U.S. Sulfur Dioxide Emission Reductions: Shifting Factors and a Carbon Dioxide Penalty

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ABSTRACT

For more than 20 years, the large-scale application of FGD technology has been a dominant cause of SO_2 emission reductions. From 1994-2004, electricity generation from coal increased, but the shift to low-sulfur coal eclipsed this. From 2004-2014, electricity generation from coal decreased, but a shift to higher sulfur subbituminous and lignite coal overshadowed this. The shift in coal quality has also created a CO_2 emissions penalty, representing 2% of the sector's total emissions in 2014.

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1. Introduction

The power sector is responsible for 64% of the sulfur dioxide (SO_2) emitted in the United States, damaging human health, ecosystems, crop and timber production, and the built environment. The estimated cost of SO_2 pollution from power generation in the United States ranges from $71 to $223 billion per year (NRC, 2010; Muller et al., 2011; Muller and Mendelsohn, 2007; Jaramillo and Muller, 2016).

Over the last two decades, SO_2 emissions from the U.S. electric power sector have declined sharply, even as electricity generation has increased (Fig. 1). From 1994 to 2004, the focus of this analysis, SO_2 emissions decreased by 11.7 million tons/year (a 79% decline) (EPA, 2016; EIA, 2016a).

The factors contributing to these reductions have evolved over time, and the pace of emission reductions has been variable. Prior research has highlighted the impact of various shifts in market conditions and technologies, highlighting the role of an aging and inefficient coal fleet, the increasingly expensive cost of building new coal plants and rising coal prices, advancements in technology such as FGD pollution controls, the low cost of natural gas and falling costs of renewables, and sluggish electricity demand growth, particularly after the economic downturn of 2008. Policies have also evolved, including the 1990 Clean Air Act Amendments that set limits on SO_2 and NO_x gases from power plants, renewable portfolio standards, federal energy efficiency standards on end-use equipment, and much more (e.g., Culver and Hong, 2016; Fleischman, et al., 2013, Tierney, 2012; Chan, et al., 2015).

In this article, we use decomposition analysis to estimate the impact of a range of engineering factors that influence SO_2 emissions from the electricity sector and that are driven by these market, policy, and technology shifts. Decomposition analysis has become a commonly accepted method of understanding the factors contributing to carbon emissions since it was first proposed by Kaya (1990) at a workshop of the Intergovernmental Panel on Climate Change (IPCC, 2001). The Kaya identity included three factors: energy intensity, GDP, and population growth. Decomposition analysis has also been used in two recent papers to examine air pollution from Chinese industry. Fujii, Shunsuke, and Kaneko (2013) examined five indicators of

air pollution from 10 industrial sectors, focusing on end-of-pipe treatment, coal pollution intensity, the energy mix, proactive efficiency, and production scale change. In turn, Yao, et al. (2016), examined three factors impacting air pollution from Chinese industry: engineering emission reduction, structure emission reduction, and supervision emission reduction.

Our analysis is the first application of decomposition analysis to SO_2 emissions from the U.S. electricity industry. In particular, we evaluate five factors that have historically impacted SO_2 emissions from coal-fired power plants, examining their influence over the past two decades using decomposition analysis. These factors include the amount of electricity generated by coal plants, the sulfur and heat content of the coal burned, the heat rate of electricity generation from coal, and the use of flue gas desulfurization (FGD) pollution controls. We focus on the 1994-2014 period (Fig. 1), and we uncover the dynamics across this period by examining each of the two decades separately.

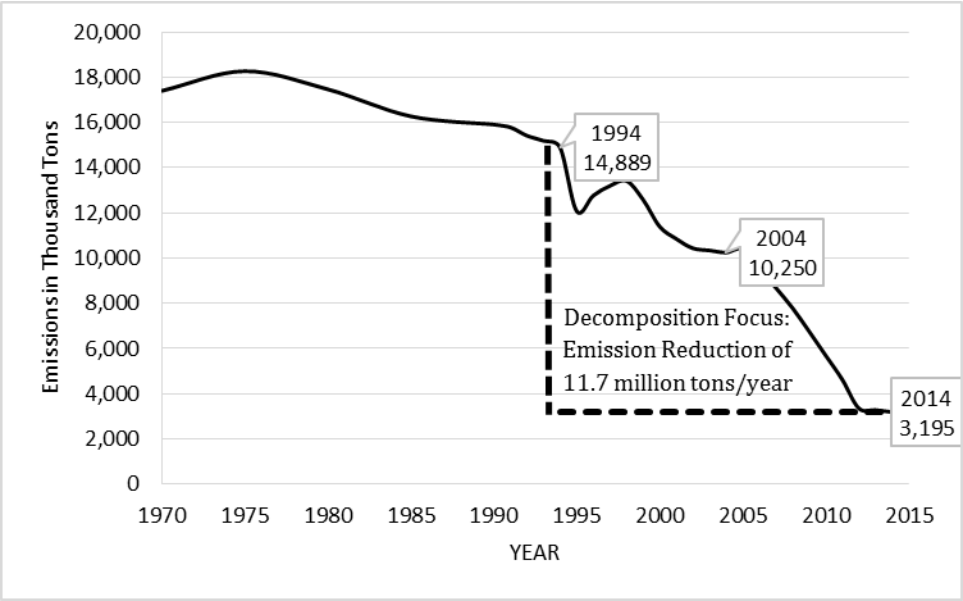


Fig. 1. 1970-2014 SO_2 emissions from electric utilities[2]

(EPA, 2015)

[2] Prior to 1994, SO_2 emissions were estimated rather than aggregated from facility-level reporting. According to Title IV (Acid Deposition Control) of the Clean Air Act Amendments of 1990 (CAAA) published in January 1994, utility units are required to report SO_2 data to EPA. Beginning January 1, 1995, all affected units were required to report heat input and SO_2 emissions. This change contributed to the "kink" in the curve between 1994 and 1995.

2. Methodology and data sources

The attribution of SO_2 emissions to different drivers can be evaluated by the following identity:

$$SO_2 = G * \left(\frac{SO_2}{S}\right) * \left[\left(\frac{S}{Coal}\right) \Big/ \left(\frac{E_{coal}}{Coal}\right)\right] * \left(\frac{E_{coal}}{G}\right) * (1 - FGD)$$

From this identity, the puzzle of SO_2 emissions reduction can be solved by illustrating the magnitude and direction of the change precipitated by each factor. Specifically, SO_2 emissions are decomposed using the following factors: total power generation (G), the sulfur content of coal (S/Coal), the heat content of coal (E_{coal}/Coal), the heat rate of coal (E_{coal}/G), and the fraction of emissions after FGD. The identity also includes a combustion factor for sulfur (SO_2/S). By assuming that that all sulfur goes into sulfur emissions after combustion, the SO_2/S value is a constant defined by the relative weight of SO_2 to S, 1.998.[3] For each of the factors, we use the natural log of the change in emissions over these two decades to simplify the analysis.[4]

These different components are described in greater detail in Table 1. This decomposition allows for attribution of the change in SO_2 emissions to each component driver and the factors contributing most to the decline in SO_2 emissions.

[3] SO_2/S is also called the sulfur retention ratio. It is a function of the fraction of sulfur in the coal that ends up in coal ash after combustion and the relative atomic weight of SO_2 to S. The former varies from 0% to about 10% resulting from the varying composition and quality of coal, along with the operational conditions of plants (Goodarzi, 2006; Sheng et al., 2000).

[4] For example, each factor's contribution over the two decades is calculated as:

$$\frac{\Delta S}{\ln(S_{2014}/S_{1994})} \ln\left(\frac{F_{2014}}{F_{1994}}\right) = emissions\ reduction\ resulting\ from\ a\ change\ in\ factor\ F$$

Table 1

Contributing Factors, Units and Data Sources

Factor	Explanation	Unit	Source
G	Total Generation from Coal Plants	MWh	EIA Monthly Energy Review http://www.eia.gov /totalenergy/data/monthly/
S/Coal	Sulfur Content of Coal Used	% in Weight	EIA-923 Survey, https://www.eia.gov/electricity/data/eia923/
E_{coal}/Coal	Heat Content of Coal used	Btu/tons coal	EIA-923 Survey, https://www.eia.gov/electricity/data/eia923/
E_{coal}/G	Heat Rate of Coal Plants	Btu/tons coal	EIA Monthly Energy Review http://www.eigov/totalenergy/data/monthly/
FGD	Fraction of Emissions Lacking Flue Gas Desulfurization	%	Form EIA-860 Annual Electric Generator Report, https://www.eia.gov/electricity/data/eia860/ Calculated from variables above as well as annual SO_2 emissions from EPA (2015) and validated by data from EIA (2016c)

3. Contributing factors and trends over the past 20 years

The five factors can be grouped into three categories: plant performance (generation and heat rate), coal quality (sulfur content and heat content), and emission control (desulfurization technology). Each is described below.

3.1 Plant performance: electricity generation and heat rate

While total electricity generation has increased over the past two decades, the electricity generated by coal plants peaked in 2007, and then declined over the subsequent decade (Figure 2). The overall reduction in coal generation over the two decades declined 7% from approximately 1700 million MWh in 1994 to 1580 million MWh in 2004.

From 1994 to 2014, total U.S. electricity generation increased while the percent of generation from coal declined slightly. Through 2004, coal accounted for about 50% of total U.S. electricity generation, but by 2014, the contribution of electricity generated from coal had declined to

40%. Over this last decade, natural gas and renewables became more prevalent, which has contributed to SO_2 emission reductions in the most recent decade.

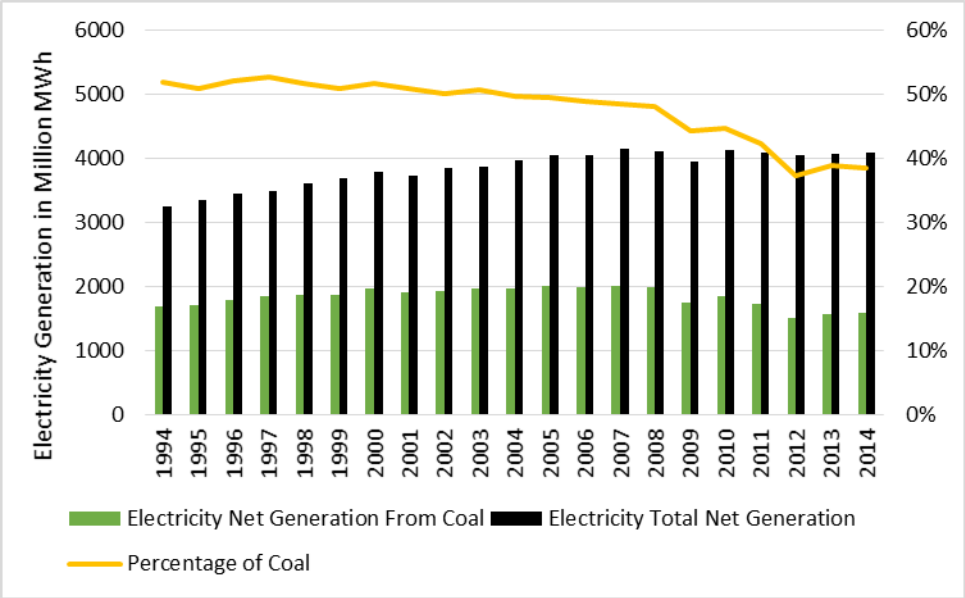


Fig. 2. Electricity generation from coal and total generation

(Source: EIA, 1995-2015 Table 7.2)

The thermal efficiency of electricity generation is measured by the heat rate, or the amount of thermal energy used to generate one kilowatt-hour of electricity, measured in British thermal units per kilowatt-hour (Btu/kWh).[5] A generator with a lower heat rate can generate the same quantity of electricity while consuming less fuel, compared to a unit with higher heat rate (EIA, 2015a). Heat rates depend in part on the type of equipment installed at a generating plant and can vary substantially across fuel and technology types. For example, in 2012 generators primarily powered by coal-fired boilers had heat rates ranging from 8,800 Btu/kWh to 25,000 Btu/kWh (EIA, 2015b). A typical heat rate for a coal-fired power plant is around 10,400 Btu/kWh. The average national heat rate of coal plants has increased by 1.8% over the past two decades, rising from 10.2 thousand Btu/kWh in 1994 to about 10.4 thousand Btu/kWh in 2014. Thus, coal plants are operating about 2% less efficiently today compared with 20 years ago,

[5] The heat rate is inversely proportional to the thermal efficiency of electricity generation. To express the efficiency of a generator as a percentage, divide the Btu content of a kilowatt-hour of electricity (which is 3,412 Btu) by the heat rate. For example, the thermal efficiency of generator with a heat rate of 10,400 Btu/kWh is equal to 3,412 / 10,400 = 32.8%.

leading to a slight upward pressure on SO_2 emissions. This trend is reasonable considering the fact that electricity generation technologies used by coal plants are mature and stable. Other contributors are the implementation of environmental control equipment, existing power plants degradation with relatively few new plants, and the possible shift of load into less efficient coal plants. Since the change in heat rate is relatively small, the driving reasons are difficult to identify.

3.2 Coal quality: sulfur and heat content

The quality of coal – including the sulfur content and heat content of coal – varies by geographic region of coal production. In general, coal with a higher sulfur content leads to greater SO_2 emissions than coal with a lower sulfur content. The heat content is the amount of thermal energy per unit of coal and is measured in British thermal units per short ton of coal (Btu/ton). Keeping all other factors fixed, a decline in the heat content of coal would result in greater consumption of coal (to produce the same amount of electricity) and greater subsequent SO_2 emissions.

Coal plants in 2014 used higher sulfur coal to generate electricity compared to the coal used in 1994, increasing from less than 1.2 to about 1.3 percentage, by weight. However, over these 20 years, sulfur content declined from 1994 to 2002, and then increased fairly consistently from 2003 to 2014.

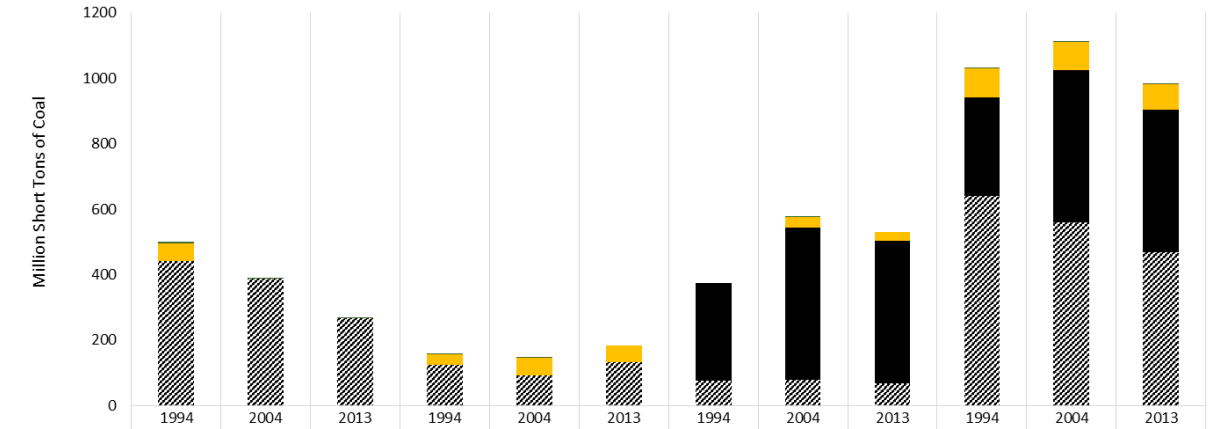
In contrast, the heat content of coal used in electric utilities has been on a steady, gradual decline over the past 20 years, decreasing from above 20 million Btu/ton coal in 1994 to slightly less than 20 million Btu/ton in 2014. (Fig. 3). Thus, coal plants in 2014 used coal with lower heat content compared to the coal used to generate electricity in 1994.

To better understand these two factors, we need to examine coal quality since these two factors are bundled together when power plants purchase and consume coal. To do this, we introduce the concepts of coal rank and quality. In the United States, the heat content of coal is highest in Anthracite and Bituminous, and is lowest in Subbituminous and Lignite. Anthracite is rare in production and consumption, so the other three types of coal are often referred to as

the main coal ranks in North American. In general, specific types of coal can be found concentrated in specific areas. In general, bituminous coal has the highest sulfur content.

- Anthracite – northeastern Pennsylvania;
- Bituminous – east of the Mississippi River, with the greatest amounts in Illinois, Kentucky, and West Virginia;
- Subbituminous coal – west of the Mississippi River, with the greatest amounts in Montana and Wyoming;
- Lignite – Montana, Texas, and North Dakota.

Fig. 3 describes the level and types of total U.S. coal production in 1994, 2004, and 2014 by region and coal rank. Note that this is the total coal generation from U.S. domestic coal mines, a portion of which is consumed by the electric power sector. Since coal used by the power sector as a percentage of total production was 89% in 1994, 91% in 2004, 92% in 2014, it is reasonable to explain the shift using the total generation data available. This figure clearly shows that in the first decade of our analysis period, U.S. coal production shifted from Appalachia bituminous to Western subbituminous. Between 2004 and 2014, the nation experienced an increase in the production of bituminous coal from mines in the Interior region. Appalachia production continued to decrease in this second decade, but less than during the first 10 years, while Western region production decreased slightly.



	Appalachia			Interior Region			Western Region			Total		
	1994	2004	2013	1994	2004	2013	1994	2004	2013	1994	2004	2013
Anthracite	5	1	2	0	0	0	0	0	0	5	1	2
Lignite	55	0	0	33	53	49	0	30	28	88	84	77
Subbituminous	0	0	0	0	0	0	301	465	434	301	465	434
Bituminous	441	388	268	124	93	134	75	79	68	640	561	469
Regional Total	501	389	270	157	146	183	376	575	530	1034	1111	983

Fig. 3. Coal production by region, year and coal rank[6]

(Source: EIA, 2016b Table 6)

The shifting of the coal production portfolio used for electric power sector may trigger unintended consequences. As discussed previously, the coal mined in each region (Appalachia, Interior, and Western) not only differ in coal ranks (Bituminous, Subbituminous, Anthracite or Lignite), but also have various quality characteristics. These quality indicators, shown in Table 2 include heat content, sulfur content and emission potentials for mercury, CO_2 emission and NOx emissions. These emission potentials per Btu energy input varies significantly. For example, it shows that the mercury emission potential ranges from 4.47 pounds per trillion Btu for Western Bituminous to 14.36 pounds per trillion Btu for Interior Lignite. Nitrogen emission, carbon dioxide potentials also vary between 0.40 pounds per million Btu for Appalachia Bituminous to 0.55 pounds per million for Interior Lignite, 203.10 pounds per million Btu for Interior Bituminous to 219.3 pounds per million Btu for Western Lignite.

[6] From 1994 to 2004, U.S. coal production shifted from Appalachia bituminous coal to Western subbituminous coal, contributing to lower overall sulfur content in the coal used for electricity generation. From 2004 to 2013, production of bituminous coal continued to decline; however, this decline was offset by an increase in the sulfur content bituminous coal (Table 2).

Table 2.

Qualities of coal by production region and rank

Region	Coal Rank	Heat Content (million Btu per short ton)	Sulfur Content (pounds per million Btu)	Mercury Content (pounds per trillion Btu)	CO_2 (pounds per million Btu)	NO_x (pounds per million Btu)
Appalachia	BIT	24.73	1.74	9.86	205.36	0.40
Interior	BIT	22.61	2.60	6.49	203.10	0.44
	LIG	13.01	1.55	14.36	212.86	0.55
Western	BIT	21.65	0.53	4.47	209.89	0.46
	LIG	13.23	1.24	8.38	219.30	0.54
	SUB	17.53	0.37	5.76	214.55	0.42

Source: EIA (2014); nitrogen oxides estimated using data from EIA (2016c, Table A.2).

Because of this regional shift in coal production, the overall national quality of coal has changed. And the quality of different ranks of coal has shifted as well. Specifically, the sulfur content of bituminous increased from 1.5% in 2004 to 2.3% by weight in 2014, driving the total change from 0.97% to 1.3% (Table 3). This rising sulfur content reduced the pace of SO_2 emission reductions over the most recent decade.

Table 3.

National qualities of coal by year and rank

Year	Coal Rank	Heat Content (million Btu per short ton)	Sulfur Content (pounds per million Btu)	Mercury Content (pounds per trillion Btu)	CO_2 (pounds per million Btu)	NO_2 (pounds per million Btu)	Sulfur in Weight %	Sulfur in Weight % (National Avg by Energy Contents of Production)
	BIT	24.0	1.8	8.7	205.4	0.4	2.1	
1994	SUB	17.5	0.4	5.8	214.5	0.4	0.3	1.17
	LIG	13.0	1.5	14.4	212.9	0.5	1.0	
	BIT	24.0	1.7	8.6	205.6	0.4	1.5	
2004	SUB	17.5	0.4	5.8	214.5	0.4	0.4	0.97
	LIG	13.1	1.4	12.2	215.2	0.5	1.1	
	BIT	23.7	1.8	8.2	205.3	0.4	2.3	
2014	SUB	17.5	0.4	5.8	214.5	0.4	0.3	1.3
	LIG	13.1	1.4	12.2	215.2	0.5	0.9	

Sources: 2004 and 2014 sulfur content of coal in weight data are from EIA (2016c). The other data are author-calculated from data in Table 2 and Figure 3.

While the sulfur content of bituminous coal was increasing, the price of coal was also on the rise. While the cost of coal across all ranks declined from 1994 to 2004, it increased from 2004 to 2014. The high price for bituminous coal may have caused power plants to move to coal with lower sulfur content, which was also cheaper. The Clean Air Act Amendments of 1990 may also have played a role. Such causal relationships d cannot be tested or determined using a decomposition approach.

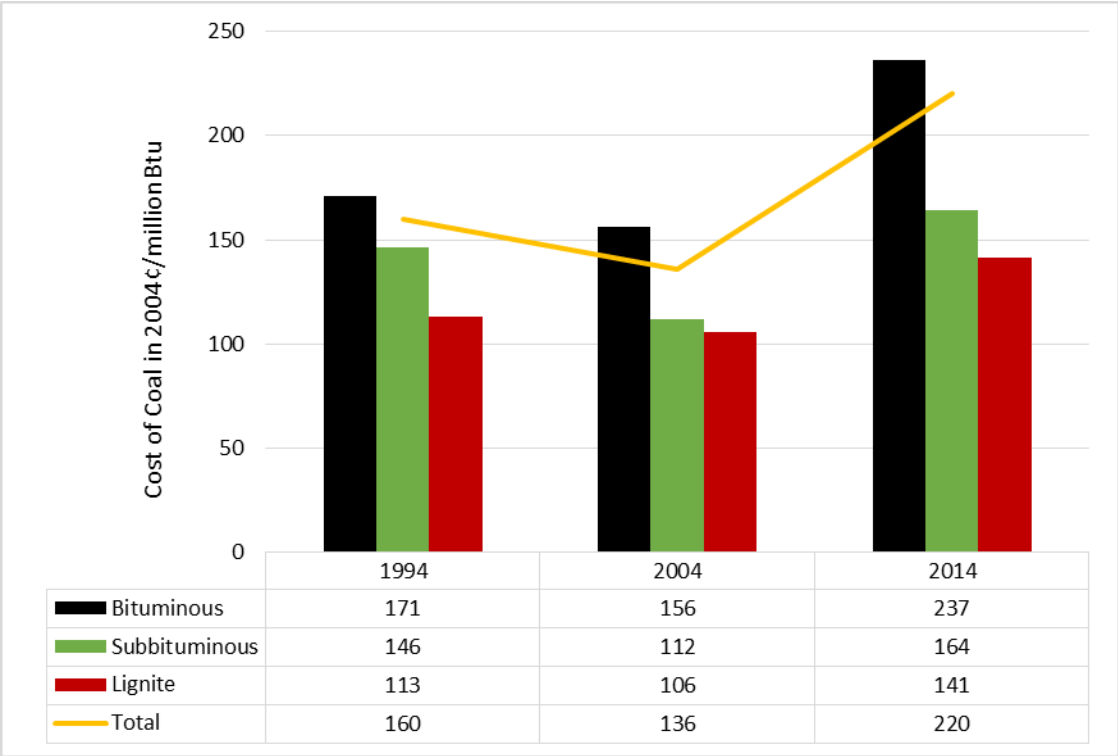


Fig. 4. The cost of coal consumed in the electric sector

(Source: EIA, 2016c, Table 31).

3.3 Emission Control: Desulfurization Technology and Removal

The final factor, the use of pollution controls, suggests a strong and obvious change over the past 20 years. The fraction of emissions lacking FGD has declined significantly. FGD is the ratio of emission with flue gas desulfurization to emission without emission control. In other words, it characterizes the proportion of emission left after applying desulfurization technologies. FGD dropped from more than 75% in 1994 to less than 15% in 2015. This trend reveals how the application of FGD technology has contributed significantly to the reduction of SO_2 emissions.

To explain this trend, we decompose the FGD removal rate using two separate contributing factors: the percent application rate to generation and the removal efficiency of the equipment. Specifically, the formula is as follows:

*FGD Removal Ratio = % of Application Rate to Generation * Removal Efficiency of Equipment.*

The FGD application rate to generation experienced a slow uptake prior to 2005 when approximately 30% of the nation's summer capacity had FGD technology. Subsequently, FGD technology experienced a more rapid decade of expansion. By 2014, FGD technology accounted was installed on 74% of the summer capacity of U.S. coal plants (EIA, 2016c).[7]

4. RESULTS: CONTRIBUTION OF EACH FACTOR TO FINAL SO_2 REDUCTION

Using the decomposition methodology and measurements described above, we calculate the changes and contributions of different factors that influenced SO_2 emission reductions between 1994, when 14.9 million tons of SO_2 were emitted, and 2014, when 3.2 million tons of SO_2 were emitted. This 11.7-million-ton reduction in annual emissions is the subject of the decomposition analysis. The results are summarized in Table 3 and are portrayed graphically in Fig.4.

[7] Unfortunately, we do not have national data on the removal efficiency of FGD equipment used in the power sector. As a result, we assume that it has not changed over the past two decades.

Table 4.

1994-2014 Changes and Contributions of Different Factors

	Emission (Thousand Tons)	S/Coal (%)	E/Coal (million Btu/ton)	E/G (Thousand Btu/kWh)	G (million MWh)	FGD (%)
1994	14,889	1.17	20.59	10.21	1691	75.9
2004	10249	0.97	19.94	10.26	1978	52.0
2014	3,195	1.3	19.31	10.39	1582	14.4
1994-2014						
Difference	-11,694	0.13	-1.28	0.19	-109	-61.5
Change	-79%	11%	-6%	2%	-6%	-81%
Single factor Contributions (thousand tons SO_2 emission)		801	489	137	-506	-12614
1994-2004						
Difference	-4,640	-0.20	-0.65	0.05	287	-23.9
Change	-31%	-17%	-3.2%	0.5%	17%	-32%
Single factor Contributions (thousand tons SO_2 emission)		-2329	398	66	1952	-4701
2004-2014						
Difference	-7,054	0.33	-0.63	0.13	-396	-37.6
Change	-69%	34%	-3.2%	1.3%	-20%	-72%
Single factor Contributions (thousand tons SO_2 emission)		1772	196	77	-1354	-7757

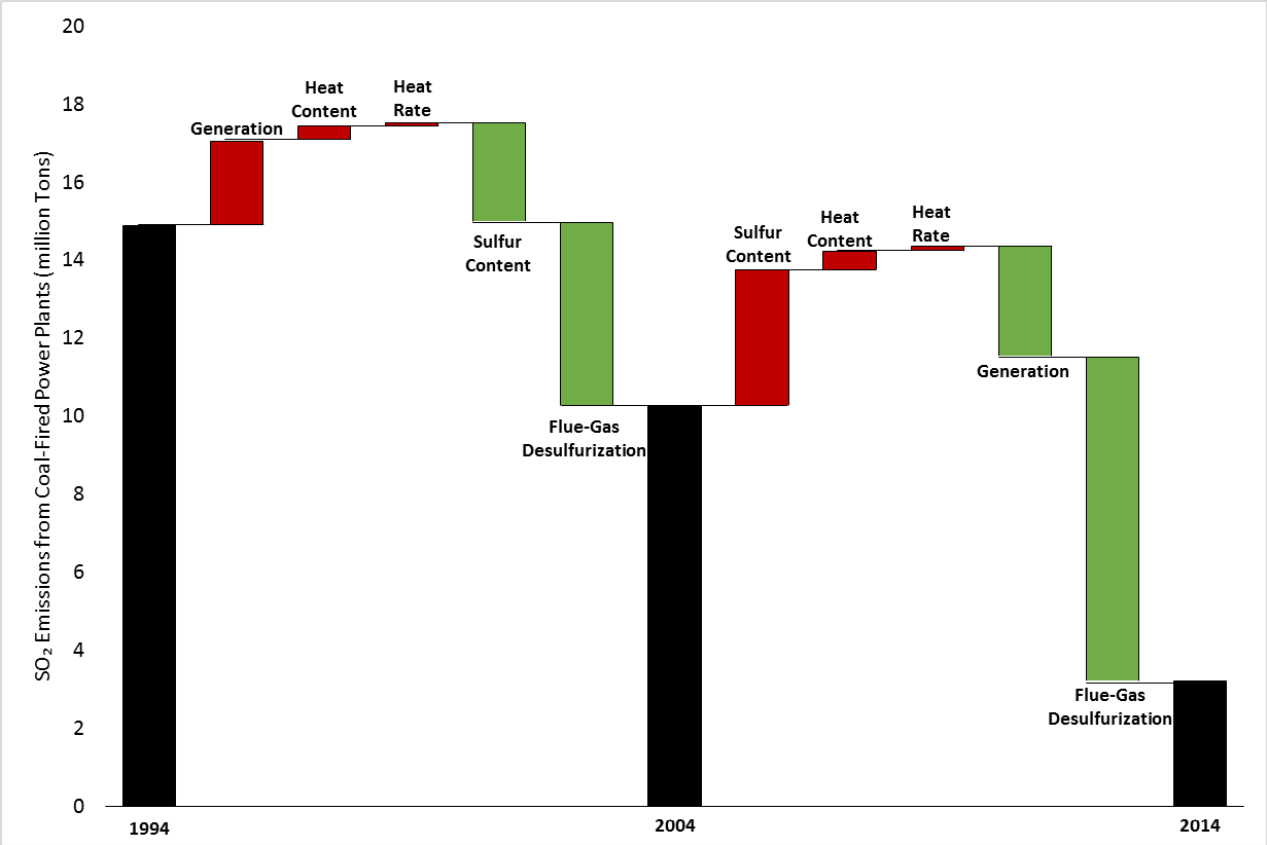


Fig. 5. Factor contributions: 1994-2004 and 2004-2014

This figure illustrates that three of the contributing factors have had consistent effects on SO_2 emissions over time, while two have had directionally different influences across the two decades.

Flue-gas desulfurization has been responsible for the greatest reduction in SO_2 emissions over both decades, accounting for a drop of 4.7 million tons in the first decade and 7.8 million tons in the second decade. The heat content of coal has contributed to small increases in SO_2 emissions over both decades, as the overall heat content of coal has decreased. Similarly, the heat rate of coal burning power plants has contributed similarly in both decades to a small uptick in SO_2 emissions, as coal plants have aged and the application of FGD technology comes with an energy penalty.

Between 1994 and 2004, coal generation increased, which would have resulted in an uptick of 2 million tons of SO_2 emissions, ceteris paribus. Over the same decade, however, the sulfur

content of the coal consumed in power plants decreased enough to more than offset the increase in generation. The opposite combination of factors occurred between 2004 and 2014. Coal generation decreased, which would have caused a reduction of 1.3 million tons of SO_2 emissions if all other factors had remained the same. Over the same decade, however, the sulfur content of the coal consumed in power plants increased enough to almost offset the decrease in generation.

5. Impacts on other pollutants

The shift of the coal production and utilization in the electricity industry from 1994 to 2013 motivated an analysis of the potential influences on the emissions of carbon dioxide, mercury and NO_x. To examine these effects, a hypothetical emission case is calculated assuming that the total energy input (in unit of Btu) remains the same as in 2013, but the production portfolio accords to the 1994 level without any coal production shifts. The intention of this mechanisms is to rule out the total energy input differences from the year 1994 and 2013, and only examine the coal shift as an influence on emissions. The results are shown in Table 5, illustrating the directions and magnitudes of the "unintended consequences" on these other pollutants. In particular, the coal shift is responsible for an additional 41 million short tons of CO_2 emissions in 2014 relative to the coal composition in 2004, representing 2% of the sector's CO_2 emissions from U.S. electric power in 2014.

Table 5.

Impact of shifting sources of coal on CO_2 emissions (in million tons of carbon dioxide)

	Appalachia-BIT	Interior-BIT	Interior-LIG	Western-BIT	Western-LIG	Western-SUB	Total (% of electric sector emissions)
1994	1119.6	284.7	45.7	170.4	0.0	565.9	**2186.2**
2004	985.6	213.1	73.7	180.6	44.0	874.9	**2371.9**
2013	680.4	307.6	67.9	154.5	40.6	815.9	**2066.9**
2013 Energy Input with 1994 Coal Mix	1050.8	267.2	42.9	159.9	0.0	531.1	**2051.8**
% Change from 2013 Real Emissions	-0.5	0.1	0.4	0.0	1.0	0.3	**15 (0.7%)**
2013 Energy Input with 2004 Coal Mix	810.8	180.4	63.0	165.7	43.3	762.4	**2025.7**
% Change from 2013 Real Emissions	-0.2	0.4	0.1	-0.1	-0.1	0.1	**41 (2.0%)**

Based on the Reference Case Forecast of coal production using Georgia Tech's National Energy Modeling System (GT-NEMS), the trend toward greater use of high-sulfur coal will continue through 2030, suggesting that the unanticipated carbon dioxide penalty could continue (Figure 6). If the Clean Power Plan were implemented with mass-based caps on state CO_2 emissions covering all affected electricity generating units, the trend toward high-carbon coal would be moderated, as bituminous Appalachian coal with relatively low carbon content retains more of its market share through 2030.

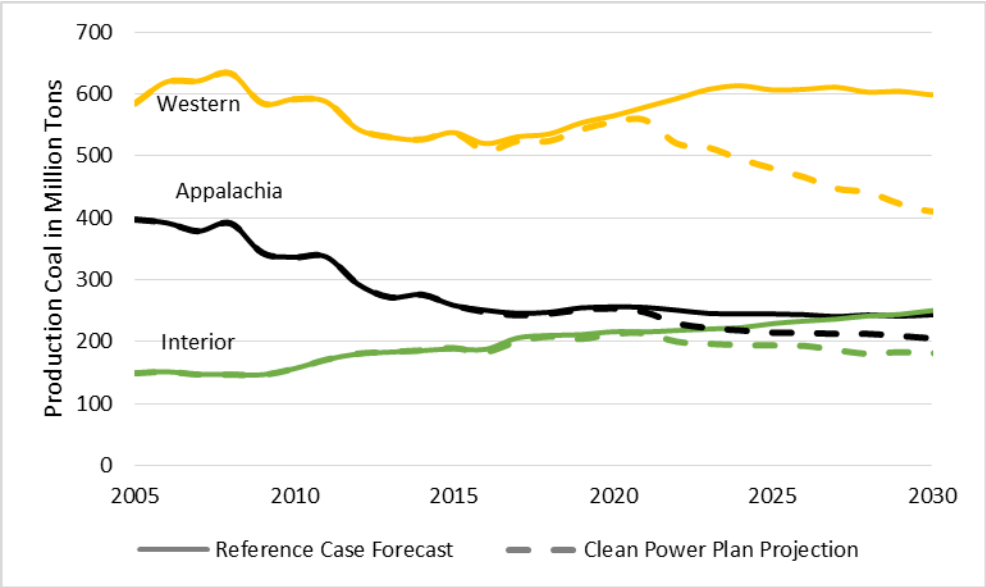


Fig. 6. Coal Production Projections by Region

6. Conclusions

From 1994 to 2014, annual SO_2 emissions from electric utilities decreased by 11.7 million tons, a 79% decline. During this period of historic improvement in air quality, both the pace of improvement and the factors contributing to SO_2 emissions reduction have varied.

Across the 20-year period, the massive application of FGD technology was the most significant cause of SO_2 emission reductions from the electricity sector. Changing levels of electricity generation from coal plants to cleaner alternatives and shifts in the sulfur content of the coal consumed by these plants were the next most influential factors, and their impacts were different and countervailing over the past 20 years. The large-scale application of FGD technology since 1994 has obscured these smaller underlying trends, especially the decreasing quality of coal being combusted to produce electricity, both in terms of its increasing sulfur content and its decreasing heat rate.

- From 1994 to 2014, the one factor that has consistently been the biggest contributor to reductions in SO_2 emissions is the installations of FGD controls, which were installed to comply with environmental regulations.
- From 1994 to 2004, the second biggest driver was the reduced sulfur content of the coal burned at power plants in the United States. Between 1994 and 2004, coal generation increased, which would have resulted in an uptick of 2 million tons of SO_2 emissions if no other changes had occurred. Over the same decade, however, the sulfur content of the coal consumed in power plants decreased enough to more than offset the increase in generation.
- From 2004 to 2014, the opposite combination of factors occurred. Coal generation decreased as a result of the greater use of natural gas and renewables, which would have caused a reduction of 1.3 million tons of SO_2 emissions in the absence of other changes. Over the same decade, however, the sulfur content of the coal consumed in power plants increased enough to almost offset the decrease in generation.

This shift in coal sources was also responsible for an estimated increase of 41 million tons of CO_2 emissions from the electric power sector in 2014 representing 2% of the sector's total and a trend that is expected to continue in the absence of the Clean Power Plan.

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