How Clean is "Refined Coal"? An Empirical Assessment of a Billion-Dollar Tax Credit

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Abstract

US tax law provides nearly $1 billion annually in tax credits for "refined coal", which is supposed to reduce local air pollution. Eligibility for the credit requires firms to demonstrate legally specified emissions reductions for three pollutants. Firms typically demonstrate eligibility through laboratory tests, but results from the lab can differ from those in practice. Using a nationally comprehensive boiler-level panel dataset, we find that emission reductions in practice are only about half of the levels required. We also show that the policy reduces social welfare. Because the tax credit is up for reauthorization in 2021, our work has immediate policy relevance.

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1 Introduction

A significant and growing group of investors and coal-fired power plants are using coal that has been "refined" prior to burning to supposedly emit less nitrogen oxides (NO_x), sulfur dioxide (SO_2), and mercury (Hg). This "refined" coal—if it meets certain restrictions and targeted reductions in these pollutants—qualifies for a tax credit of approximately \$7 per ton of coal, which is payable to owners of the refining facilities. This subsidy is not small. In 2017 an estimated \$1 billion was paid out of the US Treasury, with similar sums being paid out in prior years since the credit was passed into law. The direct beneficiaries of the tax credit are owners of coal refining facilities, which are often built on-site at power plants but are typically owned by third-party investors. These investors range from members of the pharmaceutical industry to large financial services companies. According to Reuters, one firm alone has claimed a total of \$850 million from this tax credit over the past decade (McLaughln 2019). Coal plant owners also benefit indirectly, as refiners pass on a portion of the tax credit in exchange for the right to refine the coal before it is burned.

Such sums might be socially valuable if the refined coal process actually led to the required reductions in these pollutants. But in this paper we find that in practice reductions are often much smaller than the targets stipulated in the tax law.[1] We estimate emission rates of NO_x, SO_2, and Hg from refined coal and its unrefined counterpart. The tax law requires 20 percent reductions in NO_x emissions rates (i.e., NO_x emitted per unit of thermal energy burned) and 40 percent reductions in SO_2 or Hg emissions rates, which are typically verified through laboratory tests unrelated to actual plant operations. By contrast, we estimate that in practice plants achieve negligible reductions in SO_2 emissions rates, and the reductions in NO_x and Hg rates amount to about half (or less) of the targets from the tax law. We find no evidence that any particular plant achieves the reduction targets laid out in the tax statute–and significant evidence that on average they do not.

Our analysis, even though it may not meet a legal bar for credit denial, raises significant concerns that firms receiving the tax credit are not actually achieving the required emissions reductions in practice that they claim. Our results also suggest that the subsidy is economically inefficient and social welfare would be improved if it were changed or eliminated. Indeed, we perform a cost-benefit analysis and conclude that the benefits of the small observed reductions do not justify their costs. Our findings further suggests that the IRS should demand a higher level of evidence before issuing a credit and the law, which comes up

[1]While there are no academic papers looking at the performance of refined coal, the story in Reuters (McLaughln 2019) reports that total NO_x emissions actually increased at many plants but did not control for other factors (such as electricity output), or estimate emissions rates, which are the target of the refined coal legislation.

for an extension in 2021, be adjusted if necessary to support this change. For firms already claiming the credit, the evidence could be derived from historical data surrounding the date when plants switched to refined coal. While these data are not always publicly available (as discussed below EIA only began collecting data on refined coal use in 2016), the companies claiming the tax credit assuredly have this information and can be required to submit it when demonstrating eligibility. For new claimants of the tax credit, plant operators could run controlled field experiments to demonstrate the required reductions.

The next section provides background on the refined coal process, including the laboratory tests that frequently establish its environmental performance, the legislation that created the subsidy, and how the subsidy is distributed. Then we present some plant-specific information about the actual emissions reductions achieved by using refined coal in power plants—one set provided by a series of articles appearing in Reuters (McLaughln 2018*a*,*b*,*c*) and another set provided by analyzing continuous emission monitoring system (CEMS) data and supplementary abatement technology data for the four power plants that switched to refined coal at a known date. Then we present a set of regression analyses covering nearly all coal-burning power plants in the United States—those using refined coal and those not—to examine whether the requisite NO_x, SO_2 and Hg reductions are actually being achieved, accounting for abatement technologies in place.

2 Background

2.1 The Process

Coal from a mine on its way to be burned by a power plant will be redirected (usually on-site at the plant) to a refining facility that may dry the coal (if it is lignite) and spray it with halogens (often calcium bromide) and cement kiln dust (CKD). The resulting chemically treated coal is known as “refined” coal. All standard types of coal (bituminous, subbituminous, and lignite) can be refined. The calcium bromide oxidizes elemental Hg in the coal during combustion to an ionic form that can be trapped by various pollutant control devices downstream of the boiler emissions. Together these substances also are claimed to reduce NO_x and SO_2 emissions when the coal is burned, although the engineering literature focuses on Hg removal (see, e.g., Young et al. 2016).

The process is not without its problems. For a time, Duke Energy was a user of refined coal but found it unsatisfactory on several fronts. First, changes in the use of boilers (in particular burning fuel at higher temperatures) and in catalyst characteristics can make the refining process ineffective in reducing NO_x. Second, the alternative of operating at a lower temperature to reduce NO_x formation can lead to corrosion and soot buildup that causes boiler damage. Third, unreacted calcium bromide can escape in a plant's wastewater and ultimately form carcinogenic substances called trihalomethanes in drinking water. Researchers examining surface drinking water quality near a Duke Energy plant with a refined coal facility reported significant bromide concentrations in water bodies, which subsequently dropped 75 percent when operators ceased refining operations (McLaughln 2018*a*). This is not an isolated incident. Good and VanBriesen (2019) show that bromines used in the coal refining process increase the vulnerability of drinking water supplies to the formation of toxic disinfection byproducts across the United States.

Refined coal facilities are cheap to build at scale, somewhere between $4-6 million for conveyor belts, sprayers, storage facilities for the CKD and calcium bromide, plus control devices (such as baghouses and dust collectors) to ensure particulates from the process itself and the CKD storage units are captured. Levels of incremental Hg removal varied with the downstream pollution control units in place.

2.2 The Legislation

The first appearance of a subsidy/tax credit for refined coal was in the American Jobs Act of 2004. This legislation required claimants to demonstrate that the refining process achieved 20 percent reductions in emissions rates for both NO_x and also either SO_2 or Hg. It also required that the refining process itself boost the coal's market value by at least 50 percent, presumably by reducing the need for plant owners to install abatement equipment for NO_x, SO_2, or Hg (although there were no Hg control requirements at that time). This was a difficult hurdle to overcome because it would require refiners to convince plant operators to agree to pay at least 50 percent markups for their coal. For years, take-up of the tax credit was minimal.

Four years later, this market value requirement was eliminated as part of the energy provisions in the Emergency Economic Stabilization Act of 2008—a law better known for its creation of the Troubled Asset Relief Program (TARP). Along with that change, the required emissions reductions for either Hg or SO_2 were doubled from 20 to 40 percent, while the required NO_x reductions remained at 20 percent. The law states that all such reductions are measured in comparison to standard feedstock coal, leaving the details of implementation to the Internal Revenue Service (IRS). Regulations subsequently issued by the IRS in 2010 (Internal Revenue Service 2010) determined on how these reductions would be measured. First, the IRS required the percentage reductions from refined coal to be measured as compared to the amount of feedstock (i.e., unrefined) coal "necessary to produce the same amount of useful energy"–i.e., on a heat content basis. The regulations gave the producers of refined coal several ways to demonstrate these reductions: they could use field data from the CEMS database, or they could use laboratory testing. Most evidently opted for the latter (McLaughln 2018*b*), probably because a field experiment could be costly and it might be difficult to isolate the effect of the coal itself on emissions without using rigorous statistical methods, as we do below.

The IRS also decided that, if field data were to be used, the reductions would have to be measured under the same operating conditions, although operating changes "directly attributable to changing from the feedstock coal to refined coal" would not be considered as changes in operating conditions for this purpose. Under lab testing, the IRS rules do not explicitly mention any requirement for holding operating conditions constant, although it is possible that the notion of laboratory testing implicitly involves holding some conditions constant. While this requirement of holding certain operating conditions constant may sound like legal minutiae, it has important legal and economic implications that we return to in section 3.

In addition, the tax law includes some temporal restrictions on the tax credit, primarily limiting the credit to the first 10 years of a facility's operation. This effectively eliminates the credit for many firms in 2021, if not earlier. Therefore, in 2018 legislators in Congress from coal states submitted an "extender" for this legislation to give plants an additional 10 years of eligibility (S. 2373; H.R. 5159[2]) and opened up the eligibility requirements for refining facilities built between 2017 and 2021. Further, this research has immediate policy relevance because in May 2019, two similar bills were introduced in the Senate: S. 1327 and S. 1405.[3]

2.3 The Gains

Refined coal currently makes up about a fifth of the coal used in the power sector—128 million tons in 2017. At a subsidy of about $7 per ton, the subsidy itself could amount to nearly $1 billion per year. According to IRS data, six corporations claimed nearly $300 million of credits in 2013, the last year for which the IRS published this data.[4] This figure is likely much larger and growing faster today as the use of refined coal has risen dramatically since 2013, even as conventional coal use has declined. Figure 1 plots coal use over time, illustrating that refined coal has comprised a sharply rising share of US coal consumption.

[2]The Senate bill was introduced by Sen. Hoeven (R-ND) and Sen. Heitkamp (D-ND). The House bill was introduced by then-Representative and now-Senator Cramer (R-ND).

[3]S. 1327 was sponsored by Senators Hoeven (R-ND) and Cramer (R-ND), and S. 1405 was sponsored by Senators Daines (R-MT), Cramer (R-ND), Capito (R-WV), Gardner (R-CO), and Barrasso (R-WY).

[4]IRS Corporation Income Tax Return Line Item Estimates, 2013, Form 8835, line 18, Available at https://www.irs.gov/pub/irs-soi/13colinecount.pdf.

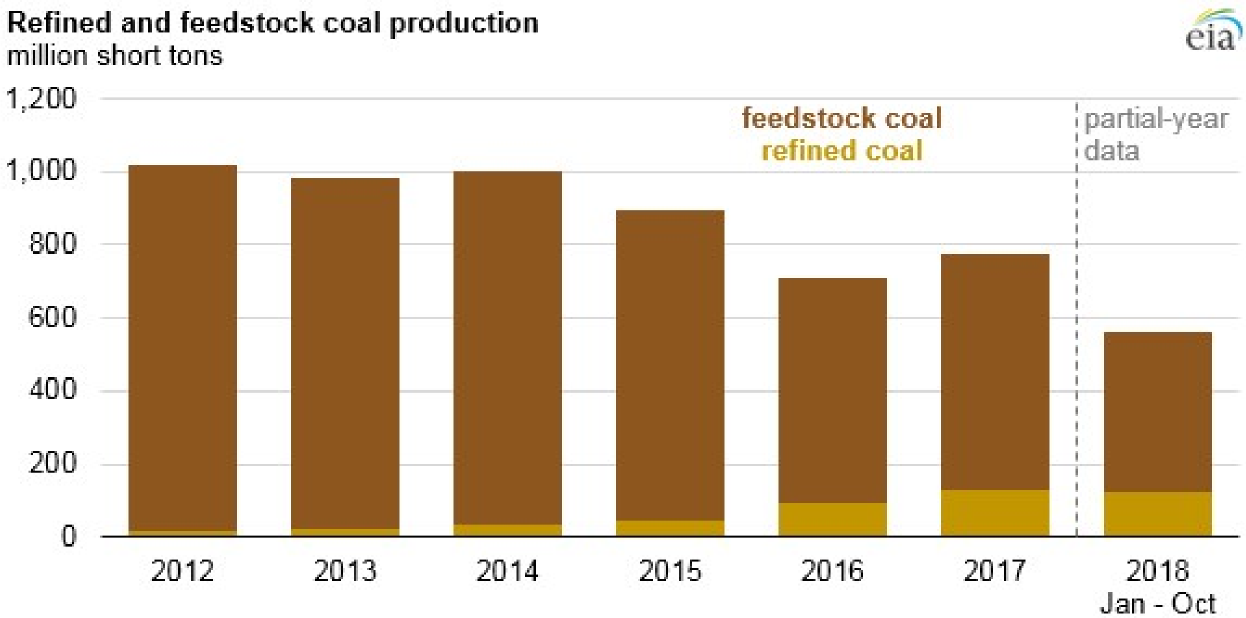

Figure 1: Coal Consumption over Time: Refined/Unrefined

Source: US EIA. 2019. Today in Energy: US production and use of refined coal continues to increase, February 8, 2019.

Figure 2 shows that refined coal makes up a similar share of the three coal types used to generate electric power. According to data from the Energy Information Administration (EIA), 48 plants burned refined coal in 2018.[5]

Figure 3 shows the power plants that we analyze in this paper, including nearly all coal-burning power plants in the United States and covering over 90 percent of coal burned in the US power sector. Figure 3 shows plants that predominantly burned refined coal in 2016-2018 (depicted in red), alongside plants primarily burning regular coal (in gray), and plants that burned both refined coal and regular coal (in blue). Plants burning refined coal are generally concentrated in the Midwest, followed by the Mid-Atlantic and the South.

The tax credit is claimed directly by the owner of the coal refining facility, which is typically a third party investor that is distinct from the coal plant owner. In addition, some of the value of the tax credit can be passed on indirectly to the power plants using the refined coal, the coal mining sector, and electricity consumers (depending on the local market and regulatory structure). The refiner typically buys the unrefined coal from the coal plant at cost, refines it, and sells the now-refined coal back at a discount from $0.75 to $2.00 per ton (McLaughln 2018*c*), implying that some of the incidence of the credit falls on coal plants. The first order effect of such a discount on coal use is to lower marginal cost

[5] See Form EIA-923 Power Plant Operations report, "EIA923_Schedules_2_3_4_5_M_11_2018_28JAN2019.xlsx", "Page 1 Generation and Fuel Data".

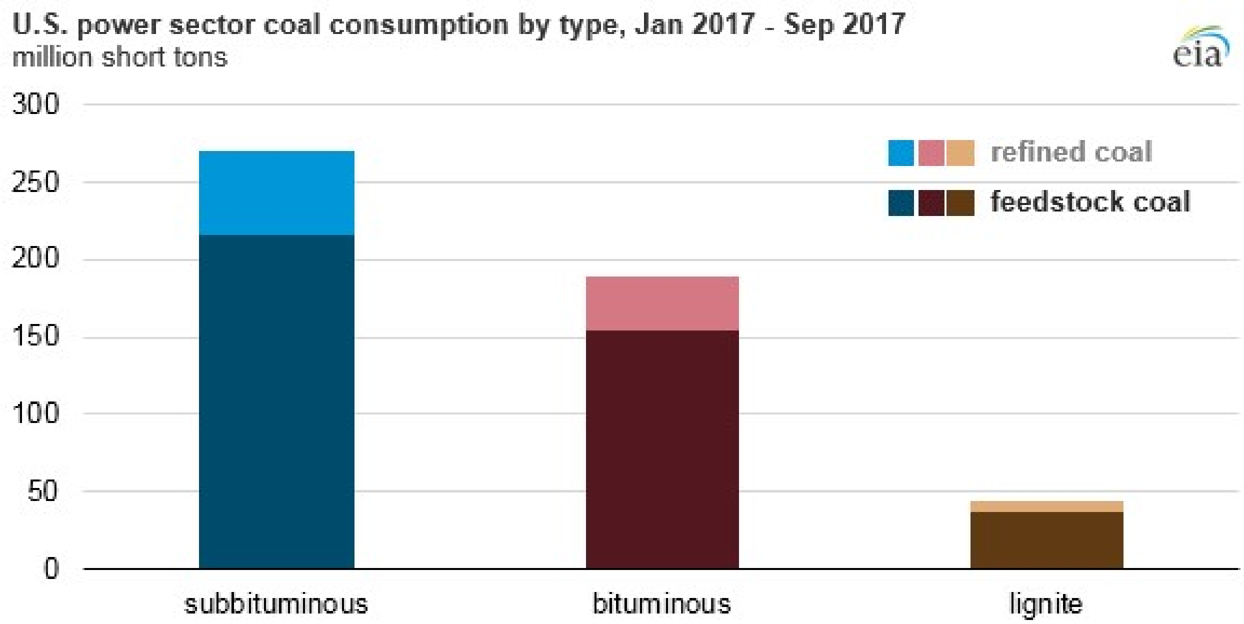

Figure 2: Coal Consumption by Coal Type

Source: US EIA. 2017. Today in Energy: Refined coal has made up nearly one-fifth of coal fired power generation so far in 2017. December 12, 2017.

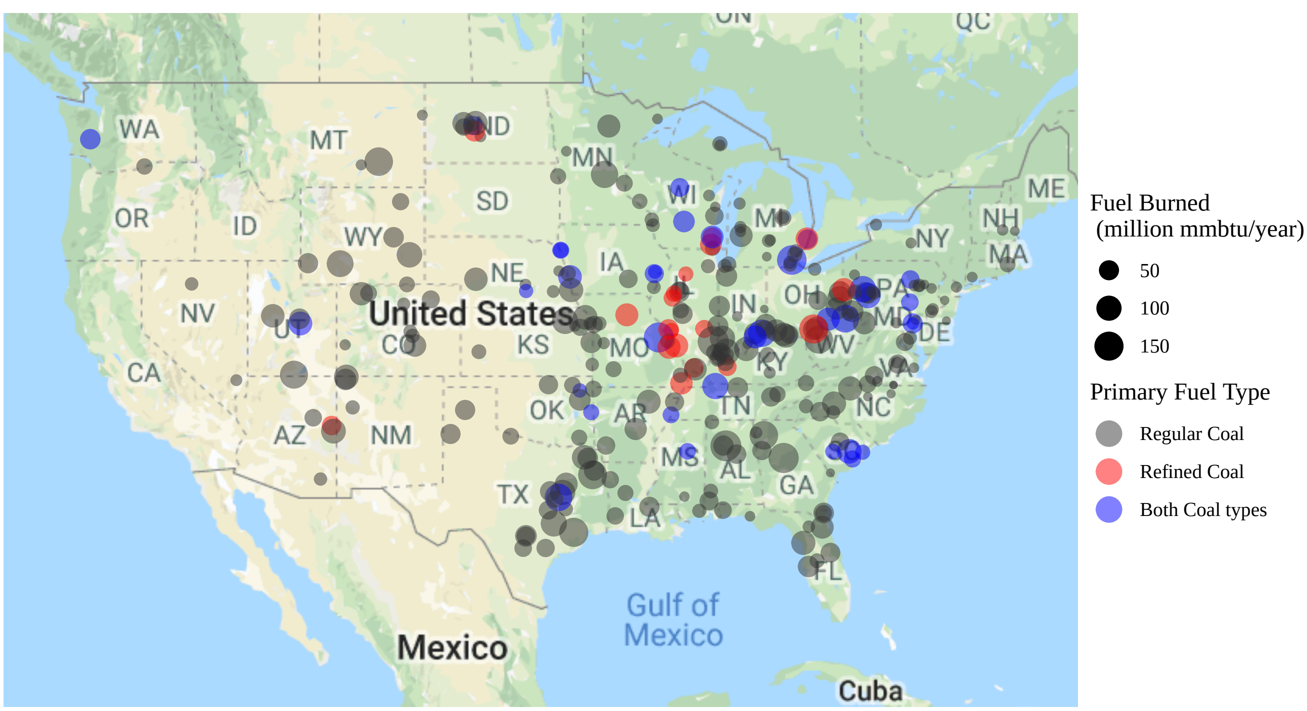

Figure 3: Coal-Burning Plants in Sample by Primary Fuel(s) in 2016-2018

Source: Authors' calculations based on EIA Form 923 data.

of coal use, which can amount to an increase in coal demand, thereby passing some gains to the coal mining sector. While any of these entities may invest directly in building and financing refined coal plants, the tax credit requires that the coal is sold "by the taxpayer to an unrelated person" (Internal Revenue Service 2010), illustrating why the refiner is generally a third party investor.

3 Qualitative Analysis

3.1 Approach

As previously noted, refiners typically demonstrate the required emissions reductions through laboratory test results, but emissions rates in the lab may differ significantly from those achieved at the plant. For example, equipment used in the lab simply typically differs (in type, size, age, pollution controls, etc.) from the equipment used at plants around the country. For example, one of the major labs uses boiler with a capacity of less than 1 megawatt (MW),[6] compared to the average boiler capacity in our sample of around 500 MW. Arguably, emissions rates in the field are simply more important for economic outcomes than those in a lab. Rather than relying on laboratory testing to see if target reductions in NO_x and either SO_2 or Hg are occurring, we examine whether, other things equal, these emissions targets are being met in the field.

We estimate reductions in emissions rates[7] from refined coal relative to standard unrefined coal using monthly variation in fuel consumption during 2016-2018.[8] Of course, during this time period, changes in regulations (such as the Mercury and Air Toxics Standards, MATS) led many plants to install Hg controls, such as activated carbon injection (ACI) or Selective Catalytic Reduction (SCR), the latter of which can reduce both NO_x and also oxidize Hg to make it easier for a baghouse or flue gas desulfurization (FGD) technology to capture.[9] We account for this by explicitly examining emission rates at the boiler level by fuel type, controlling for the installation of pollution control technology. This improves upon an anecdotal analysis performed by McLaughln (2018*a*). That analysis compared snapshots of plant-level total emissions by refined coal plants after eight years (i.e., 2017 versus 2009).

[6] McLaughln (2018*b*).

[7] Emission rates are measured in mass of emissions per unit of fuel: pounds of pollutant per British thermal unit (btu). This aligns with IRS guidance which measures emissions relative to units of "useful thermal energy" (Internal Revenue Service 2010).

[8] We can only rely on monthly variation, rather than the more granular hourly resolution of CEMS data, due to data limitations. As described below, data on fuel consumption by coal type (from EIA-923) is collected only at the monthly level.

[9] See, e.g., US EIA. 2017. Today in Energy: Coal plants installed mercury controls to meet compliance deadlines. September 18, 2017.

In contrast, the emissions rates we estimate use boiler-level monthly data separately by fuel type and by emissions control status. Our approach corresponds to the IRS eligibility requirements for the tax credit, which requires reductions in the emissions *rate*, i.e., pounds emitted per unit of useful thermal energy (mmbtu), properly identified by fuel type.

3.2 Data

We use the CEMS data from the US Environmental Protection Agency (EPA), plus data on fuel consumption and pollution control equipment at each plant from EIA and EPA in our analysis. The EIA data contains monthly, boiler-level fuel consumption data for each fuel type. EIA only began distinguishing refined coal as a separate fuel type in 2016, so our sample window is 2016-2018.[10] The CEMS data contains hourly, boiler-level emissions of NO_x, SO_2, and Hg, which we aggregate to the monthly level in order to match the monthly frequency of the EIA data.[11] We also use EPA data on pollution control equipment installations obtained directly from EPA staff (EPA 2019). In the appendix, we also use EIA data on coal characteristics and emissions control utilization to assess whether refine coal use is associated with changes in operating conditions relevant to emissions (see appendix section B).

3.3 The Legal and Economic Questions

Before turning to the substance of the analysis, we pause to note that there are two conceptually distinct questions that we aim to address. The first is the legal question of whether emissions reductions in the field are consistent with the reductions required by the tax law and applicable IRS regulations. As mentioned above, IRS regulations require emissions reductions to be measured holding constant all operational conditions that are not "directly attributable to changing" to refined coal (Internal Revenue Service 2010). Therefore, this is the question: is refined coal leading to the requisite emissions reductions, holding constant operational conditions that are not directly attributable to changing to refined coal?

While this question is relevant given the IRS's regulations, it may not be the appropriate question from the standpoint of social welfare. For example, suppose a refined coal sample achieved reductions in a test that held operational conditions constant, but then in practice operators decided to change those conditions (e.g., switching to dirtier coal or turning off

[10] We use data through November 2018. At the time of this analysis, EIA fuel consumption data was not yet available for December 2018.

[11] The Hg data begins later than the NO_x and SO_2 data because monitoring coincided with the implementation of the MATS rule. This means we have fewer observations for Hg emissions than for NO_x or SO_2.

emissions control technology) such that there were no reduction in emissions. In that case, the tax credit is not achieving any reductions in emissions, even if the claimant of the tax credit might technically be in legal compliance.[12] Hence, we also consider the economic question: is the refined coal leading to the requisite emissions reductions after accounting for all changes in operating conditions resulting from the use of refined coal?

In other words, the legal question generally holds operational conditions constant, whereas the economic question allows for operational changes that directly or indirectly result from the use of refined versus unrefined coal. Our approach is better suited to answer the economic question because we use observed plant emissions at the smoke stack. However, if refined coal does not induce operational changes relevant to emissions, then the two questions are the same, as are their answers. In appendix sections A and B we provide evidence showing that as far as we can measure, the key operational conditions relevant to NO_x, SO_2, and Hg emissions do not systematically vary with the use of refined versus unrefined coal. For example, our result is not biased by changes in coal sulfur content when plants switch to refined coal. Given the lack of observed operational changes associated with refined coal use, for the remainder of this paper we do not distinguish between the legal and economic questions. However, if there are unobserved operational changes that affect emissions and are attributable to the use of refined coal, then our results still address the economic question. To the extent that such unobservable changes are "directly attributable" to refined coal use (as opposed to indirectly), then our results also address the legal question. Finally, if there are unobservable changes that are correlated with refined coal use and that decrease emissions rates, then our estimates overstate the reduction that can be attributed to refined coal, and our results still address the legal question.

3.4 Graphical Analysis

We perform two types of analyses: a limited plant-by-plant, before-and-after analysis and an econometric analysis on boilers accounting for more than 90 percent of coal burned in the US power sector. Figures 4-7 show the results of the first comparison. There are four panels in each figure representing the amount and type of coal (by type) burned over time, and the emissions rates over time of NO_x, SO_2, and Hg. The shading around the line represents a 95

[12] Although in this scenario, it is debatable whether the claimant is technically in legal compliance. First, it is arguable that emission-increasing operational changes induced by the use of refined coal are "directly attributable to changing" to refined coal, and hence according to IRS rules should included in when measuring emissions rates. Second, IRS rules require claimants to state, under penalty of perjury, that the refined coal "will result in a qualified emissions reduction when used in the production of steam." This is a much stronger statement than saying it will result in a reduction in a laboratory or field test holding operating conditions constant.

percent confidence band for the average emissions rate.

In Figure 4, the plant switched to refined coal in November 2016. Its NO_x rate actually rose by a statistically significant 10 percent. The SO_2 rate was approximately unchanged, and the Hg rose by nearly 60 percent (also statistically significant). We have determined that none of the potentially confounding factors changed during this time period (e.g., no new technologies were installed, no significant changes occurred in the sulfur or mercury content of its coal); thus, with a high degree of confidence, this plant does not appear to have met the targeted reductions, meaning that the refined coal it used does not appear to qualify for the tax credit.

In Figure 5, the plant switched to refined coal in October 2016. Its NO_x rate was approximately unchanged (+1 percent) in the year and a half that followed. Emissions eventually fell starting in March 2018, when SCR (a NO_x control technology) was installed. This highlights the importance of controlling for pollution control technology in our statistical analysis. The SO_2 emissions rate rose by a statistically significant 21 percent, although it is unclear why. There were also no installations or retirements of sulfur control technology at the plant during the period. As shown in appendix Figure A.3, the sulfur content of this plant's coal actually declined slightly during this period. Finally, the Hg emissions rate rose insignificantly (6 percent). Overall, with a high degree of confidence we can say that this plant does not appear to have achieved the reductions required for the tax credit.

Figure 6 and Figure 7 show plants that are reducing their emissions of NO_x and Hg. The SO_2 rate is rising in Figure 7 (its coal's sulfur content remained fairly stable, see appendix Figure A.5), and in both figures the estimated Hg reductions are statistically insignificant and also fall short of the targets. So even if those plants achieved the 20% NO_x reductions, they did not appear to achieve the SO_2 or Hg reductions needed for tax credit eligibility.

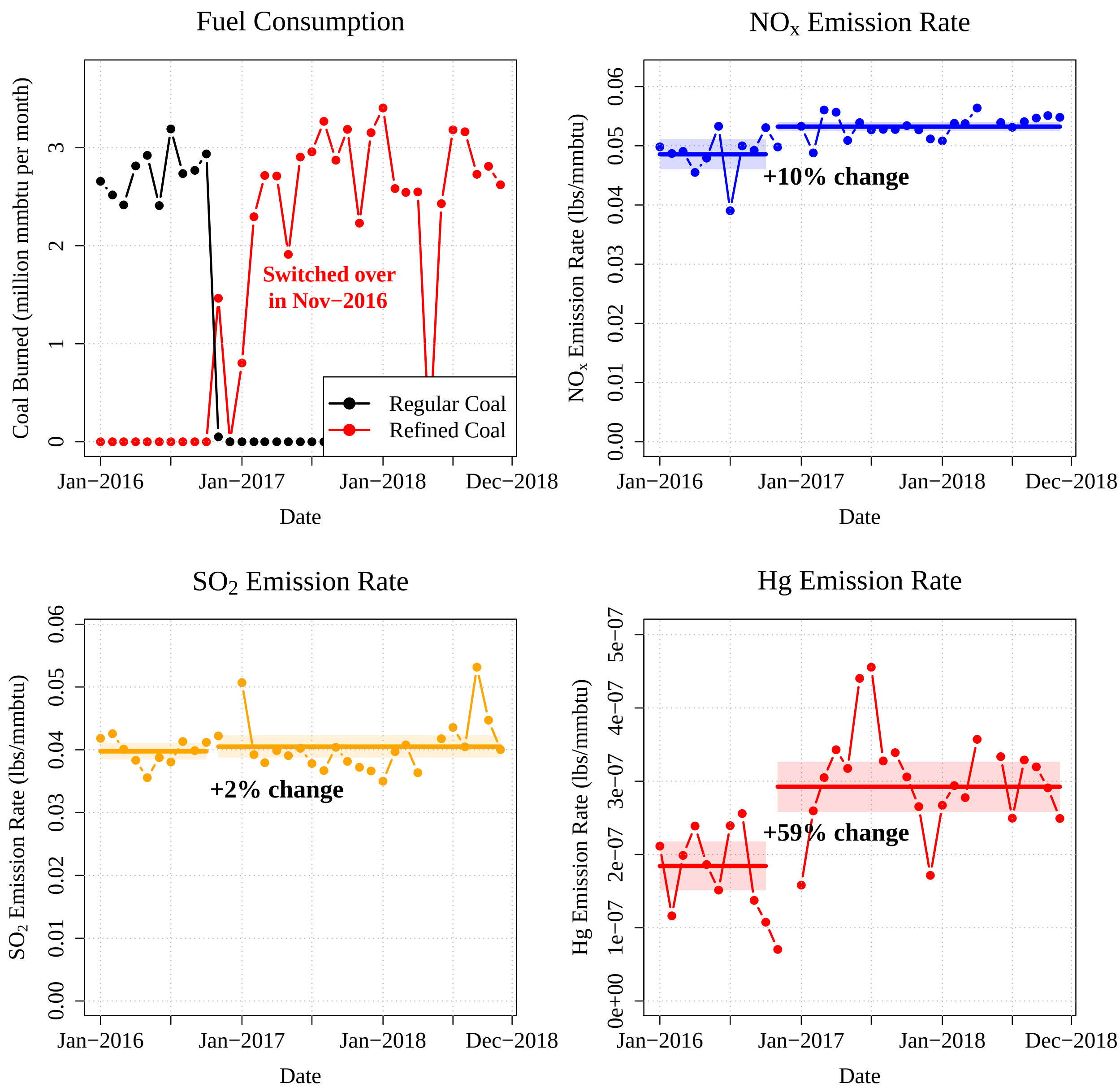

Figure 4: Fuel Consumption and Emission Rates: Plant 1

Source: Authors' calculations based on EPA CEMS data and EIA Form 923 data.

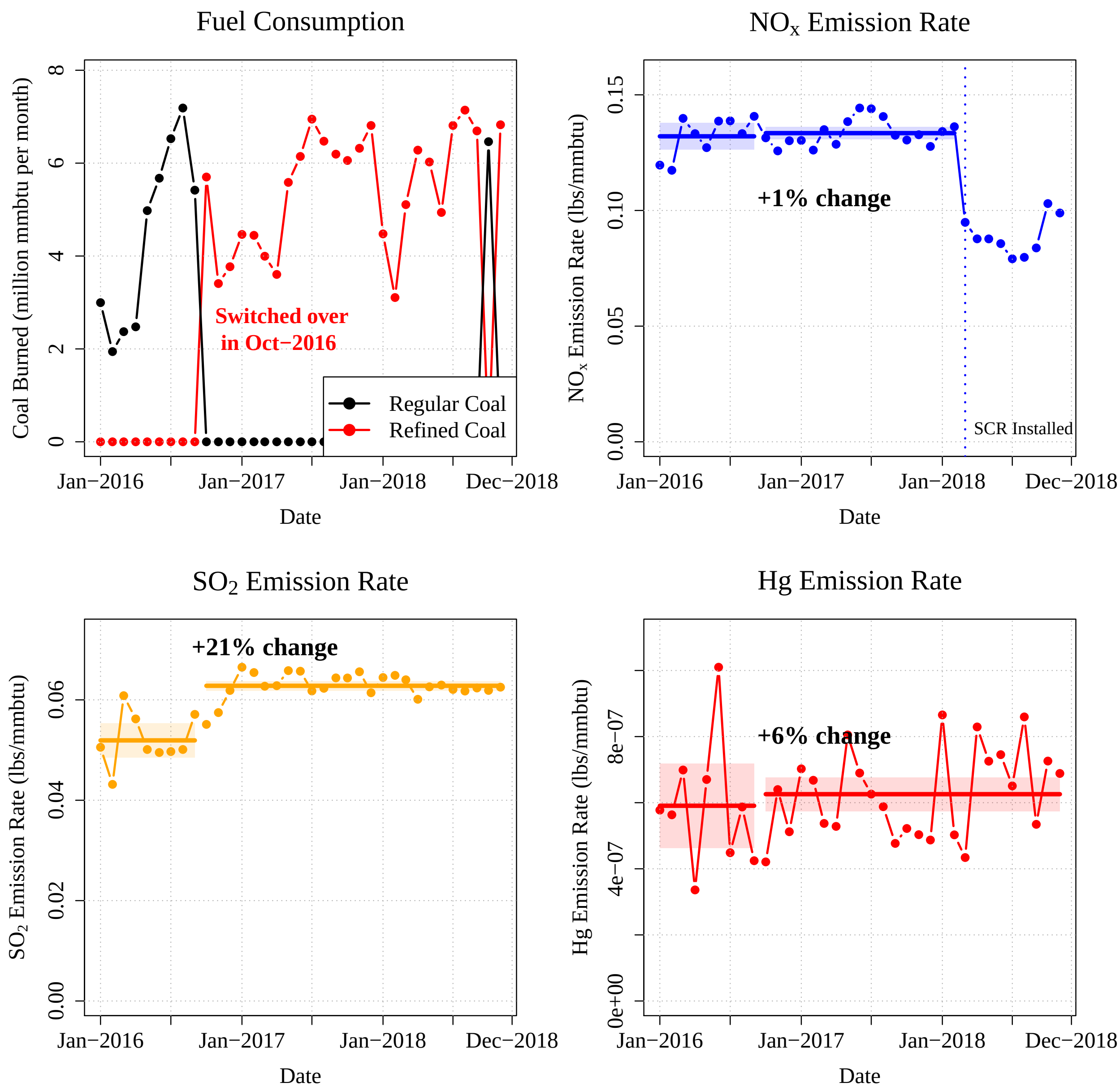

Figure 5: Fuel Consumption and Emission Rates: Plant 2

Source: Authors' calculations based on EPA CEMS and emissions controls data, and EIA Form 923 data.
Note: The average bar for the post-refined-coal NO_x rates stops at February 2018 because SCR (a NO_x control device) was installed in March 2018.

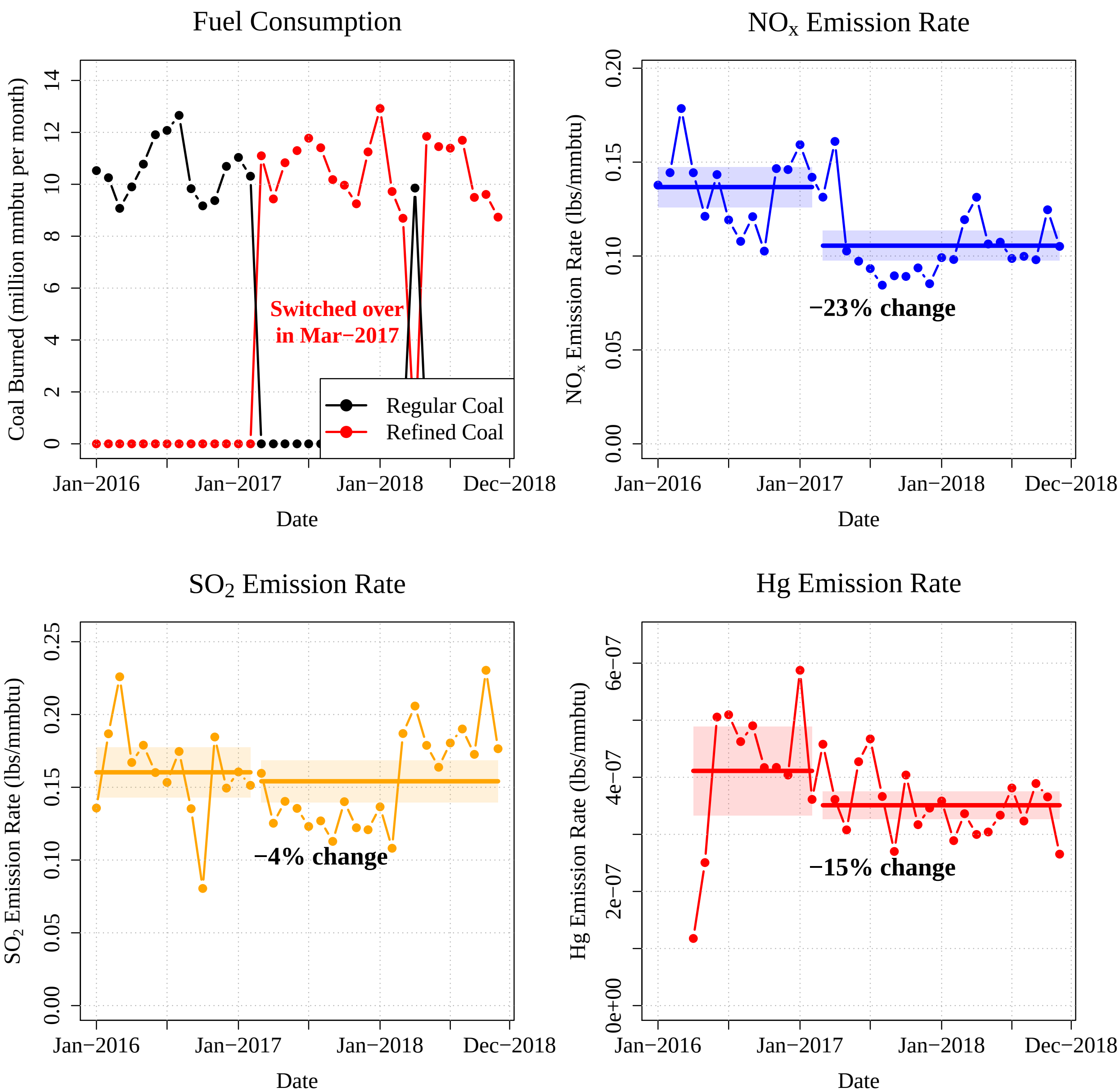

Figure 6: Fuel Consumption and Emission Rates: Plant 3

Source: Authors' calculations based on EPA CEMS data and EIA Form 923 data.

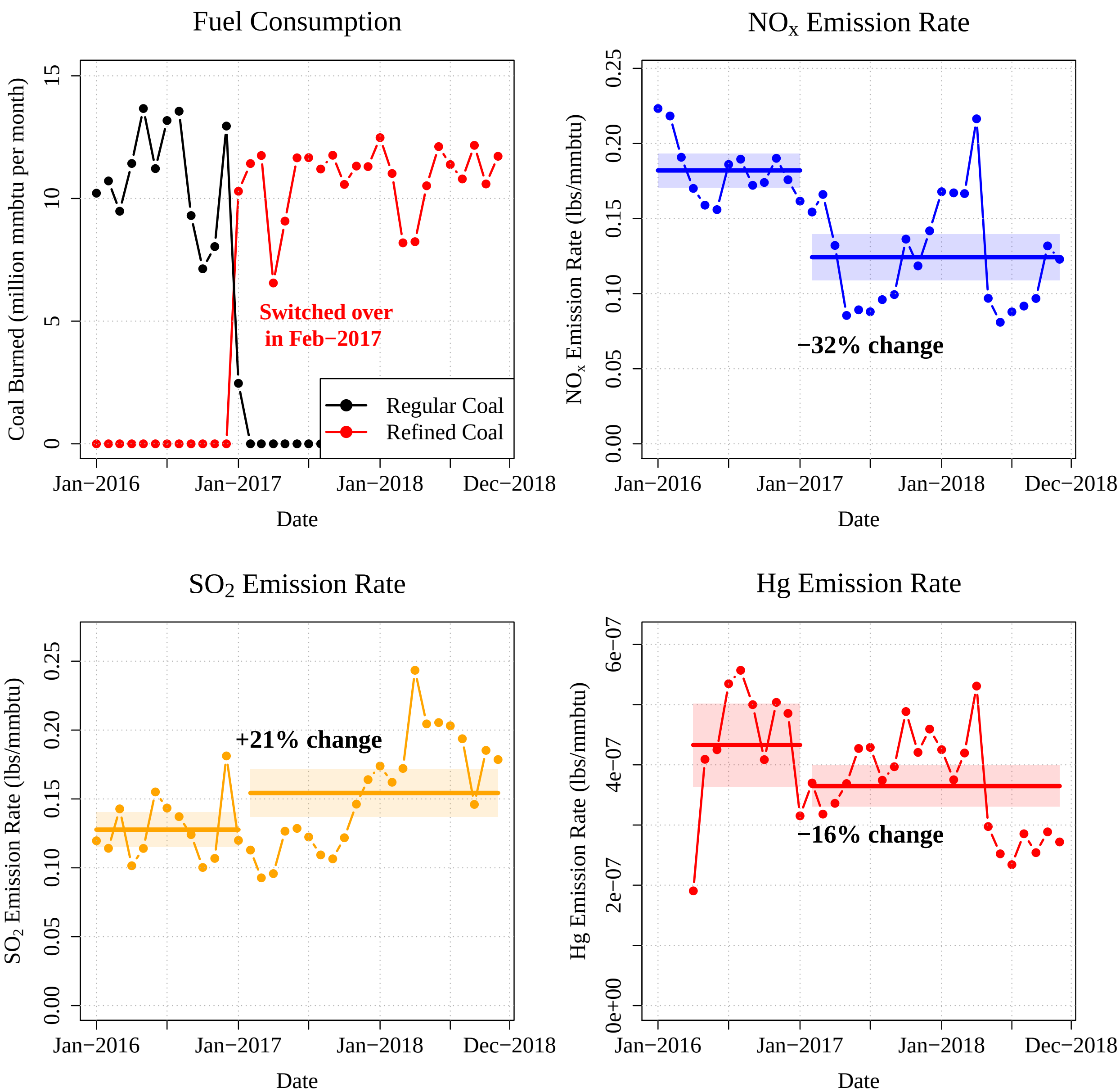

Figure 7: Fuel Consumption and Emission Rates: Plant 4

Source: Authors' calculations based on EPA CEMS data and EIA Form 923 data.

4 Quantitative Analysis

The above four graphs strongly suggest that, for this very limited sample, refined coal is not achieving the emissions reductions required to be eligible for the tax credit. Unfortunately, we do not have the information to do a plant-by-plant analysis for all generators, because some that switched to refine coal did so before the EIA tracked the use of this coal and/or before the agency collected data on Hg emissions. However, we can still statistically estimate coal emissions rates using econometric techniques applied to a dataset containing the vast majority of coal-burning power plants in the United States. We merge data from EPA and EIA, resulting in a boiler-month panel dataset of 639 boilers at 287 power plants across the country. This dataset accounts for more than 90 percent of coal burned in the US power sector.[13]

4.1 Descriptive Statistics

Table 1 shows descriptive statistics of our compiled dataset. For the purposes of this table, we separate boilers into three groups: boilers burning predominantly regular unrefined coal (95 percent or more on a Btu basis), boilers burning predominantly refined coal (also 95 percent or more), and boilers burning both regular and refined coal (referred to as "dual coal" boilers).[14] We present these results to assess whether boilers that burn refined coal versus regular coal differ systematically. As such, we present means, standard errors, and p-values comparing differences in means.

Refined coal and regular coal plants are generally similar, except for some differences in pollution control technology. The difference in presence of NO_x control technology is statistically significant but practically small (99 percent versus 97 percent). The difference in presence of SO_2 control technology is substantial (59 percent versus 80 percent), again highlighting the importance of accounting for differences in presence of control technology in our regression analysis. The average emission rates are slightly lower for NO_x and slightly higher for SO_2 and Hg, but the differences seen in the table are not statistically significant. Note that the differences in this table do not themselves imply that refined coal itself produces higher or lower emissions, since the simple comparison of emissions rates does not account for differing plant characteristics such as pollution controls.

"Dual coal" plants tend to be larger than regular coal plants. For example, dual coal

[13] The remaining 10 percent include boilers that we could not match across EPA and EIA datasets, as well as units smaller than 25 MW of capacity and units in Alaska or Hawaii, which do not appear in the EPA CEMS data.

[14] A small number of other boilers do not fall into any of these three categories, such as boilers that burn a mix of coal and natural gas. They are excluded from this table but included in our regression analysis.

boilers have an average capacity (measured as maximum observed gross load) of 600 MW on average, compared to 462 MW for regular coal plants. Similarly, they also have higher maximum heat input, maximum steam flow and coal firing rates. Some care must be taken when considering the average emissions rates of plants that burn both refined and regular coal. The average rate shown here is, in effect, a weighted average across all types of coal burned by the boilers (we disentangle these separate rates in our econometric analysis). Nonetheless, we do observe slightly lower NO_x and Hg rates (but not SO_2 rates) among dual coal boilers compared to regular coal boilers.

Finally, dual coal boilers are slightly younger (average in-service year of 1980, as compared to 1972-1975 for the other plant types) with longer to go until expected retirement (2037 versus 2025-2028). Otherwise, dual coal boilers are broadly similar to regular coal boilers on pollution controls, total emissions, and boiler efficiency.

Table 1: Summary Statistics, by Boiler Type

	Mean			Standard Error			p-value for comparison		
	Regular Coal Boilers	Refined Coal Boilers	Dual Coal Boilers	Regular Coal Boilers	Refined Coal Boilers	Dual Coal Boilers	Regular Coal Boilers	Refined Coal Boilers	Dual Coal Boilers
Variable	(1)	(2)	(3)	(4)	(5)	(6)	(1)-(2)	(1)-(3)	(2)-(3)
NOx Emissions (lbs/month)	261,965	328,739	293,277	(10,840)	(46,542)	(22,519)	0.162	0.21	0.493
NOx Emission Rate (lbs/mmbtu)	0.178	0.161	0.145	(0.005)	(0.017)	(0.012)	0.348	0.009***	0.453
SO2 Emissions (lbs/month)	373,179	554,697	414,748	(24,266)	(96,637)	(49,333)	0.068*	0.45	0.197
SO2 Emission Rate (lbs/mmbtu)	0.240	0.263	0.215	(0.011)	(0.031)	(0.025)	0.488	0.372	0.235
Hg Emissions (lbs/month)	1.421	1.751	1.329	(0.104)	(0.314)	(0.145)	0.318	0.605	0.222
Hg Emission Rate (lbs/mmbtu)	0.642	0.729	0.538	(0.027)	(0.099)	(0.045)	0.402	0.047**	0.08*
Max Gross Load (MW)	462	530	600	(13.4)	(45.4)	(29.6)	0.149	<0.001***	0.195
Max Heat Input (mmbtu/hour)	5,027	5,662	5,985	(146)	(479)	(384)	0.205	0.02**	0.599
Share NOx Controlled	0.97	0.99	0.94	(0.007)	(0.004)	(0.025)	0.018**	0.213	0.045**
Share SO2 Controlled	0.80	0.59	0.80	(0.018)	(0.073)	(0.045)	0.004***	0.976	0.012**
Share Hg Controlled	0.40	0.37	0.35	(0.023)	(0.071)	(0.054)	0.677	0.458	0.891
First Year in Service	1975.0	1972.2	1979.9	(0.6)	(1.4)	(1.8)	0.067*	0.01**	0.001***
Retirement Year	2027.6	2025.0	2036.9	(0.80)	(3.85)	(2.14)	0.514	<0.001***	0.007***
Max Steam Flow (1000lbs/hour)	3,024	3,500	3,779	(87.1)	(307.8)	(211.8)	0.137	0.001***	0.455
Coal Firing Rate (0.1 tons/hour)	208.1	236.4	236.6	(6.6)	(18.8)	(14.1)	0.154	0.067*	0.994
Boiler Efficiency at 100% Load	0.874	0.872	0.879	(0.001)	(0.003)	(0.003)	0.579	0.206	0.188
Boiler Efficiency at 50% Load	0.877	0.878	0.878	(0.001)	(0.004)	(0.004)	0.824	0.785	0.958
Observations (boiler-months)	14,459	1,470	2,552						
Number of Boilers	474	48	78						

Note: *p<0.1; **p<0.05; ***p<0.01. "Regular coal" boilers get 95% of their fuel from regular coal. "Refined coal" boilers are defined similarly. "Dual Coal" boilers are boilers that burned non-zero amounts of both refined and regular coal during the 2016–2018 sample window.

4.2 Econometric Methodology and Approach

To assess whether burning refined coal results in systematically lower emissions than regular coal, we use an econometric model that estimates emissions rates separately for NO_x, SO_2, and Hg. We estimate emissions rates separately by fuel type (refined coal, unrefined coal, and other) and by an indicator for whether boilers had pollution controls installed. We do this by jointly estimating the following system of three equations:

$$NO\mathrm{x}_{it} = \alpha_i^{NO\mathrm{x}} + c_{it}^{NO\mathrm{x}} + \sum_j \left[\beta_{jc}^{NO\mathrm{x}} F_{jit} \cdot c_{it}^{NO\mathrm{x}} + \beta_{ju}^{NO\mathrm{x}} F_{jit} \cdot (1 - c_{it}^{NO\mathrm{x}})\right] + \varepsilon_{it}^{NO\mathrm{x}} \quad (1)$$

$$SO2_{it} = \alpha_i^{SO_2} + c_{it}^{SO_2} + \sum_j \left[\beta_{jc}^{SO_2} F_{jit} \cdot c_{it}^{SO_2} + \beta_{ju}^{SO_2} F_{jit} \cdot (1 - c_{it}^{SO_2})\right] + \varepsilon_{it}^{SO_2} \quad (2)$$

$$Hg_{it} = \alpha_i^{Hg} + c_{it}^{Hg} + \sum_j \left[\beta_{jc}^{Hg} F_{jit} \cdot c_{it}^{Hg} + \beta_{ju}^{Hg} F_{jit} \cdot (1 - c_{it}^{Hg})\right] + \varepsilon_{it}^{Hg} \quad (3)$$

where $NO\mathrm{x}_{it}$, $SO2_{it}$, and Hg_{it} are emissions (in lbs) by boiler i in month t. The α_i terms are boiler-level fixed effects (i.e., used to capture time-invariant differences across boilers not captured by other variables), and the c_{it} terms are indicators for whether boiler i had emissions control equipment installed (for NO_x, SO_2, or Hg) at time t. F_{jit} is boiler i's fuel consumption (in million British thermal units, or mmbtu) of fuel type $j \in \{\textit{Regular Coal, Refined Coal, Other Fuels}\}$ in month t.[15] Hence, the β_{jc}^p parameters measure the average marginal emissions rates (in lbs/mmbtu) for each fuel j and pollutant p, separately for when a boiler has emissions control (β_{jc}^p) versus uncontrolled emissions (β_{ju}^p). With three fuel types and two potential control statuses (yes or no), we estimate six emissions rates per pollutant. We then compare the estimated emissions rates of refined coal to those of regular coal to calculate emissions reductions.

We estimate the system of equations using seemingly unrelated regression (SUR), which permits statistically testing the joint hypothesis that refined coal is achieving the statutorily targeted reductions of 20 percent on NO_x emissions and 40 percent on either SO_2 or Hg. We account for within-boiler correlation in the errors by clustering standard errors at the boiler level. We compute the covariance matrix using the cluster bootstrap methodology of Cameron and Miller (2015) with 1,000 draws.[16]

[15] We include other fuels to avoid omitted variable bias. Burning other fuels can also result in emissions. To the extent that the burning of other fuels is correlated with the burning of coal, this could threaten to bias the coefficients of interest. For example, if other fuels are a substitute for coal and hence negatively related, as they are at dual-fuel plants (and indeed coal and other fuel use are negatively related in our data) failing to include them in the regression will bias the estimated coal emissions rate down toward zero.

[16] Cameron and Miller (2015) recommend using 400 draws or more. The other benefit of using a bootstrapped distribution is that it allows us to test the compound joint hypothesis that the law's required reductions are achieved for **both** NO_x **and** either SO_2 **or** Hg. The standard Wald test is not designed to

We estimate this set of equations twice. First, we estimate it using all coal boilers in our data, representing more than 90 percent of coal burned in the US power sector. In this case, the emissions estimated are identified by both within-boiler variation in emissions and fuel consumption, as well as across-boiler variation (e.g., comparing boilers burning regular coal to others burning refined coal). Because there is some concern that the latter source of identification could bias our results if there are other unobserved differences across boilers, we also estimate emissions rates only for the 78 boilers that burned both refined coal and regular coal in our sample window, which were previously discussed in Table 1. Since for these boilers we observe emissions by the same boiler using different coal types, we can be confident that the results are not being confounded by time-invariant unobserved boiler characteristics, such as differing efficiencies. The other potential threat to identification is the installation of pollution control technology (e.g., see Figure 5), but we observe this and directly control for it.

The results are shown in Table 2. The first three columns show the estimates for all boilers, whereas the latter three show the results just for the dual coal boilers. The top panel presents the emissions rates. For example, in column 1 we find that, with pollution controls, the NO_x emissions rate from burning refined coal is 0.123 lbs/mmbtu, compared to 0.140 lbs/mmbtu for regular coal, a 12.5 percent reduction. Column 2 shows little difference for SO_2 rates (with controls: 0.155 lbs/mmbtu with refined coal versus 0.159 with regular coal). Column 3 shows (again for plants with controls) Hg rates of 0.576 μlbs/mmbtu for refined coal compared to 0.759 for regular coal, a 24.1 percent reduction.

In the second panel of Table 2, we test whether these reductions are statistically significant. Namely, we test two hypotheses. First, we test whether the reduction is statistically significant from zero to determine whether refined coal is leading to any emission reductions at all. Second, we test whether the reduction is statistically different from the statutorily required levels (20 percent for NO_x, 40 percent for SO_2 and Hg). We conduct one-tailed hypothesis tests for both tests because we want to test whether the reductions are sufficiently large, either compared to 0 percent or to the legal targets of 20 percent and 40 percent.[17]

In most cases, we reject both null hypotheses. This means that refined coal appears to

test such a hypothesis involving an "or" condition.

[17]E.g., in one case our point estimate is a +24% higher emission rate, which would reject a two-tailed test for different from zero (H_0: $\beta_{RC} = \beta_C$, where β_{RC} and β_C are the emissions rates for refined coal and regular coal), but not a one-tailed test where the null hypothesis is that there are no reductions (H_0: $\beta_{RC} \geq \beta_C$). Similarly, our uncontrolled NO_x estimate of a −60% difference would easily reject a two-tailed test for −40% (H_0: $\beta_{RC} = (1 - 40\%)\beta_C$), but this would be a misleading interpretation. Formally, the null hypotheses are $\beta_{RC} \geq \beta_C$ and $\beta_{RC} \leq (1-t)\beta_C$, where t is the targeted reduction (20% or 40%). We calculate the p-values here using the bootstrapped distribution directly, but the results are essentially identical when running standard hypothesis testing procedure using the covariance matrix of the bootstrap sample.

Table 2: Emissions Regressions

Sample:	All Boilers			Boilers that Burned Both Refined and Unrefined Coal		
Dependent variable:	NO_x (lbs)	SO_2 (lbs)	Hg (μlbs)	NO_x (lbs)	SO_2 (lbs)	Hg (μlbs)
	(1)	(2)	(3)	(4)	(5)	(6)
Emissions Controlled						
Refined Coal Burned (mmbtu)	0.123***	0.155***	0.576***	0.110***	0.131***	0.549***
	(0.009)	(0.013)	(0.057)	(0.012)	(0.015)	(0.065)
Unrefined Coal Burned (mmbtu)	0.140***	0.159***	0.759***	0.130***	0.135***	0.765***
	(0.005)	(0.013)	(0.052)	(0.013)	(0.015)	(0.141)
Other Fuel Burned (mmbtu)	0.050	-0.039	0.031	0.012	-0.064	1.632
	(0.036)	(0.027)	(0.373)	(0.138)	(0.045)	(2.584)
Emissions Uncontrolled						
Refined Coal Burned (mmbtu)	0.147***	0.511***	0.560***	0.146***	0.653***	0.406***
	(0.013)	(0.044)	(0.054)	(0.016)	(0.087)	(0.047)
Unrefined Coal Burned (mmbtu)	0.367***	0.570***	0.577***	0.423***	0.525***	0.416***
	(0.053)	(0.042)	(0.044)	(0.064)	(0.044)	(0.049)
Other Fuel Burned (mmbtu)	0.190	0.402***	0.186	0.983***	3.869*	0.122
	(0.391)	(0.151)	(0.124)	(0.247)	(2.037)	(0.112)
Emission Control Indicator	Y	Y	Y	Y	Y	Y
Emissions Controlled						
Emission Rate Difference (%)	**-12.5%**	**-2.3%**	**-24.1%**	**-15.5%**	**-2.7%**	**-28.2%**
p-value for H_0: No improvement	0.035**	0.368	$<$0.001***	0.020**	0.283	0.001***
p-value for H_0: Required improvement	0.077*	$<$0.001***	0.018**	0.250	$<$0.001***	0.048**
Emissions Uncontrolled						
Emission Rate Difference (%)	**-59.9%**	**-10.4%**	**-2.9%**	**-65.4%**	**24.4%**	**-2.4%**
p-value for H_0: No improvement	0.002***	0.154	0.368	$<$0.001***	0.998	0.377
p-value for H_0: Required improvement	0.997	$<$0.001***	$<$0.001***	0.999	$<$0.001***	$<$0.001***
R-Squared (projected model)	0.465	0.533	0.319	0.412	0.605	0.346
Observations (boiler-months)	19,408	19,408	14,825	2,552	2,552	2,127
Number of Boilers	639	639	507	78	78	73
Share of observations controlled	96.3%	78.2%	44.6%	94.0%	80.3%	38.7%

Note: *p$<$0.1; **p$<$0.05; ***p$<$0.01. Columns (4) through (6) only include boilers that burned both refined and unrefined coal during the sample window (2016-2018). The statutorily required reductions are 20% for NO_x and 40% for SO_2 and Hg.

produce some statistically detectable emissions reductions, but they are smaller than the reductions required by the tax law.

With emissions controls, the 12.5 percent estimated reduction in the NO_x rate is significantly different than zero at the 5 percent level ($p = 0.035$), but we can also reject that it achieves the 20 percent reduction target at the 10 percent confidence level ($p = 0.077$). For Hg with controls, the result is even stronger: the 24.1 percent reduction is strongly significant ($p < 0.001$), but it does not achieve the 40 percent target ($p = 0.018$). We find little reduction in the SO_2 emissions rate with controls: a 2.3 percent reduction, not significantly different from zero, but significantly different from the 40 percent reduction target.

Turning to the results for the relatively few boilers without controls, the results are a bit different. Without NO_x control technology installed, refined coal appears to create NO_x reductions of 60 percent, which exceeds the 20 percent target. However, so few plants lack NO_x controls (4 percent) that this finding has little practical implication. In fact, the data show that there is only one power plant without NO_x controls that burns refined coal, so these estimated reductions derive entirely from that single plant.[18] For SO_2, refined coal appears to produce somewhat larger reductions of 10 percent; however, this reduction is not significantly different from zero, and we can also reject that it achieves the 40 percent reduction target. For Hg, the impact of refined coal is a statistically insignificant 2.9 percent reduction. This finding accords with engineering information that Hg reductions should only be expected for plants with Hg reduction technology. This is because the chemical process by which refined coal is meant to work is by oxidizing the Hg to allow it to be better captured by these technologies.

The estimates using the full sample are generally similar to those using only the 78 boilers that burned both refined coal and regular coal in the 2016-2018 window. When using this restricted sample, the reductions are slightly larger for NO_x (both controlled and uncontrolled) and Hg (controlled only). Without controls, the reductions for Hg remain negligible. The SO_2 reductions with controls are very similar, but without controls the reduction disappears and we actually estimate that SO_2 emissions are larger for refined coal. All estimates retain their previous significance levels except for whether the NO_x reductions with controls achieve the 20 percent reduction target. We can no longer reject that the 20 percent reduction NO_x target is achieved ($p = 0.25$). However, we can still reject that the 40 percent reduction targets for SO_2 and Hg are achieved ($p<0.001$ for SO_2 and $p = 0.048$ for Hg). Since the law requires reductions on not only NO_x but also SO_2 or Hg, we can therefore

[18] That plant is currently being acquired by a new owner that has announced "operational changes to reduce coal use by more than 50 percent initially" (The Southwest Times Record 2019, "OG&E buying Shady Point power plant", January 2019).

still reject that the program is, on average, achieving the statutorily required targets.

We can test this more directly by considering the joint hypothesis that the NO_x targets and one of the SO_2 or Hg targets is being achieved. Since this is a nonstandard statistical test, we assess it by calculating the share of the draws in the joint bootstrapped distribution achieving those targets.[19] Since we have separately estimated reductions with and without emissions control equipment for NO_x, SO_2, and Hg, there are different possible combinations of reductions to test (e.g., with all three pollutants controlled, with NO_x and SO_2 controlled but Hg uncontrolled, etc.). For completeness, we test each possible combination, both for the regression results using all boilers and for the results using only dual coal boilers.

The results are shown in tables 3 and 4. Those tables show the share of bootstrapped parameter distributions under which the targeted reductions are achieved, alongside the point estimate for the emissions reductions for reference. In all cases, we can reject, at the 95 percent confidence level or better (and typically at the 99 percent level), that the targets are achieved. The primary reason for the variation across cases is whether the Hg targets are achieved. In the 1,000 bootstrap draws, the SO_2 target is never achieved, so compliance requires achieving 40 percent reductions in Hg. When Hg is controlled, only 1.8 percent and 4.8 percent (for the full and restricted samples, respectively) of the bootstrapped draws achieve the 40 percent reduction target. This alone places an upper bound on the share in compliance with the statute, which also requires achieving the NO_x target.

The emissions control equipment scenario under which compliance with the statute (i.e., 4.8 percent in the bottom-left cells in Table 4) is most likely is (1) based on the regression results that use only the sample of dual coal boilers, (2) requires that Hg control equipment is installed (38 percent of the sample), and (3) NO_x is uncontrolled (4 percent of the sample). Only three plants in the country have Hg controls but not NO_x controls, and none burned refined coal in the sample window. This provides further evidence that the program is not achieving the targets required by the statute.

4.3 Boiler Level Regressions

For further evidence, we estimate emissions reductions at the boiler level, where possible. Whereas the preceding results show average emissions rates, it is possible that these averages mask heterogeneous effects whereby some plants achieve the targeted reductions whereas others do not.

[19] This corresponds to a null hypothesis under which the parameters comply with the rules for eligibility criteria in the tax law. That is:

$$H_0 : \{\beta_{RC}^{NO_x} < (1-20\%)\beta_C^{NO_x}\} \textbf{ AND } \{\beta_{RC}^{SO_2} < (1-40\%)\beta_C^{SO_2} \textbf{ OR } \beta_{RC}^{Hg} < (1-40\%)\beta_C^{Hg}\}$$

Table 3: P-values for Joint Tests of Meeting IRS Requirements, based on Bootstrapped Distribution of Parameters from Regression of All Boilers

SO_2 Controlled (Estimated Reduction (-): -2.3%)

			Hg	
			Controlled	Uncontrolled
		Estimated Reduction	-24.1%	-2.9%
NO_x	Controlled	-12.5%	0.001	<0.001
	Uncontrolled	-59.9%	0.018	<0.001

SO_2 Uncontrolled (Estimated Reduction (-): -10.4%)

			Hg	
			Controlled	Uncontrolled
		Estimated Reduction	-24.1%	-2.9%
NO_x	Controlled	-12.5%	0.001	<0.001
	Uncontrolled	-59.9%	0.018	<0.001

Table 4: P-values for Joint Tests of Meeting IRS Requirements, based on Bootstrapped Distribution of Parameters from Regression of Boilers Burning Both Coal Types

SO_2 Controlled (Estimated Reduction (-): -2.7%)

			Hg	
			Controlled	Uncontrolled
		Estimated Reduction	-28.2%	-2.4%
NO_x	Controlled	-15.5%	0.011	<0.001
	Uncontrolled	-65.4%	0.048	<0.001

SO_2 Uncontrolled (Estimated Reduction (-): +24.4%)

			Hg	
			Controlled	Uncontrolled
		Estimated Reduction	-28.2%	-2.4%
NO_x	Controlled	-15.5%	0.011	<0.001
	Uncontrolled	-65.4%	0.048	<0.001

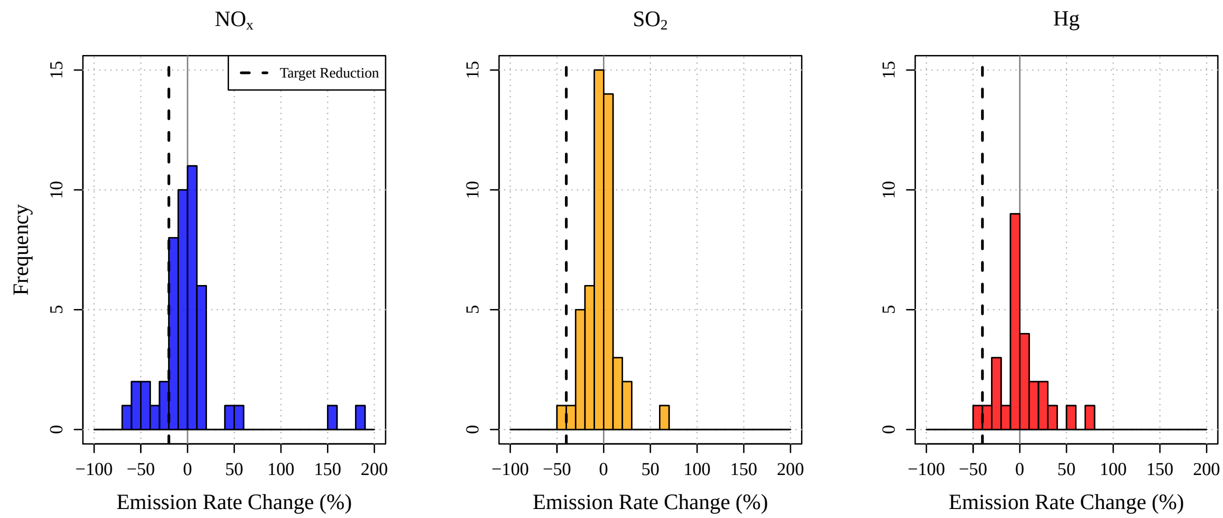

Figure 8: Histograms of Estimated Emission Rate Reductions for Boilers with Sufficient Data

Source: Authors' calculations based on EPA CEMS and emissions controls data, and EIA Form 923 data.

To address this possibility, we re-estimate our model at the boiler level where there is enough identifying variation to do so. This is possible for the majority of the "dual coal" boilers. It is not possible for all boilers because it requires observing a given boiler both before and after switching from regular to refined coal (or vice versa), and under identical emissions control conditions. We have sufficient variation in the data to estimate potential reductions from refined coal for 47 boilers for NO_x, 48 boilers for SO_2, and 26 boilers for Hg.[20]

Histograms of these reductions are shown in Figure 8 (negative changes indicate reductions, positive ones indicate increases). Less than a fifth of these boilers is estimated to achieve the required NO_x reductions. Only one boiler achieved the reductions in SO_2 (but it did not achieve the Hg or NO_x reductions), and another achieved the reductions in Hg (but not the SO_2 or NO_x reductions). As a result, none of these boilers is estimated to achieve the reductions required by the tax law. Quite a few estimates even suggest an increase in emissions from refined coal use. In summary, we find no evidence that any single plant is

[20]This is out of 78 boilers that burned both refined and unrefined coal during the 2016-2018 sample period. We cannot reliably estimate NO_x or SO_2 reductions for about 30 of the boilers because of insufficient variation, primarily due to insufficient variation in one of the types of coal. The boilers excluded are either (1) boilers with a negative estimated coal emissions rate, (2) boilers with a coal emissions rate that is statistically indistinguishable from zero (usually due to insufficient observations), or (3) boilers with extremely limited observed coal use of one type or the other leading to extreme estimates well outside of their observed historical ranges. The number of identified boilers on Hg is smaller than for the other pollutants because there is less available data on Hg emissions due to the relative recency of reporting requirements for Hg.

achieving the required reductions in practice. However, as already noted, we do not have sufficient data to estimate these reductions for every plant in the country.

4.4 Reasons Why Plants Might Not Achieve Emissions Reductions

Why might plants not be achieving the 20 percent and 40 percent reductions in emissions rates that the law requires? While we do not know how policymakers chose these particular targets when devising the legislation, we can speculate as to potential reasons that plants might be falling short.

First, while the mechanism for the Hg reductions is well understood based on conversations with engineers (it oxidizes the Hg, making it easier to capture), it is not obvious why this would reduce NO_x or SO_2 emissions at all. This aligns well with our finding of negligible SO_2 reductions, but we do estimate modest NO_x reductions. The mechanism behind this reduction is not clear.

A second possibility is that refined coal does reduce emissions, but plants systematically dial back or even shut down other emissions control technologies. For example, plants can save money by reducing the amount of ammonia injected to a SCR, although the low NO_x allowance prices (which reflect the marginal cost of abatement)in recent years suggest that marginal costs are low. Based on conversations with industry and EPA experts, some plants have indeed reduced their use of pollution controls when the NO_x allowance caps became non-binding. While there is no engineering reason why this behavior might be correlated with refined coal use, if plants are indeed reducing the use of pollution control technology due to the refined coal tax credit, then the credit is creating perverse incentives and undermining the stated purpose of the tax credit. If this behavior is occurring, our estimates would include this effect and hence be more relevant to the economic question discussed in section 3.3 concerning economic welfare. In appendix section A, we test whether refined coal use is associated with reduced utilization of variable-control NO_x technology, finding a modest and statistically insignificant reduction.

A final possibility is that firms switch to dirtier coal when they begin refining it. This would similarly undermine the goals of the tax credit. In appendix section B, we examine whether the use of refined coal is associated with changes in its coal's ash, sulfur, or mercury content. For the four illustrative plants discussed in section 3, we observe no major changes in coal characteristics after the switch to refined coal. For sulfur, we use sulfur content data to re-run the SO_2 component of the main analysis effectively weighted by sulfur content, finding that our SO_x results are robust to this concern. Unfortunately, the data on coal mercury content is generally unavailable except for a relatively small group of self-selected plants, precluding an analogous analysis for mercury emissions. But we do observe mercury content for plant 1 (in Figure 4), which is the plant that saw increased mercury emissions after switching to refined coal. This plant saw no substantial change in its mercury content, indicating that its emissions changes cannot be explained by a change in coal type.

4.5 Policy Evaluation and Cost-Benefit Analysis

While our econometric analysis strongly suggests that the subsidy to refined coal plants is failing to generate the requisite NO_x and SO_2, or Hg emissions reductions, it may still be the case that the legislation passes a cost-benefit test (CBT) from either or both of two perspectives: (1) based on the actual pollution reductions, or (2) based on the larger pollution reduction targets in the legislation. Therefore, we estimate these benefits and compare them to the social costs of the subsidy, which we estimate to be about $7 per ton (including private refining costs and the excess burden of taxation).

Failing a CBT based on both actual pollution reductions (1) and the larger reductions required by law (2) is evidence for repealing (or not renewing) the credit, since keeping the law would reduce social welfare even if firms were in compliance. Failing a CBT based on actual reductions (1) but nonetheless passing one based on the larger required reductions (2) implies that social welfare is higher with the legislation than without—as long as targeted emissions reductions are in fact met in the field. This implies that a change (rather than repeal) in the law is needed: dropping laboratory testing for demonstrating compliance and replace it with sophisticated field testing.

Because we observe the subsidy and the plants using the refined coal, the cost-benefit analyses are retrospective (as opposed to the prospective cost-benefit analysis performed in a federal government Regulatory Impact Analysis [RIA]). We compare the benefits in 2017 with the total costs, including the private refining costs and the excess burden of taxation (i.e., the economic inefficiency caused by the government raising funds to pay for the subsidy)

4.5.1 Benefits

The immediate impacts of using refined coal are the emissions reductions for the plants using this coal, which ultimately leads to health and environmental improvements. When these improvements are monetized, they are termed benefits.

To be specific about our benefits analysis, we discuss the potential benefit pathways and those we actually model. Pollutants from a power plant are emitted from a tall stack where they then disperse and transform in the air—in particular, the NO_x emissions convert to PM2.5 and ozone under the appropriate conditions, and the SO_2 converts to PM2.5. The unconverted NO_x and SO_2, as well as the PM2.5, ozone, and Hg emissions, all cause physical impacts, depending on the populations and sensitive environmental resources being affected. Typically, the largest monetary benefits from air pollution control are those to human health, particularly to reducing human mortality. PM2.5 reductions have the largest marginal impacts on mortality risks of any of the affected pollutants. And the monetary values typically used in emissions control cost-benefit analysis (i.e., an RIA when performed by the federal government) are far larger for mortality risk reductions than for any other impact category. While a number of impact pathways are ignored in this analysis, as noted, we capture the main ones.

Our analysis makes use of the COBRA model,[21] an EPA-approved benefits model at the county level, which incorporates source-receptor matrices, pollutant transformation functions, demographics, and a variety of concentration-health response functions. We focus on the adult mortality risk reductions from PM2.5 reductions attributable to reductions in NO_x and SO_2 emissions. We use the model to estimate the benefits in 2017 by calculating how emissions at plants burning refined coal would differ had they not achieved the reductions that we estimate. That is, we adjust actual 2017 emissions from refined coal plants according to the estimated reductions in Table 2 (columns 1-2).[22] We then calculate benefits as the difference in mortality at actual emissions levels and at the (higher) emissions levels without refined coal. As a sensitivity, we re-run this analysis using the boiler-level estimated reductions where possible. Finally, we estimate the benefits that would be achieved if the legislative targets were met.

We emphasize that our estimates likely overstate the actual benefits attributable to the refined coal tax credit for several reasons. First, we assume that the same amount of coal (in mmbtu) would be burned in absence of the refined coal tax credit, although at a different emissions rate (lbs/mmbtu). In reality, the tax credit may have increased the amount of coal burned because it reduced the marginal cost of burning coal, leading coal plants to be operated more often. For example, for a typical coal plant burning coal with a heat content of 20 mmbtu/ton at a heat rate of 10 mmbtu/MWh, a $7 per ton tax credit effectively reduces after-tax operating costs by $3.50/MWh.[23] This is a large cost reduction, for example, for plants burning cheap, low-quality coal such as lignite, which sells for $20 per ton, on

[21]Details on the COBRA model can be found at https://www.epa.gov/statelocalenergy/co-benefits-risk-assessment-cobra-health-impacts-screening-and-mapping-tool.

[22]For example, for a plant with NO_x controls that burned entirely refined coal in 2017, we adjust NO_x emissions upwards by factor of 1/(1 - 12.5%)=1.14. For plants that burned a mix of fuels in 2017, the calculation is slightly more complicated to account for the fact that observed 2017 emissions derive from both refined coal and other fuels.

[23]$3.50/MWh=$7/ton · (10 mmbtu/MWh)/(20 mmbtu/ton).

average.[24] While these estimates do not account for private refining costs, they are roughly indicative of the magnitude of the tax credit relative to fuel costs, which could increase the amount of coal burned.

The revenue from the tax credit may have an effect on the extensive margin as well, with the flow of revenues preventing the retirement of otherwise unprofitable plants. Both of these factors are ways in which the refined coal tax credit can increase total emissions by increasing the amount of coal burned, even if the coal has somewhat lower emissions per ton burned.

The second reason why our estimates may overstate the benefits of refined coal has to do with how NO_x and SO_2 emissions are regulated. Both pollutants are covered to varying degrees by emissions trading (i.e., cap-and-trade) programs: the Acid Rain Program and Cross-State Air Pollution Rule. To the extent that refined coal reduces emissions at regulated plants, this frees up emissions permits that can be sold to another plant. Some caps have been binding in recent years (i.e., summertime seasonal NO_x), whereas others have not been binding. Any emission reductions covered by a binding cap would be offset one-for-one by emission increases at other covered plants. This implies that reductions attributable to refined coal at some plants may simply redistribute the location of emissions, rather than reducing emissions overall. Thus, even if the reductions were large enough to earn a tax credit, the credit would be serving no socially beneficial purpose.

On the other hand, NO_x allowance prices have been very close to zero in recent years, except in the summer when seasonal allowances have been clearing at substantially positive prices. Further, SO_2 caps have generally been non-binding in recent years.[25] This suggests that the cap may not always be binding. Overall, to the extent emissions caps are binding, our estimates of the benefits of refined coal represent an upper bound of the true benefits. Another reason we may be overstating the impacts of the refined coal tax credit is the influence of other regulations on the choice whether to refine coal. We assume that no firm would burn refined coal in the absence of the tax credit; but some firms might continue to burn it to comply with other regulations, such as the MATS rule regulating Hg emissions. Hence, repealing the credit may have a smaller impact on refined coal use than we assume (and hence the credit would be responsible for less in benefits than we assume).

One factor goes in the other direction: we focus only on the PM2.5 adult mortality benefits from reduced NO_x and SO_2 emissions. While this captures approximately 90 percent of the benefits of reducing PM2.5 based on results in many RIAs, it does not consider the

[24] See, for example, https://www.eia.gov/energyexplained/index.php?page=coal_prices.

[25] For example, the 2018 SO_2 auction clearing price was \$0.06/ton, down from \$0.11/ton in 2015, which in turn was down from \$36/ton in 2010, which in turn was lower than \$690/ton in 2005. See https://www.epa.gov/airmarkets/so2-allowance-auctions.

benefits from reduced ozone formation and Hg emissions (the estimated benefits of the latter being particularly small in the MATS rule RIA).[26]

Finally, there is one other small potential benefit. While we have not found evidence that plant operators are reducing the use of SCR/SNCR/ammonia injection for NO_x control (see appendix section A), if that is indeed happening there are avoided marginal abatement costs, primarily from reduced reagent costs. While reagent costs are private information and hence unavailable, marginal abatement costs are identified by the market price of NO_x emission allowances. These allowance prices are very low, implying an upper bound on marginal abatement costs of $0.10 per ton of refined coal on average (see appendix C for the computation of this estimate). Since these speculative savings are nonetheless negligible relative to the other costs and benefits of the credit, we can safely ignore them.

We report our results for several runs. For test (1) above, we compute the benefits from refined coal use using our estimated reductions for NO_x and SO_2 emissions relative to the actual emissions. For test (2) we compute the benefits from refined coal use under the assumption that all plants successfully meet the legislative emission reduction targets for NO_x and SO_2, relative to the counterfactual of no refined coal use.

For the latter test, we are effectively assuming that firms comply using the SO_2 rather than the Hg emissions target. In contrast, the predominate reason for using refined coal is to reduce Hg emissions, according to literature referenced in this paper (e.g., Young et al. 2016) and conversations with industry participants. However, as noted above, the quantifiable Hg effects on health and the monetary value of these effects are very small compared to the effects of reduced SO_2 emissions and their conversion to fine particles. Thus, our approach of assuming larger benefits from SO_2 reductions greatly overstates the quantifiable benefits of refined coal in this scenario. Accordingly, we also show the COBRA model results separated by NO_x and SO_2 emissions, so we can consider the benefits if only NO_x emissions are reduced by 20 percent. This would correspond to a scenario in which plants achieve eligibility using NO_x and Hg reductions, but the Hg reductions are valued at close to zero (as EPA has done in its MATS RIA).

[26] See EPA, "Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards", which estimates quantifiable benefits of only $4-6 million from a 20 ton/year reduction in Hg (3% discount rate, see Tables ES-2 and ES-4). This estimated benefit is dwarfed by $37-90 billion in co-benefits from reductions in other pollutants.

4.5.2 Costs

There are two components of total (i.e., social) costs. The first is the private costs of the technology. Variable costs are low. We estimate[27] that the real economic costs of refining are about \$5 per ton of coal processed. Multiplying by the tons of refined coal processed and burned in 2017 suggests private costs of about \$600 million annually.[28]

The second component of social costs is the excess burden of taxation. This represents the economic inefficiency caused by other taxes used to raise public funds to finance the subsidy. Parry (2002) suggests a typical excess burden of at least 30 percent, suggesting that a conservative estimate of the cost of excess burden is $\$7 \cdot 0.3 = \$2.10$ per ton.

The social cost is the private cost plus the excess burden, or $\$5 + 0.3 \cdot \$7$, which is just about \$7 per ton. Multiplying by the total tons of coal refined in 2017 yields a social cost of about \$900 million annually.

4.5.3 Results

Figure 9 depicts the air quality benefits of using refined coal relative to conventional coal use, under four different assumptions about emissions reductions. The first bar shows the benefits assuming all boilers reduce emissions by the estimates shown in the first three columns of Table 2 (i.e., 12.5 percent NO_x when controlled, 2.3 percent SO_2 when controlled, etc.). We estimate emissions benefits of \$457 million annually (2017\$). Since 122 million tons of refined coal were burned by the plants in our simulation in 2017, this corresponds to benefits of \$3.80 per ton. Most of this benefit comes from SO_2 reductions. If plants comply primarily by reducing NO_x and Hg, the benefits would be a much smaller \$129 million from NO_x, plus a negligible quantifiable benefit from Hg reductions.[29]

[27] According to an industry observer quoted in a Reuters article (Erman 2017), the total costs amount to 60% of the value of the credit of \$7 per ton. That figure includes an adjustment for the benefit of claiming a tax deduction for operating losses arising from operating without pre-tax revenue, which is not a real economic cost. Thus, real economic cost (denoted c) plus the loss from purchasing and reselling coal to the power plant at a discount (denoted d), together after taxes $(1-\tau)$ equals 60% of \$7: $(c+d)(1-\tau) = 0.6 \cdot \$7$. Solving for the real economic cost c yields: $c = (0.6 \cdot \$7)/(1-\tau) - d$. According to another article (McLaughln 2018*c*), the discount ranges "anywhere from 75 cents to \$2 per ton". Using the appopriate historical corporate tax rate of 35 percent and plugging these values in yields estimates of c between \$4.46 and \$5.71 per ton, or about \$5 per ton.

[28] These costs include both variable costs and amortized fixed costs.

[29] Our estimates suggest that refined coal may reduce Hg emissions by 0.06-0.08 tons per year in practice, or 0.46 tons per year if the 40% reductions were actually achieved. These impacts are much smaller than the reductions of 20 tons per year that EPA valued at \$4-6 million in present value (EPA, "Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards", Tables ES-2 and ES-4). Therefore, adding in the benefits of Hg reductions is unlikely to change our results very much. That said, EPA was unable to quantify all the benefits of Hg reductions.

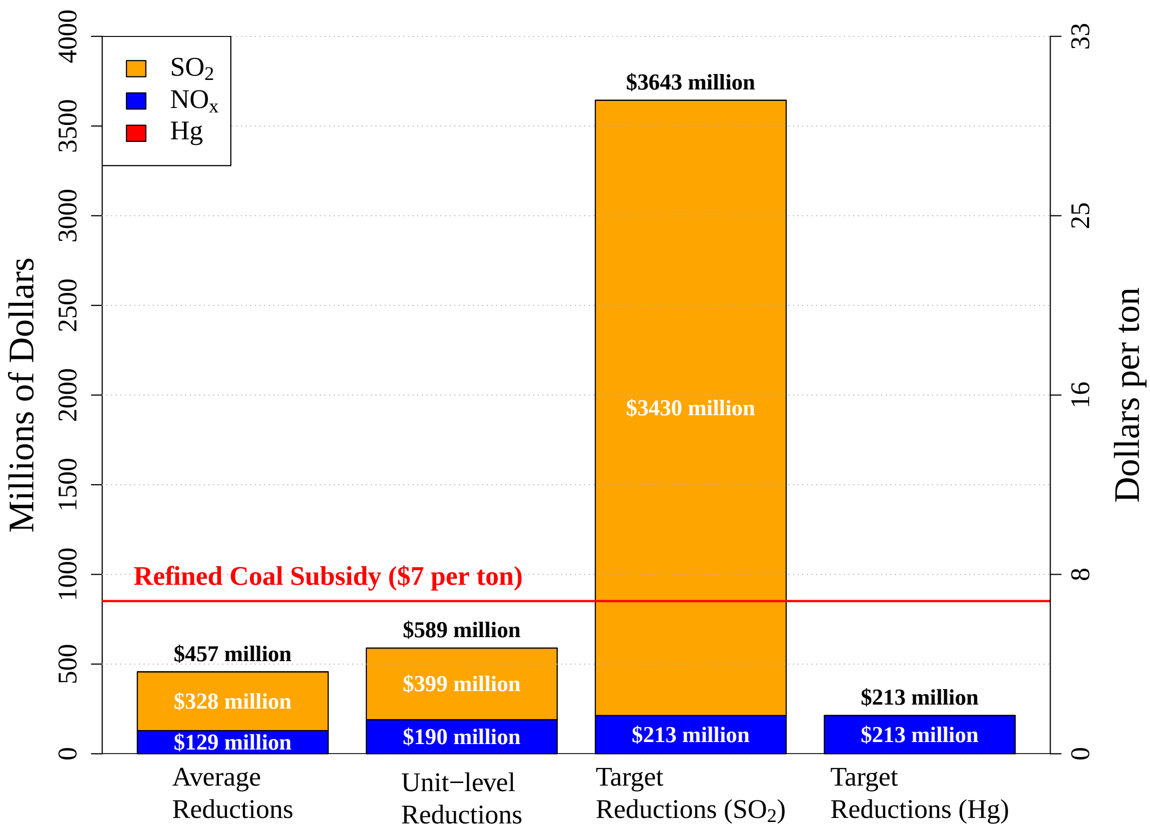

Figure 9: Environmental Benefits ($2017) under Different Emissions Reductions Scenarios

Source: Authors' calculations based on EPA CEMS and emissions controls data, EIA Form 923, and EPA COBRA model.

The estimates are similar if we use plant-level emission reductions where possible (i.e., the reductions shown in Figure 8): $589 million annually, or $4.80 per ton. In both cases, the estimated benefits are below the social costs of burning refined coal, as well as below the subsidy value of $7 per ton. In the final case, we estimate what the benefits would be if all plants were achieving the targets required by the tax statute (20 percent reduction in NO_x and 40 percent reduction in SO_2).

If the NO_x and SO_2 targets were achieved, we find benefits of more than $3.6 billion annually ($30 per ton), which greatly exceeds the subsidy value. This suggests that the policy could be beneficial if the NO_x and SO_2 targets were actually being met and were incremental to reductions currently occurring from pollution control equipment. However, the vast majority (94 percent) of the benefits arise from SO_2 reductions, which our estimates suggest are not actually arising in practice (see Table 2).

Put differently, had NO_x and SO_2 emission rates actually fallen by 20 percent and 40 percent to qualify for the subsidy, benefits of more than $3 billion annually would have been realized, reflecting the monetized value of 340 reduced premature deaths each year.

However, based on conversations with industry participants, achieving such SO_2 large reductions with refined coal is unrealistic, which explains why most companies aim to comply by achieving the 40 percent reductions in mercury. The fourth bar in Figure 9 shows the benefits under this scenario (assuming 20 percent reductions in NO_x and 40 percent reductions in mercury). The benefits are again well short of the costs, reflecting $213 million ($1.80 per ton) in benefits from NO_x and negligible quantifiable benefits from mercury.

Figure 10 shows the geographic distribution of the benefits of improved air quality under the "average reductions" scenario (note: the color shading is in logarithmic scale to better illustrate county-to-county variation). The benefits are generally concentrated in and around large Midwestern cities such as Chicago, Detroit, Columbus, and Cleveland. Other cities further east also benefit from reduced concentrations (in particular, Pittsburgh, Buffalo, and Rochester), since they are affected by Midwestern emissions due to predominant winds that blow from west to east. Corresponding maps for the other scenarios look qualitatively similar and are shown in the appendix.

Figure 11 shows the same benefits normalized by county-level population. This illustrates that the positive impacts are similar on a per-capita basis, and the clustering of benefits in cities is the natural result of a larger number of households exposed to lower concentrations in cities. The benefits for the median county are $2.46 per capita, but a small number of counties are particularly impacted (primarily counties with multiple nearby plants burning refined coal), while a large number of distant counties experience minimal impacts.

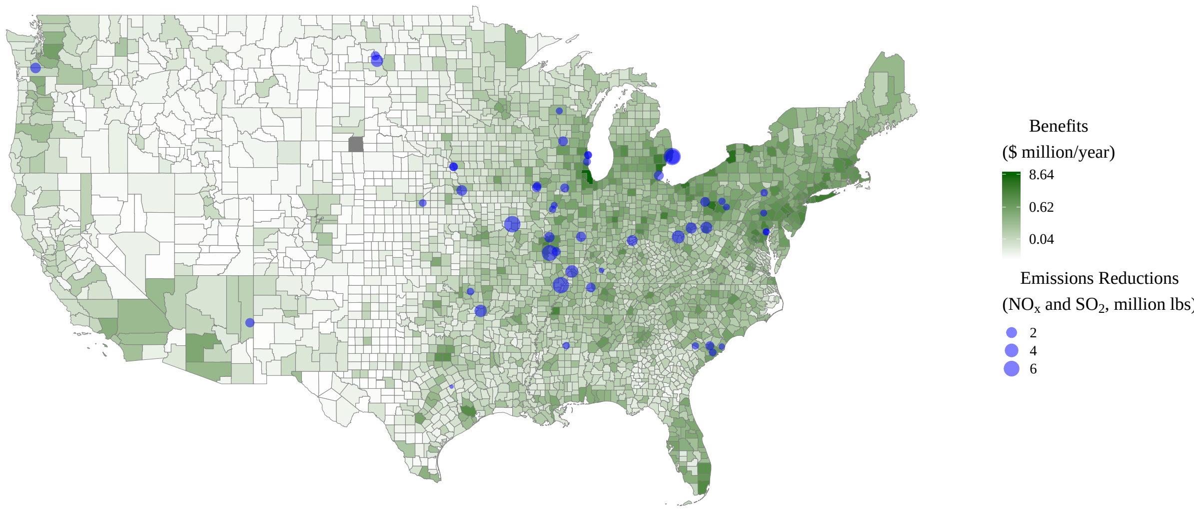

Figure 10: Distribution of Air Quality Benefits (millions of dollars, \$2017) from SO_2 and NO_x, under the "Average Reductions" Scenario

Source: Authors' calculations based on EPA CEMS and emissions controls data, EIA Form 923, and EPA COBRA model.

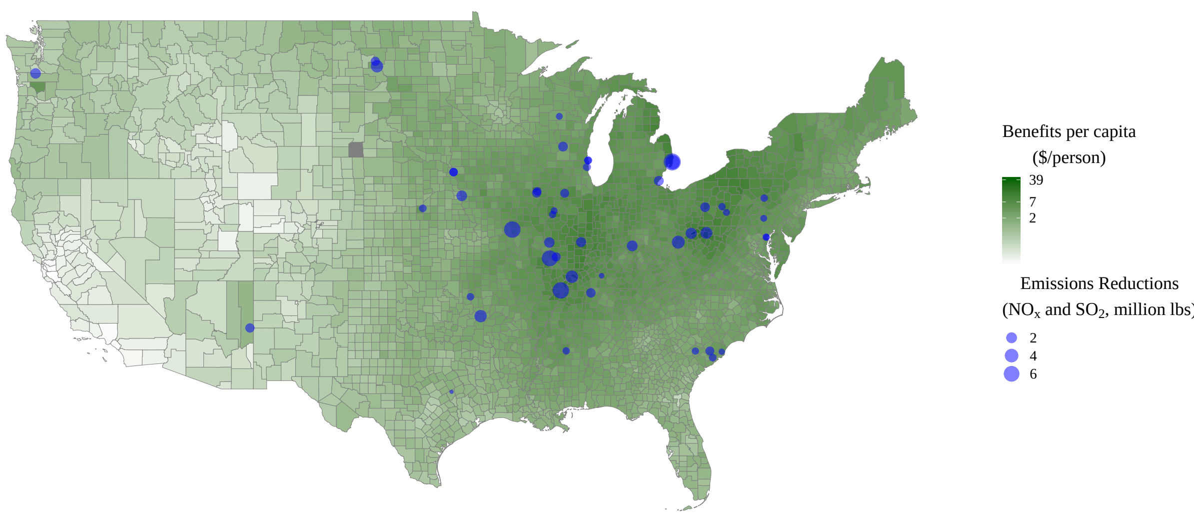

Figure 11: Distribution of Air Quality Benefits (dollars per capita, \$2017) from SO_2 and NO_x, under the "Average Reductions" Scenario

Source: Authors' calculations based on EPA CEMS and emissions controls data, EIA Form 923, and EPA COBRA model.

5 Conclusion

Using a dataset covering more than 90 percent of coal in the US power sector, we find that the emissions reductions from refined coal achieved in the field fall short of the targets for tax credit eligibility, suggesting that companies claiming it may not be in compliance with the tax law.

While the tax law requires 20 percent reductions in NO_x emissions per mmbtu and 40 percent reductions in SO_2 or Hg emissions per mmbtu, these reductions are typically verified using lab tests, as opposed to actual operational outcomes. Using data on actual operations, we find that in practice plants achieve negligible reductions in SO_2 emissions, and the reductions in NO_x and Hg amount to about half (or less) of the reductions required. We find no evidence that any particular plant is achieving the reduction targets stated in the tax law, and significant evidence that on average they are not.

Our results suggest that the credit, which comes up for an extension in 2021, is economically inefficient and from a social welfare perspective should be changed or eliminated. A cost-benefit analysis confirms that the benefits of the small observed reductions do not justify their costs. The credit could be improved by basing eligibility on actual operational data (as opposed to lab tests), so that the credits are only granted to plants that can prove that they are actually achieving, in practice, the reductions required by law. However, even with this improvement, and even if firms actually achieved the 20 percent and 40 percent required reductions, the policy would still fail a cost-benefit test if firms comply on mercury emissions, as they commonly do, and if the benefits of mercury are sufficiently small, as EPA estimates.

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A Robustness Check: Use of NO_x Control Technology Is Unchanged

One possible reason for insufficient decline in NO_x emission rates is that firms compensate by reducing the use of other emissions control technology that can be variably controlled. NO_x control technologies generally fall into two categories: (i) "always on" controls that reduce the formation of NO_x during combustion in the boiler and (ii) variable controls that reduce post-combustion emissions of NO_x selective catalytic (or non-catalytic) reduction (SCR or SNCR).

The first type, which includes overfired air and low NO_x burners, are typically always active once they are installed. Hence, operators do not realistically have the ability to dial these control technologies down, meaning there is no feasible response on this margin.

However, the second type of technology, SCR and SNCR, and their associated ammonia injection, do allow for variable control. Plant operators can simply turn these technologies off or they can reduce reagent injections (primarily ammonia), thereby capturing less NO_x and increasing emissions. Doing so can save operating costs associated with running the equipment; on the other hand, some plants may be required by rules to run their equipment at constant rates, shutting off this potential response.

While we do not observe the amount of ammonia injected, we do observe in EIA Form 923 the number of hours that SCR, SNCR, and ammonia injection devices are used. While the data are collected only annually (as opposed to the monthly data for fuel consumption) they can provide some insight into whether plant operators turn off their NO_x controls, and most importantly whether such actions are correlated with the use of refined coal. If the use of refined coal is associated with reduced utilization of NO_x control technology, this could mask a true reduction associated with refined coal use. Importantly, while such an association would confound identification of the emissions impact of refined coal *holding operational conditions constant*, it would not threaten the identification of the complete impacts of refined coal use (direct effect + indirect effect on NO_x control use). The identification of the former might be relevant for determining compliance with the legal requirements of the tax credit based on IRS regulations (which holds constant operational conditions not "directly attributable to changing" to refined coal), whereas the identification of the latter is relevant for determining the welfare impact of the refined coal tax credit.

A.1 NO_x Control Usage at Illustrative Plants

Figure A.1 shows the fraction of hours each year that NO_x controls are in use for each of the four illustrative plants. Recall from Figures 4-7 that these plants switched to refined coal in late 2016 or early 2017, so one should compare 2016 to subsequent years. Hence, a decline in NO_x use after 2016 would indicate that refined coal use coincided with reduced use of NO_x controls, which would imply our main analysis understates the reductions directly attributable to refined coal. On the contrary, we generally see flat or rising SCR use. For plant 1, NO_x control use is somewhat higher in 2017-8 (refined coal) compared to 2016 (unrefined coal). Plant 2 did not have SCR/SNCR/ammonia injection installed in 2016-7, so there was no opportunity to reduce its use. Plant 3 saw a small decline, but this was a plant that did actually appear to achieve the 20% reductions (-23%). Plant 4 lacks data for 2016, but it reported not using NO_x controls in 2017 (when it switched to refined coal) but then began to use it in 2018 (also refined coal). This means the plant's observed decline in emissions is partially explained by higher utilization of NO_x controls, and not by refined coal.

In summary, there is no obvious general decrease in the use of NO_x controls for our four illustrative plants. Three of the four saw increases in NO_x use after switching to refined coal. One saw decreases in the use of NO_x controls, but oddly this is one of the plants that appeared to achieve the required reductions anyway. In the next subsection, we use these data for the broader sample of all plants with variable NO_x control technology to estimate if there are any systematic differences in the use of these control technologies when plants use refined coal.

A.2 NO_x Control Usage Regressions

To extend the plant-specific analysis of NO_x control use in the previous subsection to the full sample of plants with variable-control NO_x technologies, we estimate a regression that relates the use of NO_x controls to the number of plant operating hours, weighted by fuel consumption by type. In particular, we run the following regression:

$$ControlHours_{iy} = \chi_i + \gamma^{RC} BoilerHours_{iy}^{RC} + \gamma^{URC} BoilerHours_{iy}^{URC} + \gamma^{Oth} BoilerHours_{iy}^{Oth} + \epsilon_{iy}$$

where $ControlHours_{iy}$ is the number of hours in year y that boiler i's NO_x SCR/SNCR/ammonia injection device was active.[30] $BoilerHours^{RC}$ is the number of hours the boiler was operated,

[30]Naturally, only boilers using SCR, SNCR, and/or ammonia injection controls were included, which accounts for about 60% of boilers; the remaining boilers generally use "always on" control technologies like low NO_x burners. A very small number have no NO_x control technology installed. The majority (83%)

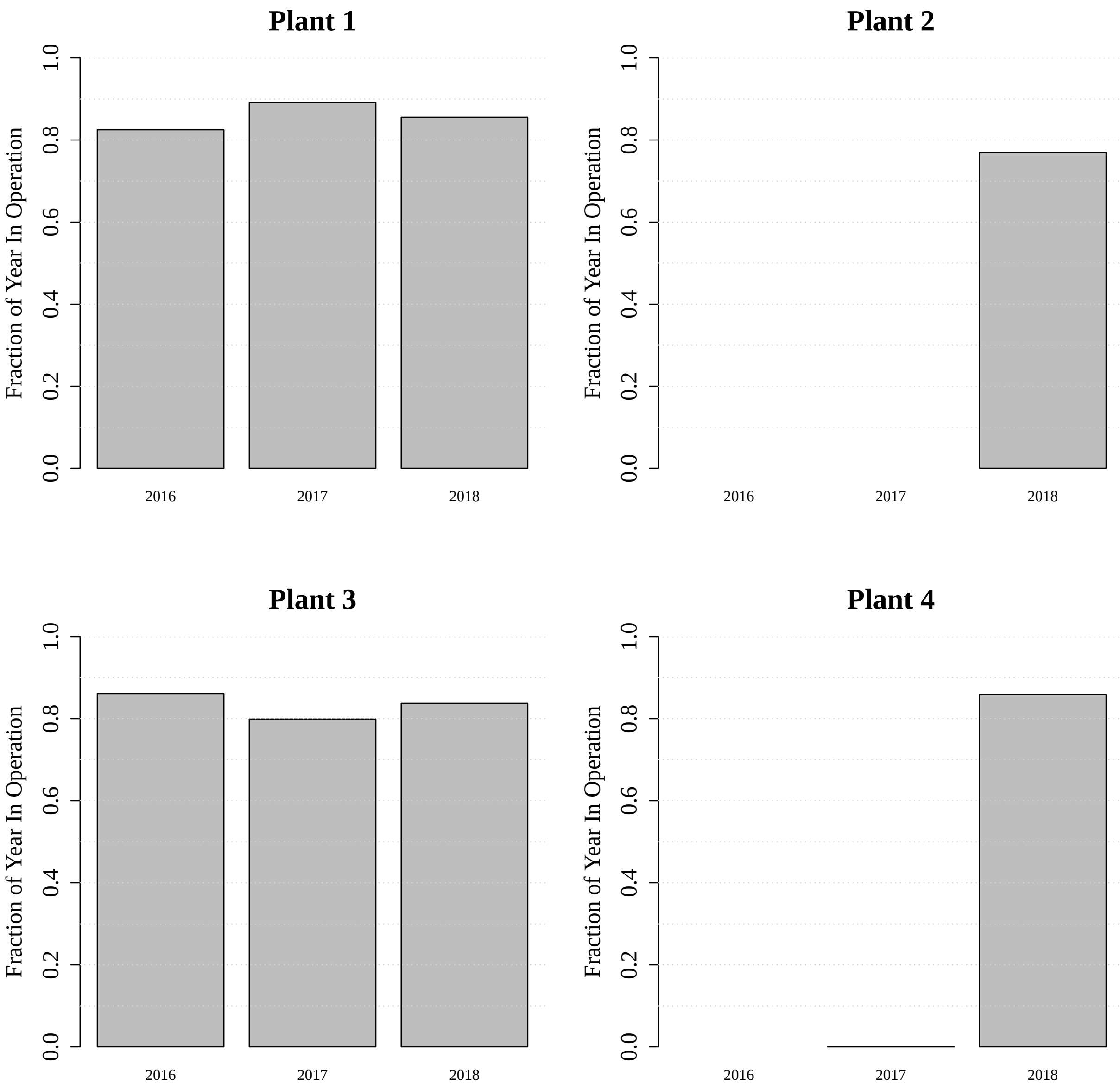

Figure A.1: Variable NO_x Control Use (SCR/SNCR/Ammonia Injection) for Plants 1-4

Source: Authors' calculations based on EIA Forms 860 and 923 data. Note: all four plants switched to refined coal in late 2016 or early 2017. See Figures 4-7. For plant 2, SCR was installed in 2018, so no earlier data exist, but they are effectively zero given the lack of installed technology. Plant 4 did not report control hours for 2016 and reported zero hours in 2017. Hours are averaged across boilers to the plant level.

multiplied by refined coal's (RC's) share of fuel burned (in mmbtu) during those hours.[31] $BoilerHours^{URC}$ and $BoilerHours^{Oth}$ are defined similarly for unrefined coal (URC) and other (Oth) fuels. Hence, the three terms sum to the number of operating hours. χ_i is a boiler fixed effect, although the results are similar without it.

The parameters of interest are γ^{RC} and γ^{URC}. γ^{RC} represents the expected additional number of hours of NO_x controls for each additional hour of burning 100% refined coal. If this is smaller than the expected number of hours for unrefined coal, it indicates that refine coal use is associated with lower NO_x control utilization. We run this regression for the full sample, as well as restricted to the "Dual Coal" plants that burned both refined and unrefined coal during the sample window. The results are shown in Table A.1. For the full sample, each extra hour of operation is associated with 0.71 hours (refined coal) and 0.74 (unrefined coal) hours of SCR/SNCR/ammonia injection control technologies. This indicates that about 70% of incremental hours of boiler operations are covered by SCR/SNCR/ammonia injection technologies, but this is about the same for refined and unrefined coal. The difference of about 0.03 is small and insignificant ($p = 0.43$). For "Dual Coal" plants, the difference is a larger 0.075 but is again insignificant ($p = 0.36$).

If one takes this statistically insignificant 7.5 percentage point difference at face value, it could have an effect on NO_x emissions for these plants. However, it represents an upper bound for the effect on average fleet-wide emission rates for four reasons: (i) this sample only reflects the "dual coal" boilers (47 boilers out of the full sample of 639), (ii) this sample only reflects the ∼60% of the sample that have variable control technologies, (iii) a 1% change in SCR/SNCR/ammonia injection use will change emissions by less than 1%, since it is not a perfect capture technology even at 100% utilization, and (iv) emissions rates reflect the combined effect of always-on technologies like low NO_x burners in addition to the effect of SCR/SNCR/ammonia injection, and this effect is only relevant to the latter. Therefore, the 7.5 percentage point reduction for that specification likely overstates average impact.

of included systems report operational hours for only one out of the three devices (SCR, SNCR, ammonia injection). The remaining 17% of systems report hours separately for multiple devices, but in most cases those hours are identical across devices (i.e., reporting an equal number of hours for both for ammonia injection and SCR/SNCR). A very small number of systems (<2%) report a different number of hours for different devices (e.g., for 2016 one system reported 5,980 hours for SCR but only 5,864 hours for ammonia injection, whereas another reported 3,223 hours for SCR but 0 hours for ammonia injection). For these, we take the average reported values across the reported devices. The panel is not perfectly balanced because some boilers retired during the sample and some pollution control systems were built partway through the sample.

[31] I.e., $BoilerHours^{RC}_{iy} = \text{Total Operational Hours}_{iy} \frac{\text{Refined Coal mmbtus}_{iy}}{\text{Total mmbtus}_{iy}}$

Table A.1: Regression of Emissions Control Operational Hours on Fuel-Weighted Boiler Operating Time

	Dependent variable: # of Hours Device In Operation	
	All Boilers	Dual Coal Boilers
Boiler Operating Hours, Weighted by...		
Refined Coal Fuel Share (% of mmbtu)	0.710***	0.806***
	(0.079)	(0.197)
Unrefined Coal Fuel Share (% of mmbtu)	0.736***	0.881***
	(0.062)	(0.186)
Other Fuel Share (% of mmbtu)	0.750***	0.331
	(0.201)	(0.948)
Refined-Unrefined Coefficient Difference	-0.027	-0.075
	(0.055)	(0.058)
R-Squared (projected model)	0.428	0.358
Observations (boiler-years)	1,013	134
Number of boilers	367	47

Note: *p<0.1; **p<0.05; ***p<0.01. All specifications have boiler fixed effects, although the results are similar without them. Standard errors clustered at the boiler level. The dependent variable is the number of hours SCR, SNCR, and/or ammonia injection controls were in operation at each boiler in each year.

B Robustness Check: Coal Characteristics Are Unchanged

Another potential concern with the main analysis is that is does not account for changes in coal characteristics. If a plant operator decides to change coal type at the same time it begins to refine its coal, our estimates would capture both of these effects. For example, perhaps refined coal does in fact reduces SO_2 or mercury emissions, but this is hidden by the firms also switching to coal with higher sulfur or mercury content.[32] In general, we would not expect major sudden changes in coal content because plants purchase coal through multi-year contracts with specific mines, making it difficult for plant operators to quickly shift coal types. Further, IRS rules require claimants of the tax credit to re-run laboratory tests whenever the source or rank of feedstock coal changes, creating another cost to changing coal types. Nonetheless, coal quality can vary for the same mine.

We first examine the four illustrative plants, finding no meaningful changes to coal characteristics around the switch to refined coal. Due to data limitations, we are primarily restricted to examining the ash and sulfur content of the coal. Where possible, we also examine mercury content, although these data are generally unavailable. We then extend this analysis to the larger sample by estimating an analogous regression to the main analysis, but replacing the amount of *coal* burned (in mmbtu) with the amount of *sulfur* burned (in pounds). This purges the estimates of the effects of any changes in sulfur content. Here, we find that the difference in SO_2 emissions rates of refined and unrefined coal is small and insignificant, indicating that changing sulfur content is not confounding our main analysis. Unfortunately, this statistical approach is only feasible for sulfur content, since data on mercury content are generally unavailable.

B.1 Coal Characteristics at Illustrative Plants

Figures A.2-A.5 show data on coal characteristics for each of the four illustrative plants in Figures 4-7. These data come from EIA-923's boiler fuel and fuel receipts datasets, and they represent quantity-weighted averages of fuel content (ash content, sulfur content, and mercury content, all in share by weight). They reveal no obvious changes in coal characteristics after each plant switched to refined coal. Ash content remained largely constant after plants switch, showing no obvious changes in coal type. Plant 1 shows a small uptick in sulfur content in the month following switching to refined coal (bottom left graph), but in the next

[32] This argument is not applicable for NO_x, since the nitrogen originates in the air inside the boiler, and not in the coal itself. Therefore, there is no obvious reason why NO_x emissions would be affected by changing coal characteristics.

month sulfur content fell back to its previous level and remained there for all subsequent months. Plant 2 shows a modest *decline* in its coal's sulfur content after the switch, which rules out the possibility that the persisent $\sim 20\%$ rise in SO_2 emissions rates in Figure 5 could be attributable to higher sulfur coal.

As for mercury content, EIA does not mandate that plants report mercury content, so unfortunately the data are unavailable for the vast majority ($\sim 80\%$) of coal deliveries. It is only available for the relatively few plants that voluntarily choose to measure and report it. According to experts at EIA, the decision to do so is largely driven by regulations and by company policy. In addition, the available data represent mercury content *as delivered*, which is a less precise and appropriate metric than the ash and sulfur data, which represent ash and sulfur content *as burned*.

Fortunately, we do observe mercury content for plant 1, which experienced a large *increase* in mercury emissions rates after switching to refined coal. The mercury content of the coal used at that plant remained fairly constant before and after its switch, indicating that changing coal quality cannot explain the substantial increase in mercury emissions after switching to refined coal. Unfortunately, mercury data are largely unavailable for the other plants, with the exception of plant 2 where the data are only available for the first six months of 2016 (during which period it is reportedly constant). This predates the switch to refined coal, which precludes a before/after comparison.

Plants 3 and 4 show no substantial changes in ash or sulfur content before and after the switch. In particular, there are no rises in sulfur content that could conceptually mask SO_2 reductions attributable to refined coal. Again, mercury data for these plants are unfortunately unavailable.

More specifically, we also reviewed other qualitative aspects of the fuel receipts data, finding no obvious changes of coal source (e.g., supplier or mine name) for these four plants. This is consistent with the existence of multi-year coal contracts, making it unlikely that changing coal suppliers are coinciding with refined coal use.

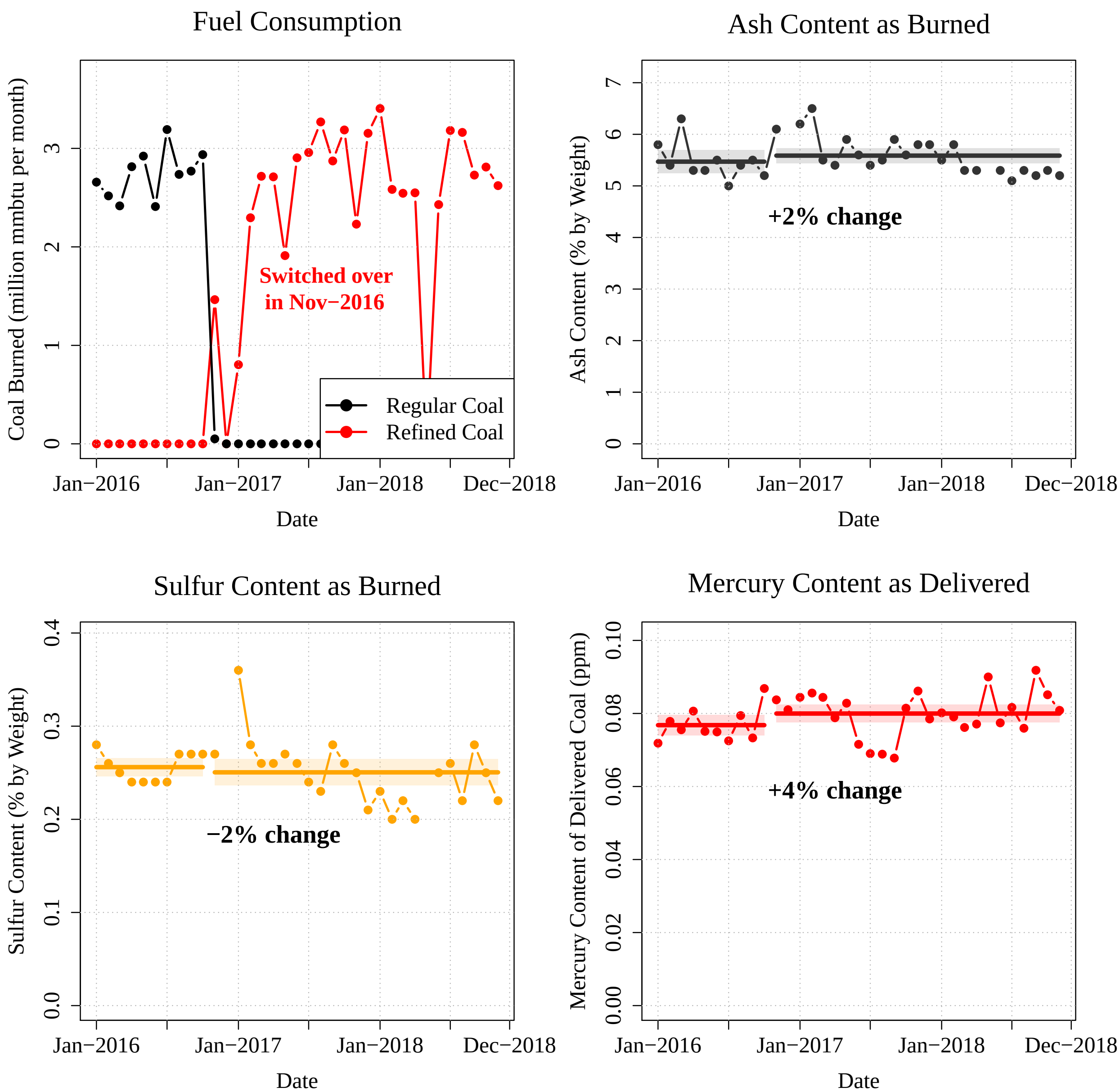

Figure A.2: Coal Characteristics for Plant 1 (in Figure 4)

Source: Authors' calculations based on EIA Form 923 data.

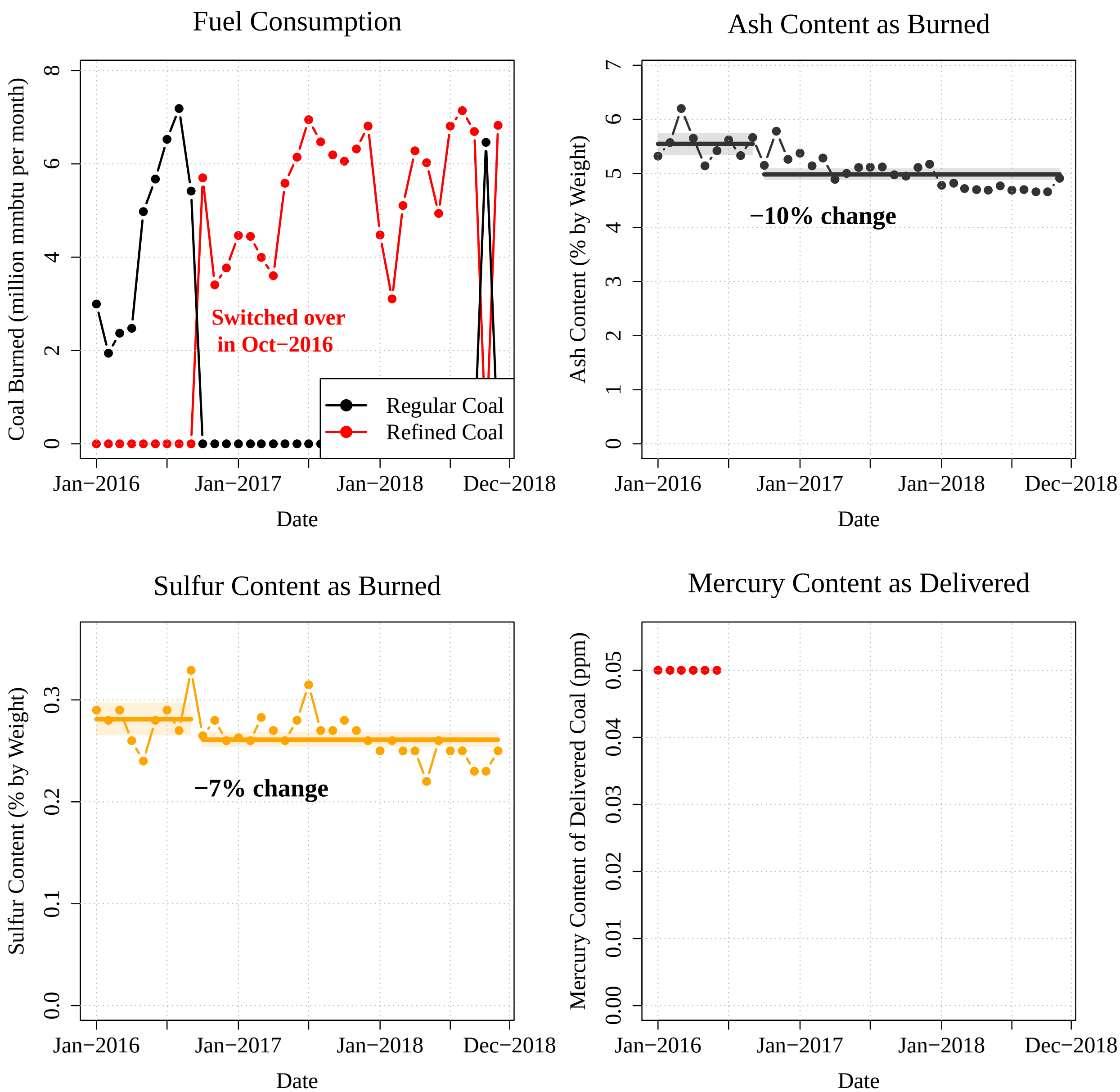

Figure A.3: Coal Characteristics for Plant 2 (in Figure 5)

Source: Authors' calculations based on EIA Form 923 data.

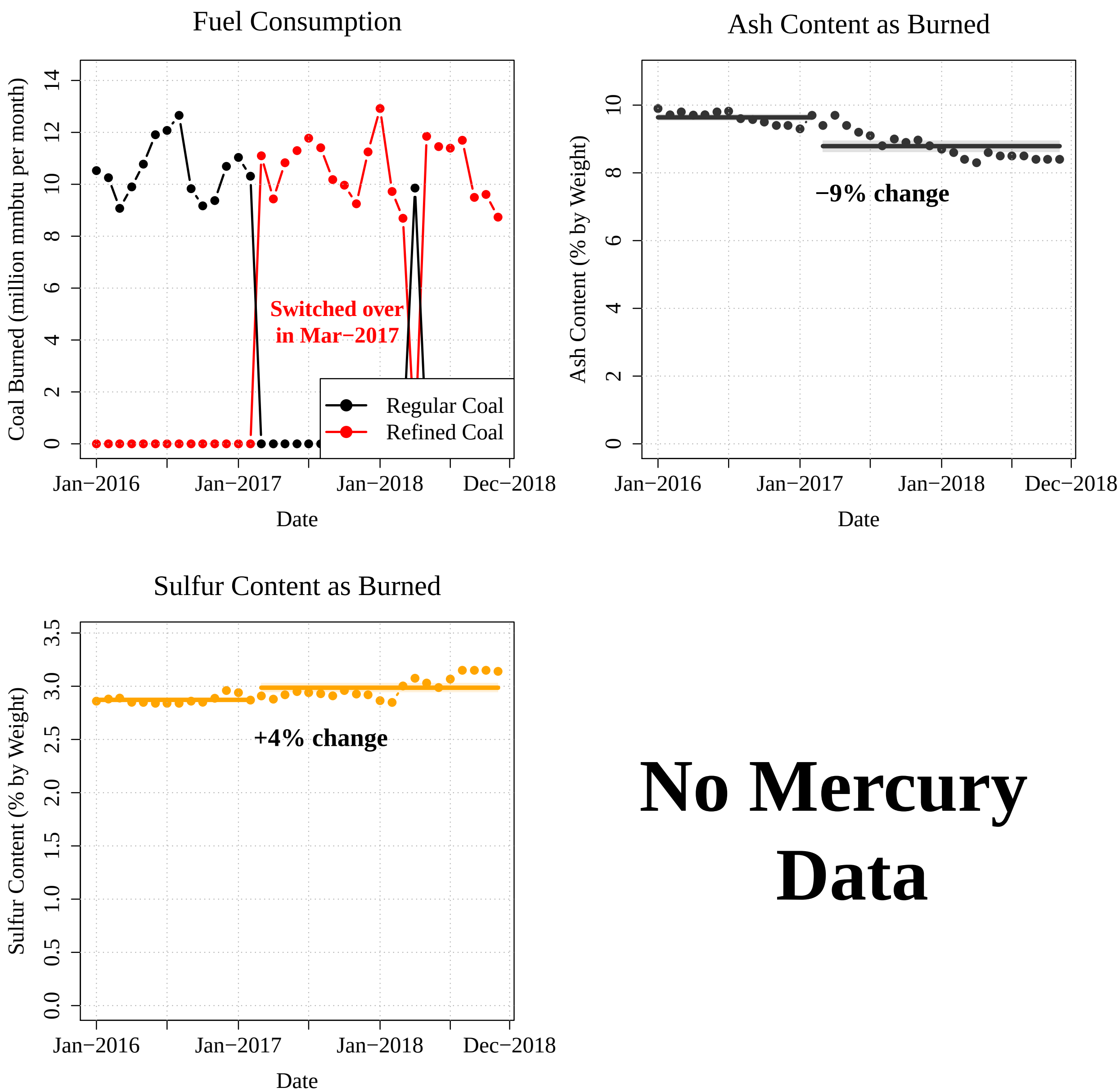

Figure A.4: Coal Characteristics for Plant 3 (in Figure 6)

Source: Authors' calculations based on EIA Form 923 data.

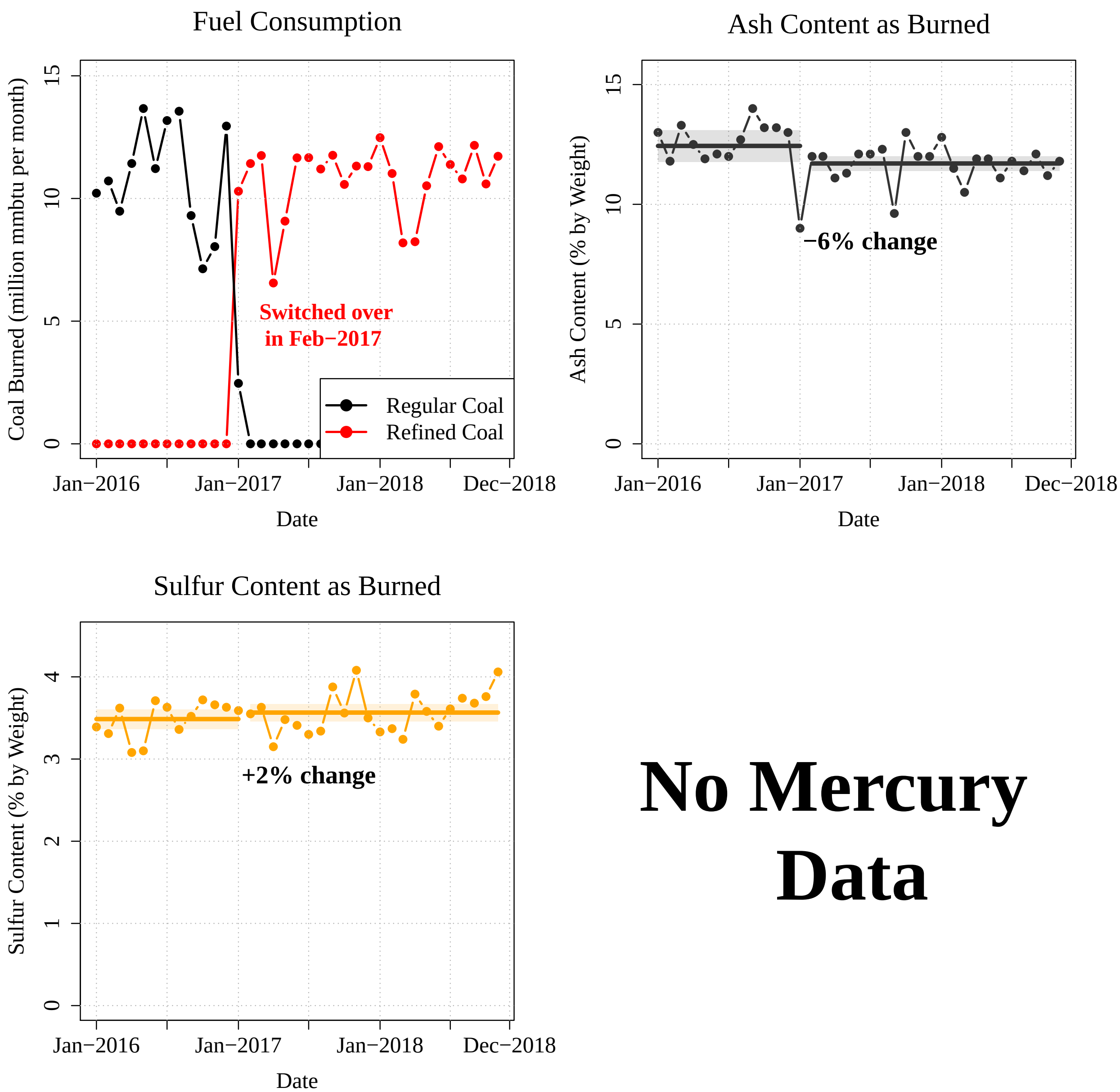

Figure A.5: Coal Characteristics for Plant 4 (in Figure 7)

Source: Authors' calculations based on EIA Form 923 data.

B.2 Sulfur Input Emissions Rate Regressions

To include more plants in the analysis, we also use the full dataset to control for any changes in sulfur content when estimating the SO_2 emissions rate. We estimate an analogous regression to the main analysis, which regressed SO_2 emissions on fuel burned (in mmbtu), by replacing the amount of *coal* burned (in mmbtu) with the amount of *sulfur* burned (in pounds). This purges the estimates of the effects of any changes in sulfur content, measuring the sulfur-in to sulfur-out rate, separately for refined and unrefined coal. We use the sulfur content (in percentage by weight of coal burned) *as burned* from EIA's form 923 dataset.[33]

The results are shown in Table A.2. The results reinforce the main findings that emission rates from refined coal are not lower than that of unrefined coal. Among boilers with SO_2 controls installed, the emission rates are about 0.08 pounds of SO_2 per pound of sulfur in the coal burned, for both refined and unrefined coal.[34] If we restrict the sample to boilers that burned both coal types, the rate falls slightly to about 0.07, for both coal types. Among boilers without controls, the rate is about 1.6 to 1.7 for refined coal, compared to 1.3 to 1.7 for unrefined coal. In all cases, we cannot reject the null hypothesis of equal emissions rates, and we can easily reject the null of achieving the 40% target reduction.

This strongly rebuts the possibility that the negligible observed reduction in the main analysis simply reflects an increase in sulfur content coincident with refined coal use. Unfortunately, we cannot run this test for mercury emissions because EIA does not require plants to report their coal's mercury content. While a small subset of plants voluntarily report mercury emissions of coal *as delivered*, there are not enough observations of mercury content for plants burning refined coal to reliably estimate an analogous regression. Further, for plants where we do observe mercury content, we observe mercury content of coal *as delivered*, which may differ from the mercury content *as burned*, given that coal plants typically keep stockpiles of several months' of fuel supply on site. Accounting for this would require building a model of coal stockpile additions and withdrawals, including making assumptions about what coal deliveries are burned when. Finally, relying entirely on the mercury content of the self-selected set of firms that choose to report would introduce severe selection bias into the analysis, in addition to being unrepresentative of plants in general. However, the lack of any observed changes in ash or sulfur content lends some confidence to the notion that plants are not obviously changing coal quality coincident with refined coal use.

[33] The sulfur content of coal *burned* in a given month is distinct from—and for this analysis is more appropriate than—the sulfur content of coal *delivered* in that month.

[34] Because the molecular weight of SO_2 is roughly twice the molecular weight of Sulfur (S), complete conversion of S into SO_2 would imply a coefficient of 2.

Table A.2: Regression of SO_2 Emissions on Sulfur Input.

	Dependent Variable: SO_2 Emissions (lbs)	
	All Boilers	Dual Coal Boilers
	(1)	(2)
SO_2 Emissions Controlled		
Sulfur Embodied in Refined Coal Burned (lbs)	0.083***	0.071***
	(0.005)	(0.008)
Sulfur Embodied in Unrefined Coal Burned (lbs)	0.085***	0.072***
	(0.006)	(0.008)
Sulfur Embodied in Other Fuel Burned (lbs)	1.472	0.238
	(1.851)	(4.214)
SO_2 Emissions Uncontrolled		
Sulfur Embodied in Refined Coal Burned (lbs)	1.611***	1.669***
	(0.063)	(0.061)
Sulfur Embodied in Unrefined Coal Burned (lbs)	1.303***	1.685***
	(0.197)	(0.029)
Sulfur Embodied in Other Fuel Burned (lbs)	−6.560	−5.000
	(10.125)	(9.077)
SO_2 Controlled Indicator	Y	Y
Emissions Controlled		
Emission Rate Difference (%)	**-3.2%**	**-2.3%**
p-value for H_0: No improvement	0.29	0.34
p-value for H_0: 40% improvement	<0.001***	<0.001***
Emissions Uncontrolled		
Emission Rate Difference (%)	**+24%**	**-1.0%**
p-value for H_0: No improvement	0.94	0.39
p-value for H_0: 40% improvement	<0.001***	<0.001***
R-Squared (projected model)	0.55	0.65
Observations (boiler-months)	19,408	2,552
Number of Boilers	639	78
Share of observations controlled	78.2%	80.3%

Note: *p<0.1; **p<0.05; ***p<0.01. Because the molecular weight of SO_2 is roughly twice the molecular weight of Sulfur (S), complete conversion of S into SO_2 would imply a coefficient of 2.

C Estimated NO_x Cost Savings

In section 4.5.1, we claimed that the potential savings from reduced reagent costs for NO_x controls is small—less than \$0.10 per ton of refined coal used. This appendix shows the calculations underlying this estimate. It is the result of a back of the envelope calculation that represents the NO_x allowance price levels in recent years, converted to a per ton of refined coal basis assuming the full 20% reductions are achieved. As background, there are two NO_x caps: annual and seasonal. While the seasonal program has had low but positive allowance prices in recent years (ranging from \$165 to \$750 per ton of NO_x), the annual program has largely been non-binding with near-zero prices (\$2-7/ton)[35]

Using an illustrative value of \$500 per ton for seasonal prices, this reveals marginal abatement costs of $\frac{\$500/\text{ton}}{2000\ \text{lbs/ton}} = \$0.25$ per pound of NO_x. To convert this value to a dollar savings per ton of refined coal, we must make some assumptions about the characteristics of the refined coal, which we will base on sample averages. First, we start with the average NO_x emission rate of 0.173 lbs/mmbtu and assume that refined coal actually achieved the 20% reduction as the tax law requires. Then refined coal would reduce the emission rate by 0.035 lbs/mmbtu, or about 0.69 lbs of NO_x per ton of refined coal assuming a coal heat content of 20 mmbtu/ton (0.69 lbs/ton $\approx$ 0.035 lbs/mmbtu $\times$ 20 mmmbtu/ton).

Hence, under these assumptions, refined coal would reduce NO_x abatement costs by $\frac{0.69\ \text{lbs}\ NO_x}{\text{tons refined coal}} \times \frac{\$0.25}{\text{lbs}\ NO_x} = \$0.173$ per ton of refined coal, but only during the ozone season (allowance prices off-season are about 100 times smaller than seasonal prices and can be ignored). The ozone season is typically 7 months of the year (or less), which to a first approximation implies an average savings of $\$0.173\frac{7}{12} = \$0.10$ per ton of refined coal. Note that allowance prices identify the marginal abatement costs for the most expensive unit of abatement, so this calculation reflects an upper bound on the potential savings. In addition, it assumes refined coal is actually achieving the full 20% reduction and uses an allowance price on the high end of the recent range; less generous assumptions would produce even smaller estimated savings.

[35] For allowance price values, see https://www3.epa.gov/airmarkets/progress/reports/market_activity_figures.html#figure2).

D Benefit Maps under Alternative Reductions

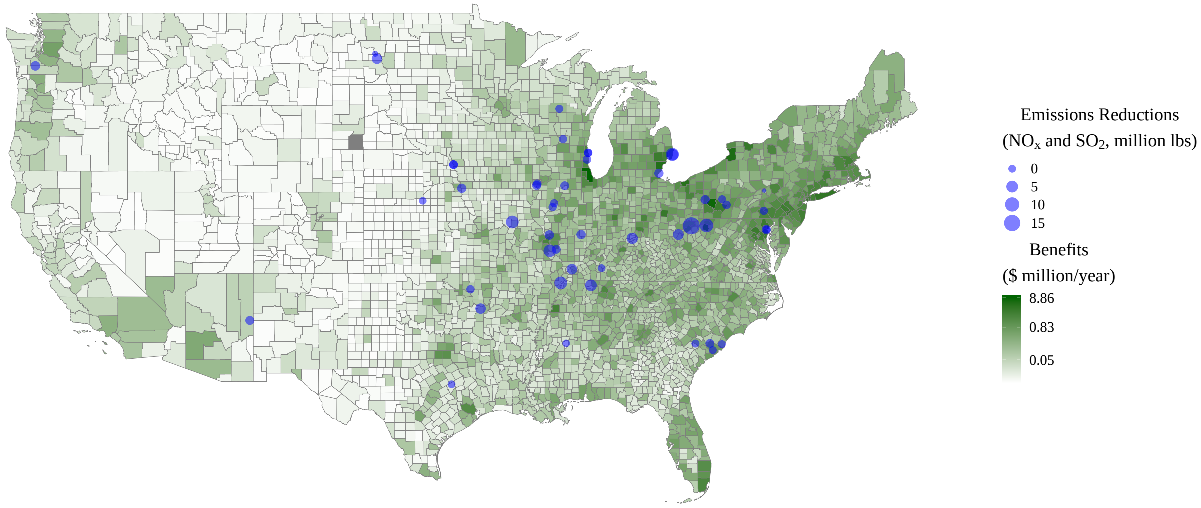

Figure A.6: Distribution of Air Quality Benefits (millions of dollars, \$2017) from SO_2 and NO_x, under the "Boiler-Level Reductions" Scenario

Source: Authors' calculations based on EPA CEMS and emissions controls data, EIA Form 923, and EPA COBRA model.

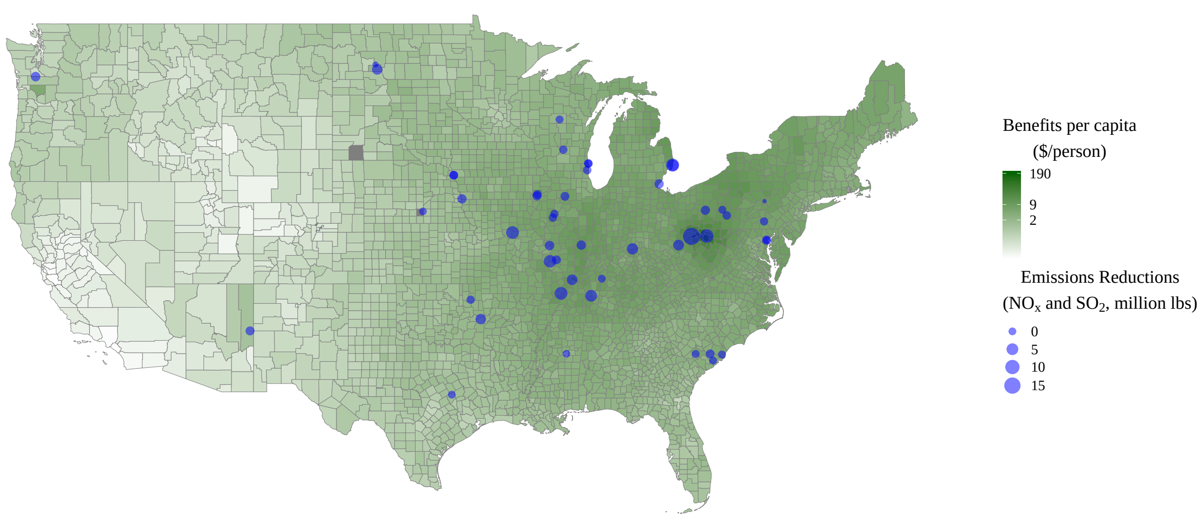

Figure A.7: Distribution of Air Quality Benefits (dollars per capita, \$2017) from SO_2 and NO_x, under the "Boiler-Level Reductions" Scenario

Source: Authors' calculations based on EPA CEMS and emissions controls data, EIA Form 923, and EPA COBRA model.

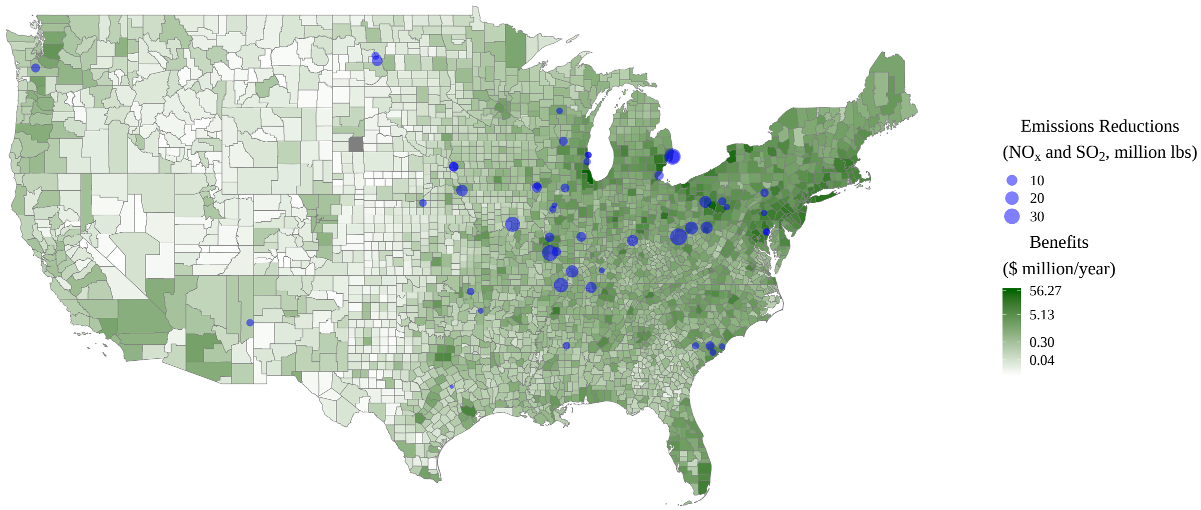

Figure A.8: Distribution of Air Quality Benefits (millions of dollars, \$2017) from SO_2 and NO_x, under the “Target Reductions (SO_2)” Scenario

Source: Authors’ calculations based on EPA CEMS and emissions controls data, EIA Form 923, and EPA COBRA model.

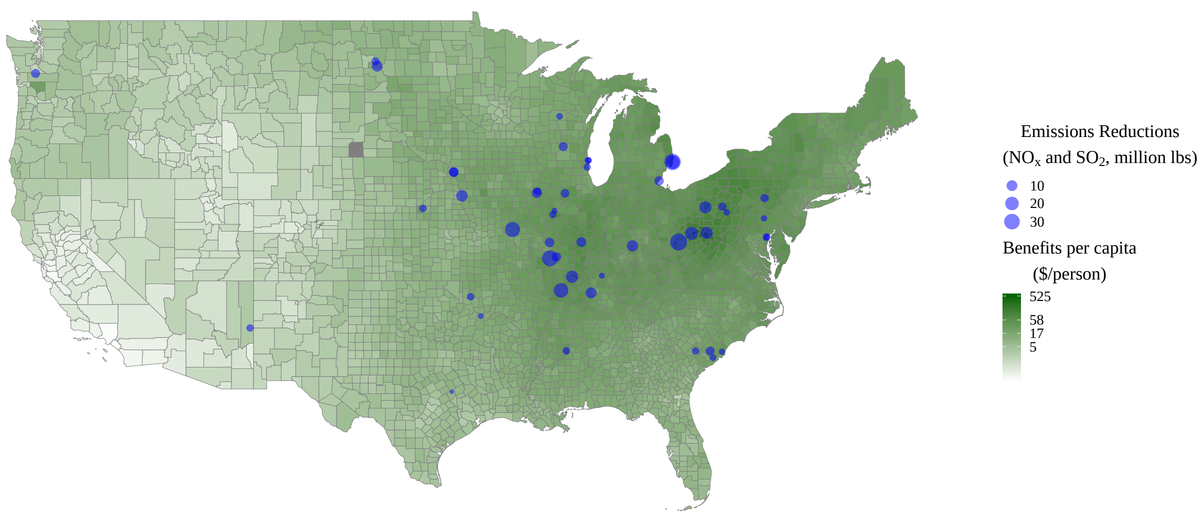

Figure A.9: Distribution of Air Quality Benefits (dollars per capita, \$2017) from SO2 and NO_x, under the “Target Reductions (SO_2)” Scenario

Source: Authors’ calculations based on EPA CEMS and emissions controls data, EIA Form 923, and EPA COBRA model.

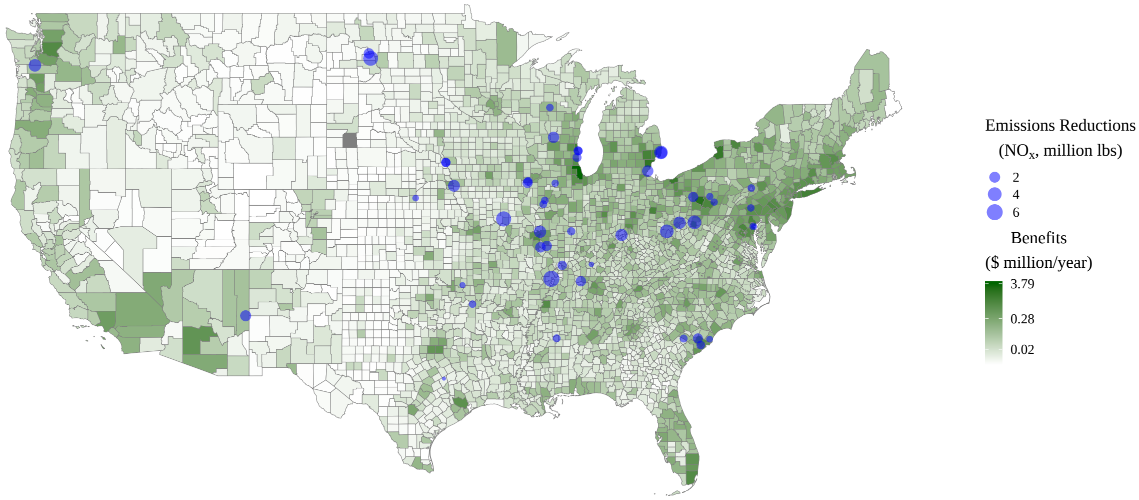

Figure A.10: Distribution of Air Quality Benefits (millions of dollars, \$2017) from NO_x, under the "Target Reductions (Hg)" Scenario

Source: Authors' calculations based on EPA CEMS and emissions controls data, EIA Form 923, and EPA COBRA model.

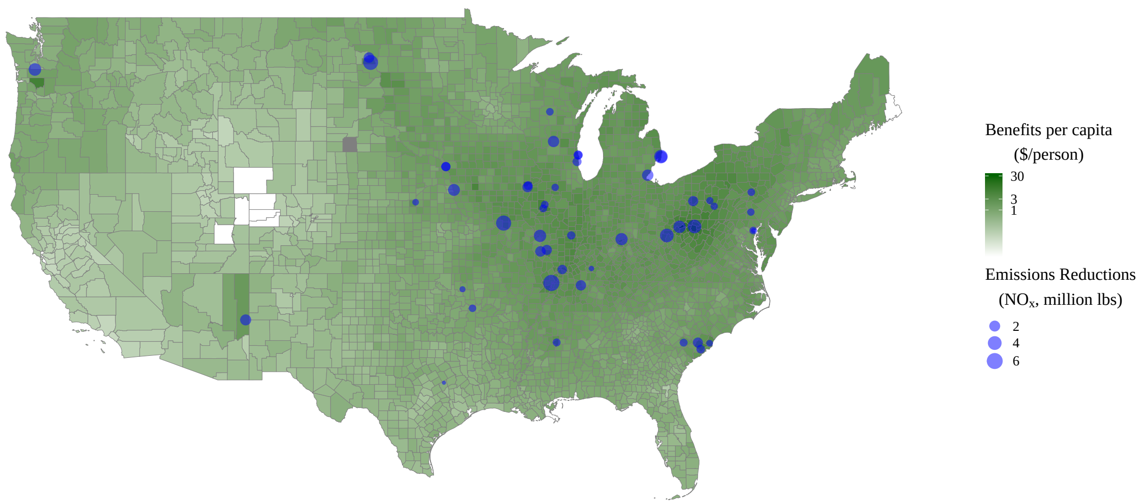

Figure A.11: Distribution of Air Quality Benefits (dollars per capita, \$2017) from NO_x, under the "Target Reductions (Hg)" Scenario

Source: Authors' calculations based on EPA CEMS and emissions controls data, EIA Form 923, and EPA COBRA model. The six counties in white experienced precisely zero change in PM concentrations. The apparent sharp color discontinuity with neighboring counties owes to the log scale of the color shading.