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This dissertation analyzes North Carolina's Clean Smokestacks Act (CSA). By targeting sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions at fourteen coal-fired powerplants owned by Duke Energy and Progress Energy, the CSA implements utility level caps in two phases and allows for trading of emissions within each utility. In my analysis I employ emissions data from the Continuous Emissions Monitoring System (CEMS) and powerplant characteristics from the Emissions and Generation Resource Integrated Database (eGRID). Difference-in-differences and the synthetic control method are used in concert with a nationally representative control group to analyze effectiveness, leakage, and the distribution of damages in the CSA. I estimate that the CSA reduced annual emissions of SO_2 by approximately 100,000 tons and emissions of NO_X by approximately 50,000 tons. This result is a smaller estimated effect of the policy than prior studies have shown. Additionally, I provide evidence that the reductions are not due to utilities shifting production and are due to the installation of abatement technology. Estimating avoided damages from 2003 to 2014, the CSA results in estimated benefits of $1.88 billion (2014$).

NORTH CAROLINA'S CLEAN SMOKESTACKS ACT:

UNTANGLING A TANGLED RELATIONSHIP

by

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CHAPTER I

INTRODUCTION

Regulators have two broad categories of policy tools for handling air pollution. The first category is command-and-control policies where the methods and distribution of abatement are dictated by a regulator. The second category consists of market-based emission policies, where the methods and distribution of abatement are dictated by market forces. The resulting difference in impact between the two policy options is in the compliance cost. By allowing for flexibility, market-based policies exploit the heterogeneity in abatement costs across firms to reach a least-cost distribution of abatement (Tietenberg, 1980). Additionally, the lower compliance costs and increased compliance flexibility may make greater emission reductions more politically feasible (Ellerman, 2006; Keohane et al., 1998; Tietenberg, 2006; US EPA, OPA, 1992). While market-based emissions policies may be more efficient in theory, the question remains: How effective are these policies in practice, given the obstacles of real-world implementation?

Unfortunately, market-based emission policies are limited to a handful of real-world examples. Focusing on cap-and-trade (C&T) in the United States, there are three policies that have been studied extensively. The first is the Acid Rain Program (Title IV of the 1990 Clean Air Act Amendment), which is a Federal policy that targets emissions of SO_2 and NO_X at powerplants across the United States. The ability to trade leads to estimated benefits of $780 million (Carlson et al., 2000) to over $100 billion annually (Chestnut & Mills, 2005).[1] The second is the Regional Clean Air Incentives Market (RECLAIM) which regulates emissions of SO_2 and NO_x on a regional level for California. Despite volatility in the permit market[2], RECLAIM results in an average reduction in NO_x emissions of 20% (Fowlie et al., 2012). The third is the Regional Greenhouse Gas Initiative (RGGI) which brings together nine states in the Northeastern U.S. to form a regional C&T greenhouse gas (GHG) program. According to Murray & Maniloff (2015), RGGI caused a 24% reduction in emissions, but other factors, such as natural gas prices and other environmental programs, were influential. Outside of the United States, the largest C&T program is the European Union Emissions Trading Scheme (EU-ETS). Covering all EU member states plus Iceland, Liechtenstein, and Norway, the EU-ETS accounts for almost 75% of international carbon trading (CLIMA, 2015). In their meta-analysis of empirical studies, Zhang & Wei (2010) find the EU-ETS to be effective but call for further empirical research.

[1] The large range in estimated benefits is due to differences in the number of benefits included. For example, (Chestnut & Mills, 2005) include avoided damages from particulate matter whereas (Carlson et al.(2000) does not.

[2] Providing a lesson in safety valves (permit price ceilings), in 1999 the RECLAIM cap became binding and led to runaway prices in the permit market. In the beginning of 2000, the price was approximately $2,000 per ton of NO_X but in the following year prices rapidly climbed, exceeding $120,000 per ton of NO_x (SCAQMD, 2001). In response, regulators amended the program and implemented a safety valve for the NO_x permit market.

This dissertation analyzes North Carolina's Clean Smokestacks Act (CSA) in a manner that previous studies have not, by comparing actual emissions to an estimated counterfactual. Prior studies of the CSA focused on the observed reduction in emissions without comparing the actual emissions to what would have happened in the absence of the CSA (Hoppock et al., 2013). In order to make this comparison and estimate a counterfactual, I employ a difference-in-differences (DiD) model along with the synthetic control method (SCM). The SCM is an econometric technique that is a novel application to the empirical cap-and-trade literature. In the analysis, three questions are addressed. First, how effective is the CSA in reducing emissions of SO_2 and NO_x at targeted plants? How do plants under the purview of the CSA reduce emissions in comparison to an estimated counterfactual? Using emissions data from the Continuous Emissions Monitoring System (CEMS) and plant characteristics from the Emissions and Generation Resource Integrated Database (eGRID), I use both the DiD model and the SCM to estimate the effectiveness of the CSA.

Second, how prevalent is leakage when the targeted utilities can shift production to unregulated plants? Here, *leakage* is defined as the reduction of emissions at a CSA plant with a corresponding increase of emissions in non-CSA plants in bordering states. Using the DiD framework, each state sharing a border with North Carolina is defined as a separate treatment group. Conveniently the three states that share the majority of North Carolina's border also have three distinct characteristics. First, the utilities targeted by the CSA extend into the northern half of South Carolina. With the ease of being able to shift production to powerplants in South Carolina, leakage to South Carolina should be expected. Second, Virginia is almost entirely under the purview of the PJM independent service operator (ISO). Between Virginia and South Carolina, leakage is more likely to occur in South Carolina given the greater ease of trade. Third, the Tennessee Valley Authority (TVA) faced a lawsuit from North Carolina that ended in a settlement. The settlement forced the TVA to implement abatement technology at its coal powerplants. Thus the CSA had an indirect effect on emissions for the TVA, that is not leakage, and abatement costs increased at the TVA coal plants.

My third question is: What are the benefits of avoided damages due to changes in emissions of SO_2 and NO_x at the plant-level, from the CSA? Since SO_2 and NO_x are local pollutants, location of their source matters in estimating their impacts. Plant-specific treatment effects are estimated using the SCM. The plant-specific estimates of changes in emissions are coupled with marginal damage estimates from Muller and Mendelsohn (2009). The emission reductions and the subsequent avoided damages are benefits North Carolina accrued from the CSA.

This analysis of the CSA is important and timely for three reasons. First, as shown above, the CSA is one of only a few implemented cap-and-trade policies. Second, the CSA is unique in its limited trading and lack of a formal permit market. This uniqueness provides an opportunity for learning that prior C&T policies cannot. Third, the observation window of emissions data is now long enough to analyze the question of effectiveness. Studying the CSA provides policy makers and researchers with additional empirical evidence into how C&T works.

The dissertation is organized as follows: Chapter II describes the CSA and the policy environment for which the CSA operates in. Chapter III chronicles the legal history of the CSA. Chapter IV provides a brief history of Duke Power and Progress Energy and how they operate today. Chapter V is a review of theoretical and empirical literature surrounding cap-and-trade as well as empirical research. Chapter VI puts forth a conceptual model for framing the abatement decision. Chapter VII summarizes the emissions data and provides a descriptive analysis of the CSA. Chapter VIII explains difference-in-differences model and the synthetic control method. Chapter IX describes the results for the questions of effectiveness, potential leakage, and plant specific effects. Chapter X analyzes the benefits of the CSA and compares them to the utility reported compliance costs. Chapter XI concludes the analysis.

CHAPTER II

A BRIEF HISTORY OF THE POLICY ENVIRONMENT

In 1955 the Air Pollution Control Act was passed, and the U.S. government began to acknowledge the issue of air pollution. However, it was not until the Clean Air Act (CAA) of 1963 that the Federal government put forth policy to specifically target air pollution. After the initial CAA became law, it was amended in 1970, 1977 and 1990. Each amendment brought about significant expansions of environmental policies and protections.

With the passing of the 1990 CAA amendment, came the National Ambient Air Quality Standard (NAAQS) and the Acid Rain Program (also known as “Title IV”). Both policies had major implications for the electric power industry at the national and state levels, especially with respect to the emission of nitrogen oxides (NO_x) and sulfur dioxide (SO_2). The 1990 amendment also created a framework for what would eventually be the Clean Air Interstate Rule (CAIR). The CAIR addressed the flow of pollutants across state lines, with respect to the NAAQS. To comply with the CAIR, North Carolina’s regulatory response was to create the Clean Smokestacks Act (CSA).

The subsequent sections are as follows. Section two summarizes the relevant sections of the CAA and relates these policies to the CSA. Section three explains the issue of interstate pollution and its influence on the CSA. Section four introduces the CSA and explains the policy in greater detail.

Clean Air Act (CAA)

A watershed moment in environmental legislation, the CAA was one of the first U.S. federal policies to directly address issues surrounding environmental quality. The bill has been amended three times since its initial passing in 1963; in 1970, 1977, and again in 1990. Each amendment brought about key changes in environmental policy; for example, the creation of the EPA with the 1970 amendment and the Acid Rain Program in the 1990 amendment. In following subsections, I take a closer look at the areas of the CAA as they relate to powerplants.

Title I – National Ambient Air Quality Standards

Addressing issues of air quality, the 1990 CAA amendment introduces the National Ambient Air Quality Standards (NAAQS). The NAAQS require the EPA to set national standards for pollutants deemed harmful to the health of both the public and environment. The standards are categorized as primary and secondary. A *primary standard* protects the health of the public (i.e. asthma in children) while a *secondary standard* protects public welfare (i.e. agriculture). Depending on the pollutant, counties are either deemed as in attainment or nonattainment. *Nonattainment* means that the pollutant surpasses a set standard over a certain period. Table 1 shows the NAAQS by pollutant and classification.

Table 1. NAAQS by Pollutant and Classification

Pollutant	**Primary/Secondary**	**Averaging Time**	**Level**	**Form**
Carbon Monoxide	Primary	8 hours	9 ppm	Not to be exceeded more than once per year
		1 hour	35 ppm	
Lead	Primary & Secondary	Rolling 3 month average	0.15 $\mu g/m^3$	Not to be exceeded
Nitrogen Dioxide	Primary	1 hour	100 ppb	98th percentile of 1-hour daily maximum concentrations averaged over 3 years
	Primary & Secondary	1 year	53 ppb	Annual Mean
Ozone	Primary & Secondary	8 hours	0.070 ppm	Annual fourth-highest daily maximum 8-hour concentration averaged over 3 years
Particulate Matter $(PM_{2.5})$	Primary	1 year	12.0 $\mu g/m^3$	Annual mean, averaged over 3 years
	Secondary	1 year	15.0 $\mu g/m^3$	Annual mean, averaged over 3 years
	Primary & Secondary	24 hours	35.0 $\mu g/m^3$	98th percentile, averaged over 3 years
Particulate Matter (PM_{10})	Primary & Secondary	24 hours	150 $\mu g/m^3$	Not to be exceeded more than once per year on average over 3 years
Sulfur Dioxide	Primary	1 hour	75 ppb	99th percentile of 1-hour daily maximum concentrations averaged over 3 years
	Secondary	3 hours	0.5 ppm	Not to be exceeded more than once per year

Source: NAAQS table from the EPA's webpage on criteria air pollutants. (https://www.epa.gov/criteria-air-pollutants/naaqs-table)

Once a county is in the nonattainment category, the county and state must follow the guidelines the state outlines in its State Implementation Plan (SIP). Depending on the severity of nonattainment, a county was allowed between three and twenty years from November 15th, 1990 to comply. Failure to comply could result in withholding of Federal funds (e.g. highway funding). Additionally, the EPA has the power to supersede the state and implement Federal rules for failed areas with continual nonattainment status.

Placing the compliance burden on states means state legislators are responsible for drafting and implementing the policies necessary to become compliant. It is this burden that is a point of contention between states, due to the problem of pollutant transport and dispersion. For example, pollutants emitted from plants in Tennessee are blown into North Carolina and cause counties in North Carolina to be in nonattainment of air quality standards. This issue of pollution transport and contribution to nonattainment status plays a role in the creation of the CSA, via the CAIR.

<u>Title IV – Acid Depositions</u>

Perhaps one of the most recognized sections of the 1990 CAA amendment is Title IV. Colloquially known as the Acid Rain Program, Title IV is the poster child for cap-and-trade in the United States. With the goal of reducing annual emissions of SO_2 by 10 million tons, from 1980 levels, Title IV was implemented in two phases.

Beginning in 1995, Phase 1 explicitly targeted 110 coal-fired powerplants, none of which were in North Carolina. Initial allocations were determined by the following formula:

$$Allocation\ (level) = \frac{2.5\ lbs\ of\ SO_2}{mmBtu} \times Average\ fuel\ use\ between\ 1985 - 1987$$

Targeted plants are allocated permits based on an emissions rate of 2.5 pounds of SO_2 per unit of fuel consumption, where fuel consumption is measured in millions of British thermal units (mmBtu), multiplied by a baseline of fuel use between 1985 and 1987. The effective cap is the sum of allocated permits across all plants. The 110 plants were also incentivized to make capital investments related to abatement, such as SO_2 scrubbers, in return for a compliance extension until 1997. During Phase 1, powerplants that were not part of the original 110 had the option of opting into the program.

In 2000 Phase 2 commenced encompassing almost the entirety of coal-fired powerplants in the United States. Scaling up to over 2,000 coal burning units, Phase 2 expanded to include oil and gas powerplants as well. Restricting SO_2 emissions further than Phase 1, allowances were calculated as follows:

$$Allocation\ (level) = \frac{1.2\ lbs\ of\ SO_2}{mmBtu} \times Average\ fuel\ use\ between\ 1985 - 1987$$

Just as in Phase 1, the permit allocation is calculated using a target rate of SO_2 emissions and a baseline of fuel use. However, in Phase 2, the target emissions rate dropped from 2.5 lbs of SO_2 per mmBtu to 1.2 lbs of SO_2 per mmBtu.

In addition to regulating SO_2 emissions, Title IV also targets emissions of NO_X. The abatement goal for NO_x is a two-million-ton reduction from 1980 levels by the year

2000. As with the SO_2 reductions, NO_x reductions are instituted in phases. Regulating at the boiler level, boilers are placed into one of two groups. Group one consists of dry bottomed, wall-fired, and tangential boilers. Group two consists of cell burners, cyclones, wet bottoms, and vertically fired boilers.

Table 2. NO_x Groups for Acid Rain Program (Title IV)

Boiler Types	Number of Boilers	Phase 2 Emission Limits
Group 1		
Dry bottom wall-fired	308	0.46 lb/mmBtu
Tangential	299	0.40 lb/mmBtu
Group 2		
Cell burner	36	0.68 lb/mmBtu
Cyclones (>155 MW)	55	0.86 lb/mmBtu
It bottoms (>65MW)	26	0.84 lb/mmBtu
Vertically fired	28	0.80 lb/mmBtu

In Phase 1, Group 1 boilers are targeted. Then in Phase 2, Group 2 boilers are brought in. Phase 1 was implemented in 1995 and continued until 2000, when Phase 2 was implemented. According to the EPA, most boilers achieved target emission rates by implementing NO_x scrubbing technologies. Additionally, utilities could average the emissions rates of two more boilers.

While the SO_2 provisions of the Acid Rain Program may not have direct effects on the CSA, the NO_x provisions may. As will be shown in the data section, there is a downward trend in the emissions of NO_X at the fourteen plants targeted by the CSA both before and after the CSA is passed. This pre-trend is likely due to the NO_X provisions of the Acid Rain Program.

Interstate Pollution and the Clean Smokestacks Act

Precipitating the creation of the CSA were various responses to the problem of interstate pollution. The issue was that pollutants, such as NO_x and SO_2 from upwind states would blow into states downwind and significantly contribute to the nonattainment status of counties within those downwind states. In response the downwind states petitioned regulatory changes by policy makers.

NO_X SIP Call

In late 1996, the Clinton Administration put forth a proposal to tighten the NAAQS for ozone and particulate matter. The proposal led to a 1997 report by the Ozone Transport Advisory Group (OTAG) that showed the interstate transport of pollutants (i.e. NO_X) played a significant role in the NAAQS nonattainment status of downwind states. After the release of the OTAG report, eight states in the Northeast filed petitions for the EPA to address the issue of upwind emissions by designating the upwind states as significantly contributing to the nonattainment status of downwind states.

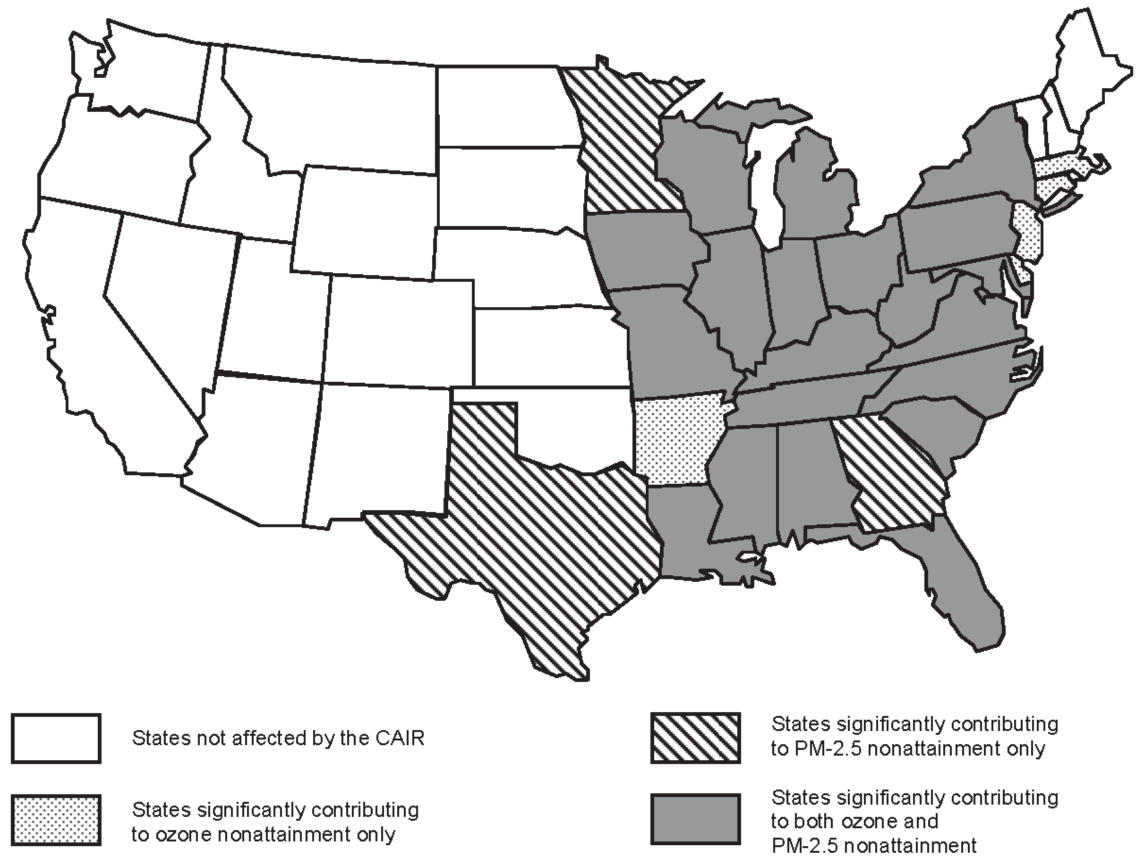
In 1999 the EPA responded to the demands of downwind states by issuing the "NO_X SIP Call", which required twenty-two states and the District of Columbia to address the issue of interstate pollution by modifying their NAAQS SIP. In the new ruling the twenty-two states and D.C. were required to reduce annual summertime NO_x emissions by approximately 28% by 2003. To meet the requirements, the EPA recommended the adoption of a NO_x cap-and-trade program within each SIP. The NO_X SIP call, petitions by downwind states, and proposals by multiple environmental groups culminated in a broader rule made by the EPA called the Clean Air Interstate Rule (CAIR).

Clean Air Interstate Rule (CAIR)

The CAIR required 28 states in the eastern United States to choose between one of two compliance strategies. One compliance option was to join an interstate cap-and-trade program that would be regulated by the Environmental Protection Agency (EPA). An alternative compliance option was to implement a state-level policy that reduced emissions to a level at or below a target set by the EPA (Air Pollution Consultant, 2005). The goal of the CAIR was to address the issue of pollutants moving across stateliness and contribution to the nonattainment status of downwind states.

Figure 1 shows states that significantly contributed to ozone and 2.5-micrometer particulate matter ($PM_{2.5}$) NAAQS nonattainment for downwind states. The white states are not affected by the CAIR, the light grey states contribute only to ozone nonattainment of downwind states. The lined states contribute to only $PM_{2.5}$ nonattainment of downwind states. The dark grey states contribute to both ozone and $PM_{2.5}$ nonattainment of downwind states. As Figure 1 shows, North Carolina is labeled as significantly contributing to nonattainment of both ozone and $PM_{2.5}$ ambient air quality standards for downwind states.

Figure 1. States with Significant Contribution to Downwind Nonattainment



Source: (Air Pollution Consultant, 2005)

To reduce the impacts of upwind emissions on the attainment status of downwind states, the CAIR sets targets for emissions of two local pollutants that impact attainment status. To reduce upwind emissions of PM-2.5, region-wide annual emission caps for SO_2 and NO_x are set. Likewise, for ozone, the CAIR sets ozone-season NO_x targets to meet the eight-hour ozone NAAQS. Total annual emission caps are as follows (US EPA, 2005):

- $\boldsymbol{SO_2}$**:** 3.6 million tons in 2010 and 2.5 million tons in 2015
- $\boldsymbol{NO_x}$**:** 1.5 million tons in 2009 and 1.3 million tons in 2015
- $\boldsymbol{NO_x\ Ozone\ Season}$**:** 580,000 tons in 2009 and 480,000 tons in 2015

The CAIR divides annual emissions caps into state-level caps. Table 3 shows the state-level emission caps set by the CAIR for North Carolina and bordering states. North Carolina's SO_2 budget from 2010 to 2015 was 137,342 tons and 96,139 tons for 2015 and beyond. For NO_x, North Carolina's budget was 62,183 tons for 2009 to 2014 and 51,819 tons for 2015 and beyond. Compared to bordering states, Tennessee is most like North Carolina with respect to emission caps. The caps for South Carolina and Virginia are roughly half of North Carolina's. Georgia's SO_2 cap is approximately 50% more than North Carolina's, while their NO_x cap is approximately the same as North Carolina's.

Table 3. State-level CAIR Emission Caps for North Carolina and Bordering States

	SO_2 $(tons)$		NO_x $(tons)$		$NO_x\ Ozone\ Season$ $(tons)$	
	2010	2015	2009	2015	2009	2015
North Carolina	137,342	96,139	62,183	51,819	28,392	23,660
Georgia	213,057	149,140	66,321	55,268	NA	NA
South Carolina	57,271	40,089	32,662	27,219	15,249	12,707
Tennessee	137,216	96,051	50,973	42,478	22,842	19,035
Virginia	63,478	44,435	36,074	30,062	15,994	13,328

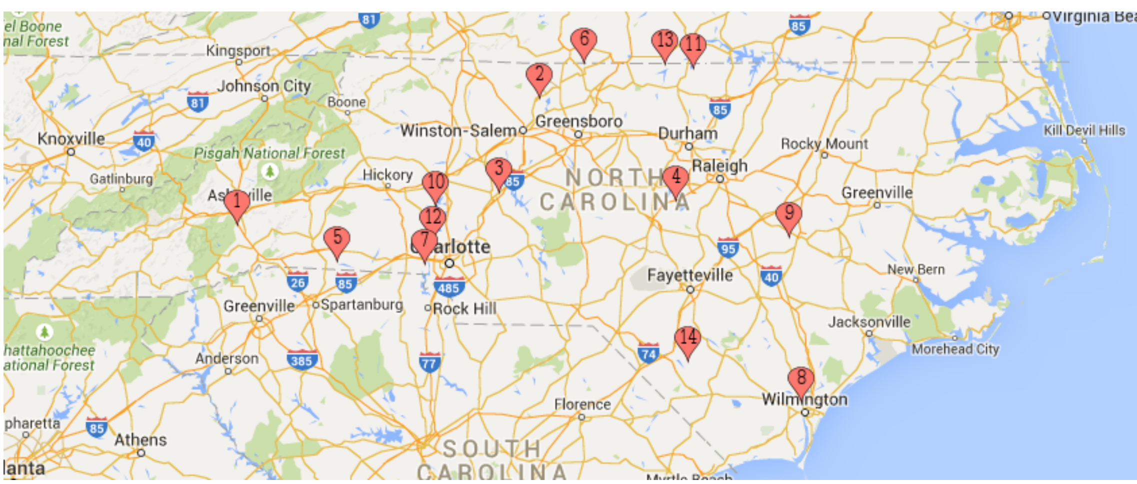
Source: (Air Pollution Consultant, 2005)

To comply with the CAIR, North Carolina chose to implement their own policy instead of opting into an interstate cap-and-trade policy. The policy solution that North Carolina lawmakers came up with was the Clean Smokestacks Act (CSA). Despite the eventual demise of the CAIR in court, North Carolina left the CSA in place. Doing so, moved North Carolina to a small subset of states operating under a market-based emissions policy. Additionally, the CSA is the only policy of its kind in the southeastern region of the U.S, a fact that becomes a point of contention between North Carolina and surrounding states.

Clean Smokestacks Act (CSA)

To comply with the NO_x SIP call, and what would later be called the CAIR, North Carolina's CSA aimed to reduce SO_2 emissions by approximately 75% and NO_x emissions by approximately 50%. To do so, the CSA focused on large coal-fired powerplants run by the state's two largest electric utilities: Duke Energy and Progress Energy. More specifically, the CSA targets coal-fired powerplants with greater than 25 MW of capacity, directly affecting 14 plants.

Figure 2. Locations of Plants Targeted by the Clean Smokestacks Act



Source: Plant locations from Continuous Emissions Monitoring System (CEMS) and compiled in Google Maps

Policy Implementation

The CSA implements emission caps in phases, with separate caps for each pollutant and for each utility. Table 4 shows the annual emission caps of SO_2 and NO_x for the CSA plants. For SO_2, Duke Energy is required to reduce emissions to 150,000 tons by 2009 and 80,000 tons by 2013. Progress Energy is required to reduce SO_2 emissions to 100,000 tons by 2009 and 50,000 tons by 2013. For NO_x, Duke is required to reduce emissions to 35,000 tons by 2007 and to 31,000 tons by 2009. Progress is required to reduce NO_x emissions to 25,000 tons by 2007. The CSA determines the caps as a function of past emission levels, using 2000 as the baseline year.

Table 4. Annual Emission Caps for CSA Plants (Tons)

Pollutant	Year Effective	Duke Energy	Progress Energy	Total Cap
SO_2	2009 – 2012	150,000	100,000	250,000
	2013 – Present	80,000	50,000	130,000
NO_x	2007 – 2008	35,000	25,000	60,000
	2009 – Present	31,000	25,000	56,000

Unlike other cap-and-trade policies, no formal permit market exists with the CSA. Permits are not allocated to each firm and then traded through a regulated market. Instead, caps are set at the utility level and then utilities can decide on the distribution of emissions across its powerplants. Despite the lack of a permit market, there are still market forces in motion. Since the CSA fixes the quantity of emissions but allows the utilities to decide how and where to reduce emissions, plants within each utility should shift emissions to one another such that total abatement costs are minimized. Regardless of a formal permit market, the outcome remains the same. Although, without a formal market for permits, three common features of cap-and-trade policies are excluded from the CSA.

First, third-party organizations cannot buy permits. Thus, philanthropists, environmentalists, and non-profits cannot obtain a permit for the sake of reducing the effective emissions cap. Second, utilities can shift production between each other but cannot trade permits (shift their effective cap) between each other. If utilities could trade, theory suggests a lower total abatement cost may be reached. This potentially lower cost outcome is unattainable under the CSA. Finally, since there is no formal market for permits, there is no direct source of revenue for either the utilities or the regulator in the buying and selling of permits.

To enforce the policy, data from the Continuous Emissions Monitoring System (CEMS) is used. Additionally, at the end of each year the utilities must report their annual emissions as well as information regarding compliance costs and any construction permits associated with compliance. If a utility is not in compliance by the end of the year, a \$10,000 penalty is applied for each day of non-compliance. For example, if a utility reached their cap on December 1st, then the utility will be charged \$10,000 per day through December 31st.

For a utility to comply, several methods may be implemented: installation of abatement technology, reduction of generation, changing of fuel, changing the burn process, and shutting down entire plants. A plant may abate using multiple abatement methods simultaneously and is not limited to a particular method. For example, a plant may decide to reduce generation while also installing a SO_2 scrubber. A plant may also decide to install abatement technologies in one year and then shut down a few years later.

Compliance Cost Recovery

To lessen the burden of compliance on the targeted utilities, the CSA allows for cost recovery through amortized costs. Compliance costs are defined as costs associated with, and exclusive to, the act of compliance. The amortized compliance costs appear as an expense on the utility's annual balance sheet, reducing the utility's tax burden for that year. Initially, compliance cost recovery can be accelerated over a seven-year period, beginning January 1st, 2003 and ending December 31st, 2009. Over this period, Duke Energy can amortize[3] $1.5 billion while Progress Energy can amortize $813 million. Additionally, from January 1st, 2003 to December 31st, 2007, rates are frozen. During this rate freeze period, utilities must amortize a minimum of 70% of the allowed amount. The minimum cost amortization requirement imposes a minimum abatement expenditure on both utilities. The maximum allowed amortization amount during the rate freeze period is 150%.

Superficially, the rate freeze is an additional constraint on the utilities. However, the rate freeze was sought by the utilities and was part of the legislative negotiations.

[3] Amortize, in this context, is defined as the process of writing down debts over time. The amortized costs can then be used to reduce the burden of taxes over that period.

According to Laura DeVivo[4] (personal communication, September 26th, 2017), the utilities projected electricity rates to fall as debt was being paid down on past capital investments. As these capital investments moved off the balance sheets of utilities, leverage was lost for keeping regulated electricity rates at current levels. By freezing regulated rates, utilities gained a higher regulated rate than they would have otherwise; with the caveat that utilities incur a minimum level of compliance costs. If utilities believe that rates are about to decline, then the minimum amount of compliance cost amortization, coupled with the rate freeze, provides an incentive for utilities to make capital investments in abatement technology.

[4] Laura DeVivo was the Director of Legislative Affairs at the Department of Environmental and Natural Resources from 1998 to 2003, a period that included the passing of the CSA.

CHAPTER III

LEGAL HISTORY OF THE CLEAN SMOKESTACKS ACT

Understanding the full impact of the CSA requires understanding the legislative history of the policy. By knowing the lawsuits, interactions with other policies, and policy responses by other states; it is possible to create a more complete characterization of the CSA's impact. There are three interactions that will play a role in the empirical analysis of the CSA. First, the legal battle between North Carolina and the Tennessee Valley Authority results in a spillover effect of the CSA on Tennessee's emissions. Second, the CSA and the lack of adoption of the CAIR by other states creates a potential environment for leakage of emissions from CSA plants to bordering states. Third, chronicling the lawsuits by upwind states provides a better understanding of the political environment the CSA was operating within.

The CSA and TVA

Even though it is a state policy, the CSA was not without both regional and federal controversy. The main point of contention was the lack of similar policies by other states to address the issue of SO_2 and NO_x emissions, with the primary example being the Tennessee Valley Authority. In the text of the CSA, the TVA is explicitly called upon to make policy changes similar to North Carolina. Unfortunately, the TVA and surrounding states, did not follow North Carolina's lead and instead chose the path of lawsuits.[5] At the passing of the CSA, legislators called on the TVA and surrounding states to follow North Carolina's lead on regulating emissions of SO_2 and NO_X from coal-fired powerplants. Given that emissions do not necessarily stay contained within a state's borders, emissions by TVA utilities can impact North Carolina communities. Perhaps most relevant for policy makers, emissions outside of the state can affect North Carolina's compliance with the NAAQS of the CAA. Furthermore, without having bordering states in agreement, leakage of emissions poses a problem for the overall effectiveness of emissions regulation such as the CSA.

The transport of pollutants from Tennessee to western counties in North Carolina led to a legal battle between the North Carolina Attorney General and the TVA. On January 30th, 2006, the North Carolina Attorney General sued the TVA in a federal district court in Asheville, North Carolina (North Carolina DENR, 2014). On January 13th, 2009, a judge ruled in favor of North Carolina and ordered the TVA to install abatement technologies in four of its powerplants. However, on January 26th, 2010 the TVA won an appeal and the original court decision was reversed.

On April 14th, 2011, the TVA and North Carolina reached a settlement over the air pollution allegations. The result was a system-wide cap on TVA coal plants to permanent annual levels of 110,000 tons of SO_2 by 2019 and 52,000 tons of NO_x by

[5] The lawsuits, and subsequent rulings, play a key role in determining appropriate control groups in the chapters to follow.

2018. In meeting the emission requirements, the TVA must either install abatement technologies or shutdown.[6] Lastly, the TVA would also pay North Carolina $11.2 million to help fund mitigation projects.

The resulting settlement from the lawsuit had impacts on more than just the emissions from TVA plants. The cost to comply with the strict reduction in emissions meant that one of the largest electricity producers in the region, the TVA, faced a sharp increase in the cost to produce and made one potential haven for leakage from the CSA much less feasible. This also means that plants in Tennessee should not be included in the control group as there is an effect on the TVA plant emissions from the CSA, through the lawsuit.

The CSA and the CAIR

The CSA's original motivation was to make North Carolina comply with the CAIR. However, the CAIR would become a point of contention between North Carolina and the EPA. On July 8th, 2005 the North Carolina Attorney General filed a petition in the US Court of Appeals in DC for review of the CAIR (North Carolina DENR, 2014). The petition claimed that the CAIR did not adequately address the air quality problems in North Carolina. Specifically, not enough focus was placed on control measures. Subsequently, on July 11th 2008, the DC court granted North Carolina's petition in part.

[6] The Shawnee plant was excluded from the settlement.

The court found that the CAIR's trading program did not address the air quality of states downwind from target powerplants.

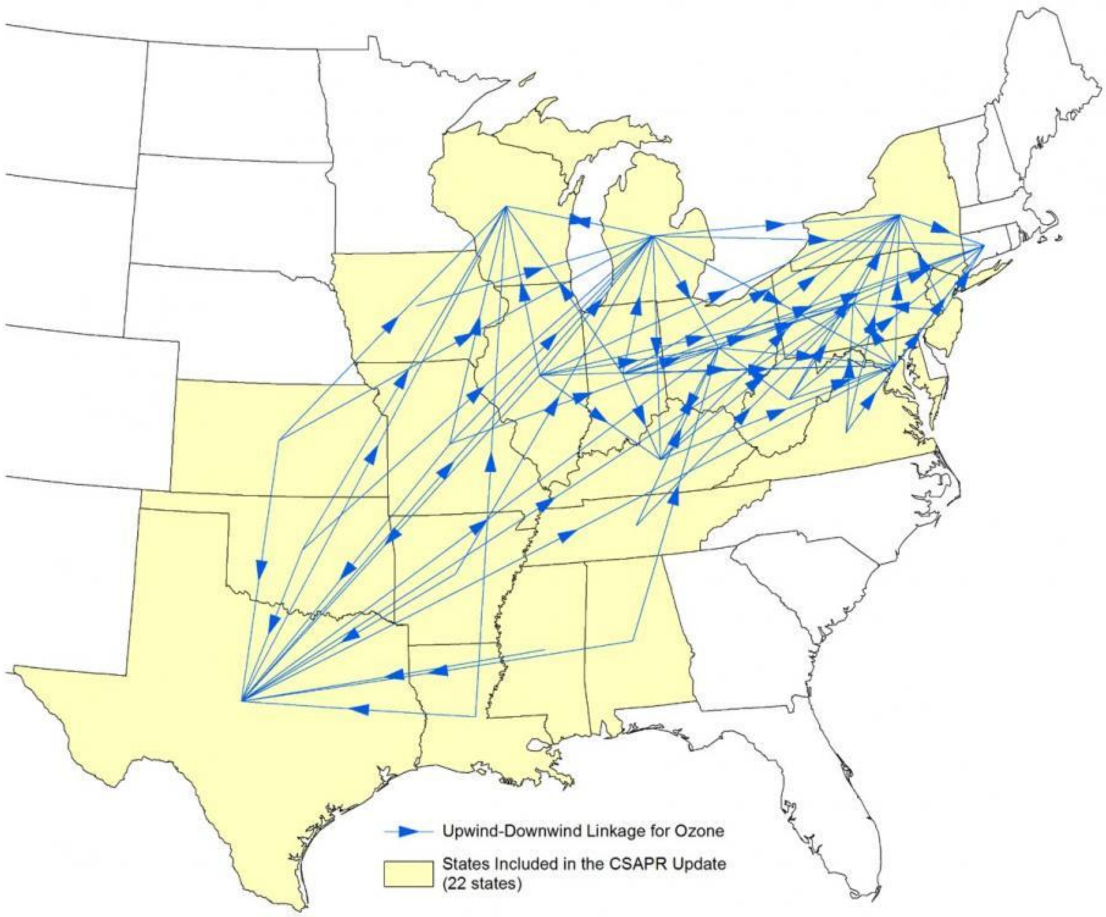
In response, on July 6th 2010, the EPA proposed the Clean Air Transport Rule (CATR) and abandoned the interstate pollution permits from CAIR. The CATR would cap SO_2 and NO_x emissions of states that impact the attainment or maintenance of states downwind. For example, if emissions from Tennessee caused counties in western North Carolina to be in non-attainment of the NAAQS, then caps would be implemented on emissions in Tennessee. The caps would then be determined by estimated transport of emissions from Tennessee to North Carolina. The deadlines for cap compliance would also be determined by the needs of the downwind state(s). However, by March of 2011, the EPA had yet to provide greater detail about the implementation of CATR. Thus, on March 14th, North Carolina and NY requested the EPA establish a schedule for CATR by the end of July, 2011.

Then on July 6th, 2011, the EPA promoted the Cross-State Air Pollution Rule (CSAPR). CSAPR came under scrutiny and was challenged by several states. However, North Carolina and other parties supported the EPA and helped defend CSAPR. Despite North Carolina's support, CSPAR was ruled unlawful by a DC court on August 12, 2012. The court stated the EPA did not provide adequate guidance for states to develop their State Implementation Plans (SIP), allowing the EPA to impose a Federal Implementation Plan. Additionally, the court found the EPA's calculations of states' downwind impacts to be improper.

The legal battle continued all the way to the U.S. Supreme Court. On December 10th, 2013, the court heard arguments from opposing parties. On April 29th, 2014, the court reversed the DC court's decision. Throughout the legal battle surrounding the CAIR and CSAPR, North Carolina pushed ahead with its plans to comply with the rule and implemented the CSA. Most states chose to abstain entirely from any policy decisions. The decision by North Carolina to move forward may have played a role in North Carolina's exclusion from the final CSAPR rule.

Figure 3 maps the 22 states included in the final CSAPR rule, along with their upwind-downwind ozone linkages. A *downwind linkage* implies that state's NAAQS ozone attainment status is directly impacted by the upwind state it is linked with. Likewise, an upwind linkage implies that state's emissions directly impact the NAAQS ozone attainment status in the downwind state it is linked with. As shown, North Carolina is not included as part of the final CSAPR rule, likewise for South Carolina. While Tennessee is included in the final CSAPR rule, it only has two upwind linkages.

Figure 3. Map of CSAPR Ozone Linkages for Final CSAPR Rule Update



The upwind linkages for Tennessee appear to be driven entirely by just three powerplants. The three plants, in order from largest to smallest polluter are Gallatin, Cumberland, and Johnsonville. All three plants are coal-fired powerplants owned and operated by the TVA. Source for map and plant-level data is from the US EPA (2016).

Figure 3 stands in contrast to Figure 1, where North Carolina, South Carolina, and Tennessee were all considered to have a significant impact on the non-attainment status of downwind states. The change in inclusion could be due to impacts of the CSA or could be due to other factors such as increased generation from natural gas.

CSA and Upwind States

On March 18th, 2004, North Carolina filed a petition under the CAA for the EPA to impose SO_2 and NO_x controls on large coal-fired powerplants in thirteen upwind states. On March 15th, the EPA responded with a denial of North Carolina's petition request. In response to the EPA, the North Carolina Attorney General petitioned the EPA for an administrative reconsideration, which was subsequently denied as well.

However, due to the later court ruling on CAIR, the EPA and DC court agreed that the EPA must reconsider North Carolina's original petition. North Carolina continued with negotiations with the EPA but withdrew its petition against two parties, Maryland and the TVA. The petition was withdrawn from Maryland due to Maryland's own passing of strict emissions limits. As for the TVA, the petition was withdrawn due to the earlier settlement reached by both parties.

In April of 2008, the EPA exempted sources of NO_x in Georgia from any summertime restrictions under the EPA's NO_x SIP Call rule. On June 20th of that same year, the North Carolina Attorney General filed a petition in the DC court for review of the EPA's decision to exempt Georgia. On November 24th of 2009, the DC court ruled against North Carolina, stating that the petition had no legal standing

CHAPTER IV

HISTORY OF DUKE POWER AND PROGRESS ENERGY

To provide context for this retrospective policy analysis, this chapter summarizes the history of Duke Energy and Progress Energy and highlights the transition from on-site generation to trade across a grid. In the last section of this chapter I focus on the structure of the modern-day market for electricity and the differences between an independent service operator (ISO) and integrated utilities. The key relevance for the final analysis is in how easily Duke Energy and Progress Energy can trade electricity, both between themselves and across state lines.

For both utilities, the historical timelines can be divided into three broad periods: direct selling of electricity to customers, bilateral trade of electricity, and the formation of wholesale electricity markets. The overall evolution of the utilities was from on-site generation for a manufacturer to a modern-day electricity grid.

Duke Power

In the late 19th century, the market for electricity was in its infancy. Most manufacturing used steam from coal boilers or belts driven by a water wheel and shaft. However, manufacturers began to realize that electricity offered productivity gains, which sparked the shift towards electrification (Hughes, 1983). As manufacturers began installing generators and electrifying factories in the Northeast, manufacturers throughout the South followed.

At the turn of the 20^{th} century, tobacco magnate James Duke began investing in electricity. Leveraging the wealth Duke amassed from the American Tobacco Company, he purchased land along rivers in proximity to large textile mills throughout the Carolinas. Before Duke had constructed his first plant, he had grand plans of dominating the Southeast's electricity market. The first company, of what would later become Duke Power, was a company called the Catawba Power Company (Duke Energy, n.d.).

In 1904 the Catawba Power Company brought its first powerplant online, the Catawba Hydro Station, in South Carolina. The hydroelectric dam served just one customer, the Victoria Cotton Mills in South Carolina. For Duke, this arrangement was typical: building a hydroelectric plant near textile mills, providing power directly to those textile mills, and acting as a monopoly for electrical generation. Duke and his business partners, Dr. Gill Wylie and William States Lee, hoped that by building hydroelectric facilities at existing mill sites they would not only improve the productivity of existing manufacturers but also entice more complex industries to open facilities in the South (Maynor, 1980).

In 1911, The American Tobacco Company was broken up as part of a trust-busting campaign. While not directly impacting Duke's electricity business, this shift for Duke led him to expand the customer base of his electricity business. The shift in Duke's business led Southern Power Company to diversify its customer base and push to provide electricity to residential customers. Yet for there to be residential customers there needed to be demand for electricity from households.

To solve this issue, a subsidiary of The Southern Power Company, called Mill-Power Supply Company, began an aggressive campaign to sell electric appliances to households (Grant, 2007). In addition to showing households the efficiency gains to be had by using electric appliances, Mill-Power Supply Company also sold their appliances at a deep discount. Such marketing and incentives resulted in Mill-Power Supply Company becoming the top appliance seller for much of the Piedmont region. It also led to a significant customer base expansion of the Southern Power Company. By the 1920s, residential sales represented approximately 25% of Southern Power Company's total revenues.

After the mid-1920s, the Southern Power Company became known as Duke Power. Struck by a drought in 1925, Duke Power could not meet demand with its hydroelectric plants and responded by turning on all its auxiliary coal-fired powerplants. The 1925 drought led Duke Power to pivot towards larger centralized steam plants for generation (Maynor, 1980). In 1926 the Buck Steam station in Salisbury came online and was Duke Power's first coal-fired powerplant. With 256 megawatts of capacity at its peak, the Buck Steam Station was only the beginning.

After the Great Depression and World War II, Duke's portfolio of powerplants expanded greatly and two of Duke's largest coal-fired powerplants were built, the Dan River plant in North Carolina and the W.S. Lee plant in South Carolina. Both plants were online by 1952 and brought a combined capacity of 320 megawatts to Duke Power's grid (Grant, 2007). By the 1990s, Duke Power's portfolio in North Carolina expanded to include seven coal-fired powerplants for a total capacity of 7.55 gigawatts.

Table 5 lists Duke Power's seven coal-fired powerplants in North Carolina. Duke Power's youngest powerplants, Belews Creek and Marshall, are also the largest in terms of generating capacity. By 2013, three of the plants retired. Of the three retired plants, the Buck and Dan River stations are now 620 megawatt combined-cycle plants.[7] These seven coal-fired powerplants are Duke Power's portion of the powerplants targeted by the CSA.

Table 5. Duke Power's Coal-fired Powerplants in North Carolina

Plant Name	Nameplate Capacity (MW)	Number of Boilers	Number of Generators	Year Online	Status (as of 2017)
Belews Creek	2160.144	2	2	1974	Operating
Buck	474.565	5	7	1926	Retired (2013)
Cliffside	780.9	5	5	1940	Operating
Dan River	387.97	3	6	1949	Retired (2012)
G. G. Allen	1155	5	5	1957	Operating
Marshall	2000	4	4	1964	Operating
Riverbend	601.2	4	8	1929	Retired (2013)

Source: Plant characteristics from the 1999 eGRID while vintages and operating status are from plant profiles on Duke Energy's website (https://www.duke-energy.com/our-company/about-us/power-plants).

Progress Energy

Progress Energy began as the merger of three companies, creating the Carolina Power and Light Company (CP&L) in 1908. Like Duke Power, CP&L's first plants were

[7] Combined-cycle plants use both a natural gas turbine and a steam turbine to spin generators. The natural gas turbine spins a direct-drive generator. Meanwhile, the excess heat from the natural gas engine is used to make steam and power a steam turbine.

hydroelectric dams and targeted textile mills as their initial customers. Starting with 1100 customers in 1908, the initial service area was confined to Raleigh, Sanford and Jonesboro (Morris, n.d.).

In 1926 CP&L reincorporated, adding four companies: the Yadkin River Power Company, the Asheville Power and Light Company, the Pigeon River Power Company, and the Carolina Power Company. The reincorporation expanded CP&L's service greatly, a trend that would continue over the next ten years. This expansion led CP&L to invest heavily in increasing capacity, only to be hit by the Great Depression soon thereafter. From 1933 to 1936 CP&L paid no dividends and reduced salaries while a significant portion of its recently increased capacity sat idle (Dinger, n.d.).

As the United States' economy was recovering, the nation was soon dragged into World War II and CP&L's excess capacity soon found a need. During wartime CP&L increased capacity, laid miles of transmission lines, and added radio communications. All of the infrastructure investments made during wartime led CP&L to be a leader in rural electrification for the Carolinas (Riley, 1958).

With the increased customer base came the need for more generating capacity. Over a period of 30 years (1954 – 1983), CP&L (Progress Energy) brought the majority of its coal-fired powerplants online. By 1983 Progress Energy had 6.149 gigawatts of capacity across seven coal-fired powerplants in North Carolina. Table 6 lists Progress Energy's seven plants. The largest plant is the Roxboro plant with 2.57 gigawatts of capacity. Of the seven plants, only three are still in operation. Two of the retired plants converted to combined-cycle, L.V. Sutton (625 megawatts) and Lee (920 megawatts).

Table 6. Progress Energy's Coal-fired Powerplants in North Carolina

Plant Name	Nameplate Capacity (MW)	Number of Boilers	Number of Generators	Year Online	Status (as of 2017)
Asheville	837.165	3	4	1964	Operating
Cape Fear	405.973	2	8	1923	Retired (2012)
L. V. Sutton	744.936	3	6	1954	Retired (2013)
Lee	508.62	3	7	1951	Retired (2012)
Mayo	735.84	2	1	1983	Operating
Roxboro	2574.57	6	5	1966	Operating
Weatherspoon	342.192	3	7	1949	Retired (2011)

Source: Plant characteristics from the 1999 eGRID while vintages and operating status are from plant profiles on Duke Energy's website (https://www.duke-energy.com/our-company/about-us/power-plants).

Duke Energy: Duke and Progress Merger

Seeking to reduce operating and capital costs, Duke Power and Progress Energy proposed a merger. On January 10th of 2011 the merger was announced to the public and on July 3rd, 2012 the merger officially completed. The resulting company is now called Duke Energy. Under the CSA, the utilities are targeted separately, regardless of a merger. However, the increased integration of the two utilities should theoretically allow for a reduction in marginal cost. While I do not address the merger in my analysis, an interesting extension would be in estimating any gains from allowing the utilities to trade (e.g. cap across utilities).

Ease of Trade: Integrated Utilities versus ISOs

Both Duke Power and Progress Energy began by directly serving their customers. They built a plant for the sole purpose of providing power to one textile mill or one manufacturing plant. As time progressed, and trade increased between firms, the market for electricity expanded. This general progression is how the industry in North Carolina evolved to its current state.

Sales of electricity fall into one of two broad categories: retail or wholesale. *Retail* sales refer to the purchase of electricity by an end user. *Wholesale* sales are the purchase of electricity from one generating entity to another for reselling. From this point on, the trade of electricity is referring to transactions between utilities within the wholesale market. Within the category of wholesale sales, there are two typical arrangements.

First, utilities that control the supply chain of power from generation to end-of-use are called *integrated utilities*. Integrated utilities will enter into bilateral agreements with other providers of electricity within an interconnected grid.[8] Trade can then be determined by the marginal variable cost of production, known as the *system lambda*. A utility's difference from the system lambda determines if the utility wants to buy or sell electricity in the system at any given point in time (Energy Policy Group, 2016).

Second, utilities can hand over all dispatch and transmission decisions to a third-party. An *Independent System Operator (ISO)* is a third-party that operates and manages

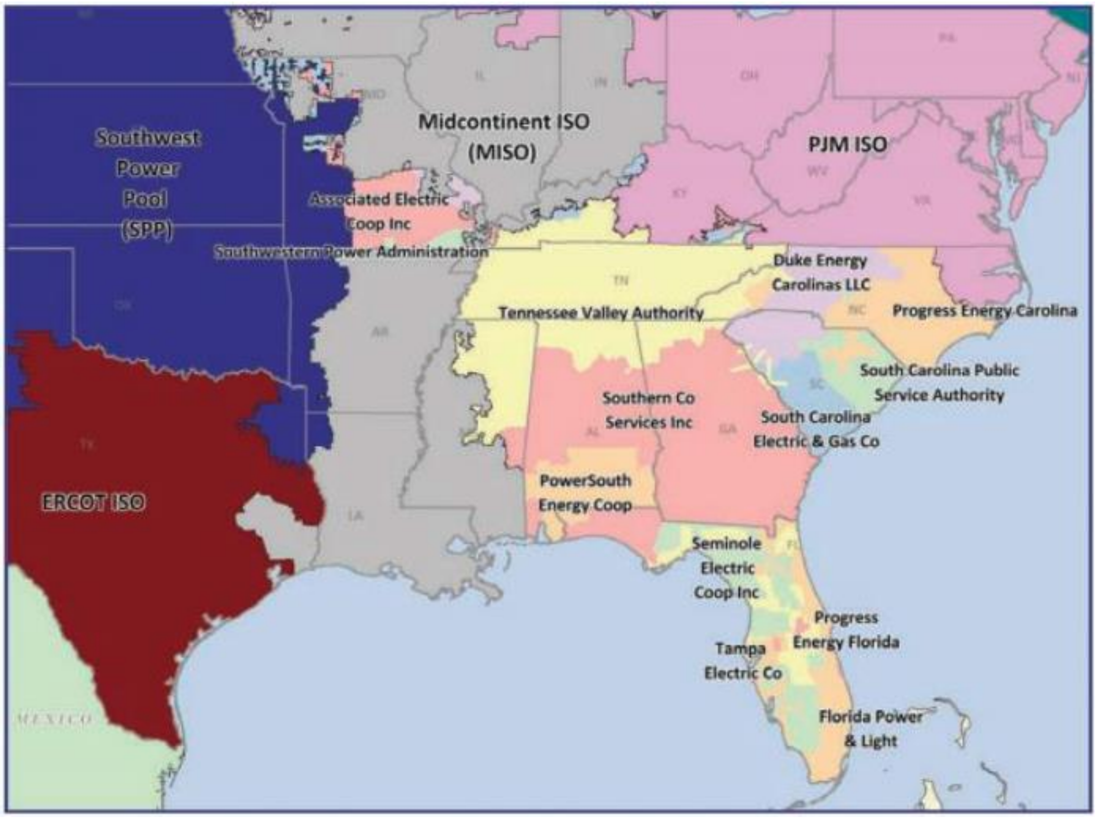
[8] An interconnected grid is a transmission system that is harmonized to the same frequency, allowing for movement of electricity throughout the entire system.

the transmission and dispatch of electricity within a wholesale market (FERC, 2015). In the ISO framework, the distribution of generation is usually determined through an auction process. Each generating utility submits a bid for providing a certain amount of power at a specific time of day. Bids are generally made 24 hours in advance in 1-hour increments. This allows utilities (power producers) to plan accordingly for the next day's generation needs, given the lead time needed to bring certain facilities online. Then, in real-time, the ISO will decide the final dispatch of power and payments are based on a market clearing bid.

Falling into the first category, Duke Power and Progress Energy are integrated utilities. Duke Power is interconnected with Progress Energy and the TVA as part of the Southeast Electricity Reliability Council (SERC).[9] Conversely, most of Virginia and the northeastern corner of North Carolina are within the PJM ISO. Figure 4 shows a map of the current Southeast electricity market, as well as bordering markets.

[9] SERC is the NERC region that encompasses most of the Southeast, excluding the majority of Florida. SERC is within the Eastern Interconnection.

Figure 4. Current Southeast Electricity Market



Source: FERC

Even though integrated utilities and ISOs handle wholesale interactions differently, ISOs are not isolated and are often interconnected beyond the boundaries of their operating region. Integrated utilities and ISOs can, and often do, enter into agreements. These agreements, called *joint operating agreements*, set the conditions under which trade will occur between the integrated utility and the ISO. In the case of Duke Energy and Progress Energy, both utilities held joint operating agreements with PJM (Duke Energy & PJM, 2014; PJM, 2005) The bordering electricity markets play an important role in determining a control group and for analyzing the leakage problem. For both issues, the problem reduces to how easily trade can occur. If Duke and Progress can shift load to bordering utilities, by purchasing power directly or on an open market, then a certain amount of emissions will simply be shifted to bordering states and not abated. For the purposes of picking a control group, this means that areas where trade can occur, with either Duke or Progress, are potentially contaminated as control groups. For the purposes of leakage, determining the ease of trade may help to determine the propensity to leak emissions

CHAPTER V

LITERATURE REVIEW

This chapter is a literature review pertaining to the problem of negative externalities associated with pollution and a potential solution, cap-and-trade. The chapter is divided into two broad categories of work, theoretical and empirical. The theoretical section reviews the literature for the negative externalities problem, cap-and-trade as a policy solution, potential issues with policy design, and criticisms of emissions trading. For the empirical section, four emissions trading programs are explored: Title IV of the Clean Air Act (Acid Rain Program), RECLAIM, RGGI, and the CSA. The empirical section ends with a study of the estimated marginal damages of emissions and how to calculate marginal damages trading ratios.

Table 7. Summary of Research on Cap-and-Trade

Author(s) (Year)	**Research Topic**	**Results**
Theoretical Literature		
Problem: Negative Externality of Pollution		
Pigou (1932)	Negative externalities	The social cost of air pollution is not internalized in the market for electricity. Market failure leads to suboptimal levels of pollution.

Coase (1960)	Property rights and transaction costs	Clearly defined property rights and low-transaction costs can resolve the externality problem.
Hardin (1968)	Firms and social cost	Firms are profit maximizers/cost minimizers and do not consider social cost.
Solution: Cap-and-Trade		
Ackerman & Hassler (1981)	Command-and-control aspects of CAA	Show how a command-and-control approach is vulnerable to political pressures and dealings.
CED (1993)	Overview of environmental issues and policies	Market-based emissions policies are more efficient than command-and-control policies.
Tietenberg (1980)	Efficiency of cap-and-trade	Heterogeneity in abatement costs leads to efficiency gains.
Stavins (1998)	Design of cap-and-trade policy	Four "lessons" of an efficient and effective cap-and-trade policy.
Keohane et al. (1998)	Regulatory options for negative externality problem	Elaborates on the differences between market-based solutions and command-and-control. Also acknowledge issues of political feasibility.
Ellerman (2006)	Effectiveness of cap-and-trade	Cap-and-trade has been effective in the United States, even compared to other policies.
Tietenberg (2006)	Cap-and-trade, theory vs. practice	Overview of cap-and-trade in the United States. Compares how cap-and-trade has been implemented in practice versus theory.

Uncertainty and Asymmetric Information		
Weitzman (1974)	Asymmetric Information; Prices vs. Quantities	Firms' private information on abatement costs leads to sub-optimal cap choice by regulator. Slopes of marginal abatement costs and marginal benefits determine which policy option is more efficient (tax vs. cap-and-trade).
Newell & Pizer (2003)	Dynamic implications; pollution as a stock	Extending Weitzman (1974) to allow for issues of decay, social discount rates, and growth rates of benefits over time.
Trading Ratios		
Montgomery (1972)	Introduction of trading ratios	Heterogeneity in social costs of pollution should be included in the value of a pollution permit.
Mendelsohn (1986)	Marginal damages and trading ratios	Suggests that a regulator uses the relative marginal damages between two firms to fix the trading ratios between two firms.
Farrow, Schultz, Celikkol, & Houtven (2005)	Application of trading ratios	Empirical study of trading ratios used for sewer overflow management in the Upper Ohio River Basin. Trading ratios are welfare improving.
Trading Ratios and Asymmetric Information		
Fowlie & Muller (2013)	Trading ratios and asymmetric information on abatement costs	Firm's private information on abatement costs leads to traditional marginal damage trading ratios to be sub-optimal.
Holland & Yates (2015)	Optimal trading ratios with asymmetric information.	Construct optimal trading ratios when firms hold private information about abatement costs.

Non-economics Criticisms of Cap-and-Trade		
Sandel (1997)	Morality and Cap-and-Trade	Cap-and-trade is immoral due to the ability to buy pollution.
Page (2013)	Ethics of Cap-and-Trade	A market for pollution reduces obligations to be good stewards of the environment.
Empirical Literature		
Acid Rain Program (Title IV)		
US EPA OPA (1992)	EPA Report	Annual benefits of acid rain program are approximately $700 million.
Carlson et al. (2000)	Gains from Trade	The acid rain program led to $780 million in benefits compared to a command-and-control counterfactual.
Chestnut & Mills (2005)	Additional benefits	Reductions by Title IV also had impacts on particulate matter. Including reductions in particulate matter leads to a new net benefit calculation of over $100 billion annually.
Regional Clean Air Incentives Market (RECLAIM)		
(Fowlie, Holland, & Mansur, 2012)	Effectiveness of RECLAIM	Emissions fell about 20% more under RECLAIM compared to command-and-control.
Regional Greenhouse Gas Initiative (RGGI)		
Murray & Maniloff (2015)	Effectiveness of RGGI	A reduction of 24% in emissions is attributable to RGGI. Other factors played a role in overall reductions (i.e. natural gas).

Clean Smokestacks Act (CSA)		
Hoppock, Adair, Murray, & Tarr, (2013)	Cost-Benefit Analysis of CSA	Uses an engineering calculation for estimating the effect of the CSA. Finds range of benefits from $500 million to $16 billion.
Marginal Damages		
Muller & Mendelsohn (2009)	Marginal damages	Estimate county-level marginal damages for SO_2 and NO_x at varying effective stack heights.

Theoretical Literature

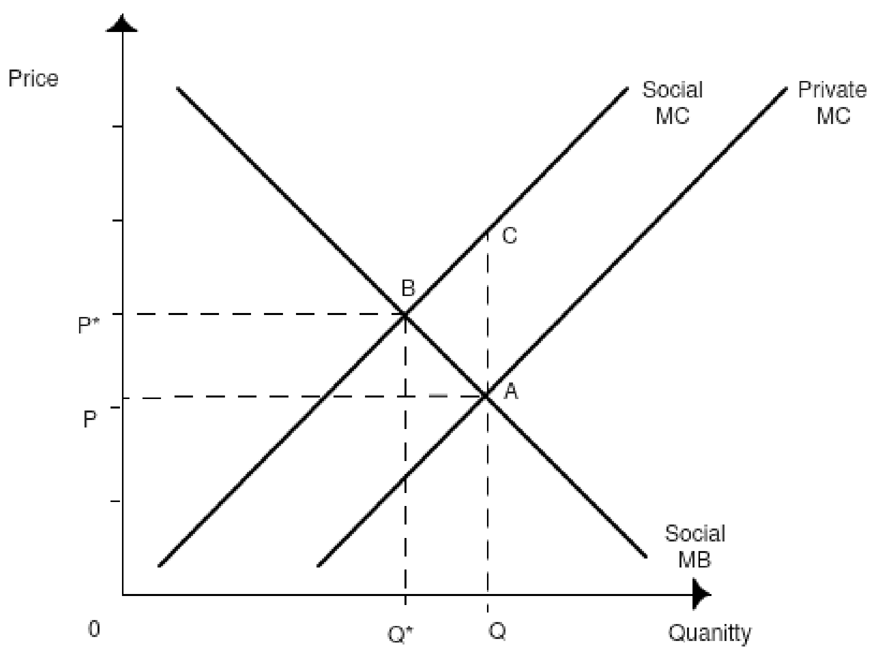
In the case of cap-and-trade, the policy addresses the market failure associated with the cost to society caused by air pollution. More specifically, when a utility produces electricity, it also produces air pollutants which then place a cost on society that is not incorporated into the market. These ancillary outputs affect agents both within and outside the market for electricity.

The Problem: Negative Externalities of Emissions

The market for electricity has two sides: the consumers of electricity and the producers of electricity. Consumers should buy so long as their marginal benefit is greater than or equal to the price of electricity. Firms should produce so long as their marginal cost is less than or equal to the price of electricity. The market equilibrium is where the marginal benefit to consumers is equal to the marginal cost to produce. The *private marginal* cost is defined as the marginal cost to produce, excluding any additional costs imposed on society, such as health costs or agricultural damage stemming from emissions of pollutants. The *social marginal cost* includes the private marginal cost and the additional costs on society. The difference between the private marginal cost and the social marginal cost is the *marginal external cost*.

The market failure surrounding electricity production hinges on the marginal external cost. Without the marginal external cost internalized into the market, the *market equilibrium* is the point where marginal benefit equals the private marginal cost. In Figure 5, the free market equilibrium is point A with a price of P and a quantity of Q. Conversely, with the marginal external cost internalized, the *socially efficient allocation* is where marginal benefit equals the social marginal cost. The socially efficient allocation is represented by point B with a price of $P^*$and a quantity of Q^*.

Figure 5. Negative Externality



To move society towards the socially efficient allocation, there are two broad categories of market-based emissions policies. An *emissions tax* is a fixed dollar amount, per unit of emissions, that emitters pay to the government. With an emissions tax, the regulator is choosing to fix the price of emissions and allowing markets to dictate the equilibrium quantity. The other option is a *cap-and-trade* policy, which allows the regulator to choose a fixed quantity of emissions by issuing permits to pollute, thereby allowing markets to dictate the equilibrium price. In this model, producers can then buy and sell permits on an open market. The key distinction in implementing the two policies is in which variable is being held fixed by the regulator, the price or a quantity.

When the regulator chooses to fix a quantity by implementing a cap-and-trade policy, firms will either buy permits, sell permits, or maintain their level of permits. The choice of whether to buy or sell permits depends on two variables: the current market price for a permit and the marginal abatement cost associated with reducing one more unit of emissions. A plant will buy a permit if the marginal cost to abate is more than the price of a permit. Conversely, a plant will sell a permit if the marginal cost to abate is less than the price of a permit. If the marginal abatement cost is exactly equal to the market permit price, the plant will neither buy or sell. All plants under the cap will behave in this manner, buying or selling permits, until each plant's marginal abatement cost is equal to the market price for one permit.[10]

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[10] There are two caveats. First, the cap must be binding. A non-binding cap will result in a permit price of zero, as there is no demand for permits. Second, the cap is not overly constraining. If a cap is too restrictive,

The first to comprehensively explore the welfare implications of these external costs was Pigou (1932). In Pigou's framework, damages from pollutants are not internalized by the market for electricity. Subsequently, the resulting marginal cost of electricity does not consider the damages from pollutants. Ideally, firms would voluntarily incorporate the cost of emissions. Thus, the ideal marginal cost function, often called the social marginal cost, is greater than the actual marginal cost. In turn, the equilibrium quantity of electricity is greater than the socially optimal quantity. The overconsumption of electricity leads to a deadweight loss to society. Pigou's solution for the externalities problem is to implement a corrective tax. The *Pigouvian tax* is a tax equal to the marginal external cost, shifting the market price closer to the socially optimal price.

Rebutting Pigou, Coase (1960) offers an alternative to a Pigouvian tax. Coase suggests that with clearly defined property rights and near-zero transaction costs, the externalities problem can be resolved through bargaining, without the imposition of a tax. Known as the Coase Theorem, this result relies on the low transaction cost assumption. If the cost is too great for firms to negotiate, bargaining fails and the resulting outcome is inefficient.

Regardless of the solution to the externalities problem, ideally, firms would internalize the cost of pollution on their own. However, in reality, firms do not exhibit

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the price for permits will be too high and may overshoot the penalty for emitting without a permit or force powerplants to shut down.

this behavior. Hardin (1968) shows that as each firm is a profit maximizer, the firm will want to take the least cost approach, irrespective of social cost. Thus, each firm, motivated by its own profits, would not internalize the cost of emissions, resulting in a less than socially optimal quantity of emissions.

Solution: Cap-and-Trade

Tasked with correcting the market inefficiency caused by air pollution, regulators have a multitude of choices. The most primitive policy is for regulators to demand a level of abatement by firms or require a specific abatement technology to be employed This policy option is typically referred to as command-and-control. If abatement costs are homogeneous across firms and are known to the regulator, the command-and-control option can be the cost-effective choice. However, command-and-control is the most rigid of the policy choices. The inflexibility frequently leads to a result that is costlier than a market-based policy. By some estimates, command-and-control is five times costlier than its market-based counterpart (CED, 1993). Additionally, political pressures can have a greater influence on command-and-control than in a decentralized market-based approach (Ackerman & Hassler, 1981).

To arrive at the least cost solution, a market-based policy option employs market forces to cost-effectively distribute abatement costs across firms. Tietenberg (1980) explains that by exploiting the heterogeneity of abatement cost functions between firms, a cap-and-trade policy can meet the same emissions target as a command-and-control policy but with lower total abatement cost. Each firm minimizes abatement costs due to the flexibility of cap-and-trade.

Summarizing the cap-and-trade literature, Stavins (1998) compiles a comprehensive list of “lessons” for the design of cap-and-trade policies. First, the flexibility of cap-and-trade allows firms to choose the appropriate abatement method and spur innovation. Second, the simplicity of the policy can keep enforcement and compliance costs low for the regulator and firms. Third, when there is credible enforcement, such as stiff penalties and continuous emissions monitoring, confidence can be instilled in the permit market. Lastly, revenues can be raised by the government if permits are auctioned as opposed to freely-allocated. Revenues can then be used to offset enforcement and compliance costs.

Exploring in detail the regulatory options for tackling the negative externality problem, Keohane et al. (1998) explains why thirty years of environmental policy has diverged from economic theory. In their article they list four gaps between economic theory and environmental policy in practice. First, command-and-control is used significantly more often than market-based solutions despite the potential efficiency gains of the latter. Second, *grandfathering*, or disproportionately regulating emissions of new plants, incentivizes firms to keep older and often dirtier plants in service. Third, almost all (as of 1998) market-based policies have been cap-and-trade and not emissions taxes. Fourth, there is a gulf between political acceptance and policies in practice.

On market-based emissions policies, Ellerman (2006) collects essays analyzing the market-based policies in practice throughout the world and compares those policies to traditional command-and-control policies. The consensus is that market-based policies have been more efficient than command-and-control policies. However, the contributors of those essays warn of the potential pitfalls of poor policy design and weak enforcement.

Another overview of cap-and-trade in practice, Tietenberg (2006) summarizes most of the cap-and-trade policies implemented in the United States and delves into the theory surrounding them. Theoretical topics include issues of location, how to initially allocate permits, the inclusion of offsets, market power, and enforcement. Looking across thirty years of policy, Tietenberg (2006) arrives at a similar conclusion as Ellerman (2006). Cap-and-trade policies have largely been effective, but care should be taken by policy makers in their implementation.

Uncertainty and Asymmetric Information:

In a perfect world, the regulator would know the firm's abatement cost function, prior to setting the parameters of an emissions trading program. However, the regulator only observes abatement cost information ex post. This asymmetry of information between the firm and the regulator is what Weitzman (1974) studies. By introducing uncertainty into the regulator's optimization problem, Weitzman shows that a regulator's choice of an equilibrium quantity is likely to not be the cost-effective quantity. The reason being, ex post, the cap is either too tight and abatement costs are larger than expected or too loose and the abatement costs are lower than expected. Furthermore, the choice of whether to fix a price or a quantity is determined by the slopes of marginal costs and marginal benefits.

Using Weitzman (1974) for inspiration, Newell & Pizer (2003) focus on. CO_2, which builds in concentrations over time, and frame CO_2 emissions as a stock and the subsequent externalities as stocks. This distinction has dynamic implications for policy. As in Weitzman (1974), Newell & Pizer (2003) the slopes of the marginal cost and marginal benefit curves dictate the prices vs. quantities decision. However, dynamic parameters such as decay rates of pollutant stock, social discount rates, and the growth rates of benefits over time all affect the prices vs. quantities debate.

Trading Ratios:

When implementing an emissions trading scheme a regulator has more than the emissions cap at their disposal. One potential concern by the regulator is the distribution of damages. When thinking of local pollutants such as sulfur dioxide (SO_2) and nitrogen oxides (NO_x) location matters. If a coal plant is positioned in proximity to a densely-populated area, society may wish to place a higher cost on that firm to pollute. Conversely, in a rural area, without much in terms of agriculture, society may wish to lower the cost to pollute.

One such option is to alter how permits are traded. More specifically, to implement differentiated trading permits, as recommended by Montgomery (1972). For example, let us assume firm A wishes to sell permits to firm B. The regulator can dictate the amount of firm A's permits that are equivalent to a permit for firm B. If the trading ratio was 2:1 for firm B, it would mean that firm B would need to purchase two permits for every unit of emissions. By deviating from the 1:1 ratios of a standard permit market, a regulator can attempt to address concerns other than cost-effectiveness. Mendelsohn (1986) suggests that a regulator could calculate the marginal damage of emissions from each plant and calculate trading ratios using marginal damages for each plant. The heterogeneity in social cost due to emissions, in terms of damages, would then be incorporated into the market.

Outside of air pollution, trading ratios can also be used for the cost-effective controlling of other forms of emissions. For example, Farrow et al (2005) study marginal damages trading ratios for effluent. In the context of sewer overflow management in the Upper Ohio River Basin, they find that trading ratios are welfare improving and exhibit significant cost-savings in comparison to a command-and-control policy. The welfare gains found in Farrow et al (2005), further bolster the argument for the use of trading ratios.

Trading Ratios and Asymmetric Information:

In a world of perfect information, marginal damages trading ratios could be optimal. Under imperfect information, marginal damages trading ratios are only optimal under special circumstances. The divergence of optimal trading ratios from marginal damages trading ratios arises when there is uncertainty about a firm's abatement function. The result is a mismatch between expected costs of abatement and realized costs of abatement, as the regulator cannot set a cap ex post. The first to address the mismatch between optimal and actual trading ratios is a working paper by Fowlie and Muller (2013). Their paper shows that when incorporating uncertainty about abatement costs, marginal damages trading ratios are sub-optimal. However, the working paper does not explore what an optimal trading ratio may be.

To answer the question of what an optimal trading ratio is, Holland and Yates (2015) and give insight into what an optimal trading ratio is in the presence of asymmetric information. If the regulator knows distributional information about abatement costs, then expectations about abatement costs can be included into the trading ratios of firms. Thus the Holland & Yates (2015) optimal trading ratios lessen the difference between expected costs and actual costs.

Non-economics Criticisms of Cap-and-Trade

Despite cap-and-trade's theoretical economic appeal, the policy option is no stranger to criticism. In an article to the New York Times, Sandel (1997) makes a moral argument against cap-and-trade. Sandal makes three main objections. First, Wealthy countries are able to purchase their way out of environmental obligations. Second, placing a price on emissions removes the "moral stigma" surrounding emissions. Third, cap-and-trade can remove the sense of "shared responsibility" surrounding environmental issues.

Page (2013) critiques an international cap-and-trade policy to combat the rise of greenhouse gases. Page lists four counterpoints to cap-and-trade as a policy. First, cap-and-trade weakens the obligation for firms to take responsibility for their emissions.

Second, the market-based policies are indiscriminate in their treatment of rich and poor countries and place an undue strain on impoverished countries. Third, clean air is a public good and should not be treated as a private good by placing it within a market. Lastly, the intrinsic value of emissions reductions will erode over time by attaching reductions to market forces.

Empirical Literature

Acid Rain Program

Title IV of the 1990 Clean Air Act is, currently, the largest experiment of cap-and-trade in the United States. Such an expansive policy gives researchers a prime opportunity to test for the theoretical literature. US EPA, OPA (1992) provides an exhaustive summary of environmental policies in the United States, as of 1992. In their report, the EPA's Office of Policy Analysis provides an initial estimate of net benefits for the Acid Rain Program of $700 million annually.

Perhaps the most comprehensive empirical study of the Acid Rain Program is Carlson et al, (2000). In their paper, Carlson and his co-authors estimate the gains from trade associated with cap-and-trade. To do so, a counter-factual "enhanced command-and-control" case is created. The result is an estimated $780 million of gains from trade. Furthermore, Carlson et al, (2000) states that ex ante estimates of gains can be sensitive to dynamics such as fuel prices over time and the evolution of technology.

Revisiting the Acid Rain Program, Chestnut & Mills (2005) includes recent research on the health impacts of $PM_{2.5}$ and recalculates the estimated net benefits of the policy. Including avoided damages from the reduction of $PM_{2.5}$ results in net benefits greater than $100 billion annually by 2010 when the NO_x reductions portion of the policy are fully implemented.

Regional Clean Air Incentives Market (RECLAIM)

Another implementation of an emissions trading scheme is the NO_x trading program in Southern California , the Regional Clean Air Incentives Market (RECLAIM). Fowlie et al (2012) uses RECLAIM as a natural experiment to answer two theoretical questions. First, does cap-and-trade allow for more stringent emissions targets than a command-and-control policy? Second, should policy makers be concerned about environmental injustice?

In short, the answer to the first question is a, "yes." Using a difference-in-differences approach, Fowlie and her coauthors find that emissions fell by about 20% under RECLAIM in comparison to the counter-factual of a command-and-control policy. As for the second question, using neighborhood demographic data, no statistically significant relationship exists between characteristics like income or race and an increase in emissions due to RECLAIM.

Regional Greenhouse Gas Initiative (RGGI)

The Regional Greenhouse Gas Initiative (RGGI) brings together nine states in the Northeastern U.S. to form a regional C&T greenhouse gas (GHG) program. According to Murray & Maniloff (2015), RGGI caused a 24% reduction in emissions, but other factors, such as natural gas prices and other environmental programs, were influential.

Clean Smokestacks Act (CSA)

As illustrated in Chapter II, the CSA is a state-level cap-and-trade policy for utility-owned coal-fired powerplants in North Carolina. Given its scale and scope, there is only one study evaluating the effectiveness of the policy. (Hoppock et al., 2013) is a working paper from the Nicholas Institute at Duke University that estimates the reductions in emissions through an engineering calculation. The authors assume that the units which install abatement technology would have otherwise emitted at the emission rates in the year prior to installation. By taking this approach for determining emissions in the absence of the CSA, it is assumed reductions in emissions are only made via the installation of abatement technology and not through the reduction in generation. Additionally, any overall trends in the electricity generation industry are ignored; such as the natural gas boom that encouraged, and continues to encourage, the switch from coal to natural gas for electricity generation.

Marginal Damages

To implement marginal damages trading ratios, estimates of marginal damages are necessary. Muller & Mendelsohn (2009) were the first to calculate estimates of marginal damages, on a national level. Using the 2002 National Emissions Inventory (NEI) data, the paper calculates a baseline of damages then increases pollution at one source by one unit and recalculates total damages. The difference between the baseline and new total damages is the marginal damage of pollution x from firm y. This process is repeated for six pollutants, coarse particulate matter, fine particulate matter, NO_x, SO_2, volatile organic compounds, and ammonia across 10,000 sources. The result is a marginal damage estimate for each county, varying by stack height of emitter.

CHAPTER VI

TO LEAK OR NOT TO LEAK

In implementing a regional emissions policy there is often the risk of a spillover of emissions called e*missions leakage*. The emissions leakage occurs in an area where the policy is not in effect. For example, in the context of the CSA, powerplants in bordering states can emit SO_2 and NO_x freely in comparison to the CSA plants. Without a cost imposed on emissions at the non-CSA plants, the marginal cost at a non-CSA plant would be less than the marginal cost at a CSA plant, all else equal. The cheaper production cost should provide an incentive to shift production from the CSA targeted plants to the non-CSA targeted plants.

To explore the issue of leakage, two models are presented. The first is a model of abatement cost minimization without leakage, and the second a model of abatement cost minimization with leakage. Both models are identical except for the leakage component. In both models, firms are minimizing their net abatement costs.

Without Leakage

The exogenous variables to the firm are the initial allocation of permits (emissions) to firm i, defined as E_i^0, and the market permit price, P. In the context of the CSA, which does not have an explicit permit market, the market permit price can be thought of as the marginal cost of shifting emissions to another CSA plant. The plant reducing emissions is behaving like a buyer of permits and the plant increasing emissions is behaving like a seller of permits. The choice variables are the level of emissions from firm i, defined as E_i, and the net permits traded by firm i, E_{NT_i}. Let the cost of emissions be $C_i(E_i)$, where it is assumed the more a firm abates the greater the total abatement cost and the greater the marginal cost of abatement[11]. In the context of electric utilities, the first few units of emissions would be cheaper to abate as the utility could adjust how it burns fuel or in the type of fuel used, such as switching to low-sulphur coal. As the utility abates more, greater investments in capital are needed, resulting in a much higher marginal cost to abate. For example the marginal abatement cost will be higher for the twentieth ton of emissions compared to the first ton.

The resulting problem the firm faces is the minimization of net abatement costs, subject to the constraint that a firm cannot emit more than the amount of permits it holds.

$$\min_{E_i, E_{NT_i}} C_i(E_i) + P * E_{NT_i} \;\; s.t. \;\; E_i \leq E_i^0 + E_{NT_i}$$

The net abatement cost is simply the sum of the cost of abatement and the cost of permits purchased. [12] At the individual firm level, each firm is constrained to pollute no more than their initial allocation of permits net the permits sold or bought. Following from the minimization problem, the following Lagrangian can be formed.[13]

[11] The assumption can also be stated as $\frac{\partial C}{\partial E_i} < 0$ and $\frac{\partial^2 C}{\partial E_i^2} > 0$

[12] The cost of permits purchased is negative if the firm is a net seller of permits.

[13] Multiplying the objective function by -1, turns the minimization problem into a maximization problem.

$$L = -C_i(E_i) - P * E_{NT_i} + \lambda(E_i^0 + E_{NT_i} - E_i)$$

Deriving the Kuhn Tucker conditions:

$$E_i \geq 0\text{:}\ -\left(\frac{\partial C_i}{\partial E_i}\right) - \lambda_\mathrm{i} \leq 0$$

$$E_{NT_i} \geq 0;\ \ P + \lambda_i \leq 0$$

$$\lambda_i \geq 0;\ E_i - E_i^0 + E_{NT_i} \geq 0$$

Then by complementary slackness, the following first order conditions hold:

$$-\left(\frac{\partial C_i}{\partial E_i}\right) = \lambda_\mathrm{i}$$

$$P = \lambda_i$$

$$E_i = E_i^0 + E_{NT_i}$$

The first order conditions imply that in equilibrium, firms will choose the level of abatement which equates marginal abatement cost, defined as MAC_i, to the market permit price $\left(MAC_i(E_i) = \frac{\partial C_i}{\partial E_i} = P\right)$. Note that the equilibrium level of emissions for a firm does not depend on the firm's initial allocation of permits. Thus, the distribution of initial permits does not impact the equilibrium distribution of emissions. For the regulator, this means the importance of how to allocate initial permits is trivial.

From the first order conditions, the following propositions can be derived:

Proposition 1

If a firm's marginal abatement cost is less than the permit price, the firm will be a net seller of permits. If a firm's marginal abatement cost is greater than the permit price, the firm will be a net buyer of permits.

$$MAC_i(E_i^0) < P \Rightarrow \; E_{NT_i} < 0$$

$$MAC_i(E_i^0) > P \Rightarrow E_{NT_i} > 0$$

Proof: Suppose $E_{NT_i} > 0$,

$$MAC_i(E_i) = P$$

$$MAC\left(E_i^0 + E_{NT_i}\right) = P$$

$$MAC(E_i^0) > MC\left(E_i^0 + E_{NT_i}\right)$$

$$MAC(E_i^0) > P$$

Proposition 2

The number of permits bought and sold is the net of the firm's equilibrium level of emissions and their initial allocation of permits.

$$E_{NT_i} = E_i - E_i^0$$

Proof: The first order conditions give $E_i = E_i^0 + E_{NT_i}$. By a rearranging of terms, I can arrive at $E_{NT_i} = E_i - E_i^0$.

Through propositions 1 and 2 it is evident that the initial allocation of permits is merely a starting point for firms, dictating only how the firms arrive at the equilibrium level of emissions. If the firm starts with an excess of permits, they will sell. If the firm starts with a shortage of permits, they will buy. The subsequent decision to buy or sell permits depends on the firm's marginal abatement cost. Maintaining the same framework, I now introduce leakage in the model.

With Leakage

To allow for leakage, only a couple of modifications to the original model are needed. First, define the level of emissions leaked as, E_{L_i}. Second, the cost for a firm to leak emissions is $C_{L_i}(E_{L_i})$. Assume that leaked emission costs are increasing at an increasing rate[14]. In other words, the more a firm decides to shift emissions to non-CSA plants, the more expensive the marginal unit of leaked emissions.

Placing the cost to leak emissions in the context of electrical utilities, the cost for the first few units of leaked emissions is relatively cheap. A utility can generate less electricity at one plant and more at another, which is outside of the policy area, assuming the plants are on the same grid. Yet as the firm shifts production to other plants, changes

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[14] The assumption can also be stated as $\frac{\partial C_L}{\partial E_{L_i}} > 0$ and $\frac{\partial^2 C_L}{\partial E_{L_i}^2} > 0$

in capital must occur. A utility would have to start expanding existing plants or build new plants that are outside of the policy area.

As before, the firm is faced with a cost minimization problem. With leakage, the net abatement cost is defined as the sum of abatement cost, cost of permits purchased, and the cost to leak emissions. The minimization problem can then be written as:

$$\min_{E_i, E_{NT_i}, E_{L_i}} C_i(E_i) + P * E_{NT_i} + C_{L_i}\left(E_{L_i}\right)\ s.t.\ E_i \leq E_i^0 + E_{NT_i} + E_{L_i}$$

The subsequent Lagrangian[15] can then be written as:

$$L = -C_i(E_i) - P * E_{NT_i} - C_{L_i}(E_{L_i}) + \lambda_{L_i}(E_i^0 + E_{NT_i} + E_{L_i} + E_i)$$

Deriving the Kuhn-Tucker conditions I arrive at the following:

$$E_i \geq 0;\ -\left(\frac{\partial C}{\partial E_i}\right) - \lambda_{\mathrm{i}} \leq 0$$

$$E_{NT_i} \geq 0;\ P - \lambda_i \leq 0$$

$$E_{L_i} \geq 0;\ -\left(\frac{\partial C_L}{\partial E_{L_i}}\right) - \lambda_{\mathrm{L_i}} \leq 0$$

$$\lambda_{L_i} \geq 0; E_i - E_i^0 - E_{NT_i} - E_{L_i} \geq 0$$

[15] Once again, the minimization problem is turned into a maximization problem.

By complementary slackness, the subsequent first order conditions hold:

$$-\left(\frac{\partial C}{\partial E_i}\right) = \lambda_{\mathrm{L_i}}$$

$$-P = \lambda_{L_i}$$

$$-\left(\frac{\partial C_L}{\partial E_{L_i}}\right) = \lambda_{\mathrm{L}_i}$$

$$E_i = E_i^0 + E_{NT_i} + E_{L_i}$$

Just as before, the first order conditions imply that a firm chooses the level of abatement which equates the marginal abatement cost to the permit price. Once again, the equilibrium level of abatement does not depend on the initial allocation of permits. Diverging from the model without leakage, a firm will choose a level of leaked emissions which equates the marginal cost to leak $\left(MC_{L_i}\right)$ with the permit price.

<u>Proposition 3</u>

If the marginal cost to leak emissions is less than the permit price, firms will increase leaked emissions.

$$MC_{L_i}\left(E_{L_i}\right) < P \Rightarrow \mathrm{E'}_{\mathrm{L_i}} > E_{L_i}$$

Proof:

$$MC_{L_i}(E'_{L_i}) = P$$

$$MC_{L_i}(E_{L_i}) < MC_{L_i}(E'_{L_I})$$

$$MC_{L_i}(E_{L_i}) < P$$

Proposition 3 states that a firm will leak emissions up until the point where it is just as costly to purchase an emissions permit as it is to leak emissions. Additionally, if the marginal cost of leaking emissions is greater than the permit price then the firm will not leak emissions.

CSA Plants and Leakage

The intuition behind this modeling exercise is simple, the plants in the CSA reduce emissions such that costs are minimized across each utility. To achieve this least-cost solution, the plants implement some combination of installing abatement technology, shifting production to other CSA plants, and/or leaking emissions. The choice between the abatement options depends on the marginal costs associated with each option. So long as a plant is reducing emissions, it will choose the cheapest abatement option available

CHAPTER VII

DATA

To evaluate the impact of the CSA on emissions, data on emissions at the powerplant-level is necessary. Additionally, plant characteristics are needed when applying the synthetic control method. Publicly available powerplant emissions data for the United States comes from the Continuous Emissions Monitoring System (CEMS). Put in place to facilitate enforcement of the Acid Rain Program, the CEMS provides hourly emissions data by generating unit for almost all powerplants in the United States. Plant characteristics are from the Emissions and Generation Resource Integrated Database (eGRID). The result of combining the two datasets is a panel of each utility-level powerplant in the United States, complete with emissions, generation, and plant characteristics. Plant characteristics include number of boilers, number of generators, nameplate capacity, fuel type, utility ownership, operator, location, and regulatory region.

Sources Processing

To arrive at the final dataset used for this analysis, the starting point is the raw CEMS data. Managed and hosted by the EPA, the raw CEMS data spans from 1995 to 2017.[16] The raw data can be queried using the EPA's data query web application or

[16] At the time of analysis, the most complete data is from 1997 to 2014.

downloaded directly from their ftp server. Choosing the ftp option,[32] the data is downloaded as individual zip-files containing a .csv file at the state-month-year level. Within each .csv file, the unit of observation is at the boiler-hourly level. Using STATA to loop over every file within a state, each individual zip-file is unzipped, and then the .csv file is extracted and converted to a STATA dataset (.dta file). Once the individual .csv file is converted to a STATA dataset, it is then aggregated from the boiler-hourly level to the plant-monthly level. Levels of emissions, generation, and heat input are summed across plant-month while emission rates are averaged across plant-month. The plant-month cross-sections are then compiled into a panel for each state. After looping over each state, a master panel of all states within the analysis is created.

[32] ftp://ftp.epa.gov/dmdnload/emissions/hourly/monthly/

Figure 6. Flowchart of Process to Clean and Compile Data

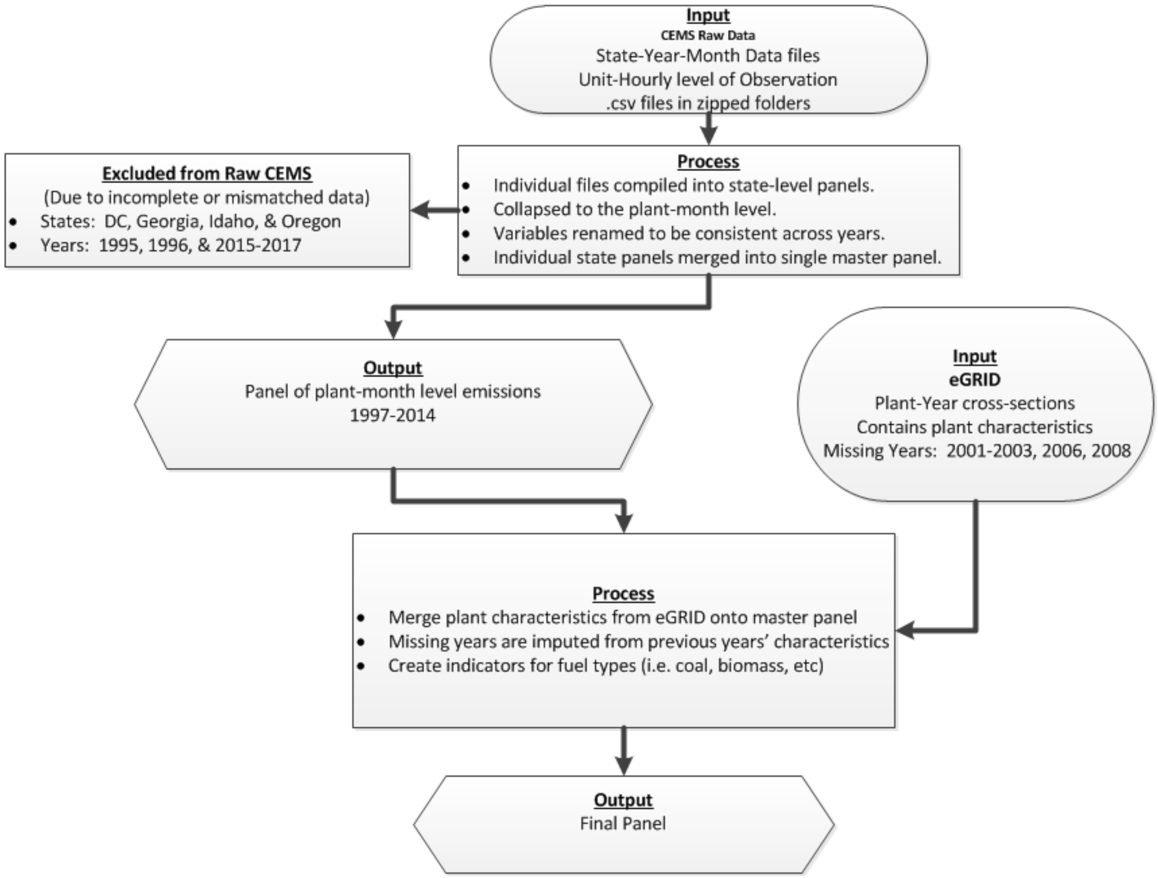


Figure 6 summarizes the steps for compiling the final analytical dataset. Beginning with the CEMS raw data files, the state-month .csv files are compiled into a single panel at the plant-month level. The District of Columbia, Georgia, Idaho, and Oregon are excluded from the final panel due to systemic missing data and inconsistent variables (posing a problem for compiling a complete panel). The years 1995 and 1996 are excluded due to incomplete cross-sections. At the time of the analysis, the years 2015 through 2017 were not yet publicly available. The resulting panel is from 1997 to 2014 at the plant-month level.

Plant characteristics from the eGRID data are then merged onto the compiled CEMS panel. Missing years from the eGRID data are assumed to be identical to their prior years. For example, if a plant was primarily a coal-fired powerplant in 2003 with four generating units then it is assumed to be a coal-fired powerplant in 2004 with four generating units. Indicators are also created to group the primary fuel types.[33] Table 8 shows the grouping of the primary fuel types.

[33] The broader fuel types are used later in the pre-treatment minimization required for the synthetic control method.

Table 8. Grouping of Primary Fuel Types

Fuel Group	Primary Fuel Type
Biomass	Agricultural byproducts
	Black liquor
	Digester gas (other biomass gas)
	Landfill gas
	Municipal solid waste
	Other biomass liquids
	Other biomass solids
	Sludge waste
	Wood, wood waste liquid
	Wood, wood waste solid
Coal	Bituminous coal
	Lignite coal
	Subbituminous coal
	Synthetic coal
	Waste coal
Natural Gas	Natural gas
Other Gas	Blast Furnace gas
	Butane gas
	Other gas
	Process gas
	Refinery gas
	Coke oven gas
Oil	Distillate fuel oil, light fuel oil, FO2, diesel oil
	Jet fuel
	Kerosene
	Other oil
	Petroleum coke
	Residual fuel oil, heavy fuel oil, petroleum
	Waste oil
Other Fuel	Hydrogen
	Tire-derived fuel

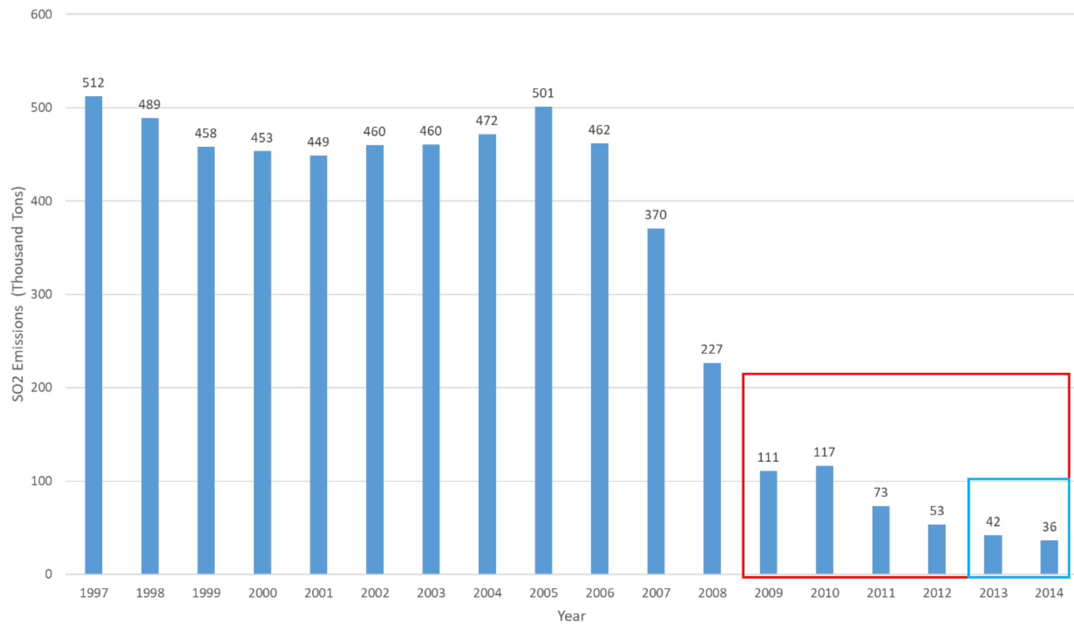
Continuous Emissions Monitoring System (CEMS)

The CEMS came about due to the enforcement requirements of Title IV, when regulators needed the ability to measure SO_2, NO_x, and CO_2 emissions. Emissions are reported as rates and levels. SO_2 and NO_x levels are reported in pounds and CO_2 levels are reported in tons. Rates are reported in pounds per one million British Thermal Units (mmBTUs) for SO_2 and NO_x, while CO_2 rates are in tons per mmBTUs. In addition to emissions, the CEMS data also includes heat input (mmBTU) and generation (MWh).

CSA Plants

The CSA targets fourteen coal-fired powerplants: seven owned by Duke Power and seven by Progress Energy. Figure 7 graphs aggregate annual emissions of SO_2 for the CSA plants from 1997 to 2014. In 1997, the CSA plants emitted 512,000 tons of SO_2. In 2000, annual emissions dropped to 453,000 tons and then returned to 501,000 tons in 2005. When the first cap came into effect in 2009, emissions dropped to about 111,000 tons. Overall, SO_2 emissions were relatively stable in the leadup to the phase-one cap until a steep decline in the three years preceding the phase-one cap. After the initial cap, emissions dropped by approximately 50% to comply with the phase-two cap.

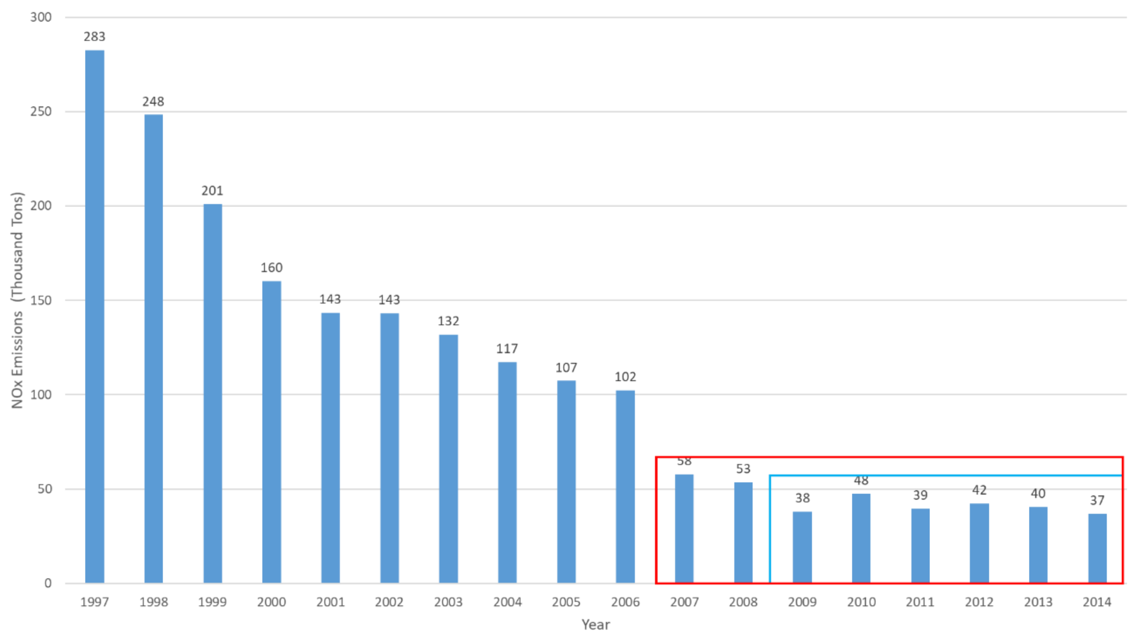
Figure 7. Total Annual Emissions of SO_2 for CSA Plants



The red box indicates the phase-one cap and the blue box indicates the phase-two cap.

Figure 8 shows aggregate annual emissions of NO_x from the fourteen CSA plants. The red box represents the phase-one cap and the blue box represents the phase-two cap. Starting in 1997, the CSA plants collectively emitted 283,000 tons of NO_x. By 2002, when the CSA passed, emissions of NO_x dropped to 143,000 tons. This downward trend continues until 2007, when the first cap is enforced, and the CSA plants emitted 58,000 tons of NO_x. From 2007 to 2014, aggregate annual emissions of NO_X remain flat.

Figure 8. Total Annual Emissions of NO_x for CSA Plants



The red box indicates the phase-one cap and the blue box indicates the phase-two cap.

The downward trend in NO_x emissions starts almost immediately in the observation window and continues until the phase-one cap is implemented. Since this trend begins prior to the CSA being passed and enforced, it begs the question, "What was causing NO_x emissions to fall?" Additionally, this downward trend in NO_x emissions prior to the CSA being implemented adds skepticism to the claim that the CSA caused the reduction in NO_X emissions.[34]

The key takeaway from Figure 7 and Figure 8 is that the impact of the CSA on emissions is unclear. Graphically, it appears as if the policy may have had an effect for

[34] The pre-CSA downward trend is possibly due to the NO_X trading program stemming from Title IV.

SO_2 emissions but may not have an effect for NO_x emissions. This inconclusive evidnce, coupled with the potential for leakage, motivates a more rigorous analysis of the policy's effect. To untangle the CSA's tangled relationship with emissions, a closer look at trends among coal-fired powerplants in the rest of the country is an appropriate next-step.

National Trends

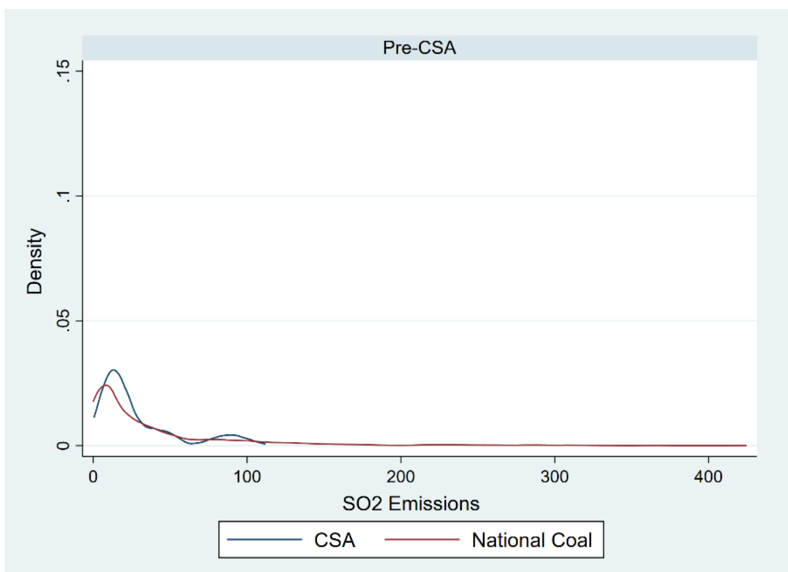
Analyzing the effect of the CSA plants requires a comparison group of non-CSA plants. This comparison group should be different from the CSA and not be exposed to any direct or indirect effects of the CSA. As such, a nationally representative control group (*National Coal*) is constructed from powerplants in the United States. The group excludes states bordering North Carolina,[35] states participating in the Regional Greenhouse Gas Initiative (RGGI),[36] or California for its implementation of the Regional Clean Air Incentives Market (RECLAIM).

An ideal control group should match the treatment group, sans treatment. In order to evaluate if the control group constructed is an ideal match for the CSA plants (treatment group), the next three figures show the kernel densities of $SO_2, NO_x,$ and CO_2 emissions. If the control group closely matches the CSA plants, absent treatment, then the kernel densities should look similar in the pre-CSA period for both groups.

[35] Bordering states include Georgia, South Carolina, Tennessee, and Virginia.
[36] RGGI states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont

Figure 9 shows the kernel density of SO_2 emissions for the CSA plants and the National Coal plants, before the SO_2 phase-one cap. Comparing the kernel densities of the two groups, the CSA plants overlap the National Coal plants up until 100 thousand tons per year. However, the distribution of National Coal plants extends beyond 400 thousand tons of SO_2 emissions per year. The lack of overlap beyond 100 thousand tons SO_2 per year suggests that the National Coal plants are, on average, either larger plants or dirtier plants (emitting more SO_2 per mmBTU than their CSA counterparts).

Figure 9. Kernel Density of SO_2 Emissions

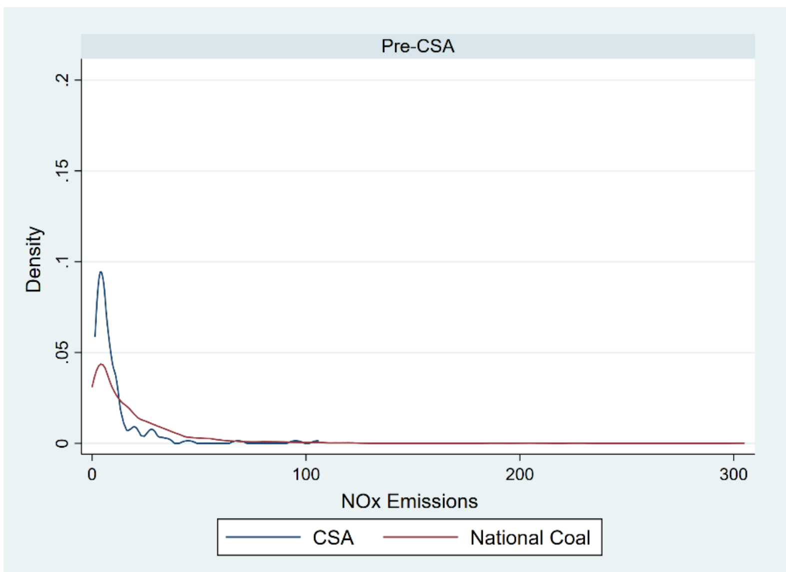


The pre-CSA period is from 1997 to 2008, the years preceding the phase-one cap of SO_2 emissions.

Two conclusions can be drawn from Figure 9. First, the control group (National Coal) contains plants that are much larger emitters of SO_2 than the treatment group (CSA plants). Second, within the CSA plants, there are a few outliers that are large emitters of

SO_2. Significant reductions in SO_2 emissions across the CSA plants may be due to changes at these outlier plants. Figure 10 plots the kernel density of NO_x emissions in a similar fashion to Figure 9. As with SO_2 emissions, the CSA plants appear to be smaller emitters of NO_x compared to the National Coal plants. The two conclusions from Figure 9 apply to Figure 10. There are plants within the National Coal group that are two to three times larger, with respect to NO_x emissions, than the largest emitter in the CSA group. Additionally, within the CSA, there are plants that are outliers in NO_x emissions.

Figure 10. Kernel Density of NO_x Emissions

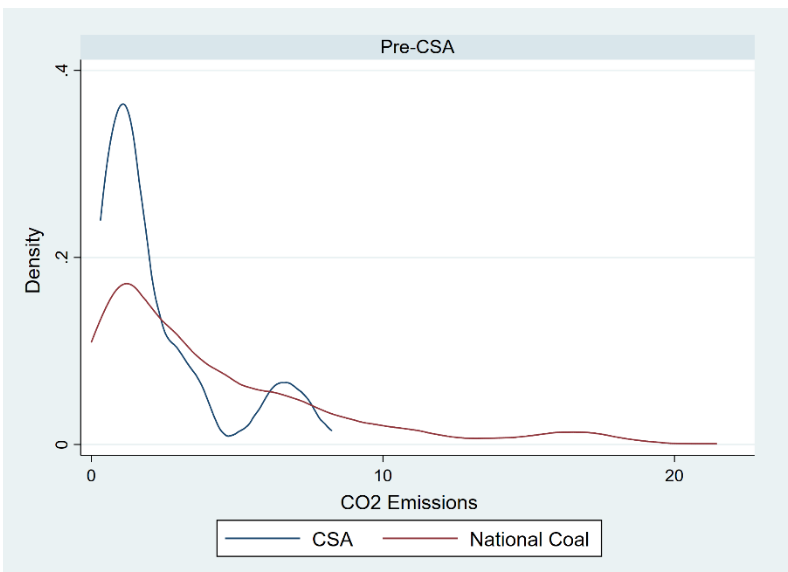


The pre-CSA period is from 1997 to 2006, the years preceding the phase-one cap of NO_x emissions.

While not explicitly targeted by the CSA, CO_2 emissions may have been indirectly affected by the CSA. If plants reduce SO_2 and NO_x emissions by reducing generation, then a decrease in CO_2 emissions should be observed because of the positive relationship between generation and CO_2 emissions. If the plants are reducing SO_2 and NO_x emissions by installing abatement technology, then CO_2 emissions should remain relatively unchanged.

Providing an initial look at CO_2 emissions, Figure 11 plots the kernel density of CO_2 emissions. Just as the SO_2 and NO_x kernel densities show, the CSA plants tend to be smaller emitters than the National Coal plants. Since the CSA plants emit less CO_2 than many of the National Coal plants, it implies that the CSA plants are also smaller producers. The difference between the CSA and National Coal plants' CO_2 kernel densities provides another example of the problem of overlap between the two groups.

Figure 11. Kernel Density of CO_2 Emissions

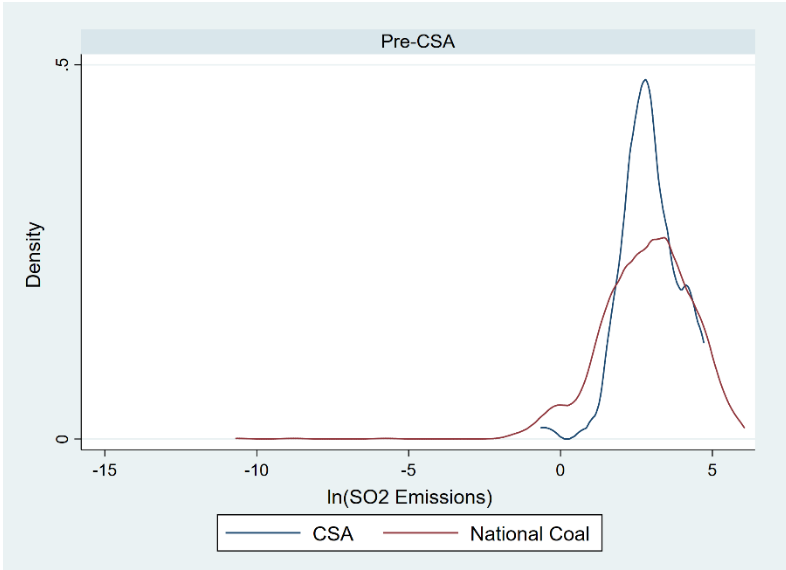


The pre-CSA period is from 1997 to 2006, the years preceding the phase-one cap of NO_x emissions.

One option for handling the outliers is to impose a log-transformation on the outcome variables. Taking the natural log of a skewed distribution will penalize outliers and create a more normal distribution. In the case of SO_2, NO_x, and CO_2 emissions, the log transformation may also create more overlap between the treatment and control groups.

Figure 12, Figure 13, and Figure 14 plot the kernel densities for the natural log of SO_2, NO_x, and CO_2 emissions of the CSA plants and National Coal plants, prior to the phase-one cap. In Figure 12, the overlap in $\ln(SO_2)$ between the CSA plants and National Coal plants is similar as that in the levels of SO_2 emissions shown in Figure 9. However, the outlier plants in levels of SO_2 emissions are given less weight after performing the log transformation.

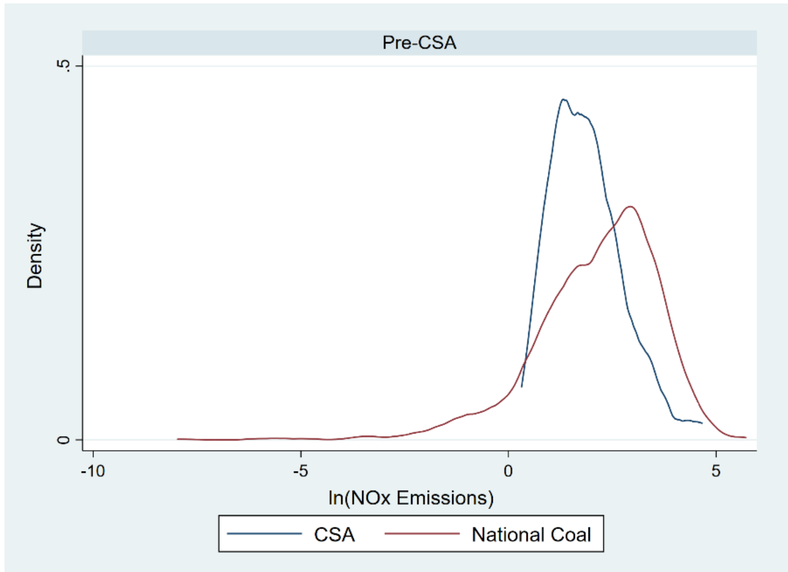
Figure 12. Kernel Density of the $ln(SO_2\ Emissions)$



The pre-CSA period is from 1997 to 2008, the years preceding the phase-one cap of SO_2 emissions.

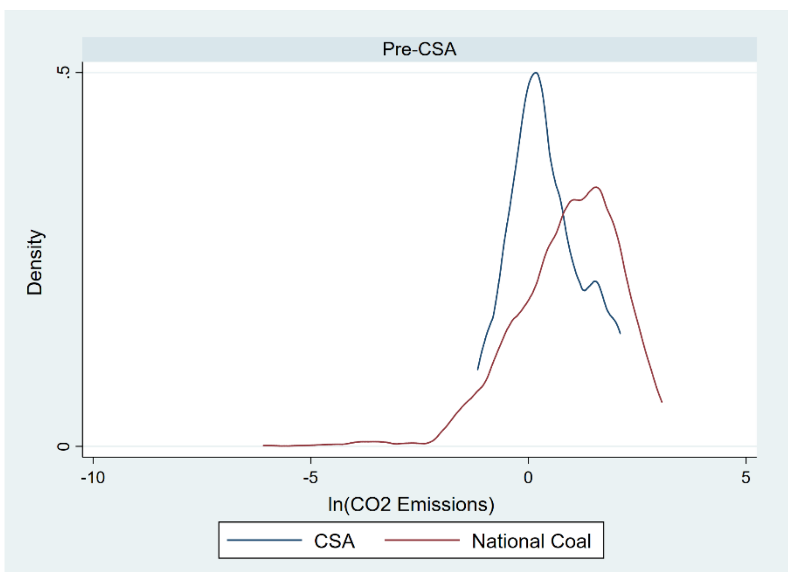
In Figure 13, the CSA plants appear to emit less than the rest of the country on average before phase-one cap. However, compared to Figure 10, the skewness of the National Coal group's NO_x emissions after the log transformation is not as severe.

Figure 13. Kernel Density of the $ln(NO_x\ Emissions)$



The pre-CSA period is from 1997 to 2006, the years preceding the phase-one cap of NO_x emissions.

Figure 14. Kernel Density of the $ln(CO_2\ Emissions)$



The pre-CSA period is from 1997 to 2006, the years preceding the phase-one cap of NO_x emissions.

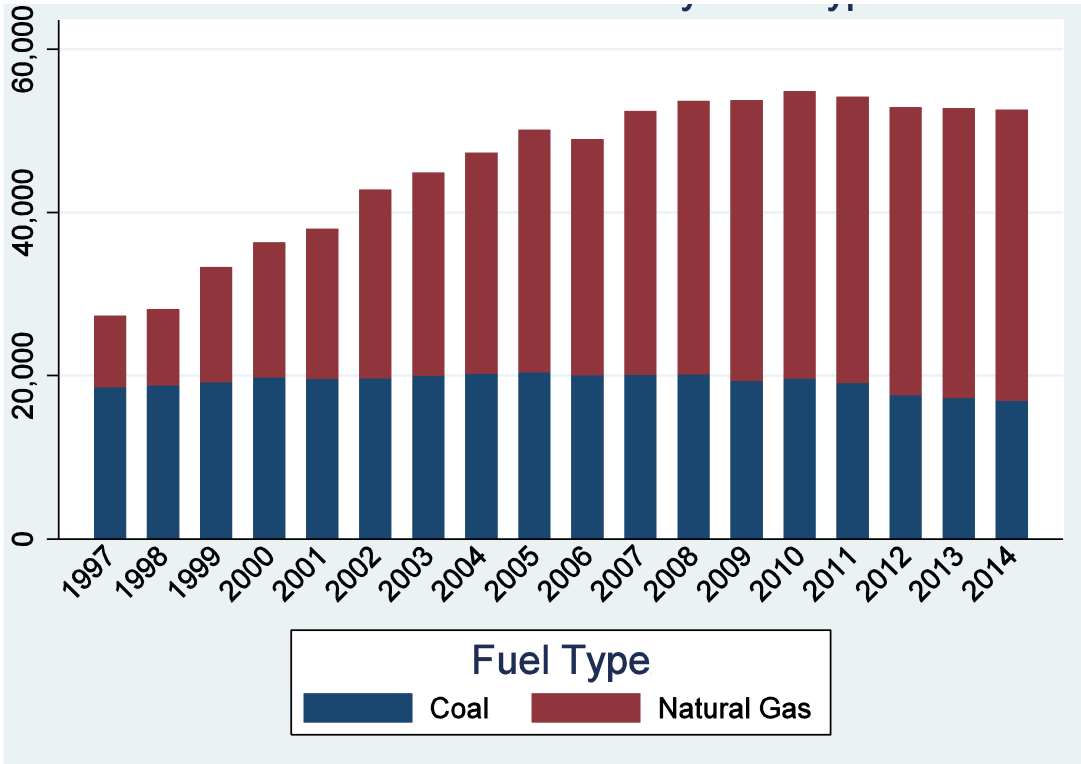
Figure 14 shows kernel density of the log transformed CO_2 emissions. Just as with SO_2 and NO_x, the log transformation reduces the skewness in the National Coal group's emissions. However, as with the emissions data in levels, there is still greater dispersion in the logged emissions data for the National Coal plants compared to the CSA plants.

Across all three figures, the density plots of logged emissions for the CSA plants and National Coal plants overlap more than the levels of emissions. The increased common support between the CSA plants and National Coal plants in the pre-phase-one period suggests that the log-level specification of the DiD model may be more appropriate than the level-level specification. The differences in common support between the specifications may provide an explanation for the differences in results discussed in Chapter VIII.

Plotting the kernel densities for levels of emission and logged emissions provides four key insights. First, the CSA plants are smaller emitters than many of the coal-fired powerplants in the United States. Second, the National Coal group contains many plants that are much larger polluters than the largest CSA plant. Third, the inexact overlap in the levels of emissions may pose a problem for the DiD portion of the econometric analysis. The SCM can address the issue of common support. Lastly, the logged emissions alleviate some of the data issues present in the levels of emissions.

If the CSA plants are decreasing production, then other plants must increase production or new plants must be built if demand is held constant. Coincidentally, the downturn in emissions and production from CSA plants coincides with the natural gas boom in the United States. This leads to another possible explanation for the changes in emissions: production moving to natural gas plants. Figure 15 shows that starting in 1999, there is a steady rise in the number of natural gas generating units in the U.S. until approximately 2007 or 2008. Over this eight to nine-year period, the number of natural gas generating units triples while the number of coal units stays the same. After 2008, the number of natural gas generating units remains steady while the number of coal plants begins to drop. In short, utilities are substituting coal-fired generation with natural-gas and are doing so across the nation. This change in the generating portfolio may be a cause of reduced emissions that is not a result of the CSA.

Figure 15. Total Number of Generating Units by Fuel Type (Coal vs. Natural Gas)



Emissions and Generation Resource Integrated Database (eGRID)

For the synthetic control method, plant characteristics can be used to create a better synthetic control group. The characteristics used are number of boilers, number of generators, and name plate capacity. These three characteristics are drawn from the Emissions and Generation Resource Integrated Database. Table 9 provides a summary of the three plant characteristics for the CSA plants and the National Coal plants.

Table 9. Plant Characteristics from eGRID

		Mean	Std. Dev	Min	Max
CSA	$No. of\ Boilers$	4.19	1.53	2	8
	$No. of\ Gen.$	5.34	1.76	2	8
	$Capacity$	980.56	742.57	342.19	2559.56
National Coal	$No. of\ Boilers$	2.90	1.93	1	13
	$No. of\ Gen.$	3.61	2.47	1	14
	$Capacity$	876.44	742.47	31.9	3969.59

Number of boilers and generators are counts. Capacity is name plate capacity in megawatts (MW).

The average CSA plant has 4.19 boilers with the minimum number of boilers being two and the largest being eight. Perhaps somewhat counter-intuitive, the plants with the least number of boilers among the CSA plants are also the plants with the most amount of capacity. Duke Power's Belews Creek steam station has just two boilers and two generators but has a nameplate capacity of 2160.144 MW. The average National Coal plant has 2.90 boilers with the least amount of boilers being one and the maximum being 13.

For the number of generators, the average CSA plant has 5.34 generating units while the average National Coal plant has 3.61. The maximum number of generating units at the CSA plants is eight while the maximum amongst the National Coal plants is 14. As for name plate capacity, the average CSA plant has a name plate capacity of 980.56 MW with a maximum of 2559.56 MW (Progress Energy's Roxboro plant) while the average capacity amongst the National Coal plants is 876.44 MW with a maximum of 3969.59.

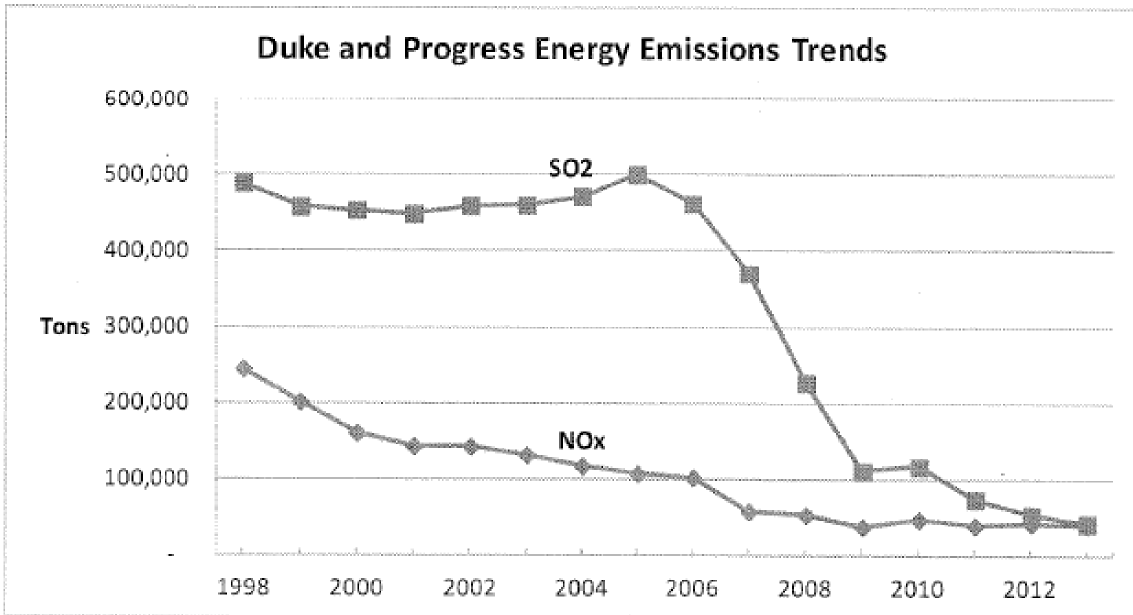
State Legislative Reports

The CSA required Duke Power and Progress Energy to report total annual emissions for their affected plants, permit applications for any plant modifications (i.e. installing abatement technology), planned construction for the following year, estimated future compliance costs, actual compliance costs, and total compliance costs recovered. Reports were required annually and represented the activities of the prior year.[37] Certain years also provided summaries of events related to the CSA, for example the lawsuits levied against the TVA.

Directly from the 2014 report, Figure 16 graphs reported annual emissions by Duke Progress Energy (post-merger name). This table serves as a secondary source of emissions data to validate the data processing detailed above. Comparing SO_2 emissions from the CEMS data with that emissions reported in the 2014 report, Figure 7 reports 1998 emissions as approximately 489,000 tons, 2004 emissions as 472,000 tons, 2008 emissions as 227,000 tons, and 2012 emissions as 53,000 tons. The totals in Figure 7 appear to match the totals reported in Figure 16.

[37] Reporting started in 2003, after one year of the CSA being enacted, and ended in 2014.

Figure 16. Reported Annual Emissions by Duke and Progress



Source: 2014 Annual Report for the Clean Smokestacks Act

Performing a similar comparison for NO_x emissions, Figure 8 shows 1998 emissions as approximately 248,000 tons, 2004 emissions as 117,000 tons, 2008 emissions as 53,000 tons, and 2012 emissions as 42,000 tons. The totals in Figure 8 appear to match the totals reported in Figure 16. The annual totals provided in the reports from 2003 to 2013 also serve as an additional source of data validation.

The most important information in the annual CSA state legislative reports is the cost of compliance. Figure 17 shows, by unit, the reported compliance costs, technology classification, and operational date, for the Duke Power CSA plants that installed abatement measures. For SO_2 the only technology reported is scrubbing. For NO_x there are three options, selective non-catalytic reduction (SCNR), low NO_x burners, and classified technologies. From Figure 17, most of the compliance costs occur in the early years of the CSA between 2001 and 2008.[38] Additionally, only four projects were reported for SO_2 compliance while 29 projects were reported for NO_x compliance. However, individual SO_2 projects were on average 100 times costlier than the NO_x projects. The total reported compliance cost for Duke Power is $1,839,630,000.

Figure 18 is the compliance cost table for Progress Energy. SO_2 scrubbers (Flue Gas Desulfurization or FGD) were installed at three plants, Asheville, Mayo, and Roxboro for a total cost of $934,704,000 (nominal). A total of $40,049,000 was spent on NO_x abatement across three plants: Asheville, Lee, and Sutton. As was the case with Duke Power, Progress Energy incurred most of the compliance costs in the early years of the CSA, with most of the SO_2 being the largest portion of compliance costs.

[38] While the CSA is not enacted until 2002, the 2001 costs are presumably reported to include projects that were already underway prior to the CSA's enactment but completed after 2002.

Figure 17. Reported Final Compliance Cost Summary for Duke Power

Facility	Technol ogy	Operational Date	Spent to Date 2001-'03 ($000)	2004 ($000)	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)	2009 ($000)	2010 ($000)	2011 ($000)	2012 ($000)	2013 ($000)	Project Total ($000)
Allen 1-5	Scrubbe	2009	$1,100	($12)	$5,348	$62,753	$209,06	$153,69	$51,765	($1,385	$182	$110	$557	$483,179
Belews Creek 1-2	Scrubbe	2008	$1,121	$5,999	$106,43	$250,64	$128,05	$34,629	$1,338	($0)	$0	$0	$0	$528,227
Cliffside 5	Scrubbe	2010	$978	$287	$112	$3,175	$57,778	$77,525	$96,111	$79,67	$3,403	$198	($750)	$318,490
Marshall 4	Scrubbe	2007	$10,214	$92,096	$218,13	$74,163	$23,632	($1,250)	$0	($228)	$0	$0	$0	$416,757
Allen 1-5	SNCR	2003	$3,224	$365	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,589
Allen 2	SNCR	2007	$0	$0	$239	$2,711	$2,332	($208)	$0	$0	$0	$0	$0	$5,074
Allen 3	SNCR	2005	$216	$2,584	$4,092	$32	$0	$0	$0	$0	$0	$0	$0	$6,924
Allen 4	SNCR	2006	$0	$218	$1,122	$4,258	$171	$16	$0	$0	$0	$0	$0	$5,785
5	SNCR	2008	$99	$165	$122	$23	$2,161	$2,425	$0	$0	$0	$0	$0	$4,994
Buck 3	Burner	2007	$0	$0	$0	$615	$3,565	$0	$0	$0	$0	$0	$0	$4,179
Buck 3	Classifie	2007	$0	$0	$0	$0	$216	$0	$0	$0	$0	$0	$0	$216
Buck 4	Burner	2007	$0	$0	$0	$358	$1,882	$1	$0	$0	$0	$0	$0	$2,241
Buck 4	Classifie	2007	$0	$0	$0	$0	$93	$0	$0	$0	$0	$0	$0	$93
Buck 5	SNCR	2006	$0	$268	$346	$4,837	$183	$160	$0	$0	$0	$0	$0	$5,794
Buck 6	SNCR	2006	$0	$266	$335	$3,814	($685)	($29)	($2)	$0	$0	$0	$0	$3,699
Dan River 1	Burner	2008	$0	$0	$0	$0	$1,560	$1,633	$0	$0	$0	$0	$0	$3,194
Dan River 1	Classifie	2008	$0	$0	$0	$0	$124	$0	$0	$0	$0	$0	$0	$124
Dan River 3	Burner	2006	$0	$0	$775	$1,694	$239	$0	$0	$0	$0	$0	$0	$2,708
Dan River 2	Classifie	2005	$0	$0	$131	$0	$0	$0	$0	$0	$0	$0	$0	$131
Dan River 3	Burner	2006	$192	$513	$679	$1,441	$377	$0	$0	$0	$0	$0	$0	$3,202
Dan River 3	Classifie	2005	$0	$0	$184	$0	$0	$0	$0	$0	$0	$0	$0	$184
Marshall 1	SNCR	2006	$1	$167	$1,418	$2,106	$182	$0	$0	$0	$0	$0	$0	$3,874
Marshall 2	SNCR	2007	$198	$185	$778	$2,761	$1,382	$322	$0	$0	$0	$0	$0	$5,626
Marshall 3	SNCR	2005	$1,577	$652	$2,042	$32	$0	$0	$0	$0	$0	$0	$0	$4,304
Marshall 4	SNCR	2007	$0	$0	$43	$2,614	$494	$0	$0	$0	$0	$0	$0	$3,151
Riverbend 4	SNCR	2007	$0	$46	$474	$1,082	$1,982	($53)	$0	$0	$0	$0	$0	$3,531
Riverbend 5	Burner	2005	$650	$2,313	$180	$0	$0	$0	$0	$0	$0	$0	$0	$3,143
Riverbend 5	Classifie	2005	$0	$160	$0	$0	$0	$0	$0	$0	$0	$0	$0	$160
Riverbend 5	SNCR	2008	$0	$2	$322	$1,475	$2,587	$6	$0	$0	$0	$0	$0	$4,390
Riverbend 6	Burner	2005	$572	$510	$2,096	$0	$0	$0	$0	$0	$0	$0	$0	$3,179
Riverbend 6	Classifie	2005	$0	$0	$189	$0	$0	$0	$0	$0	$0	$0	$0	$189
Riverbend 6	SNCR	2006	$0	$2	$340	$3,454	$504	$4	$0	$0	$0	$0	$0	$4,304
Riverbend 7	SNCR	2006	$0	$48	$486	$3,939	$521	$5	$0	$0	$0	$0	$0	$4,999
		Subtotals:	$20,142	$106,83	$346,42	$427,98	$438,40	$268,88	$149,21	$78,05	$3,585	$309	($193)	
														$1,839,63

SO_2

NO_x

Source: 2013 Annual Report for the Clean Smokestacks Act

Figure 18. Reported Final Compliance Cost Summary for Progress Energy

	Spent to Date										Remaining	
Facility	2001-'03 ($000)	2004 ($000)	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)	2009 ($000)	2010 ($000)	2011 ($000)	2012 ($000)	2013 ($000)	Project Total ($000)
Asheville 1 FGD	$9,752	$33,574	$35,769	$3,930	($1,850)	$0	$0	$0	$0	$0	$0	**$81,175**
Asheville 1 SCR	$0	$688	$1,423	$14,608	$11,942	($262)	$0	$0	$0	$0	$0	**$28,399**
Asheville 2 FGD	$7,842	$28,390	$24,238	$11,701	($1,543)	$0	$0	$0	$0	$0	$0	**$70,628**
Asheville FGD Common	$467	$0	$0	$0	($479)	$0	$0	$0	$0	$0	$0	($12)
Mayo 1 FGD	$187	$276	$644	$22,794	$104,886	$67,703	$23,799	$108	$0	$0	$0	**$220,397**
Roxboro 1 FGD	$434	$0	$3,135	$12,164	$32,841	$24,905	$1,181	($200)	$0	$0	$0	**$74,460**
Roxboro 2 FGD	$3,694	$6,848	$30,782	$46,014	$18,975	($357)	$0	$0	$0	$0	$0	**$105,956**
Roxboro 3 FGD	$0	$244	$10,628	$36,661	$49,985	$9,006	$255	$0	$0	$0	$0	**$106,779**
Roxboro 4 FGD	$0	$0	$9,074	$28,550	$57,610	$1,876	$135	$0	$0	$0	$0	**$97,245**
Roxboro FGD Common	$5,545	$10,030	$51,717	$72,934	$36,491	($1,360)	$2,717	$4	$0	$0	$0	**$178,078**
Lee 3 Rotamix	$0	$0	$198	$6,424	$600	$0	$0	$0	$0	$0	$0	**$7,222**
Lee 2 LNB	$0	$133	$273	$1,886	$0	$0	$0	$0	$0	$0	$0	**$2,292**
Sutton 2 LNB	$0	$0	$236	$1,900	$0	$0	$0	$0	$0	$0	$0	**$2,136**
Total without Waste Water	**$27,920**	**$80,184**	**$168,118**	**$259,566**	**$309,456**	**$101,510**	**$28,087**	($88)	**$0**	**$0**	**$0**	**$974,753**
Asheville WWT	$0	$0	$12,365	$1,289	($306)	$0	$0	$0	$0	$0	$0	**$13,348**
Mayo WWT	$0	$0	$0	$0	$4,042	$6,604	$9,000	13	$0	$0	$0	**$19,659**
Roxboro WWT	$0	$0	$791	$11,965	$16,932	$5,127	$4,815	$5,339	$1,811	$0	$0	**$46,780**
Total Waste Water Treatment	**$0**	**$0**	**$13,156**	**$13,253**	**$20,668**	**$11,732**	**$13,815**	**$5,352**	**$1,811**	**$0**	**$0**	**$79,787**
Total NC Smokestacks	**$27,920**	**$80,184**	**$181,273**	**$272,819**	**$330,124**	**$113,242**	**$41,902**	**$5,264**	**$1,811**	**$0**	**$0**	**$1,054,539**

Source: 2013 Annual Report for the Clean Smokestacks Act

Abatement Technology Summary

The cost differentials across abatement methods can be put into context with an understanding of how the different technologies operate. Beginning with the costliest method, SO_2 scrubbers, there are three broad categories: wet systems, semi-dry systems, and dry system.[24] All three operate using the same chemical reaction, i.e. by cooling the flue gas and combining it with a calcium or sodium based alkaline reagent. The SO_2 combines with the reagent to form either calcium sulfate or sodium sulfate. The resulting compound is either disposed of or used as a byproduct (e.g., an input in the production of products such as gypsum) (F-03-034 EPA-452, n.d.). The high cost of SO_2 scrubbers (a.k.a flue gas desulfurization) is due to the high capital costs associated with redirecting flue gas to a separate set of equipment and the energy costs associated with operating the scrubbers.[25]

SCNR operates by breaking NO_x down into nitrogen (N_2) and water (H_2O) via the injection of a nitrogen-based reagent (i.e. ammonia) into the flue gas. The ammonia reacts with the NO_x in the flue gas when temperatures are between 1600°F (870°C) and 2100°F (1150°C) (F-03-031 EPA-452, n.d.). Low-NO_x burners operate by maintaining a flame with multiple zones. One zone is dedicated to primary combustion of the coal, another for a process called fuel burning, and a final zone for final combustion in a reduced air environment to lower the temperature. The zone dedicated to *fuel burning* has

[24] The categories differentiate by their delivery of the reagent.
[25] The compliance costs reported in Figure 1 are only the fixed costs associated with the capital costs.

coal added to the zone. The NO_x from the initial combustion stage attaches to the available hydrocarbons in the newly added coal and is decomposed in the air-lean final stage (EPA, 1999). Compared to SO_2 scrubbers, SCNR and low-NO_X burners require significantly smaller capital investments as evident by their relatively lower costs.

Final Panel for Analysis

The unit of observation is at the unit-hour level and the observation window is from 1997 to 2014. Each powerplant may have multiple units. For analytical purposes, the data is aggregated to the plant-year level.

Table 10 contains summary statistics for the CSA plants and the control group (*National Coal*). For each group, means and standard deviations are reported for before and after the first caps.[26]

Table 10. Summary Statistics for Level of Emissions

	CSA			National Coal		
	Pre-	Post-	Difference	Pre-	Post-	Difference
SO_2	28.11	5.025	-23.08***	38.33	17.77	-20.56***
	(25.73)	(4.772)		(54.54)	(27.85)	
NO_x	10.27	2.937	-7.33***	17.78	8.151	-9.63***
	(14.19)	(2.849)		(23.42)	(10.38)	
CO_2	2.272	2.052	-0.22	4.112	3.491	-0.62***
	(2.014)	(2.011)		(4.170)	(3.838)	
$Generation$	2.202	2.157	-0.045	3.967	3.460	-0.51***
	(2.380)	(2.295)		(4.133)	(3.916)	

*Standard deviations in parentheses. *** p<0.01, ** p<0.05, * p<0.1*

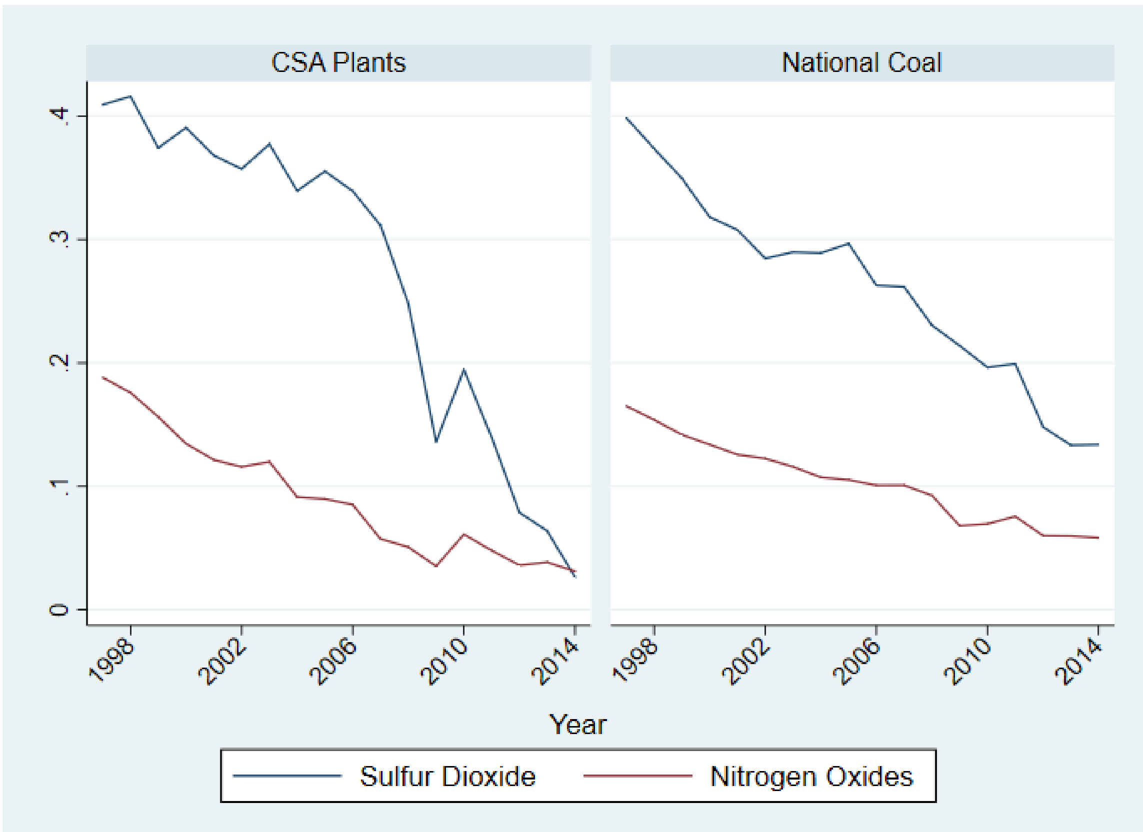
[26] CO_2 and generation do not have explicit caps, the phase one NO_X cap is used since it is the earliest of the phase one caps.

The difference column is the difference in means, before and after the cap. For both the CSA and the control group plants, both groups experience a significant decrease in SO_2 and NO_x emissions. The average reduction in annual emissions of SO_2 at CSA plants is 23.08 tons per plant and 20.56 tons per plant in the control group. For NO_x, the change is 7.33 tons per plant at CSA plants and 9.63 tons per plant in the control group. However, the CSA plants are smaller with respect to emissions and generation in comparison to the control group. This difference holds before and after the first caps.

Figure 19 plots the average emission rates of SO_2 and NO_x over time for the CSA plants and the National Coal plants. For the CSA plants, average rate of emission for SO_2 is approximately 0.4 lbs per mmBTU in 1998 and declines steadily to 0.35 lbs per mmbtu in 2006. From 2006 to 2014, the average rate of emission falls to 0.05 lbs of SO_2 per mmBTU. For the National Coal plants, the average rate of SO_2 emission is approximately the same as the CSA plants in 1998 and steadily declines over the observation window. However, the decline in the average SO_2 emission rate for the National Coal plants settles at 0.13 lbs per mmBTU in 2014, more than double the average for the CSA plants.

For NO_x emissions, the average rate of emission is approximately 0.19 lbs per mmBTU in 1998 for the CSA plants and 0.175 in 1998 for the National Coal plants. The average rate of NO_x emission declines steadily for both groups over the entire window of observation. In 2014, the average rate of NO_X emission is 0.05 for the CSA plants and 0.65 for the National Coal plants. Comparing both panels of Figure 19, the CSA plants are emitting less SO_2 per mmBTU, on average, than the National Coal plants, whereas, there is no distinguishable difference in the average rate of NO_x emissions between the two groups.

Figure 19. Average Emission Rates of SO_2 and NO_x



Emission rates are in pounds per mmBTU

Table 10 and Figure 19 provide a few insights into what should be expected in the empirical results. First, there are statistically significant differences in emissions before and after the phase-one caps are implemented. However, both the CSA plants and the National Coal plants experience a significant decline in emissions across the two periods.

As such, foreshadowing the empirical results, the level-level DiD specifications may be inconclusive. Second, the average CSA plant decreases the rate of SO_2 emission sooner and in larger magnitude than the average National Coal plant. This change suggests that at least some of the CSA plants are adopting SO_2 abatement technology, a conclusion that is supported by Figure 19. Finally, there are changes happening across the electric power industry from 1997 to 2014. Yet it is uncertain whether there are additional trends that are unique to the CSA plants.

CHAPTER VIII

EMPIRICAL STRATEGIES

When retrospectively determining if a policy is effective, a common strategy is to think of the policy as a treatment. Borrowing language from randomized controlled trials, the *treatment group* refers to the group that the policy targets and the *control group* refers to the group not targeted by the policy. The difference in outcomes between the treatment and control groups, after implementation of the policy, is the *treatment effect.* For the CSA, the difference in emissions between the treated fourteen coal-fired powerplants and the control powerplants, post treatment, is the treatment effect of the CSA.

In analyzing treatment effects, a common parameter of interest is the average treatment effect. The *average treatment effect (ATE)* is the mean difference in outcomes, with and without the policy Formally, let Y^C be the outcome in the absence of the policy, Y^T be the outcome of interest in the presence of the policy (Wooldridge, 2010). The ATE is the expected value of the difference in outcomes:

$$ATE = E(Y^T - Y^C) \tag{1}$$

For ideal inference, it would be possible to observe two realities for each powerplant, one where the plant is targeted by the CSA and one where it is not while holding everything else constant. Unfortunately, it is only possible to observe the scenario where the policy is implemented. To overcome this shortcoming, researchers rely on certain assumptions, model specifications, and policy characteristics to estimate Eq (1).

Difference-in-Differences

Since (Card, 1990), the workhorse for estimating treatment effects in the public policy realm is the difference-in-differences (DiD) approach. In the DiD framework, as presented in Athey & Imbens (2006), the outcome for an individual plant-*i* is as follows:

$$Y_i = Y_i^C \cdot (1 - I_i) + I_i \cdot Y_i^T$$

where I_i is an indicator for receiving the policy (treatment). When I_i = 0 the *i*-th plant does not receive the policy and the outcome is $Y_i = Y_i^C$. When $I_i = 1$, the *i*-th plant does receive the policy and the outcome is $Y_i = Y_i^T$. Generalizing to the two-period and two-group scenario, let $I_i = CSA_i * Post_i$. Where CSA_i is an indicator for the fourteen coal-fired powerplants targeted by the CSA and $Post_t$ is an indicator for the post-treatment period[27].

In the absence of the CSA, within the DiD model, the outcome (e.g. emissions of SO_2) for the *i*-th plant is represented by

$$Y_i^N = \beta_0 + \beta_1 CSA_i + \beta_2 Post_i + \varepsilon_i \tag{2}$$

[27] Post-treatment is defined as the year a phase one cap is implemented, and beyond.

where β_0 is a constant, β_1 is the time-invariant group-specific effect, β_2 is the time effect (before versus after the phase-one cap), and ε_i is an individual-specific error term.

As the name suggests, DiD exploits the differences across time and between groups. In the two-period and two-group scenario, the DiD model estimates the treatment effect by comparing the difference before and after a point in time and compares this difference across two groups. In the context of the CSA, the difference in emissions or generation before and after the phase-one cap is compared between the CSA plants and non-CSA powerplants (i.e. National Coal plants).

Now suppose the CSA is implemented within the DiD framework, the outcome for the *i*-th plant is represented by

$$Y_i = \beta_0 + \beta_1 CSA_i + \beta_2 Post_t + \beta_3 CSA_i * Post_t + \varepsilon_{it}. \tag{3}$$

The interaction of $CSA_i * Post_t$ represents the treatment group, post-treatment. Thus, the coefficient β_3 is the coefficient of interest and is the average effect of belonging to the CSA plants group and being in the post-phase-one period. In other words, β_3 is the average treatment effect of the CSA.

To better understand the treatment effect in the context of the CSA, let i index the individual power plants; T and C indicate the treatment and control groups respectively; the superscripts 1 and 2 indicate the pre-treatment and post-treatment periods. Thus, for all observations, the outcome variable is placed into one of four categories:

$Y^{T,1}$: Outcome for the treated group, pre-treatment

$Y^{T,2}$: Outcome for the treated group, post-treatment

$Y^{C,1}$: Outcome for the control group, pre-treatment

$Y^{C,2}$: Outcome for the control group, post-treatment

Defining $\bar{Y}$ as the average outcome ($\bar{Y} = \frac{1}{n}\sum_{i=1}^{n} Y_i$), an estimate of the average treatment effect is given by Eq (4)

$$\widehat{\beta_3} = (\bar{Y}^{T,2} - \bar{Y}^{T,1}) - (\bar{Y}^{C,2} - \bar{Y}^{C,1}) \tag{4}$$

Formally, the β_3 is the difference between the change in average outcomes for the treatment group, before and after the treatment, and the change in average outcomes for the control group, before and after the treatment.

The advantage of the DiD approach is in its simplicity. Estimates can be interpreted easily, estimation is not computationally intense, and DiD uses a framework (linear regression) that researchers and policy makers are familiar with. However, DiD has its disadvantages. First, the parallel trend assumption implies that the control group is not impacted at all by the treatment (Meyer, 1995). In a laboratory setting, this may be appropriate; in the real world, this assumption is less likely to hold true. For example, if coal-fired power plants residing in states bordering NC were included in the control group and leakage occurred then the parallel trend assumption would not be appropriate.

Another drawback is the sensitivity of results to control group selection. Since DiD requires that the researcher make judgements on picking the control group, these judgements have direct implications for results. When estimating treatment effects of policies, it can be a daunting task to pick an appropriate control group, especially in the presence of spillovers. Outside of a laboratory setting, it is unlikely that the control group is a perfect representation of the treatment group sans treatment. Ancillary policies, differing economic environments, and spillovers all pose challenges to the researcher in producing an adequate representation of what the treatment group would have been like absent the treatment. Due to these two disadvantages, DiD may not be appropriate for estimating a treatment effect (Abadie et al., 2010).

Synthetic Control Method

To address these two issues, one option is to implement the *Synthetic Control Method (SCM)*. SCM uses all potential control units but weights each unit based on its similarity to the treatment group during the pre-treatment period. By weighting and aggregating the control group, a synthetic counterfactual is created that may provide a closer approximation to the true counterfactual than the DiD setup. The first to implement this strategy is Abadie & Gardeazabal (2003), where economic indicators for the Basque region of Spain are compared to a synthetic control group of surrounding regions in order to estimate the economic impacts of terrorism.[28]

The idea behind the SCM is straightforward. Generate a weight matrix such that the distance[29] between the treatment group and the control group, pre-treatment, is

[28] Other examples of the SCM in practice are Abadie et al. (2010) and Doudchenko & Imbens (2016)
[29] In this context, distance is the difference between plants based off a set of characteristics (i.e. fuel type, capacity, and number of boilers).

minimized. The weight matrix is then applied to the control group to create a weighted average of the outcome variable, post-treatment. The difference between the observed outcome variable for the treatment group, post-treatment, and the estimated outcome variable for the synthetic control group is the estimated treatment effect.

Following the framework from Abadie et al. (2010), let Y_{it}^{N} be the outcome variable (e.g. NO_x emissions) when the treatment is not present for units $i = 1 \ldots J + 1$, where $J =$ the number of control units and the first unit receives the treatment, and time periods $t = 1 \ldots T$. Let Y_{it}^{I} be the counterfactual outcome and T_0 represent the number of pre-treatment periods. Assume that the treatment does not have any effect on the outcome during the pre-treatment periods. For all pre-treatment time periods $Y_{it}^{N} = Y_{it}^{I}$.

To define the treatment effect, let $\alpha_{it} = Y_{it}^{I} - Y_{it}^{N}$ and D_{it} be an indicator for the treatment. Thus, the observed outcome for any given unit and time-period is:

$$Y_{it} = Y_{it}^{N} + \alpha_{it} D_{it} \tag{5}$$

Recall that the first unit is the treatment group, resulting in the following:

$$D_{it} = \begin{cases} 1 & if\ i = 1\ and\ t > T_0 \\ 0 & otherwise \end{cases}$$

The effects of interest are the differences between the observed outcome and what the outcome would have been without the treatment, post-treatment, $\left(\alpha_{1T_0+1} \ldots \alpha_{1T}\right)$. Rearranging Eq (4), for all periods post-treatment $(t > T_0)$ the treatment effect is:

$$\alpha_{1t} = Y_{1t}^{I} - Y_{1t}^{N} = Y_{1t} - Y_{1t}^{N} \tag{6}$$

However, Y_{it}^{N} is unobserved for the control group in the post-treatment period. So, to estimate α_{1t} an estimate of Y_{1t}^{N} is necessary. Suppose that Y_{it}^{N} can be modeled as such:

$$Y_{it}^{N} = \delta_t + \theta_t Z_i + \lambda_t \mu_i + \varepsilon_{it} \tag{7}$$

Where δ_t is a time specific constant, Z_i is a vector of observable characteristics that are not impacted by the treatment, θ_t is a vector of unknown parameters, μ_i is a vector of unobservable time-invariant characteristics, λ_t is a vector of unknown parameters, and ε_{it} is an idiosyncratic error term.

Now consider a $(J \times 1)$ vector of weights $W = \left(w_2, \dots, w_{J+1}\right)'$ such that $w_j \geq 0$ for $j = 2, \dots, J + 1$ and the weights sum to 1 ($w_2 + \cdots + w_{J+1} = 1$). Thus, for each value W is a different weighted average of the control units or a potential synthetic control group. Combining the weight matrix with the linear model, the resulting outcome variable for each synthetic control group is:

$$\sum_{j=2}^{J+1} w_j Y_{jt} = \delta_t + \theta_t \sum_{J=2}^{J+1} w_j Z_i + \sum_{J=2}^{J+1} w_j \lambda_t \mu_i + \sum_{j=2}^{j+1} w_j \varepsilon_{it} \tag{8}$$

Then the question remains: Which value of W to choose?

Suppose that a weight matrix could be chosen such that the weighted average of the observables for control group is equal to the treatment group.

$$\sum_{j=2}^{J+1} w_j^* Y_{jt} = Y_{1t} \; \forall \; t = 1 \ldots T_0 \tag{9}$$

$$\sum_{J=2}^{J+1} w_j^* Z_j = Z_1 \tag{10}$$

Then with the choice of w^* as a weight matrix, the treatment effect can be estimated as

$$\widehat{\alpha_{1t}} = Y_{1t} - \sum_{j=2}^{J+1} w_j^* Y_{jt}\, , \forall \; t > T_0 \tag{11}$$

Unfortunately, it is nearly impossible to know the true w^* in Eq (10) given the limitations of observable data. Instead, the next best option is to approximate w^*. One potential approximation of $w^*$is the choice of weight matrix which minimizes the differences between the treatment and control group observables, during the pre-treatment period.

To approximate w^*, and subsequently estimate the treatment effect, let X_1 be a $(K \times 1)$ vector of pre-treatment values of outcome predictors for the treatment group and X_0 be a $(K \times J)$ matrix of the same outcome predictors but for the control group during the pre-treatment period. Now let V be a diagonal matrix with diagonal elements being nonnegative and representing the importance of each of the outcome predictors in X_0 and X_1. Thus W^* is chosen such that it minimizes the distance between the outcome predictors for the treatment and control groups during the pre-treatment period. Formally,

$$W^* = argmin[(X_1 - X_0 W)' V (X_1 - X_0 W)] \; subject \; to$$

$$w_j \geq 0 \; (j = 1,2, \ldots, J) \tag{12}$$

$$w_1 + \cdots + w_J = 1$$

Note that solution for the weight vector in Eq (11) depends on the choice of variable weights (V). Variable weights can be chosen based on priors a researcher may have or by using the data at hand. To take a data driven approach, V is chosen such that the mean square prediction error of the synthetic group's outcome variable is minimized in the pre-treatment period.

CHAPTER IX

RESULTS

The results presented in this chapter address three questions. First, did the CSA have an effect on the emissions of SO_2 and NO_x? Second, how prevalent was the issue of leakage? Third, how did the damages change after the implementation of the CSA? The chapter ends with a discussion of the limitations of this analysis.

CSA Effectiveness

For SO_2 emissions and NO_x emissions, in both levels and logs, the tables present four specifications. The first specification is the standard DiD. The second specification adds year effects while the third adds plant effects. The fourth specification includes both plant and year effects. *CSA* is an indicator for the CSA plants and *Post-CSA* is an indicator for the post-treatment period. *CSA Effect* represents the interaction of the indicators *CSA* and *Post-CSA*. The coefficient on *CSA Effect* is the estimated average treatment effect of the CSA on the outcome variable.

In Table 11, coefficient estimates for the *CSA effect* on SO_2 emissions remain relatively constant across all specifications for both levels and logs. In levels, the CSA plants are smaller emitters on average than their national counterparts. Both the CSA plants and national coal plants see a decrease in emissions in the post-CSA period. In levels, there is no significant effect of the CSA on SO_2 emissions, whereas there is a significant effect of the CSA on $\ln(SO_2)$ emissions. For $\ln(SO_2)$, the estimated effect, on average, of the CSA is approximately a 68.75% to 73.23% reduction in SO_2 emissions.[30]

Table 11. Difference-in-Difference Results for SO_2 Emissions

	$Thousand\ Tons\ of\ SO_2$			
CSA Effect	-3.658	-3.769	-4.237	-4.353
	(3.189)	(3.169)	(3.544)	(3.527)
CSA	-9.777	-9.874		
	(5.852)	(5.869)		
Post-CSA	-19.43***		-19.87***	
	(3.189)		(3.544)	
R-squared	0.043	0.055	0.140	0.177
	$\ln(Thousand\ Tons\ of\ SO_2)$			
CSA Effect	-1.163***	-1.182***	-1.298***	-1.318***
	(0.135)	(0.136)	(0.116)	(0.117)
CSA	0.130	0.129		
	(0.154)	(0.155)		
Post-CSA	-1.054***		-0.946***	
	(0.135)		(0.116)	
R-squared	0.094	0.114	0.236	0.291
Year FE	*No*	*Yes*	*No*	*Yes*
Plant FE	*No*	*No*	*Yes*	*Yes*

*The control group consists of all coal-fired powerplants in the United States that are not a part of RECLAIM, RGGI, or in states bordering North Carolina. For the level-level regressions, there are 339 plants and 4030 observations. For the log-level regressions, there are 336 plants and 3961 observations. Standard errors are in parentheses and are clustered at the state level. *** p<0.01, ** p<0.05, * p<0.1*

Table 12 displays results for the NO_x regressions. Like SO_2, the CSA plants are smaller emitters of NO_x than their nationally representative counterparts. Likewise, all plants experienced a decrease in NO_x emissions during the post-treatment period. There is no significant impact of the CSA on levels of emissions, but there is a significant

[30] Coefficient estimates from the logged emissions regressions are interpreted as follows:

$$\%\Delta y = 100 \times (e^{\beta_x} - 1)$$

impact on the $\ln(NO_X)$ emissions. For the log-level specifications, the estimated effect of the CSA is approximately a 43.11% to 46.58% reduction in NO_x emissions.

Table 12. Difference-in-Differences Results for NO_x Emissions

	Thousand Tons of NO_x			
CSA Effect	1.707	1.674	1.500	1.487
	(1.614)	(1.594)	(1.636)	(1.623)
CSA	-7.340***	-7.375***		
	(2.286)	(2.281)		
Post-CSA	-9.039***		-9.096***	
	(1.614)		(1.636)	
R-squared	0.067	0.092	0.170	0.241
	ln(*Thousand Tons of* NO_x)			
CSA Effect	-0.564***	-0.575***	-0.617***	-0.627***
	(0.0779)	(0.0744)	(0.0711)	(0.0701)
CSA	-0.218	-0.219		
	(0.181)	(0.180)		
Post-CSA	-0.747***		-0.722***	
	(0.0779)		(0.0711)	
R-squared	0.072	0.097	0.293	0.401
Year FE	*No*	*Yes*	*No*	*Yes*
Plant FE	*No*	*No*	*Yes*	*Yes*

*The control group consists of all coal-fired powerplants in the United States that are not a part of RECLAIM, RGGI, or in states bordering North Carolina. For the level-level regressions, there are 339 plants and 4030 observations. For the log-level regressions, there are 339 plants and 4030 observations. Standard errors are in parentheses and are clustered at the state level. *** p<0.01, ** p<0.05, * p<0.1*

Note that for both SO_2 and NO_x, there is no significant effect of the CSA in the levels of emissions. However, there is a negative and significant effect of the CSA on logged emissions. This is due to the differences in the average plant for the CSA and national coal groups. Recall that in Table 10, the average CSA plant is a smaller emitter of SO_2 and NO_x than the average plant in the control group. Also, the difference in average levels of emissions for both groups between the pre- and post-treatment periods is approximately the same. Thus, if both the treatment and control groups exhibit a similar drop in the level of emissions, then there will appear to be no significant effect from the policy. However, the CSA plants are smaller on average than the control plants. A similar decrease in the level of emissions for the CSA plants is a larger percentage decrease than for the control plants, which leads to a significant estimated effect of the policy for the log-level specifications.

If the mismatch in results between the level-level and log-level specifications is due to the lack of overlap between the treatment and control groups, then SCM can help address this problem. An indication of an appropriate SCM specification is a matching of the treatment and control group outcomes in the pre-treatment period.

Figure 20 plots SCM results for SO_2 and NO_x emissions. The solid line represents the actual levels of emissions from the CSA plants while the dashed line represents the estimated levels of emissions for the synthetic control unit. For both pollutants, the synthetic control unit closely tracks emissions at the CSA plants during the pre-treatment period. Then, in the one to two years preceding the phase-one cap, the estimated emissions for the synthetic control unit diverges from the observed emissions from the CSA plants. The gulf between the two lines represents the treatment effect of the CSA. The difference is approximately 100,000 tons per year for SO_2 emissions and 25,000 to 50,000 tons per year for NO_x emissions. The SCM results come with the caveat that they are point estimates only. No statement is being made about the uncertainty surrounding these estimates. This is discussed further in the *Placebo Tests* section.

Figure 20. Synthetic Control Method for SO_2 and NO_x Emissions

Donor pool for synthetic control unit consists of all coal powerplants in the United States that are not part of RECLAIM, RGGI, or in states bordering North Carolina.

The log-level DiD and SCM results, provide evidence that the CSA had a significant impact on emissions of SO_2 and NO_x. Yet it is unclear how the reductions are occurring. Plants can be implementing abatement technology, and consequently burning cleaner, and plants can be shifting generation elsewhere. If the CSA plants are installing abatement technology to reduce emissions, then the plants should have lower emission rates[31].

Table 13 and Table 14 show the DiD results when the outcome variable is the rate of SO_2 emissions and NO_x emissions. From

[31] Emissions per unit of generation or per unit of heat input.

Table 13 and Table 14, there is evidence that the CSA had a significant impact on the emission rates of SO_2 and NO_x. In terms of levels, the CSA reduced SO_2 emission rates by approximately 0.29 $lbs/mmBTU$. In logged emission rates, the CSA led to a 73.23% reduction in the rate of SO_2 emissions. As for rates of NO_x emissions the estimated reductions are approximately 0.074 $lbs/mmBTU$ or 46.58%.

Table 13. Difference-in-Differences Results for Rate of SO_2 Emissions

	$lbs\ of\ SO_2/mmBTU$			
CSA Effect	-0.249***	-0.253***	-0.286***	-0.288***
	(0.0629)	(0.0640)	(0.0487)	(0.0501)
CSA	0.156	0.154		
	(0.111)	(0.112)		
Post-CSA	-0.413***		-0.349***	
	(0.0629)		(0.0487)	
R-squared	0.046	0.069	0.111	0.177
	$\ln(lbs\ of\ SO_2/mmBTU)$			
CSA Effect	-1.061***	-1.077***	-1.106***	-1.119***
	(0.0818)	(0.0826)	(0.0721)	(0.0737)
CSA	0.479***	0.477***		
	(0.106)	(0.106)		
Post-CSA	-0.729***		-0.635***	
	(0.0818)		(0.0721)	
R-squared	0.105	0.141	0.194	0.262
Year FE	*No*	*Yes*	*No*	*Yes*
Plant FE	*No*	*No*	*Yes*	*Yes*

*The control group consists of all coal-fired powerplants in the United States that are not a part of RECLAIM, RGGI, or in states bordering North Carolina. For the level-level regressions, there are 336 plants and 3965 observations. For the log-level regressions, there are 336 plants and 3961 observations. Standard errors are in parentheses and are clustered at the state level. *** p<0.01, ** p<0.05, * p<0.1*

Table 14. Difference-in-Differences Results for Rate of NO_x Emissions

	$lbs\ of\ NO_x/mmBTU$			
CSA Effect	-0.0766***	-0.0770***	-0.0745***	-0.0738***
	(0.0198)	(0.0194)	(0.0224)	(0.0219)
CSA	0.0352	0.0342		
	(0.0235)	(0.0232)		
Post-CSA	-0.164***		-0.154***	
	(0.0198)		(0.0224)	
R-squared	0.152	0.222	0.271	0.399
	$\ln(lbs\ of\ NO_x/mmBTU)$			
CSA Effect	-0.446***	-0.451***	-0.469***	-0.470***
	(0.0523)	(0.0510)	(0.0604)	(0.0595)
CSA	0.140**	0.138**		
	(0.0577)	(0.0565)		
Post-CSA	-0.540***		-0.486***	
	(0.0523)		(0.0604)	
R-squared	0.189	0.251	0.327	0.433
Year FE	*No*	*Yes*	*No*	*Yes*
Plant FE	*No*	*No*	*Yes*	*Yes*

*The control group consists of all coal-fired powerplants in the United States that are not part of RECLAIM, RGGI, or in states bordering North Carolina. For the level-level regressions, there are 338 plants and 4012 observations. For the log-level regressions, there are 338 plants and 4012 observations. Standard errors are in parentheses and are clustered at the state level. *** p<0.01, ** p<0.05, * p<0.1*

The DiD results, provide evidence that the CSA caused reductions in SO_2 and NO_x emissions and that some of these reductions are due to reductions in emission rates (e.g. installation of abatement technology). However, a question remains if some of the reductions are due to shifting of generation to non-CSA plants (i.e. leakage). To address the question of leakage, I use generation and emissions of CO_2 in the DiD specifications. If there is a significant amount of leakage occurring, then the results will show a reduction in generation and CO_2 emissions.

The DiD results in Table 15 and Table 16 do not provide evidence that the CSA significantly impacted generation and emissions of CO_2. For generation the baseline DiD specifications estimate a marginally significant increase due to the CSA. However, this increase is insignificant if plant fixed effects are introduced and is insignificant across the log-level specifications. As for CO_2, Table 16 shows no significant effect of the CSA in the level-level specifications. For the $\ln(CO_2)$ regressions, there is a marginally significant 8.48% reduction in CO_2 emissions in the specifications that include plant fixed effects. The DiD results in Table 15 show no evidence of leakage occurring.

Table 15. Difference-in-Differences Results for Generation (MWh)

		$Generation$		
CSA Effect	0.186*	0.178*	0.0778	0.0647
	(0.0970)	(0.0941)	(0.0780)	(0.0763)
CSA	-1.768***	-1.768***		
	(0.380)	(0.380)		
Post-CSA	-0.231**		-0.210**	
	(0.0970)		(0.0780)	
R-squared	0.011	0.013	0.018	0.093
		$\ln(Generation)$		
CSA Effect	0.0633	0.0585	0.00199	-0.00566
	(0.0516)	(0.0496)	(0.0456)	(0.0439)
CSA	-0.318**	-0.318**		
	(0.135)	(0.135)		
Post-CSA	-0.178***		-0.180***	
	(0.0516)		(0.0456)	
R-squared	0.006	0.010	0.027	0.073
Year FE	*No*	*Yes*	*No*	*Yes*
Plant FE	*No*	*No*	*Yes*	*Yes*

*The control group consists of all coal-fired powerplants in the United States that are not part of RECLAIM, RGGI, or in states bordering North Carolina. For the level-level regressions, there are 339 plants and 4030 observations. For the log-level regressions, there are 338 plants and 4,012 observations. State-clustered Standard errors are in parentheses and are clustered at the state level. *** p<0.01, ** p<0.05, * p<0.1*

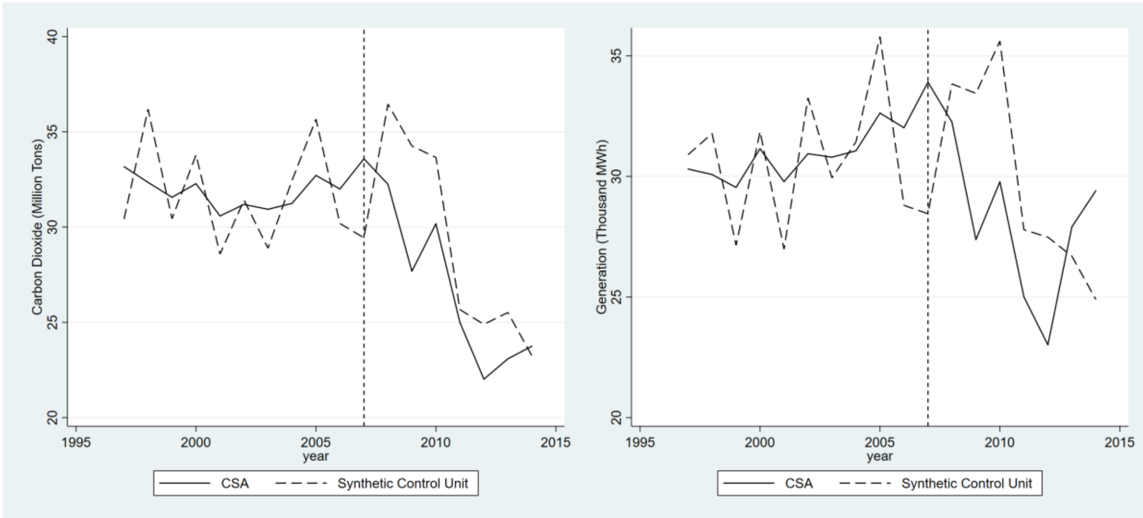
Table 16. Difference-in-Differences Results for CO_2 Emissions

	$Million\ Tons\ of\ CO_2$			
CSA Effect	0.118	0.110	0.0356	0.0229
	(0.115)	(0.111)	(0.0826)	(0.0805)
CSA	-1.834***	-1.835***		
	(0.396)	(0.396)		
Post-CSA	-0.337***		-0.342***	
	(0.115)		(0.0826)	
R-squared	0.013	0.015	0.049	0.115
	$\ln(Million\ Tons\ of\ CO_2)$			
CSA Effect	-0.0376	-0.0425	-0.0836	-0.0886*
	(0.0602)	(0.0587)	(0.0499)	(0.0494)
CSA	-0.410***	-0.410***		
	(0.111)	(0.112)		
Post-CSA	-0.207***		-0.217***	
	(0.0602)		(0.0499)	
R-squared	0.013	0.019	0.070	0.141
Year FE	*No*	*Yes*	*No*	*Yes*
Plant FE	*No*	*No*	*Yes*	*Yes*

*The control group consists of all coal-fired powerplants in the United States that are not part of RECLAIM, RGGI, or in states bordering North Carolina. For the level-level regressions, there are 309 plants and 4030 observations. For the log-level regressions, there are 331 plants and 3,940 observations. Standard errors are in parentheses and are clustered at the state level. *** p<0.01, ** p<0.05, * p<0.1*

Table 15 and Table 16 do not show evidence of a reduction in generation and CO_2, but the SCM results show some evidence of a reduction. From Figure 21, both generation and CO_2 show a reduction the first half of the post-treatment period but this reduction starts to disappear in the second half of the post-treatment period. This initial reduction may be evidence of leakage. If leakage occurred in the early years of the caps for the CSA plants to comply, then the SCM results will support this story. As with Figure 19, SCM results should be interpreted with caution as they are point estimates only.

Figure 21. Synthetic Control Method for CO_2 Emissions and Generation



Donor pool for synthetic control unit consists of all coal-fired powerplants in the United States that are not part of RECLAIM, RGGI, or in states bordering North Carolina.

Comparing all the DiD and SCM results, the CSA caused a significant reduction in emissions of SO_2 and NO_x. The reduction is partially due to CSA plants becoming cleaner (emission rates) but also might be due to leakage, at least in the early years of the caps. The DiD results do not give any clear direction on leakage, and the SCM results suggest that leakage is happening as a stop-gap in the early years of the caps. The question remains, “How much leakage occurred?”

Leakage

To address question of leakage, I use the DiD framework but redefine the treatment group. If the leakage is thought of as indirect exposure of the CSA, then potential leakage states can be thought of as additional treatment groups. Using the DiD specification with plant and year effects, each pollutant is regressed in levels and then again in logs. The process is repeated for South Carolina (SC), Virginia (VA), and Tennessee (TN). Differing from the regressions above, the treatment group is defined as all plants within the state and not just coal plants. Likewise, the control group refers to all plants nationwide[32] and not just coal plants.

Table 17. SO_2 and NO_x Leakage DiD Regressions by State.

	Treated State Outcome	SC Level	SC ln(·)	VA Level	VA ln(·)	TN Level	TN ln(·)
	CSA Effect	2.076	-0.0256	1.768	-0.0645	-71.99***	-0.518***
		(1.983)	(0.103)	(1.855)	(0.101)	(2.069)	(0.107)
SO_2	Observations	14,630	13,931	14,660	13,941	14,452	13,764
	R-squared	0.086	0.130	0.087	0.130	0.133	0.132
	# of Plants	1,033	1,001	1,037	1,005	1,024	990
	CSA Effect	1.372*	0.00241	1.372*	0.0826*	-34.04***	-0.476***
		(0.741)	(0.0448)	(0.741)	(0.0438)	(0.786)	(0.0458)
NO_x	Observations	14,630	14,628	14,630	14,658	14,452	14,449
	R-squared	0.148	0.179	0.148	0.179	0.172	0.183
	# of Plants	1,033	1,033	1,033	1,037	1,024	1,024

*The control group consists of all powerplants (i.e. coal, natural gas, oil, etc.) in the United States that are not part of RECLAIM, RGGI, or in states bordering North Carolina. Standard errors are in parentheses and are clustered at the state level. *** p<0.01, ** p<0.05, * p<0.1*

Table 17 reports results for the SO_2 and NO_x leakage DiD regressions. For South Carolina, there appears to be no leakage of SO_2 and negligible leakage of NO_x emissions. Likewise, there is no evidence of SO_2 leakage to Virginia and minute leakage of NO_x emissions. However, Tennessee exhibits a completely different story. The CSA is estimated to have decreased SO_2 emissions in Tennessee by approximately 40% and NO_x emissions by 38%. This significant impact of the CSA on emissions in Tennessee is

[32] Bordering states, RGGI states, and California are excluded.

likely a result of the lawsuit between North Carolina and the TVA. The lawsuit ended in settlement, requiring the TVA's coal plants to implement abatement technology or shut down.

Table 18. CO_2 and Generation Leakage DiD Regressions by State

	Treated State Outcome	SC Level	SC ln(·)	VA Level	VA ln(·)	TN Level	TN ln(·)
	CSA Effect	0.0809**	0.0960***	-0.227***	-0.0561*	-2.232***	0.0630*
		(0.0315)	(0.0328)	(0.0287)	(0.0317)	(0.0334)	(0.0331)
CO_2	Observations	14,630	13,624	14,660	13,632	14,452	13,469
	R-squared	0.020	0.046	0.023	0.046	0.065	0.047
	# of Plants	1,033	950	1,037	954	1,024	941
	CSA Effect	0.0232	0.126***	-0.217***	0.114***	-2.137***	0.0879**
		(0.0285)	(0.0364)	(0.0261)	(0.0360)	(0.0303)	(0.0371)
Gen	Observations	14,630	14,630	14,660	14,452	14,452	14,452
	R-squared	0.006	0.043	0.006	0.045	0.036	0.045
	# of Plants	1,033	1,033	1,037	1,024	1,024	1,024

*The control group consists of all powerplants (i.e. coal, natural gas, oil, etc.) in the United States that are not part of RECLAIM, RGGI, or in states bordering North Carolina. Standard errors are in parentheses and are clustered at the state level. *** p<0.01, ** p<0.05, * p<0.1*

Table 18 reports results from the CO_2 and generation leakage DiD regressions. South Carolina shows evidence of increasing production because of the CSA. This would imply a shifting of production from North Carolina to South Carolina. For Virginia, the converse is true for levels and logs of CO_2 emissions and level of generation, with the CSA causing a decrease in production. For Tennessee, we also see a decrease in production, but this is likely due to the constraints put in place by the lawsuit settlement.

Considering all the results, there is enough evidence to conclude that leakage was not an endemic problem for the CSA. While there may have been some shifting of production from North Carolina to South Carolina, most of the CSA plant emission reductions appear to have happened due to plants lowering their emission rates (e.g. installing SO_2 scrubbers) or by reducing production all together and shifting to alternative sources (e.g. natural gas). Also, both utilities were projecting a rate decrease. Thus, the rate freeze and minimum compliance cost requirement created an additional incentive for the utilities to install abatement technology instead of shifting production.

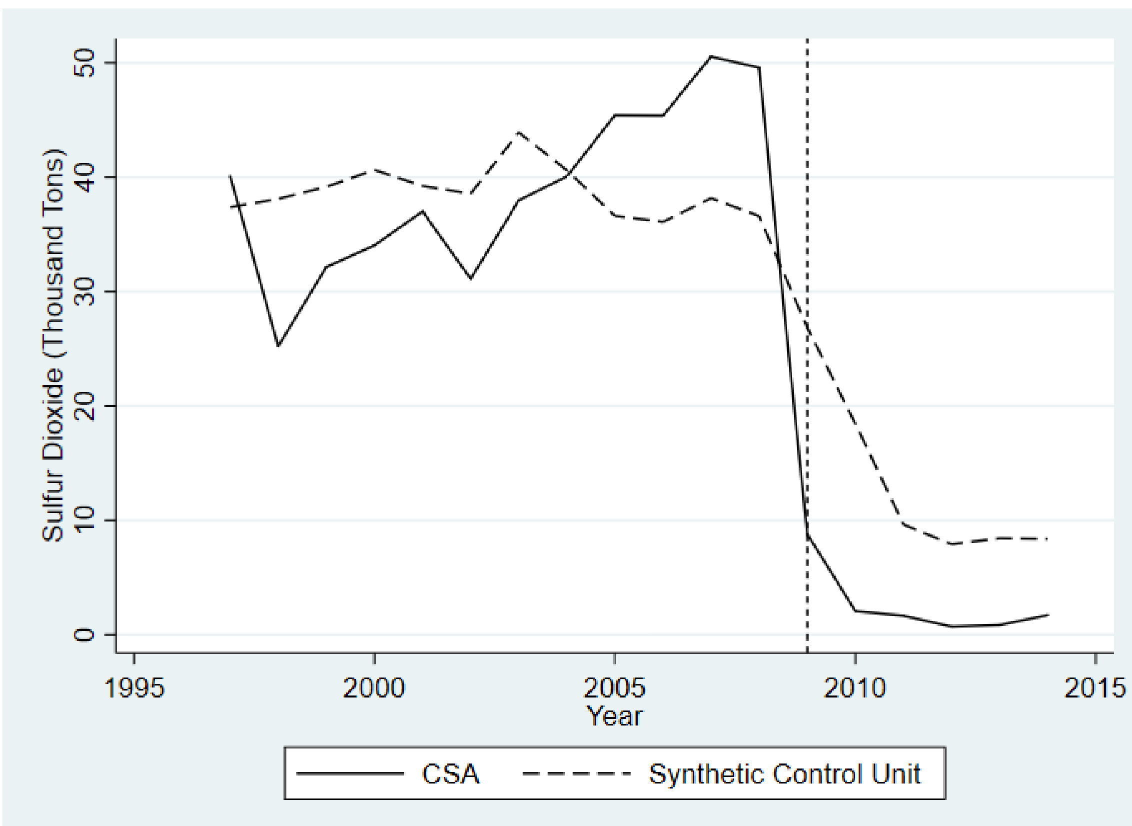
Plant-Specific Effects of the CSA

In the aggregate, the CSA had a significant impact on the emissions of SO_2 and NO_x. However, focusing on just the aggregate tells only part of the story. Exploring the plant-specific effects, instead, provides a holistic view of the CSA and the responses by Duke Power and Progress Energy. For example, some plants install abatement technology and reduce emissions when they otherwise would not, while other plants install abatement technology and reduce emissions when they would have done so regardless of the CSA. For Figure 22 through Figure 38, actual emissions by the powerplant are represented by the solid line while emissions under the counterfactual of no CSA being implemented (synthetic control unit) are represented by the dashed line. The difference between the actual emissions and counterfactual emissions is the estimated effect of the CSA using the synthetic control method (SCM).

Plants with SO_2 Abatement Technology

Figure 22 through Figure 28 show the estimated plant-specific effects of the CSA on SO_2 emissions for the plants which reported compliance costs associated with installing SO_2 scrubbers. Figure 22 shows the actual SO_2 emissions from the G G Allen plant and the estimated emissions form the synthetic control unit. The SO_2 scrubber is reported to be operational in 2009, with a total project cost of $483,179,000 [33] and coincides with an estimated decrease of 18,065 tons of SO_2. In 2010 the estimated decrease is 16,385 tons. However, the estimated effect decreases to approximately 7,000 tons of SO_2 emissions annually, from 2011-2014.

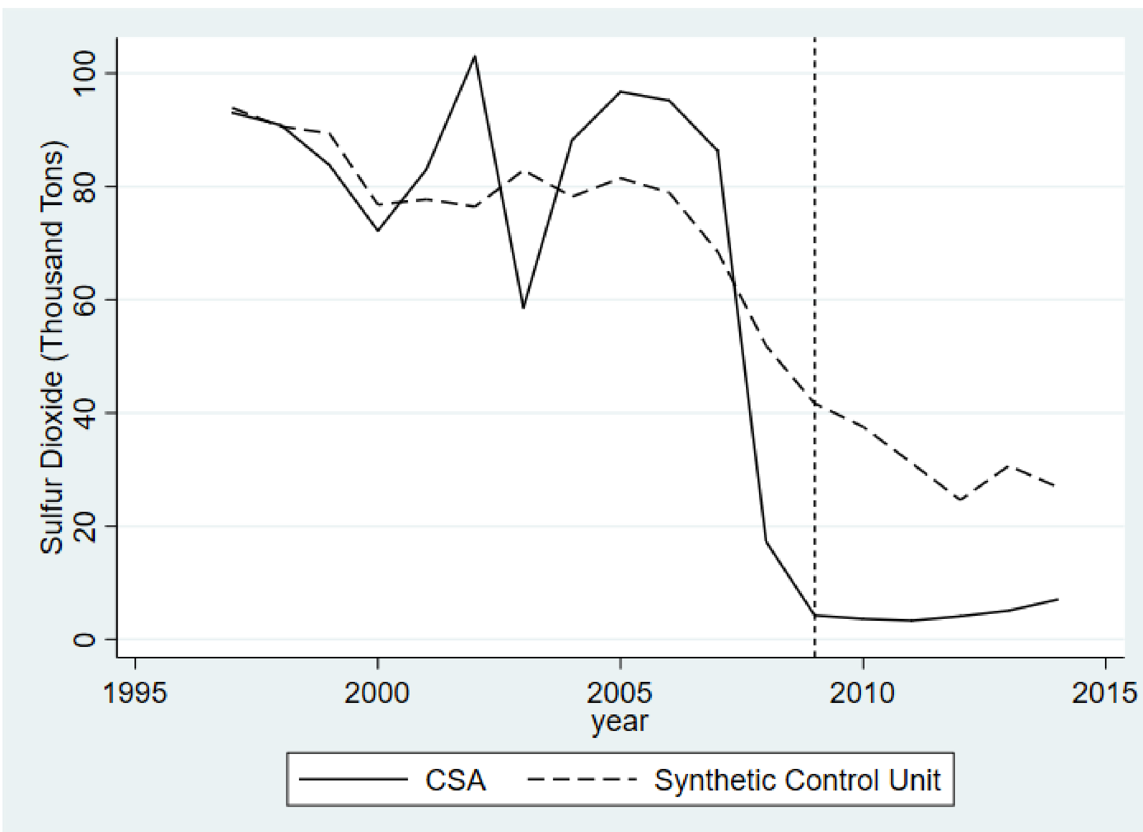
Figure 22. Duke - G G Allen Plant SO_2 Emissions Using SCM



[33] Compliance costs reported in this section are nominal.

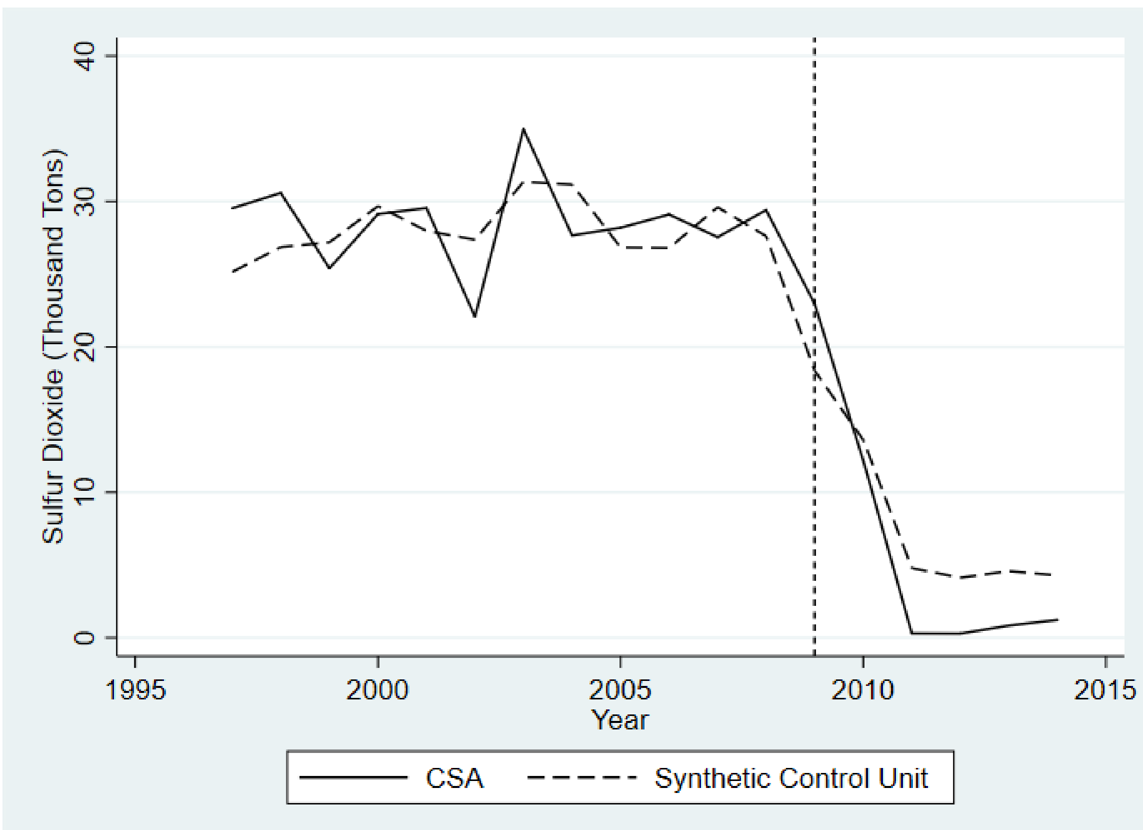
Figure 23 plots the actual and estimated SO_2 emissions for the Belews Creek plant owned by Duke Power. The SO_2 scrubber is operational in 2008, coinciding with an estimated decrease of 34,618 tons of SO_2 emissions. In 2009 and 2010 the estimated decreases in SO_2 emissions are 37,456 and 33,936 tons respectively. In 2011, the estimated effect of the CSA on SO_2 emissions at Belews Creek is 27,843 tons and continues to decrease to an average maintained annual reduction of 22,000 tons from 2012 to 2014.

Figure 23. Duke - Belews Creek Plant SO_2 Emissions Using SCM



The estimated effect of the CSA on SO_2 emissions at the Cliffside plant is shown in Figure 24. The Cliffside plant, owned by Duke Power, brings its SO_2 scrubber online in 2010. Unlike the G G Allen and Belews Creek plants, the estimated effect of the CSA on SO_2 emissions at the Cliffside plant is minimal. Starting in 2010, the estimated reduction in SO_2 emissions is only 1,409 tons, 4,491 tons in 2011, with an average reduction of 3,500 tons from 2012 to 2014.

Figure 24. Duke - Cliffside Plant SO_2 Emissions Using SCM



Recall that the synthetic control unit is a weighted average of all control group plants such that the synthetic control unit best represents the Cliffside plant in the absence of the CSA. Another potential reason is that plants like Cliffside (i.e. smaller nameplate capacity, four boilers, four generating units, and generally older) are likely shutting down due to the natural gas boom. If plants like the Cliffside plant are shutting down and the trend coincides with the 2009 phase-one SO_2 cap of the CSA, then the estimated effect of the CSA on SO_2 emissions at the Cliffside plant will be smaller than the larger plants. If this is the true reason behind the small estimated effect, then the Cliffside plant serves as anecdotal evidence of an unintended consequence of cap-and-trade policies. By creating an incentive to invest in old and relatively dirty plants, the CSA may have kept certain plants operating longer than they would have in the absence of the CSA.

Figure 25 shows the SO_2 emissions for the Marshall plant using SCM. The SO_2 scrubber became operational in 2007, and its introduction coincides with a 47,702-ton reduction in SO_2 emissions. From 2008 through 2010 the annual reduction in emissions is approximately 40,000 tons. From 2011 to 2014, the difference between the Marshall plant and the synthetic control unit decreases to 30,000 tons per year.

Figure 25. Duke - Marshall Plant SO_2 Emissions Using SCM

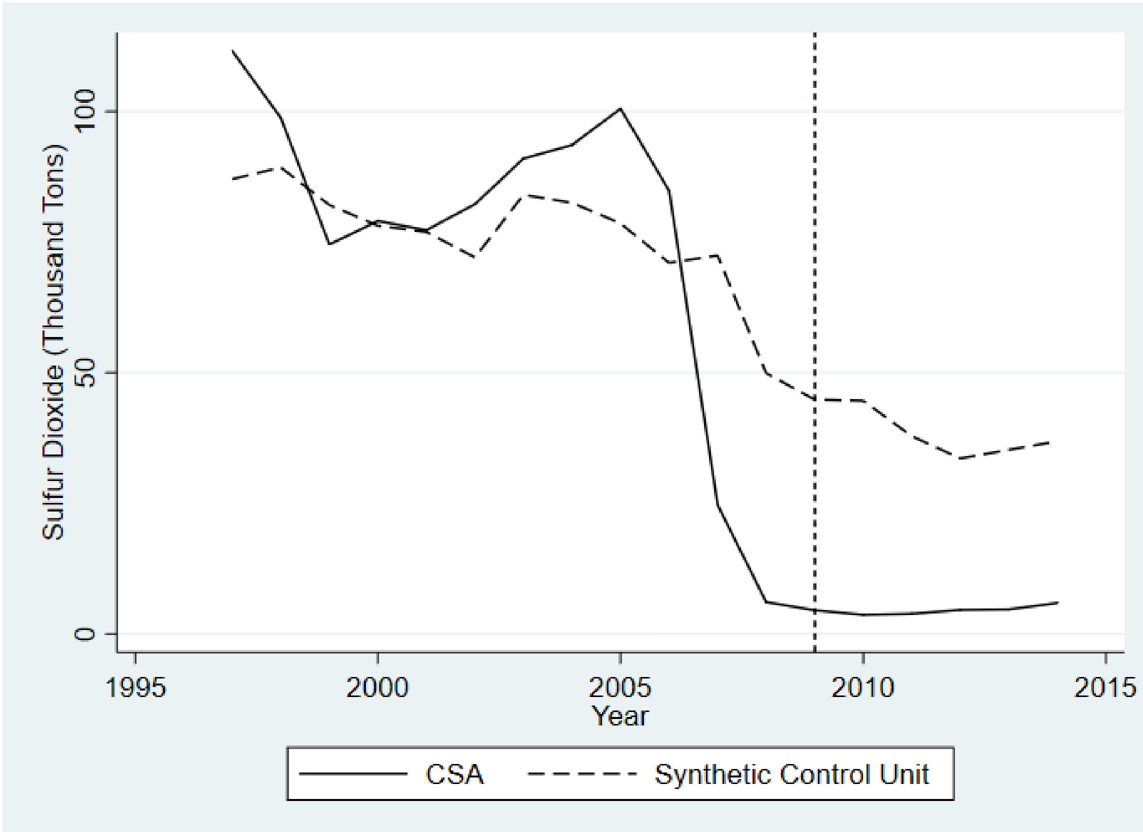
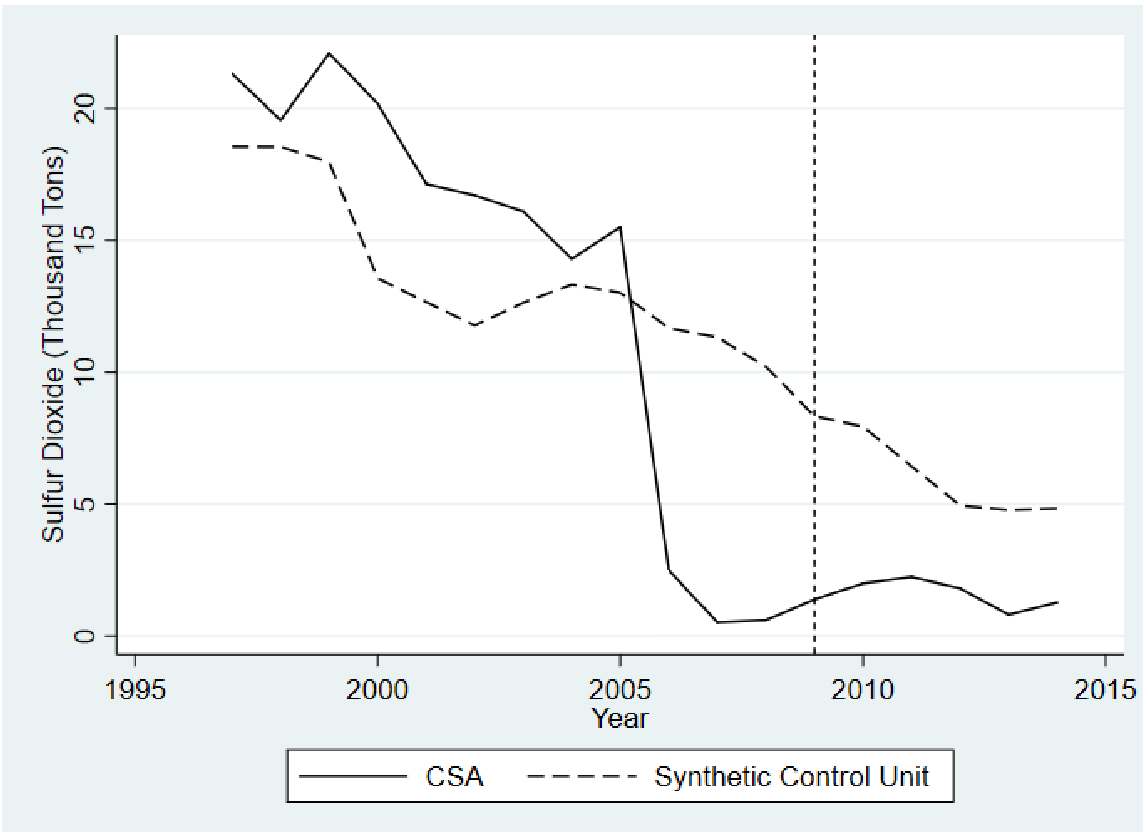


Figure 26 through Figure 28 show the plant-specific effects of the CSA on SO_2 emissions for plants owned by Progress Energy. Figure 26 plots the SCM results for SO_2 emissions by the Progress Energy Asheville plant. Unfortunately, the compliance cost report for Progress Energy does not include the operational date for the installed abatement technology. However, the last year of incurred costs is a rough approximation. For the Asheville plant, the last year of reported compliance costs for SO_2 abatement is 2006 and coincides with a reduction of 9,180 tons. In 2009 the difference between actual emissions and the synthetic control unit emissions is 6,931 and it decreases annually through 2014 to 3,557 tons.

Figure 26. Progress - Asheville Plant SO_2 Emissions Using SCM



SO_2 emissions at the Mayo plant are presented in Figure 27. Compliance costs are reported from 2001 to 2010. The costs in 2009 are $23,799,000 compared to only $108,000 in 2010. Given the sudden decline in costs, 2009 is the assumed operational date of the Mayo plant SO_2 scrubber. In 2009 the estimated effect is a reduction of 9,471 tons of SO_2 emissions. In 2010, the estimated effect is approximately the same, at 9,510 tons. In 2011 and 2012 the difference between actual emissions and the synthetic control unit's emissions falls to 5,616 tons and 1,336 tons, respectively. In 2013 and 2014 the estimated effect increases to 3,613 tons and 6,241 tons, respectively.

Figure 27. Progress - Mayo Plant SO_2 Emissions Using SCM

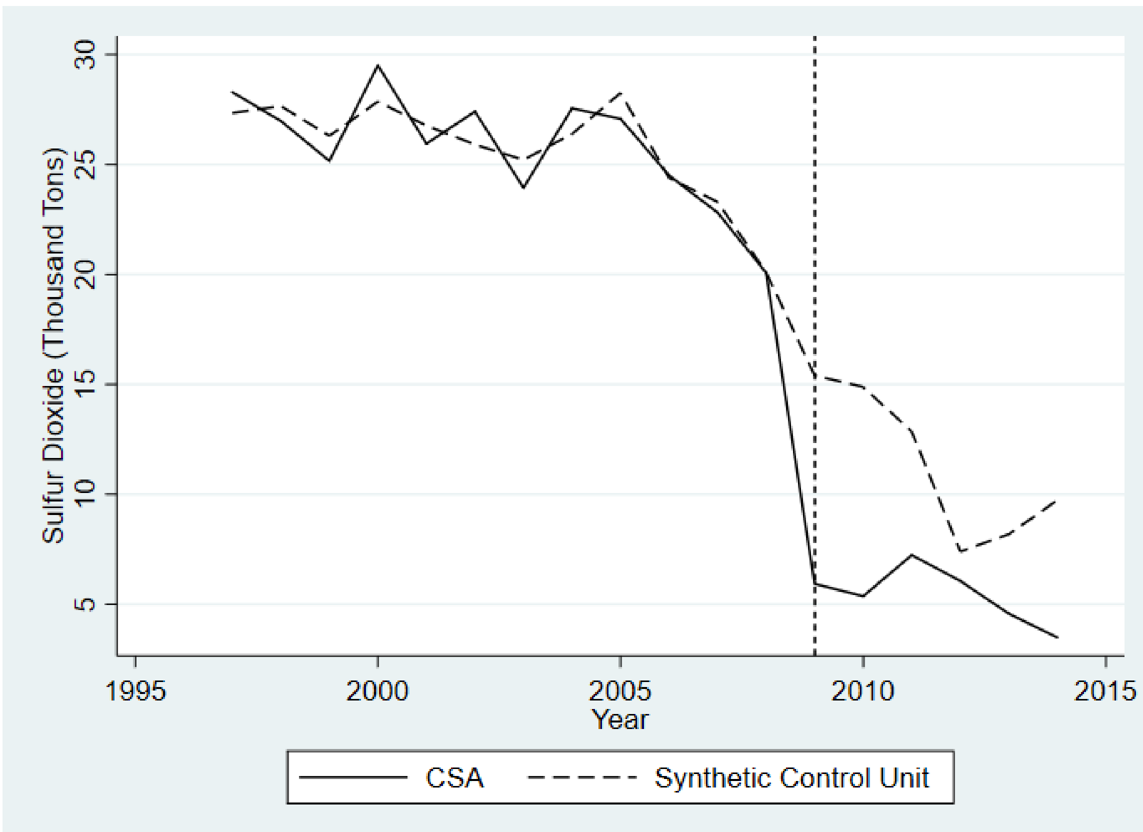
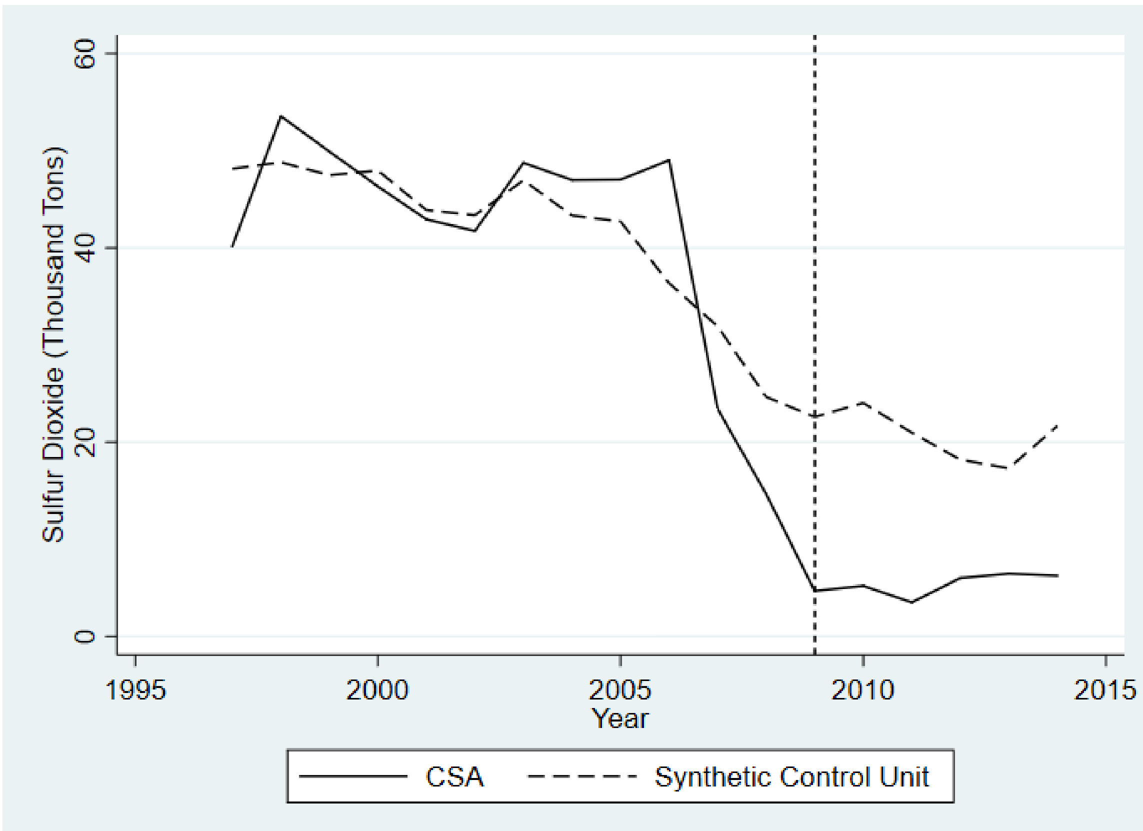


Figure 28 plots the SO_2 emissions of the Roxboro plant. Judging by the timing of reported compliance costs, the Roxboro plant applied SO_2 scrubbing to its generating units in stages. Scrubbing begins in 2007 for Unit 2. In the following two years, SO_2 scrubbing begins in the other three units. In 2007, the estimated effect of the CSA on SO_2

emissions is a reduction of 8,484 tons. Once all the units are online in 2009, the estimated reduction increases to approximately 17,900 tons. From 2010 through 2013, the estimated effect decreases to a low of 10,840 tons in 2013.

Figure 28. Progress - Roxboro Plant SO_2 Emissions Using SCM



Almost all plants that installed abatement technology showed an estimated reduction in SO_2 emissions when using the SCM, except for the Cliffside plant in Figure 24. The fact that counterfactual emissions of the Cliffside plant closely follow the actual emissions throughout the observation window, suggests that the Cliffside plant would have made the same reductions in SO_2 regardless of the CSA. For all plants that installed abatement technology, the estimated effects decreased over time. The gradual reduction in the estimated effect is likely due to the substitution of natural gas powerplants for coal powerplants occurring throughout the United States.

Plants with NO_x Abatement Technology

Figure 29 through Figure 35 show the estimated plant-specific effects of the CSA on NO_x emissions for the plants which reported compliance costs associated with installing technology or implementing methods for reducing NO_x emissions. Figure 29 shows the NO_x emissions for the G G Allen plant owned by Duke Power. Both the actual emissions (CSA) and the counterfactual emissions (Synthetic Control Unit) follow a steady trend downwards over the entire observation window. In the post-phase-one period the actual emissions are only slightly below the counterfactual emissions by approximately 1,000 tons, except for 2010 and 2011. The relatively small, perhaps insignificant, estimated effect of the CSA on NO_x from the G G Allen plant suggests the plant may have reduced emissions regardless of the CSA's implementation.

Figure 29. Duke - G G Allen Plant NO_x Emissions Using SCM

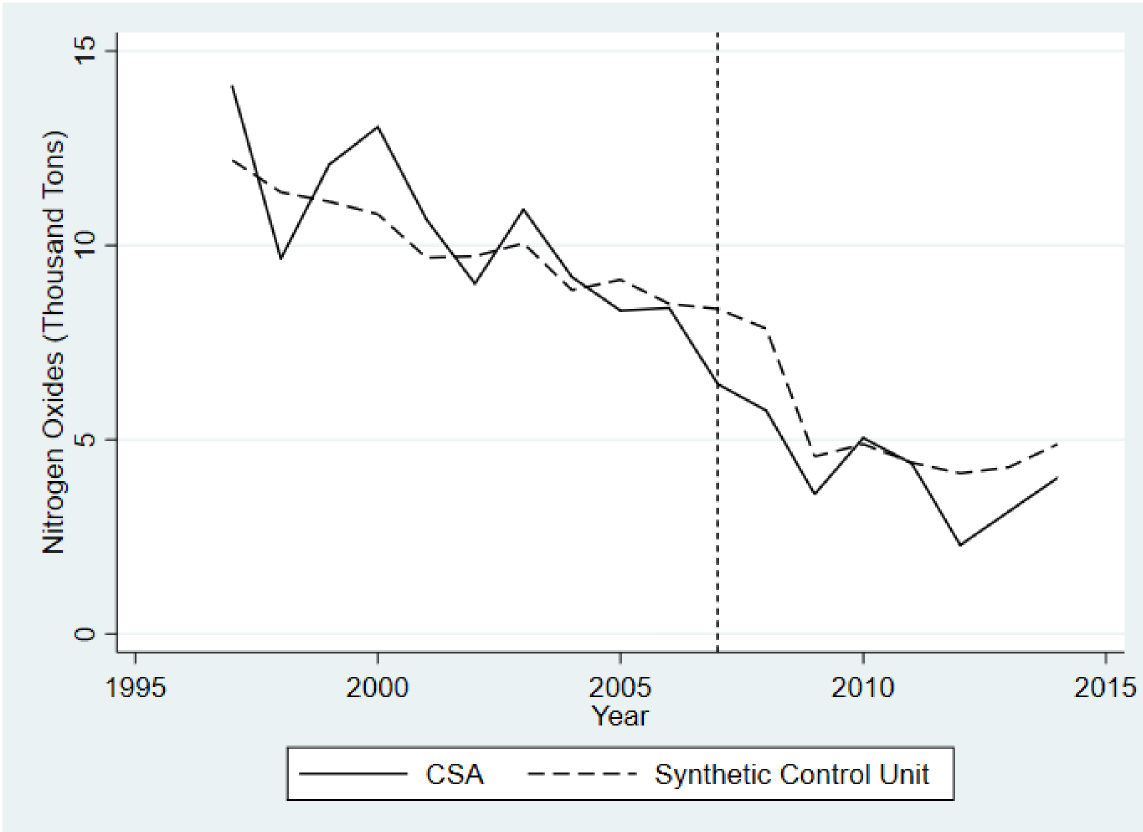


Figure 30 shows the SCM results for NO_X emissions from Duke Power's Buck plant. According to the compliance cost report, most of the costs associated with the CSA were incurred between 2004 and 2008. However, the estimated reduction in NO_x emissions begins in 2002 and continues through to 2014. The poor match of the emissions from the synthetic control unit in the pre-phase-one period to the actual emissions suggests there is another factor contributing to the decline in NO_X emissions at the Buck plant. On the other hand, the poor match could simply be a result of the Buck plant being an outlier compared to the other plants in the control group.

Figure 30. Duke - Buck Plant NO_x Emissions Using SCM

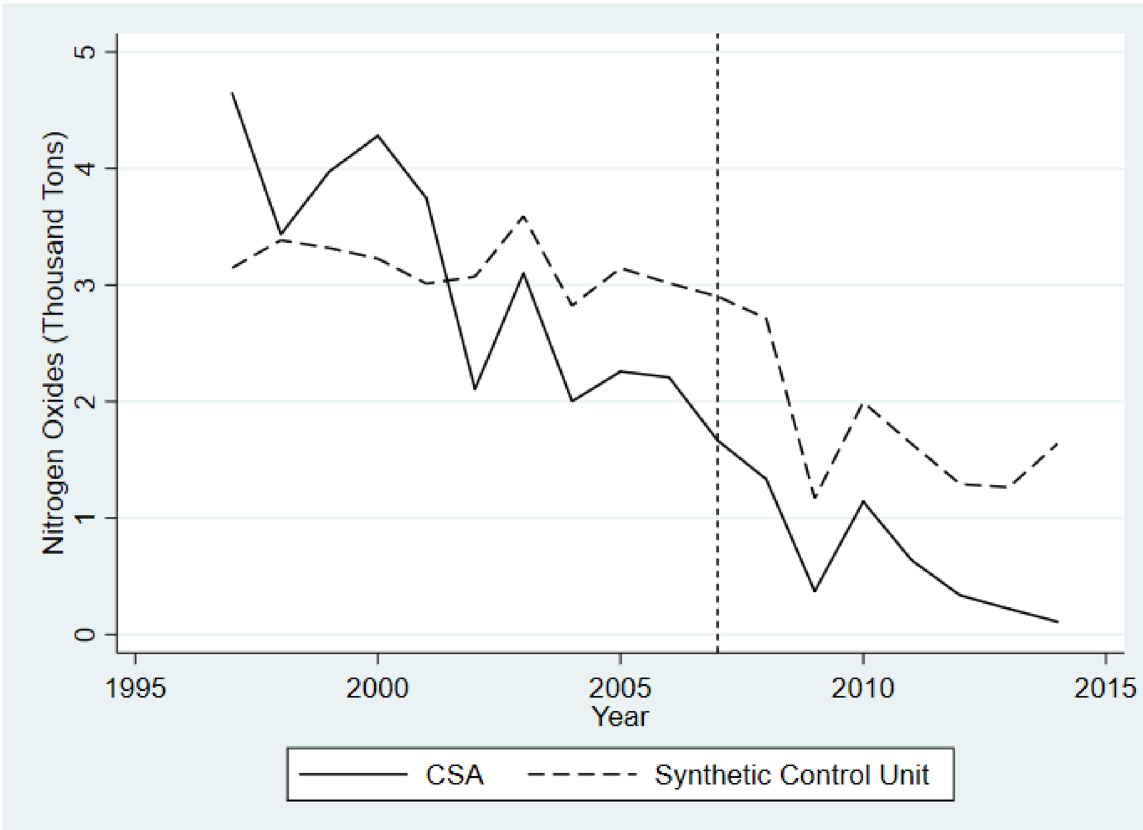


Figure 31 shows NO_x emissions for the Dan River plant owned by Duke Power. The Dan River plant exhibits volatility in NO_x emissions before the phase-one cap. Despite the volatility, the synthetic control unit emissions approximately follow the actual emissions. After the phase-one cap is implemented, the actual emissions are less than the counterfactual emissions, except for a spike in actual emissions during 2010. The difference between the actual and counterfactual emissions is approximately 500 tons throughout the phase-one cap, except for 2010 and 2011.

Figure 31. Duke – Dan River Plant NO_x Emissions Using SCM

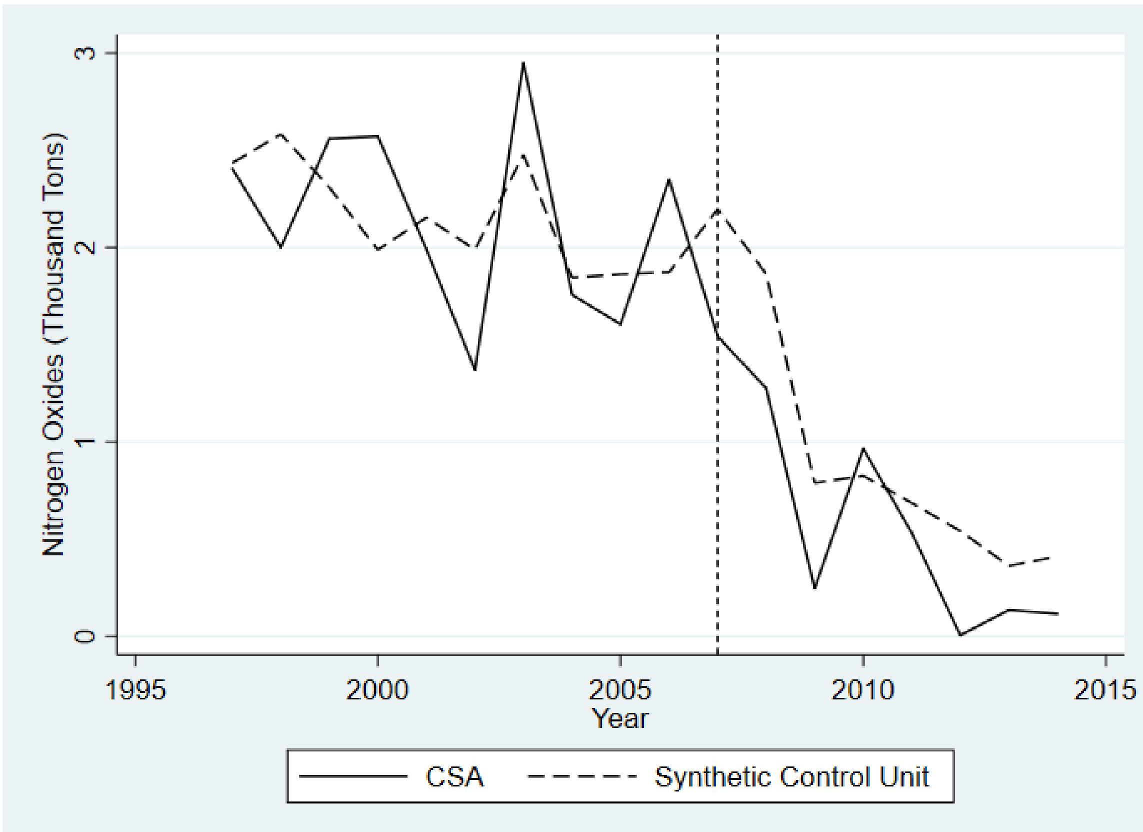


Figure 32 shows the NO_X emissions by Duke Power's Marshall plant. Throughout the observation window, the counterfactual emission by the synthetic control unit approximately matches the actual emissions by the Marshall plant. The lack of an estimated effect leads me to the conclusion that the Marshall plant would have made the NO_x reductions with or without the CSA in place.

Figure 32. Duke - Marshall Plant NO_x Emissions Using SCM

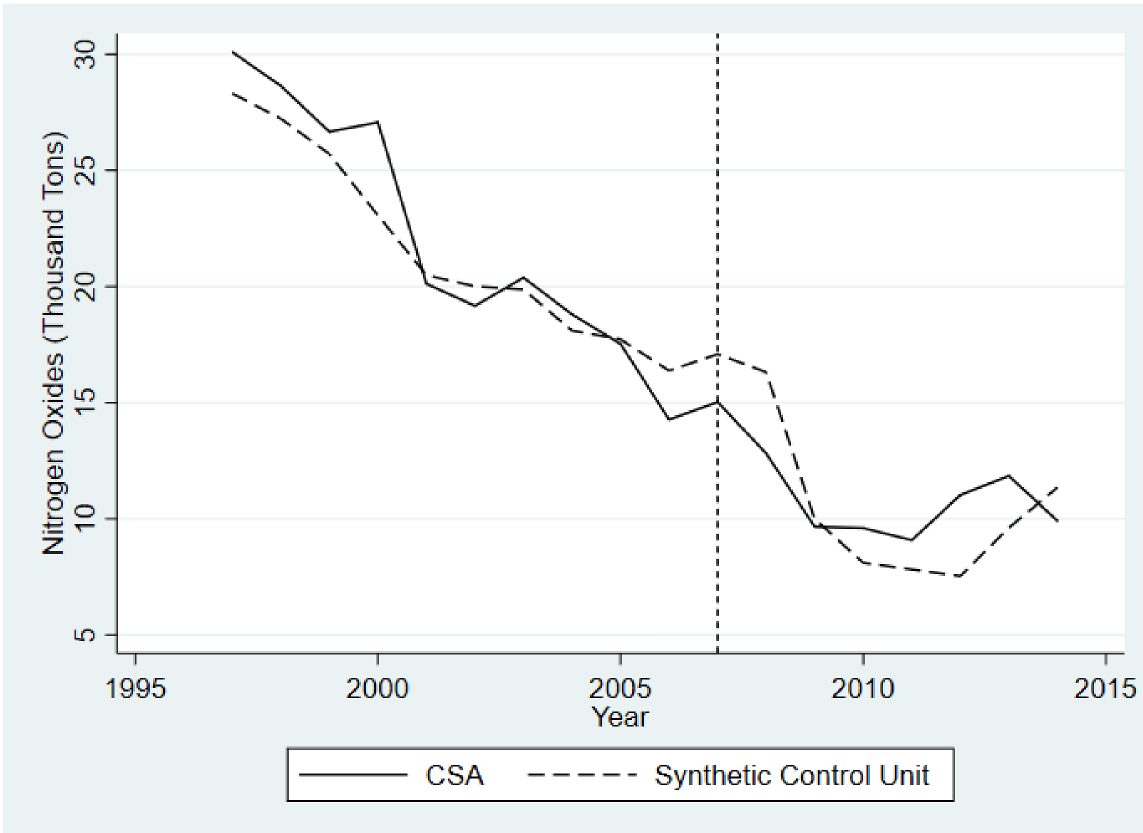


Figure 33 plots emissions for the Riverbend Plant owned by Duke Power. Except for the two years preceding the phase-one cap, the emissions by the synthetic control unit closely track the actual emissions by the Riverbend plant. Starting in 2005, the actual emissions fall below the counterfactual emissions and stay below until 2010. Between 2005 and 2010 the estimated reduction in NO_X emissions from the CSA varies from 1,368 tons in 2005 to 986 tons in 2006 and averages approximately 1,100 tons from 2007 through 2009. In 2010 and 2011 the estimated effect is positive before becoming negative again in 2012. In 2013 the Riverbend plant ceased operations and does not report emissions in 2014.

Figure 33. Duke - Riverbend NO_x Emissions Using SCM

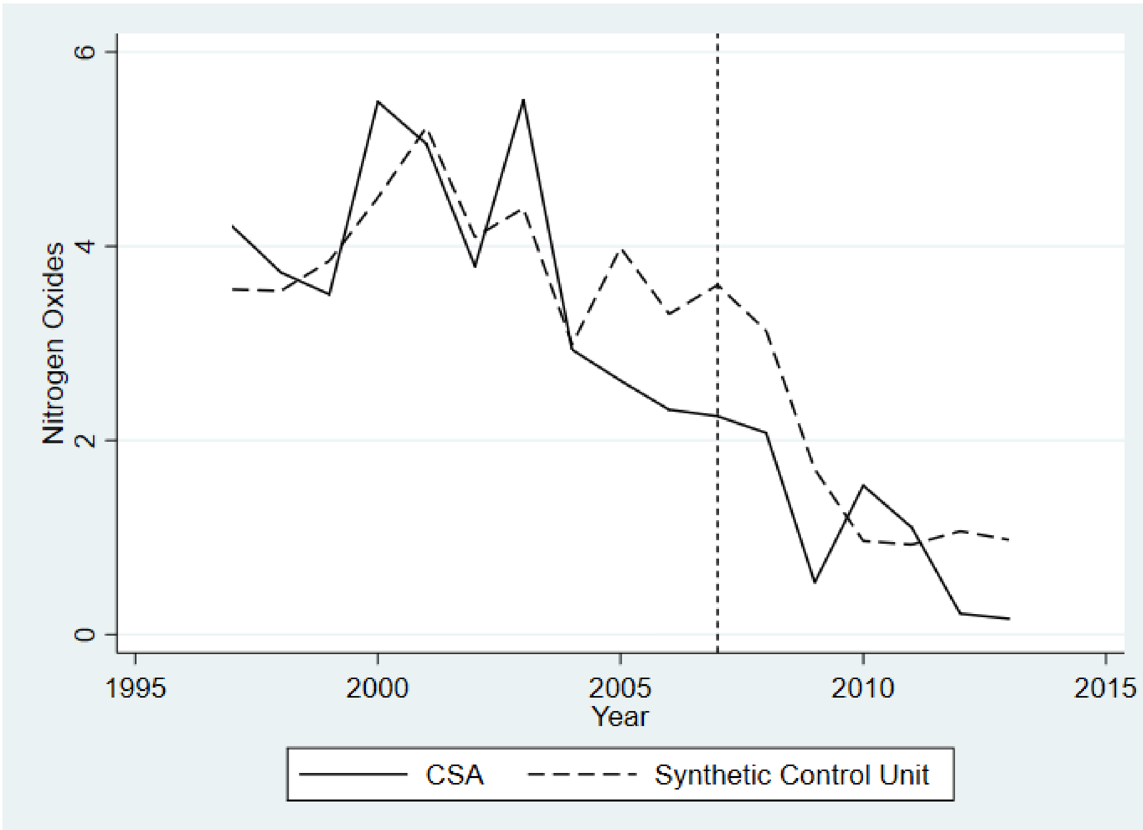


Figure 34, the Asheville plant shows a spike in NO_x emissions at the start of the observation window in 1997. Throughout the pre-phase-one period, the synthetic control unit approximates the actual emissions till 2006. In 2007 actual emissions are 2,963 tons lower than the estimated counterfactual emissions. This gap persists in 2008 for a difference of 3,213 tons. From 2009 to 2014 the actual emissions and estimated counterfactual emissions begin to converge, with a final difference of 1,053 tons in 2014.

Figure 34. Progress - Asheville Plant NO_x Emissions Using SCM

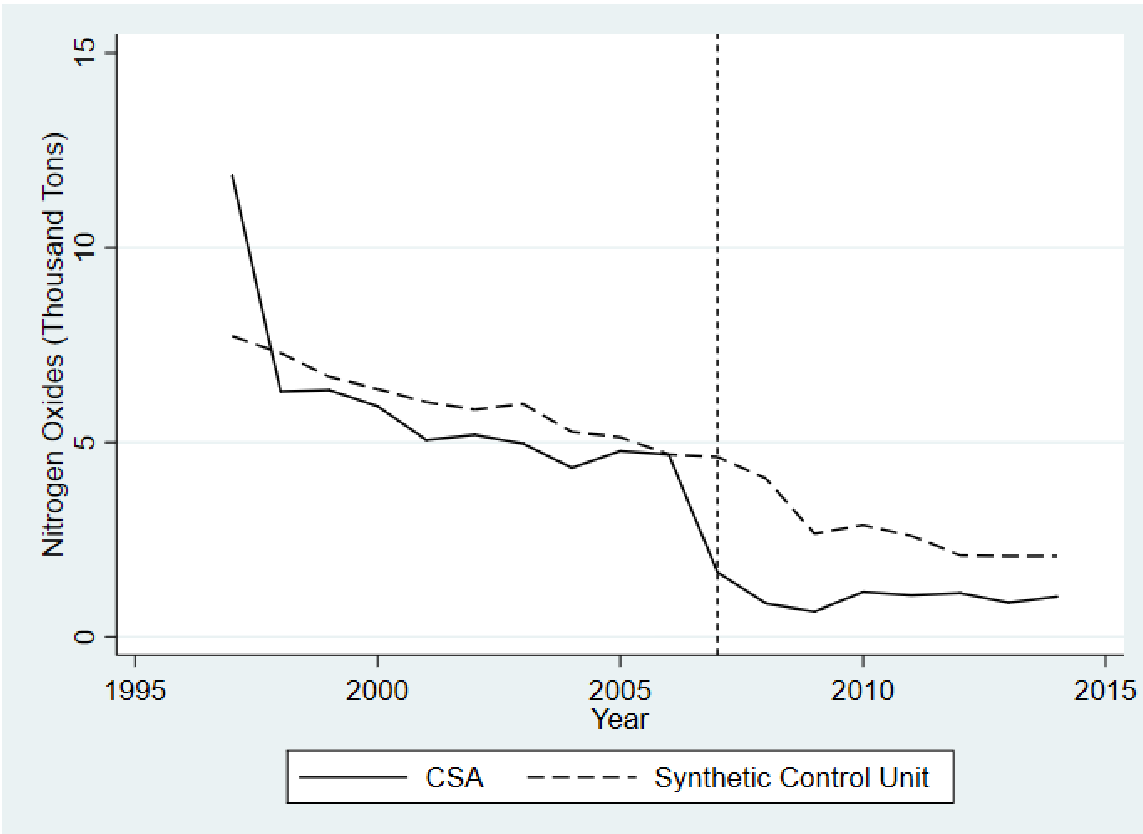


Figure 35 shows the NO_x emissions of Progress Energy's Lee plant. The emissions from the synthetic control unit closely match the actual emissions in the pre-phase-one period, suggesting the synthetic control unit is a good representation of the Lee plant. In the year preceding the phase-one cap, actual emissions begin to fall faster than the estimated counterfactual emissions. This trend continues until 2009, when the actual emissions rises above the estimated counterfactual emissions and remains higher until 2013. Despite having installed abatement technology, the estimated impact of the CSA is an increase NO_x emissions.

This counterintuitive result may be due to two reasons. One potential reason is noise. The difference between the Lee plant's actual emissions and estimated counterfactual emissions may be random noise and not a significant difference. This issue is discussed further in the *Placebo Tests* subsection. The other potential reason is that the Lee plant only installed the abatement technology for financial reasons and did not actually implement it. For example, when considering the entire tax situation of Progress Energy, the reduced tax burden from the incurred compliance costs may have been greater than the compliance cost. Like the Lee plant, the Sutton plant's results exhibit similar behavior.

Figure 35. Progress - Lee Plant NO_x Emissions Using SCM

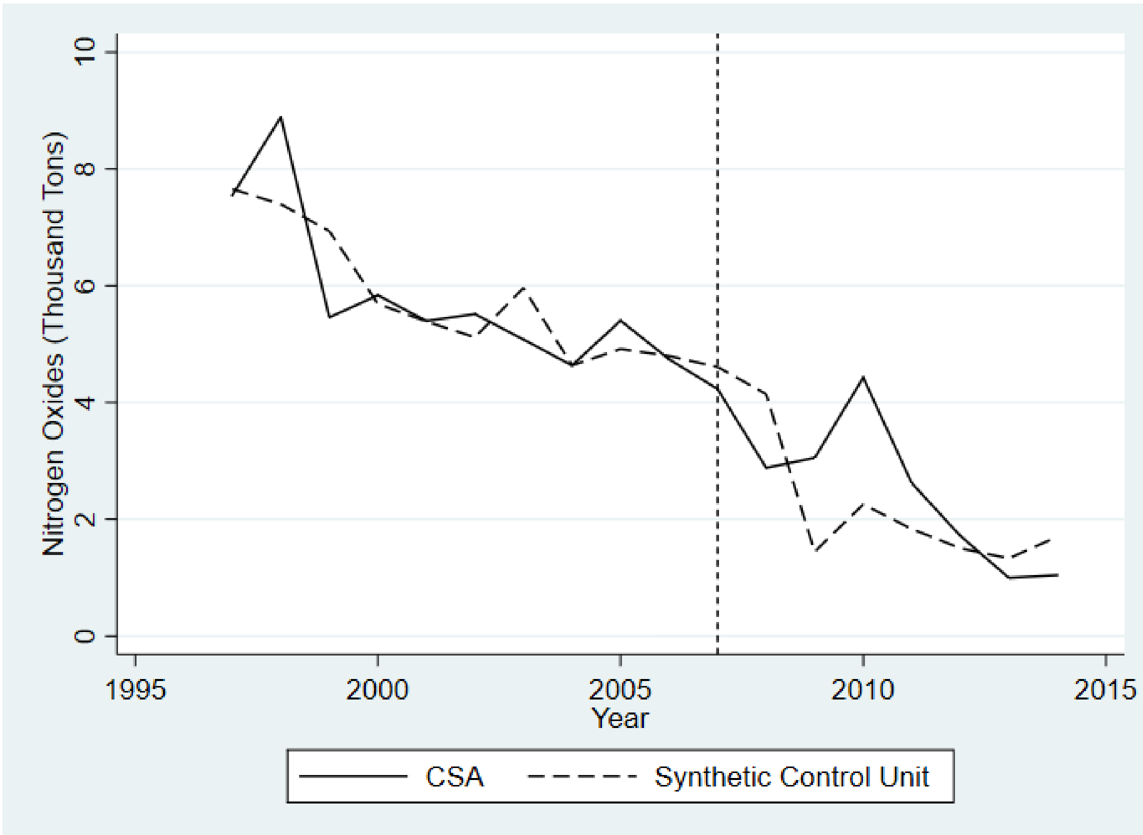


Figure 36. Progress - Sutton Plant NO_x Emissions Using SCM

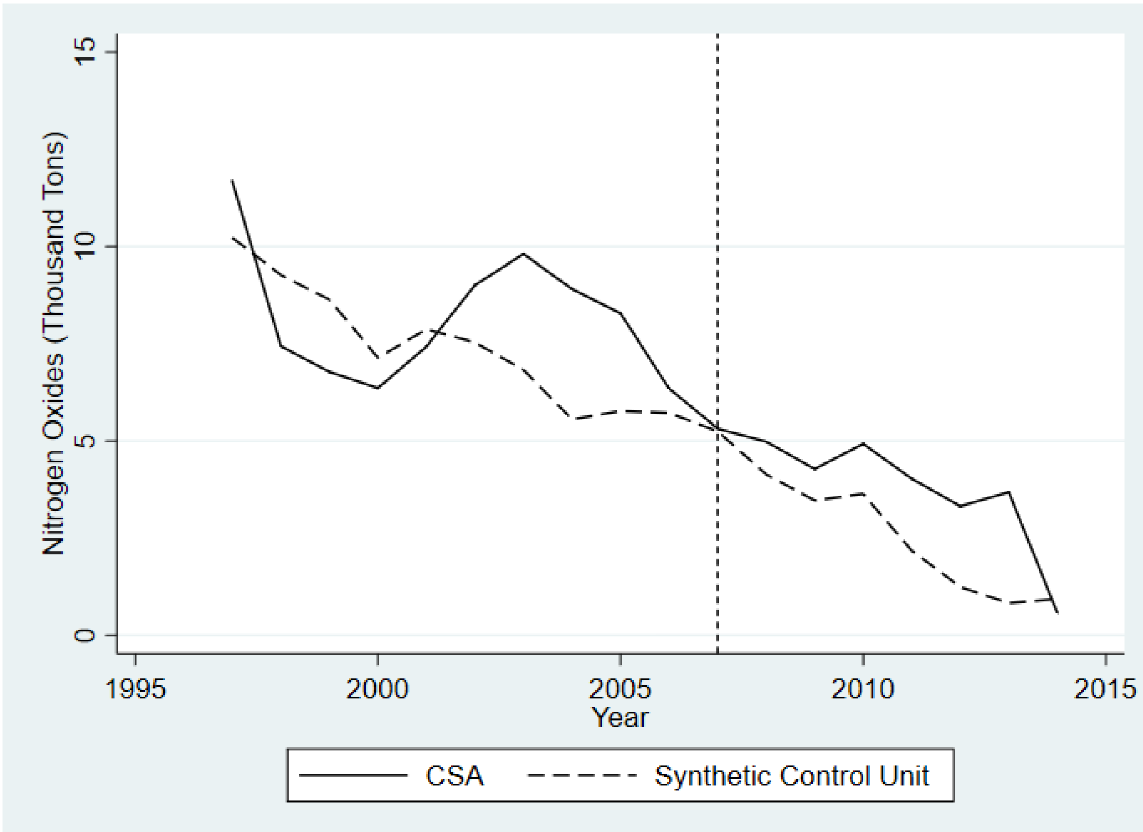


Figure 36 plots the SCM results for NO_X emissions by the Sutton plant. In the pre-phase-one period, estimated emissions by the synthetic control unit do not closely match the actual emissions. This mismatch suggests the synthetic control unit is a poor representation of the Sutton plant. As such, it is difficult to draw any conclusions from Figure 36.

From Figure 29 to Figure 36 estimated effects of the CSA on NO_x cover the full set of possibilities. Some plants show a reduction in emissions, some plants show no effect, and some plants show an increase in emissions. As with the DiD results, there is some evidence of an effect of the CSA on NO_x emissions albeit a small effect. The only constant across all the plants that installed abatement technology is that NO_x emissions were decreasing throughout the window of observation.

Avoided Damages from the CSA

Additional to the question of effectiveness is the issue of damages. Since SO_2 and NO_x are local pollutants, geographic distribution matters. If the CSA caused a reduction in emissions at a remote rural plant but an increase in emissions at a plant upwind from a major city, then the CSA impact on damages could be different than the impact on emissions.. To estimate the overall change in damages, I use all plant-specific effects. The difference between the plant's actual emissions and the synthetic control unit for that plant is the estimated effect of the CSA on the plant's emissions. Since the avoided damages estimates are based on the SCM results, the damage estimates are also point estimates only and should be interpreted as such.

Figure 37 shows the estimated plant-specific effects of the CSA on SO_2 emissions, using SCM. Most plants decline in the lead up to the phase-one cap in 2009. The plant with the largest estimated effect is the Belews Creek plant, one of Duke Power's largest coal-fired facilities ("Duke Energy," n.d.-a). For most plants, there is a negative effect of the CSA on SO_2 emissions. Figure 38 shows the estimated plant-specific effects of the CSA on NO_x emissions, using SCM. The largest reduction in NO_x emissions is also at the Belews Creek plant.

Figure 37. Estimated SO_2 Plant-Specific Effects Using SCM

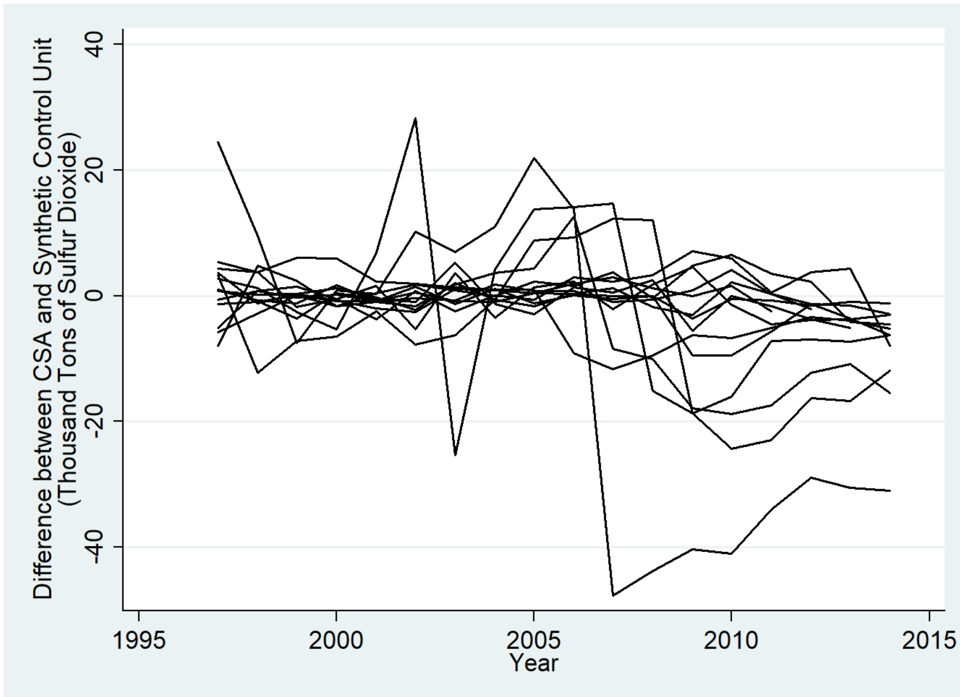
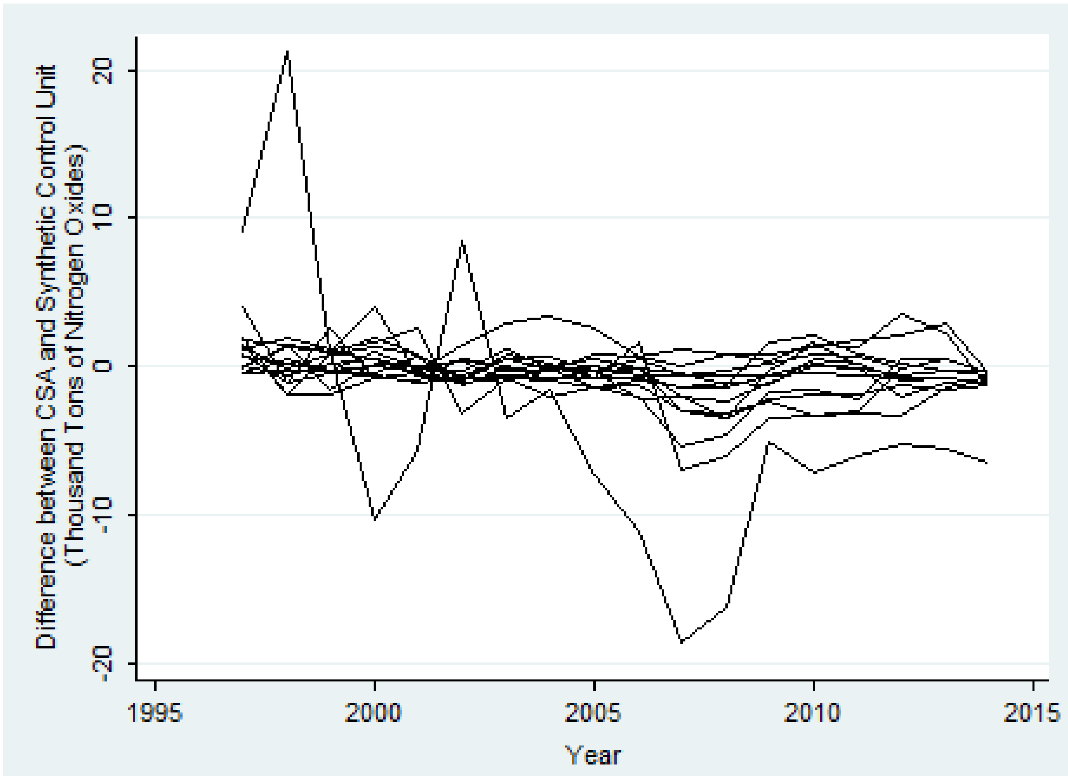


Figure 38. Estimated NO_x Plant-Specific Effects Using SCM



Multiplying the plant-specific annual effects, relative to the SCM, with marginal damage estimates from Muller & Mendelsohn (2009), estimates the avoided damages from the CSA. With all CSA plants assumed to have an effective stack height[34] between 250 and 500 meters, I then aggregate damages across all plants.

Figure 39 and Figure 40 graph the total damages from change in SO_2 and NO_x emissions by the CSA plants. Damages are reported in millions of 2014$. For SO_2, the

[34] Effective stack height includes the physical stack height plus the vertical rise in emissions due to the stack effect. The stack effect is a function of the pressure difference between the outside air and air inside the chimney (Briggs, 1982). A lower effective stack height assumption would increase marginal damages, leading to large estimates of avoided damages.

CSA caused a reduction of approximately \$200 to \$400 million in damages annually. For NO_x, there is a sharp reduction in damages of about \$10 to 15 million in the beginning of the phase-one cap.

Figure 39. Estimated Damages from SO_2 Emissions by CSA Plants

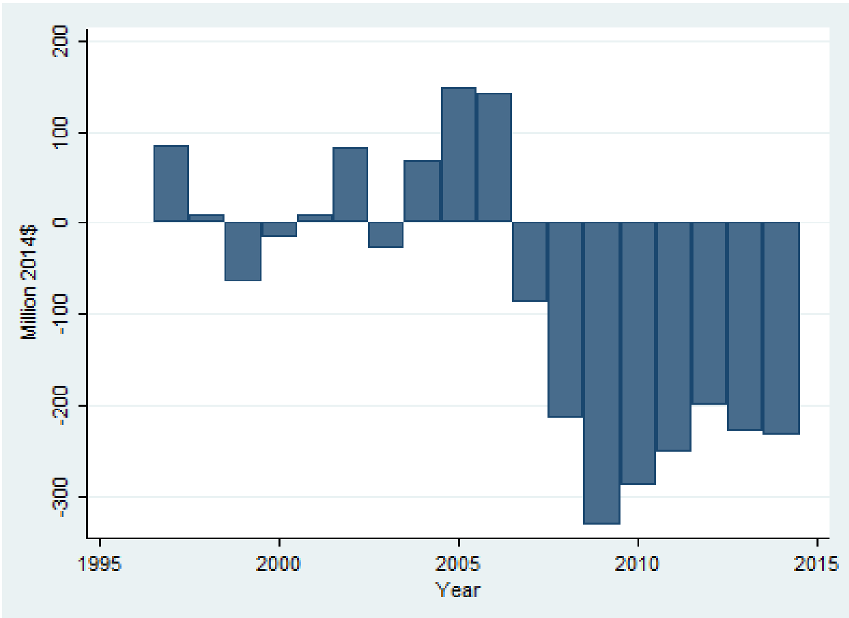
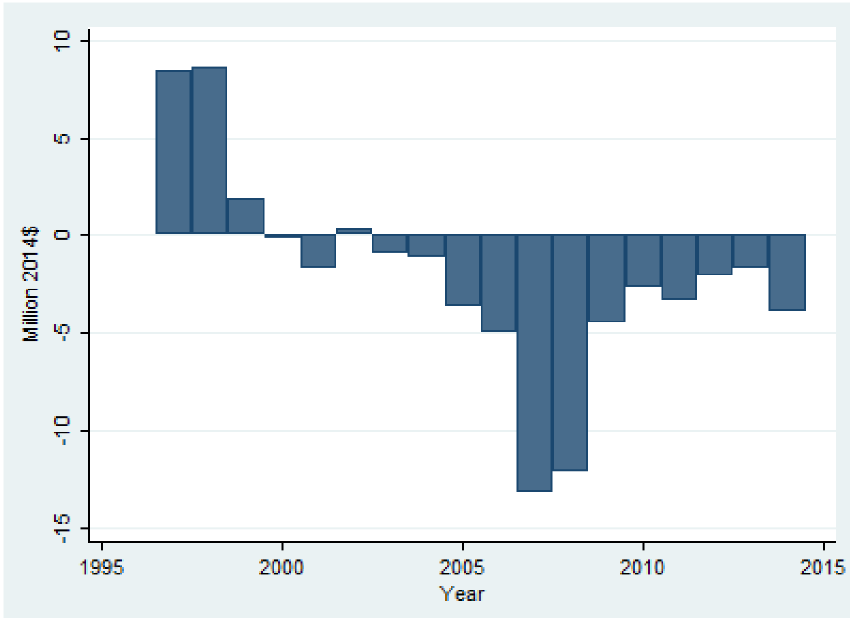


Figure 40. Estimated Damages from NO_x Emissions by CSA Plants

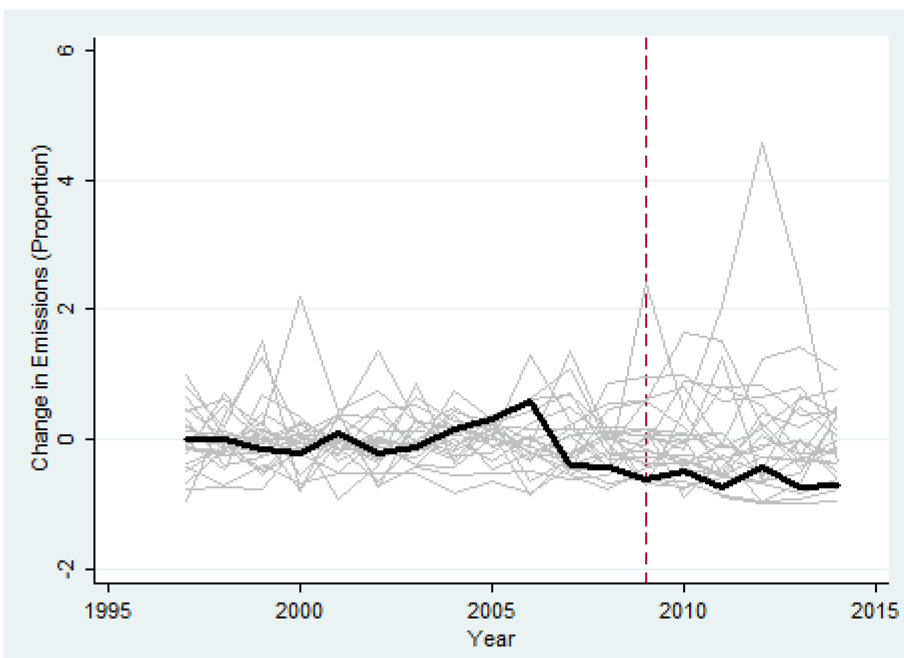


Placebo Tests

With the synthetic control method, typical inference methods are not available. As an alternative method, Abadie & Gardeazabal (2003) use a permutation test. This permutation test is referred to as a *placebo test*. The placebo in this case, is the changing of the treatment group to one of the members of the control group. If there is evidence of a treatment effect, the actual treatment unit will be an outlier in the distribution of all the placebo units. This is typically expressed with a line graph, with the real treatment group boldened and the placebo treatment groups labeled as opaque.

Figure 41 shows the synthetic control unit's SO_2 emissions in comparison to the placebo units. Up until 2005, the synthetic control unit is in the middle of the distribution of placebo runs. In 2007 the synthetic control unit becomes an outlier in comparison to the placebos and continues to be an outlier until the end of the observation window in 2014. Since the estimated effects are calculated by comparing the actual emissions to that of the synthetic control unit, another way of interpreting Figure 41 is that the point estimates for reductions in SO_2 using SCM appear to be outliers in the distribution of estimated effects. By implementing the placebo test, Figure 41 provides an initial look to the issue of uncertainty of the point estimates.

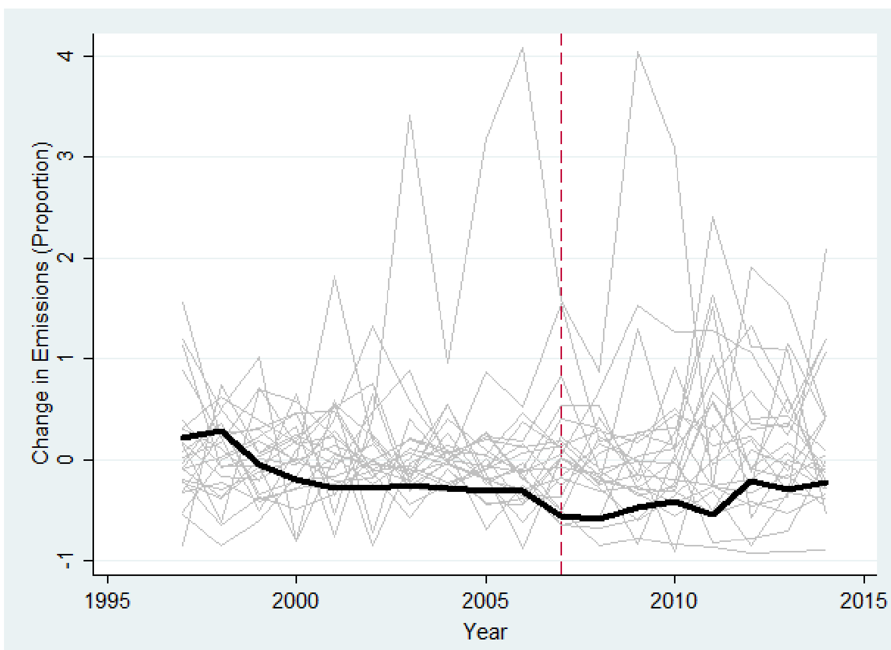
Figure 41. CSA Effect on SO_2 Emissions Placebo Runs



The black line represents the effect of CSA on North Carolina. Grey lines represent the effect of CSA on placebos. The dotted vertical line represents the phase-one cap.

Figure 42 shows the placebo runs for NO_X emissions. Starting in 2000, the synthetic control unit is an outlier in comparison to the placebo units. This continues to be the case until the end of the observation window. This suggests two things. First, the estimated effects of the CSA on NO_x emissions using the SCM are an outlier in comparison to the placebo runs. Second, there is a something unique about the CSA plants with respect to NO_x emissions. This unique characteristic is likely the same factor that influenced the decline in NO_X emission from 1997 to 2002.[35]

Figure 42. CSA Effect on NO_x Emissions Placebo Runs



The black line represents the effect of CSA on North Carolina. Grey lines represent the effect of CSA on placebos. The dotted vertical line represents the phase-one cap

[35] The likely suspect is compliance with the National Ambient Air Quality Standards (NAAQS). During this period, several states in the western parts of North Carolina were in non-attainment status of the NAAQS. Thus, the reductions in NO_X before the CSA, may be due in part to the NAAQS.

Limitations of the Synthetic Control Method Results

The estimated impacts of the CSA when using the SCM are a comparative study between actual emissions and the emissions from the synthetic control unit. This comparative study provides point estimates of the effect of the CSA. However, the point estimates are uncertain. Without the ability to apply traditional large-sample hypothesis testing, the results from the SCM should be interpreted with caution. The reader should keep this in mind when reviewing the avoided damage estimates in the following chapter.

Supplementing the SCM results, the placebo estimates provide a glimpse into the uncertainty of the point estimates. While the placebo estimates do not allow for inference in the traditional sense, current econometric research in this area has led to the possibility of applying hypothesis testing. By imposing certain assumptions about the distribution of potential counterfactuals, confidence intervals can be estimated (Firpo & Possebom, 2017). The proposed method also alludes to the possibility of estimating p-values. This is a topic I will explore in future work.

CHAPTER X

POLICY ANALYSIS

Evaluating a policy requires more than estimating its effectiveness. One part of the evaluation process is understanding the benefits the policy has generated for society and comparing those benefits to the overall cost of implementing the policy. Another part of the evaluation process is to explore what parts of the policy worked well and which parts did not. The intent is to inform policy makers when crafting similar policies in the future. In this chapter, I make a simple comparison of benefits and costs, examine the lessons learned from the CSA, and discuss the caveats of this analysis.

Benefits and Costs

Benefits are the avoided damages from the estimated changes in emissions of SO_2 and NO_X at CSA plants, estimated from the SCM, and multiplied by the marginal damage estimates from (Muller & Mendelsohn, 2009). Table 19 summarizes the total benefits by pollutant. For SO_2, total benefits are \$1,837,666,000 (in 2014\$) and represent 97.7% of the total benefits estimated from CSA. For NO_x, total benefits are \$43,552,000 and represent only 2.3% of the total benefits from the CSA.

Table 19. Estimated Benefits (Avoided Damages) Due to the CSA

Pollutant	Benefits (2014 $)	Share of Benefits
SO_2	1.84 Billion	97.7%
NO_x	.04 Billion	2.3%
Total	1.88 Billion	

To achieve the reductions in emissions, some of the CSA plants installed abatement technology. From 2003 to 2014, Duke Power and Progress Energy were required to submit annual reports to state regulators that included annual compliance costs associated with the CSA. Abatement technology that was implemented includes SO_2 scrubbers, selective non-catalytic reduction (SCNR) to reduce NO_x emissions, low NO_x burners, and classified projects. In the North Carolina DENR (2014) report, the compliance costs are summarized by plant, abatement technology, and target pollutant. Table 20 summarizes the utility reported abatement costs. The majority, 94.9%, of costs incurred were for SO_2 reductions with a total of $1.97 billion. NO_x reductions were 5.1% of total costs or $0.10 billion.

Table 20. Utility Reported Abatement Costs by Pollutant

	Duke Power		Progress Energy	
Pollutant	Abatement Cost (2014 $)	Share of Costs	Abatement Cost (2014 $)	Share of Costs
SO_2	1.97 Billion	94.9%	1.09 Billion	95.8%
NO_x	.10 Billion	5.1%	.05 Billion	4.2%
Subtotal	2.07 Billion		1.14 Billion	
Total Cost		3.21 Billion		

The benefits estimated here are contingent on the results from the SCM and are relative to an estimated counterfactual (the synthetic control unit). However, the costs are not in comparison to a counterfactual. Since the comparison being made is that between what happened and what would have happened in the absence of the CSA, the costs estimated here should be reduced by the costs these plants would have incurred in the absence of the CSA. Without an estimate of the counterfactual costs, the reader should not draw conclusions by directly comparing the costs and benefits estimated here. In order to compare the benefits and the costs, an estimate of counterfactual costs are necessary. Given the limitations of the estimates, the reader cannot directly compare the benefits and costs. Additionally, the limitations to the SCM results also apply to the estimates in Table 19 and Table 20.

Lessons for Policy Maker

Despite the inability to directly compare the benefit and cost estimates, there are still lessons to be learned for the state's future policies. Furthermore, there are aspects of the policy that legislators of state governments around the country can learn from.

<u>Lesson 1: Stakeholders Matter</u>

Part of what made the CSA politically feasible is that it brought lobbyist groups, political groups, state agencies, and utilities together to craft the policy. While not every party was satisfied with the policy, the result was a compromise. Part of the compromise included two provisions that benefited the utilities. First, the compliance cost recovery mechanism allowed for the utilities to amortize their compliance costs by reducing their tax burden. Second, rates were frozen for an initial period. The rate freeze coincided with expectations by the utilities that regulated rates would decrease.

By allowing for compromise and bringing the major stakeholders together in crafting the policy, legislators could pass legislation that has traditionally been unpopular. However, to write a politically feasible bill, tradeoffs were made that may have led to a policy with perverse incentives. Despite the compromises, my results provide evidence that the CSA was effective.

Lesson 2: Cost Recovery and Perverse Incentives

The compliance cost recovery created an incentive for utilities to install abatement technology. By incentivizing utilities to install abatement technology, the intent was for utilities to reduce emissions at the targeted plants without shifting production elsewhere. However, the incentive to install abatement technology assumed the status quo and did not account for structural changes in energy markets, such as the natural gas boom. Without flexibility in the compliance cost recovery measure, the CSA provided an incentive for capital investments in coal instead of switching to natural gas, a fuel input that had become cheaper per MWh.

The compliance cost provision led Duke Power and Progress Energy made investments in old and dirty powerplants. In the absence of the CSA, some of these powerplants may have shut down, or at least shut down sooner than they did. By 2017, seven of the CSA powerplants ceased operations but none of those plants had SO_2 scrubbers installed during the CSA compliance period. The plants that the utilities incurred the most compliance costs for are those they have kept in operation, while shutting down the rest.

Among the plant-specific effects, there is at least one example, empirically, of this behavior. Duke Power's Cliffside plant's actual SO_2 emissions are almost identical to the synthetic control unit's emissions throughout the entire observation period. Recall that the synthetic control unit is a representation of the Cliffside plant in the absence of the CSA. Thus, the Cliffside plant would have reduced emissions of SO_2 regardless of the CSA and most likely would have done so by shutting down some or all its generating units.

Lesson 3: Expectations Matter

Part of the motivation for the utilities to support the CSA was their expectations of rates. Leading up to the CSA, Duke Power and Progress Energy expected regulated rates to fall, as prior capital investments were being paid off. Then the CSA came and provided the utilities with a mechanism to freeze rates at levels higher than rates would have been in the absence of the CSA. Additionally, the fixed costs associated with installing abatement measures as well as the associated operating costs gave utilities standing in the argument for increased rates in future rate cases.

Without the expectation of rates decreasing, the utilities may have been less supportive of the CSA. Furthermore, the expected rates in the absence of the CSA could have been incorporated into the CSA. By taking into account the benefits to the utilities that the rate freeze had, a less generous compliance cost recovery provision may have proved more appropriate.

Caveats

As with any study, there are caveats to the conclusions drawn. In this study there are a few caveats to the results. First, every policy cannot be accounted for. Across the United States there is a patchwork of municipal, state, regional, and federal policies that impact the entire electric power industry. Each policy that applies to either the treatment or control group, and not the other, violates the parallel trends assumption and is a potential source of bias. In my analysis there are two major policies that I do address, RECLAIM and RGGI. By excluding states under the purview of these policies from the control group, there is more reason to assume parallel trends between the treatment and control groups.

Second, not all the benefits of the CSA are accounted for. While the marginal damage estimates from Muller & Mendelsohn (2009) cover a wide range of impacts from SO_2 and NO_x pollution, there are likely impacts which have not been included in the estimates. As further research improves our understanding of the impacts from pollutants, damage estimates will inevitably change. This is what happened to the estimated impacts of the Acid Rain Program. After the initial estimates, numerous studies linked particulate matter to adverse health impacts. An updated analysis was performed that included the benefits associated with reducing particulate matter.

Additionally, there are regulatory benefits that are not included. The CSA could contribute to the changing of counties within North Carolina from nonattainment to attainment, with respect to the NAAQS. The CSA led to reductions in NO_x large enough to make North Carolina exempt from the final CSAPR ruling. The avoided costs to comply and fees associated with noncompliance are benefits to utilities and ratepayers. As for the unknown benefits, there is not much to be done in the absence of new information. Any additional benefits would decrease the net benefits associated with the CSA.

Third, not all costs incurred by society for the CSA are accounted for. For example, the compliance cost recovery mechanism means forgone tax revenues for the state. Another example is the operating cost associated with any installed abatement measures, for as long as a retrofitted plant is in operation. There is also the cost imposed on ratepayers for frozen rates that, without the CSA, were expected to decline. Inclusion of these costs would only increase the estimated net loss of the CSA.

The final caveat is that the cost estimates that are reported by the utilities are likely inflated. Since the utilities can recover their compliance costs through a reduction in their tax burden and can use the increased operating costs to justify a rate hike, the utilities have an incentive to overestimate the actual costs. However, without additional information on the actual compliance costs the utility reported costs suffice.

CHAPTER XI

CONCLUSION

Using the CEMS data in conjunction with eGRID, this paper analyzes the impact of the CSA from three angles. First, my results provide evidence that the CSA did reduce emissions of SO_2 and NO_x. For SO_2, the CSA reduces annual emissions by approximately 100,000 tons, whereas for NO_x emissions, the CSA reduces annual emissions by approximately 25,000 to 50,000 tons. These estimated reductions are approximately 35% of the observed reductions in SO_2 emissions and 75% of the observed NO_x reductions. Second, the reductions in emissions are mostly due to installation of abatement technology. Leakage accounts for a minor part of the emission reductions. Third, as of 2014, the estimated benefits of the CSA yields $1.88 billion in avoided damages for North Carolina.

Compiling empirical studies of cap-and-trade, Stavins (1998) provides four lessons for a successful cap-and-trade policy. First, flexibility, to allow firms to choose the appropriate abatement method and spur innovation. While the CSA could potentially have been more flexible, by allowing for trading across utilities, it still allowed for decision making to fall to firms instead of the regulator. Increased ability to trade may have reduced the total compliance costs. Second, the simplicity of a policy should keep enforcement and compliance costs low for the regulator and firms. Compared to other C&T policies, the CSA is the simplest. With no formal permit market to maintain and permits to account for, regulators must only focus on enforcement. Third, credible enforcement, such as stiff penalties and continuous emissions monitoring, can instill confidence in the market. The CSA utilizes the CEMS data for verification of compliance and imposes a $10,000 per ton per day penalty. Lastly, revenues can be raised by the government if permits are auctioned as opposed to freely-allocated. Unfortunately, the CSA does not generate revenues. This is an area of potential regulatory improvement.

Just as Title IV provided lessons for Stavins (1998), there are lessons to be learned from the CSA. The first lesson is that stakeholders matter. Being one of only a handful of cap-and-trade policies to be implemented, the CSA's passing shows the importance of compromise and collaboration with all stakeholders. Second, special attention should be paid to compliance cost recovery measures and the incentives they provide. Finally, expectations matter. When utilities are making decisions, they are considering expectations about future rates. These expectations should be taken into account when crafting policy, especially in the presence of compliance cost recovery mechanisms.

Even though the CSA may have provided perverse incentives for utilities, policy makers constructed a policy that was political feasible and without knowing the structural changes in store for energy markets in the future. The difficulty in crafting policy is finding the balance between what is politically feasible and what is theoretically ideal. When writing the CSA, legislators were operating under the assumption that coal would maintain its dominance. However, lessons can be learned from the CSA and should be taken into consideration for future policies.

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