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Short-Term Energy Outlook Supplement: Forecast Sensitivity of Carbon Dioxide Emissions to Temperatures

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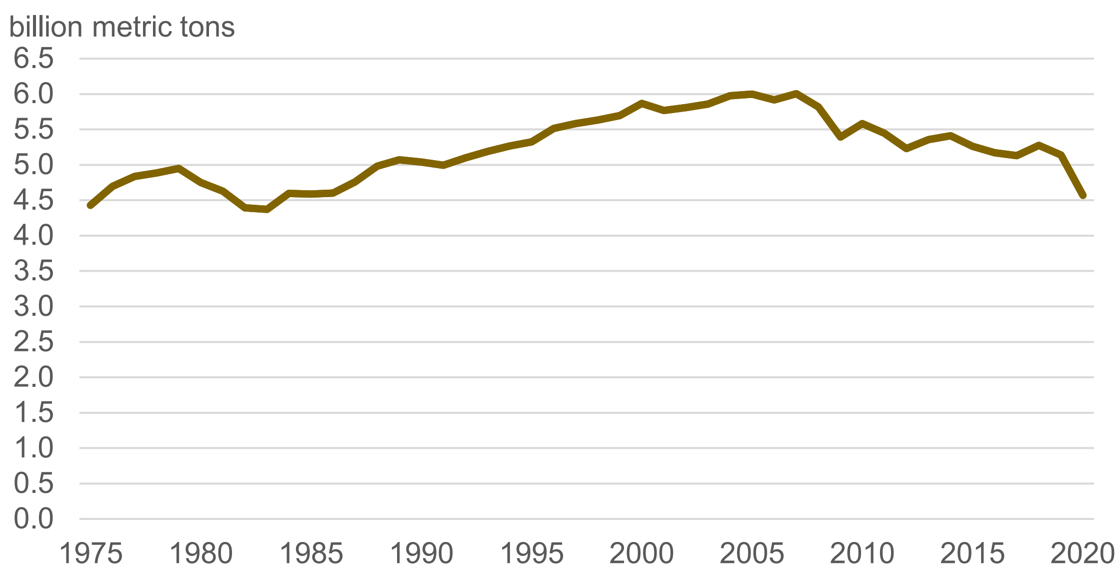
Introduction

After peaking at 6.0 billion metric tons in 2007, U.S. energy-related carbon dioxide (CO_2) emissions declined to 5.1 billion metric tons in 2019 (Figure 1), a 14% drop. This decline in emissions occurred even though U.S. real GDP grew by 22% during the same period. Several factors contributed to falling CO_2 emissions amid rising economic activity, including:

- Increases in the energy efficiency of buildings, equipment, and vehicles reduced the level of energy demand
- Increases in the capacity to generate electricity from renewable energy sources led to more electricity generation without emissions
- Decreases in the price of natural gas made natural gas increasingly competitive compared with coal to dispatch for electricity generation, which in turn reduced the carbon intensity of the electric power sector

U.S. CO_2 emissions declined to less than 4.6 billion metric tons in 2020, the lowest level since 1983. However, the 2020 drop in emissions was largely the result of reduced economic and travel activities that lowered the level of energy use in response to the COVID-19 pandemic. As economic activity has begun to grow and commuting and travel is increasing, we expect energy-related CO_2 emissions to grow somewhat in 2021 and 2022, reaching almost 5.0 billion metric tons next year, which would still be less than 2019 emissions of more than 5.1 billion metric tons.

Figure 1. U.S. energy-related CO_2 emissions, 1975–2020



Source: U.S. Energy Information Administration, *Monthly Energy Review*

Although U.S. CO_2 emissions have generally fallen since 2007, this decline has not been constant. Emissions increased in four separate years since the 2007 peak (2010, 2013, 2014, and 2018). During the 2007–2020 period of generally declining emissions, the years when U.S. emissions increased also saw temperatures that deviated significantly from average. Annual U.S. CO_2 emissions grew by 2% during

2013 and by 1% during 2014. U.S. population-weighted heating degree days (HDD)—a measure of how cold winter temperatures are—were 3% more than the 1991–2020 average in 2013 and 5% more in 2014. Emissions also increased by 3% in 2018, when U.S. population-weighted cooling degree days (CDD)—a measure of how hot summer temperatures are—were 19% more than the 1991–2020 average. In 2010, HDDs were 3% and CDDs and 9%, respectively more than their 1991–2020 averages.

Three broad factors drive energy-related CO_2 emissions in the United States:

1. The level of economic activity across sectors of the U.S. economy
2. Energy consumption in relation to the economic activity in each sector of the economy (energy intensity)
3. The rate of CO_2 emissions associated with energy use in different sectors (carbon intensity)

We compiled this supplement to the *Short-Term Energy Outlook* (STEO) to examine how sensitive our U.S. energy-related CO_2 emissions models are to changes in temperatures. We compared our baseline STEO forecast for 2022 with eight different scenarios (cases) of HDDs and CDDs for 2022 that cover a significant range of alternative outcomes for heating and cooling requirements. The cases show the general sensitivity of energy consumption and CO_2 emissions across a wide variety of temperatures and should not be interpreted as our forecast of future temperature or energy consumption outcomes for 2022 or beyond.

Our results indicate that variability in temperature affects not only the level of energy demand in different U.S. economic sectors, but also the carbon intensity of the sectors, depending on the relative sensitivity of coal and natural gas prices to changing demand. In particular, when winter temperatures significantly differ from our Base Case forecasts, more variation in energy consumption and emissions occurs than when summer temperatures significantly differ from our Base Case.

Methodology

Among the factors affecting energy-related CO_2 emissions, some are relatively stable in the short term, including consumer behavior and the energy-consuming capital stock of the economy—items such as buildings, power plants, vehicles, and manufacturing equipment. These factors set the general baseline level of energy and carbon intensity of an economy.

However, the amount of energy that consumers use with the existing stock in any given year is subject to additional variable factors, such as the rate of economic growth, energy prices, and temperatures. All of these factors can cause energy use and CO_2 emissions to vary significantly from year to year.

We set up eight cases with different temperature assumptions to test this sensitivity in the United States. We used the May 2021 STEO results for 2022 as the baseline for the cases. The HDD and CDD data that we used as STEO inputs for each month came from the National Oceanic and Atmospheric Administration (NOAA). To compile the HDD and CDD forecasts used in STEO, we took NOAA's monthly forecasts by state and weighted the HDDs and CDDs by state population to arrive at the census region forecasts and U.S. forecasts published in STEO. The NOAA forecasts of HDDs and CDDs cover the next 15 months, so for the May 2021 STEO, the NOAA forecast covered May 2021 through July 2022. For the remaining five months of 2022 for which NOAA did not issue a forecast, we used NOAA's forecast for HDDs and CDDs for those months in 2021.

Table 2. Cooling degree days (CDD), heating degree days (HDD), and Henry Hub and power sector natural gas prices

	Case	CDDs	HDDs	Henry Hub spot price ($/MMBtu)	Power sector price ($/MMBtu)
0	Base Case	1,425	4,131	$3.02	$3.33
1	Hot Summer/Cold Winter	1,694	4,735	$4.21	$4.66
2	Hot Summer/Mild Winter	1,694	3,528	$2.78	$3.14
3	Mild Summer/Cold Winter	1,163	4,735	$3.26	$3.59
4	Mild Summer/Mild Winter	1,163	3,528	$2.14	$2.49
5	Hot Summer/Base Winter	1,694	4,131	$3.41	$3.81
6	Base Summer/Mild Winter	1,425	3,528	$2.42	$2.76
7	Base Summer/Cold Winter	1,425	4,735	$3.68	$4.09
8	Mild Summer/Base Winter	1,163	4,131	$2.64	$2.97

Source: U.S. Energy Information Administration, Short-Term Integrated Forecasting System
Note: $/MMBtu=dollars per million British thermal unit

To construct the hot/mild summer and cold/mild winter cases, we calculated a (+/-) one standard deviation to average HDDs and CDDs—based on a sample of data from 1991 to 2020. We then applied that one standard deviation to the forecast HDDs and CDDs for each month in a given season for each of the states and then calculated population-weighted regional and U.S. averages. For this supplement, summer is April through September, and winter is October through March. For example, in the hot summer cases, we added one standard deviation to the CDD forecast for each state in each month from April through September. We then used the same population-weighting method used in the Base Case.

Because we constructed these cases to demonstrate the sensitivity of emissions to various temperature forecasts, the cases were intended to illustrate what would happen with fairly extreme temperature variation from the baseline. As noted, we did not create these cases to reflect a forecast of actual temperature outcomes or possibilities. Because we calculated the standard deviation of HDDs and CDDs at the state level and then aggregated the population weighted-values up to the regional and national level, the calculation produced more than one standard deviation outcome for the census regions and U.S. totals. This result occurs because temperature variation in individual states is more than for the country as a whole. This method assumes that each state is experiencing a one standard deviation in CDD/HDD at the same time, which historically has not happened. More often, when one area of the country is experiencing colder/warmer temperatures, another area might be experiencing more mild temperatures.

The hot summer cases have 1,694 CDDs, which would be the hottest year in our population-weighted CDD data, which go back to 1975. The cold winter cases have 4,735 HDDs, which would be the 16th coldest year in our population-weighted HDD data, which go back to 1975. Because CDDs and HDDs are weighted by population in each year, they not only represent reflect temperatures but also population shifts over time. Because of warmer average temperatures since 1975 and a shift of the relative population in the United States toward areas with warmer temperatures, the hot summer cases result in the warmest years in the data set, but the cold winter cases result in the 16th coldest year (rather than the coldest year) in the data set. These same trends mean the mild winter cases result in what would be the mildest year (fewest HDDs) since 1975, but the mild summer cases would result in the 13th mildest year (fewest CDDs) since 1975.

In addition to HDDs and CDDs, the only other input variable we changed across the cases was the monthly average Henry Hub natural gas spot price because this variable can be especially sensitive to changes in weather. To generate the Henry Hub price forecasts across the cases, we used a simple linear regression[1] that included among its independent variables:

- HDDs
- CDDs
- Monthly dummy variables
- The Henry Hub spot price lagged by one month

We then conducted eight separate STEO model runs using the different HDDs, CDDs, and Henry Hub natural gas spot price assumptions as inputs.

During a normal STEO model run to produce our forecast, we often make adjustments based on analyst judgement to align all components of each energy sector, including production, consumption, inventories, trade, and prices. For the scenarios in this supplement, we did not make any such adjustments and focused only on how our assumed changes in inputs affect the resulting CO_2 emissions.

Results

The modeled variation in energy-related CO_2 emissions compared with the Base Case are greater than the overall variations in energy demand across the cases. The variations in energy use across cases are generally symmetric. As we expected, Case 1 (Hot Summer/Cold Winter) results in the highest level of overall energy consumption among the cases. In Case 1, U.S. total energy consumption is 101.4 quadrillion British thermal units (quads), which is 3% more than in the Base Case because more energy is needed both in the winter for heating and in the summer for cooling. On the other hand, Case 4 (Mild Summer/Mild Winter) produces the lowest level of energy consumption among the cases. In Case 4, U.S. total energy consumption is 95.3 quads, which is 3% less than in the Base Case because energy consumption in both the winter heating season and the summer cooling season is less than the Base Case (Table 2).

Table 2. U.S. total energy consumption and energy-related CO_2 emissions

	Case	U.S. energy consumption (quads)	CO_2 emissions total (MMmt)	CO_2 emissions petroleum (MMmt)	CO_2 emissions natural gas (MMmt)	CO_2 emissions coal (MMmt)
0	Base Case	98.1	4,955	2,300	1,633	1,011
1	Hot Summer/Cold Winter	101.4	5,295	2,320	1,572	1,392
2	Hot Summer/Mild Winter	97.2	4,898	2,292	1,603	992
3	Mild Summer/Cold Winter	99.4	5,072	2,312	1,625	1,124
4	Mild Summer/Mild Winter	95.3	4,685	2,285	1,646	742
5	Hot Summer/Base Winter	99.2	5,089	2,305	1,591	1,182

[1] For the full equation, see the appendix on page 10 of this report.

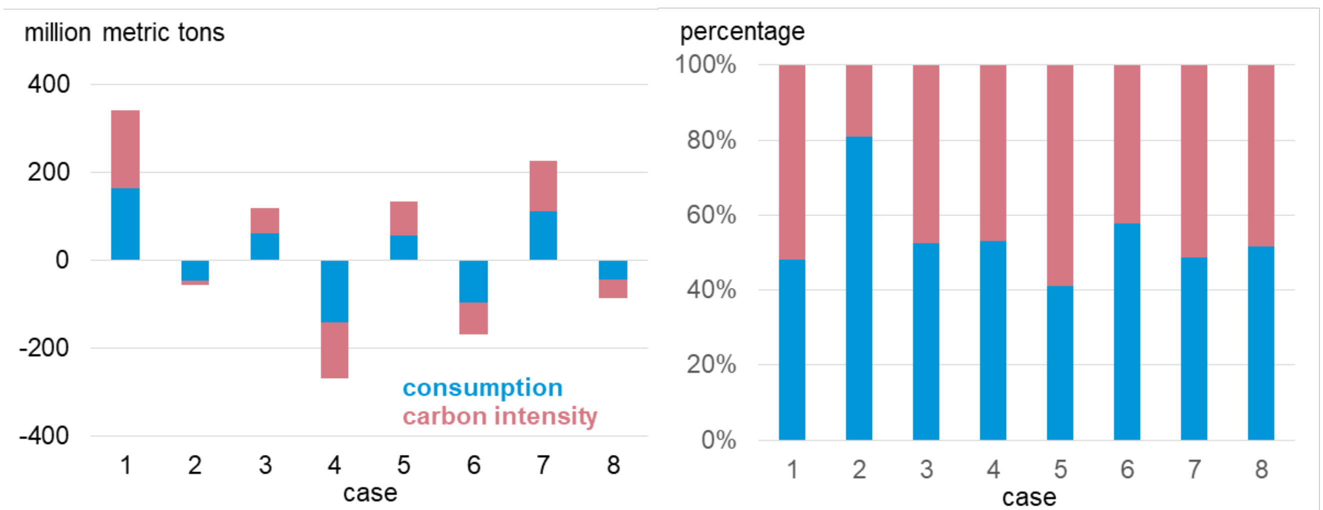
6	Base Summer/Mild Winter	96.2	4,787	2,288	1,626	861
7	Base Summer/Cold Winter	100.3	5,180	2,315	1,597	1,256
8	Mild Summer/Base Winter	97.3	4,869	2,298	1,642	917

Source: U.S. Energy Information Administration, Short-Term Integrated Forecasting System
Note: Quadrillion British thermal units=quads and million metric tons=MMmt

The associated CO_2 emissions in these cases do not exhibit the same symmetry as total energy demand. In Case 1 (Hot Summer/Cold Winter), total U.S. energy-related CO_2 emissions are 7% above the Base Case. However, in Case 4 (Mild Summer/Mild Winter), total emissions are 5% below the Base Case. This difference implies that carbon intensity (CO_2 per British thermal unit of energy) increases in Case 1 (Hot Sumer/Cold Winter) and decreases in Case 4 (Mild Summer/Mild Winter).

The carbon intensity of total U.S. energy consumed is 50.5 kilograms per million British thermal units (kg/MMBtu) in the Base Case. The carbon intensity is 52.2 kg/MMTBtu in Case 1 (Hot Summer/Cold Winter) and 49.2 kg/MMBtu in Case 4 (Mild Summer/Mild Winter). These differences in carbon intensity reflect changes in the fuel mix within the overall change in total energy consumption—most notably, fuel switching in the electric power sector between coal and natural gas (natural gas is about half as carbon intensive as coal) (Figure 2).

Figure 2. Contribution of total U.S. energy consumption and carbon intensity to changes in CO_2 emissions relative to the Base Case



Source: U.S. Energy Information Administration, Short-Term Integrated Forecasting System

Both the amount and the types of fuel used are important in determining energy use and CO_2 emissions. Across the cases, variations in consumption and emissions are affected very differently depending on the fuel type. Petroleum emissions vary slightly across the cases, coal emissions vary significantly, and natural gas emissions vary somewhat. The differences in variations among the fossil fuels relates to their uses.

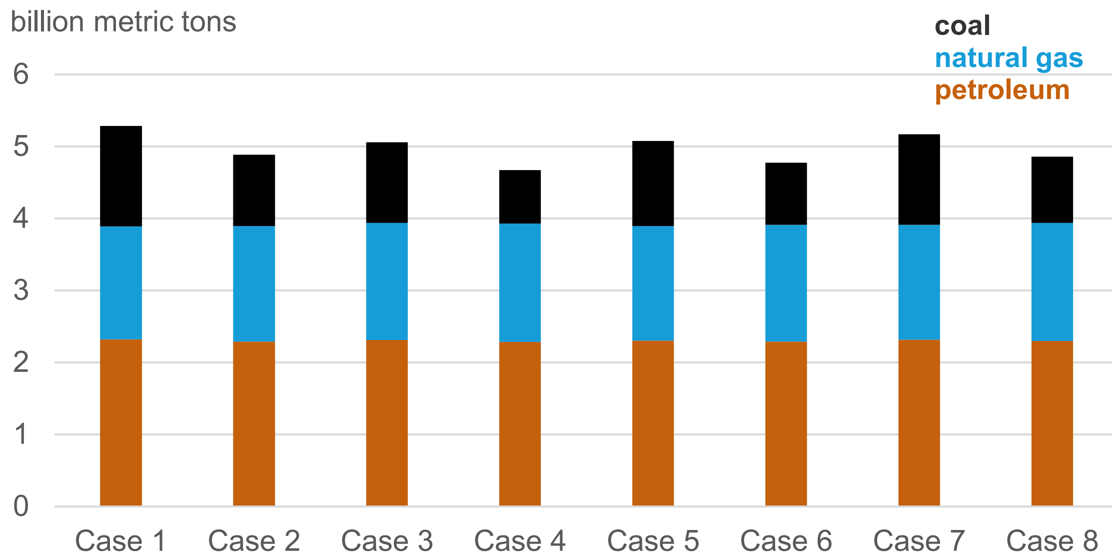
Petroleum consumption varies only slightly (less than 1% from the Base Case) in each of the eight cases. Most petroleum in the United States is consumed in the transportation and industrial sectors, and it is less affected by the weather. The variation in petroleum use across cases is primarily because demand for heating fuels used in the Northeast and Midwest regions increases during a colder winter and decreases during a warmer one. Among the regions of the United States, the Northeast has the highest share of households that use heating oil as a primary space heating fuel, and the Midwest has the highest share of households that use propane as a primary space heating fuel.

Natural gas has a dual role as a heating fuel and as a fuel for electricity generation. In Case 1 (Hot Summer/Cold Winter), U.S. natural gas CO_2 emissions are 4% below the Base Case. Demand for natural gas as a space heating fuel is significantly higher than the Base Case during a cold winter. However, increased natural gas use for space heating causes natural gas inventories to fall sharply during the winter months. Low natural gas inventories put upward pressure on prices, and the effects can persist for several months following the winter, making natural gas less economical to dispatch for electricity generation relative to coal even in the summer. In Case 1, the effects of lower natural gas use for electricity generation outweigh the effects of higher space heating use and lead to overall less natural gas use than in the Base Case.

The largest increase in U.S. natural gas CO_2 emissions compared with the Base Case (1%) occurs in Case 4 (Mild Summer/Mild Winter) and Case 8 (Mild Summer/Base Winter). In Case 4, the relatively warm winter puts downward pressure on natural gas prices ($2.49/MMBtu is the annual average for natural gas consumed by the electric power sector) and makes natural gas very competitive compared with coal for electricity generation in the summer cooling season. As a result, Case 4 has the largest share of natural gas generation in all eight cases, almost 40%. However, in Case 4, overall electricity demand is lower because of the mild summer, which limits the amount of natural gas used as an input fuel for electricity generation, despite the overall high share of natural gas-fired generation. The shares of the other electricity energy sources, such as wind and solar, are also highest (44%) in Case 4. Finally, in Case 4, the mild winter results in less use of natural gas for space heating than in the Base Case, which offsets some of the consumption and emissions that come from a high share of natural gas use for electricity generation in the summer.

U.S. coal CO_2 emissions vary most significantly across the cases for two reasons. First, coal emits the most CO_2 per unit of energy of all fossil fuels. Second, more than 90% of U.S. coal consumption is for electricity generation, and coal use in the electric power sector is very sensitive to the relative price of coal versus natural gas. In Case 1 (Hot Summer/Cold Winter), coal CO_2 emissions are 38% above the Base Case. The increase in coal emissions Case 1 results from both high natural gas prices, making coal more economical to dispatch for electricity generation, and more overall electricity generation. In Case 4 (Mild Summer/Mild Winter), coal CO_2 emissions are 27% below the Base Case. In Case 4, low natural gas prices resulting from less natural gas demand for space heating in the winter reduce coal's competitiveness in the electric power sector amid overall lower energy use because of mild winter temperatures. In only two cases do coal CO_2 emissions vary less than 10% from the Base Case: in Case 8 (Mild Summer/Base Winter) emissions are down 9% from the Base Case, and in Case 2 (Hot Summer/Mild Winter) emissions are down 2% from the Base Case (Figure 3).

Figure 3. CO_2 emissions in the United States by fossil fuel



Source: U.S. Energy Information Administration, Short-Term Integrated Forecasting System

Because coal use in the U.S. electric power sector is very responsive to changes in natural gas prices, the relative prices of natural gas and coal play an important role in the fuel mix of total energy consumed. The price of coal for the electric power sector is relatively similar across cases. Coal prices average $1.98/MMBtu in the Base Case and range from a high of $2.05/MMBtu in Case 1 (Hot Summer/Cold Winter) to a low of $1.93/MMBtu in Case 4 (Mild Summer/Mild Winter). This relative lack of variation in coal prices across the cases reflects stable coal spot market prices in recent years. Increasing coal mine productivity has offset what would be higher extraction costs because of deeper and thinner seams in coal mines.

In contrast to coal, the price of natural gas is relatively variable across cases. In Case 1 (Hot Summer/Cold Winter), the price of natural gas to the U.S. electric power sector is $4.66/MMBtu, which is 40% above the Base Case ($3.33/MMBtu). In Case 4 (Mild Summer/Mild Winter), the natural gas price to the power sector is $2.49/MMBtu, which is 25% below the Base Case. This variability is partly caused by the multiple roles natural gas plays in the U.S. economy as a heating fuel, a fuel for industrial processes, and—increasingly in recent years—an important fuel for the electric power sector. Winter temperatures can have especially significant effects on natural gas prices. In a cold winter, natural gas use for space heating can rise significantly, causing natural gas inventories to decline and natural gas prices to rise. Conversely, in a warm winter, lower space heating use can limit natural gas inventory draws and cause natural gas prices to decline. In contrast, coal is primarily a fuel for the electric power sector, along with some minor industrial uses.

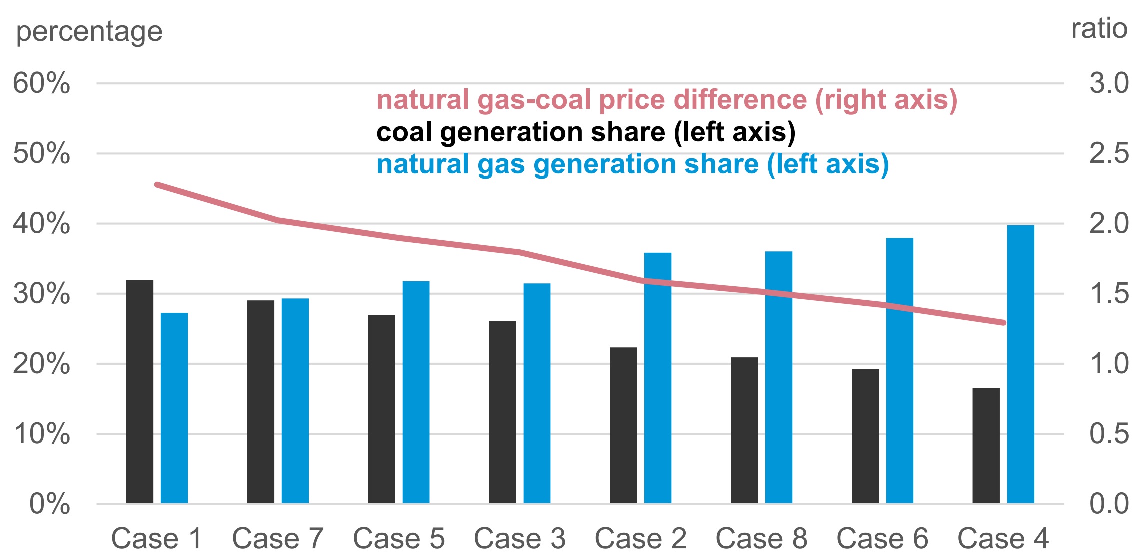
In the Base Case, coal-fired electricity generation in the United States totals 903 terawatthours (TWh), or 23% of total generation. In Case 1 (Hot Summer/Cold Winter), coal-fired electricity generation increases to 1,313 TWh, 45% more than in the Base Case. In Case 1, coal accounts for a generation share of 32%. Natural gas-fired generation in the Base Case totals 1,379 TWh, which is a 35% share. In Case 1, natural gas-fired generation declines to 1,120 TWh, which is a 19% decline from the Base Case. In Case 1, natural gas accounts for a generation share of 27%.

In Case 1 (Hot Summer/Cold Winter), natural gas consumption in the U.S. residential and commercial buildings sectors totals 24.6 billion cubic feet per day (Bcf/d)—almost 11% more than in the Base Case. This increase is also true in all cases with cold winters because the demand for natural gas as a heating fuel is price inelastic.

On the other hand, in Case 4 (Mild Summer/Mild Winter), U.S. coal-fired generation totals 628 TWh, which is a 17% generation share and 30% below the Base Case. In Case 4, the natural gas generation share is 40% with 1,511 TWh, or 14% above the Base Case.

In a year when a relatively warm winter yields abundant natural gas in storage, coal to natural gas switching can occur in the U.S. electric power sector even when natural gas is priced higher on a per MMBtu basis because newer combined-cycle generators are more efficient and are more economical on a per kilowatthour (kWh) basis than older coal plants. The cases in Figure 4 are arranged by descending order of the ratio of the natural gas price to coal price in the electric power sector to illustrate the relationship between relative prices and the share of generation.

Figure 4. U.S. natural gas and coal generation shares and price natural gas to coal price ratio



Source: U.S. Energy Information Administration, Short-Term Integrated Forecasting System

The short-term price inelasticity of natural gas as a heating fuel versus the highly elastic nature of natural gas and coal in the U.S. electric power sector is the primary reason that energy-related CO_2 emissions can be very temperature sensitive and that changes in the carbon intensity of the fuel mix can be as important as the changes in total energy demand. These year-to-year changes do not signal a change in long-term trends but represent temporary departures from the trend.

Appendix

We used the following linear regression to forecast the natural gas price in each of the scenarios.

Where:

NGHHUUS = Henry Hub spot price, monthly average
ZWHDPUS = U.S. population weighted heating degree days
ZWHNPUS =
ZWCDPUS = U.S. population weighted cooling degree days
ZWCNPUS =
ZSAJQUS = number of days in a given month
D*yymm* = monthly dummy variable (e.g. D1204 is a dummy variable for April 2012)
D*yy* = annual dummy variable
mmm = seasonal dummy variable (e.g. Feb is a dummy variable for February)

Dependent Variable: LOG(NGHHUUS)
Method: Least Squares

Sample: 2010M01 2019M12
Included observations: 120

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.202651	0.045526	4.451343	0.0000
(ZWHDPUS-ZWHNPUS)/ZSAJQUS	0.032115	0.003968	8.094345	0.0000
(ZWCDPUS-ZWCNPUS)/ZSAJQUS	0.041385	0.012341	3.353508	0.0011
D1204	-0.165290	0.075092	-2.201167	0.0301
D1402	0.286019	0.075680	3.779302	0.0003
D1403	-0.197674	0.077376	-2.554705	0.0122
D15	-0.067664	0.022106	-3.060874	0.0029
D1612	0.263206	0.075497	3.486319	0.0007
D1801	0.197909	0.075228	2.630791	0.0099
D1901	-0.245888	0.074770	-3.288606	0.0014
D1912	-0.181421	0.075074	-2.416557	0.0175
FEB	-0.128060	0.034234	-3.740708	0.0003
MAR	-0.048971	0.034497	-1.419549	0.1589
APR	-0.014484	0.034402	-0.421027	0.6747
MAY	-0.002205	0.033953	-0.064944	0.9484
JUN	-0.029670	0.035378	-0.838656	0.4037
JUL	-0.070444	0.036085	-1.952186	0.0538
AUG	-0.086262	0.034425	-2.505814	0.0139
SEP	-0.049829	0.036427	-1.367945	0.1745
OCT	-0.034358	0.033706	-1.019360	0.3106
NOV	-0.016341	0.033751	-0.484180	0.6293
DEC	0.025087	0.035702	0.702664	0.4839
LOG(NGHHUUS(-1))	0.857655	0.029263	29.30893	0.0000

R-squared	0.937262	Mean dependent var	1.165330
Adjusted R-squared	0.923033	S.D. dependent var	0.253665
S.E. of regression	0.070374	Akaike info criterion	-2.299429
Sum squared resid	0.480395	Schwarz criterion	-1.765160
Log likelihood	160.9657	Hannan-Quinn criter.	-2.082460
F-statistic	65.86863	Durbin-Watson stat	1.681951
Prob(F-statistic)	0.000000		