.2% after signs of support from China's central bank helped boost beaten-down shares of Chinese real-estate developers. The People's Bank of China said late Monday it would "maintain the healthy development of the property market and safeguard the legitimate rights and interests of house buyers."

Shares of Country Garden Holdings, China Vanke and China Overseas Land and Investment all jumped between 5% and 6%. China Evergrande Group, the ailing real estate giant that has fallen behind on a payment to international bondholders, rose more than 4%. Sunac China Holdings surged almost 15%, snapping two days of steep declines, after the property company played down a leaked plea for help from a local government, and said sales were good.

Meanwhile, Japan's Nikkei Stock Average finished down 0.2%.

Higher bond yields drew investors into the U.S. dollar, which strengthened against major currencies from the euro to the Swiss franc. The WSJ Dollar Index, which tracks the currency against a basket of others, was up 0.4% and trading around a five-week high.

Some investors are recalibrating portfolios to prepare for the gradual end of ultra-easy monetary policies.

PHOTO: BRENDAN MCDERMID/REUTERS

—Xie Yu and Frances Yoon contributed to this article.

Write to Akane Otani at akane.otani@wsj.com and Will Horner at william.horner@wsj.com

Appeared in the September 29, 2021, print edition as 'Stocks Dive as Bond Yields Draw Technology Investors.'

REUTERS®

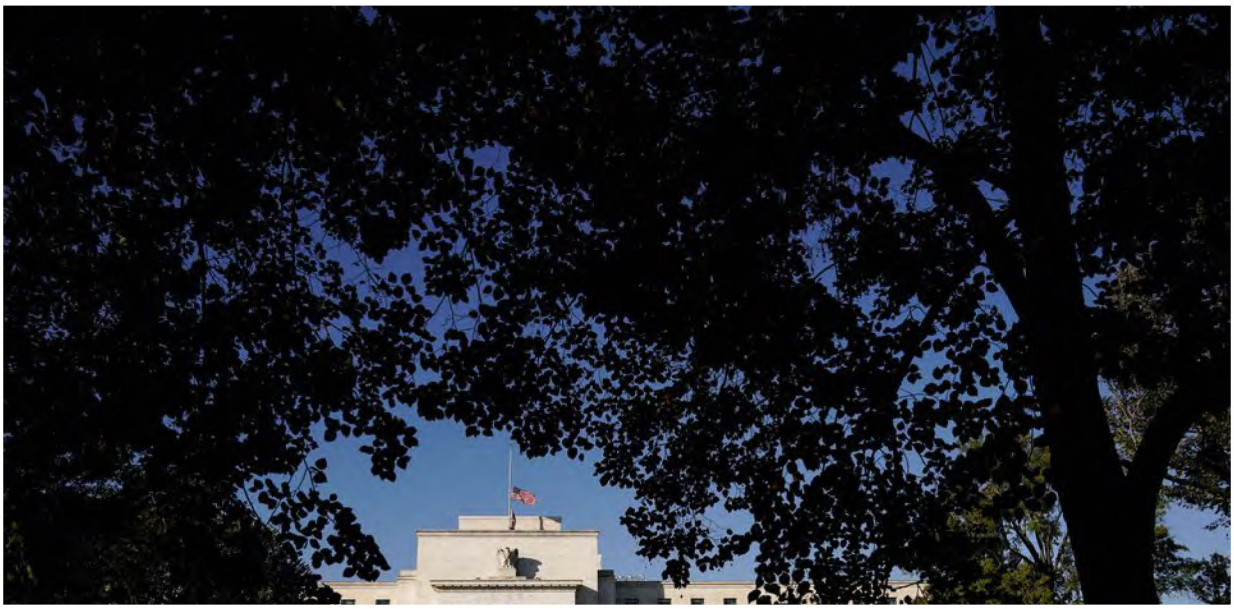
November 11, 2021 6:10 AM EST Last Updated 10 hours ago

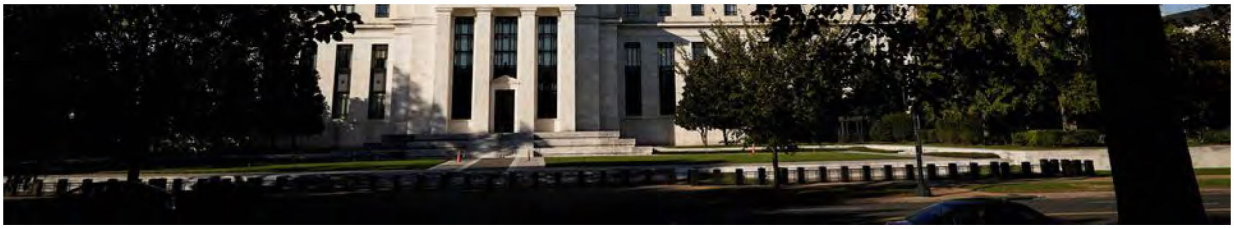
Macro Matters

Fed's 'transitory' inflation plot thickens again with rate at 30-year high

By Howard Schneider

4 minute read





The Federal Reserve building is seen in Washington, U.S., October 20, 2021. REUTERS/Joshua Roberts/File Photo

WASHINGTON, Nov 11 (Reuters) - Inflation pushed more broadly through the economy in October again challenging the Federal Reserve's outlook for only "transitory" price increases, offsetting recent wage hikes in a blow to consumers, and prompting investors to boost bets the central bank will raise interest rates sooner than expected.

Yields on two-year Treasury notes , a proxy for the outlook for the overnight interest rate set by the Fed, jumped 6 basis points, the most in three weeks and among the largest daily increases in the last year and a half, to 0.485% on Wednesday after the release of data showing consumer prices rose by 6.2% in October versus the year before.

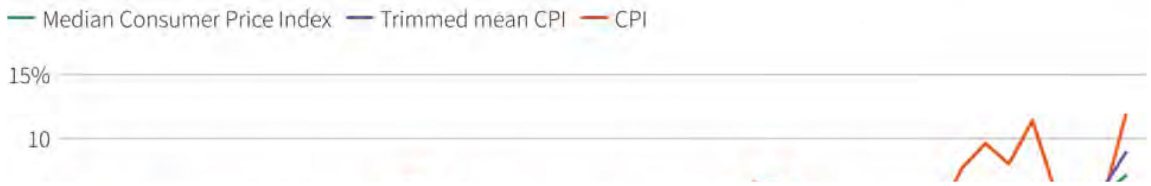
That was the largest one-year jump in prices in 30 years and applied across staples like food, energy and rent, as well as to items like automobiles where the Fed has expected the pace of price increases to ease alongside pandemic-driven "bottlenecks" in global supply chains.

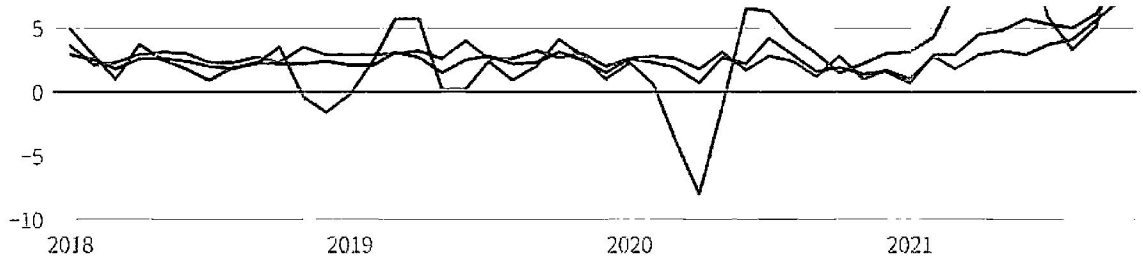
But those "bottlenecks" remain overrun by strong U.S. consumer demand, and inflation measures meant to diminish the impact of one-time spikes in goods and services are also rising.

Both a Cleveland Fed "trimmed mean" index of consumer prices and one that tracks the median level of price increases surged in a sign that price pressures were rising across a more extensive set of goods and services.

Alternate inflation measures

Trimmed mean and median price indexes try to limit the influence of larger or smaller, outlying price increases. Those measures are also rising in an indication of broader price pressures.





Source: Cleveland Federal Reserve

Reuters Graphics

Still, one Fed policymaker on Wednesday said the central bank should still remain patient.

"We need to wait to see how this percolates through the economy," before changing monetary policy in response to it, San Francisco Fed president Mary Daly said on Bloomberg TV .

Markets had a shorter leash. Pricing in futures contracts tied to the target federal funds rate showed investors boosting odds the Fed will by September raise rates twice by a cumulative 0.50 percentage point. Expectations for a third quarter-point rate increase in December increased to nearly 50% compared to less than 30% on Tuesday.

"The risks stemming from inflation have become increasingly top of mind to Federal Reserve policymakers, since excessive accommodation for too long, or essentially running the economy hot, could well hold unintended market consequences that further erode confidence and eventually impair the recovery," said Rick Rieder, chief investment officer for global fixed income at investment giant Blackrock.

With demand, supply and wage pressures expected to continue, "near-term inflation readings may be intimidating to 'inflation fighters'...which could press central bankers to at least discuss a faster reaction-function."

NOT 'LINEAR'

For both the Fed and the Biden administration, what was an adamant faith in transitory inflation has been tempered.

"We know that the recovery from the pandemic will not be linear," Biden's Council of Economic Advisers said on Twitter in a nod to prices rising still faster than anticipated. The CEA "will

continue to monitor the data as they come in," the office said.

The price rises also have had the disconcerting effect of outpacing wage increases that the Fed and White House hoped would flow to lower-paid workers in the hotel, restaurant and other industries hardest hit during the pandemic shutdowns last year and the cautious return to in-person services since then.

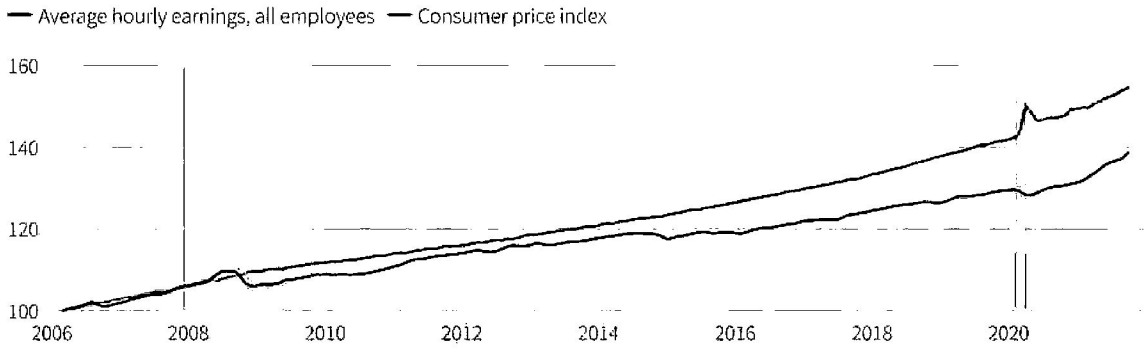
On a month-to-month basis inflation almost fully offset the strong wage increases seen in the leisure and hospitality industry in October, noted Nick Bunker, research director for North America at job site Indeed.

Overall, **real hourly wages** fell 1.2% in October compared with the year before, with the nearly 5% wage gain of the past 12 months more than offset by the 6.2% rise in prices.

That continues reversing what had been a steady rise in workers' purchasing power since around 2013, with the benefits of low inflation boosting "real" wages after several years of stagnation following the 2007-2009 financial crisis and recession.

Wages vs. prices

Indexed to a common starting point, wages and prices roughly kept pace in the years after the 2007 to 2009 recession, before "real" wages began to accelerate around 2014. High inflation this year has begun to reverse those gains.



Note: Gray bars denote recession.
Source: Bureau of Labor Statistics

Reuters Graphics

The Fed has said it is reluctant to raise interest rates until more people have returned to jobs after being sidelined during the pandemic, even if inflation runs above its formal 2% target "for

some time."

The jobs-first strategy is a change from the previous approach which tried to use higher unemployment as a way to keep prices under control - in effect imposing the cost of inflation-fighting onto those rendered jobless during economic slowdowns.

The Fed still hopes inflation will ease, over time, without the need to ratchet interest rates higher to cool the economy, and risk slowing or reversing job growth in the process.

But the longer inflation data run beyond expectations, the tougher that will be.

"With annual inflation now topping 6%, is this sufficient to force the Fed's hand? This long, long transitory period has to heap pressure on the Fed," said Seema Shah, chief strategist at Principal Global Investors.

Reporting by Howard Schneider Additional reporting by Ann Saphir in San Francisco and Shreyashi Sanyal in Bengaluru; Editing by Dan Burns and Andrea Ricci

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Macro Matters · 12:30 PM EST

Working from home may hurt women's careers, says Bank of England's Mann

Women who work mostly from home risk seeing their careers suffer now that significant numbers of workers are returning to the office after the COVID-19 pandemic, Bank of England policymaker Catherine Mann said on Thursday.

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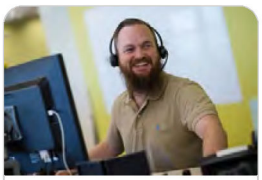

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10 Lessons to Take

Duke Energy partners with GIC to secure minority investment in Duke Energy Indiana, increases long-term EPS growth rate

January 28, 2021

Share This Story

- **GIC to acquire 19.9 percent minority interest in Duke Energy Indiana for total of $2.05 billion; Duke Energy to remain majority owner and sole operator of DEI.**
- **Company announces 2021 adjusted EPS guidance range of $5.00 to $5.30.**
- **Attractive valuation and efficient form of financing supports increased long-term adjusted EPS growth rate of 5 to 7% through 2025, based off midpoint of 2021 range.**
- **Innovative two-stage closing replaces planned common equity in five-year plan and funds increased $58 to $60 billion capital plan.**

CHARLOTTE, N.C. – Duke Energy (NYSE: DUK), alongside GIC, today announced that it has entered into a definitive agreement for an acquisition of a 19.9 percent interest in Duke Energy Indiana (DEI), a subsidiary of Duke Energy, by an affiliate of GIC Private Limited, Singapore's sovereign wealth fund and an experienced investor in U.S. infrastructure.

Duke Energy today also announced its 2021 adjusted earnings per share (EPS) guidance range of $5.00 to $5.30. The transaction with GIC bolsters the company's growth potential and supports its increased long-term adjusted EPS

growth rate of 5 to 7% through 2025, based off of a 2021 adjusted EPS midpoint of $5.15. This is up from the previously stated 4 to 6% rate.

Under the terms of the agreement, GIC will acquire a 19.9 percent indirect minority interest in Duke Energy Indiana for a total purchase price of $2.05 billion, a significant premium to Duke Energy's current public equity valuation.

Proceeds from the transaction will fund Duke Energy's increased $58 to $60 billion capital plan – a five-year plan that will accelerate its clean energy transition – and redeploy capital to support increased growth investments within its portfolio of regulated utilities. With this source of capital and increased financial strength, Duke Energy will continue providing reliable service and investing in important energy infrastructure while maintaining affordable rates for customers.

Given the innovative transaction structure, Duke Energy will receive proceeds in two, separate phases to efficiently align with the company's capital needs. The transaction allows Duke Energy to forego its previously announced plan to raise $1 billion of common equity.

Duke Energy will continue to operate DEI with its best-in-class workforce and will remain the majority owner, with an 80.1 percent stake in the business.

"We are pleased to have GIC as a long-term investor in DEI," said Lynn Good, Duke Energy's chair, president and chief executive officer. "This agreement with GIC allows Duke Energy to not only partner with a highly respected global investor, it also strengthens our confidence as we increase our long-term adjusted EPS growth rate to 5 to 7 percent. With this agreement, Duke Energy is well positioned to effectively finance our robust investment plan in a clean energy future and continue delivering sustainable value to our investors."

"Our agreement with GIC highlights the value and growth potential of DEI and recognizes the continued hard work and commitment of our people," said Stan Pinegar, DEI state president. "Delivering safe and reliable service to our customers and serving our communities remains our top priority."

Ang Eng Seng, GIC's Chief Investment Officer of Infrastructure, said, "As a long-term investor, GIC strongly believes that companies focused on meaningful sustainability practices will create better risk-adjusted returns over the long term. Duke Energy's proven management team and clear commitment to a clean energy transition make this an attractive partnership opportunity for GIC. This capital will help create long-term value by directly supporting Duke Energy's ability to capitalize on their stated ESG and decarbonization goals. We look forward to a successful transaction and long-term investment."

Transaction structure

The $2.05 billion in proceeds will be received in a staggered, two-phase closing, structured in evenly split payments. The first closing is expected to occur in the second quarter of 2021. Under the terms of the agreement, Duke Energy has the discretion to determine the timing of the second closing, but it will occur no later than January 2023.

GIC will invest in a newly formed intermediate holding company of which DEI will be a wholly owned subsidiary. GIC will receive certain limited rights commensurate with the minority stake.

The transaction is subject to customary closing conditions, including approval from the Federal Energy Regulatory Commission (FERC) and completion of review by the Committee on Foreign Investment in the United States (CFIUS).

J.P. Morgan Securities LLC served as Duke Energy's lead financial advisor, and Centerview Partners also served as a financial advisor. Skadden, Arps, Slate, Meagher & Flom LLP served as Duke Energy's legal advisor.

Barclays served as GIC's exclusive financial advisor. Sidley Austin LLP served as GIC's lead legal advisor alongside Steptoe & Johnson LLP and Ice Miller LLP.

Duke Energy

Duke Energy (NYSE: DUK), a Fortune 150 company headquartered in Charlotte, N.C., is one of the largest energy holding companies in the U.S. It employs 29,000 people and has an electric generating capacity of 51,000 megawatts through its regulated utilities and 2,300 megawatts through its nonregulated Duke Energy Renewables unit.

Duke Energy is transforming its customers' experience, modernizing the energy grid, generating cleaner energy and expanding natural gas infrastructure to create a smarter energy future for the people and communities it serves. The Electric Utilities and Infrastructure unit's regulated utilities serve 7.8 million retail electric customers in six states: North Carolina, South Carolina, Florida, Indiana, Ohio and Kentucky. The Gas Utilities and Infrastructure unit distributes natural gas to 1.6 million customers in five states: North Carolina, South Carolina, Tennessee, Ohio and Kentucky. The Duke Energy Renewables unit operates wind and solar generation facilities across the U.S., as well as energy storage and microgrid projects.

Duke Energy was named to Fortune's 2020 "World's Most Admired Companies" list and Forbes' "America's Best Employers" list. More information about the company is available at duke-energy.com. The Duke Energy News Center contains news releases, fact sheets, photos, videos and other materials. Duke Energy's illumination features stories about people, innovations, community topics and environmental issues. Follow Duke Energy on Twitter, LinkedIn, Instagram and Facebook.

GIC

GIC is a leading global investment firm established in 1981 to manage Singapore's foreign reserves. As a disciplined long-term value investor, GIC is uniquely positioned for investments across a wide range of asset classes, including equities, fixed income, private equity, real estate and infrastructure. GIC invests through funds and directly in companies, partnering with its fund managers and management teams to help world-class businesses achieve their objectives. GIC has investments in over 40 countries and has been investing in emerging markets for more than two decades. Headquartered in Singapore, GIC employs over 1,700 people across 10 offices in key financial cities worldwide. For more information about GIC, please visit www.gic.com.sg.

Non-GAAP Reconciliation

Duke Energy Corporation's (Duke Energy) materials for the GIC Investment in Duke Energy Indiana include a reference to the forecasted 2021 adjusted EPS guidance range of $5.00 to $5.30 per share, with a midpoint of approximately $5.15 per share. The materials also reference the long-term range of annual growth of 5% - 7% off the midpoint of the 2021 adjusted EPS guidance range, revised up from 4% - 6%. The forecasted adjusted EPS is a non-GAAP financial measure as it represents basic EPS available to Duke Energy Corporation common stockholders, adjusted for the per share impact of special items. Special items represent certain charges and credits, which management believes are not indicative of Duke Energy's ongoing performance.

Management believes the presentation of adjusted EPS provides useful information to investors, as it provides them with an additional relevant comparison of Duke Energy's performance across periods. Management uses this non-GAAP financial measure for planning and forecasting and for reporting financial results to the Duke Energy Board of Directors, employees, stockholders, analysts and investors. Adjusted EPS is also used as a basis for employee incentive bonuses.

The most directly comparable GAAP measure for adjusted EPS is reported basic EPS available to Duke Energy Corporation common stockholders. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items for future periods, such as legal settlements, the impact of regulatory orders or asset impairments.

Forward-Looking Information

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions and can often be identified by terms and phrases that include "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target," "guidance," "outlook" or other similar terminology. Various factors may cause actual results to be materially different than the suggested outcomes within forward-looking statements; accordingly, there is no assurance that such results will be realized. For details on the uncertainties that may cause our actual future results to be materially different than those expressed in our forward-looking statements, see our 2019 Form 10-K and Quarterly Reports on Form 10-Q filed with the SEC and available at the SEC's website at sec.gov. In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than described. Forward-looking statements speak only as of the date they are made. Duke Energy expressly disclaims an obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

Duke Energy media contact: Catherine Butler
800.559.3853

Duke Energy analysts contact: Jack Sullivan
980.373.3564

GIC media contact: Katy Conrad
212.856.2407

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Form 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2020
Or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____

Commission File Number 001-31303

BLACK HILLS CORPORATION

Incorporated in South Dakota IRS Identification Number 46-0458824

7001 Mount Rushmore Road
Rapid City, South Dakota 57702
Registrant's telephone number (605) 721-1700

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange on which registered
Common stock of $1.00 par value	BKH	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C.7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the voting common equity held by non-affiliates of the registrant on the last business day of the registrant's most recently completed second fiscal quarter, June 30, 2020, was $3,528,768,075

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding at January 31, 2021
Common stock, $1.00 par value	62,794,490 shares

Documents Incorporated by Reference
Portions of the registrant's Definitive Proxy Statement being prepared for the solicitation of proxies in connection with the 2021 Annual Meeting of Stockholders to be held on April 27, 2021, are incorporated by reference in Part III of this Form 10-K.

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GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms and abbreviations appear in the text of this report and have the definitions described below:

AC	Alternating Current
AFUDC	Allowance for Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income (Loss)
Aquila Transaction	Our July 14, 2008 acquisition of five utilities from Aquila, Inc.
APSC	Arkansas Public Service Commission
Arkansas Gas	Black Hills Energy Arkansas, Inc., an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Arkansas (doing business as Black Hills Energy).
ARO	Asset Retirement Obligations
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
ATM	At-the-market equity offering program
Availability	The availability factor of a power plant is the percentage of the time that it is available to provide energy.
BHC	Black Hills Corporation; the Company
BHSC	Black Hills Service Company, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Colorado IPP	Black Hills Colorado IPP, LLC, a 50.1% owned subsidiary of Black Hills Electric Generation
Black Hills Electric Generation	Black Hills Electric Generation, LLC, a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, providing wholesale electric capacity and energy primarily to our affiliate utilities.
Black Hills Energy	The name used to conduct the business of our utility companies
Black Hills Energy Services	Black Hills Energy Services Company, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas commodity supply for the Choice Gas Programs (doing business as Black Hills Energy).
Black Hills Non-regulated Holdings	Black Hills Non-regulated Holdings, LLC, a direct, wholly-owned subsidiary of Black Hills Corporation
Black Hills Utility Holdings	Black Hills Utility Holdings, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation (doing business as Black Hills Energy)
Black Hills Wyoming	Black Hills Wyoming, LLC, a direct, wholly-owned subsidiary of Black Hills Electric Generation
BLM	United States Bureau of Land Management
Btu	British thermal unit
Busch Ranch I	The 29 MW wind farm near Pueblo, Colorado, jointly owned by Colorado Electric and Black Hills Electric Generation. Colorado Electric and Black Hills Electric Generation each have a 50% ownership interest in the wind farm.
Busch Ranch II	The 60 MW wind farm near Pueblo, Colorado owned by Black Hills Electric Generation to provide wind energy to Colorado Electric through a power purchase agreement expiring in November 2044.
CARES Act	Coronavirus Aid, Relief, and Economic Security Act, signed on March 27, 2020, which is a tax and spending package intended to provide additional economic relief and address the impact of the COVID-19 pandemic.
CFTC	United States Commodity Futures Trading Commission
Cheyenne Prairie	Cheyenne Prairie Generating Station serves the utility customers of South Dakota Electric and Wyoming Electric. The facility includes one simple-cycle, 37 MW combustion turbine that is wholly-owned by Wyoming Electric and one combined-cycle, 95 MW unit that is jointly-owned by Wyoming Electric (40 MW) and South Dakota Electric (55 MW).
Chief Operating Decision Maker (CODM)	Chief Executive Officer
Choice Gas Program	Regulator approved programs in Wyoming and Nebraska that allow certain utility customers to select their natural gas commodity supplier, providing the unbundling of the commodity service from the distribution delivery service.
CIAC	Contribution in Aid of Construction
City of Cheyenne	Cheyenne, Wyoming

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City of Colorado Springs	Colorado Springs, Colorado
City of Gillette	Gillette, Wyoming
Colorado Electric	Black Hills Colorado Electric, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings, providing electric service to customers in Colorado (doing business as Black Hills Energy).
Colorado Gas	Black Hills Colorado Gas, Inc., an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Colorado (doing business as Black Hills Energy).
Common Use System (CUS)	The Common Use System is a jointly operated transmission system we participate in with Basin Electric Power Cooperative and Powder River Energy Corporation. The Common Use System provides transmission service over these utilities' combined 230-kilovolt (kV) and limited 69-kV transmission facilities within areas of southwestern South Dakota and northeastern Wyoming.
Consolidated Indebtedness to Capitalization Ratio	Any Indebtedness outstanding at such time, divided by capital at such time. Capital being consolidated net-worth (excluding noncontrolling interest) plus consolidated indebtedness (including letters of credit and certain guarantees issued) as defined within the current Revolving Credit Facility.
Cooling Degree Day (CDD)	A cooling degree day is equivalent to each degree that the average of the high and low temperature for a day is above 65 degrees. The warmer the climate, the greater the number of cooling degree days. Cooling degree days are used in the utility industry to measure the relative warmth of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations.
Corriedale	The 52.5 MW wind farm near Cheyenne, Wyoming, jointly owned by South Dakota Electric and Wyoming Electric, serving as the dedicated wind energy supply to the Renewable Ready program.
COVID-19	The official name for the 2019 novel coronavirus disease announced on February 11, 2020, by the World Health Organization, that is causing a global pandemic.
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CP Program	Commercial Paper Program
CPUC	Colorado Public Utilities Commission
CT	Combustion Turbine
CTII	The 40 MW Gillette CT, a simple-cycle, gas-fired combustion turbine owned by the City of Gillette.
Cushion Gas	The portion of natural gas necessary to force saleable gas from a storage field into the transmission system and for system balancing, representing a permanent investment necessary to use storage facilities and maintain reliability.
CVA	Credit Valuation Adjustment
DC	Direct Current
Dividend payout ratio	Annual dividends paid on common stock divided by net income from continuing operations available for common stock
DRSPP	Dividend Reinvestment and Stock Purchase Plan
DSM	Demand Side Management
Dth	Dekatherm. A unit of energy equal to 10 therms or one million British thermal units (MMBtu).
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP measurement
ECA	Energy Cost Adjustment is an adjustment that allows us to pass the prudently-incurred cost of fuel and purchased energy through to customers.
Economy Energy	Purchased energy that costs less than that produced with the utilities' owned generation.
EECR	Energy Efficiency Cost Recovery is an adjustment mechanism that allows us to recover from customers the costs associated with providing energy efficiency programs.
EIA	Environmental Improvement Adjustment is an annual adjustment mechanism that allows us to recover from customers eligible investments in, and expense related to, new environmental measures.
EPA	United States Environmental Protection Agency

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Equity Unit	Each Equity Unit had a stated amount of $50, consisting of a purchase contract issued by BHC to purchase shares of BHC common stock and a 1/20, or 5% undivided beneficial ownership interest in $1,000 principal amount of BHC remarketable junior subordinated notes issued on November 23, 2015 and retired on August 17, 2018. On November 1, 2018, we completed settlement of the stock purchase contracts that are components of the Equity Units issued in November 2015.
EWG	Exempt Wholesale Generator
FASB	Financial Accounting Standards Board
FERC	United States Federal Energy Regulatory Commission
Fitch	Fitch Ratings Inc.
GAAP	Accounting principles generally accepted in the United States of America
GCA	Gas Cost Adjustment is an adjustment that allows us to pass the prudently-incurred cost of gas and certain services through to customers.
GHG	Greenhouse gases
Global Settlement	Settlement with a utility's commission where the revenue requirement is agreed upon, but the specific adjustments used by each party to arrive at the amount are not specified in public rate orders.
Happy Jack	Happy Jack Wind Farm, LLC, owned by Duke Energy Generation Services
Heating Degree Day (HDD)	A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the utility industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on the National Weather Service data for selected locations.
HomeServe	We offer HomeServe products to our natural gas residential customers interested in purchasing additional home repair service plans.
ICFR	Internal Controls Over Financial Reporting
Iowa Gas	Black Hills Iowa Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Iowa (doing business as Black Hills Energy).
IPP	Independent Power Producer
IRC	Internal Revenue Code
IRS	United States Internal Revenue Service
ITC	Investment Tax Credit
Kansas Gas	Black Hills Kansas Gas Utility Company, LLC, a direct, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Kansas (doing business as Black Hills Energy).
kV	Kilovolt
LIBOR	London Interbank Offered Rate
Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day
MDU	Montana-Dakota Utilities Co., a subsidiary of MDU Resources Group, Inc.
MEAN	Municipal Energy Agency of Nebraska
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MSHA	Mine Safety and Health Administration
MTPSC	Montana Public Service Commission
MW	Megawatts
MWh	Megawatt-hours
N/A	Not Applicable
NAV	Net Asset Value
Nebraska Gas	Black Hills Nebraska Gas, LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Nebraska (doing business as Black Hills Energy).
Neil Simpson II	A mine-mouth, coal-fired power plant owned and operated by South Dakota Electric with a total capacity of 90 MW located at our Gillette, Wyoming energy complex.

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NERC	North American Electric Reliability Corporation
NO_x	Nitrogen oxide
NOL	Net Operating Loss
NPSC	Nebraska Public Service Commission
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OSHA	Occupational Safety & Health Administration
OSM	United States Department of the Interior's Office of Surface Mining
PacifiCorp	PacifiCorp, a wholly owned subsidiary of MidAmerican Energy Holdings Company, itself an affiliate of Berkshire Hathaway.
PCA	Power Cost Adjustment is an annual adjustment mechanism that allows us to pass a portion of prudently-incurred delivered power costs, including fuel, purchased capacity and energy, and transmission costs, through to customers.
PCCA	Power Capacity Cost Adjustment is an annual adjustment that allows us to pass the prudently-incurred purchased capacity costs, incremental to costs included in base rates, through to customers.
Peak View	The 60 MW wind farm owned by Colorado Electric.
PPA	Power Purchase Agreement
PRPA	Platte River Power Authority
PSA	Power Sales Agreement
Pueblo Airport Generation	The 420 MW combined cycle gas-fired power generation plants jointly owned by Colorado Electric (220 MW) and Black Hills Colorado IPP (200 MW). Black Hills Colorado IPP owns and operates this facility. The plants commenced operation on January 1, 2012.
PTC	Production Tax Credit
PUHCA 2005	Public Utility Holding Company Act of 2005
Ready	The Company's branding platform which emphasizes that we will 1) prioritize our customers; 2) act as a thoughtful, responsible leader; 3) listen first and lead with a focus on relationships; and 4) be creative in our approach to solutions.
Renewable Advantage	The 200 MW solar facility project to be constructed in Pueblo County, Colorado. The project aims to lower customer energy costs and provide economic and environmental benefits to Colorado Electric's customers and communities. This project, which was approved by the CPUC in September 2020, will be owned by a third-party renewable energy developer with Colorado Electric purchasing all of the energy generated at the facility under the terms of a 15-year PPA. The project is expected to be placed in service in 2023.
Renewable Ready	Voluntary renewable energy subscription program for large commercial, industrial and governmental agency customers in South Dakota and Wyoming.
RESA	Renewable Energy Standard Adjustment is an incremental retail rate limited to 2% for Colorado Electric customers that provides funding for renewable energy projects and programs to comply with Colorado's Renewable Energy Standard.
Revolving Credit Facility	Our $750 million credit facility used to fund working capital needs, letters of credit and other corporate purposes, which was amended and restated on July 30, 2018, and now terminates on July 30, 2023.
RMNG	Rocky Mountain Natural Gas LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas transmission and wholesale services in western Colorado (doing business as Black Hills Energy).
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
Service Guard Comfort Plan	Appliance protection plan that provides home appliance repair services through on-going monthly service agreements to residential utility customers.
Silver Sage	Silver Sage Windpower, LLC, owned by Duke Energy Generation Services
SO_2	Sulfur dioxide
S&P	Standard & Poor's, a division of The McGraw-Hill Companies, Inc.
SPP	Southwest Power Pool, Inc. which oversees the bulk electric grid and wholesale power market in the central United States

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SourceGas Transaction	On February 12, 2016, Black Hills Utility Holdings acquired SourceGas pursuant to a purchase and sale agreement executed on July 12, 2015 for approximately $1.89 billion, which included the assumption of $760 million in debt at closing.
South Dakota Electric	Black Hills Power, Inc., a direct, wholly-owned subsidiary of Black Hills Corporation, providing electric service to customers in Montana, South Dakota and Wyoming (doing business as Black Hills Energy).
SSIR	System Safety and Integrity Rider
System Peak Demand	Represents the highest point of retail customer usage for a single hour.
TCA	Transmission Cost Adjustment is an annual adjustment mechanism that allows us to recover from customers eligible transmission investments prior to the next rate review.
TCJA	Tax Cuts and Jobs Act enacted on December 22, 2017
Tech Services	Non-regulated product lines delivered by our Utilities that 1) provide electrical system construction services to large industrial customers of our electric utilities, and 2) serve gas transportation customers throughout its service territory by constructing and maintaining customer-owned gas infrastructure facilities, typically through one-time contracts.
Top of Iowa	Northern Iowa Windpower, LLC, a 80 MW wind farm located near Joice, Iowa, owned by Black Hills Electric Generation and operated by a third-party. We sell the wind energy generated in the MISO market.
TFA	Transmission Facility Adjustment is an annual adjustment mechanism that allows us to recover charges for qualifying new and modified transmission facilities from customers.
Transmission Tie	South Dakota Electric owns 35% of a DC transmission tie that interconnects the Western and Eastern transmission grids, which are independently-operated transmission grids serving the western and eastern United States, respectively. Basin Electric Power Cooperative owns the remaining ownership percentage. This transmission tie allows us to buy and sell energy in the Eastern grid without having to isolate and physically reconnect load or generation between the two transmission grids, thus enhancing the reliability of our system. It accommodates scheduling transactions in both directions simultaneously, provides additional opportunities to sell excess generation or to make economic purchases to serve our native load and contract obligations, and enables us to take advantage of power price differentials between the two grids. The total transfer capacity of the tie is 400 MW, including 200 MW from West to East and 200 MW from East to West.
Utilities	Black Hills' Electric and Gas Utilities
VEBA	Voluntary Employee Benefit Association
VIE	Variable Interest Entity
WECC	Western Electricity Coordinating Council
Wind Capacity Factor	Measures the amount of electricity a wind turbine produces in a given time period relative to its maximum potential
Working Capacity	Total gas storage capacity minus cushion gas
WPSC	Wyoming Public Service Commission
WRDC	Wyodak Resources Development Corp., a direct, wholly-owned subsidiary of Black Hills Non-regulated Holdings, providing coal supply primarily to five on-site, mine-mouth generating facilities (doing business as Black Hills Energy).
Wygen I	A mine-mouth, coal-fired generating facility with a total capacity of 90 MW located at our Gillette, Wyoming energy complex. Black Hills Wyoming owns 76.5% of the facility and Municipal Energy Agency of Nebraska (MEAN) owns the remaining 23.5%.
Wygen II	A mine-mouth, coal-fired power plant owned by Wyoming Electric with a total capacity of 95 MW located at our Gillette, Wyoming energy complex.
Wygen III	A mine-mouth, coal-fired power plant operated by South Dakota Electric with a total capacity of 110 MW located at our Gillette, Wyoming energy complex. South Dakota Electric owns 52% of the power plant, MDU owns 25% and the City of Gillette owns the remaining 23%.
Wyodak Plant	The 362 MW mine-mouth, coal-fired generating facility near Gillette, Wyoming, jointly owned by PacifiCorp (80%) and South Dakota Electric (20%). Our WRDC mine supplies all of the fuel for the facility.
Wyoming Electric	Cheyenne Light, Fuel and Power Company, a direct, wholly-owned subsidiary of Black Hills Corporation, providing electric service to customers in the Cheyenne, Wyoming area (doing business as Black Hills Energy).
Wyoming Gas	Black Hills Wyoming Gas, LLC, an indirect, wholly-owned subsidiary of Black Hills Utility Holdings, providing natural gas services to customers in Wyoming (doing business as Black Hills Energy).

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Website Access to Reports

The reports we file with the SEC are available free of charge at our website www.blackhillscorp.com as soon as reasonably practicable after they are filed. In addition, the charters of our Audit, Governance and Compensation Committees are located on our website along with our Code of Business Conduct, Code of Ethics for our Chief Executive Officer and Senior Finance Officers, Corporate Governance Guidelines of the Board of Directors and Policy for Director Independence. The information contained on our website is not part of this document.

Forward-Looking Information

This Form 10-K contains forward-looking statements as defined by the SEC. Forward-looking statements are all statements other than statements of historical fact, including, without limitation, those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 - Management's Discussion & Analysis of Financial Condition and Results of Operations.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including, without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties. Nonetheless, the Company's expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, such as the COVID-19 pandemic, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A - Risk Factors.

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PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

History and Organization

Black Hills Corporation, a South Dakota corporation (together with its subsidiaries, referred to herein as the "Company," "we," "us" or "our"), is a customer-focused, growth-oriented utility company headquartered in Rapid City, South Dakota (incorporated in South Dakota in 1941).

We operate our business in the United States, reporting our operating results through our regulated Electric Utilities, regulated Gas Utilities, Power Generation and Mining segments. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other.

Our Electric Utilities segment generates, transmits and distributes electricity to approximately 216,000 electric utility customers in Colorado, Montana, South Dakota and Wyoming. Our Electric Utilities own 992 MW of generation and 8,892 miles of electric transmission and distribution lines.

Our Gas Utilities segment serves approximately 1,083,000 natural gas utility customers in Arkansas, Colorado, Iowa, Kansas, Nebraska, and Wyoming. Our Gas Utilities own and operate 4,774 miles of intrastate gas transmission pipelines and 41,838 miles of gas distribution mains and service lines, seven natural gas storage sites, nearly 49,000 horsepower of compression and over 560 miles of gathering lines.

Our Power Generation segment produces electric power from its wind, natural gas and coal-fired generating plants and sells the electric capacity and energy primarily to our utilities under long-term contracts. Our Mining segment produces coal at our mine near Gillette, Wyoming, and sells and delivers primarily under long-term contracts to adjacent mine-mouth electric generation facilities owned by our Electric Utilities and Power Generation businesses.

Electric Utilities

We conduct electric utility operations through our Colorado, South Dakota and Wyoming subsidiaries. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our retail customers. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates. We also provide non-regulated services under the Service Guard Comfort Plan and Tech Services.

	As of December 31,		
Customers at End of Year	2020	2019	2018
Residential	184,872	183,232	181,459
Commercial	30,225	29,921	29,299
Industrial	83	83	84
Other	1,017	1,024	1,030
Total Electric Customers at End of Year	216,197	214,260	211,872

	As of December 31,		
Customers at End of Year	2020	2019	2018
Colorado Electric	98,735	97,890	96,645
South Dakota Electric	73,700	73,052	72,533
Wyoming Electric	43,762	43,318	42,694
Total Electric Customers at End of Year	216,197	214,260	211,872

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Capacity and Demand. System peak demand for the Electric Utilities' retail customers for each of the last three years are listed below:

	System Peak Demand (in MW)					
	2020		2019		2018	
	Summer	Winter	Summer	Winter	Summer	Winter
Colorado Electric	401	297	422	297	413	313
South Dakota Electric	378	304	335	320	355	314
Wyoming Electric	271	246	265	247	254	238

Regulated Power Plants. As of December 31, 2020, our Electric Utilities' ownership interests in electric generating plants were as follows:

Unit	Fuel Type	Location	Ownership Interest % [(d)]	Owned Capacity (MW)	In Service Date
Colorado Electric:					
Busch Ranch I [(a)]	Wind	Pueblo, Colorado	50%	14.5	2012
Peak View [(b)]	Wind	Pueblo, Colorado	100%	60.0	2016
Pueblo Airport Generation	Gas	Pueblo, Colorado	100%	180.0	2011
Pueblo Airport Generation CT	Gas	Pueblo, Colorado	100%	40.0	2016
AIP Diesel	Oil	Pueblo, Colorado	100%	10.0	2001
Diesel #1 and #3-5	Oil	Pueblo, Colorado	100%	8.0	1964
Diesel #1-5	Oil	Rocky Ford, Colorado	100%	10.0	1964
South Dakota Electric:					
Cheyenne Prairie	Gas	Cheyenne, Wyoming	58%	55.0	2014
Corriedale [(c)]	Wind	Cheyenne, Wyoming	62%	32.5	2020
Wygen III	Coal	Gillette, Wyoming	52%	57.2	2010
Neil Simpson II	Coal	Gillette, Wyoming	100%	90.0	1995
Wyodak Plant	Coal	Gillette, Wyoming	20%	72.4	1978
Neil Simpson CT	Gas	Gillette, Wyoming	100%	40.0	2000
Lange CT	Gas	Rapid City, South Dakota	100%	40.0	2002
Ben French Diesel #1-5	Oil	Rapid City, South Dakota	100%	10.0	1965
Ben French CTs #1-4	Gas/Oil	Rapid City, South Dakota	100%	80.0	1977-1979
Wyoming Electric:					
Cheyenne Prairie	Gas	Cheyenne, Wyoming	42%	40.0	2014
Cheyenne Prairie CT	Gas	Cheyenne, Wyoming	100%	37.0	2014
Corriedale [(c)]	Wind	Cheyenne, Wyoming	38%	20.0	2020
Wygen II	Coal	Gillette, Wyoming	100%	95.0	2008
Total MW Capacity				991.6	

(a) In 2013, Busch Ranch I was awarded a one-time cash grant in lieu of ITCs under the Section 1603 program created under the American Recovery and Reinvestment Act.
(b) The Peak View facility qualifies for PTCs at $25/MWh under IRC 45 during the 10-year period beginning November 2016. The PTCs for this facility flow back to customers through a rider mechanism as a reduction to Colorado Electric's margins.
(c) Corriedale was completed and placed in service on November 30, 2020. This facility qualifies for PTCs at $25/MWh under IRC 45 during the 10-year period beginning November 2020.
(d) Jointly owned facilities are discussed in Note 6 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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Our Electric Utilities' power supply by resource as a percent of the total power supply for our energy needs for the years ended December 31 was as follows:

Power Supply	2020	2019	2018
Coal	32.7 %	30.1 %	32.1 %
Natural Gas and Diesel Oil [(a)]	8.4	8.2	6.1
Wind	3.8	3.2	3.4
Total Generated	44.9	41.5	41.6
Coal, Natural Gas, Oil and Other Market Purchases	43.3	52.5	52.4
Wind	11.8	6.0	6.0
Total Purchased	55.1	58.5	58.4
Total	100.0 %	100.0 %	100.0 %

(a) The diesel-fueled generating units are generally used as supplemental peaking units. Power generated from these units, as a percentage of total power supply, was 0.2%, 0.1% and 0.0% for the years ended December 31, 2020, 2019, and 2018, respectively.

Our Electric Utilities' weighted average cost of fuel utilized to generate electricity and the average price paid for purchased power (excluding contracted capacity) per MWh for the years ended December 31 were as follows:

Fuel and Purchased Power (dollars per MWh)	2020	2019	2018
Coal	$ 11.00	$ 11.46	$ 11.10
Natural Gas and Diesel Oil	21.67	28.26	34.07
Total Generated Weighted Average Fuel Cost	12.07	13.86	13.53
Coal, Natural Gas, Oil and Other Market Purchases	44.61	43.73	45.62
Wind Purchases	32.01	48.61	54.31
Total Purchased Power Weighted Average Cost	41.91	44.23	46.51
Total Weighted Average Fuel and Purchased Power Cost	$ 28.52	$ 31.62	$ 32.79

Power Purchase and Power Sales Agreements. We have executed various PPAs to support our Electric Utilities' capacity and energy needs beyond our regulated power plants' generation. Our Electric Utilities also have various long-term PSAs. Key contracts are disclosed in Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Transmission and Distribution. Through our Electric Utilities, we own electric transmission and distribution systems composed of high voltage lines (greater than 69 kV) and low voltage lines (69 kV or less). We also jointly operate an electric transmission system, referred to as the Common Use System, with Basin Electric Power Cooperative and Powder River Energy Corporation. Each participant in the Common Use System individually owns assets that are operated together for a single system. The Common Use System also provides transmission service to our Transmission Tie. South Dakota Electric owns 35% of the Transmission Tie. The Transmission Tie is further discussed in Note 6 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

At December 31, 2020, our Electric Utilities owned the electric transmission and distribution lines shown below:

Utility	State	Transmission [(a)] (in Line Miles)	Distribution (in Line Miles)
Colorado Electric	Colorado	572	3,135
South Dakota Electric	South Dakota, Wyoming	1,242	2,565
Wyoming Electric	Wyoming	58	1,320
		1,872	7,020

(a) Electric transmission line miles include voltages of 69 kV and above.

Material transmission services agreements are disclosed in Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Seasonal Variations of Business. Our Electric Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for electricity is sensitive to seasonal cooling, heating and industrial load requirements, as well as market price. In particular, cooling demand is often greater in the summer and heating demand in often greater in the winter.

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Competition. We generally have limited competition for the retail generation and distribution of electricity in our service areas. Various legislative or regulatory restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives would be aimed at increasing competition or providing for distributed generation. To date, these initiatives have not had a material impact on our utilities. In Colorado, our electric utility is subject to rules which may require competitive bidding for generation supply. Because of these rules, we face competition from other utilities and non-affiliated IPPs for the right to supply electric energy and capacity for Colorado Electric when resource plans require additional resources. Additionally, electrification initiatives in our service territories could increase demand for electricity and increase customer growth.

Rates and Regulation. Our Electric Utilities are subject to the jurisdiction of the public utilities commissions in the states where they operate and the FERC for certain assets. These commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. The public utility commissions determine the rates we are allowed to charge for our utility services. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities and the creation of liens on property located in their states to secure bonds or other securities.

The following table provides regulatory information for each of our Electric Utilities:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Tariffed Mechanisms	Percentage of Power Marketing Profit Shared with Customers
Colorado Electric [(a)]	CO	9.37%	7.43%	48%/52%	$539.6	1/2017	ECA, TCA, PCCA, EECR/DSM, RESA	90%
	CO	9.37%	6.02%	67%/33%	$57.9	1/2017	Clean Air Clean Jobs Act Adjustment Rider	N/A
South Dakota Electric	WY	9.90%	8.13%	47%/53%	$46.8	10/2014	ECA	65%
	SD	Global Settlement	7.76%	Global Settlement	$543.9	10/2014	ECA, TFA, EIA	70%
	FERC	10.80%	8.76%	43%/57%	$154.0 [(b)]	2/2009	FERC Transmission Tariff	N/A
Wyoming Electric [(a)]	WY	9.90%	7.98%	46%/54%	$376.8	10/2014	PCA, EECR/DSM, Rate Base Recovery on Acquisition Adjustment	N/A

(a) For both Colorado Electric and Wyoming Electric, transmission investments are recovered through retail rates rather than FERC Transmission Tariffs.
(b) Includes $136.9 million in 2020 rate base for the 2020 Projected Common Use System formula rate that is updated annually and $17.1 million in rate base for the Transmission Tie that is based on the approved stated rate from 2005.

The regulatory provisions for recovering the costs to supply electricity vary by state. We have cost adjustment mechanisms for our Electric Utilities, subject to thresholds noted above, that allow us to pass the prudently-incurred cost of fuel and purchased power to customers. These mechanisms allow the utility operating in that state to collect, or refund the difference between the cost of commodities and certain services embedded in our base rates and the actual cost of the commodities and certain services without filing a general rate review. In addition, some states allow for recovery of new capital investment placed in service between base rate reviews through approved rider tariffs. These tariffs allow the utility a return on the investment.

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A summary of mechanisms we have in place are shown in the table below:

Electric Utility Jurisdiction	Cost Recovery Mechanisms						
	Environmental Cost	Energy Efficiency	Transmission Expense	Fuel Cost	Transmission Capital	Purchased Power	RESA
Colorado Electric		☑	☑	☑	☑	☑	☑
South Dakota Electric (SD)[a]	☑		☑	☑	☑	☑	
South Dakota Electric (WY)		☑	☑	☑		☑	
South Dakota Electric (FERC)[b]					☑		
Wyoming Electric		☑	☑	☑		☑	

(a) South Dakota Electric's Environmental Cost (EIA) and Transmission Capital (TFA) tariffs were suspended for a six-year moratorium period effective July 1, 2017. On January 7, 2020, South Dakota Electric received approval from the SDPUC to extend the 6-year moratorium period by an additional 3 years whereby these recovery mechanisms will not be effective prior to July 1, 2026. For additional information, see Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K. On December 1, 2020, South Dakota Electric (SD) terminated its Energy Efficiency program.

(b) South Dakota Electric has an approved FERC Transmission Tariff based on a formulaic approach that determines the revenue component of South Dakota Electric's open access transmission tariff.

Tariff Filings. See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for tariff filings and additional information regarding current electric regulatory activity.

Operating Statistics. See a summary of key operating statistics in the Electric Utilities segment operating results within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Gas Utilities

We conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming subsidiaries. Our Gas Utilities transport and distribute natural gas through our distribution network to approximately 1,083,000 customers. Additionally, we sell contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates, on an as-available basis.

We also provide non-regulated services to our regulated customers. Black Hills Energy Services provides natural gas supply to approximately 52,000 retail distribution customers under the Choice Gas Program in Nebraska and Wyoming. Additionally, we provide services under the Service Guard Comfort Plan, Tech Services and HomeServe.

Customers at End of Year	As of December 31, 2020	2019	2018
Residential	844,999	831,351	821,624
Commercial	83,135	82,912	82,498
Industrial	2,235	2,208	2,221
Transportation	152,568	149,971	147,550
Total Natural Gas Customers at End of Year	1,082,937	1,066,442	1,053,893

Customers at End of Year	As of December 31, 2020	2019	2018
Arkansas	178,281	174,447	171,978
Colorado	197,817	191,950	186,759
Iowa	160,952	159,641	158,485
Kansas	116,973	115,846	114,840
Nebraska	296,778	293,576	291,723
Wyoming	132,136	130,982	130,108
Total Natural Gas Customers at End of Year	1,082,937	1,066,442	1,053,893

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We procure natural gas for our distribution customers from a diverse mix of producers, processors and marketers and generally use hedging, physical fixed-price purchases and market-based price purchases to achieve dollar-cost averaging within our natural gas portfolio. The majority of our procured natural gas is transported in interstate pipelines under firm transportation service agreements.

In addition to company-owned natural gas storage assets in Arkansas, Colorado and Wyoming, we also contract with third-party transportation providers for natural gas storage service to provide gas supply during the winter heating season and to meet peak day customer demand for natural gas.

The following table summarizes certain information regarding our regulated underground gas storage facilities as of December 31, 2020:

State	Working Capacity (Mcf)	Cushion Gas (Mcf)	Total Capacity (Mcf)	Maximum Daily Withdrawal Capability (Mcfd)
Arkansas	8,442,700	13,149,040	21,591,740	196,000
Colorado	2,360,895	6,165,315	8,526,210	30,000
Wyoming	5,733,900	17,145,600	22,879,500	36,000
Total	16,537,495	36,459,955	52,997,450	262,000

The following table summarizes certain information regarding our system infrastructure as of December 31, 2020:

State	Intrastate Gas Transmission Pipelines (in line miles)	Gas Distribution Mains (in line miles)	Gas Distribution Service Lines (in line miles)
Arkansas	935	5,090	1,223
Colorado	693	6,879	2,618
Iowa	165	2,839	2,151
Kansas	330	2,961	1,366
Nebraska	1,312	8,739	3,252
Wyoming	1,339	3,495	1,225
Total	4,774	30,003	11,835

Seasonal Variations of Business. Our Gas Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for natural gas is sensitive to seasonal heating and industrial load requirements, as well as market price. In particular, demand is often greater in the winter months for heating. Natural gas is used primarily for residential and commercial heating, so the demand for this product depends heavily upon weather throughout our service territories. As a result, a significant amount of natural gas revenue is normally recognized in the heating season consisting of the first and fourth quarters. Demand for natural gas can also be impacted by summer temperatures and precipitation, which can affect demand for irrigation.

Competition. We generally have limited competition for the retail distribution of natural gas in our service areas. Various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives are aimed at increasing competition. Additionally, electrification initiatives in our service territories could negatively impact demand for natural gas and decrease customer growth. To date, these initiatives have not had a material impact on our utilities. Although we face competition from independent marketers for the sale of natural gas to our industrial and commercial customers, in instances where independent marketers displace us as the seller of natural gas, we still collect a charge for transporting the gas through our distribution network.

Rates and Regulation. Our Gas Utilities are subject to the jurisdiction of the public utility commissions in the states where they operate. These commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. The public utility commissions determine the rates we are allowed to charge for our utility services. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities and the creation of liens on property located in their states to secure bonds or other securities.

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Our Gas Utilities are authorized to use natural gas cost recovery mechanisms allowing rate adjustments reflecting changes in the wholesale cost of natural gas and recovery of all the costs prudently incurred in purchasing gas for customers. In addition to natural gas cost recovery mechanisms, other recovery mechanisms, which vary by utility, allow us to recover certain costs or earn a return on capital investments, such as energy efficiency plan costs and system safety and integrity investments.

The following table provides regulatory information for each of our natural gas utilities:

Subsidiary	Jurisdic-tion	Authorized Rate of Return on Equity	Authorized Return on Rate Base	Authorized Capital Structure Debt/Equity	Authorized Rate Base (in millions)	Effective Date	Additional Tariffed Mechanisms
Arkansas Gas	AR	9.61%	6.82% [a]	51%/49%	$451.5 [b]	10/2018	GCA, Main Replacement Program, At-Risk Meter Relocation Program, Legislative or Regulatory Mandated Expenditures, EECR, Weather Normalization Adjustment, Billing Determinant Adjustment
Colorado Gas	CO	9.20%	6.76%	50%/50%	$231.2	7/2020	GCA, EECR/DSM
RMNG	CO	9.90%	6.71%	53%/ 47%	$118.7	6/2018	System Safety Integrity Rider, Liquids/Off-system/Market Center Services Revenue Sharing
Iowa Gas	IA	Global Settlement	Global Settlement	Global Settlement	$109.2	2/2011	GCA, EECR, Capital Infrastructure Automatic Adjustment Mechanism, Farm Tap Tracker Adjustment, Gas Supply Optimization revenue sharing
Kansas Gas	KS	Global Settlement	Global Settlement	Global Settlement	$127.9	1/2015	GCA, Weather Normalization Tariff, Gas System Reliability Surcharge, Ad Valorem Tax Surcharge, Cost of Bad Debt Collected through GCA, Pension Levelized Adjustment
Nebraska Gas [c] [d]	NE	9.50%	6.71%	50%/50%	$504.2	3/2021	GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge, Choice Gas Program, System Safety and Integrity Rider, Bad Debt expense recovered through Choice Supplier Fee
Wyoming Gas [d]	WY	9.40%	6.98%	50%/50%	$354.4	3/2020	GCA, EECR, Rate Base Recovery on Acquisition Adjustment, Wyoming Integrity Rider, Choice Gas Program

(a) Arkansas Gas return on rate base is adjusted to remove current liabilities from rate review capital structure for comparison with other subsidiaries.
(b) Arkansas Gas rate base is adjusted to include current liabilities for comparison with other subsidiaries.
(c) Information above reflects the NPSC order received on January 26, 2021. For additional information, see Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.
(d) The Choice Gas Program mechanisms are applicable to only a portion of Nebraska Gas and Wyoming Gas customers.

All of our Gas Utilities, except where the Choice Gas Program is the only option, have GCAs that allow us to pass the prudently-incurred cost of gas and certain services through to the customer between rate reviews. Some of the mechanisms we have in place include the following:

Gas Utility Jurisdiction	Cost Recovery Mechanisms						
	DSM/Energy Efficiency	Integrity Additions	Bad Debt	Weather Normal	Pension Recovery	Gas Cost	Revenue Decoupling
Arkansas Gas	☑	☑		☑		☑	☑
Colorado Gas	☑					☑	
RMNG[a]		☑					
Iowa Gas	☑	☑				☑	
Kansas Gas		☑	☑	☑	☑	☑	
Nebraska Gas		☑	☑			☑	
Wyoming Gas	☑	☑				☑	

(a) RMNG, which is an intrastate transmission pipeline that provides natural gas transmission and wholesale services in western Colorado, has an SSIR recovery mechanism. The other cost recovery mechanisms are not applicable to RMNG.

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Tariff Filings. See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for information regarding current natural gas regulatory activity.

Operating statistics. See a summary of key operating statistics in the Gas Utilities segment operating results within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Utility Regulation Characteristics

State Renewable Energy Standards

Certain states where we conduct electric utility operations have adopted renewable energy portfolio standards that require or encourage our Electric Utilities to source, by a certain future date, a minimum percentage of the electricity delivered to customers from renewable energy generation facilities. As of December 31, 2020, we were subject to the following renewable energy portfolio standards or objectives:

- Colorado. Colorado adopted a renewable energy standard in 2004 that has two components: (i) electric resource standards and (ii) a 2% maximum annual retail rate impact for compliance with the electric resource standards. The electric resource standards require our Colorado Electric subsidiary to generate, or cause to be generated, electricity from renewable energy sources equaling: (i) 20% of retail sales from 2015 to 2019; and (ii) 30% of retail sales by 2020. Of these amounts, 3% must be generated from distributed generation sources with one-half of these resources being located at customer facilities. The net annual incremental retail rate impact for these renewable resource acquisitions (as compared to non-renewable resources) is limited to 2%. The standard encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a forward rider mechanism. We have been and currently remain in compliance with these standards.

  In 2019, the State of Colorado approved Senate Bill 236, which required qualified retail electric utilities (more than 500,000 customers) to submit a Clean Energy Plan to meet an 80% carbon reduction goal by 2030 based upon 2005 baseline levels. While Colorado Electric is not required to submit a Clean Energy Plan, the state also passed House Bill 1261 which established state-wide emission goals for greenhouse gas emitting activities that apply to Colorado Electric. Both House Bill 1261 and Senate Bill 236 include provisions that allow Colorado Electric to submit a voluntary Clean Energy Plan with a goal of 80% reduction by 2030. On January 7, 2021, Colorado Electric announced it will file a Clean Energy Plan with the CPUC voluntarily in 2022.

  On September 23, 2020, Colorado Electric received approval from the CPUC for its preferred solar bid request in support of its Renewable Advantage program. The program plans to add up to 200 MW of renewable energy in Colorado by the end of 2023, which will contribute towards the aforementioned 80% carbon reduction goal by 2030. When Renewable Advantage comes online in 2023, more than half of Colorado Electric's generation mix will be renewable sources, leading to an approximate 70% reduction in GHG emissions by 2024.

- South Dakota. South Dakota adopted a renewable portfolio objective in 2008 that encourages, but does not mandate utilities to generate, or cause to be generated, at least 10% of their retail electricity supply from renewable energy sources by 2015.

- Wyoming. Wyoming currently has not issued a renewable energy portfolio standard.

In November 2020, we announced clean energy goals to reduce GHG emissions that are based on prudent and proven solutions to reduce our emissions while minimizing cost impacts to our customers. See more information in the Key Elements of our Business Strategy within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Federal Regulation

Energy Policy Act. The Energy Policy Act of 2005 included provisions to create an Electric Reliability Organization, which is required to promulgate mandatory reliability standards governing the operation of the bulk power system in the U.S. FERC certified NERC as the Electric Reliability Organization and also issued an initial order approving many reliability standards that went into effect in 2007. Entities that violate standards will be subject to fines and can also be assessed non-monetary penalties, depending upon the nature and severity of the violation.

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Federal Power Act. The Federal Power Act gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERC's jurisdiction must maintain tariffs and rate schedules on file with FERC that govern the rates, and terms and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. Public utilities are also subject to accounting, record-keeping and reporting requirements administered by FERC. FERC also places certain limitations on transactions between public utilities and their affiliates. Our public Electric Utilities' subsidiaries provide FERC-jurisdictional services subject to FERC's oversight.

Our Electric Utilities and Power Generation entities are authorized by FERC to make wholesale sales of electric capacity and energy at market-based rates under tariffs on file with FERC. As a condition of their market-based rate authority, each files Electric Quarterly Reports with FERC. Our Electric Utilities own and operate FERC-jurisdictional interstate transmission facilities and provide open access transmission service under tariffs on file with FERC. Our Electric Utilities are subject to routine audit by FERC with respect to their compliance with FERC's regulations.

The Federal Power Act authorizes FERC to certify and oversee a national electric reliability organization with authority to promulgate and enforce mandatory reliability standards applicable to all users, owners and operators of the bulk-power system. FERC has certified NERC as the electric reliability organization. NERC has promulgated mandatory reliability standards and NERC, in conjunction with regional reliability organizations that operate under FERC's and NERC's authority and oversight, enforces those mandatory reliability standards.

PUHCA 2005. PUHCA 2005 gives FERC authority with respect to the books and records of a utility holding company. As a utility holding company whose assets consist primarily of investments in our subsidiaries, including subsidiaries that are public utilities and also a centralized service company subsidiary, BHSC, we are subject to FERC's authority under PUHCA 2005.

Power Generation

Our Power Generation segment, which operates through Black Hills Electric Generation and its subsidiaries, acquires, develops, constructs and operates our non-regulated power plants. As of December 31, 2020, we held varying interests in independent power plants with a total net ownership of 423 MW.

We produce electric power from our generating facilities and sell the electric capacity and energy, primarily to affiliates under a combination of mid- to long-term contracts, which mitigates the impacts of volatility in future power prices and fluctuations in demand.

As of December 31, 2020, the power plant ownership interests held by our Power Generation segment include:

Power Plants	Fuel Type	Location	Ownership Interest % [(d)]	Owned Capacity (MW)	In Service Date
Wygen I	Coal	Gillette, Wyoming	76.5%	68.9	2003
Pueblo Airport Generation [(a)]	Gas	Pueblo, Colorado	50.1%	200.0	2012
Busch Ranch I [(b)]	Wind	Pueblo, Colorado	50.0%	14.5	2012
Busch Ranch II [(c)]	Wind	Pueblo, Colorado	100.0%	60.0	2019
Top of Iowa [(c)]	Wind	Joice, Iowa	100.0%	80.0	2019
				423.4	

(a) In 2016, Black Hills Electric Generation sold a 49.9% noncontrolling interest in Black Hills Colorado IPP to a third party. See Note 14 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.
(b) In 2013, Busch Ranch I was awarded a one-time cash grant in lieu of ITCs under the Section 1603 program created under the American Recovery and Reinvestment Act.
(c) The Busch Ranch II and Top of Iowa facilities qualify for PTCs at $25/MWh under IRC 45 during the 10-year period beginning on the date each facility was originally placed in service.
(d) Jointly owned facilities are discussed in Note 6 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Power Sales Agreements and Operating Agreements. Our Power Generation facilities have various mid- to long-term power sales agreements and operating agreements. Key contracts are disclosed in Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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Competition. The independent power industry consists of many strong and capable competitors, some of which may have more extensive operations or greater financial resources than we possess.

With respect to the merchant power sector, FERC has taken steps to increase access to the national transmission grid by utility and non-utility purchasers and sellers of electricity and foster competition within the wholesale electricity markets. Our Power Generation business could face greater competition if utilities are permitted to robustly invest in power generation assets. Conversely, state regulatory rules requiring utilities to competitively bid generation resources may provide opportunity for IPPs in some regions. To date, these initiatives have not had a material impact on our Power Generation segment.

The Energy Policy Act of 1992 and Public Utility Holding Company Act of 2005 (PUHCA 2005). PUHCA 2005 reiterated the definition and benefits of Exempt Wholesale Generator (EWG) status. Under PUHCA 2005, an EWG is an entity or generator engaged, directly or indirectly through one or more affiliates, exclusively in the business of owning, operating or both owning and operating all or part of one or more eligible facilities and selling electric energy at wholesale. Though EWGs are public utilities within the definition set forth in the Federal Power Act and are subject to FERC regulation of rates and charges, they are exempt from other FERC requirements. Through its subsidiaries, Black Hills Corporation is affiliated with three EWGs, Wygen I, Pueblo Airport Generating and Top of Iowa. Each of these three EWG's have been granted market-based rate authority.

Operating statistics. See a summary of key operating statistics in the Power Generation segment operating results within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Mining

Our Mining segment operates a single coal mine through our WRDC subsidiary. We surface mine, process and sell low-sulfur sub-bituminous coal at our mine near Gillette, Wyoming. The WRDC mine, which we acquired in 1956 from Homestake Mining Company, is located in the Powder River Basin. We produced approximately 3.7 million tons of coal in 2020.

During our surface mining operations, we strip and store the topsoil. We then remove the overburden (earth and rock covering the coal) with heavy equipment. Removal of the overburden typically requires drilling and blasting. Once the coal is exposed, we drill, fracture and systematically remove it, using front-end loaders and conveyors to transport the coal to the mine-mouth generating facilities. We reclaim disturbed areas as part of our normal mining activities by back-filling the pit with overburden removed during the mining process. Once we have replaced the overburden and topsoil, we reestablish vegetation and plant life in accordance with our approved post-mining topography plan.

In a basin characterized by thick coal seams, our overburden ratio, a comparison of the cubic yards of dirt removed to a ton of coal uncovered, has trended upwards over the last fifteen years. However, the overburden ratio at December 31, 2020 was 2.17 which decreased from 2.30 in the prior year as we mined in areas with lower overburden. We expect our stripping ratio to increase to approximately 2.27 by the end of 2021 as we mine in areas with higher overburden.

Mining rights to the reserves are based on three federal leases and one state lease. The federal leases expire between March 31, 2021 and September 30, 2025 and the state lease expires on August 1, 2023. The duration of the leases varies; however, the lease terms generally are extended to the exhaustion of economically recoverable reserves, as long as active mining continues. The federal lease expiring March 31, 2021 relates to an area we are no longer mining and will not be renewed. The Biden Administration recently issued an executive order that suspends new oil and gas leases on federal lands and eliminates fossil fuel subsidies. However, this moratorium does not apply to federal mining leases and we have not received federal subsidies.

We pay federal and state royalties of 12.5% of the selling price of all coal. As of December 31, 2020, we estimated our recoverable reserves to be approximately 182 million tons, based on a life-of-mine engineering study utilizing currently available drilling data and geological information prepared by internal engineering studies. The recoverable reserve life is equal to approximately 49 years at the current production levels. Our recoverable reserve estimates are periodically updated to reflect past production and other geological and mining data. Changes in mining methods or the utilization of new technologies may increase or decrease the recovery basis for a coal seam. Our recoverable reserves include reserves that can be economically and legally extracted at the time of their determination.

Substantially all of the mine's production is currently sold under contracts to:

- South Dakota Electric for use at the 90 MW Neil Simpson II plant to which we sell approximately 500,000 tons each year. This contract is for the life of the plant;
- Wyoming Electric for use at the 95 MW Wygen II plant to which we sell approximately 550,000 tons each year. This contract is for the life of the plant;

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- The 362 MW Wyodak Plant owned 80% by PacifiCorp and 20% by South Dakota Electric. PacifiCorp is obligated to purchase a minimum of 1.5 million tons each year, subject to adjustments for planned outages and other contract terms. This contract expires December 31, 2022 and negotiations to extend the contract are ongoing. South Dakota Electric is also obligated to purchase a minimum of 375,000 tons per year for its 20% share of the power plant, subject to adjustments for planned outages and other contract terms;

- The 110 MW Wygen III power plant jointly owned 52% by South Dakota Electric, 25% by MDU and 23% by the City of Gillette to which we sell approximately 600,000 tons each year;

- The 90 MW Wygen I power plant jointly owned 76.5% by Black Hills Wyoming and 23.5% by MEAN to which we sell approximately 500,000 tons each year; and

- Certain regional industrial customers served by truck to which we sell a total of approximately 300,000 tons each year. These contracts have terms of one to five years.

Our Mining segment sells coal to South Dakota Electric and Wyoming Electric for all of their requirements under cost-based agreements that regulate earnings from these affiliate sales to a specified return on our mine's cost-depreciated investment base. The return calculated annually is 400 basis points above Moody's A-Rated Utility Bond Index applied to our Mining investment base.

The price of unprocessed coal sold to PacifiCorp for the Wyodak Plant is determined by the supply agreement described above. The agreement included a price adjustment in 2019. The price adjustment essentially allowed us to retain the full economic advantage of the mine's location adjacent to the plant. The price adjustment was based on market price plus considerations for the avoided costs of rail transportation and an unloading facility, which PacifiCorp would have to incur if it purchased from another mine. In addition, the agreement also provided for the monthly escalation of price based on an escalation factor.

In October 2019, negotiations were completed for the price re-opener in the contract with the Wyodak Plant. The new price was reset at $17.94 per ton effective July 1, 2019, compared to the prior contract price of $18.25 per ton. The current contract price is comprised of three components: 1) avoided transportation costs (approximately 20% of current price); 2) avoided costs of an unloading facility (approximately 30% of current price); and 3) a rolling 12-month average of the Coal Daily spot market price of 8,400 Btu Powder River Basin coal (approximately 50% of current price).

WRDC supplies coal to Black Hills Wyoming for the Wygen I generating facility for requirements under an agreement through June 30, 2038. Currently, this agreement uses a base price that includes price escalators and quality adjustments and includes actual cost per ton plus a margin equal to the yield for Moody's A-Rated Utility Bond Index plus 400 basis points with the base price being adjusted on a 5-year interval. Effective January 1, 2022, in conjunction with the new Wygen I 60 MW PPA, WRDC's current coal supply agreement will be revised using pricing that will be cost-based to regulate earnings to a specified return on the cost-depreciated investment base. For additional information regarding the new Wygen I 60 MW PPA, see Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Competition. Our strategy is to sell the majority of our production to on-site, mine-mouth generation facilities under long-term supply contracts. Historically, any off-site sales have been to consumers within close proximity to the WRDC mine. Rail transport market opportunities for WRDC are limited due to the lower heating value (Btu) of the coal, combined with the fact that the WRDC mine is served by only one railroad, resulting in less competitive transportation rates.

Additionally, coal competes with other energy sources, such as natural gas, wind, solar and hydropower. Costs and other factors relating to these alternative fuels, such as safety, environmental and availability considerations affect the overall demand for coal as a fuel.

Environmental Matters. We are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. See Environmental Matters section for further information.

Mine Reclamation. Reclamation is completed during production and after mining has finished. Under applicable law, we must submit applications to, and receive approval from, the Wyoming Department of Environmental Quality for any mining and reclamation plans that provide for orderly mining, reclamation and restoration of the WRDC mine. We have approved mining permits and are in compliance with other permitting programs administered by various regulatory agencies. The WRDC mine is permitted to operate under a five-year mining permit issued by the State of Wyoming. In 2016, that five-year permit was re-issued and we are currently in the process of renewing this permit. Based on extensive reclamation studies, we have accrued approximately $13 million for reclamation costs as of December 31, 2020. See additional information in Note 7 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

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Operating statistics. See a summary of key operating statistics in the Mining segment operating results within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Environmental Matters

In November 2020, we announced clean energy goals to reduce GHG emissions that are based on prudent and proven solutions to reduce our emissions while minimizing cost impacts to our customers. See more information in Key Elements of our Business Strategy within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

Environmental Management System (EMS). We operate an EMS that is composed of environmental policies and procedures, voluntary initiatives, objectives and annual targets, operational controls, training, a sophisticated task scheduling/tracking and document control system, and a continuous improvement process. The program attained Colorado's highest level in their Environmental Leadership Program (Gold Level status in 2014) and has continued this status through 2020.

Methane Rules (Greenhouse Gas Emissions). The EPA and the State of Colorado have implemented strict regulatory requirements on hydrocarbon and methane emissions associated with natural gas gathering and transmission systems. Presently, we have facilities in our natural gas transmission operations affected by the methane reduction rules.

Our operations are in compliance with both EPA and State of Colorado rules. Future modifications to our gathering and transmissions systems are anticipated to trigger EPA methane rules that we will adhere to. We developed a corporate-wide methane control strategy to address GHG emissions. As a proactive measure in reducing methane emissions beyond current regulatory requirements, we have entered into the EPA's Methane Challenge Program. This is a voluntary program founded by the EPA in collaboration with oil and natural gas companies that recognizes companies that make specific and transparent commitments to reduce methane emissions.

Short-term Emission Limits. The EPA and State Air Quality Programs implemented short-term emission limits for coal and natural gas-fired generating units during normal and start-up operating scenarios for SO2, NOx and opacity. The limits pertain to emissions during start-up periods and upset conditions such as mechanical malfunctions. State and federal regulatory agencies typically excuse short-term emissions exceedances if they are reported and corrected immediately or if it occurs during start-up.

We proactively manage this requirement through maintenance efforts and installing additional pollution control systems to control SO2 emission short-term excursions during start-up. These actions have nearly eliminated our short-term emission limit compliance risk while plant availability remained above 90% for all four of our coal-fired plants. To eliminate the remaining potential for exceedances, an innovative trip logic mechanism was implemented to shut down the power plant if we anticipate the emission limit will be exceeded. There have been limited instances of the trip logic mechanism being used and we experienced zero exceedances during 2020.

Regional Haze (Impacts to the Wyodak Plant). The EPA Regional Haze rule was promulgated to improve visibility in our National Parks and Wilderness Areas. The State of Wyoming proposed controls in its Regional Haze State Implementation Plan (SIP) which allowed PacifiCorp to install low-NO_x burners in the Wyodak Plant, of which South Dakota Electric owns 20%. The EPA did not agree with the State of Wyoming's determination, overruled it in a Federal Implementation Plan (FIP) and proposed a Selective Catalytic Reactor to be installed to control NO_x emissions. This would cost South Dakota Electric approximately $27 million due to its 20% ownership of the Wyodak Plant. PacifiCorp and the State of Wyoming challenged the EPA's determination. Prior to proceeding to court, PacifiCorp and the EPA reached a verbal agreement on December 16, 2020, to limit operating hours and determined that low-NO_x burners would be considered appropriate to control NO_x emissions. This proposed agreement was published in the Federal Register, but remains in the public comment period until March 1, 2021. The final agreement must be published in the Federal Register and approved in Wyoming's State Implementation Plan through the rule making process.

Mining. Operations at the WRDC mine must regularly address issues related to the proximity of the mine disturbance boundary to the City of Gillette and to residential properties. Homeowner complaints and challenges to the permits may occur as mining operations move closer to residential areas. Specific concerns could include damage to wells, fugitive dust emissions, vibration and an emissions cloud from blasting. The mine makes every effort to reduce these impacts by monitoring blasts, modifying blast techniques to reduce blast vibration, applying dust suppression controls on roads and reclaiming lands to reduce windblown dust.

Former Manufactured Gas Plants (FMGP). Federal and state laws authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment. As of December 31, 2020, our Gas Utilities have two active FMGP sites, which are located in Council Bluffs, Iowa, and McCook, Nebraska. At the Council Bluffs site, the EPA issued an order for the responsible parties to proceed with an Engineering Evaluation and Cost Analysis (EECA) to clean up the site. Three viable Potential Responsible Parties (PRP) continue to deny their legal attachment to the site. The Company will continue conducting the EECA and anticipates pursuing the PRP's through legal action. There is currently no action being taken at the McCook, Nebraska site. A third-party initially indicated they intend to manage and pay for the clean-up at this site. However, after further investigation, the third-party assessed they owned the property after the gas plant ceased operations. We expect to conduct an assessment to determine viable PRPs.

For additional information, see Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Affordable Clean Energy Rule. The EPA was directed to repeal, revise and replace the Clean Power Plan rule. On August 31, 2018, the EPA published the proposed Affordable Clean Energy (ACE) rule. This rule focused on heat-rate improvements on coal-fired boiler units and applied only to our coal-fired plants. The Company's coal-fired plants subject to the rule had implemented or planned to implement a majority of the efficiency requirements listed in the rule. On January 19, 2021, a three-judge panel of the U.S. Court of Appeals for the District of Columbia Circuit vacated the ACE rule. The court remanded the regulation regarding carbon dioxide emissions from existing power plants back to the EPA for reconsideration. Currently, there is no rule governing power plant GHG emissions and it is uncertain when a new rule will be promulgated.

OSM Coal Combustion Residual Rule (CCR). The EPA issued the CCR which is currently effective and establishes requirements to protect surface and groundwater from impacts of coal ash impoundments. WRDC is exempt from the EPA CCR because ash is used for backfill reclamation in areas previously mined. The Office of Surface Mining (OSM) was considering CCR rules that would apply to the mine, but these rules were not proposed during the Trump administration. We will continue to monitor to see if the Biden administration pursues these rules.

Environmental risk changes constantly with the implementation of new or modified regulations, changing stakeholder interests and needs, and through the introduction of innovative work practices and technologies. We assess risk annually and develop mitigation strategies to successfully and responsibly manage and ensure compliance across the enterprise. For additional information on environmental matters, see Item 1A and Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Other Properties

In addition to the properties previously disclosed in the sections above, we own or lease several facilities throughout our service territories including a corporate headquarters building and various office, service center, storage, shop and warehouse space. Substantially all of the tangible utility properties of South Dakota Electric and Wyoming Electric are subject to liens securing first mortgage bonds issued by South Dakota Electric and Wyoming Electric, respectively.

Human Capital Resources

Overview

Black Hills Corporation is committed to supporting operational excellence by attracting, motivating, retaining and encouraging the development of highly qualified employees. Our employees' drive and dedication to their work, and their commitment to the safety of our customers and their fellow employees, allows Black Hills Corporation to successfully grow and manage our business year over year. The impacts of COVID-19 to our businesses and employees are discussed in the Company Highlights within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K.

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Our Team	As of December 31, 2020
Total employees	3,011
Gender diversity (women as a % of total employees)	26%
Women in executive leadership positions [(a)]	31%
Ethnic diversity (non-white employees as a % of total)	11%
Military veterans	16%
Represented by a union	25%
	For the year ended December 31, 2020
Number of external hires	299
External hires gender diversity (as a % of total external hires)	29%
External hires ethnic diversity (as a % of total external hires)	16%
Turnover rate [(b)]	8%
Retirement rate	3%

(a) Executive leadership positions are defined as positions with Vice President, Senior Vice President or Chief in their title.
(b) Includes voluntary and involuntary separations, but excludes internships.

Total Employees

	Number of Employees At December 31, 2020
Electric Utilities	379
Gas Utilities	1,237
Power Generation and Mining	60
Corporate and Other	1,335
Total	3,011

At December 31, 2020, approximately 21% of our total employees and 23% of our Electric and Gas Utilities employees were eligible for regular (age 65 with at least 5 years of service) or early (ages 55 to 64 with at least 5 years of service) retirement.

Collective Bargaining Agreements

At December 31, 2020, certain employees of our Electric Utilities and Gas Utilities were covered by the collective bargaining agreements as shown in the table below. We have not experienced any labor stoppages in decades.

Utility	Number of Employees	Union Affiliation	Expiration Date of Collective Bargaining Agreement
Colorado Electric	95	IBEW Local 667	April 15, 2023
South Dakota Electric	137	IBEW Local 1250	March 31, 2022
Wyoming Electric	26	IBEW Local 111	June 30, 2024
Total Electric Utilities	258		
Iowa Gas	121	IBEW Local 204	January 31, 2026
Kansas Gas	17	Communications Workers of America, AFL-CIO Local 6407	December 31, 2024
Nebraska Gas	100	IBEW Local 244	March 13, 2022
Nebraska Gas	147	CWA Local 7476	October 30, 2023
Wyoming Gas	15	IBEW Local 111	June 30, 2024
Wyoming Gas	84	CWA Local 7476	October 30, 2023
Total Gas Utilities	484		
Total	742		

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Attraction

Continuous attraction of qualified team members is critical to our ability to serve our 1.3 million customers safely and efficiently. We actively recruit diverse candidates and continuously evaluate our interviewing and hiring practices to ensure equitable pay and processes. Our attraction efforts include the use of multiple nation-wide job boards, local college and high school outreach programs, a strong college internship program and participation in national and local job fairs. Another key area of attraction is our commitment to our military personnel and veterans. We have targeted attraction efforts specific to military personnel transitioning into civilian life and for veterans of all types.

Diversity & Inclusion

At Black Hills Corporation, we believe in the benefits of diversity, equity and inclusion. We believe that a diverse workforce will assist us in achieving our goals of becoming the safest utility in the nation, providing exceptional customer service and achieving new levels of growth in a rapidly evolving industry. Workforce diversity trends, including diverse new hires, promotions and turnover, are monitored at regular intervals.

Development and Retention

Retaining and developing team members is critical to our continued success. Our retention efforts include competitive compensation programs, career development resources for all employees and internal training programs. Our compensation programs are designed to be strategically aligned, externally competitive, internally equitable, personally motivating, cost effective and legally compliant. Our career development resources include management onboarding, leadership development programs, mentoring programs, individual development assessments and more. Internal training opportunities include corporate-wide trainings such as our code of conduct and specialized training opportunities for different job functions. Our Field Career Path Program (FCPP) promotes career growth through established standards of knowledge, skills, abilities and performance.

ITEM 1A. RISK FACTORS

The nature of our business subjects us to a number of uncertainties and risks. Risks that may adversely affect the business operations, financial condition, results of operations or cash flows are described below. These risk factors, along with other risk factors that we discuss in our periodic reports filed with the SEC should be considered for a better understanding of our Company.

STRATEGIC RISKS

Our continued success is dependent on execution of our strategic business plans including our growth strategy.

Our success depends, in significant part, on our ability to execute our strategic business plans, including our growth strategy. Our plans and strategy include reducing GHG emissions for our Electric Utilities and Gas Utilities, transforming the customer experience, growing our electric and natural gas customer load, pursuing operating efficiencies and modernizing our utility infrastructure. Our current plans and strategy may be negatively impacted by disruptive forces and innovations in the marketplace, changing political, business or regulatory conditions, and technology advancements.

In addition, we have significant capital investment programs planned for the next five years that are key to our strategic business plans. The successful execution of our capital investment program depends on, or could be affected by, a variety of factors that include, but are not limited to: weather conditions, effective management of projects, availability of qualified construction personnel including contractors, changes in commodity and other prices, availability of materials, governmental approvals and permitting, regulatory cost recovery and return on investment.

An inability to successfully and timely adapt to changing conditions and execute our strategic plans, including our growth strategy could materially affect our financial operating results including earnings, cash flow and liquidity.

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Customer growth and usage in our service territories may fluctuate with economic conditions, emerging technologies or responses to price increases.

Our financial operating results are impacted by energy demand in our service territories. Customer growth and usage may be impacted by a number of factors, including the voluntary reduction in consumption of electricity and natural gas by our customers in response to increases in prices and energy efficiency programs, electrification initiatives that could negatively impact the demand for natural gas, economic conditions impacting customers' disposable income and the use of distributed generation resources or other emerging technologies. Continued technological improvements may make customer and third-party distributed generation and energy storage systems, including fuel cells, micro-turbines, wind turbines, solar cells and batteries, more cost effective and feasible for our customers. If more customers utilize their own generation, demand for energy from us would decline. Such developments could affect the price of energy and delivery of energy, require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Each of these factors could materially affect our financial operating results including earnings, cash flow and liquidity.

REGULATORY, LEGISLATIVE AND LEGAL RISKS

We may be subject to future laws, regulations, or actions associated with climate change, including those relating to fossil-fuel generation and GHG emissions, which could increase our operating costs or restrict our market opportunities.

We own and operate regulated and unregulated electric power plants that burn fossil fuels (natural gas and coal) and a surface mine that extracts and sells coal. We also purchase, store and deliver natural gas to our customers. These business activities are subject to evolving public concern regarding fossil fuels, GHG emissions (such as carbon dioxide and methane) and their impact on the climate.

There is uncertainty surrounding climate regulation due to legal challenges to some current regulations and anticipated new federal and/or state climate legislation and regulation. The Biden administration has issued executive orders aimed at reducing GHG emissions and declared climate change a national security policy for the first time. New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, the closure or capacity reductions of coal-fired power generation facilities and potential increased production from our combined cycle natural gas-fired generating units. Increased rules and regulations associated with fossil fuels and GHG emissions could result in the impairment or retirement of some of our existing or future transmission, distribution, generation and natural gas storage facilities or our coal mine. Further, these rules could create the need to purchase or build clean-energy fuel sources to fulfill obligations to our customers. These actions could also result in increased operating costs which could adversely impact customers and our financial operating results including earnings, cash flow and liquidity. We cannot definitively estimate the effect of GHG legislation or regulation on our results of operations, financial condition or cash flows.

Future GHG constraints designed to minimize emissions from natural gas could likewise result in increased costs and affect the demand for natural gas as well as the prices charged to customers and the competitive position of natural gas. Certain cities in our operational footprint are focused on electrification and have adopted initiatives to prohibit the construction of new natural gas distribution facilities. Any such initiatives and legislation could have a material impact on our results of operations, financial condition and cash flows.

We may be subject to unfavorable or untimely federal and state regulatory outcomes.

Our regulated Electric and Gas Utilities are subject to cost-of-service/rate-of-return regulation and earnings oversight from federal and eight state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our customer rates are regulated by either the FERC or the respective state utility regulatory authority based on an analysis of our costs and investments, as reviewed and approved in a regulatory proceeding. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that our various regulatory authorities will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will result in full or timely recovery of our costs and the allowed return on invested capital. In addition, adverse rate decisions, including rate moratoriums, rate refunds, limits on rate increases, lower allowed returns on investments or rate reductions, could be influenced by competitive, economic, political, legislative, public perception and regulatory pressures and adversely impact results of operations, financial condition and cash flows.

Each of our Electric and Gas Utilities are permitted to recover certain costs (such as increased fuel and purchased power costs or integrity capital investments) outside of a base rate review in order to stabilize customer rates and reduce regulatory lag. If regulators decide to discontinue these tariff-based recovery mechanisms, it could negatively impact results of operations, financial condition and cash flows.

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Costs could significantly increase to achieve or maintain compliance with existing or future environmental laws, regulations or requirements.

Our business segments are subject to numerous environmental laws and regulations affecting many aspects of present and future operations, including air emissions (i.e. SO_2, NO_x, volatile organic compounds, particulate matter and GHG), water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations may result in increased capital, operating and other costs. These laws and regulations generally require the business segments to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations may require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure or inability to comply with evolving environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets.

Our business segments may not be successful in recovering increased capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and contracts with customers. More stringent environmental laws or regulations could result in additional costs of operation for existing facilities or impede the development of new facilities. Although it is not expected that the costs to comply with current environmental regulations will have a material adverse effect on our business segments' financial position, results of operations or cash flows, future environmental compliance costs could have a significant negative impact.

Legislative and regulatory requirements may lead to increased costs and result in compliance penalties.

Business activities in the energy sector are heavily regulated, primarily by agencies of the federal government. Many agencies employ mandatory civil penalty structures for regulatory violations. The FERC, NERC, CFTC, EPA, OSHA, SEC and MSHA may impose significant civil and criminal penalties to enforce compliance requirements relative to our business, which could have a material adverse effect on our financial operating results including earnings, cash flow and liquidity.

Municipal governments may seek to limit or deny our franchise privileges.

Municipal governments within our utility service territories possess the power of condemnation and could establish a municipal utility within a portion of our current service territories by limiting or denying franchise privileges for our operations and exercising powers of condemnation over all or part of our utility assets within municipal boundaries. We regularly engage in negotiations on renewals of franchise agreements with our municipal governments. We have from time to time faced challenges or ballot initiatives on franchise renewals. To date, we have been successful in resolving or defending each of these challenges. Although condemnation is a process that is subject to constitutional protections requiring just and fair compensation, as with any judicial procedure, the outcome is uncertain. If a municipality sought to pursue this course of action, we cannot assure that we would secure adequate recovery of our investment in assets subject to condemnation. We also cannot quantify the impact that such action would have on the remainder of our business operations.

Changes in Federal tax law may significantly impact our business.

We are subject to taxation by the various taxing authorities at the federal, state and local levels where we do business. Similar to the TCJA, sweeping legislation or regulation could be enacted by any of these governmental authorities which may affect our tax burden. Changes may include numerous provisions that affect businesses, including changes to U.S. corporate tax rates, business-related exclusions, and deductions and credits. The outcome of regulatory proceedings regarding the extent to which the effect of a change in corporate tax rate will impact our utility customers and the time period over which the impact will occur could significantly impact future earnings and cash flows. Separately, a challenge by a taxing authority, changes in taxing authorities' administrative interpretations, decisions, policies and positions, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates.

OPERATING RISKS

Our financial performance depends on the successful operation of electric generating facilities, electric and natural gas transmission and distribution systems, natural gas storage facilities, and a coal mine.

The risks associated with management of these operations include:

- Inherent dangers. Electricity and natural gas can be dangerous to employees and the general public. Failures of or contact with power lines, natural gas pipelines or service facilities and equipment may result in fires, explosions, property damage and personal injuries, including death. While we maintain liability and property insurance coverage, such policies are subject to certain limits and deductibles. The occurrence of any of these events may not be fully covered by our insurance;

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- Weather, natural conditions and disasters. Severe weather events, such as snow and ice storms, fires, tornadoes, strong winds, significant thunderstorms, flooding and drought, could negatively impact operations, including our ability to provide energy safely, reliably and profitably and our ability to complete construction, expansion or refurbishment of facilities as planned;

- Acts of sabotage, terrorism or other malicious attacks. Damage to our facilities due to deliberate acts could lead to outages or other adverse effects;

- Operating hazards. Operating hazards such as leaks, mechanical problems and accidents, including fires or explosions could impact employee and public safety, reliability and customer confidence;

- Equipment and processes. Breakdown or failure of equipment or processes, unavailability or increased cost of equipment, and performance below expected levels of output or efficiency could negatively impact our results of operations;

- Disrupted transmission and distribution. We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity and gas that we sell to our retail and wholesale customers. If transmission is interrupted physically, mechanically, or with cyber means, our ability to sell or deliver utility services and satisfy our contractual obligations may be hindered;

- Natural gas supply for generation and distribution. Our regulated utilities and non-regulated entities purchase natural gas from a number of suppliers for our generating facilities and for distribution to our customers. Our results of operations could be negatively impacted by the lack of availability and cost of natural gas, and disruptions in the delivery of natural gas due to various factors, including but not limited to, transportation delays, labor relations, weather and environmental regulations;

- Replacement power. The cost of supplying or securing replacement power during scheduled and unscheduled outages of generation facilities could negatively impact our results of operations;

- Governmental permits. The inability to obtain required governmental permits and approvals along with the cost of complying with or satisfying conditions imposed upon such approvals could negatively impact our ability to operate
and our results of operations;

- Operational limitations. Operational limitations imposed by environmental and other regulatory requirements and contractual agreements, including those that restrict the timing of generation plant scheduled outages, could negatively impact our results of operations;

- Increased costs. Increased capital and operating costs to comply with increasingly stringent laws and regulations; unexpected engineering, environmental and geological problems; and unanticipated cost overruns could negatively impact our results of operations;

- Labor and labor relations. The cost of recruiting and retaining skilled technical labor or the unavailability of such resources could have a negative impact on our operations. Our ability to transition and replace our retirement-eligible utility employees is a risk; at December 31, 2020, approximately 23% of our Electric Utilities and Gas Utilities employees were eligible for regular or early retirement. Our ability to avoid or minimize supply interruptions, work stoppages and labor disputes is also a risk; approximately 25% of our employees are represented by unions;

- Public opposition. Opposition by members of public or special-interest groups could negatively impact our ability to operate our businesses; and

The ongoing operation of our business involves the risks described above, in addition to risks associated with threats to our overall business model, such as electrification initiatives. Any of these risks could cause us to experience negative financial results and damage to our reputation and public confidence. These risks could cause us to incur significant costs or be unable to deliver energy and/or operate below expected capacity levels, which in turn could reduce revenues or cause us to incur higher operating and maintenance costs and penalties. While we maintain insurance and obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance and our rights under contracts, warranties or performance guarantees may not be timely or adequate to cover lost revenues, increased expenses, liability or liquidated damage payments.

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Cyberattacks, terrorism, or other malicious acts targeting our key technology systems could disrupt our operations, or lead to a loss or misuse of confidential and proprietary information.

To effectively operate our business, we rely upon a sophisticated electronic control system, information and operation technology systems and network infrastructure to generate, distribute and deliver energy, and collect and retain sensitive information including personal information about our customers and employees. Cyberattacks, terrorism or other malicious acts targeting electronic control systems could result in a full or partial disruption of our electric and/or gas operations. Attacks targeting other key technology systems, including our third-party vendors' information systems, could further add to a full or partial disruption of our operations. Any disruption of these operations could result in a loss of service to customers and associated revenues, as well as significant expense to repair damages and remedy security breaches. In addition, any theft, loss and/or fraudulent use of customer, shareowner, employee or proprietary data could subject us to significant litigation, liability and costs, as well as adversely impact our reputation with customers and regulators, among others.

We have instituted security measures and safeguards to protect our operational systems and information technology assets, including certain safeguards required by FERC. Despite our implementation of security measures and safeguards, all of our technology systems may still be vulnerable to disability, failures or unauthorized access.

Weather conditions, including the impacts of climate change, may cause fluctuation in customer usage.

Our utility businesses are seasonal businesses and weather conditions and patterns can have a material impact on our operating performance. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating, respectively. Demand for natural gas depends heavily upon winter-weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our utility operations have historically generated lower revenues and income when weather conditions are cooler than normal in the summer and warmer than normal in the winter. Demand for natural gas is also impacted by summer weather patterns that are cooler than normal and provide higher than normal precipitation; both of which can reduce natural gas demand for irrigation. Unusually mild summers and winters, therefore, could have an adverse effect on our financial operating results, including earnings, cash flow and liquidity.

FINANCIAL RISKS

A sub-investment grade credit rating could impact our ability to access capital markets.

Our issuer credit rating is Baa2 (Stable outlook) by Moody's; BBB+ (Stable outlook) by S&P; and BBB+ (Stable outlook) by Fitch. Reduction of our investment grade credit ratings could impair our ability to refinance or repay our existing debt and complete new financings on reasonable terms, if at all. A credit rating downgrade, particularly to sub-investment grade, could also result in counterparties requiring us to post additional collateral under existing or new contracts. In addition, a ratings downgrade would increase our interest expense under some of our existing debt obligations, including borrowings under our credit facilities, potentially significantly increasing our cost of capital and other associated operating costs which may not be recoverable through existing regulatory rate structures and contracts with customers.

Our use of derivative financial instruments as hedges against commodity prices and financial market risks could result in material financial losses.

We use various financial and physical derivatives, including futures, forwards, options and swaps to manage commodity price and interest rate risks. The timing of the recognition of gains or losses on these economic hedges in accordance with GAAP does not always match up with the gains or losses on the commodities being hedged. For Black Hills Energy Services under the Choice Gas Program, and in certain instances within our regulated Utilities where unrealized and realized gains and losses from derivative instruments are not approved for regulatory accounting treatment, fluctuating commodity prices may cause fluctuations in reported financial results due to mark-to-market accounting treatment.

To the extent that we hedge our commodity price and interest rate exposures, we forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though they are closely monitored by management, our hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is economically imperfect, commodity prices or interest rates move unfavorably related to our physical or financial positions, or hedging policies and procedures are not followed.

Additionally, our exchange-traded futures contracts are subject to futures margin posting requirements. To the extent we are unable to meet these requirements, this could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price uncertainty and to protect cash flows. Requirements to post collateral may cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or may require us to increase our level of debt. Further, a requirement for our counterparties to post collateral could result in additional costs being passed on to us, thereby decreasing our profitability.

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We have a holding company corporate structure with multiple subsidiaries. Corporate dividends and debt payments are dependent upon cash distributions to the holding company from the subsidiaries.

As a holding company, our investments in our subsidiaries are our primary assets. Our operating cash flow and ability to service our indebtedness depend on the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends or advances. Our subsidiaries are separate legal entities that have no obligation to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary's ability to pay dividends to us depends on any applicable contractual or regulatory restrictions that may include requirements to maintain minimum levels of cash, working capital, equity or debt service funds.

There is no assurance as to the amount, if any, of future dividends to the holding company because these subsidiaries depend on our future earnings, capital requirements and financial condition and are subject to declaration by the Board of Directors. See "Liquidity and Capital Resources" within Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7 and Note 9 of our Notes to Consolidated Financial Statements of this Annual Report on Form 10-K for further information regarding these restrictions and their impact on our liquidity.

We may be unable to obtain financing on reasonable terms needed to refinance debt, fund planned capital expenditures or otherwise execute our operating strategy.

Our ability to execute our operating strategy is highly dependent upon our access to capital. Historically, we have addressed our liquidity needs (including funds required to make scheduled principal and interest payments, refinance debt, pay dividends and fund working capital and planned capital expenditures) with operating cash flow, borrowings under credit facilities, proceeds of debt and equity offerings and proceeds from asset sales. Our ability to access the capital markets and the costs and terms of available financing depend on many factors, including changes in our credit ratings, changes in the federal or state regulatory environment affecting energy companies, volatility in commodity or electricity prices and general economic and market conditions.

In addition, because we are a holding company and our utility assets are owned by our subsidiaries, if we are unable to adequately access the credit markets, we could be required to take additional measures designed to ensure that our utility subsidiaries are adequately capitalized to provide safe and reliable service. Possible additional measures would be evaluated in the context of then-prevailing market conditions, prudent financial management and any applicable regulatory requirements.

National and regional economic conditions may cause increased counterparty credit risk, late payments and uncollectible accounts.

A future recession or pandemic, if one occurs, may lead to an increase in late payments or non-payment from retail residential, commercial and industrial utility customers, as well as from our non-utility customers. If late payments and uncollectible accounts increase, earnings and cash flows from our continuing operations may be reduced.

We may be unable to obtain insurance coverage, and the coverage we currently have may not apply or may be insufficient to cover a significant loss.

Our ability to obtain insurance, as well as the cost of such insurance, could be impacted by developments affecting the insurance industry and the financial condition of insurers. Additionally insurance providers could deny coverage or decline to extend coverage under the same or similar terms that are presently available to us. A loss for which we are not adequately insured could materially affect our financial results. The coverage we currently have in place may not apply to a particular loss, or it may not be sufficient to cover all liabilities to which the Company may be subject, including liability and losses associated with wildfire, natural gas and gas storage field explosions, cyber-security breaches, environmental hazards and natural disasters.

Market performance or changes in key valuation assumptions could require us to make significant unplanned contributions to our pension plan and other postretirement benefit plans.

Assumptions related to interest rates, expected return on investments, mortality and other key actuarial assumptions have a significant impact on our funding requirements and the expense recognized related to these plans. An adverse change to key assumptions associated with our defined benefit retirement plans may require significant unplanned contributions to the plans which could adversely affect our financial operating results including earnings, cash flow and liquidity.

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Costs associated with our healthcare plans and other benefits could increase significantly.

The costs of providing healthcare benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to healthcare plans for our employees and former employees, will continue to rise. Significant regulatory developments have required, and likely will continue to require, changes to our current employee benefit plans and supporting administrative processes. Our electric and gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. Within our utility rates we have generally recovered the cost of providing employee benefits. As benefit costs continue to rise, there is no assurance that the state utility commissions will allow recovery of these increased costs. The rising employee benefit costs, or inadequate recovery of such costs, may adversely affect our financial operating results including earnings, cash flow, or liquidity.

PANDEMIC RISK

Our business operations, results of operations, financial condition and cash flows could be adversely affected by the coronavirus (COVID-19) pandemic.

We have responded to the global pandemic of COVID-19 by taking steps to mitigate the potential risks to us posed by its spread.

For the year ended December 31, 2020, the COVID-19 pandemic had a limited net financial impact on our business operations, financial condition and cash flows. In particular, we experienced:

- Increased allowance for credit losses and bad debt expense due to anticipated customer non-payment as a result of suspended disconnections;
- Increased costs due to sequestration of mission-critical and essential employees;
- Lower commercial and certain transport volumes partially offset by higher electric and natural gas residential usage;
- Waived customer late payment fees;
- Reduced availability of our employees;
- Increased costs for personal protection equipment and cleaning supplies;
- Minimal disruptions receiving the materials and supplies necessary to maintain operations and continue executing our capital investment plan;
- Minimal impacts to the availability of our contractors;
- Minimal decline in the funded status of our pension plan;
- Minimal interest expense increase due to disruptions in the Commercial Paper markets; and
- Reduced training, travel, and outside services related expenses.

Should the COVID-19 pandemic continue for a prolonged period or impact the areas we serve more significantly than it has to date, our business operations, financial condition and cash flows could be impacted in more significant ways. In addition to exacerbating the impacts described above, we could experience:

- Adverse impacts on our strategic business plans, growth strategy and capital investments;
- Increased adverse impacts to electricity and natural gas demand from our customers, particularly from commercial and industrial customers;
- Further reduction in the availability of our employees and contractors;
- Increased costs as a result of our preventative measures, such as sequestration of essential employees and facility cleaning services;
- Increased allowance for credit losses and bad debt expense as a result of delayed or non-payment from our customers, both of which could be magnified by Federal or state government legislation that requires us to extend suspensions of disconnections for non-payment;
- Delays and disruptions in the availability, timely delivery and cost of materials and components used in our operations;
- Disruptions in the commercial operation dates of certain projects impacting qualification criteria for certain tax credits and triggering potential damages under our power purchase agreements;
- Deterioration of the credit quality of our counterparties, including gas commodity contract counterparties, power purchase agreement counterparties, contractors or retail customers, that could result in credit losses;
- Impairment of goodwill or long-lived assets;
- Adverse impacts on our ability to construct and operate facilities;
- Inability to meet the requirements of the covenants in our existing credit facilities, including covenants regarding Consolidated Indebtedness to Capitalization Ratio;
- Deterioration in our financial metrics or the business environment that adversely impacts our credit ratings;
- Delay in the permitting process of certain development projects, affecting the timing of final investment decisions and start dates of construction;
- Adverse impact on our liquidity position and cost of and ability to access funds from financial institutions and capital markets; and
- Delays in our ability to change rates through regulatory proceedings.