Going Nuclear for Climate Mitigation and Energy Systems Modeling of Carbon Dioxide and Air Pollution Taxes

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Abstract

The consumption of energy in the United States (U.S.) results in the emission of both carbon dioxide (CO_2), which damages the atmosphere, and local air pollutants (LAP), which causes damage to human health and the environment. In this thesis, I assess the efficacy of different policy strategies focusing on the abatement of CO_2, LAP, and both simultaneously. The thesis begins by examining whether preserving existing nuclear plants is a cost-effective means for avoiding CO_2 emissions.

Following the nuclear analysis, I broaden the scope of my work to include all sectors of the U.S. energy system. Using the Environmental Protection Agency's TIMES model, I simulate energy-system taxes on CO_2 as well as on LAPs, including sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter 2.5 micro-meters in diameter and below ($PM_{2.5}$). Additionally, I compare the efficacy of LAP tax scenarios at a national and regional level. Across Chapters 3-4, I compare total emissions across multiple simulated tax scenarios to a business as usual scenario. Additionally, using integrated assessment reduced complexity models, I estimate damages from CO_2 and LAPs emissions across these scenarios. To measure the efficiency of tax scenarios in this thesis, I model the net-benefits compared to BAU across multiple environmental policies.

In Chapter 2, I examine whether preserving existing U.S. nuclear power plants is a cost-effective strategy to avoid CO_2 emissions. I perform a Monte Carlo-based analysis to determine the break-even price of electricity that each U.S. nuclear plant must receive in order to avoid financial loses between 2015 and 2040. Subsequently, I model nuclear power plant revenue under four separate future prices of electricity. Under the lowest electric price trajectory, my modeled results suggest that nuclear power plants would

require a subsidy in order to break-even. Under the low electric price scenario, assuming natural gas combined-cycle power plants would replace nuclear power plants, I estimate the median cost of avoided CO_2 emissions to range from $18-$30 per metric ton of avoided CO_2 for multi-reactor plants, and $47-$97 per metric ton of avoided CO_2 for single reactor plants (2014$).

In Chapter 3, I simulate business as usual as well as two CO_2 tax policies from 2015 to 2030 on the United States energy system, using the TIMES optimization model. I find limited near-term decarbonization opportunities outside of the power generation sector, which results in substantial and enduring CO_2 tax revenue through 2030. Second, because the social cost of carbon, and therefore the optimal CO_2 tax, is uncertain, I perform analysis comparing the deadweight loss associated with picking the wrong, non-optimal CO_2 tax. Due to the convex nature of the CO_2 abatement cost curve implicit in the TIMES model, I find that it is more efficient to tax high when the social cost of carbon is low, versus taxing low when the social cost of carbon is high. Additionally, I quantify the co-benefits of LAP emissions reductions that occur under both CO_2 tax policies.

In Chapter 4, I use energy system and integrated assessment models for air pollution to estimate the consequences of LAP and CO_2 policy on technology choice, emissions, and pollution damages in the U.S. economy. Chapter 4 explores various combinations of policies targeting just CO_2, just LAPs, and both types of pollutants simultaneously. One goal is to assess whether simultaneous tax policies on both LAPs and CO_2 are needed or whether significant spillovers merit control of only LAPs or CO_2. I find substantial spillovers across policies, that a scenario taxing both CO_2 and LAPs simultaneously produces the highest net-benefits, as opposed to scenarios that target either CO_2 or LAPs, and that the timing of taxes is important with regard to technology lock-in in the electric sector.

Also in Chapter 4, I simulate national and regional taxes levied on the emission of LAPs from the U.S. energy system. I estimate the efficiency gains, relative to BAU, from taxation of LAPs under two systems: in one scenario taxes are set to the emission-weighted average marginal damage on a national level and the other employs a 9-region taxation system on SO_2, NO_x, and $PM_{2.5}$, where the regions are defined according to U.S. census regions. I find that both national and regional taxes induce substantial and nearly identical reductions in the emissions of SO_2, NO_x, and $PM_{2.5}$. Importantly, across regions and sectors, there is not a substantial difference in emissions between the national and regional tax scenarios. As a result, the modeled welfare gains stemming from policy differentiation are minimal. It is important to note that the lack of an increase in net-benefits between the national and regional tax scenarios is likely due to the lack of additional abatement options built into TIMES, which does not allow additional regional abatement in many sectors, regardless of whether there is a substantial tax increase.

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Chapter 1 : Introduction

The consumption of fossil-fuel derived energy results in emissions of greenhouse gases (GHG) and local air pollutants (LAP). Both types of emissions cause damages but in different ways. GHG emissions cause changes to the earth's atmosphere, resulting in global climate change, and an increase in average global temperatures. LAP emissions can have an impact on the climate, however, they primarily cause damage to human health and the environment. GHG emissions are unique in that they occur across the world, but cause the same amount of damage regardless of location. The location of LAP emissions is highly important since they cause damage in large part as a function of exposure to human population.

In an attempt to mitigate global GHG emissions, in 2016, the majority of the world's countries were signatories to the Paris Agreement, which aims to limit the increase in global temperature to 2° Celsius above pre-industrial levels [1]. In order to limit the global temperature increase to 2° Celsius, GHG emissions will likely need to decrease by 25% of 2010 levels by 2030, and reach near-zero by 2070 [2]. Carbon dioxide (CO_2) from fossil fuel and industrial processes accounts for 65% of global GHG emissions [3]. In 2014, the largest emitters of CO_2 from fossil fuel combustion were China at 30%, the United States at 15%, the EU-28 at 9%, India at 7%, and the rest of the world at 39% of total global CO_2 emissions [4]. As the second-largest emitter of CO_2 in the world, future U.S. CO_2 emissions reductions are necessary if the goals in Paris Agreement are to be met.

In addition to GHG emissions, substantial damage from LAP emissions in the U.S. is realized, predominantly through increased human mortality and morbidity. Most of the damages to human health are a result of $PM_{2.5}$ emissions, the ambient concentration of which is also increased by the emissions of other criteria pollutants. Heo, Adams, and Gao (2016) estimated that the damages from air pollution, including emissions of $PM_{2.5}$, SO_2, NO_x, and ammonia (NH_3), totaled $1 trillion (2005$) in 2005 in the U.S. alone. Tschofen, Azevedo, and Muller (2019) estimated that U.S. LAP damages have decreased to $610 billion (2005$) by 2014. Most of the damages to human health are a result of $PM_{2.5}$ exposure, which can cause respiratory problems such as asthma, cardiovascular diseases, pregnancy complications, and premature death [7], [8].

The main regulatory instruments for LAP in the U.S., established under the Clean Air Act, are the National Ambient Air Quality Standards (NAAQS), a cap and trade system limiting the emissions of SO_2 and NO_x, as well as a host of other standards regulating tailpipe and industrial emissions. The NAAQS set national limits on the concentration of criteria air pollutants. Given that there are large negative externalities from LAP emissions across the U.S. suggests that these emissions are not efficiently regulated, despite the presence of the NAAQS.

This dissertation consists of three research papers that I wrote during my PhD at Carnegie Mellon University's Department of Engineering and Public Policy. My earliest work, presented in Chapter 2, focuses on whether preserving existing U.S. nuclear power plants is a cost-effective strategy to avoid future CO_2 emissions. In Chapters 3 and 4, I model emissions externalities and economically efficient environmental regulations across all sectors of the U.S. energy system using the U.S. Environmental Protection Agency's (EPA) TIMES model.

In Chapter 2, I perform a Monte Carlo-based scenario analysis to determine the break-even price of electricity that existing nuclear plants must secure in order to avoid financial loses between 2015 and 2040. I find median break-even electricity prices to range between \$35 and \$73 per MWh (2014\$) at existing nuclear power plants across the U.S.[1] Based on estimates of future electricity prices under a low natural gas price scenario from the Energy Information Administration, this analysis suggests that U.S. nuclear plants would require between \$8 and \$44 per MWh (median results) on top of electric sales revenue in order to break-even. Assuming natural gas plants would replace retired nuclear power plants, I estimate an equivalent cost of avoided CO_2 emissions to be \$18-\$30 per metric ton of avoided CO_2 (median results) for multi-reactor nuclear plants and \$47-\$97 per metric ton of avoided CO_2 (median results) for single-reactor plants. Preserving the existing nuclear power plant fleet, especially multi-reactor plants, is thus a cost-effective carbon-avoidance strategy compared to the social cost of carbon.

In Chapter 3, I investigate the energy system response to environmental policies focusing on CO_2 emissions reductions. I use the EPA's TIMES optimization model to simulate the U.S. energy system from 2010-2030. In Chapter 3, I begin by modeling a business as usual (BAU) scenario, which includes policies such as the Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS), Renewable Portfolio Standards (RPS), and Corporate Average Fuel Economy (CAFE) standards. In addition to the BAU scenario, I model a \$35 and \$100 per ton tax trajectory on the energy

[1] All values in Chapter 2 are expressed in 2014\$. All values in Chapters 3 and 4 are expressed in 2005\$.

system (2005$). I find that energy system decarbonization occurs mainly in the electric sector due to the lack of low carbon technologies in other sectors in TIMES. Under both carbon tax trajectories, I find enduring CO_2 tax revenue from 2015 to 2030. The benefits of CO_2 damage reductions or air pollution damage reductions compared to BAU outweigh the increase in costs to the energy system in both scenarios. Lastly, I find asymmetric deadweight loss from implementing mistakenly low or high CO_2 taxes, which yields efficiency-based support for the precautionary principle.

In Chapter 4, I expand the time horizon to range from 2010 to 2035 and model seven different national tax scenarios and one regional tax scenario. This chapter uses TIMES and integrated assessment models for air pollution to estimate the consequences of LAP and GHG policy on technology choice, emissions, and pollution damages in the U.S. economy. The analysis explores various combinations of policies targeting just CO_2, just LAPs, and both types of pollutants. The goal is to assess whether simultaneous tax policies on both LAPs and CO_2 are needed or whether significant spillovers merit control of only LAPs or CO_2. I find that a scenario taxing both CO_2 and LAP simultaneously produces the highest net-benefits, as opposed to scenarios that target either GHGs or LAPs. Additionally, the timing of the taxes is important. If LAPs are taxed starting in 2015 and a CO_2 tax does not begin until 2025, then the electric system technology is locked into higher levels of natural gas electric generation.

As part of Chapter 4, I model the U.S. energy system under three states of the world: BAU, a national LAP tax, and a regional LAP tax. The TIMES energy system model is divided regionally according to nine U.S. census regions. Using integrated assessment air pollution models, I compute emissions weighted $ per ton marginal damages from LAP emissions in each region. I then implement these marginal damages as regional taxes in the TIMES model. I compare emissions, costs, and damages across the regional and national tax scenarios. I find that there is a slight increase in net-benefits compared to BAU under a regional versus a national tax.

Chapter 2 : Going nuclear for climate mitigation: An analysis of the cost effectiveness of preserving existing U.S. nuclear power plants as a carbon avoidance strategy

2.1 Abstract

Nuclear power plants generate over 60% of the carbon-free electricity in the U.S. Due to a decrease in electricity prices as a result of the availability of cheaper natural gas and increased low-cost renewables, many of these plants are at risk of premature retirement. If nuclear power plants retire, CO_2 emissions in many U.S. states could increase, even while the states comply with EPA legislation aimed at mitigating emissions of greenhouse gases that contribute to climate change. In this paper, we perform a Monte Carlo-based analysis to determine the break-even price of electricity these plants must secure in order to avoid financial loses between 2015-2040, and find median break-even electricity prices to range between \$35 and \$73 per MWh. Based on our estimates of future electricity prices under a low natural gas price scenario from the Energy Information Administration, our analysis suggests that U.S. nuclear plants would require between \$8 and \$44 per MWh (median results) on top of electric sales revenue in order to break-even. Assuming natural gas plants would replace retired nuclear power plants, we estimate an equivalent cost of avoided CO_2 emissions to be \$18-\$30 per metric ton of avoided CO_2 (median results) for multi-reactor nuclear plants, and \$47-\$97 per metric ton of avoided CO_2 (median results) for single-reactor plants. Preserving the existing nuclear power plant fleet, especially multi-reactor plants, is thus a cost-effective carbon-avoidance strategy compared to the social cost of carbon.

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2.2 Introduction and Motivation

Nuclear power currently accounts for 20% of total U.S. electricity generation and, excluding hydroelectric generation, accounts for all of U.S. low-carbon and criteria pollutant-free dispatchable generation [9]. However, recent drops in wholesale electricity prices, resulting from an abundance of natural gas due to hydraulic fracturing and increased penetration of renewable resources, are putting a number of technically sound nuclear power plants at risk of early retirement [10]–[16]. Since 2013, for example, a combination of economic and life-extension construction issues have led to the premature retirement of Crystal River (FL), Kewaunee (WI), San Onofre (CA), and the Vermont Yankee (VT) nuclear power plants. While Crystal River and San Onofre retired due to complications surrounding steam generator replacement, the Kewaunee plant did not have any operational problems and could have extended its operating license through at least 2033. Kewaunee was owned by Dominion who claimed that the sole reason for retirement was low electricity prices resulting from low natural gas prices [17]. Similarly, due to economic conditions, the owners of Clinton (IL), Quad Cities (IL), Fitzpatrick (NY), Pilgrim (MA), and Oyster Creek (NJ) power plants recently announced plans to close plants prematurely despite 20-year Nuclear Regulatory Commission (NRC) extensions permitting operation through 2026, 2032, 2034, 2032, and 2029, respectively (the Clinton plant is also eligible to apply for its first 20-year license extension, permitting operation until 2046 [18].

Figure 2.1 below outlines the current nuclear fleet with designations for plant capacity, location, and operational status. We also highlight plants whose owners have claimed they may be at risk of early retirement without subsidies. Note, that the Nuclear Energy Institute estimates that 15-20 other reactors are at risk of early retirement over the next 5-10 years [19]. While there are four new nuclear reactors currently under construction (Vogtle 3&4 and Summer 2&3), it is unlikely that the U.S. will build any additional nuclear power plants in the immediate future [20], [21]. The premature retirement of the existing nuclear plants without additional new low-carbon capacity could thus limit the benefits of efforts to reduce carbon emissions from the U.S. power sector.

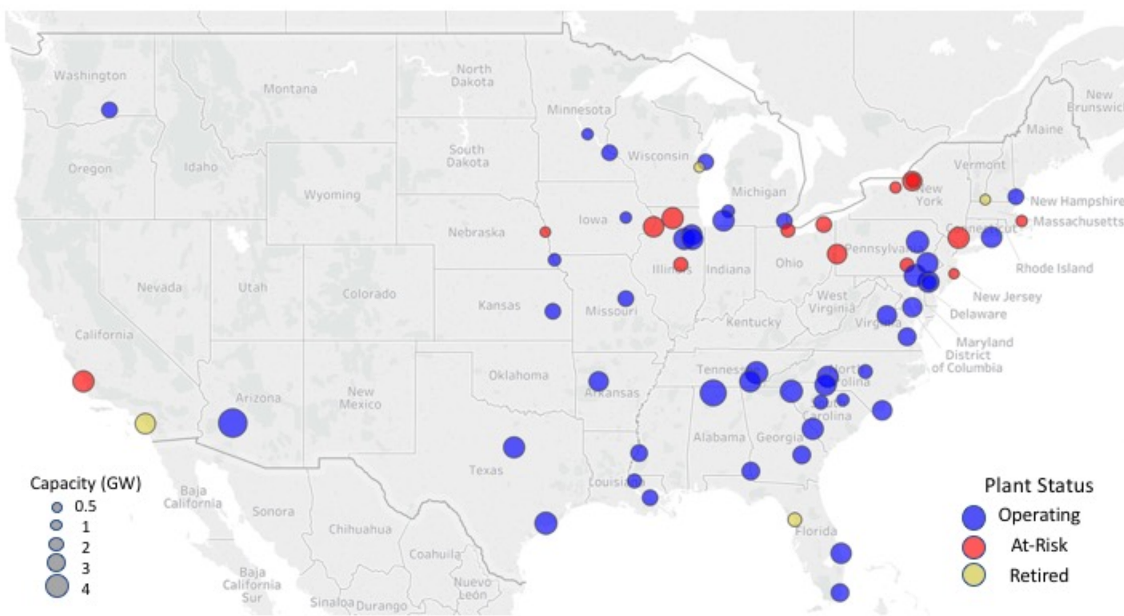


Figure 2.1: U.S. nuclear power plant location, capacity, and operational status. Operating plants are displayed in blue, at-risk plants in red, and retired plants in yellow.

The United States Environmental Protection Agency's (EPA) Clean Power Plan (CPP) and New Source Performance Standards (NSPS) aim to reduce greenhouse gas emissions from the power sector by 32% below 2005 levels by 2030. While the future of these regulations in uncertain, the retirement of existing nuclear power plants would result in large amounts of zero-carbon baseload electricity being replaced with generation from fossil-based power plants, which would likely limit the U.S.'s ability to reduce greenhouse gas emissions from the power sector. This has already been evident with the closure of the Crystal River nuclear plant in Florida and the San Onofre nuclear plant in California, after which natural gas generation increased to meet the deficit in generation [22], [23]. Recent trends further suggest that this situation could become more common with natural gas plants, rather than coal, making-up for the generation gap if nuclear plants retire. Over the last several years, 14 GW of coal capacity has retired, and more than 30 GW of coal capacity may be decommissioned by 2020 [24]. At the same time construction of new coal power plants is unlikely and only 5 new coal plants, with a nameplate capacity of 0.8 GW, are being considered for construction in the U.S. by 2020 [25]. By contrast, expansion of natural gas-based capacity is expected to continue. For example, 36 GW of natural gas-based capacity have cleared capacity markets in PJM, the largest Regional Transmission Organization in the U.S. with an installed capacity of 190 GW in 2016. Nationally, there are close to 400 planned natural gas generators that may become operational by 2020, totaling 71 GW of nameplate capacity [25]. The construction of this capacity will lock the U.S. into reliance on natural gas-based electricity even as expansions in renewable capacity continue (by 2020, 23 GW of new wind capacity, and 15 GW of new solar thermal and PV may become available throughout the U.S. [25]. In fact, in the absence of low-cost storage technologies, natural gas will also be needed to an extent to support the integration of variable and intermittent renewable resources [26]. The availability of such capacity would likely result in such plants making up for lost generation from retired nuclear power plants.

To date much of the research examining the economic viability of nuclear power plants and their efficacy in preventing CO_2 emissions has been focused on the construction of new plants, not the preservation of existing plants. L. W. Davis (2012) used data from the U.S. Energy Information Administration (EIA) to demonstrate that capital costs of building new nuclear power plants have had a strong upward trend in the U.S. since the early 1970s and 1980s, when most of the U.S. nuclear reactors were built. Studies at both The University of Chicago and MIT found that new nuclear power plants are not cost competitive with new natural gas plants in the absence of subsidies or carbon legislation [28]–[30]. According to the EIA, the levelized cost of electricity (LCOE) of a new NGCC plant ranges between \$56 and \$58/MWh while the LCOE of a new advanced nuclear plant ranges between \$100 and \$103/MWh, implying that the cost premium of new nuclear over NGCC is approximately \$44 per MWh [31]. If NGCC plants emit 454 kg-CO_2/MWh, which is the limit specified in the NSPS, then the cost of avoided CO_2 achieved by building new nuclear plants instead of NGCC plants would be approximately \$44/metric ton of avoided CO_2. Lazard (2014) similarly claimed that new nuclear is not cost competitive with new coal or gas plants, estimating an implied abatement cost of \$31 per metric ton of CO_2 if replacing coal-based generation and of \$88 per metric ton of CO_2 if replacing natural gas-based generation. New nuclear power plants are more expensive than new coal plants, though Vujić, Antić, and Vukmirović (2012) suggest that the LCOE for new advanced coal plants with a carbon tax of \$25 is higher than that of new nuclear plants [31]. On the other hand, Moore, Borgert, and Apt (2014) find that if a Low Carbon

Capacity standard were enacted in PJM, new nuclear plants would still be more expensive than other low-carbon generating resources, including carbon capture utilization and storage (CCUS) for enhanced oil recovery (though not as costly as carbon capture and sequestration). This previous work has focused on generation III nuclear power plants. Recently, there has been some interest in small modular reactors. Alonso, Bilbao, and Valle (2016) perform a scenario analysis to show that there are circumstances in which small modular nuclear reactor plants could be a cost-effective replacement for rural coal and natural gas plants in the U.S. and internationally. However, there are currently no designs for small modular reactors ready for commercialization.

Research focusing on the economics of existing U.S. nuclear power plants and their preservation as a CO_2 avoidance mechanism is sparse. Cooper (2014) explains the overall trends that are driving down the price of wholesale electricity and predicts that many single unit reactors in restructured electricity markets in the U.S. are at risk of premature retirement. The author references a UBS report to point out that cash margins at a number of plants are close to zero but does not expand the analysis to evaluate the implied carbon cost of supporting the financial viability of these plants. As part of the analysis to support the CPP, the U.S. EPA estimated that some nuclear plants may be running at a deficit of $6 per MWh, which they calculated to be equivalent to a $12 to $17 per metric ton cost of avoided CO_2 [37]. Finally, the Brattle Group relied on this single point estimate in their evaluation of the implications of the CPP [38].

In this paper we aim to fill the gap in the literature on the future of nuclear power in the U.S. by modeling the future economic viability of existing U.S. nuclear power plants. Using historical blinded cost data provided by the nuclear industry, we determine a break-even price of electricity that each nuclear power plant would need to receive annually in order to cover costs between 2015-2040. We then use these break-even prices combined with forecasted revenues from selling electricity using low, medium, and high electric price scenarios to determine a plant level “missing-money payment” (MMP). We define this MMP as the payment, in addition to electric sales revenue, that each nuclear power plant would have to receive to break even through 2040. This break-even analysis will provide the necessary information required to bound the implicit cost of avoided CO_2 emissions of preserving “at-risk” nuclear power plants in the U.S.

2.3 Methods and Data

This study uses a Monte Carlo-based simulation approach to model a plant’s specific break-even price of electricity and MMP between 2015-2040, as well as an achievable cost of avoided CO_2 emissions. **Error! Reference source not found.** defines the break-even price of electricity and **Error! Reference source not found.** defines the missing money payment, or the required marginal payment the plant would need to receive in order to avoid loses from 2015-2040. These equations do not include the initial construction capital costs. Since the majority of these power plants were built in the 1970s and 1980s, we assume they have already paid off these costs, so we only include new capital expenditures necessary for continued plant operation and compliance with NRC regulations. Additionally, these equations do not account for revenue from capacity markets. As explained in section 2.3 capacity market income is not a consistent source of income for many nuclear plants and was excluded from this analysis. We note, however, capacity markets may offer the structure through which nuclear plants could receive the MMP we estimate in this paper.

Equation 1:

$$BEP_j = \sum_{n=0}^{25} \frac{[\,Fuel\ Costs_{j,n} + Fixed\ O\&M_{j,n} + Capital\ Expenditures_{j,n}] * (1+i)^{-n}}{[(Generation_{j,n}) * (1+i)^{-n}]}$$

Equation 2:

$$MMP_j = \sum_{n=0}^{25} \frac{[(Generation_{j,n} * Price\ of\ Electricity_n) * (1+i)^{-n} - (Fuel\ Costs_{j,n} + Fixed\ O\&M_{j,n} + Capital\ Expenditures_{j,n}) * (1+i)^{-n}]}{[(Generation_{j,n}) * (1+i)^{-n}]}$$

Where BEP_j is the break-even price of plant j, Fuel $\text{Costs}_{j,n}$ are the costs of fuel in plant j in year n, Fixed $\text{O\&M}_{j,n}$ are the fixed operation and maintenance costs in plant j in year n, Capital $\text{Expenditures}_{j,n}$ are the capital expenditures required to maintain NRC compliance in plant j in year n, $\text{Generation}_{j,n}$ is the amount of electricity generated in plant j in year n, and i is a discount rate. In this analysis we converted all values to 2014$ and assumed a discount rate of 7% [39].

2.3.1 Modeling Operations, Maintenance, and Capital Expenditures

For this analysis we rely on historical data provided by the Electric Utility Cost Group's (EUCG) Nuclear Committee. The EUCG data consist of blinded annual capital expenditures and average non-fuel operation, maintenance, administrative, and general costs (O&M) from 62 U.S. nuclear power plants from 2002-2014. Because the EUCG data are blinded, we are unable to determine historical plant-specific costs. Instead, we categorized the data by reactor type and size in order to develop distribution functions for these costs, from which we sample into the future through Monte Carlo simulations. The plant categories include Single (n=15) and Multi (n=24) unit Pressurized Water Reactor (PWR) plants, and Single (n=14) and Multi (n=9) unit Boiler Water Reactor (BWR) plants. We assume that past changes in O&M and capital expenditures are representative of those in the future. The results of these Monte Carlo simulations suggest that, on average, non-fuel O&M costs account for 60% of the present value of the cost of operating the plants between 2015-2040. At individual plants, this contribution ranges between 50% and 70%. Similarly, fuel costs account for 20% of total costs on average, with a range between 11% and 27% at individual plants. Finally, capital expenditures account for 20% of the present value of total costs, on average, with a range between 11% and 38% at individual plants.

At each of the 62 power plants in the dataset, fixed O&M costs have both increased and decreased from one year to the next and over the course of 2002-2014. If additional information such as plant location, age, owner, and repair records becomes available, it may be possible to identify a statistically significant trend over time using time-series regression. However, such regression did not produce meaningful results with the available data. Instead, to model O&M costs we first determined a distribution of starting O&M costs for the year 2014 for each plant type. Table A.1 in the appendix provides summary statistics for the starting O&M cost in year 2014, broken out by reactor size and type. In order to project O&M costs through 2040, we then derived a distribution of "average annual change" in O&M costs (shown in Figure A.1 in the appendix) to be added to the starting costs. These data consist of an average annual change in O&M values from each power plant between 2002-2014. In Table A.1 in the appendix we demonstrate that plant O&M costs generally fall into two distinct groups by reactor size. Since the dataset for the average annual changes in O&M costs is small (62 in total) and depends largely on plant capacity, we grouped the data for single-reactor (n=29) and multi-reactor (n=33) plants and fit a distribution to each group. Starting in 2015 in our Monte Carlo simulation, we determined the annual change in O&M costs at each plant by independently sampling from one of the two triangular distributions, depending on the number of reactors at the specific plant. This method allows for any specific year to vary up or down while accounting for general characteristics of the empirical data.

In addition to fixed O&M costs, the EUCG database includes information about capital expenditures at U.S. nuclear power plants. Most power plants in the EUCG database incurred large capital expenditures once or twice between 2002 and 2014; however, expenditures (in $/kW) were low in most years. These annual expenditures are likely the result of unexpected maintenance costs or expenditures to ensure the plant's efficient operation and compliance with NRC regulations. To model these capital expenditures we fit a loglogistic distribution to the capital expenditure data for each power plant type. A summary of these data in Table A.2 in the appendix shows that plant capital expenditures ranged from $0/kW to as high as $845/kW in any given year between 2002-2014.

Instead of relying solely on the distribution of the annual capital expenditures, we modeled future capital expenditures using a mean-difference approach. Most nuclear power plants have modest capital expenditures in any given year, with large expenditures typically occurring only once over a one or two-decade period, usually when large components such as steam generators are replaced. Since the data we use are blinded, we cannot draw inference on the likelihood of a specific plant requiring a large capital expenditure in the future. We thus use the mean-difference approach in order to account for the general trend of capital expenditures over time by plant size and type. For each of the four power plant types, we used the EUCG data to calculate a mean annual capital expenditure, or base value, by using every single data entry across all years by plant type. Next, we calculated the difference (for each data entry) from this mean for each plant and year and fit a distribution to the "differences" data points. To model the capital expenditures at each plant each year between 2015-2040, we start with a base value of the mean capital expenditure at each plant according to type and then add a draw from the distribution of the differences. We truncated each distribution, shown in Figure A.2 in the appendix, so that there would not be a negative cost in any given year or a cost that was more than double the maximum capital cost observed in the original EUCG data (displayed in Table A.2 in the appendix). Since the mean-differences approach assumes a constant mean increase in capital expenditures each year and we sample annually for the difference from the mean, there is less uncertainty in our results than if we used raw expenditure data.

2.3.2 Fuel Costs

Data on the quantity of nuclear fuel consumed as well as the price paid for fuel at a specific nuclear plant are not publicly available. As part of its 2015 Annual Energy Outlook (AEO) report, the EIA produces a price forecast for finished ready-load fuel for nuclear power plants, which includes "fuel processing costs such as conversion, enrichment, and fuel assembly services" presented in $/MMBTU of extractable heat energy [40]. We use EIA's fuel price point estimate because it accounts for a broad range of macro-economic trends included in the EIA models, and it is the only publicly available forecast for future nuclear fuel prices through 2040.

We similarly rely on the heat-rate of 10,449 Btu/kWh for nuclear power plants reported by EIA to derive the final fuel cost in $/MWh, as shown in Figure A.3 in the appendix [41]. Due to data unavailability, we use this single estimate for all the plants in our study. This limitation likely introduces a bias to our results as some plants are more efficient than others or may have secured long-term contracts for fuel at a lower or higher price than others. This could lead to a slight over or underestimation of the financial health of a particular power plant, as fuel costs are typically 15-20% of annual expenditures [42]. Future work could incorporate such differences if data become available.

2.3.3 Scenarios & Income Inputs to Missing Money Payment

Across the U.S., nuclear power plants receive income in different ways. Some plants, such as those operating in vertically integrated utilities are compensated based on a rate recovery mechanism in which they receive income to cover costs as well as a fixed rate of return [43]. Compensation for plants that sell into electricity markets can come from electricity sales and, in some markets such as PJM, there are also capacity market payments that are designed to ensure that sufficient generation capacity is available in the future. Capacity market prices can be very volatile and may not always comprise a large percentage of total plant income [44]. In PJM, for instance, capacity market payments have ranged from a minimum of $16 per MW-day up to over $245 per MW-day since the 2007/2008 auction. In a recent capacity market auction for 2017/2018, there were at least three Exelon-owned nuclear power plants that did not clear the auction [45]. Given the large uncertainty on the future of capacity payment for nuclear power plants, in this analysis we model income only from electricity sales. To do so, we developed scenarios of future electricity prices based on natural gas price projections. We treat this marginal cost of generation from natural gas based NGCC plants as the price of electricity that nuclear power plants would receive between 2015-2040. We use NGCC plants to establish electricity prices as these plants make up the vast majority of dispatchable power plants that are currently under construction in the U.S. and can thus be expected to be the dominant marginal generator in the future, particularly as coal plants retire as a result of regulatory constraints [25], [46], [47]. While renewable energy capacity will continue to grow, these plants generally operate as must-run and do not set prices in wholesale markets (though they can depress them).

The AEO provides Henry Hub natural gas price ($/MMBTU) projections out to 2040 under four different scenarios ranging from low to high natural gas price pathways (see Figure A.4 in the appendix). EIA projections between 2015 and 2040 are publicly available and include a plausible range of natural gas prices given a number of different macro-economic trends. We use a low (High Oil & Gas Resource), reference (Reference), and high (High Oil Price) natural gas price scenario from the EIA forecast to estimate the marginal cost of generation from new NGCC plants. We use Equation A.1 in the appendix to calculate the price of electricity in any given year and assume a typical NGCC heat rate of 7,658 Btu/kWh [48]. As an additional scenario, we use the LCOE of a new NGCC plant to evaluate a scenario in which nuclear power plants could receive a long-term power purchase agreement equivalent to such LCOE. We include this scenario because maintaining the current fleet of nuclear plants could be seen as a mechanism to avoid the cost of building new natural gas plants. Finally, we relied on historical reactor-specific annual capacity factor data for each power plant between 1994 and 2014 (available from International Atomic Energy Agency-IAEA) to estimate annual electricity generation from nuclear power plants through 2040 [49]. To do so, we re-sampled from the IAEA capacity factor data, with replacement, to obtain a capacity factor at each reactor for each year of our analysis.

2.3.4 Cost of Avoided CO_2 Emissions

As described in the introduction, if nuclear plants retire in the future because they could not recover "missing money," they would likely be replaced with power plants that produce CO_2 emissions. Thus, providing a payment to the nuclear plants equivalent to the "missing money" could be interpreted as the cost of avoiding CO_2 emissions. Under the NSPS, the emissions factor for new NGCC plants, which we assume would most likely replace generation from retired nuclear plants, would have to remain below 454 kg CO_2/MWh. We thus use this emissions factor to estimate the value of avoided emissions, as defined in Equation 3. For this analysis we only consider stack emissions from power generation and do not include upstream emissions that could occur from various sources including methane leakage in the natural gas system, fuel refining processes, or power plant construction. Natural gas systems are a well-known source of methane emissions [50]. While EPA has developed regulations to constrain such emissions in the future, even a small methane leakage rate from the natural gas system would imply additional benefits from avoiding increased natural gas generation by maintaining the nuclear power plant fleet. Thus, our estimates may over-estimate the cost of avoided greenhouse gas emissions.

Equation 3:

$$Cost\ of\ Avoided\ CO2_j = \sum_{n=0}^{25} \frac{\left[\left(Generation_{j,n} * Price\ of\ Electricity\right) * (1+i)^{-n} - \left(Fuel\ Costs_{j,n} + Fixed\ O\&M_{j,n} + Capital\ Expenditures_{j,n}\right) * (1+i)^{-n}\right]}{\left[\left(Generation_{j,n}\right) * 0.454\ MT\ CO2\ per\ MWh\right]}$$

2.4 Results

2.4.1 Required Break-even Price of Electricity

The top panel in Figure 2.2 displays the break-even price of electricity for 25 single-reactor plants. This figure also includes the results for the Watts Bar plant, which currently has two reactors, one of which was completed in 1996 and the second in 2015. The box-plots below show 5th, 25th, 50th, 75th, 95th percentiles of the results from the Monte Carlo simulation for each nuclear power plant. The black dotted lines in Figure 2.2 display the average electricity price that nuclear power plants would receive between 2015-2040 in each of three EIA natural gas scenarios, as well as a $70/MWh value, which is the LCOE for a new NGCC plant from the National Energy Technology Laboratory (NETL) [51]. It is important to note that there are varying NGCC LCOE estimates across a number of studies ranging from $69-$93/MWh as outlined in Rubin and Zhai (2012). For this analysis, we use a NETL 2012 estimate, which is a mid-point in the range of LCOE values listed in the literature. Furthermore, this scenario serves as an optimistic scenario in which nuclear plants could receive an electric price greater than the marginal costs of electricity generation in the high natural gas price scenario.

Figure 2.2 highlights that under the low gas price scenario, which results in an average electricity price of $29/MWh, none of the single-reactor plants break even. This is also true for the reference gas price scenario, which is lower than most of the plants' 5th percentile break-even electricity prices. Lastly, the $70 per MWh LCOE of a new NGCC plant is larger than the median break-even electricity price of all but the Fort Calhoun plant. This implies that preserving any of the single-reactor nuclear plants is a less expensive option than building new NGCC plants.

The bottom panel in Figure 2.2 displays the break-even prices for 34 multi-reactor plants. Similarly to the single-reactor plants, none of the multi-reactor plants break even under the low natural gas price scenario. The reference natural gas price is likely high enough for all of the multi-reactor plants to break even, but does fall slightly below the 95th percentile break-even electricity prices for ten of the plants. The high natural gas price scenario and LCOE of a new NGCC are both substantially higher than the break-even electricity prices for all of these multi-reactor plants. These results suggest multi-reactor plants, as a group, would remain economically viable under all but the lowest gas price scenario, while single-reactor plants are only economically viable under the $70 LCOE scenario.

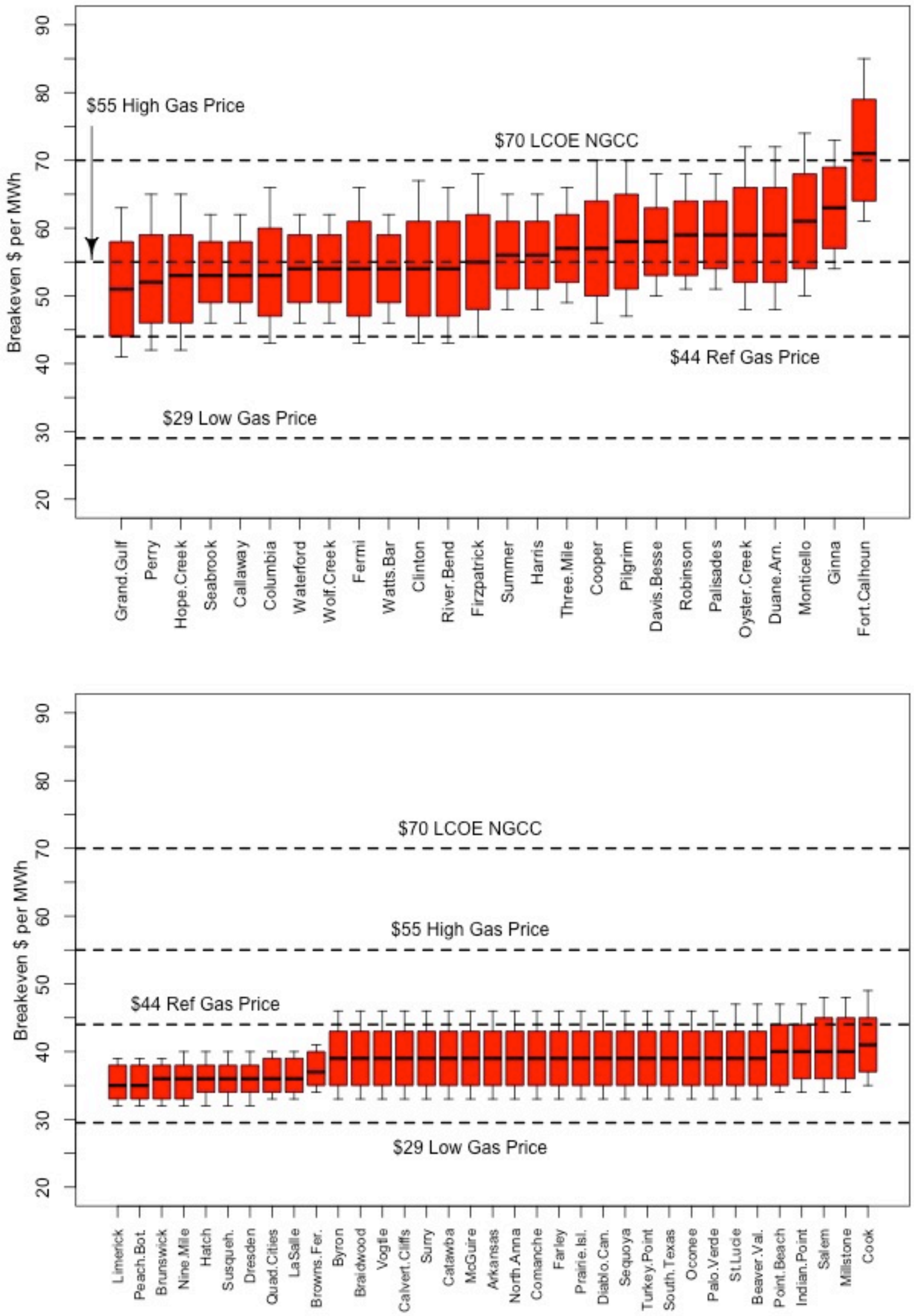
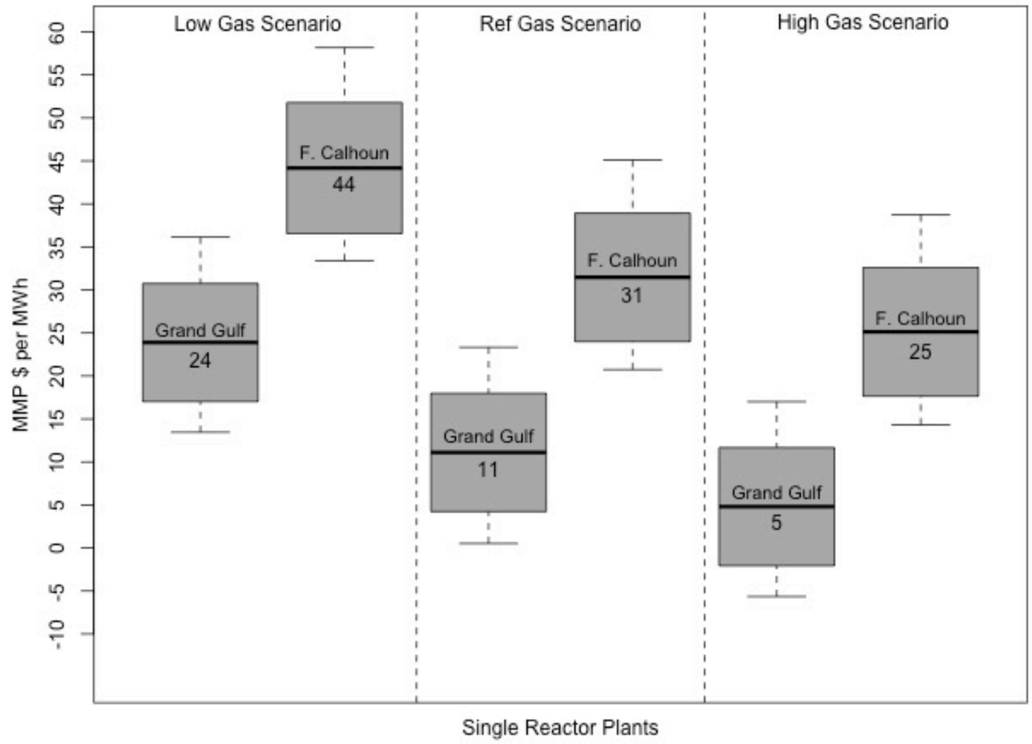


Figure 2.2: 26-year break-even electricity price ($ per MWh) for single-reactors plants (top panel) and the multi-reactor plants (bottom panel) with reference lines for electricity price scenarios. Note that the dotted lines represent an average electricity price based on the EIA scenarios for natural gas prices through 2040. However, the price of electricity used in our model changes from year to year based on the annual EIA forecasts.

2.4.2 Missing Money Payment

The MMP for each power plant for a given scenario can be conceptualized in Figure 2.2 as the distance of the boxplot above a black dotted scenario-line. For instance, the Fort Calhoun plant on the far right in Figure 2.2 is completely above the Low, Reference, and High natural gas price scenario-lines. Thus, this plant will require a MMP proportional to its distance above a particular dotted scenario-line. If a particular box-plot is below a dotted line, than the plant would break even and would not require a MMP. It is important to note, however, that since we use a 7% discount rate, as recommended by the Office of Management and Budget (OMB) for private projects, that the MMP will be different than simply taking the distance between the power plant break-even data points and the gas scenario average electricity price lines in Figure 2.2 [53].

In Figure 2.3 we display the MMP results for the plants with the highest and lowest financial viability under each price scenario. Figure 2.3 shows that the median MMP for single-reactor plants ranges from $24 to $44/MWh in the low natural gas price scenario, $11 to $31/MWh in the reference scenario, and $5-$25 in the high gas price scenario. The median MMP at the least and most financially viable multi-reactor plants ranges from $8 to $14/MWh in the low gas scenario, no MMP to $1/MWh in the reference scenario, and no MMP under the high gas scenario. Tables A.3-A.5 in the appendix include the numerical values shown in Figure 2.3. Note that these results do not include the scenario in which nuclear power plants receive an electricity price equivalent to the LCOE of a new NGCC plant because under this electricity price scenario all plants (except the Fort Calhoun single-reactor plant) break even without an MPP. Figures A.5-A.7 in the appendix include the distribution of the MMPs for all nuclear power plants in our study.



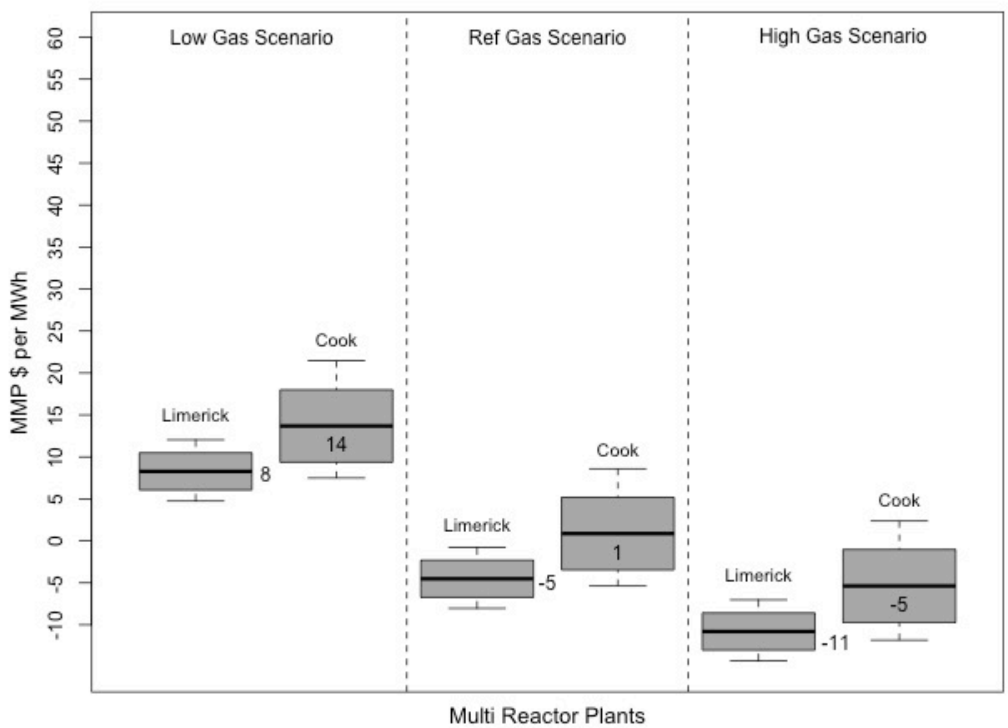


Figure 2.3: Missing Money Payment at the most (left box-plot) and least (right box-plot) financially viable single and multi-reactor plants under the Low, Reference, and High gas price scenario.

2.4.3 Cost of Avoided CO_2 Emissions

Figure 2.4 below displays the cost of avoided CO_2 at the plants with the highest and lowest financial viability in each gas price scenario. As previously mentioned, we assume that maintaining the nuclear power plants avoids the need for new natural gas generation with a CO_2 emissions factor of 454 kg CO2/MWh. The dotted line at $41/metric ton of CO_2 represents the 2015 social cost of carbon, with a 3% discount rate, a moderate social discount rate recommended by the OMB [39].

Figure 2.4 shows that, for all natural gas price scenarios, preserving multi-reactor nuclear plants could avoid CO_2 emissions at a cost that is below the social cost of carbon. Under the low gas scenario, the social cost of carbon is lower than the cost of avoided CO_2 for single-reactor plants. In the reference and high natural gas scenarios, the single-reactor plants have a lower cost of avoided CO_2 than the social cost of carbon, however, the median cost of avoided CO_2 in the least financially viable single-reactor plant remains above the social cost of carbon. Tables A.6 and A.7 and Figures A.8-A.10 in the appendix include the distribution of the cost of avoided CO_2 emissions for all nuclear power plants in our study.

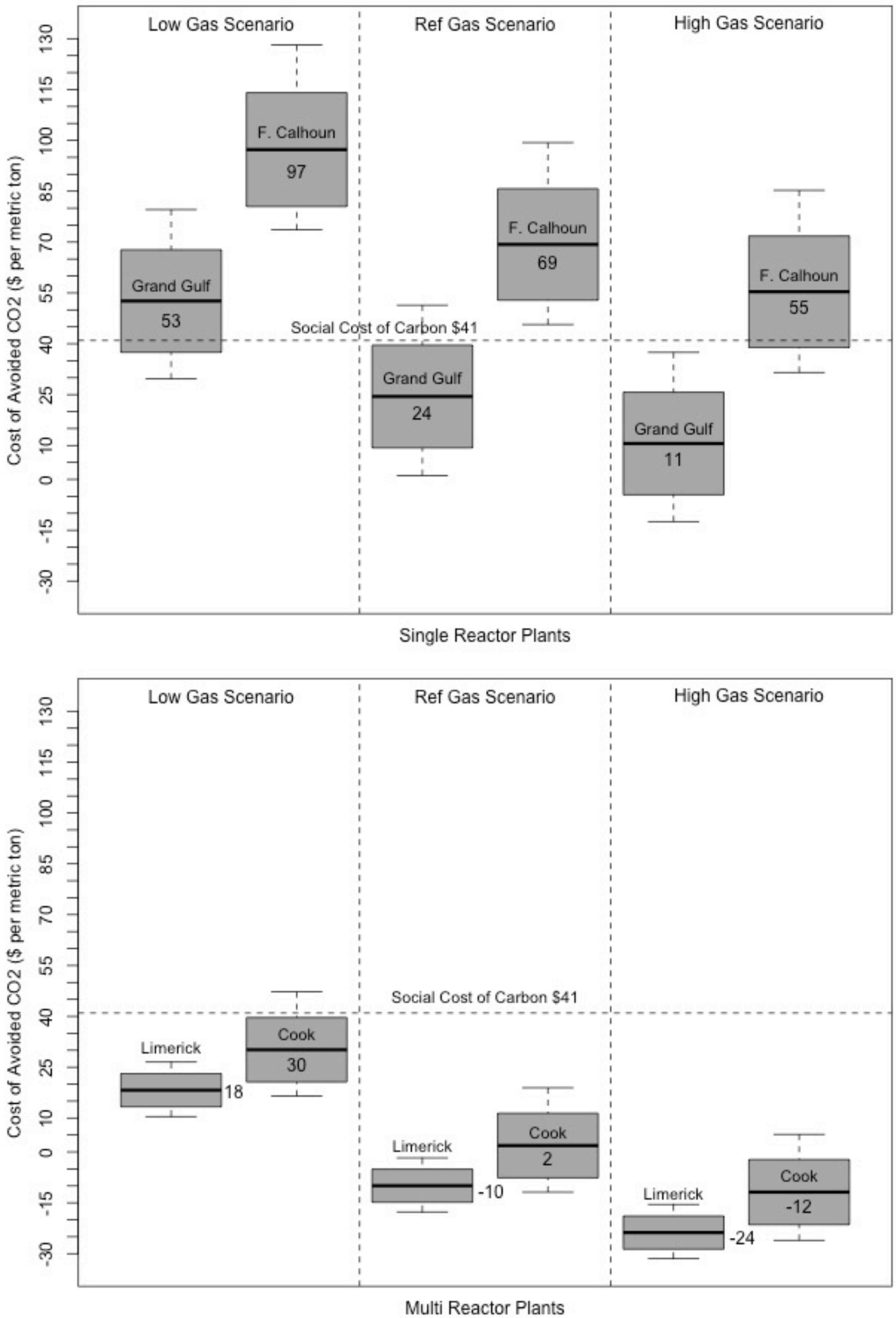


Figure 2.4: Cost of Avoided CO_2 per metric ton for most and least financially viable single (top graph) and multi (bottom graph) reactor plants. Black dotted horizontal line represents the social cost of carbon ($41 per metric ton). The left two box plots in each chart illustrate the low gas scenario, the middle two the reference scenario, and the right two the high scenario.

2.5 Nuclear Power and Carbon Regulations

To address CO_2 emissions from the power sector, in 2015 the EPA announced rules to control emissions from new and existing power plants. The NSPS require that new fossil-based generating units do not exceed an emissions rate target. EPA set the emissions rates for new generating units at 454 kg CO_2/MWh for new natural gas plants and 635 kg CO_2/MWh for new coal power plants [54]. In addition, under the CPP, existing (electricity) generating units (EGUs) must meet an average fleet emissions rate or total mass-based emissions level in each state. If the rule is upheld in court, the CPP would reduce U.S. emissions from EGUs to 32% below 2005 levels by 2030 [55].

The CPP sets individual emissions reductions targets from EGUs in each state, which can comply with the rule through a rate-based, mass-based, or individualized compliance strategy. Under the mass-based standards, total emissions from all EGUs in a state have to remain below a set limit; and under the rate-based reduction strategy all fossil EGUs, such as coal and natural gas power plants, have to meet an aggregated state-specific average target emissions rate. A number of mechanisms are available for CPP compliance, including heat rate improvements, re-dispatching from coal to natural gas power plants, and increased generation from new renewable and low-carbon sources. The proposed CPP rule, first published in 2014, also allowed states to include the preservation of economically challenged or “at-risk” nuclear power plants as part of their compliance strategies, but this mechanism was not included in the final rule published in 2015 [54]. As a result, the retirement of a nuclear power plant may not affect a state’s ability to comply with new carbon regulations. Since existing nuclear plants are not covered under the CPP, their retirement does not affect compliance with the rule. Similarly, while any new plant built to replace generation from retired nuclear power plants would have to meet the NSPS for new generating units, these plants would likely have higher emissions factors than the retired nuclear plants and as a result total CO_2 emissions from the state's generation sector could increase, undermining the initial intent of the rules. Indeed, in 20 out of the 30 states with nuclear plants, emissions from new NGCC plants replacing retiring nuclear power plants would eclipse the emissions savings from the CPP. For example, under a rate-based compliance strategy, Illinois' average EGU emissions rate should decrease from 920 kg CO_2/MWh in 2012 to 565 kg CO_2/MWh in 2030, which EPA predicted would reduce total EGU emissions from 87 metric tons of CO_2 in 2012 to 60 metric tons in 2030. In 2012 generators in Illinois produced 200 million MWh of electricity, half of which came from nuclear power plants [56]. If Illinois' nuclear fleet were to retire by 2030 and be replaced with NGCC plants with an NSPS emissions factor of 454 kg CO_2/MWh, these new plants would emit 41 million metric tons of CO_2 a year. Such emissions would eclipse the 27 million metric tons of CO_2 saved by lowering the average EGU emissions rate under the CPP. While a complete nuclear phase out in the U.S. seems unlikely by 2030, if all nuclear power plants in the U.S. retired and were replaced with new NGCC plants that comply with the NSPS, 350 million metric tons of CO_2 would be emitted each year from these new plants. Such increased emissions would nullify 82% of the national emissions reductions expected from the CPP and illustrates a potential policy design problem. Figure A.11 in the appendix shows the expected CPP reductions in each state compared to the emissions that would result if new NGCC plants replaced nuclear plants in each state. Figure A.12 in the appendix shows these values for the entire U.S. Given the political situation in the U.S. in 2017, the future of the regulations to control greenhouse gas emissions from the power sector are uncertain. However, this study highlights the limitations of climate policies that do not consider the future of the existing nuclear power plant fleet.

2.6 Conclusions and Policy Implications

In this paper we evaluate the cost of preserving existing nuclear power plants as a mechanism to avoid increases in CO_2 emissions from the power generation sector. Our results suggest that the cost of preserving multi-reactor plants through 2040 is lower than the social cost of carbon, under any of the EIA natural gas price pathways. In order to reach the deep decarbonization needed to mitigate climate change, low-carbon sources of electricity are essential. It thus makes sense to compare the cost of building new nuclear, wind, and solar generation to that of preserving already built nuclear plants that could be operational for decades to come. The EIA lists the LCOE of new wind, solar, and nuclear built in 2022 at $59/MWh, $74/MWh, and $100/MWh respectively [31]. If we assume that these new generators would replace generation emitting 454 kg/MWh, then new wind, solar, and nuclear achieve a cost of avoided CO_2 of $129/metric ton, $163/metric ton, and $220/metric ton, respectively. Even wind generation, which has the lowest cost of avoided CO_2 among these options, is more expensive than preserving the least financially viable nuclear plant currently in operation in the lowest gas price scenario.

While wholesale electricity markets and some electric utilities have provided an environment for achieving short-term efficiencies, they fail to achieve economic efficiencies in the long-term as they do not properly account for environmental externalities or place a proper value on generation diversity [57]–[60]. If states wish to preserve their at-risk nuclear power plants during periods of low wholesale electricity prices, policy interventions at the state or federal level may be necessary to keep these valuable assets from disappearing. While economists suggest that a carbon tax would be the most efficient way to regulate CO_2 emissions and would likely increase the economic competitiveness of existing nuclear power plants, such a tax seems politically infeasible in the U.S. As a result, interventions that allow nuclear power plants to receive the missing money payments we estimate in this paper may be necessary. Recognizing this need, in the fall of 2016 governor Cuomo of New York developed legislation in conjunction with a Clean Energy Standard, which would provide a subsidy of \$17.48/MWh, or approximately \$965 million over its first two years to prevent the closure of the Fitzpatrick plant [61], [62]. Similar legislation was signed into action in late 2016 by governor Rauner of Illinois to prevent the Quad Cities and Clinton plants from closing [63], [64]. The Exelon-owned Quad Cities and Clinton plants will receive a \$235 million annual credit for the carbon-free electricity they produce [65].

While our results suggest that the climate benefits of existing nuclear power plants are significant, the decision on whether or not policy should be enacted to preserve nuclear power plants should not be solely based on these benefits. If natural gas plants replace nuclear power, there would also be an increase in emissions of criteria pollutants and associated social costs. Furthermore, methane emissions from the life cycle of natural gas used to replace nuclear power would further diminish the climate stabilization goals of EPA regulation [66], [67]. Finally, nuclear is currently the only non-hydro form of dispatchable low-carbon power. Due to the intermittent nature of power production from wind and solar power, deep decarbonization of the U.S. electric sector will require low-carbon sources of baseload power, which existing nuclear power plants are able to provide.

While we relied on the best available data to characterize the uncertainty in all the model parameters, this analysis relies on blinded data for O&M and capital expenditures at nuclear power plants, as well as limited data on nuclear fuel costs. We also note that this paper aims to provide a bounding estimate of the benefits of preserving nuclear power plants as a carbon avoidance strategy, but it is not meant to be a comprehensive analysis of the future of nuclear power under different regulatory structures at the federal and state levels. Renewable Portfolio Standards, for example, will continue to increase the deployment of renewable resources. Such deployments could have different effects on electricity markets: they could further depress wholesale electricity prices and increase the MMP value we calculate in this paper, though it is unlikely that these resources will be price-setters in wholesale markets in the near to medium-term future. In the absence of low-cost storage technologies, increased penetration of renewable generation may also increase the need for natural gas capacity that could continue to displace nuclear power during base-load hours. Furthermore, we do not model the effect of support for nuclear generation, or any other market intervention, on the bidding behavior of power plant operators, which could further affect electricity prices. Finally, we do not propose specific policy design structures for supporting the continued operation of existing nuclear power plants. These limitations non-withstanding, this study provides a first-of-a-kind analysis that aims to quantify the cost of preserving nuclear power plants that may otherwise retire for economic reasons as a strategy for avoiding CO_2 emissions. Without these plants, emissions from new natural gas plants built in replacement could eliminate a substantial portion of the reductions in CO_2 emissions envisioned in the recent carbon regulation for the U.S. power sector.

Chapter 3 : Near Term Carbon Policy in the U.S. Economy: Limits to Deep Decarbonization.

3.1 Abstract

This paper explores carbon dioxide (CO_2) tax policies from 2015 to 2030 in the United States economy using an energy system least-cost optimization model. We report limited near-term decarbonization opportunities outside of the power generation sector, which results in substantial and enduring CO_2 tax revenue through 2030. Second, the social cost of carbon, and therefore the optimal CO_2 tax, is uncertain. We find asymmetric deadweight loss from implementing mistakenly high or low CO_2 taxes providing efficiency-based support for the precautionary principle. Third, benefit-cost ratios range between 2:1 and 3:1. Including reductions in air pollution damages, these ratios increase to 5:1.

3.2 Introduction

In 2016, nearly all the world's countries ratified the Paris Agreement, which aims to limit the global temperature increase to less than 2° Celsius above pre-industrial temperatures [1]. In order to prevent warming greater than 2° Celsius, global greenhouse gas emissions will likely need to decrease by roughly 25% below 2010 levels by 2030 and reach near-zero by 2070 [68]. In 2014, China emitted 30% of global carbon dioxide (CO_2), followed by the United States (U.S.), at 15% [4]. As one of the largest emitters of greenhouse gases globally, the emission trajectory of the U.S. will play a central role in whether the Paris Agreement's temperature targets are met.

In this paper, we explore economy-wide CO_2 tax policies in the U.S. The analysis uses the TIMES least-cost energy system optimization model to simulate energy use by sector, fuel type and technology, system costs, and pollution emissions under a series of carbon taxes from 2010 to 2030 [69]. The analysis includes CO_2 emissions as well as emissions of local air pollutants such as sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter ($PM_{2.5}$). We focus on near-term policies through 2030 because the characterization of energy system technologies in the model is likely most valid over this time period. Further, with dynamic incentives for research and development of low carbon technologies in the presence of binding CO_2 policy, current characterizations of low-carbon technology beyond 2030 is speculative at best. We explore a series of carbon tax policies in which the tax rate is set equal to recent estimates of the Social Cost of Carbon (SCC), the per-ton damage associated with CO_2 emissions. However, since the "true" SCC is unknown, we also examine the inefficiencies associated with carbon tax mistakes; that is, scenarios in which the carbon tax rate departs from the SCC estimate.

We use the TIMES model even though other economy-wide models are available. The impetus for this choice is the detailed technology characterization of the energy system in seven sectors, and myriad sub-sectors, specified in TIMES. This detail facilitates an analysis of responses by different sub-sectors to the carbon tax policies that we explore herein. For example, in the carbon tax scenarios, the TIMES model estimates changes in the fuel mix in the electric generation sector by geographic region, as well as responses within the vehicle fleet. Our joint analysis of CO_2 and local air pollution emissions is also enabled by the use of TIMES. The shortcomings of our approach center on two areas: the inability to estimate tax incidence and intersectoral spillovers, which would be enabled by computable general equilibrium models [70].

We find that \$35 and \$100 per ton CO_2 tax trajectories (outlined in Figure B.1 of the appendix) reduce CO_2 emissions by 24% and 38%, respectively, by 2030 compared to 2010 levels. These reductions are largely consistent with the 2° Celsius temperature stabilization trajectory established in the Paris Agreement. The \$35 and \$100 CO_2 tax trajectories impose cumulative present value costs on the energy system of $124 billion and $444 billion ($2005) above a business as usual (BAU) scenario between 2010 and 2030, respectively. The $35 and $100 tax policies yield climate benefits that outweigh increased system cost by a factor of 1.9 and 3.1, respectively. These benefits do not include the air quality co-benefits from reductions in emissions of SO_2, NO_x, and $PM_{2.5}$. Under the $35 and $100 CO_2 tax, the present value of cumulative air quality co-benefits between 2010 and 2030 total $441 billion and $686 billion, respectively. Carbon tax revenue from the $35 and $100 taxes is substantial, amounting to 8%-34% of federal income tax revenue depending on the year and tax scenario. In modeling the efficiency implications of carbon tax mistakes, we find strong support for the precautionary principle. That is, implementing a tax that is calibrated lower than the SCC yields greater deadweight loss than a high tax when the SCC is low. This asymmetry stems from the convexity in marginal costs of CO_2 abatement.

Prior research has estimated CO_2 tax revenue and emissions reductions in the U.S. Brown, Henze, and Milford (2017) quantified tax revenue from varying CO_2 taxes in the year 2045 and found a maximum reduction of 36% in CO_2 emissions compared to BAU in 2045. Metcalf (2008) found that a $15 per ton CO_2 tax lead to significant revenue and 8% CO_2 emissions reductions in 2015. Other work, such as Carbone et al. (2013), estimated potential CO_2 tax revenue from a $20, $30, and $50 per ton CO_2 tax, and a resulting 13% to 24% reduction in CO_2 emissions by 2025 compared to BAU.

Other analyses simulated air pollution reduction co-benefits under varying CO_2 abatement policies. Across the literature, there is substantial variation in estimated co-benefits from CO_2 policies. Air pollution reduction co-benefits may vary due to differences in time horizons, air pollutant species included in the analysis, choice of discount rate, and valuation of damage per ton of pollution abated. Saari et al. (2015) found that a 10% reduction of CO_2 emissions in 2030 compared to 2006 levels lead to an estimated \$3 billion to \$21 billion reduction in damages from $PM_{2.5}$ emissions. Thompson et al. (2014) modeled a 10% CO_2 reduction by 2030 relative to 2006 levels and found that cumulative median ozone and $PM_{2.5}$ damages decreased between \$110 billion to \$385 billion depending on the policy (\$220 to \$770 in co-benefits per ton of CO_2 abated). Balbus et al. (2014) found $PM_{2.5}$ damage reduction benefits ranging from \$36 to \$179 per ton of CO_2. Nemet, Holloway, and Meier (2010) surveyed the co-benefits literature and found that for developed countries, across 22 estimates, co-benefits ranged from \$2 to \$116 per ton of CO_2 abated. In our analysis, we find co-benefits to range from \$314 to \$316 per ton of CO_2 abated using AP3 damage values for SO_2, NO_x, and $PM_{2.5}$ emissions.

3.3 Methods

This paper uses a bottom-up energy system optimization model (TIMES) to explore carbon taxes in the U.S. economy [69]. The optimization algorithm in TIMES minimizes costs including, fixed, investment, and operations and maintenance costs to meet exogenous energy demand in each sector of the economy [69]. The model also includes a market clearing condition that requires all energy and commodity demand to be met in each year. For this work, we use the EPAUS9rT (EPA TIMES 9-region) database version 16.1.3 [69]. Sectors in EPAUS9rT include commercial, electricity production, industrial, refinery, residential, resource supply (upstream), and transportation. Each sector in EPAUS9rT includes a roster of energy technologies with detailed cost, pollutant-specific emissions rates, and efficiencies. End-use demand in each of these sectors is specified by projections in the 2016 EIA Annual Energy Outlook from 2010-2050 [78]. The EPAUS9rT database includes energy system constraints, including limits to local air pollutants through the inclusion of the CSAPR and MATS rules, renewable portfolio standards in the electric sector, and CAFE standards in the transportation sector [79]–[82].

We model the U.S. energy system from 2010 to 2030, and the analysis in this paper focuses on two scenarios, one with a lower and one with a higher carbon tax. The benchmark is a BAU scenario that simulates how technology and emissions may evolve in the absence of new policies limiting CO_2 emissions. In two additional scenarios, we implement a $35 and $100 per ton CO_2 tax trajectory on the energy system starting in 2015 and lasting through 2030. These tax trajectories are derived from the U.S. federal government's interagency working group on the social cost of carbon (USFWGSCC) report and represent lower and upper bounds on the estimated SCC [83]. The carbon taxes are calibrated to the SCC trajectories in the USFWGSCC report. As CO_2 concentrations in the atmosphere increase over time, the marginal damage from the emission of one ton of CO_2 is also expected to increase. The tax rate in the $35 tax scenario increases from $34 per metric ton of CO_2 in 2015 to $47 in 2030. Similarly, in the $100 tax scenario, the tax rate ranges from $99 to $143 per metric ton of CO_2 from 2015 to 2030 [83]. Lastly, in version 16.1.3, TIMES projects significant electric vehicle penetration starting in 2015. Because actual electric vehicle VMT was a small portion of overall light-duty VMT in the U.S., we add a constraint on EPAUS9rT that limits electric vehicle VMT to near-zero until 2020.

The TIMES model also simulates the emissions of SO_2, NO_x, and $PM_{2.5}$ associated with energy production. To monetize the co-benefits associated with reductions in these emissions, we use the AP3 model to calculate the average national damage caused by one ton of emissions from SO_2, NO_x, and $PM_{2.5}$ in the U.S. [6], [84]. Using the TIMES criteria pollutant emission estimates paired with the AP3 per ton marginal damage, we then calculate the total aggregate national damages caused by emissions (see Figure B.2 in the appendix for the marginal damage rates by year and species). Marginal damages from local air pollutant emissions increase over time to reflect increasing projections in population and per capita GDP. As a sensitivity analysis, we also use the EASIUR and InMAP models to estimate the national aggregated damage from local air pollutant emissions [85], [86]. We use these three reduced complexity models in order to bound what the damage from air pollution may be on a national level.

3.4 Results

Modeled U.S. CO_2 emissions total 5.8 billion tons in 2010. From this level, CO_2 emissions are estimated to decrease by 24% and 38% in 2030, under the $35 and $100 tax scenarios, respectively (see Figure 3.1). The two biggest sources of 2010 modeled emissions are the electric sector, which is responsible for 2.3 billion tons of CO_2 emissions, and the transportation sector, responsible for 2 billion tons of CO_2 emissions. Under the $100 CO_2 tax, 2030 electric sector emissions decrease by 92% compared to 2010 levels, while transportation sector emissions fall by only 7% in 2030 relative to 2010 levels.

The asymmetric CO_2 abatement in these sectors manifests because the electric sector has a number of carbon-reducing technology options, including carbon capture and sequestration, fuel switching from coal to gas, nuclear power, and renewable options such as wind and solar. The transportation sector does not decarbonize to the same extent because the only near-term, low-carbon technologies available are light-duty electric vehicles. There are not any deployable, low-carbon technologies in the EPAUS9rT database for medium and heavy-duty vehicles. Of course, were these CO_2 taxes modeled in this analysis enacted, strong dynamic incentives for vehicle manufacturers to develop low-carbon technologies would exist. However, given the nascent state of electrification among medium and heavy-duty vehicles, the characterization of this sector in the near term is reasonable. The upshot is that the medium and heavy-duty transportation sectors cannot respond to the CO_2 taxes and thus generate substantial tax revenue. The remaining sectors in the TIMES model have essentially no near-term low carbon technologies, and thus, like medium and heavy-duty vehicles, are significant sources of CO_2 tax revenue, not abatement.

Without an added constraint, the TIMES model introduces an artificially high quantity of light-duty electric VMT beginning in 2015. In the U.S., new electric light-duty vehicle sales were 17,700 in 2011 and increased to 195,200 in 2017 [87]. Electric vehicles comprised only 1% of new 2017 U.S. light-duty vehicle sales, which totaled 17 million vehicles [88]. To reflect historically low electric vehicle penetration rates in the U.S., we have constrained TIMES to allow electric vehicle use beginning in 2020. As a result of the constraint on electric vehicle adoption, under the BAU scenario, modeled electric vehicle use is 0% of light-duty VMT from 2010-2020, but increases to 25% of light-duty VMT by 2030. The fact that electric vehicles make up a substantial portion of light-duty VMT in the BAU scenario implies that they become a cost-effective alternative to internal combustion vehicles in meeting transportation demand in TIMES.

A CO_2 tax of $35 and $100 per ton is estimated to increase the price of gasoline by approximately $0.35 and $1 per gallon, respectively [89]. However, under a $35 tax scenario and a $100 tax scenario, 2030 electric vehicle VMT do not increase significantly compared to BAU, reaching 25% and 26% of light-duty VMT, respectively. The reason for similar electric vehicle penetration rates across scenarios, is that TIMES requires light-duty vehicle technology to last exactly 15 years, which leads to longer turnover rates for the light-duty vehicle fleet. Simulated results through 2050 show higher electric vehicle penetration under the CO_2 tax scenarios compared to BAU. What we learn from this analysis is that from 2020-2030, TIMES is introducing close to the maximum amount of electric VMT possible given model constraints under BAU, even without the presence of a CO_2 tax.

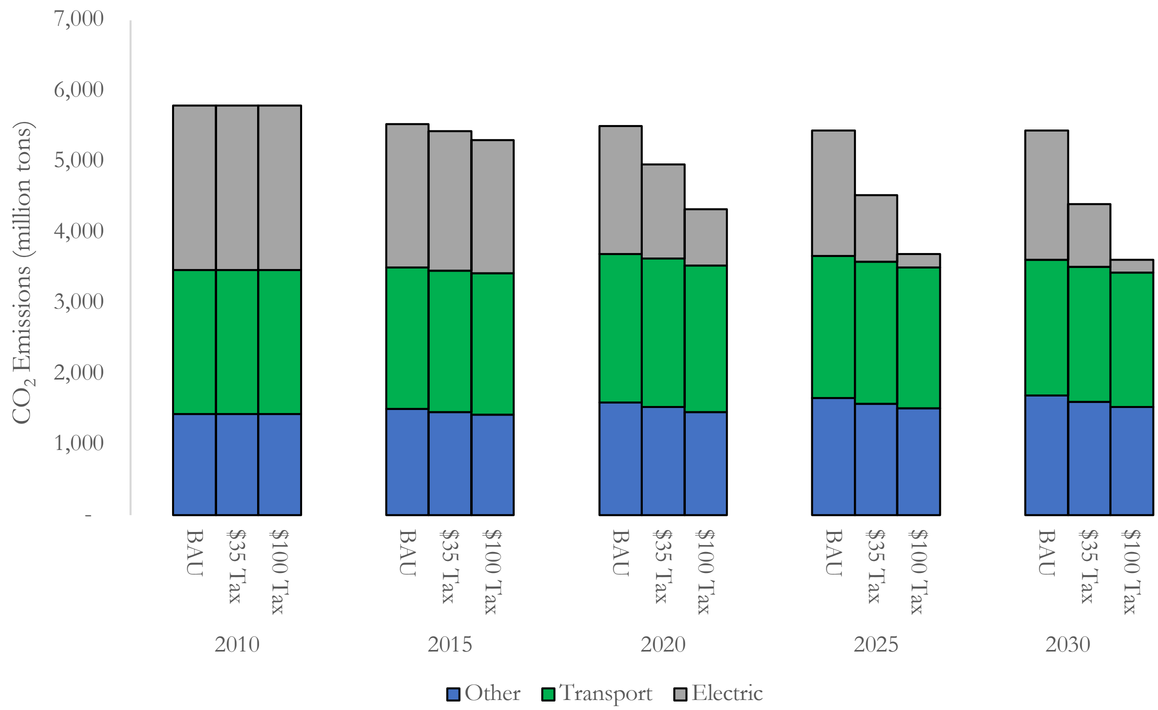


Figure 3.1: Total CO_2 Emissions by sector under BAU, a $35 CO_2 tax trajectory, and a $100 per ton CO_2 tax trajectory from 2010-2030.

The \$35 and \$100 tax policies increase the present value of cumulative costs to meet energy demand through 2030 by \$124 billion and \$444 billion, respectively. In Figure 3.2, we show the increase in cumulative system costs under carbon tax scenarios, the decrease in CO_2 damages, and the decrease in air pollution damages compared to the BAU scenario for the \$35 and \$100 CO_2 taxes. While there is a substantial increase in cost to meet energy demand under the CO_2 taxes, the estimated benefit-cost ratios are 1.9 and 3.1 for the \$35 and \$100 CO_2 tax policies, respectively. It is important to note that the CO_2 taxes implemented herein are calibrated to SCC estimates [83]. Thus, the tax policies essentially assume two possible states of the world: a low SCC state and a high SCC state. Reductions in CO_2 damage stemming from the tax policies are calculated as the reduction in emissions times the SCC, by year. This approach to damage estimation is important to consider when interpreting the benefit-cost ratios above.

Importantly, as carbon taxes spur decarbonization of the energy system, emissions of SO_2, NO_x, and $PM_{2.5}$ also fall. The pollution reductions resulting from the carbon tax policies increase cumulative present value benefits by roughly $441 and $686 billion from 2010 to 2030 in the $35 and $100 CO_2 tax scenarios, respectively. Air pollution reduction co-benefits using EASIUR and InMAP-derived damage values, range from $345-$495 billion and $321-$478 billion under the $35 and $100 CO_2 tax scenarios, respectively.

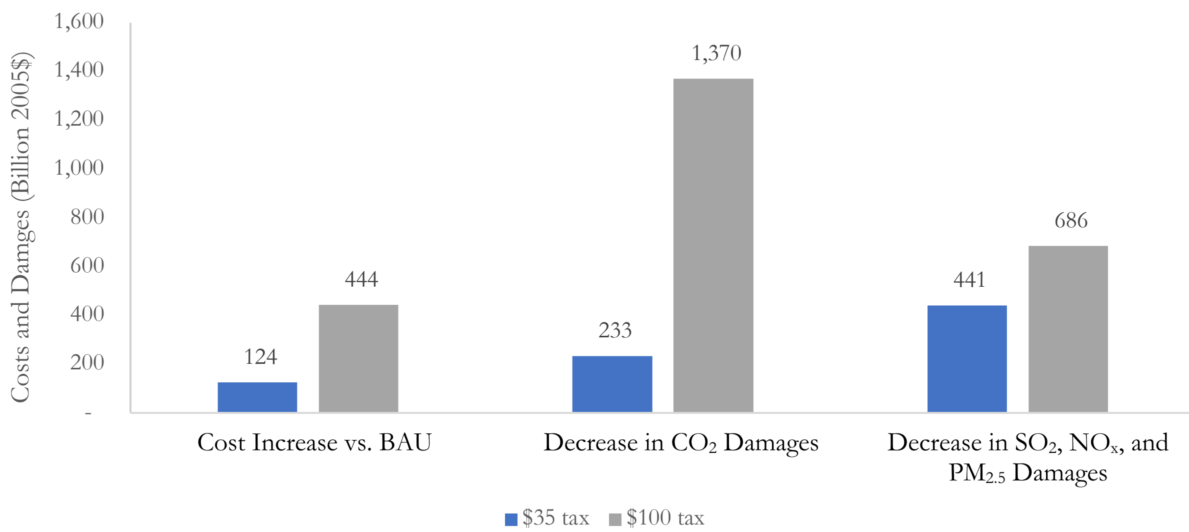


Figure 3.2: Cost increase over BAU (left), decrease in CO_2 damages (center), and decrease in AP3 derived air pollution damages (right) for the $35 (blue) and $100 (grey) CO_2 tax scenarios.

This analysis finds that, from 2010 to 2030, CO_2 taxes levied on the U.S. energy system yield a large and enduring source of revenue. Because CO_2 emissions constitute an externality, abatement of CO_2 relative to the BAU levels bolsters economy-wide allocative efficiency. In contrast, other taxes (the income tax, for example) impose considerable distortions on the U.S. economy in order to generate revenue [90]. Implementation of carbon taxes represents an opportunity for the U.S. economy to transition from a distortionary tax system to one that corrects large-scale market failure.

The proceeds from a $35 CO_2 tax increase from $184 billion to $207 billion per year between 2015 and 2030, while those from a $100 CO_2 tax range from $479 billion to $524 billion annually (see Figure 3.3). Near-term limits to technological decarbonization in the transportation sector and gradually increasing CO_2 taxes result in constant, or slightly increasing, carbon tax revenue out to 2030. While this substantial source of revenue is positive news from the perspective of federal fiscal policy, if low-carbon technologies do not become available to the medium and heavy-duty transportation sectors in the future, it is possible that persistent emission levels could ultimately prohibit attainment of longer-term CO_2 targets established in the Paris Agreement. If low-carbon technologies do become viable in the future and the SCC remains constant over time, then CO_2 tax revenue would potentially fall as the energy system decarbonizes.

The $35 and $100 carbon tax revenues projected herein comprise between approximately 8%-34% of federal income tax depending on the year and tax scenario [91]. For instance, as displayed in Figure 3.3, 2015 federal income tax revenue totaled $1.5 trillion and revenue from a $35 carbon tax would have totaled $184 million, or 12% of revenue. As this is a large share of total income tax revenue, it is also helpful to consider progressively designed tax offsets to alleviate income inequality. According to the Pew Research Center, individuals earning less than $50,000 per year comprised 61.4% of all filed tax returns, but accounted for only 5.4% of all paid income tax revenue [92]. The revenue from the $35 carbon tax, therefore, is more than sufficient to fully replace income taxes levied on the bottom 61% of taxpayers. Another potentially useful application of carbon tax revenue is repairing infrastructure. In 2014, total spending from the federal Highway Trust Fund and governments at the state and local levels on highways totaled $165 billion [93]. This expenditure is less than the projected revenue from the $35 carbon tax in 2015. Lastly, $111 billion (2005$) was allocated to U.S. defense and non-defense research and development in 2018 [94]. Revenue from the $35 carbon tax could potentially double federal funding for research and development in the U.S. or be allocated to decarbonization and climate adaptation research.

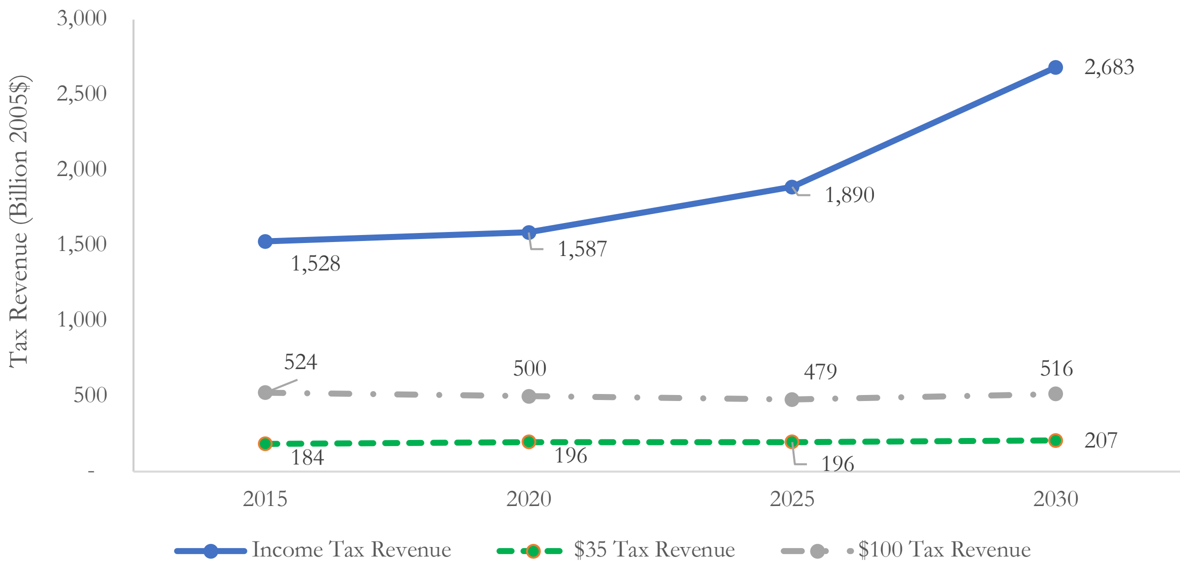


Figure 3.3: Tax revenue under the $35 and $100 CO_2 tax scenarios compared to CBO income tax projections [91].

As we examine tax revenue by sector, it is important to note that the demand for electricity generation as well as vehicle miles traveled increases exogenously between 2010 and 2030 in our simulations. As illustrated in Figure B.8 in the appendix, tax revenue is generated from various sectors across the economy under a CO_2 tax. Under the $35 tax, revenue is predominantly derived from the transportation and electric sectors. Under the $35 CO_2 tax trajectory, electric sector carbon tax revenue declines from $66 billion (36%) in 2015 to $42 billion (20%) in 2030, while transportation's share grows from $68 billion (37%) to $90 billion (43%) over the same time horizon. In the $100 carbon tax scenario, tax revenue from the electric sector falls from $186 billion (35%) in 2015 to $26 billion (5%) in 2030 as the revenue share from transportation increases from $198 billion (38%) in 2015 to $271 billion (53%) in 2030. While there is net decarbonization by 2030 across the energy system, transportation sector CO_2 emissions fall by only 6% or 7% in the $35 and $100 CO_2 tax scenarios, respectively. The transportation sector's share of CO_2 emissions and tax revenue increases because of the low penetration rate of light-duty electric vehicles (roughly 25% of light-duty vehicle miles traveled are electric by 2030 across both carbon tax scenarios), growth in vehicle miles traveled, and limited options to decarbonize medium and heavy-duty vehicles. Given the dynamic incentives presented by either CO_2 tax, it is likely that the transportation sector would continue to decarbonize as more vehicles and vehicle types switch from internal combustion engines to electric-based technologies.

The USFWGSCC reports a range of estimates of the SCC. In order to calculate the damage from CO_2 emissions, we multiply the SCC and remaining emissions. While the USFWGSCC provides SCC estimates, the "true" SCC is unknown. As such, our final empirical exercise asks: what are the efficiency implications of setting the wrong carbon tax rate? To explore this question, we evaluate the net benefits of the \$35 carbon tax, assuming that the "true" SCC is \$100 and then repeat this exercise for the \$100 tax assuming that the "true" SCC is \$35.

Both tax "mistakes" generate deadweight loss. We demonstrate the conceptual difference between the two tax calibration mistakes in Figures 3.4 and 3.5. Table B.1 in the appendix reports that if the true SCC is \$100 per ton, but emissions are taxed at only \$35 per ton, the resulting deadweight loss is \$353 billion. However, if the true SCC is \$35, and emissions are taxed at \$100 per ton, deadweight loss is only \$94 billion. The difference in the efficiency implications of these two symmetric miscalibrations of the CO_2 tax stems from the convexity of the marginal abatement cost curve. If the marginal cost curve is linear, the deadweight loss would be equal since, in the present simulations, the error in the tax rates are the same. The factor of three difference in deadweight loss we report suggests a highly non-linear marginal cost curve.

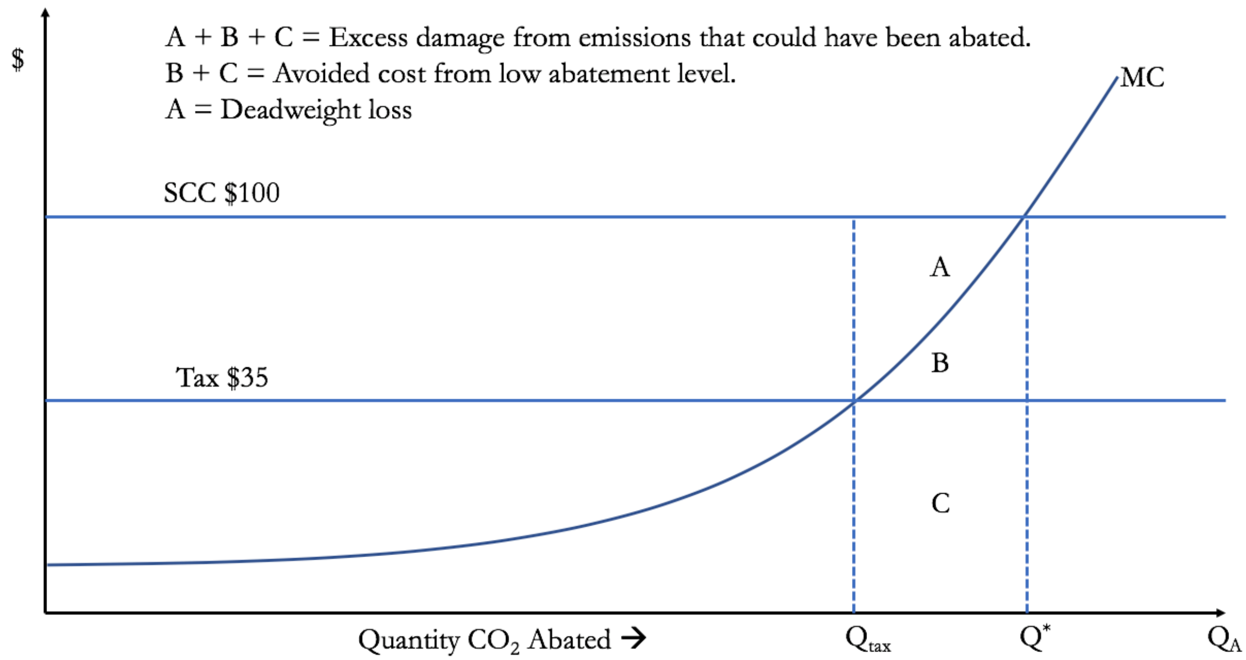


Figure 3.4: When a tax is set too low (below the SCC), then Q_{tax} is the abatement level, instead of Q^*, the efficient level of abatement. A represents available net benefits of taxing at the SCC. Because the MC curve is convex, A > B.

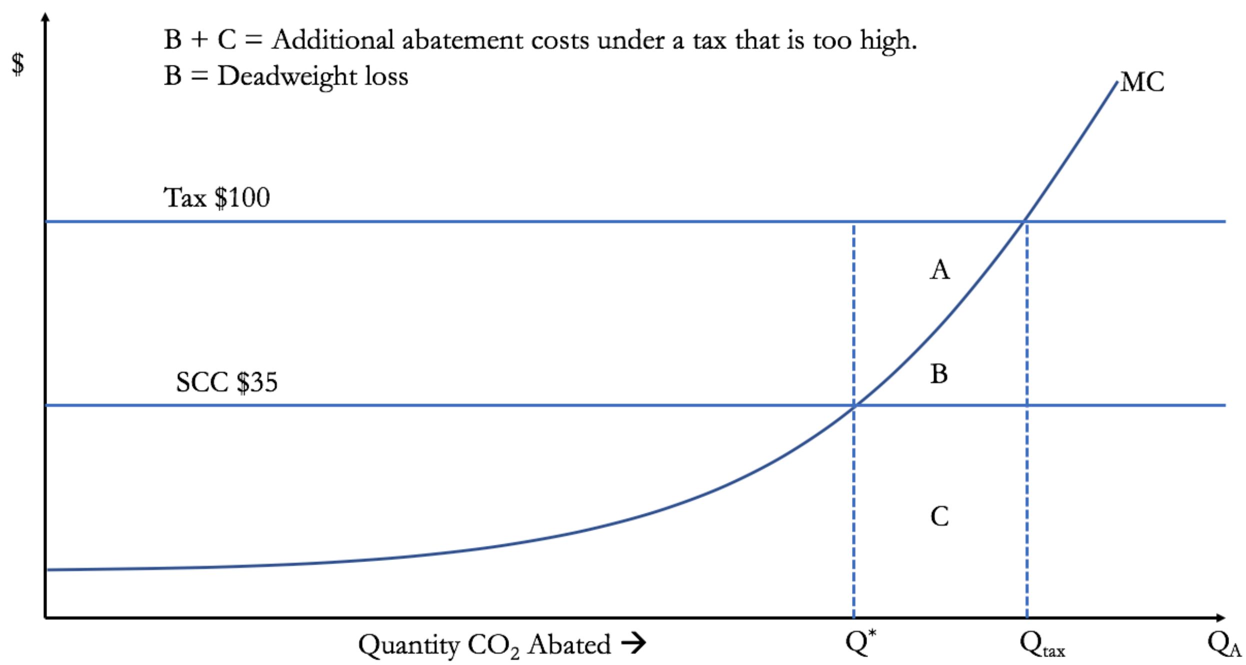


Figure 3.5: When a tax is set too high (above the SCC), then Q_{tax} is the abatement level, instead of Q^*, the efficient level of abatement. B represents available net benefits of taxing at the SCC. Because the MC curve is convex, A > B.

This exercise makes a compelling, efficiency-based argument for pursuing the precautionary principle. As the prior literature has effectively argued, the SCC is a deeply uncertain value [95]. This uncertainty poses significant challenges to policymakers charged with calibration of a carbon tax. In such a context, the present simulation argues that it is more efficient to err by overtaxing CO_2 than by implementing too lenient a tax. Our results suggest the efficiency gain from invoking the precautionary principle is on the order of a factor of three.

3.5 Conclusion

In this paper, we demonstrate that a \$35 and \$100 tax on CO_2 emissions following the SCC outlined by the EPA would put the U.S. economy on track to meet a 2° Celsius climate change trajectory in the short term. Using the TIMES model coupled with current estimates of the marginal damage from CO_2 emissions, we show that the benefits of a \$35 and \$100 carbon tax outweigh the costs by a ratio of roughly 2:1 and that this ratio is even higher if pollution reduction co-benefits are included. Further, we demonstrate that the CO_2 tax revenue could supplant a significant share of federal income tax revenue and would persist into the future, at least assuming the barriers to decarbonization of the transportation sector implied by the EPAUS9rT database. Lastly, acknowledging the uncertainty associated with the true social cost of carbon, we explore the efficiency consequences of an erroneous CO_2 tax. We find that it is more costly to under-tax CO_2 than it is to over-tax CO_2, making the case for invoking the precautionary principle on efficiency grounds.

Chapter 4 : Energy Systems Modeling: Internalizing Damages from CO_2 and Local Air Pollutant Emissions.

4.1 Abstract

In this paper, we used the TIMES energy system model in conjunction with integrated assessment models for air pollution to estimate the consequences of local air pollutant (LAP) and greenhouse gas (GHG) policy on technology choice, emissions, and pollution damages in the United States (U.S.) economy. We explored various combinations of tax policies targeting just GHGs, just LAPs, and both types of pollutants. The goal is to assess whether simultaneous tax policies on both LAPs and GHGs are needed or whether significant spillovers merit control of only LAPs or GHGs. Additionally, we examined whether there are increased benefits to taxing LAPs at a 9-region level compared to a national level.

Under any tax scenario, the majority of simulated decarbonization in TIMES occurred in the electric sector. Under LAP taxes, we found that the electric sector decarbonization was a result of an increase in natural gas generation and a near-complete phase-out of coal generation. Under both a \$35 and \$100 CO_2 tax, electric sector decarbonization was a result of increased generation from wind and solar, while gas generation remained roughly constant, and coal generation with carbon capture technology declined steadily over time. When both the LAP tax and the \$100 CO_2 tax were implemented simultaneously, generation from coal was phased out, gas generation remained roughly constant, and there were large increases in renewable generation. We also found that the timing of the CO_2 and LAP taxes was important. If we simulated a LAP tax beginning in 2015 and waited until 2025 to introduce a CO_2 tax, the electric sector was locked into higher levels of natural gas generation. Additionally, a scenario taxing both GHGs and LAPs simultaneously produced the highest net-benefits, as opposed to scenarios that target either GHGs or LAPs, or scenarios that delayed either LAP of CO_2 taxes until 2025.

We found that there were similar levels of decarbonization under a \$35 CO_2 tax and taxes on LAPs of 29% and 24%, respectively, in 2035 compared to 2010 levels. Under any scenario with a \$100 CO_2 tax, the energy system decarbonized by between 42%-44% by 2035, compared to 2010 levels.

Lastly, we found that net-benefits compared to business as usual (BAU) are higher under a regional versus a national LAP tax regime, however, that efficiency gains above BAU under the regional tax are not substantially higher than those under the national LAP tax policy. This analysis does not suggest that regional taxes are not a worthwhile policy instrument for the efficient reduction of LAP emissions in the U.S. It is important to note that the lack of an increase in net-benefits between the national and regional LAP tax scenarios is likely due to the lack of additional abatement options built into TIMES.

4.2 Introduction

Fossil fuel combustion is the primary source of emissions of carbon dioxide (CO_2) and local air pollutants (LAPs), such as sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Once emitted into the atmosphere, SO_2 and NO_x are precursors to $PM_{2.5}$. There are also significant emissions of particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) from fossil fuel combustion. It is important to note that fossil fuel combustion is not the largest source of $PM_{2.5}$ emissions in the U.S. For example, there are substantial $PM_{2.5}$ emissions originating from agricultural activities that are not simulated in this analysis, which focuses only on the U.S. energy system [96]. LAP emissions comprise major sources of damage to both natural systems and human health. Damages from LAPs in the U.S. are predominantly due to increased human mortality and morbidity. Heo, Adams, and Gao (2016) estimated that the damages from air pollution, including emissions of $PM_{2.5}$, SO_2, NO_x, and ammonia (NH_3), totaled \$1 trillion in 2005 in the U.S. alone. Tschofen, Azevedo, and Muller (2019) estimated that U.S. LAP damages have decreased to \$610 billion by 2014. Most of the damages to human health are a result of $PM_{2.5}$ exposure, which causes respiratory problems such as asthma, cardiovascular diseases, pregnancy complications, and premature death [7], [8].

Greenhouse gas emissions also contribute significantly to total pollution damage. In 2017, 6,467 million metric tons of CO_2 equivalent emissions were emitted in the U.S. [97]. CO_2 emissions represented 82% of all U.S. greenhouse gas emissions, totaling 5,302 million tons of CO_2 in 2017. Using the U.S. federal government's social cost of carbon (SCC) translates economy-wide CO_2 emissions in 2017 into \$186 billion in damages [83]. Projected growth in the SCC suggests that if CO_2 emissions remain constant through 2050, annual damages from U.S. emissions could nearly double.

Current air pollution policy in the U.S. features standards for emissions and ambient concentrations of LAPs. Specifically, the primary regulatory tools laid out in the Clean Air Act (CAA) are the National Ambient Air Quality Standards (NAAQS) for LAPs, a cap-and-trade system for SO_2 and NO_x, as well as myriad other standards that regulate tail pipe and industrial emissions. The CAA embodies a strong uniformity norm. For example, the NAAQS, which determine maximum allowable pollutant concentrations, govern ambient concentrations of LAPs. The NAAQS are levied equally across locations, however, damage caused by each LAP emission varies across the U.S. according to location [5], [57]. Essentially, LAP emissions in areas with higher population density cause higher per ton damages than in those with low population density. The fact that NAAQS are uniform across the U.S. and that damage from air pollution is geographically heterogeneous, suggests that LAP emissions could be more efficiently regulated, specifically through LAP taxes. To maximize efficiency, such a tax must be set equal to the marginal damage that each emission of pollution causes [98]. Firms, seeking to minimize compliance costs, will then equate their marginal costs of removal to the tax, and hence, the marginal damage of emissions. An efficient LAP policy would tax each emission according to the damage it causes. In practice, nodal (point-by-point) policies face numerous hurdles. Complexity and associated administrative costs are perhaps the most pertinent.

CO_2 emissions remain mostly unregulated in the U.S., with only a small number of regional cap-and-trade policies. The reliance on NAAQS for LAPs regulation does not eliminate LAP-related externalities, and the lack of CO_2 regulation suggests that both types of pollutants are not efficiently regulated. The combination of inefficient (or nonexistent) policies together with large damages suggests that a transition toward efficiently designed policies for LAPs and GHGs stands to yield substantial welfare improvements for the U.S. To this end, the present analysis examines various pollution policies targeting emissions of CO_2, SO_2, NO_x, and $PM_{2.5}$ in the U.S. energy system.

With the exception of Brown, Henze, and Milford (2017), which includes fees levied for both CO_2 and LAPs across the economy, the literature does not contain analyses that internalize both future greenhouse gas emissions damages and LAP emissions damages from $PM_{2.5}$, SO_2, and NO_x. Additionally, other analyses did not always include simulated cost increases to the energy system that resulted from taxes or the reduction in damages resulting from decreased LAP emissions [71], [99]–[102]. When only damages from either CO_2 or LAP are internalized, it is possible that externalities from the non-internalized pollutants could increase. For example, under a scenario in which LAP damages are internalized, and emissions reductions are met with pollution controls on coal power plants, it is possible that CO_2 emissions could increase as scrubbers and other pollution controls installed on coal plants to reduce LAP emissions decrease the efficiency of the power plants. With LAP controls, a coal power plant must combust a greater amount of fuel to produce the same amount of electricity, increasing CO_2 emissions per unit of electricity generated. Similarly, under a CO_2 tax, it could be the case that carbon capture and sequestration (CCS) would be installed on coal plants, however, due to parasitic load, $PM_{2.5}$ and NO_x emissions could increase. It could also be the case that a national CO_2 tax causes increased LAP emissions from coal plants near population centers, increasing damages further.

Previous literature has focused on how emissions from energy systems may change due to pollution control policies, predominantly examining co-benefits realized through policies that focused on carbon emissions. Rudokas et al. (2015) and Trail et al. (2015) found that a CO_2 tax led to a reduction in emissions of LAPs under certain scenarios. Other work modeled cap-and-trade policies and carbon taxes in order to quantify the resulting reduction of co-pollutant damages (LAPs) in the electric sector [102]–[105]. Brown, Henze, and Milford (2013) is unique in that they modeled the impact of fees on both CO_2 and LAP emissions in the electric sector. Other work focused on quantifying the effects of CO_2 policies on LAP co-benefits for all sectors on a national level. Saari et al. (2015) and Thompson et al. (2014) modeled a 10% reduction in CO_2 emissions by 2030 relative to 2006 and found that $PM_{2.5}$ reduction co-benefits could off-set a large portion of the CO_2 abatement cost. Ou et al. (2018) and Balbus et al. (2014) also modeled CO_2 reduction policies and the resulting decrease in damage from $PM_{2.5}$ emissions.

For this paper, we modeled both CO_2 and LAP taxes, resulting damages, and abatement costs from 2010-2035. Including energy system costs and emissions damage reductions enables an assessment of the net-benefit resulting from a variety of policy designs. Ultimately, the paper ranks these emission tax policies according to their net benefits, thus serving to guide policy design for LAPs and GHGs from the U.S. energy system. We are interested specifically in whether policy taxing only LAP or CO_2 alone yields similar net-benefits to policy taxing both types of emissions. Additionally, we examine the technology trajectory used to meet energy demand under LAP taxes, CO_2 taxes, or both taxes simultaneously. We also simulate whether there is technology lock-in under staggered implementation of CO_2 and LAP taxes. Lastly, we estimated the efficiency gains, relative to the business as usual (BAU) hodgepodge of policies, from taxation of LAPs under two systems: in one, we set the LAP taxes to the emission-weighted average marginal damages on a national level and the other employed a 9-region taxation system on SO_2, NO_x, and $PM_{2.5}$ where the regions were defined according to U.S. census regions (see Figure 4.1).

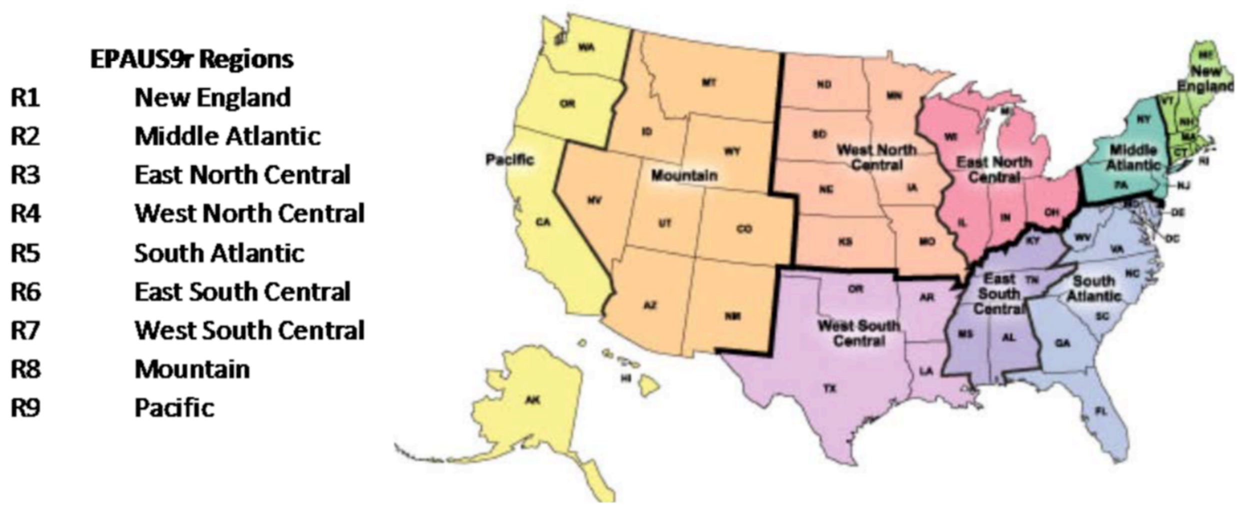


Figure 4.1: TIMES regions across the U.S. Source: U.S. EPA

To our knowledge, our research is the first to use the TIMES energy system model in combination with taxes derived from integrated assessment models for air pollution damage estimates to simulate the differences in costs, emissions, and damages between national and regional air pollution taxes on the U.S. energy system.

4.3 Methods

In this paper, we modeled a BAU trajectory as well as other scenarios featuring CO_2 taxes alone, national LAP taxes alone, taxes on both simultaneously, as well as a regional LAP tax. We outline these policies in Table 1. This paper focused on emissions of SO_2, NO_x, and $PM_{2.5}$ (the LAPs) as well as CO_2. In order to model the different policy scenarios for these pollutants, we used the TIMES energy system model calibrated to the EPAUS9rT database version 16.1.3 [69]. The EPAUS9rT database consists of data from the U.S. EIA annual energy outlook [78]. The EPAUS9rT database, spanning 2010-2050, includes projected end-use energy demand by sector and commodity, a bank of technologies in each sector for the model to choose from to meet demand, as well as technology-specific emissions factors for different pollutants, and detailed cost information for each technology. The application of TIMES herein focuses on the 2010-2035 period because the technology characterization is likely far less accurate beyond 2035, especially if the economy is subject to aggressive environmental policies.

The TIMES model uses least-cost optimization in order to meet energy demands subject to certain energy system and policy constraints over time. TIMES also includes an exogenous market-clearing requirement that all energy and commodity demand must be met each year. TIMES policy constraints, which are incorporated in each scenario in this analysis, include limits on LAP emissions through the inclusion of the Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxic Standards (MATS), constraints on electricity production technologies through the renewable portfolio standards (RPS), and constraints on the transportation sector through Corporate Average Fuel Economy (CAFE) standards.

Table 4.1: Scenarios Modeled Using TIMES. All taxes begin in 2015 unless otherwise stated.

Scenarios 2010-2035	\$35 Tax on CO_2	\$100 Tax on CO_2	Tax on SO_2, NO_x, $PM_{2.5}$
1. Business as Usual			
2. \$35 CO_2 Tax	✓		
3. \$100 CO_2 Tax		✓	
4. LAP Tax			✓
5. LAP & \$35 CO_2 Tax	✓		✓
6. LAP & \$100 CO_2 Tax		✓	✓
7. LAP Tax First, CO_2 Tax 2nd		✓ in 2025	✓
8. CO_2 Tax First, LAP Tax 2nd		✓	✓ in 2025
9. 9-Region LAP Tax			✓

In this analysis, we used a 5% economy-wide discount rate. However, some technologies in EPAUS9rT have varying hurdle rates, essentially technology-specific discount rates that affect the adoption of specific technologies. In order to reflect consumer hesitancy towards a specific technology, higher hurdle rates can be used to dampen the adoption rate. For example, in EPAUS9rT, compressed natural gas (CNG) light-duty vehicles have slightly higher hurdle rates than their gasoline-fueled equivalent in order to reflect consumer hesitancy towards adopting a non-conventional new vehicle technology. In version 16.1.3, the EPAUS9rT database lists a higher hurdle rate for electric mini and compact cars of 28%. For this analysis, we changed the mini and compact electric car hurdle rates to 18% to match that of full-size electric vehicles. The sectors included in EPAUS9rT are commercial, electric, industrial, refinery, residential, upstream, and transportation. The transportation sector in TIMES is categorized into light, medium, and heavy-duty vehicles. While there are light-duty electric vehicle technologies in TIMES, there are not electric vehicle technologies or other low carbon options in the model available to meet medium or heavy-duty vehicle demand. In version 16.1.3, TIMES projects substantial light-duty vehicle electrification beginning in 2015. Actual 2015 light-duty vehicle electrification rates in the U.S. were near-zero. To reflect historical light-duty vehicle electrification, we introduce a constraint in TIMES limiting electric vehicle use to near zero until 2020.

For this work, we simulated the operation of the energy system under different policies targeting LAPs and CO_2 by internalizing the damage from such pollutants as a tax in TIMES. To calibrate LAP taxes, and to estimate damages from emissions, we used by default the AP3 integrated assessment model for air pollution [3], [22]. The AP3 model links emissions of LAPs to exposure and determines a monetary value of marginal emission damages at a county-level resolution across the U.S. We used the AP3 model to estimate marginal ($/ton) damages, calculated as emission-weighted national and regional averages, which formed the basis of emission tax rates and were multiplied by estimated emissions to tabulate total damages. As a sensitivity exercise, we also used the EASIUR and InMAP models to estimate national marginal emissions damages, which we display in Table C.1 [85], [86]. The AP3-derived SO_2, NO_x, and $PM_{2.5}$ national damage trajectories (damage per ton of emission in each year) start at $29,200 per ton, $19,900 per ton, and $110,700 per ton in 2010, respectively. All monetary values in this paper, unless otherwise stated, are expressed in year 2005 dollars. The damages increase over time proportionally to population and per capita GDP growth raised to the 0.4 power [107], [108]. As population increases, there is increased human exposure to a given amount of emissions, and higher resulting marginal damages from LAPs. As GDP per capita increases, the value of a statistical life increases as well, along with the valuation of damage from human morbidity and mortality.

Damage from emissions varies by pollutant and location across the U.S., and in this analysis, we used two methods to estimate the values of the LAP taxes. For all but the regional

LAP tax policy scenarios, we focused on national per ton average marginal damages and created one national tax policy for each pollutant equal to these marginal damages. For the regional LAP tax, we created nine individual taxes for SO_2, NO_x, and $PM_{2.5}$, one for each TIMES region and pollutant. In order to derive the 9-region LAP tax from the raw county-level integrated assessment model for air pollution data, we computed regional average marginal damages for the emission of one ton of SO_2, NO_x, and $PM_{2.5}$ (these are emissions-weighted averages). As mentioned earlier, each tax rate increased over time proportionally to expected population and GDP growth in both the regional and national tax scenarios. In Figure C.1 in the appendix, we display the 2015 regional damage values derived using EASIUR, which are generally similar to those from AP3.

In order to internalize damages from simulated CO_2 emissions using the TIMES model, we used estimates from the U.S. federal government's interagency working group on the social cost of carbon [83]. The SCC estimates were developed using integrated assessment models that simulate the damage from the emission of one additional ton of CO_2. Federal agencies, including the EPA, use these SCC estimates when conducting policy and cost-benefit analyses involving greenhouse gas emissions. The SCC estimates vary depending on the choice of the discount rate. The analysis in this paper relied on SCC estimates corresponding to a 3% discount rate. We modeled two carbon tax scenarios. One featured CO_2 damages rising from \$34 per ton in 2015 to \$52 per ton in 2035. In a second scenario, we used a 3% discount rate and the 95th percentile high impact trajectory, yielding CO_2 damages rising from \$99 per ton in 2015 to \$158 per ton in 2035. For simplicity, we refer to these tax trajectories as the \$35 and \$100 CO_2 tax trajectories, respectively.

We modeled a BAU scenario, the two carbon tax scenarios discussed above, scenarios with air pollution taxes on SO_2, NO_x, and $PM_{2.5}$, as well as scenarios with a simultaneous tax on both CO_2 and SO_2, NO_x, and $PM_{2.5}$ emissions. While TIMES calculates the total mass of emissions by sector and the optimization internalizes the costs of these emissions based on the tax used, the model outputs do not include the damages that result from the emissions that remain in the system. For all scenarios except for the regional LAP tax, we calculate total damages from remaining emissions by assigning national per ton damage values to emissions and then computing the product of emissions and marginal damages.

In order to calculate the efficiency gains of a 9-region tax, we calculated national damages for the BAU and LAP tax scenarios a second time using regional (9-region) as opposed to national marginal damages. For the 9-region LAP tax scenario, we also used 9-region marginal damages to calculate total U.S. damages. We then compared the total damages from LAPs using 9-region marginal damages across the BAU, national LAP tax, and regional tax scenarios.

The BAU scenario established a benchmark energy system in the absence of pollution tax policies. While we did not internalize damages via taxation in the BAU scenario, this scenario, along with all other scenarios, did include some constraints on the emissions of SO_2 and NO_x resulting from the CSAPR and MATS and additional energy system constraints from CAFE standards and the RPS. Our second and third scenarios modeled \$35 and \$100 per ton CO_2 tax trajectories on the energy system. Our fourth scenario modeled air pollution taxes on SO_2, NO_x, and $PM_{2.5}$ across all TIMES-modeled sectors of the energy system, using AP3-derived national marginal damages as the tax rates.

In addition to taxing CO_2 and LAPs independently, we also applied these taxes in conjunction. In scenarios 5 and 6, we modeled either a $35 or a $100 per ton tax on CO_2 in conjunction with simultaneous taxes on SO_2, NO_x, and $PM_{2.5}$. In scenario 2 through scenario 6, all taxes started in the year 2015 and lasted through 2035. In scenario 7, we taxed SO_2, NO_x, and $PM_{2.5}$ starting in 2015, followed by a CO_2 tax starting in 2025. In Scenario 8, we modeled a CO_2 tax beginning in 2015, followed by an air pollution tax on SO_2, NO_x, and $PM_{2.5}$ beginning in 2025. We modeled staggered taxes in order to determine whether there may be technology lock-in over time and whether net-benefits may change with respect to when policy is implemented. In the regional tax scenario, we implemented 27 separate taxes starting in 2015, one for each of the nine TIMES regions, on SO_2, NO_x, and $PM_{2.5}$. In Figure 4.2, we display the heterogeneity of the AP3-derived regional taxes in 2015. Across the nine regions, SO_2, NO_x, and $PM_{2.5}$ per ton taxes ranged from $14,800 to $55,800, $11,200 to $67,800, and $52,100 to $264,600 per ton, respectively.

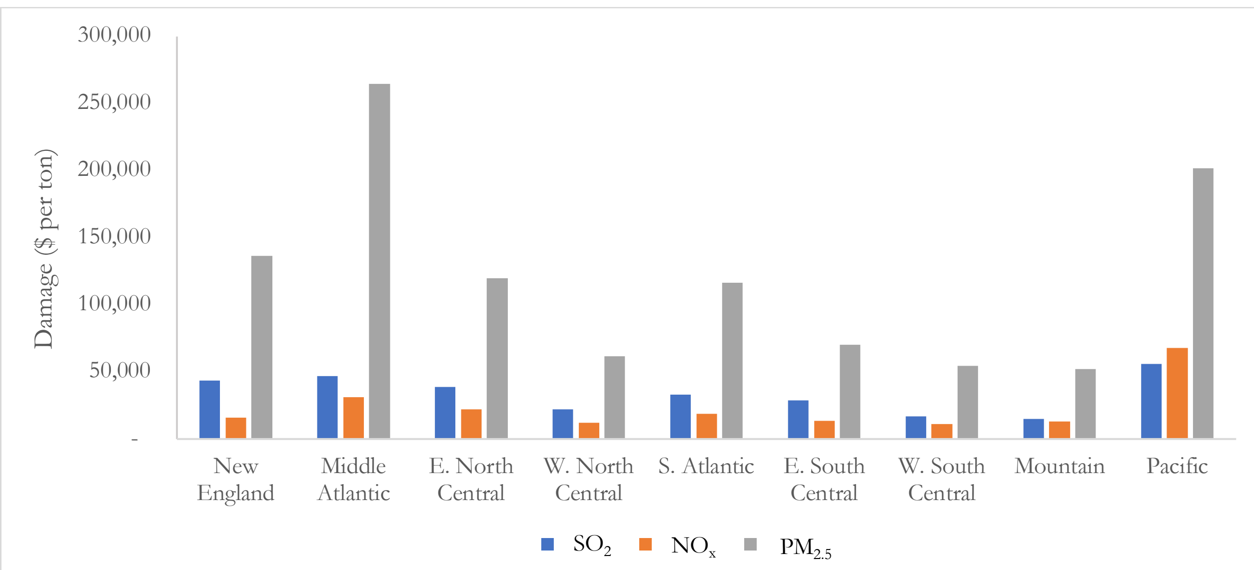


Figure 4.2: 2015 AP3 derived marginal emissions damages and per ton tax rate by region for SO_2, NO_x, and $PM_{2.5}$.

4.4 Results

4.4.1 Technology Changes and Abatement

To explore the ramifications of the different environmental tax policies, Figure 4.3 displays electric generation by type in 2010 for the BAU scenario as well as generation by type in 2035 for all scenarios. The focus is on power generation because this sector contributed the most total simulated abatement in response to the environmental taxes. Most simulated abatement occurred in the electric sector because it has mature technology options, and it is particularly well represented in the TIMES model database. Other sectors, such as transportation, do not have as many abatement options available to TIMES. The lack of abatement options in the transportation sector is because there are not currently many commercially available low-carbon technologies being implemented in the U.S. for medium and heavy-duty vehicles. While low-carbon transportation technologies could become available through innovation under the presence of carbon taxes, the TIMES model cannot model new technologies that do not have detailed cost information or are not yet invented.

Although there were substantial levels of CO_2 abatement in the electric sector across all tax scenarios, the underlying technologies used to meet electric demand differed, as shown in Figure 4.3. In general, the CO_2 tax policies induced the use of carbon capture and sequestration (CCS) and renewable generation to meet electric demand. A LAP tax phased out coal generation, which was replaced almost entirely with natural gas. A set of simultaneous \$100 CO_2 and LAP taxes phased out coal and replaced it with renewables and natural gas combined cycle (NGCC) generation with CCS. Under policies including a \$35 CO_2 tax, CCS was only implemented on coal generation, but not NGCC generation.

The LAP tax scenario in which taxation on SO_2, NO_x, and $PM_{2.5}$ began in 2015 yielded a 54% CO_2 reduction in the electric sector. In this scenario, coal generation was almost completely phased out by 2025 and was replaced with NGCC power plant generation, and some additional wind and solar. In contrast, in the \$35 CO_2 tax scenario (which produced a 67% CO_2 reduction in electric sector), coal generation outfitted with CCS remained in the system through 2035, gas generation remained roughly constant over time, nuclear and hydro generation remained constant over time, and increased solar and wind generation replaced a large portion of retired coal generation. Any scenario with a \$100 CO_2 tax caused near-complete decarbonization of the electric sector.

Electric generation by type in the BAU scenario in 2010 was identical to the generation by type for all other scenarios in 2010 because tax policies did not start until 2015. Under the BAU scenario, from 2010 to 2035 there was a decrease in coal generation from 6,700 PJ in 2010 to 4,500 PJ in 2035, a roughly equivalent increase from 3,700 PJ to 6,500 PJ in natural gas generation, as well as increased solar generation from 200 PJ in 2010 to 1,300 PJ in 2035, and increased wind generation from 300 PJ in 2010 to 1,100 PJ by 2035. In 2035 under the \$35 CO_2 tax scenario, natural gas generation remained the same as in the BAU scenario, while coal generation fell even more drastically, relative to the BAU, by 2035. Under the \$35 CO_2 tax, a large portion of coal generation was replaced with natural gas, wind, and solar generation. Under a \$100 CO_2 tax, natural gas generation remained constant over time and was outfitted with carbon capture and storage (CCS) technology, and declining coal generation was replaced with wind and solar generation by 2035.

In contrast, under an air pollution tax scenario, natural gas increased to 9,500 PJ of generation by 2035, and coal decreased to 80 PJ of generation, while wind and solar increased modestly compared to BAU in 2035. When a \$100 CO_2 tax and an air pollution tax were levied simultaneously, natural gas fell to half of the BAU 2035 levels, coal decreased to 80 PJ, nuclear increased slightly, and wind and solar increased drastically to 5,300 PJ and 4,600 PJ of annual generation, respectively, by 2035. The additional reduction in coal capacity when the economy was subject to the air pollution taxes occurred because CCS does not remove all LAPs, specifically NO_x and $PM_{2.5}$ (SO_2 must be removed from flue gas prior to CCS). Hence, it was cheaper to eliminate coal-fired capacity than to install abatement technologies for LAPs in addition to CCS.

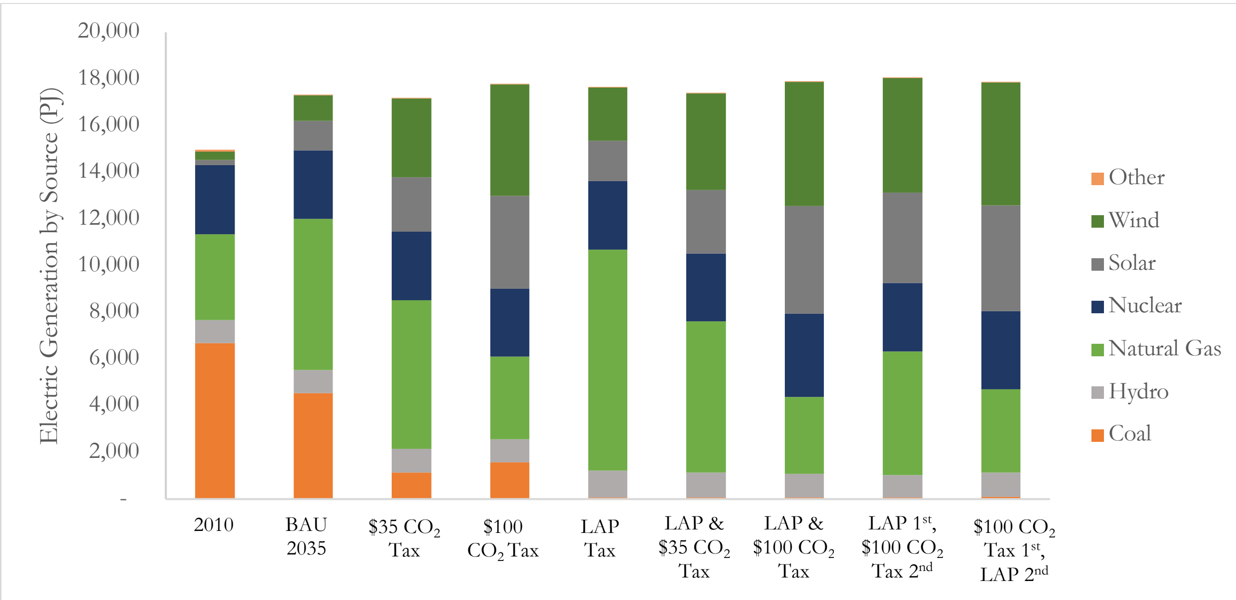


Figure 4.3: The electricity generation mix was identical across scenarios in 2010, which we display in the bar on the left. We show electric generation by source in 2035 across scenarios via the other bars.

An additional policy attribute that could impact outcomes in the energy system is the timing of LAP and CO_2 taxes. That is, tax timing could affect technology choice, emissions, and damages if an LAP tax precedes a CO_2 tax or vice versa. In order to model alternatively timed environmental taxes, we pursued the following strategies: a scenario in which air pollution taxes started in 2015 and CO_2 taxes began in 2025, and a symmetric scenario in which CO_2 taxes began in 2015 and air pollution taxes started in 2025. Modeling such situations is challenging because TIMES assumes perfect foresight. Thus, adjustments occur in the energy system in years before implementation of the taxes because doing so minimizes the present value of compliance cost. In order to prevent TIMES perfect foresight and create these two staggered tax scenarios, we ran the model four separate times. To model the CO_2 tax first and LAP tax second scenario, we first modeled a CO_2 tax in isolation. Next, we used the model output from the CO_2 tax scenario through 2025 and then ran the TIMES model again, starting in 2025 with the addition of a LAP tax. Similarly, to model the LAP tax first, CO_2 tax second scenario, we first modeled a LAP tax in isolation. Next, we used the model output from the LAP tax scenario through 2025 and then ran TIMES again, starting in 2025 with the addition of a CO_2 tax policy. In other words, to prevent TIMES perfect foresight for these two scenarios, we froze model outputs through 2025 and ran the optimization starting in year 2025 with the staggered CO_2 or LAP tax.

The results of these simulations suggest that the timing of CO_2 and LAP taxes can alter the technology used to meet demand, specifically in the electric sector. We found that if a CO_2 tax were in place in 2015, then the 2035 electricity generation mix would be the same, whether an air pollution tax was started in 2015 or 2025, as shown in Figure 4.3. The main difference between starting an air pollution tax in 2015 versus 2025 was the timing of coal generation phaseouts. Under any scenario with an air pollution tax starting in 2015, coal generation phased out to only 80 PJ annually by 2025. However, when the air pollution tax began in 2025, coal did not phase out until 2030. This change in timing may seem small. However, over this five-year window, the existing coal fleet emits non-trivial amounts of SO_2, NO_x, and $PM_{2.5}$, which increased damages and reduced net benefits of the policy scenario.

Under the national LAP tax scenario, electricity was produced predominantly from natural gas by 2035, which is illustrated in Figure 4.3. If we added a simultaneous CO_2 tax in 2015, then natural gas generation decreased over time, and generation from wind and solar increased substantially. When the LAP taxes commenced in 2015, and we levied a CO_2 tax in

2025, until 2025 there was a substantial increase in natural gas and coal phased out to 80 PJ annually by 2025. At the onset of the CO_2 tax in 2025, there was a decrease in natural gas use to 2030, and then gas generation remained constant for the remainder of the time horizon. In this scenario, natural gas was locked into the system at higher levels then it would have been if the CO_2 tax started in 2015. When we implemented a CO_2 tax in 2025 there was a decrease in the capacity factor at conventional and advanced NGCC plants and generation fell to zero at other natural gas electric generation technologies.

4.4.2 CO_2 Emissions

We begin by examining CO_2 emissions under each of our eight national tax scenarios, specifically looking at how CO_2 emissions in the simulations changed in 2035 compared to 2010. Total 2035 U.S. CO_2 emissions decreased in the simulations by between 8% in the business as usual scenario and a maximum of 44% in the joint air pollution and \$100 CO_2 tax scenario, compared to 2010 levels. Under the air pollution tax scenario, CO_2 emissions decreased by 24% by 2035, almost as much as in the \$35 per ton CO_2 tax scenario, in which CO_2 emissions fell 29% by 2035 compared to 2010 levels. A \$100 CO_2 tax reduced CO_2 emissions by 43% in 2035 compared to 2010 levels.

Compared to a single tax on CO_2, taxing CO_2, SO_2, NO_x, and $PM_{2.5}$ simultaneously only provided limited additional decarbonization benefits in the simulations. While air pollution taxes alone were responsible for considerable decarbonization in the absence of CO_2 taxes, taxing both CO_2 and LAP simultaneously only increased CO_2 abatement by an additional 1% in 2035 compared to a single tax on CO_2. Additionally, as shown in Figure 4.4, any scenario that included a \$100 CO_2 tax reduced CO_2 emissions substantially, by between 42%-44% of 2010 levels by 2035.

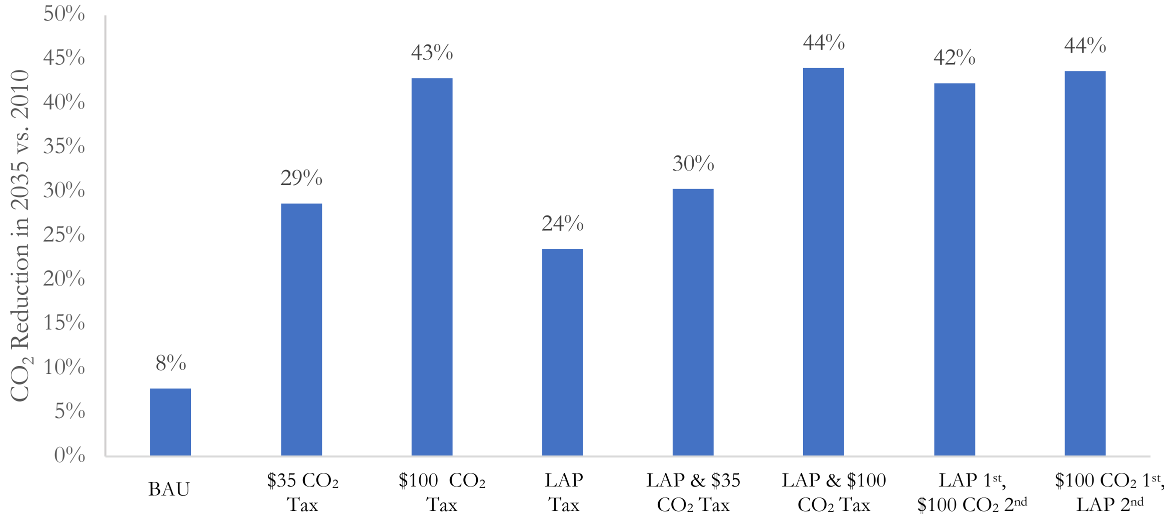


Figure 4.4: CO_2 emissions reductions (%) in 2035 compared to 2010 levels under each scenario.

Most of the simulated reductions in CO_2 emissions under these eight scenarios occurred in the electric sector. In 2010, simulated CO_2 emissions in the electric sector were 2.3 billion tons. By 2035 under the BAU scenario, electric sector CO_2 emissions decreased by 20% compared to 2010 levels. When we introduced CO_2 taxes to the energy system, there was additional electric sector decarbonization by 2035: 67% reductions under any scenario with a $35 CO_2 tax and 90%-92% reductions under any scenario with a $100 CO_2 tax compared to 2010 levels. Under any scenario with a $100 CO_2 tax, there is near total decarbonization of the electric sector.

In addition to the electric sector, TIMES simulated some decarbonization in the transportation sector. In 2010, simulated CO_2 emissions from the transportation sector totaled 2 billion tons. It is important to note that a $35 and $100 CO_2 tax would increase the cost of gasoline by approximately $0.35 and $1 per gallon, respectively [89]. Under the BAU scenario, an air pollution tax, a $35 CO_2 tax, and air pollution and $35 CO_2 tax scenarios, transportation CO_2 emissions decreased by 15% in 2035 compared to 2010 levels. Because transportation CO_2 emissions remained the same compared to BAU under a $35 CO_2 tax, an air pollution tax, and both taxes combined, we learn that these taxes are not high enough to induce CO_2 abatement in the transportation sector, given current technology available in the EPAUS9rT database. In reality, increased costs in the transportation sector resulting from a tax could cause a decrease in national VMT and a subsequent reduction in CO_2 emissions. The annual demand for VMT in TIMES is set exogenously, and as a result, national VMT does not change in response to changes in costs. Under the four remaining scenarios, all of which included a \$100 CO_2 tax, transportation CO_2 emissions decreased by 21%-22% in 2035 compared to 2010 levels. Given that 2035 BAU CO_2 reductions of transportation emissions were 15% and that a \$100 CO_2 tax only increased abatement to 22% compared to 2010 levels, indicates that most of the reductions in transportation CO_2 emissions occurred as a result of policies other than the CO_2 taxes, such as CAFE standards.

The insensitivity of the transportation sector to many of the policy scenarios is a result of the limited options for decarbonization in the transportation sector present in the EPAUS9rT database. While the EPAUS9rT database includes light-duty electric vehicles, demand for vehicle miles traveled in the medium and heavy-duty vehicle sectors can only be met with internal combustion engine-based technologies. Under strong tax incentives, it is likely that new technologies to abate CO_2 emissions in the transportation sector could be developed in the future. The TIMES model cannot predict when these technologies, such as medium and heavy-duty electric trucks, may become available or what their costs may be. In 2010, according to the EPAUS9rT database, 0% of vehicle miles traveled (VMT) were met with electric vehicles. Additionally, the electric vehicle constraint we added to TIMES prevented light-duty vehicle electrification until after 2020. Despite the electric vehicle constraint limiting electrification until 2020, the percentage of light-duty VMT met by electric vehicles increased substantially by 2035.

In Figure C.2, we show that in the light-duty vehicle sector, electric vehicles reached 24%-25% of total VMT by 2035 under the BAU, \$35 CO_2 tax, \$35 CO_2 and air pollution tax, and air pollution tax scenarios. The fact that electric vehicle VMT were the same under these four scenarios suggests that demand for electric vehicles was not driven by the taxes, but because it represents an economical means to meet end-use VMT demand in the absence of taxes. Under the four remaining scenarios, each including a \$100 CO_2 tax, electric vehicle VMT reached 38%-40% of total light-duty VMT by 2035. This increase of light-duty electric vehicle VMT suggests that the \$100 CO_2 tax increased costs enough to induce a switch away from internal combustion engines towards electric vehicles compared to the BAU scenario.

4.4.3 Local Air Pollution Emissions

In addition to reductions in CO_2 emissions, the BAU simulations indicated substantial abatement of SO_2, NO_x, and $PM_{2.5}$ by 2035 in large part due to the presence of CSAPR, MATS, and CAFE, as shown in Figure 4.5. Most of the BAU LAP emissions reductions in the simulations occurred by 2015 due to existing policies, and remaining reductions tapered off over time, which we show in Figure C.3. As shown in Figure 4.6, under the BAU scenario, SO_2, NO_x, and $PM_{2.5}$ decreased by 49%, 52%, and 30%, respectively, in 2035 compared to 2010 levels. In 2010, 69% of SO_2 emissions came from electric generation, and SO_2 reductions over time also occurred predominantly in the electric sector. Under BAU, electric sector SO_2 emissions fell from 5 million tons in 2010 to 1.3 million tons in 2035. During the same time period, there was a 32% reduction in coal-based electric generation under the BAU scenario, and the remainder of SO_2 reductions in the electric sector was due to the installation of flue gas desulfurization on remaining coal generation. In both the \$35 CO_2 tax and the \$100 CO_2 tax scenarios, SO_2 emissions from the electric sector decreased by 95% in 2035 compared to 2010 levels. Under scenarios including a LAP tax, SO_2 emissions in the electric sector decreased by 99.9% in 2035 to only 5,000 tons per year due to drastic reductions in coal generation.

As previously noted, an air pollution tax on SO_2, NO_x, and $PM_{2.5}$ caused a substantial decrease in CO_2 emissions over time (24% by 2035 compared to 2010 levels) largely due to the replacement of coal with natural gas generation in the electric sector. The simulations suggest a similar effect of a carbon tax on SO_2 and $PM_{2.5}$ emissions; a CO_2 tax caused a reduction in SO_2 and $PM_{2.5}$ emissions, though not as much as a direct air pollution tax. In Figure 4.6, we show that there were substantial simulated reductions in SO_2 under BAU, a \$35 CO_2 tax, and a \$100 CO_2 tax of 30%, 48%, and 47%, respectively, by 2035 compared to 2010 levels. Under the air pollution tax scenario, there was a 78% reduction in SO_2 emissions by 2035 compared to 2010 levels. The addition of a simultaneous \$100 CO_2 tax to an air pollution tax provided only a 1% additional decrease in SO_2 emissions.

Transportation sector SO_2 emissions decreased by 68% by 2035 compared to 2010 levels under BAU as well as under the CO_2 tax scenarios. Under any scenario with an air pollution tax, 2035 transportation SO_2 emissions decreased by 85% relative to 2010 levels. Interestingly, under BAU, the \$35 CO_2 tax, and the \$100 CO_2 tax, industrial sector SO_2 emissions increased in 2035 compared to 2010 levels. By 2035 the CO_2 taxes caused industrial sector SO_2 emissions to fall relative to 2010 levels, however, due to increasing industrial energy demand, there was still an increase in SO_2 emissions by 2035. Under all other scenarios, industrial sector SO_2 emissions decreased slightly by between 9%-11%, depending on the scenario in 2035 compared to 2010 levels. Under every scenario, industrial sector SO_2 emissions comprise a majority of remaining SO_2 emissions in 2035.

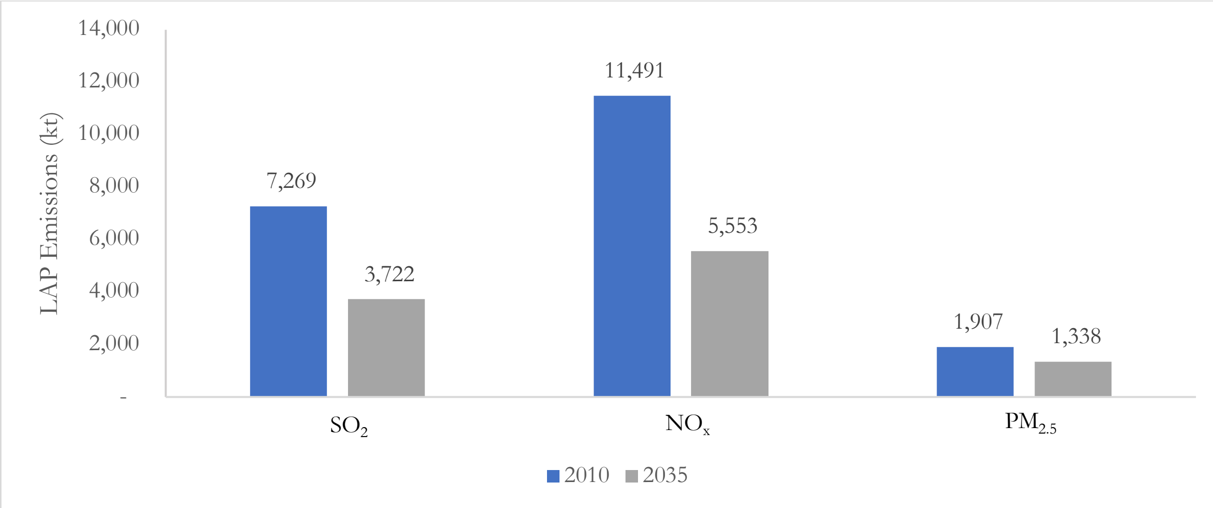


Figure 4.5: Business as usual emissions in 2035 compared to 2010. CSAPR, MATS, and CAFE standards in conjunction with fuel switching away from coal to natural gas and renewables in the electric sector resulted in decreasing emissions of SO_2, NO_x, and $PM_{2.5}$ over the modeling horizon in the BAU scenario.

In 2010 61% of total NO_x emissions were from transportation, and 20% of total NO_x emissions were from electric generation. Under the BAU scenario, NO_x emissions fell by 82% of 2010 levels by 2035 in the transportation sector as a result of both falling emissions factors per VMT as well as increased fuel efficiency. Reductions in NO_x emissions in the electric sector (35% by 2035 compared to 2010 levels) were a result of a decrease in coal-fired electricity generation and from the installation of low NO_x burners as well as selective catalytic reduction and selective non-catalytic reduction technologies. In total, NO_x emissions fell by 52% in 2035 in the BAU scenario across the energy system compared to 2010 levels.

CO_2 taxes did not cause substantial emissions reductions of NO_x, and reductions were mainly attributable to the CAFE, CSAPR, and MATS policies. Under the BAU scenario, the $35 CO_2 tax scenario, and the $100 CO_2 tax scenario reductions of NO_x were similar (52%, 52%, and 54%, respectively) by 2035 compared to 2010 levels. Under the air pollution tax scenarios, NO_x emissions decreased by 67%-70% in 2035 compared to 2010 levels. Taxing CO_2 and air pollution simultaneously reduced NO_x emissions by an additional 3% by 2035 compared to the air pollution tax alone. Under an air pollution tax, 2035 NO_x emissions fell by 90% in the electric sector, 86% in the transportation sector, but increased by 15% in the industrial sector (down from a 51% increase under BAU) and increased by 24% in upstream processes due to added natural gas related activity compared to 2010 levels. Due to increased demand for natural gas in the industrial sector over time, industrial NO_x emissions increased in 2035 compared to 2010 levels across all scenarios, though by varying amounts. It is important to note that residential NO_x emissions decreased by the same amount across scenarios and technology used to meet residential energy demand remained similar across scenarios.

The largest source of $PM_{2.5}$ emissions in 2010 was resource supply upstream processes such as coal, natural gas, and oil extraction processes, followed by the transportation sector in the BAU scenario. There was a 26% decrease in upstream $PM_{2.5}$ emissions and a 66% decrease in transportation $PM_{2.5}$ emissions that led to an overall 30% reduction in $PM_{2.5}$ emissions by 2035 compared to 2010 levels in the BAU scenario. For both CO_2 tax scenarios, $PM_{2.5}$ emissions decreased further to 47%-48% of 2010 levels by 2035. Under the air pollution tax scenarios, $PM_{2.5}$ emissions fell by between 66%-67% of 2010 levels by 2035. By 2035, with an air pollution tax, electric sector $PM_{2.5}$ emissions fell by 96%, upstream emissions fell by 90%, transportation emissions fall by 72%, residential emissions fell by 21%, refinery emissions fell by 19%, commercial emissions fell by 3%, while industrial emissions increased by 24% compared to 2010 levels.

In Table C.1, we show that national level 2010 LAP marginal damages derived from AP3, EASIUR, and InMAP vary by model and pollutant. We used the marginal damages from each model and implemented them as taxes on LAPs in TIMES to determine if emissions reductions would change substantially across varying tax rates. It should also be noted that despite the differences in national taxes across models, that there were nearly identical emissions reductions in SO_2, NO_x, and $PM_{2.5}$ across AP3, EASIUR, or InMAP derived national tax values, which we outline in Figure C.4. The similarity in LAP abatement across AP3, EASIUR, and InMAP tax rates suggests that in the TIMES model, at the magnitude of the LAP taxes, nearly all possible LAP abatement has taken place. In other words, these LAP taxes pushed the TIMES model to an inelastic region of its marginal abatement cost curve for LAPs, such that a change in the tax rate on LAPs did not cause a substantial relative change in emissions reductions by 2035. To test this hypothesis empirically, we used the national LAP tax rates and then increased these tax rates by 1% on SO_2, NO_x, and $PM_{2.5}$, to measure the impact on abatement. We found that a simultaneous 1% increase in the national tax rate on SO_2, NO_x, or $PM_{2.5}$ resulted in a 0.01%, 0.02%, and a 0.51% decrease in cumulative emissions, respectively. Additionally, the inelastic nature of the marginal abatement cost curve for LAPs at these levels suggests that there are no further technologies available for abatement.

Additionally, as illustrated in Figure C.5, under the national tax and regional tax scenarios, reductions in LAPs in 2035 are nearly identical. In both the regional and national tax scenarios, SO_2, NO_x, and $PM_{2.5}$ emissions fell by 78%, about 66%, and 65%, respectively, in 2035 compared to 2010 levels.

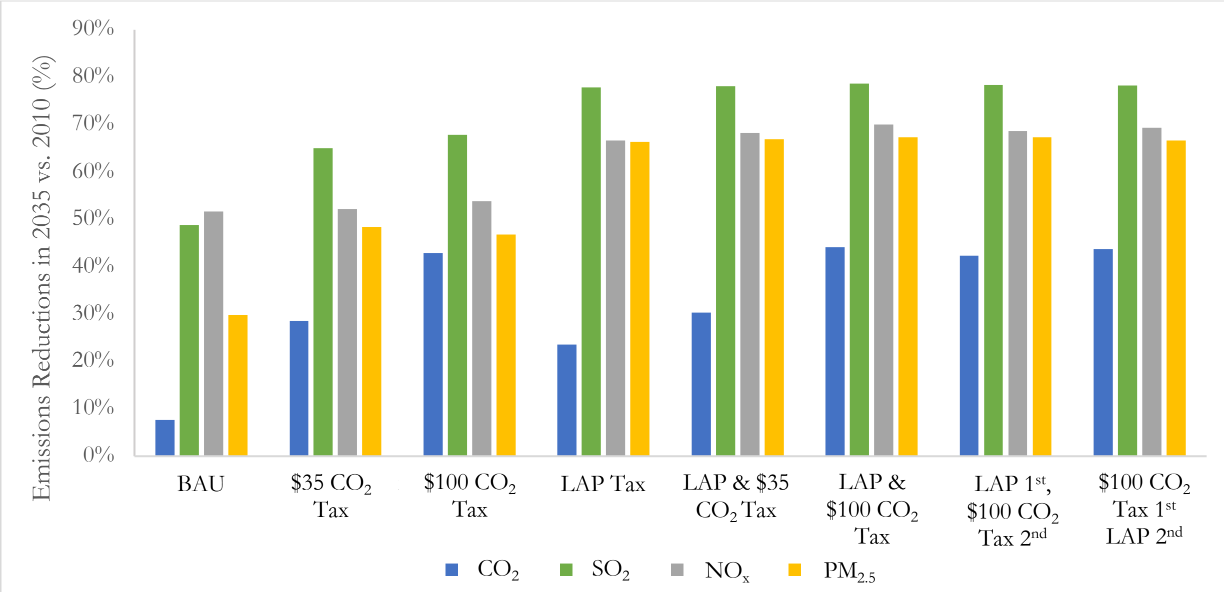
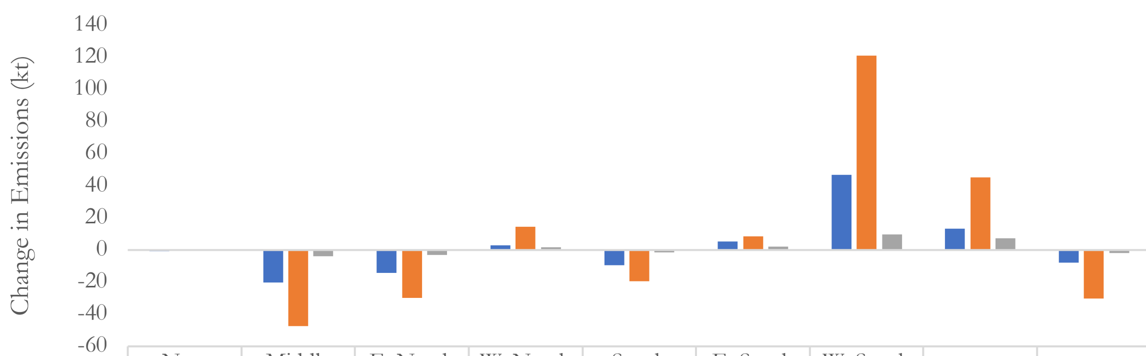


Figure 4.6: Energy-system emissions reductions of CO_2, SO_2, NO_x, and $PM_{2.5}$ in 2035 vs. 2010 across all eight scenarios.

Next, we compared 2035 emissions by region across the national tax and the regional tax scenarios. The regional tax, which we show as marginal damages in Figure 4.2, should reallocate emissions across regions according to whether the regional tax rates are higher or lower than the national average tax rate. That is, emissions and damages should fall (increase) in high (low) damage regions. The LAP taxes are highest in the middle Atlantic and Pacific regions in the regional tax scenario, so we might expect a general decrease in emissions in these regions and an increase in emissions in other regions with lower taxes, such as the West North Central, West South Central, and Mountain regions. In Table C.2, we display the 2035 emissions of SO_2, NO_x, and $PM_{2.5}$ by region under the national tax and the regional tax scenarios. Our main result here is that energy system emissions are not very responsive to the differentiated regional policy and remained largely unchanged across tax scenarios. In Figure 4.7, we show the regional change in emissions between the national and regional tax scenarios in 2035; there are only modest changes across regions. As outlined in Tables S3-S5, most of the differences in 2035 regional emissions across the regional and national taxes came from the refinery and upstream sectors, while emissions from the commercial, residential, electric, transportation, and industrial sectors remained mostly unchanged.

The largest increase, between the national and regional policies, in regional $PM_{2.5}$ emissions, was a 9% increase in the West South Central region. The largest decrease in regional $PM_{2.5}$ under a regional tax was just 6% in the Middle Atlantic region. Under the regional tax, the largest increase in SO_2 was 15% in the West South Central region, and the largest decrease was 8% in the Middle Atlantic region. Lastly, the largest increase in NO_x was 13% in the West South Central region, and the largest decrease was 11% in the Middle Atlantic region. Emissions were reallocated from the Middle Atlantic to the West South Central region due to the fact that modeled LAP taxes were the highest and the lowest across the U.S. in these regions, respectively. Therefore, it was less costly to produce emissions-intensive energy commodities in the West South Central region compared to other regions, and as a result, emissions increased.



	New England	Middle Atlantic	E. North Central	W. North Central	South Atlantic	E. South Central	W. South Central	Mountain	Pacific
ΔSO2	-1	-20	-14	3	-10	5	47	13	-8
ΔNOx	0	-48	-30	15	-19	9	121	45	-30
ΔPM2.5	0	-4	-3	2	-2	2	10	7	-2

ΔSO_2 ΔNO_x $\Delta PM_{2.5}$

Figure 4.7: Change in 2035 emissions under a regional vs. a national tax on emissions. A positive value indicates that emissions increased under a regional tax vs. a national tax. Under a regional tax, in 2035 emissions decreased in the Middle Atlantic, East North Central, South Atlantic, and Pacific regions compared to a uniform national tax.

4.4.4 Costs, Damages, and Net Benefits

As discussed in the methods section, we calculated annual damages for each pollutant by multiplying total emissions by the corresponding national marginal damage values, except for the regional tax scenario. We discussed the patterns of emission changes under each scenario above. The marginal damage from CO_2 emissions increased according to the trajectory reported by the USFWG (2016). For SO_2, NO_x, and $PM_{2.5}$, the national and regional marginal damages increased over time because of projected increases in population and income (which affects the VSL).

Figure 4.8 displays, in cumulative present value terms, the cost increase compared to BAU, the decrease in damages (which implies a benefit) compared to BAU, as well as net benefits from 2010-2035 for selected national tax scenarios, with the SCC following the $100 CO_2 tax trajectory. The air pollution tax alone had the lowest cumulative system cost of $404 billion over the BAU scenario, while the most expensive policy was the simultaneous air pollution and $100 CO_2 tax policy at $848 billion above BAU. All policies had benefit-cost ratios that exceed unity. The simultaneous CO_2 and national LAP taxes starting in 2015 had the highest present value net benefits. This policy is nearly 35% more efficient than taxing only CO_2 emissions and 20% more efficient than taxing just the LAPs. Hence, we report significant welfare advantages to policies that target individual pollutants emitted by the energy system relative to taxes that target one pollutant type and merely produce ancillary reductions in the others.

Further, Figure 8 demonstrates that the timing of the policies matters. When the LAP tax preceded the CO_2 tax, Figure 8 reports that net benefits fall by over 10% relative to the simultaneous tax scenario; there were ten additional years without a CO_2 tax, and as a result, there were higher cumulative CO_2 emissions and thus higher damages. When the CO_2 tax preceded the LAP tax, net benefits were 25% lower than the simultaneous tax scenario. Thus, delaying abatement of the LAPs would be more inefficient than delaying CO_2 abatement.

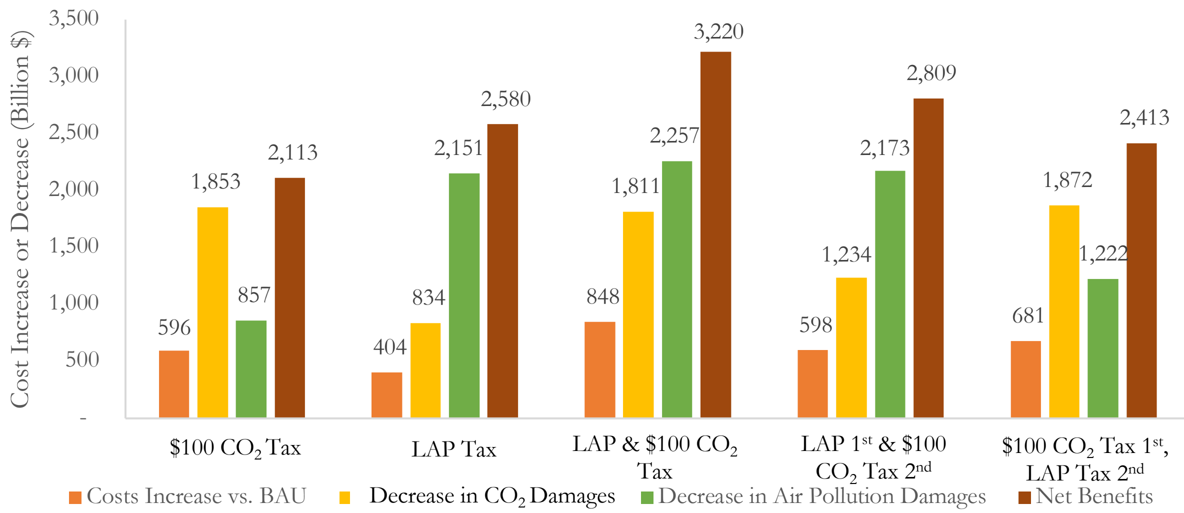


Figure 4.8: Cost increase above BAU, decrease in CO_2 damages, decrease in air pollution damages, and net benefits of selected scenarios compared to a BAU scenario from 2010-2035. The SCC in these scenarios is equal to the $100 CO_2 trajectory.

Next, we examined the change in costs to meet energy demand and the change in total emission-caused damages between the national tax scenario, the regional tax scenario, and the BAU scenario. In order to compare damage reductions across scenarios, in the BAU and national LAP tax scenarios we re-calculated damages using 9-region as opposed to national marginal damages. We also used 9-region marginal damages to tabulate total damage in the regional tax scenario. Because a regional tax policy will tax emissions at a level closer to actual marginal damages, in theory, there should be an increase in the net benefits under a regional tax compared to a national tax. Any increase in net benefits of a regional tax vs. a national tax is dependent largely on how much emissions change by region between the two tax scenarios, as well as the variance in the marginal damage caused by emissions across regions. If emissions decrease in regions with a high marginal damage and increase in regions with a lower marginal damage, then there is potential for substantial net-benefits to accrue under a regional LAP tax policy.

In Figure 4.7, we illustrate that there was some change in emissions by region when comparing a national and regional tax scenario. By 2035 there were higher emissions of LAPs in the West North Central, East South Central, West South Central, and Mountain regions and lower LAP emissions in the Middle Atlantic, East North Central, South Atlantic, and Pacific regions under the regional tax scenario compared to the national tax scenario. The re-allocation of emissions from high to low damage regions under a regional tax will cause an increase in net-benefits when comparing a national to a regional tax.

In Figure C.6, we show that the present value of the cumulative cost from 2010-2035 to meet energy demand in the business as usual scenario was \$38.7 trillion and increased to \$39.0 trillion under the regional AP3-derived LAP tax and \$39.1 trillion under a national AP3-derived LAP tax. The present value of the cumulative damages from SO_2, NO_x, and $PM_{2.5}$ emissions under the BAU scenario using 9-region marginal damages was \$7.4 trillion. Compared to BAU, cumulative system costs increased by \$405 billion under a national LAP tax and increased by \$378 billion under a regional LAP tax. Using 9-region AP3 marginal damages to calculate national damage, LAP emissions damages under a national tax fell by \$2 trillion and by \$2.1 trillion under a regional tax compared to BAU. The cumulative net benefits from 2010-2035 accrued when comparing a national LAP tax to a regional LAP tax increased from \$1.61 trillion to \$1.75 trillion, a difference of \$143 billion in present value terms. In Figure C.7, we display cumulative net-benefits using EASIUR derived damages and tax values, which total \$55 billion across the national and regional scenarios. While an increase of \$143 billion under the regional tax scenario may seem like a large increase in net benefits, it is important to realize that these benefits accrue over a 25-year time period. The implementation, administrative, and enforcement costs of a 9-region, 3-pollutant LAP tax would likely be non-trivial. The increase in net-benefits under a regional tax scenario may not be substantial compared to the administrative costs of implementing 27 individual taxes on LAPs across 9-regions in the U.S.

4.5 Conclusion and Discussion

This analysis models nine U.S. energy system scenarios spanning 2010 to 2035. In addition to a BAU baseline, the paper explores eight scenarios that levy taxes on CO_2 and LAP emissions from the energy system, either separately or together. We modeled two CO_2 tax policies, a set of simultaneous air pollution taxes on SO_2, NO_x, and $PM_{2.5}$ (at a national and regional resolution), as well as a CO_2 tax and national air pollution tax simultaneously. Two of the scenarios alter the timing of the taxes: starting a CO_2 tax in 2015 and an air pollution tax in 2025 and vice versa. The goal of these multiform simulations is two-fold: (1) to assess technological and emission responses concomitant with net benefit calculations, and (2) to determine if policies targeting LAPs and GHGs in isolation differ from simultaneous policies. Importantly, technological responses, emission reductions, and resulting net benefits of simulated policies are all relative to the BAU.

First, although taxes were applied uniformly across sectors, most of the simulated reductions in emissions occurred in the electric sector. These emissions reductions manifested because there are numerous, viable emission-reducing technologies in the electric sector. In TIMES the transportation sector does not include a low carbon technology for any transportation sub-sector except for light-duty vehicles, thus limiting the amount of decarbonization and air pollution abatement that can occur in this sector. In the BAU scenario, light-duty electric vehicle penetration increased from 0% of total vehicle miles traveled (VMT) in 2010 to 24% of VMT in 2035. Under the $100 CO_2 tax and air pollution tax scenario, light-duty electric VMT reached 40% of total light-duty VMT traveled. Other transportation subsectors such as air transportation, freight train transport, medium and heavy-duty trucks, rail, and off-highway diesel remain unchanged across tax scenarios. The present paper thus highlights the need for further work on the low carbon transportation technology characterization in TIMES.

Second, different technology trajectories in the electric sector were realized under a LAP tax alone, a CO_2 tax alone, and the optimal simultaneous LAP and \$100 CO_2 tax policy. Under the optimal scenario, in which there was a simultaneous \$100 CO_2 tax and LAP tax, coal was phased out by 2025, there was drastically increased generation from solar and wind, and constant natural gas generation over time, some of which was outfitted with CCS. Any other policy combination lead to a sub-optimal technology trajectory, resulting in lower net-benefits. Under both CO_2 tax trajectories, coal with CCS remained in the system and there was an increase in renewables to meet new demand and replace decreasing coal generation. Under a \$100 CO_2 tax, some CCS was implemented on natural gas generation. Under the LAP tax, natural gas generation increased substantially to meet new demand and replaced coal generation, which was phased out by 2025. We also found that the timing of taxes could affect technology choices in the electric sector. If we implemented an LAP tax starting in 2015 followed by a CO_2 tax in 2025, then the electric sector became locked into more natural gas than it would have had both taxes started in 2015. Also, if a CO_2 tax started in 2015 and was followed by an air pollution tax in 2025, coal did not phase out until 2030. These tax timing differences have important ramifications for emissions and net benefits decreased under both staggered policies compared to the optimal simultaneous tax policy.

Third, the TIMES energy system model projected emissions reductions of CO_2, SO_2, NO_x, and $PM_{2.5}$ in 2035 relative to 2010, even under the BAU. These reductions manifested because of continued implementation of existing environmental policies and because of changes in the relative prices of fossil fuels. 2035 BAU emissions of CO_2, SO_2, NO_x, and $PM_{2.5}$ fell by 8%, 49%, 52%, and 30%, respectively, compared to 2010 levels.

Fourth, the paper reports considerable spillovers among the policies. When either CO_2 or LAPs were taxed alone, those policies resulted in significant reductions in non-taxed species as well as targeted species, producing co-benefits under each of our tax scenarios. In the simulations for the \$35 CO_2 tax and the \$100 CO_2 tax scenarios, CO_2 emissions fell by 29%, and 43% by 2035, respectively compared to 2010 levels. By 2035 the \$35 and \$100 CO_2 taxes reduced SO_2 emissions by 65% and 68%, respectively, as well as $PM_{2.5}$ emissions by 48% and 47%, respectively compared to 2010 levels. 2035 NO_x emissions reductions remained about the same across the BAU, the \$35, and the \$100 CO_2 tax scenarios compared to 2010 levels. With LAP taxes, SO_2 emissions fell by 78%-79%, NO_x emissions fell by 67%-70%, and $PM_{2.5}$ emissions fell by 66%-67% in 2035 compared to 2010 levels. In addition, the LAP taxes induced CO_2 emissions to fall by 24% by 2035 compared to 2010 levels.

Fifth, across all scenarios, net-benefits were the highest when CO_2, SO_2, NO_x, and $PM_{2.5}$ were taxed simultaneously beginning in 2015. Joint policies offer considerable welfare advantages over either CO_2 or LAP taxes in isolation. And, delays in implementing either LAP or CO_2 taxes induce significant welfare loss.

Next, we conclude that, across regions and sectors, that there was not much difference in emissions between the national and regional taxes. Thus, the welfare gains stemming from policy differentiation appear to be minimal. This result provides critically important for policymakers. Though the marginal damages from LAP vary considerably across space, the highly inelastic marginal abatement cost schedules curtail efficiency improvements from policy differentiation; a

1% increase in the national LAP taxes (over and above the taxes modeled herein) caused only a 0.01%, 0.02%, and 0.51% decrease in cumulative SO_2, NO_x, and $PM_{2.5}$ emissions, respectively.

Relatedly, because changes in emissions were relatively small across the national and regional LAP tax scenarios, the resulting difference in cumulative net-benefits between a differentiated tax scenario versus a national tax scenario was small compared to overall system costs and total damage from emissions. One might expect a more considerable increase in cumulative net benefits when comparing a national LAP tax to a differentiated LAP tax scenario. There are several reasons why the net-benefits did not increase more substantially under the differentiated LAP tax policy. One explanation is that under the magnitude of both the national and regional LAP taxes, the TIMES model may have already abated almost all possible LAP emissions, and the model did not have many technology options available to abate further. An example of technology and emissions remaining the same across regions under a national and regional LAP tax can be found in the electric, commercial, and residential sectors. The 2035 regional emissions of SO_2, NO_x, and $PM_{2.5}$ in these sectors were close to identical across the national and regional tax scenarios. Since emissions did not change much in most sectors, this implies that instead of switching technologies in response to the differentiation in the tax rate, the energy system was staying the same. If technology deployments in these sectors remained the same, then the tax burdens increased in regions with a higher LAP tax rate and decreased in those with a lower LAP tax rate.

We conclude with the following caveats. It is important to note that the lack of efficiency gains between the national and regional taxes is likely due to the limited (regional) variation in marginal damages from LAP emissions. Prior work has demonstrated that considerable variation in the LAP marginal damages manifests in urban versus suburban and rural emissions. The regional resolution used herein simply cannot capture this. While this may be viewed as a shortcoming of the analysis, it is crucial for readers to note that this design embodies a more plausible differentiated policy scenario than, say, county-specific taxes.

Lastly, it is important to note that this analysis does not suggest that regional taxes are not a worthwhile policy instrument for the efficient reduction of LAP emissions in the U.S. It is important to note that the lack of an increase in net-benefits between the national and regional tax scenarios is likely due to the lack of additional abatement options built into TIMES, which does not allow additional regional abatement in many sectors, regardless of whether there was a substantial tax increase. In the real world, the presence of increased air pollution taxes could foster technological innovation that could both decrease the cost of abatement and increase the total amount of abatement possible. Because it is impossible to predict what these technologies may be, they are not included in the TIMES energy system representation.

Chapter 5: Conclusion

Reducing U.S. CO_2 and LAP emissions to efficient levels will require large-scale changes to the energy system. The changes necessary to decarbonize energy production and changes necessary to mitigate LAP emissions will overlap to some extent. Damages from CO_2 and LAP emissions can be viewed through an economic lens as an externality problem because the costs to the environment and human health from energy consumption are not embodied in the price. Without the proper economic incentives, inefficient levels of both CO_2 and LAP emissions would likely continue into the future. This thesis first aims to quantify the cost of avoiding CO_2 emissions via the preservation of existing nuclear power plants. Second, through energy systems modeling, I simulated myriad externality-correcting environmental policies and their impact on the U.S. energy system, emissions, costs, damages, and technology use.

In Chapter 2, I addressed uncertainty surrounding the cost of avoiding CO_2 emissions in the electric generation sector via nuclear power plant preservation. I used historical cost data from the electric utility cost group to bound the break-even price of electricity that nuclear power plants must receive into the future in order to avoid financial loss. If electricity prices remain low, many nuclear power plants would be at-risk of pre-mature retirement before their operating licenses expire. When nuclear plants retire in the U.S., their generation is replaced largely with natural gas fueled power plants, which emit CO_2. Therefore, preserving existing nuclear plants through a subsidy or missing-money payment would avoid CO_2 emissions. Under the lowest electric price scenario, I found that the median cost of avoided CO_2 ranged from $18 to $30 per ton for multi reactor plants, and $53 to $97 per ton for single reactor plants (2014$), which is within the range of federal estimates of the social cost of carbon. Future analysis could also include the cost of avoided LAP emissions, which would increase the economic rationale for preserving existing nuclear power plants.

Chapter 3 suggests that a \$35 or \$100 per ton (2005\$) CO_2 tax trajectory would cause abatement in the short term that is in line with targets in the Paris Agreement. In the short term, despite CO_2 reductions of 24% and 38% by 2030, compared to 2010 levels, both the \$35 and \$100 per ton CO_2 tax trajectories are high enough to produce enduring tax revenue through 2030. I also found that simulated carbon tax revenue was enough to displace a large portion of income tax revenue, could fund road and highway construction, or fund substantial research focusing on decarbonization and climate adaptation. Additionally, given that the social cost of carbon is uncertain, I found that on efficiency grounds, it is better to implement a high tax, as opposed to a low tax. Moreover, the damage reduction from reduced emissions of CO_2 or LAPs was greater than the increase in cost to the energy system under both tax scenarios. Lastly, most of the CO_2 abatement in this analysis occurred in the electric sector. Future work could characterize additional low-carbon technologies outside of the electric sector in the TIMES model.

In Chapter 4, I simulated a number of different scenarios that internalized damages from either CO_2 emissions, LAP emissions, or both. I found that there was substantial spillover in regulating emissions and that taxing one species lead to reductions in the non-taxed species. Despite the fact that spillovers exist, I found that net-benefits relative to BAU are the largest when both CO_2 and LAP damages are internalized simultaneously. Additionally, after modeling staggered CO_2 and LAP taxes, I learned that the timing of taxes is important. Specifically, I found that if a CO_2 tax is not implemented until after a LAP tax, the electric generation sector would be locked into higher amounts of natural gas generation, resulting in higher CO_2 emissions over time.

As part of Chapter 4, I modeled both national and regional taxes on LAPs. Under the national tax scenario, there was a uniform tax on SO_2, NO_x, and $PM_{2.5}$ across all regions of the energy system. Under the regional tax, there were nine different tax rates for SO_2, NO_x, and $PM_{2.5}$, according to census region. I found that both the national and regional taxes produced similar, and substantial LAP abatement of LAPs above BAU. The modeled damage reduction from LAP emissions abatement is large in both the national and regional scenario, however, since abatement was similar across the regions and scenarios, there were limited gains to the differentiated tax policy. Despite the small modeled gains of a regional tax policy compared to a national tax policy, policymakers should not come to the conclusion that differentiated LAP tax policy is not an effective means to regulate LAP emissions. The relative increase in net-benefits under the regional tax may have been low because the TIMES model is not capable of introducing novel abatement responses or technologies that may be incentivized under the presence of LAP taxes.

This research shows that there is large potential for environmental taxes to correct for current emissions-based externalities in the U.S. Despite a current collection of existing air-quality related policies, large damages and externalities still result from the production of energy. While spillovers exist, it is most cost-effective to address LAP and CO_2 emissions with separate taxes that target each species individually. We learn in this work that the simulated gains from a 9-region tax set at the regional marginal damage of emissions may not provide substantial benefits compared to a national tax. To realize the full benefits of differentiation, future work could implement a higher resolution tax, or more model future LAP abatement technologies.

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Appendix A: Supplemental Information for Chapter 2

Table A.1 provides summary statistics for the starting O&M cost in year 2014 that I used to model O&M costs. The values in Table A.1 are broken out by reactor size and type. I fit distribution functions to the original data summarized in Table A.1 and drew from these distributions to determine the starting O&M cost for each plant in each iteration of the Monte Carlo simulation.

Table A.1: Non-fuel operations and maintenance costs in 2014 ($ per MWh)

Plant Type	PWR	BWR	2&3 PWR	2&3 BWR
Min	19	15	14	15
Mean	28	28	20	19
Max	39	47	31	24
Median	28	30	19	18
Standard Deviation	5.7	10.0	3.2	3.3

In order to project future O&M costs through 2040, I derived a distribution of "average annual change" in O&M costs from EUCG data for single and multi-reactor power plants. Starting in 2016 and continuing through 2040, each year I drew from these distributions to determine the change in O&M from the previous year.

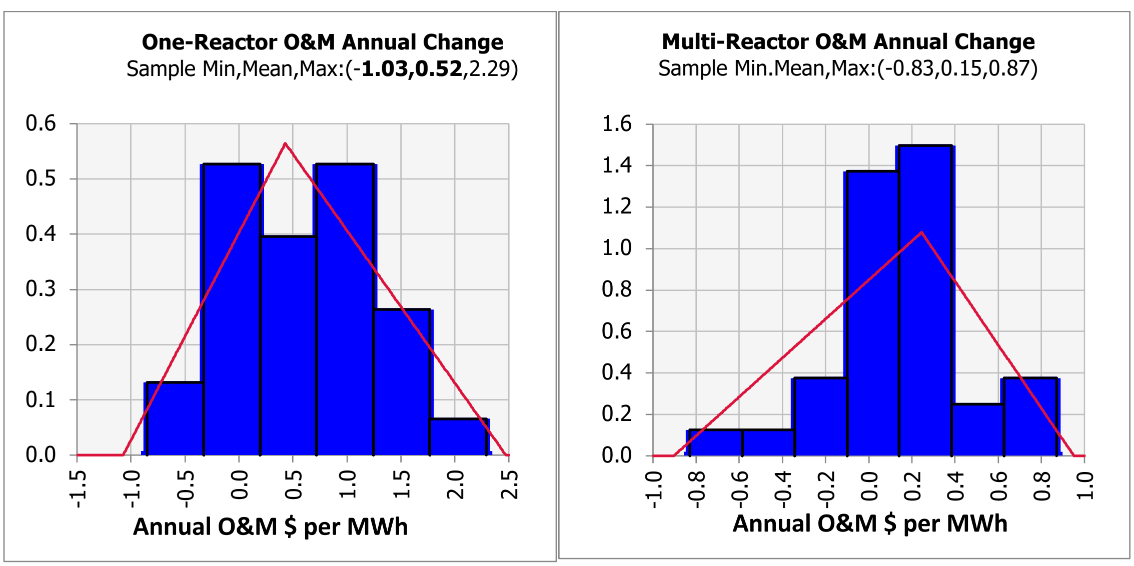

Figure A.1: Parameters of triangular distribution for year-to-year change in non-fuel-O&M costs. One-reactor (n =29 sd=0.71) and multi-reactor (n=33 sd=0.32)

The data in Table A.2 summarize the annual capital expenditures for each of the four types of nuclear power plants between 2002-2014, as observed in the EUCG data. Figure A.2 displays the distribution of the mean differences in annual capital expenditures and the mean reported in Table A.2 for each plant type (in blue) and the function (red line) that we fit to these data.

Table A.2: Annual capital expenditures between 2002-2014 ($ per kW of capacity)

Plant Type	1 PWR	1 BWR	2&3 PWR	2&3 BWR
Min	0	0	0	11
Mean	84	64	60	47
Max	412	410	845	164
Standard Deviation	69	57	70	28

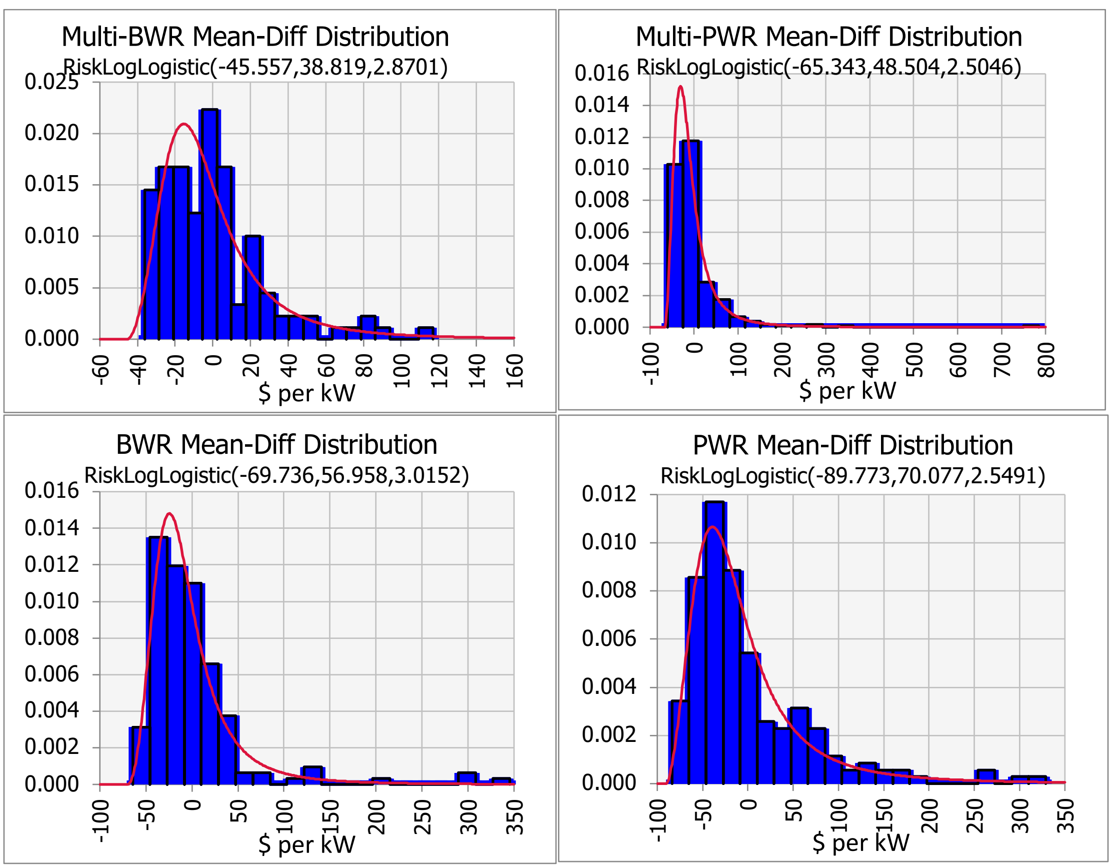

Figure A.2: Plant Size and Type-Specific Distribution of mean-difference capital expenditures ($ per kw of capacity).

Data on the quantity of nuclear fuel consumed as well as the price paid for fuel at a specific nuclear plant are not publicly available. I use EIA's uranium fuel price point estimate to produce Figure A.3, as it accounts for a broad range of macro-economic trends included in the EIA models, and it is the only publicly available forecast for future nuclear fuel prices through 2040. Similarly, The EIA Annual Energy Outlook provides Henry Hub natural gas price ($/MMBTU) projections out to 2040 under four different scenarios ranging from low to high natural gas price pathways as show in Figure A.4. I use these forecasted gas prices to determine the short run marginal cost that NGCC plants could achieve, which we assume set the electricity price nuclear plants would receive under each scenario. Equation A.1 was used to determine the short run marginal cost of an NGCC plant, assuming a heat rate of 7,658 Btu/kWh [109].

Equation A.1: Price of Electricity $/MWh = Heat Rate * EIA Henry Hub Price

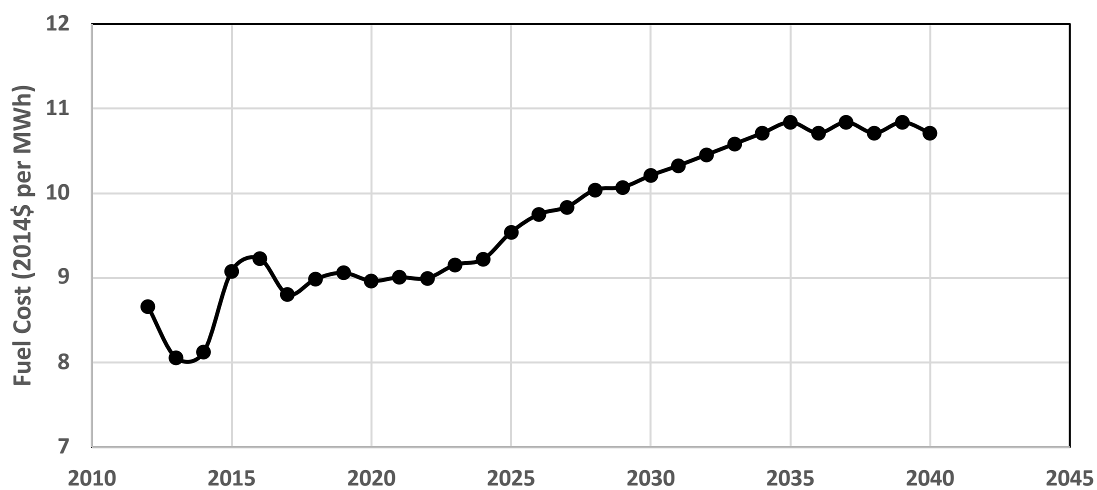

Figure A.3: Projected Ready-Load Nuclear Fuel Price 2014$/MWh (Data Source: U.S. EIA [40]*).*

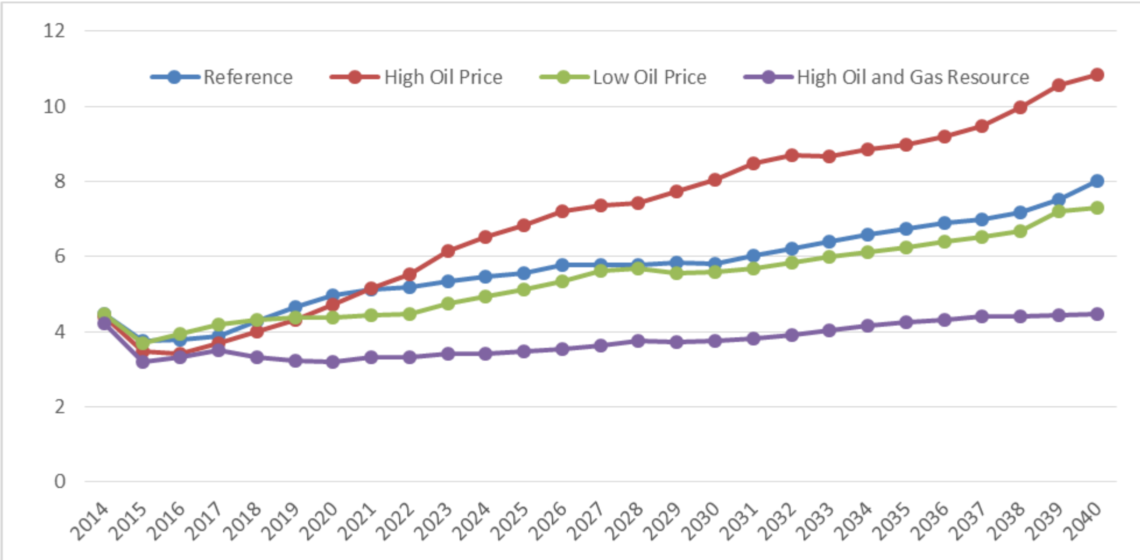

Figure A.4: EIA Henry Hub Natural Gas Price Projections in 2014$ per MMBTU (Data Source: U.S. EIA [110]*).*

Equation A.2 describes the estimates for income from reactor *i* in year *k*, given the capacity factor for reactor *i* in year *k* (sampled from the IAEA data previously described), the net capacity from EIA at plant *i*, and the projected electricity price given an EIA forecasted Henry Hub Price of natural gas in year *k* (derived from Equation A.1). For plants with multiple reactors we added the income from each reactor. Note that Equation A.2 describes the first term in the denominator of Equation 2 in the main paper, which yields the MMP at plant *i*.

Equation A.1: Price of Electricity $/MWh = Heat Rate * EIA Henry Hub Price

Equation A.2: $\text{Income}_{i,k} = \text{Capacity Factor}_{i,k} * \text{Net Summer Capacity}_{i} * \text{Price of Elec}_{k} * 8760_{\text{hours/year}}$

Table A.3 shows the 5th, 50th, and 95th percentile MMP values used to produce Figure 2.3 of the main paper. Each cell in Table A.3 displays data from the lowest and highest performing plant under a given scenario and plant type. Furthermore, Table A.4 shows the MMP for each individual multi-reactor power plant under a low, reference, and high natural gas price scenario, while Table A.5 shows the MMP for each individual single-reactor power plant under the same natural gas price scenarios. Finally, Figures A.5-A.7 display the MMP data from Tables A.4 and A.5 graphically for each individual plant under a low, reference, and high natural gas price scenario. The box plots display the 5th, 25th, 50th, 75th, and 95th percentile data that result from the Monte Carlo simulation.

Table A.3: MMP Best and Worst Plants By Reactor Size and Scenario

MMP: 5th, 50th, 95th Percentile $/MWh			
Scenario:	Low Gas Price	Reference Gas Price	High Gas Price
Single	($14, $24, $36) ($33, $44, **$58**)	($1, $11, $23) ($21, $31, $45)	(**-$6**, $5, $17) ($14, $25, $39)
Multi	($5, $8, $12) ($8, $14, **$22**)	(-$8, -$5, -$1) (-$5, $1, $9)	(**-$14**, -$11, -$7) (-$12, -$5, $2)

Table A.4 Missing Money Payment Data for Low, Reference, and High Gas Scenarios for Multi Reactor Plants ($/MWh).

Scenario:	MMP Low Gas $/MWh					MMP Ref Gas $/MWh					High Ref Gas $/MWh				
Plant	5th	25th	50th	75th	95th	5th	25th	50th	75th	95th	5th	25th	50th	75th	95th
Limerick	5	6	8	10	12	-8	-7	-5	-2	-1	-14	-13	-11	-9	-7
Peach Bottom	5	6	8	11	12	-8	-7	-5	-2	-1	-14	-13	-11	-9	-7
Brunswick	5	6	8	11	12	-8	-7	-4	-2	-1	-14	-13	-11	-8	-7
NineMilePoint	5	6	9	11	12	-8	-6	-4	-2	0	-14	-13	-11	-8	-7
Hatch	5	6	9	11	12	-8	-6	-4	-2	0	-14	-13	-11	-8	-7
Susquehanna	5	6	9	11	12	-8	-6	-4	-2	0	-14	-13	-10	-8	-7
Dresden	5	7	9	11	13	-8	-6	-4	-2	0	-14	-12	-10	-8	-6
QuadCities	5	7	9	11	13	-7	-6	-4	-1	0	-14	-12	-10	-8	-6
LaSalle	6	7	9	11	13	-7	-6	-4	-1	0	-14	-12	-10	-8	-6
BrownsFerry	6	8	10	12	14	-6	-5	-3	0	1	-13	-11	-9	-7	-5
Byron	6	8	12	16	19	-7	-5	-1	3	6	-13	-12	-8	-4	0
Braidwood	6	8	12	16	19	-7	-5	-1	3	6	-13	-12	-8	-4	0
Vogtle	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
CalvertCliffs	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
Surry	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
Catawba	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
McGuire	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
Arkansas	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
NorthAnna	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
ComanchePeak	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
Farley	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
PrairieIsland	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
DiabloCanyon	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
Sequoya	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
TurkeyPoint	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
SouthTexas	6	8	12	16	19	-7	-5	-1	3	6	-13	-11	-7	-3	0
Oconee	6	8	12	16	19	-7	-5	-1	3	7	-13	-11	-7	-3	0
PaloVerde	6	8	12	16	19	-7	-5	-1	3	7	-13	-11	-7	-3	0
StLucie	6	8	12	16	19	-7	-5	-1	3	7	-13	-11	-7	-3	0
BeaverValley	6	8	12	16	19	-7	-5	-1	3	7	-13	-11	-7	-3	0
PointBeach	6	8	12	16	20	-6	-5	0	4	7	-13	-11	-7	-3	1
IndianPoint	6	8	12	17	20	-6	-4	0	4	7	-13	-11	-7	-2	1
Salem	7	9	13	17	21	-6	-4	0	5	8	-12	-10	-6	-2	2
Millstone	7	9	13	17	21	-6	-4	0	5	8	-12	-10	-6	-2	2
Cook	7	9	14	18	21	-5	-3	1	5	9	-12	-10	-5	-1	2

Table A.5 Missing Money Payment Data for Low, Reference, and High Gas Scenarios for Multi Reactor Plants ($/MWh).

Scenario:	MMP Low Gas $/MWh					MMP Ref Gas $/MWh					High Ref Gas $/MWh				
Plant	5th	25th	50th	75th	95th	5th	25th	50th	75th	95th	5th	25th	50th	75th	95th
GrandGulf	13	17	24	31	36	1	4	11	18	23	-6	-2	5	12	17
Perry	15	18	25	32	37	2	6	12	19	25	-4	-1	6	13	18
HopeCreek	15	19	25	32	38	2	6	13	19	25	-4	-1	6	13	19
Seabrook	19	21	26	31	34	6	9	13	18	22	-1	2	7	12	15
Callaway	19	21	26	31	35	6	9	13	18	22	0	2	7	12	15
Columbia	16	19	26	33	39	3	7	13	20	26	-3	0	7	14	20
Waterford	19	22	27	31	35	6	9	14	19	22	0	3	7	12	16
WolfCreek	19	22	27	31	35	6	9	14	19	22	0	3	8	12	16
Fermi	16	20	27	34	39	3	7	14	21	26	-3	1	8	15	20
WattsBar	19	22	27	32	35	6	9	14	19	22	0	3	8	13	16
Clinton	16	20	27	34	39	3	7	14	21	26	-3	1	8	15	20
RiverBend	16	20	27	34	39	3	7	14	21	26	-3	1	8	15	20
Firzpatrick	17	21	28	35	40	4	8	15	22	28	-2	2	9	16	21
Summer	21	24	29	34	37	8	11	16	21	24	2	5	10	15	18
Harris	21	24	29	34	37	8	11	16	21	25	2	5	10	15	18
ThreeMile	22	25	30	35	39	9	12	17	22	26	3	6	11	16	20
Cooper	19	23	30	37	42	6	10	17	24	30	0	4	11	18	23
Pilgrim	20	24	31	38	43	7	11	18	25	30	1	4	12	19	24
DavisBesse	23	26	31	36	40	10	13	18	23	27	3	6	12	17	21
Robinson	23	26	32	37	41	11	13	19	24	28	4	7	13	18	22
Palisades	24	27	32	37	41	11	14	19	25	28	5	7	13	18	22
OysterCreek	21	25	32	39	45	8	12	19	26	32	2	6	13	20	26
DuaneArnold	21	25	32	39	45	8	12	19	26	32	2	6	13	20	26
Monticello	23	26	34	41	47	10	14	21	28	34	3	7	15	22	28
Ginna	27	30	36	41	46	14	17	23	29	33	8	11	17	22	27
FortCalhoun	33	37	44	52	58	21	24	31	39	45	14	18	25	33	39

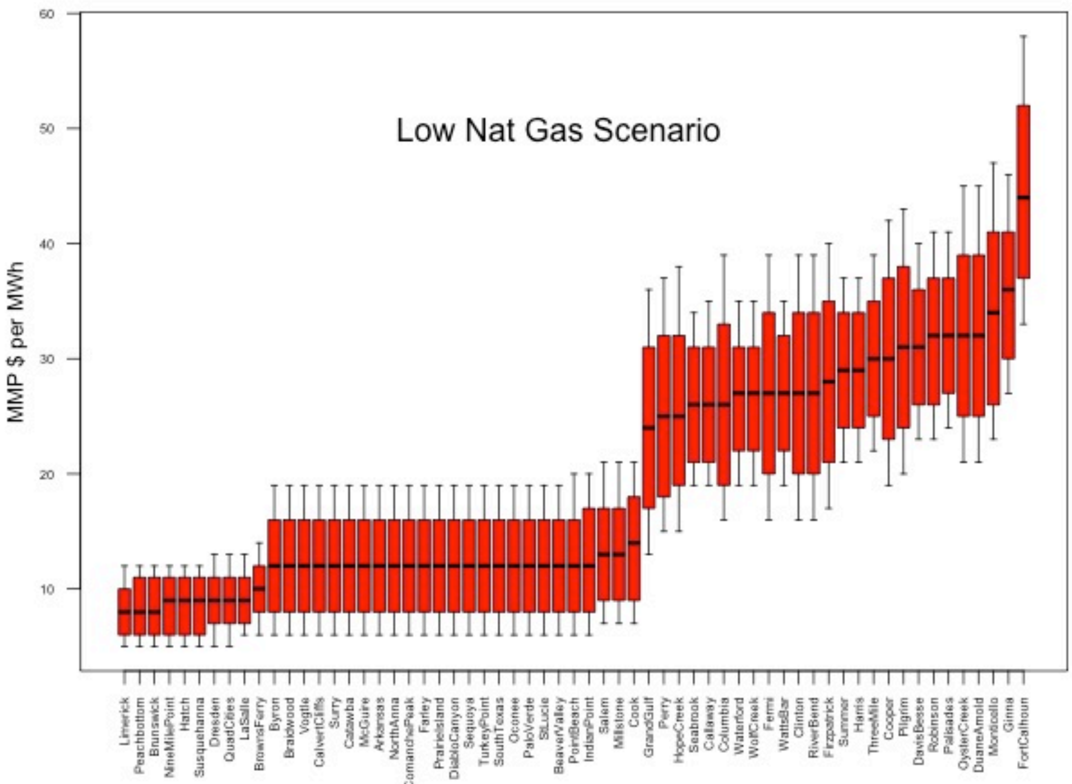

Figure A.5: Missing Money Payment for US Nuclear Power Plants in Low Gas Scenario ($/MWh).

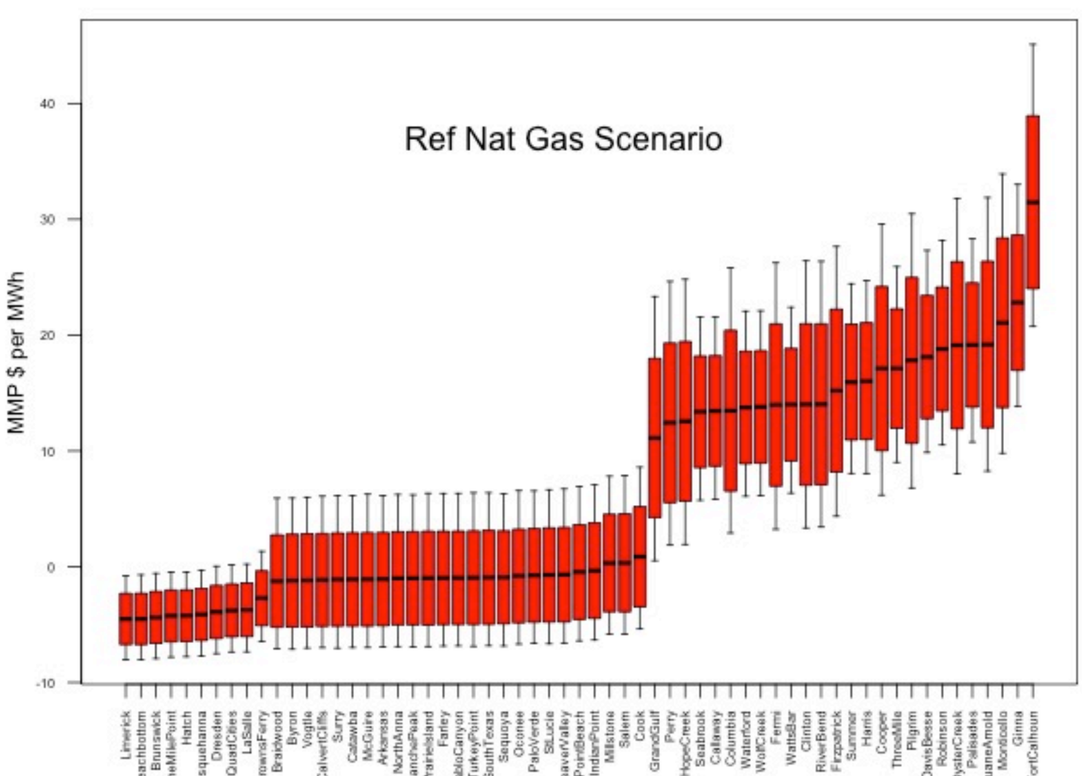

Figure A.6: Missing Money Payment for US Nuclear Power Plants in Reference Gas Scenario ($/MWh).

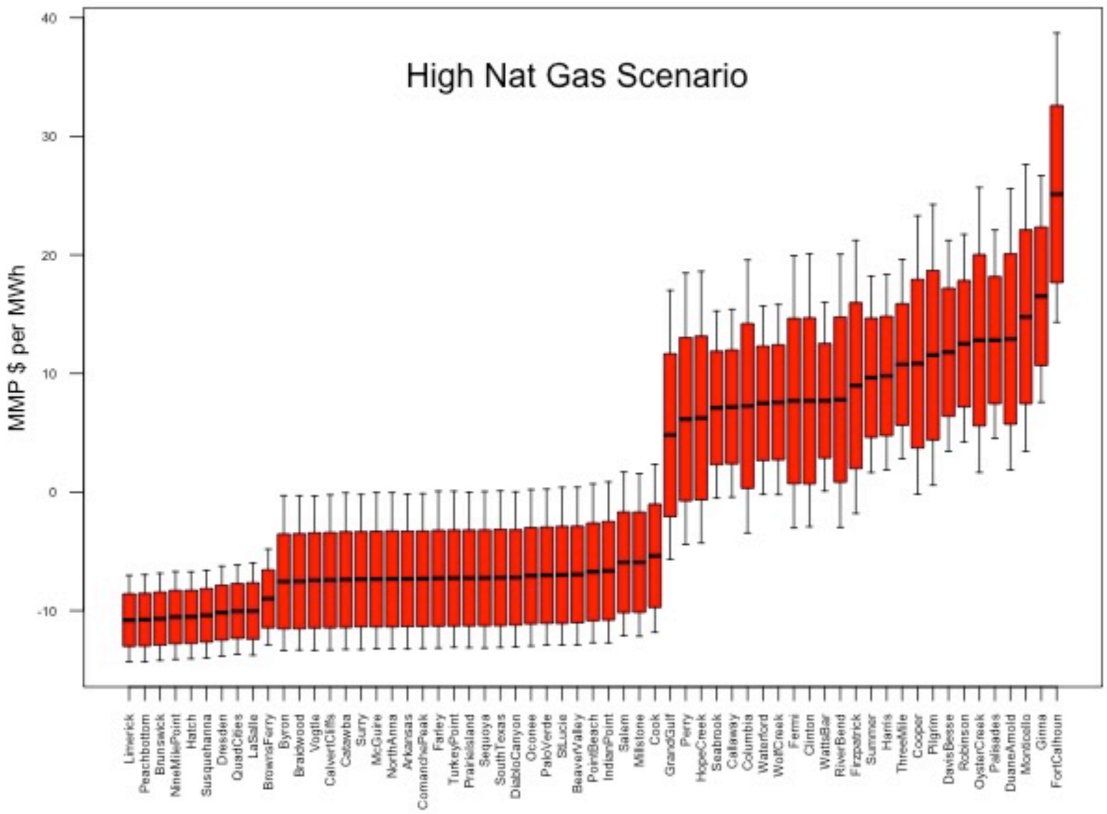

Figure A.7: Missing Money Payment for US Nuclear Power Plants in High Gas Scenario ($/MWh).

Table A.6 displays the 5th, 25th, 50th, 75th, 95th, percentile data for the cost of avoided CO_2 from each multi-reactor power plant. Similarly, Table A.7 displays the 5th, 25th, 50th, 75th, 95th, percentile data for the cost of avoided CO_2 from each single reactor power plant. Finally, Figures A.8-A.10 provide a graphical display of the cost of avoided CO_2 data from Tables A.6 and A.7 for each individual power plant under a low, reference, and high natural gas price scenario. The box plots display the 5th, 25th, 50th, 75th, and 95th percentile data that result from the Monte Carlo simulation.

Table A.6: Cost of Avoided CO_2 Data for Low, Reference, and High Gas Scenarios for Multi Reactor Plants \$/metric ton.

Scenario:	Avoided CO_2 Low Gas \$/metric ton					Avoided CO_2 Ref Gas \$/metric ton					Avoided CO_2 High Ref Gas \$/metric ton				
Plant	5th	25th	50th	75th	95th	5th	25th	50th	75th	95th	5th	25th	50th	75th	95th
Limerick	11	13	18	22	26	-18	-15	-10	-5	-2	-31	-29	-24	-19	-15
PeachBottom	11	13	18	24	26	-18	-15	-10	-5	-2	-32	-29	-24	-19	-15
Brunswick	11	13	18	24	26	-17	-15	-10	-5	-1	-31	-28	-24	-19	-15
NineMilePoint	11	13	20	24	26	-17	-14	-9	-4	-1	-31	-28	-23	-18	-15
Hatch	11	13	20	24	26	-17	-14	-9	-4	-1	-31	-28	-23	-18	-15
Susquehanna	11	13	20	24	26	-17	-14	-9	-4	-1	-31	-28	-23	-18	-15
Dresden	11	15	20	24	29	-17	-14	-9	-4	0	-30	-27	-22	-17	-14
QuadCities	11	15	20	24	29	-16	-13	-8	-3	0	-30	-27	-22	-17	-14
LaSalle	13	15	20	24	29	-16	-13	-8	-3	0	-30	-27	-22	-17	-13
BrownsFerry	13	18	22	26	31	-14	-11	-6	-1	3	-28	-25	-20	-14	-11
Byron	13	18	26	35	42	-16	-11	-3	6	13	-29	-25	-17	-8	-1
Braidwood	13	18	26	35	42	-16	-11	-3	6	13	-29	-25	-17	-8	-1
Vogtle	13	18	26	35	42	-15	-11	-3	6	13	-29	-25	-16	-8	-1
CalvertCliffs	13	18	26	35	42	-15	-11	-3	6	13	-29	-25	-16	-8	-1
Surry	13	18	26	35	42	-15	-11	-2	6	13	-29	-25	-16	-7	0
Catawba	13	18	26	35	42	-15	-11	-2	6	14	-29	-25	-16	-7	0
McGuire	13	18	26	35	42	-15	-11	-2	6	14	-29	-25	-16	-7	0
Arkansas	13	18	26	35	42	-15	-11	-2	6	14	-29	-25	-16	-7	0
NorthAnna	13	18	26	35	42	-15	-11	-2	7	14	-29	-25	-16	-7	0
ComanchePeak	13	18	26	35	42	-15	-11	-2	7	14	-29	-25	-16	-7	0
Farley	13	18	26	35	42	-15	-11	-2	7	14	-29	-25	-16	-7	0
PrairieIsland	13	18	26	35	42	-15	-11	-2	7	14	-29	-25	-16	-7	0
DiabloCanyon	13	18	26	35	42	-15	-11	-2	7	14	-29	-25	-16	-7	0
Sequoya	13	18	26	35	42	-15	-11	-2	7	14	-29	-25	-16	-7	0
TurkeyPoint	13	18	26	35	42	-15	-11	-2	7	14	-29	-25	-16	-7	0
SouthTexas	13	18	26	35	42	-15	-11	-2	7	14	-29	-25	-16	-7	0
Oconee	13	18	26	35	42	-15	-11	-2	7	14	-29	-24	-16	-7	0
PaloVerde	13	18	26	35	42	-15	-11	-2	7	14	-28	-24	-15	-7	1
StLucie	13	18	26	35	42	-15	-11	-2	7	15	-28	-24	-15	-6	1
BeaverValley	13	18	26	35	42	-15	-11	-2	7	15	-28	-24	-15	-6	1
PointBeach	13	18	26	35	44	-14	-10	-1	8	15	-28	-24	-15	-6	2
IndianPoint	13	18	26	37	44	-14	-10	-1	8	16	-28	-24	-15	-5	2
Salem	15	20	29	37	46	-13	-9	1	10	17	-27	-22	-13	-4	4
Millstone	15	20	29	37	46	-13	-9	1	10	17	-27	-22	-13	-4	3
Cook	15	20	31	40	46	-12	-8	2	11	19	-26	-21	-12	-2	5

Table A.7: Cost of Avoided CO_2 Data for Low, Reference, and High Gas Scenarios for Single Reactor Plants $/metric ton.

Scenario:	Avoided CO_2 Low Gas $/metric ton					Avoided CO_2 Ref Gas $/metric ton					Avoided CO_2 High Ref Gas $/metric ton				
Plant	5th	25th	50th	75th	95th	5th	25th	50th	75th	95th	5th	25th	50th	75th	95th
GrandGulf	29	37	53	68	79	1	9	24	40	51	-12	-5	11	26	37
Perry	33	40	55	70	81	4	12	27	43	54	-10	-2	14	29	41
HopeCreek	33	42	55	70	84	4	12	28	43	55	-9	-1	14	29	41
Seabrook	42	46	57	68	75	13	19	29	40	47	-1	5	16	26	34
Callaway	42	46	57	68	77	13	19	30	40	48	-1	5	16	26	34
Columbia	35	42	57	73	86	6	14	30	45	57	-8	1	16	31	43
Waterford	42	48	59	68	77	13	20	30	41	49	0	6	16	27	35
WolfCreek	42	48	59	68	77	14	20	30	41	49	0	6	17	27	35
Fermi	35	44	59	75	86	7	15	31	46	58	-7	2	17	32	44
WattsBar	42	48	59	70	77	14	20	31	42	49	0	6	17	28	35
Clinton	35	44	59	75	86	7	16	31	46	58	-6	2	17	32	44
RiverBend	35	44	59	75	86	8	16	31	46	58	-7	2	17	33	44
Firzpatrick	37	46	62	77	88	10	18	33	49	61	-4	4	20	35	47
Summer	46	53	64	75	81	18	24	35	46	54	4	10	21	32	40
Harris	46	53	64	75	81	18	24	35	46	54	4	10	22	33	40
ThreeMile	48	55	66	77	86	20	26	38	49	57	6	12	24	35	43
Cooper	42	51	66	81	93	14	22	38	53	65	0	8	24	39	51
Pilgrim	44	53	68	84	95	15	23	39	55	67	1	10	25	41	53
DavisBesse	51	57	68	79	88	22	28	40	52	60	8	14	26	38	47
Robinson	51	57	70	81	90	23	30	41	53	62	9	16	28	39	48
Palisades	53	59	70	81	90	24	30	42	54	62	10	16	28	40	49
OysterCreek	46	55	70	86	99	18	26	42	58	70	4	12	28	44	57
DuaneArnold	46	55	70	86	99	18	26	42	58	70	4	13	28	44	56
Monticello	51	57	75	90	104	22	30	46	63	75	8	16	33	49	61
Ginna	59	66	79	90	101	30	37	50	63	73	17	24	36	49	59
FortCalhoun	73	81	97	115	128	46	53	69	86	99	32	39	55	72	85

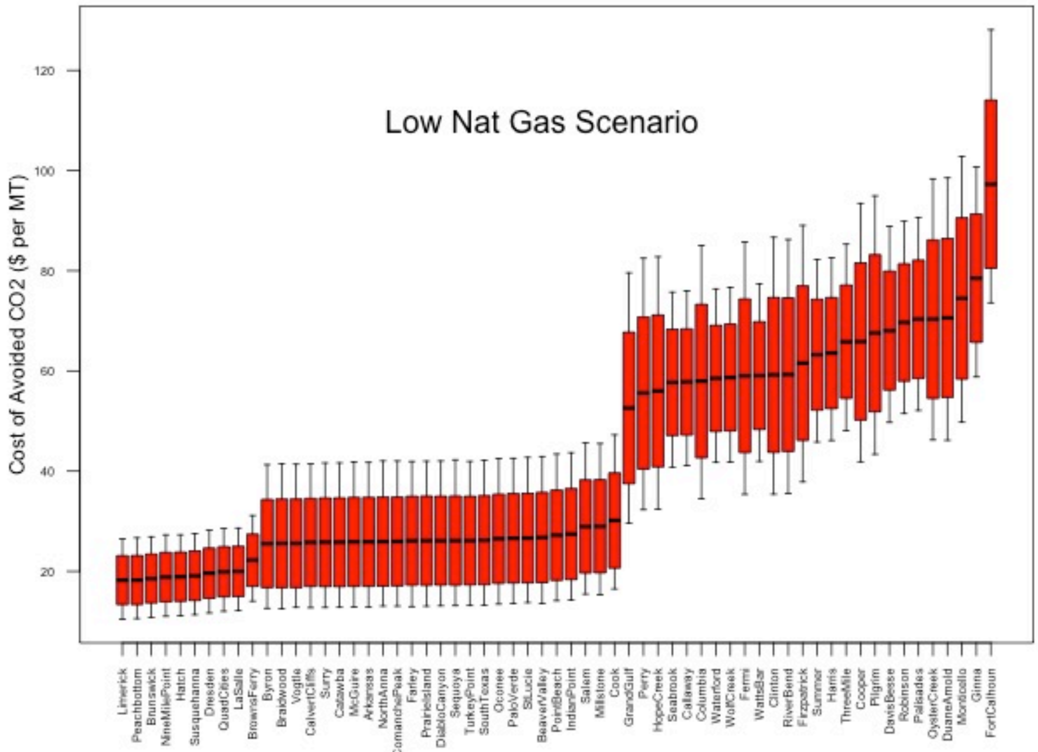

Figure A.8: Cost of Avoided CO_2 in Low Gas Scenario ($/metric ton CO_2 avoided)

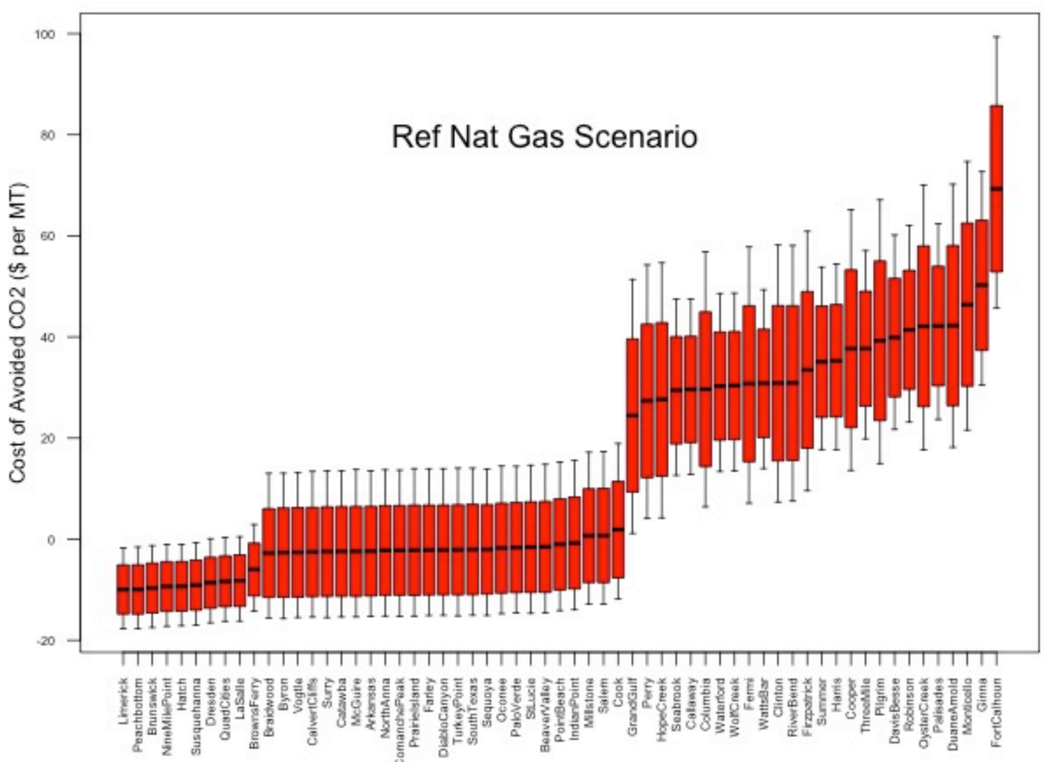

Figure A.9: Cost of Avoided CO_2 in Reference Gas Scenario ($/metric ton CO_2 avoided)

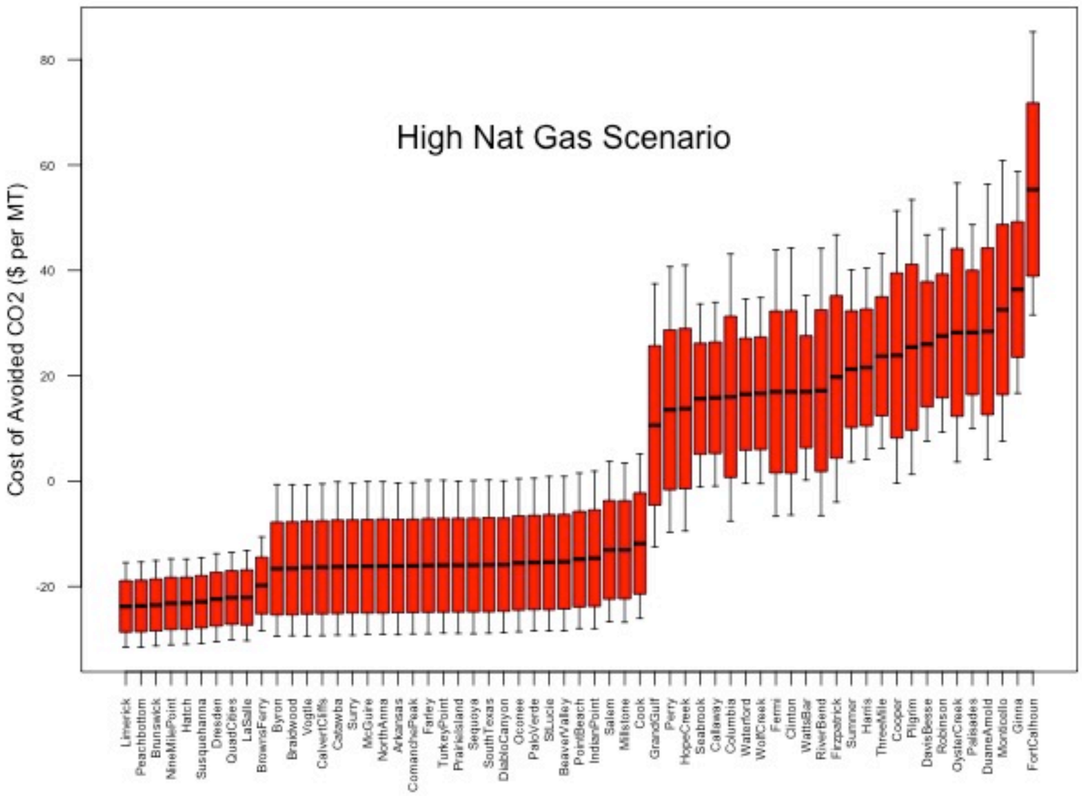

Figure A.10: Cost of Avoided CO_2 in Low Gas Scenario ($/metric ton CO_2 avoided)

As discussed in the main paper, the premature retirement of the existing nuclear plant fleet could undermine the success of the policies like the Clean Power Plan (CPP). Figure A.11 show the 2030 CO_2 emission reduction targets of the CPP (in blue) [111]. The red columns in Figure A.11 show the increase in CO_2 emissions that would occur if a state's nuclear plants were replaced with new NGCC plants. Figure A.12 summarizes the data from Figure A.11 to compare the national CO_2 emission reduction targets of the CPP by 2030 with the emissions that would result from a national phase out of the nuclear plant fleet by 2030, assuming the natural gas plants would replace the electricity for the retired nuclear plants. I find that if states comply with the CPP, there would be a reduction 431 million metric tons of CO_2 emissions from the power sector. However, if all U.S. nuclear generation were replaced with generation from new NGCC plants, an additional 353 million metric tons of CO_2 would be emitted, negating much of the CPP [112].

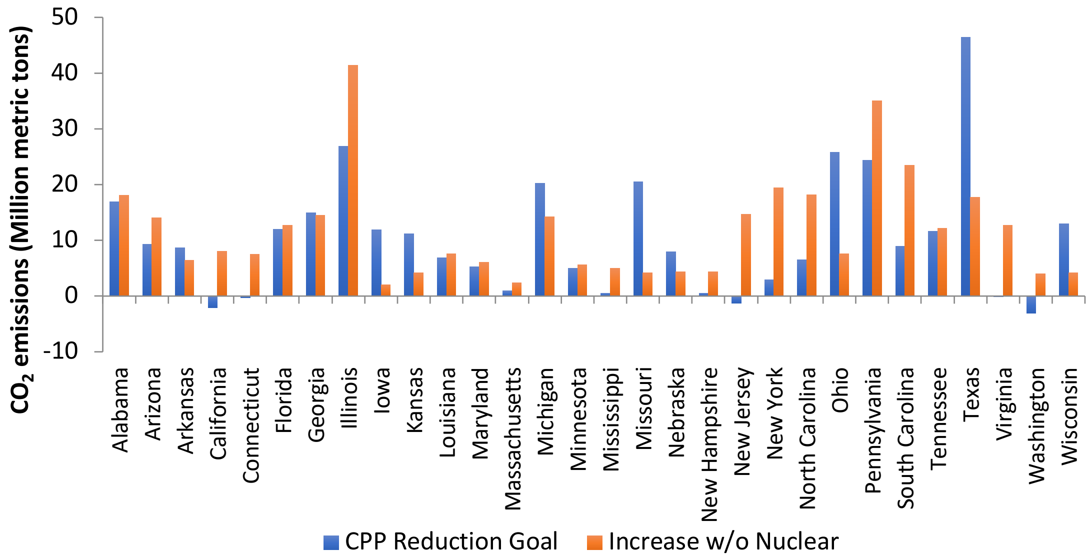

Figure A.11: CPP emissions reduction target by 2030 compared to increased emissions if 100% of nuclear plants replaced with NGCC.

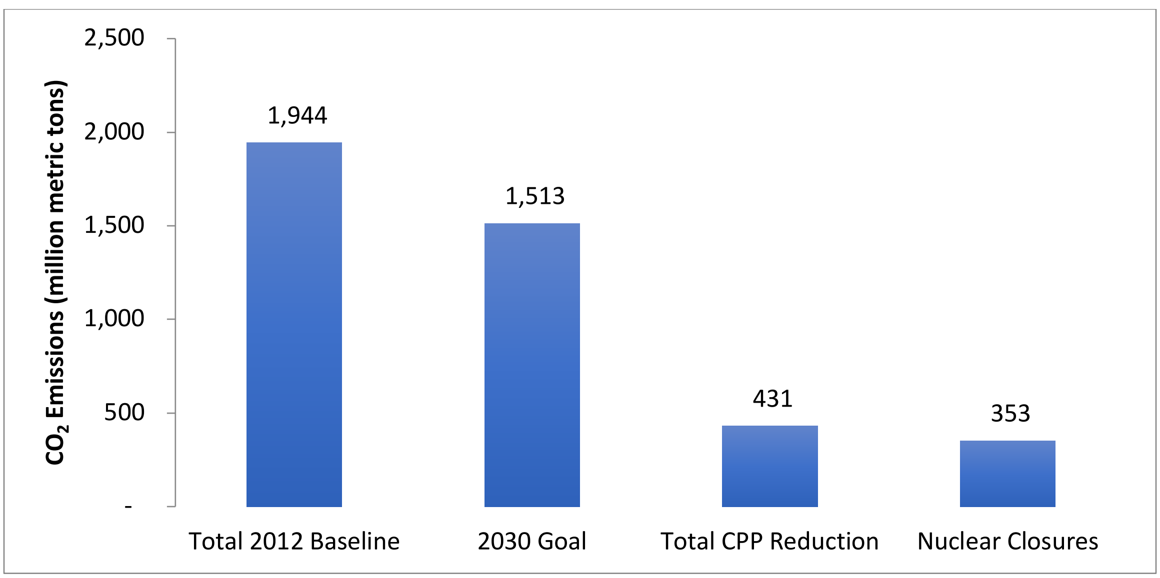

Figure A.12: National emission reductions under CPP compared to increased emissions from nuclear power plant retirements.

Appendix B : Supplemental Information for Chapter 3

B.1: Methods

We use the TIMES model in this paper, which is a bottom-up energy system optimization model. The model uses as input a database built by the U.S. Environmental Protection Agency (EPA) entitled EPAUS9rT (EPA TIMES 9-region) and includes the commercial, electric, industrial, refinery, residential, resource supply (upstream), and transportation sectors for the U.S. economy. THE EPAUS9rT database is populated using data from the U.S. EIA Annual Energy Outlook. The TIMES model uses linear optimization and a specified set of end-use demands in order to model U.S. energy use, costs, and emissions of CO_2, SO_2, NO_x, and $PM_{2.5}$ from the energy system between 2010-2050.

The EPAUS9rT database contains a number of technologies for the TIMES model to choose from during optimization. Each technology has an associated investment cost, operations and maintenance cost, fuel efficiency, and emissions factors. Many of the technologies in the EPAUS9rT database have increasing fuel efficiency over time; however, there is not endogenous learning in this model, and technology cost and performance do not depend on quantity deployed. Since the EPAUS9rT database includes a limited description of future technologies, we focus on the years 2010-2030 for this analysis because the characterization of technologies is likely most accurate.

The TIMES model can be used to model different policies such as a business-as-usual (BAU) case, which includes the Cross-State Air Pollution Rule (CSAPR), Mercury and Air Toxics Standards (MATS), renewable portfolio standards (RPS), and the Corporate Average Fuel Economy Standards (CAFE). In this analysis, we run the TIMES model to produce a BAU scenario from 2010-2030 and then run the model two additional times with the CO_2 taxes outlined in Figure B.1, which includes CO_2 tax trajectories that we label as \$35 and \$100 taxes for simplicity (all monetary values in this analysis are reported in 2005$). The $35 and $100 CO_2 taxes follow estimates of the U.S. federal government's intra-agency working group on the social cost of carbon report (USFWGSCC).

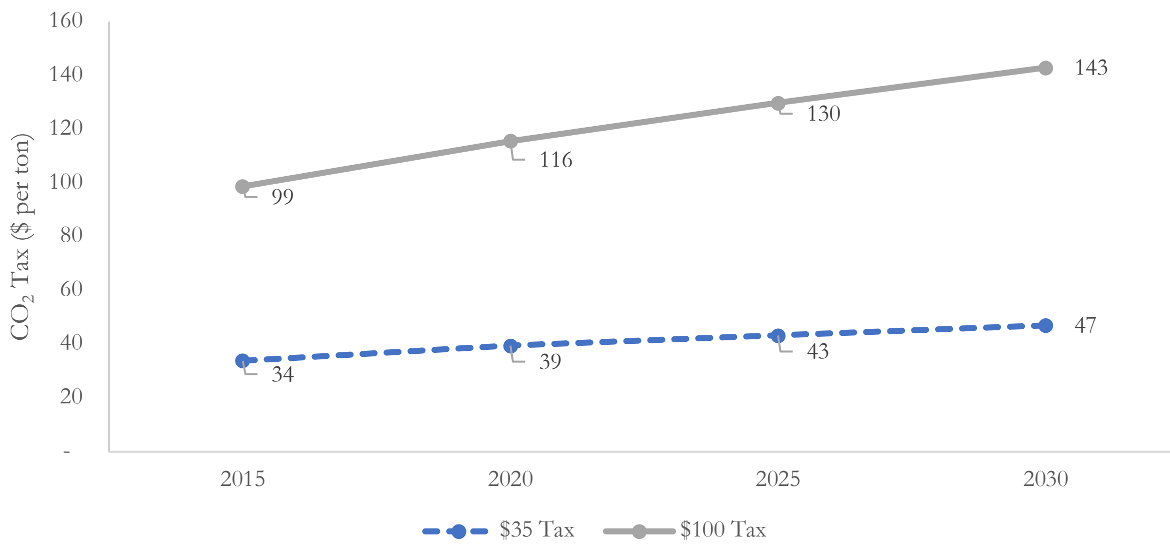

Figure B.1: Annual CO_2 tax rate values for the $35 and $100 CO_2 tax scenarios.

In addition to CO_2, TIMES also simulates the emissions of SO_2, NO_x, and $PM_{2.5}$ from the U.S. energy system. In our analysis, the TIMES model calculates the emissions of each air pollutant species under the BAU scenario as well as under our CO_2 tax scenarios. We calculate the damage resulting from the emissions of SO_2, NO_x, and $PM_{2.5}$ under the BAU, $35, and $100 CO_2 tax scenarios. In order to calculate damages, we use reduced complexity models (RCMs) entitled AP3, EASIUR, and InMAP in combination with other datasets from the EPA, the U.S. Census, and the Organization for Economic Co-operation and Development (OECD). The RCMs calculate the damage that results from the emission of one ton of a pollutant in each county throughout the U.S. In order to calculate a national average marginal social cost by pollutant for the entire U.S., we use the RCM county-level damage data in combination with data from the U.S. EPA National Emissions Inventory (NEI). The U.S. EPA NEI lists emissions from various sources by type and location. For the results presented in this paper, we use the NEI emissions inventory's energy-related emissions data and AP3 damage data to produce an emissions-weighted national per ton marginal social cost for SO_2, NO_x, and $PM_{2.5}$.

Over time, population in the U.S. is forecasted to increase, which implies that the marginal damage from emissions on a per ton basis will also increase. The U.S. Census provides population projections through 2060, and the OECD provides a GDP forecast for the U.S. through 2060 [107], [108]. From the population and GDP projections, we calculated the increase in per capita GDP in the U.S. through the end of our modeling horizon. We use this increase in population and per capita GDP over time to extrapolate the concurrent annual increase in damages per ton from SO_2, NO_x, and $PM_{2.5}$, which we illustrate in Figure B.2 below. To calculate total damage by pollutant in the U.S., we next multiply the total emissions of SO_2, NO_x, and $PM_{2.5}$ modeled in TIMES by the national damages outlined in Figure B.2.

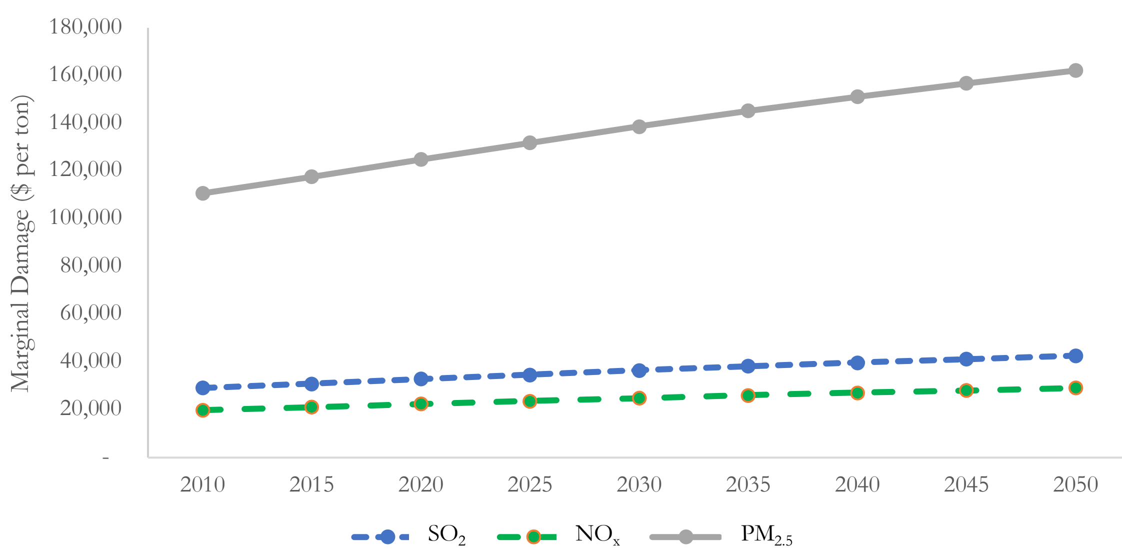

Figure B.2: National U.S. damage per ton of NO_x, SO_2, and $PM_{2.5}$ emitted, as derived from AP3.

B.2: Results

The \$35 and \$100 CO_2 taxes reduce CO_2 by 24% and 38% in 2030, respectively, compared to 2010 levels. In the BAU scenario, without a CO_2 tax, emissions decrease by only 6% in 2030 compared to 2010 levels. Decreases in BAU CO_2 emissions occur primarily in the electric sector. As illustrated in Figure B.3, which shows emissions under a $100 tax on CO_2, the majority of CO_2 reductions take place through the decarbonization of the electric sector, while other sectors' CO_2 emissions remain relatively constant from 2010-2030. In Figure B.4, we show that much of the decarbonization in the electric sector is a result of decreasing coal generation and increasing solar and wind generation. Coal and natural gas remain part of the electric system, however, much of the emissions from generation are abated with carbon capture and sequestration (CCS), as shown in Figure B.5.

In the $35 and $100 CO_2 tax scenarios, the present value of the 2010-2030 cumulative increases in cost of the energy system is $124 and $444 billion, respectively. The reduction in damages from CO_2, SO_2, or $PM_{2.5}$ alone, which we outline in Figure B.6, are enough to justify the $35 CO_2 tax policy from a cost-benefit perspective. Furthermore, cumulative reductions in NO_x damages are approximately half the value of the cost increase to the energy system from 2010-2030 under the $35 CO_2 tax.

As outlined in Table B.1, making a mistake and choosing a tax rate other than the true social cost of carbon will produce a deadweight loss. If damages from CO_2 emissions are $100 per ton and emissions are taxed at $35 per ton, there are $353 million in net benefits available that could be gained by taxing CO_2 at $100 per ton instead. Additionally, if damages from CO_2 emissions are $35 and emissions are taxed at $100 per ton, there are $94 billion in net benefits available that could be gained by taxing CO_2 at $35 per ton instead.

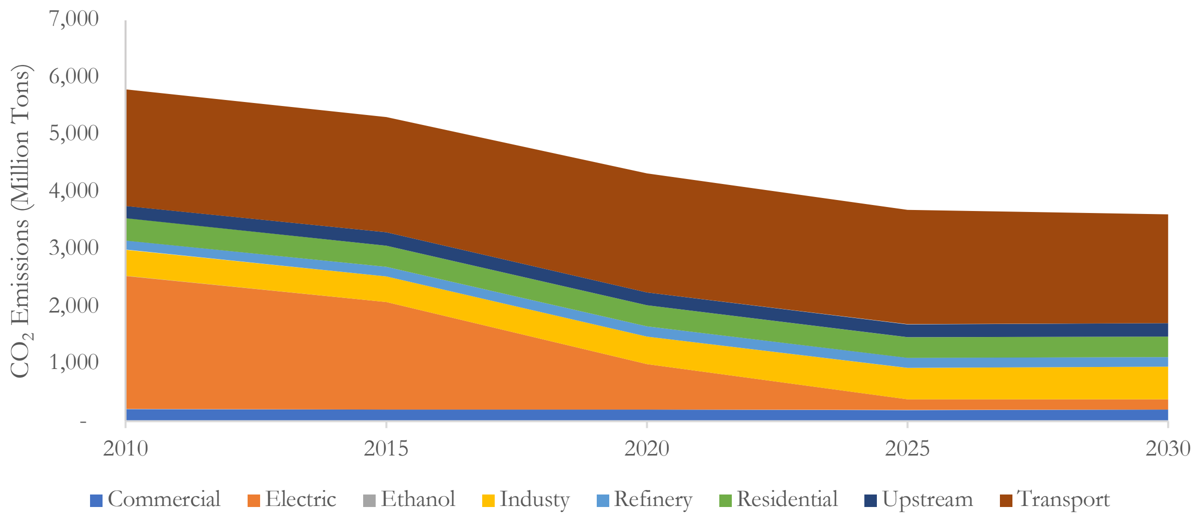

Figure B.3: U.S. CO_2 Emissions by Sector from 2010-2030 under a \$100 CO_2 tax.

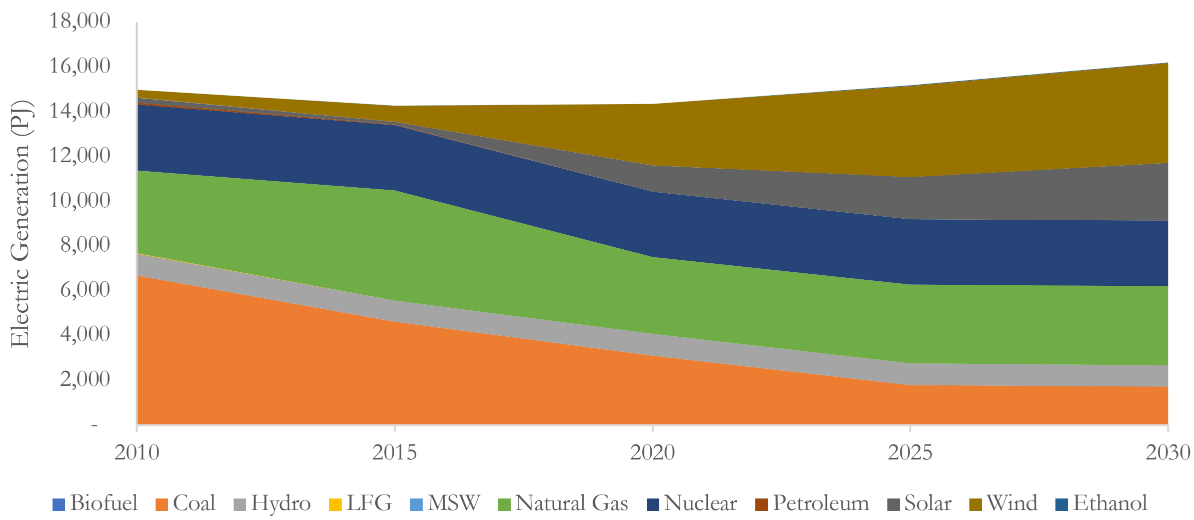

Figure B.4: Electric generation by source under a \$100 CO_2 tax from 2010-2030.

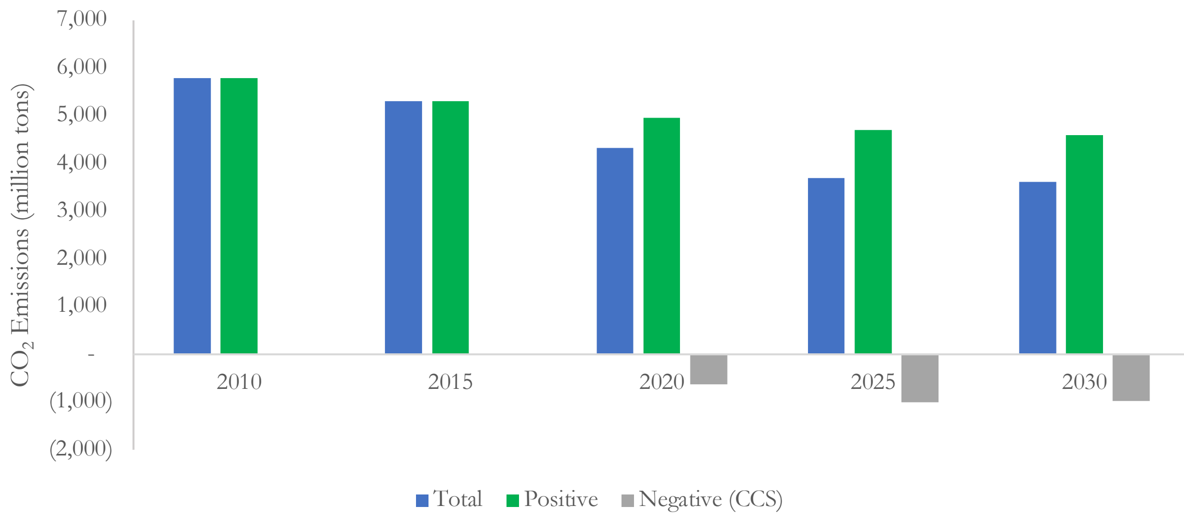

Figure B.5: Total net CO_2 emissions (blue), total emissions without CCS (orange), and abated CO_2 via CCS (grey) under a \$100 CO_2 tax.

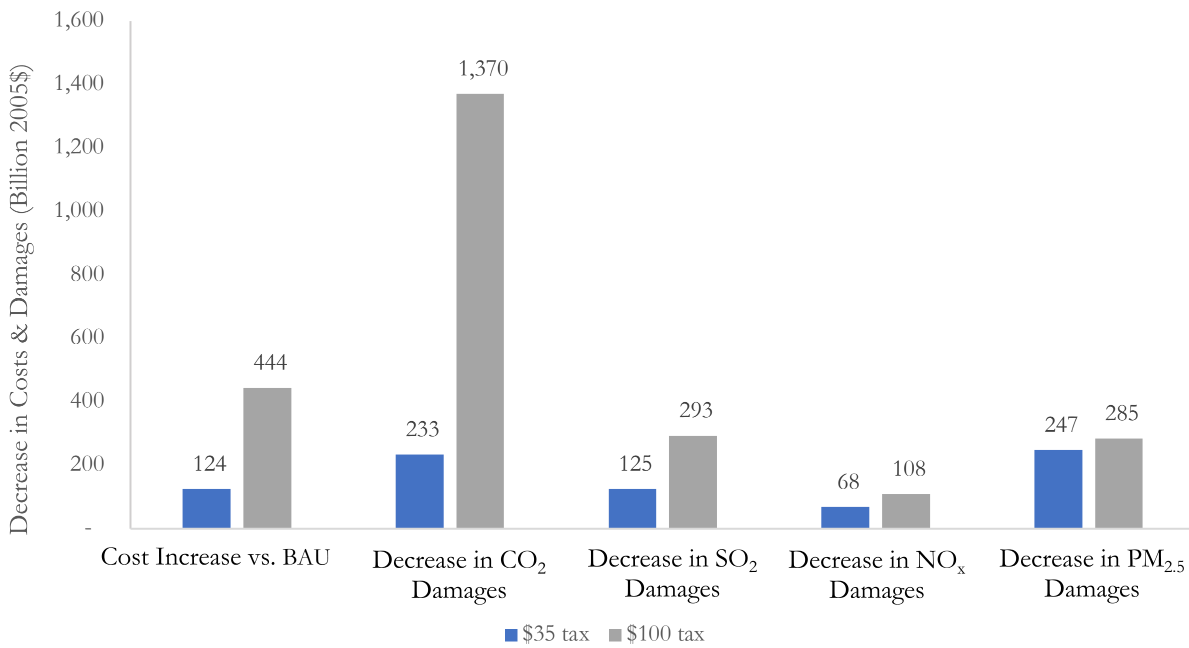

Figure B.6: 2010-2030 cumulative cost increase vs. BAU (left) and decrease in cumulative emissions (AP3) damages by species vs. BAU.

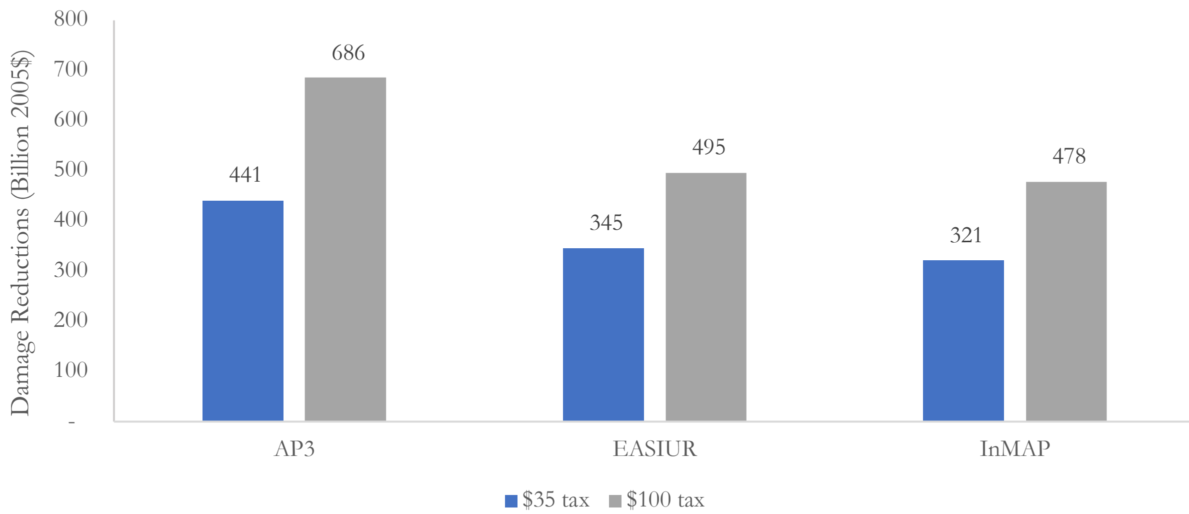

Figure B.7: Decrease in cumulative damages from SO_2, NO_x, and $PM_{2.5}$ emissions vs. BAU from 2010-2030, using marginal social costs from AP3, EASIUR, and InMAP.

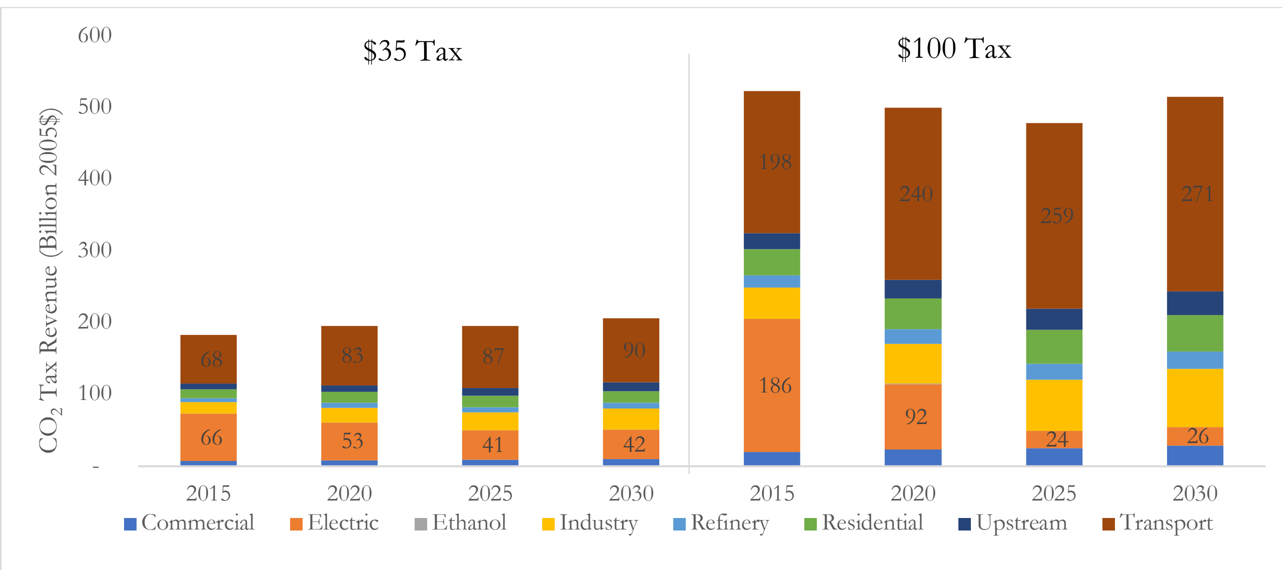

Figure B.8: Share of carbon tax revenue generated by sector under the \$35 CO_2 tax scenario (left) and \$100 CO_2 tax scenario (right).

Table B.1: CO_2 tax policy and the implications of picking the "wrong" tax and SCC combination.

CO_2 Policy	Social Cost of CO_2	Cost Inc. vs. BAU (billion 2005$)	CO_2 Reduction Benefits (billion 2005$)	Net Benefits (billion 2005$)
Tax $100	$100 SCC	$444	$1,370	$926
Tax $35	$100 SCC	$124	$697	$572
Difference				$353
CO_2 Policy	Social Cost of CO_2	Cost Inc. vs. BAU (billion 2005$)	CO_2 Reduction Benefits (billion 2005$)	Net Benefits (billion 2005$)
Tax $100	$35 SCC	$444	$460	$15
Tax $35	$35 SCC	$124	$234	$109
Difference				$94

Table B.2: $35 CO_2 tax scenario: CO_2 tax rate, system cost increase above BAU, CO_2 reduction benefits, and local air pollutant (LAP) reduction benefits.

$35 CO_2 Tax Scenario				
	CO_2 Tax	Cost Inc. vs. BAU	CO_2 Benefits	LAP Benefits
Year	$ per ton	Billion 2005$	Billion 2005$	Billion 2005$
2010	0			
2015	34	1.16	3.45	13.64
2020	39	10.62	21.39	37.53
2025	43	22.59	39.52	69.75
2030	47	25.61	48.62	81.61
Present Value		124.34	233.49	440.52

Table B.3: $100 CO_2 tax scenario: CO_2 tax rate, system cost increase above BAU, CO_2 reduction benefits, and local air pollutant (LAP) reduction benefits.

$100 CO_2 Tax Scenario				
	CO_2 Tax	Cost Inc. vs. BAU	CO_2 Benefits	LAP Benefits
Year	$ per ton	Billion 2005$	Billion 2005$	Billion 2005$
2010	0			
2015	99	7.03	22.14	29.48
2020	116	47.33	136.23	64.26
2025	130	73.26	227.30	94.09
2030	143	76.65	260.95	102.16
Present Value		444.42	1370.12	685.56

Appendix C : Supplemental Information for Chapter 4

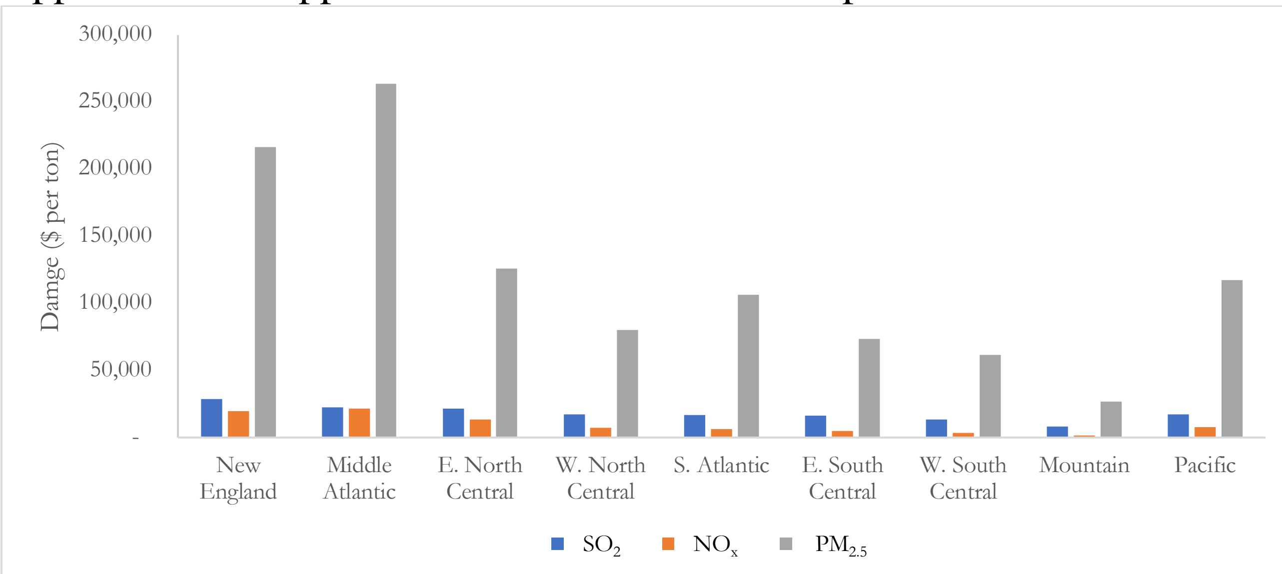

Figure C.1: 2015 EASIUR derived marginal emissions damages and per ton tax rate by region for SO_2, NO_x, and $PM_{2.5}$.

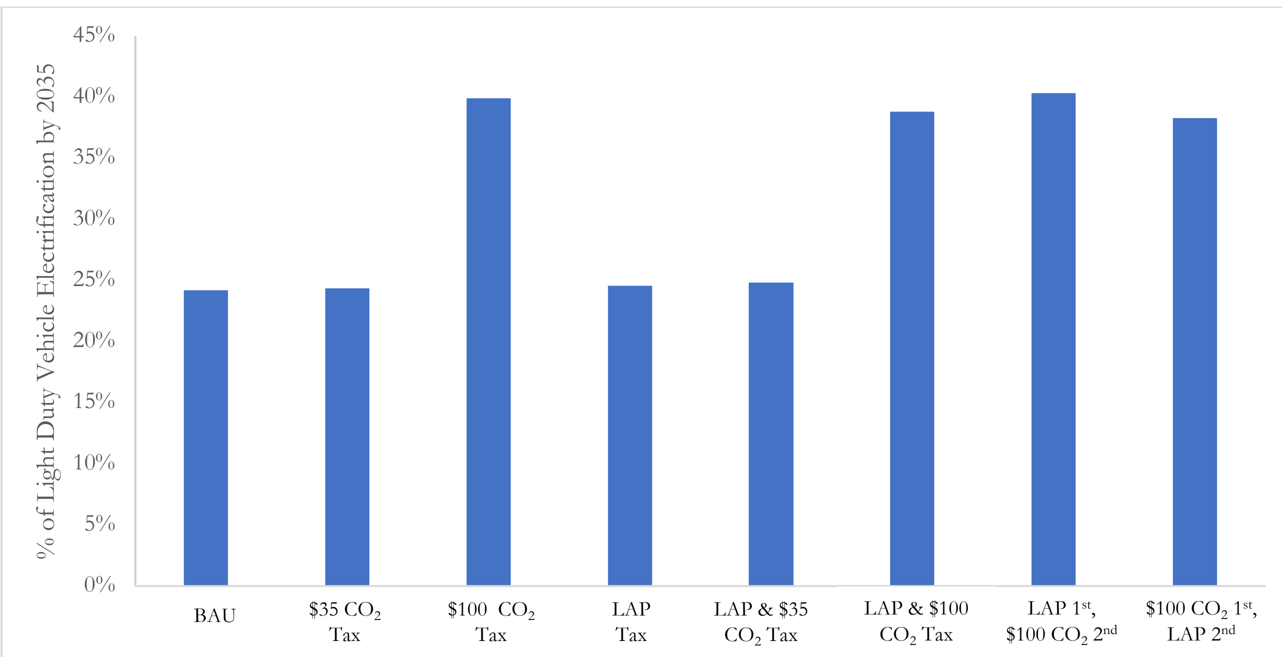

Figure C.2: Percentage of light-duty vehicle miles met by electric vehicles in 2035 across all scenarios.

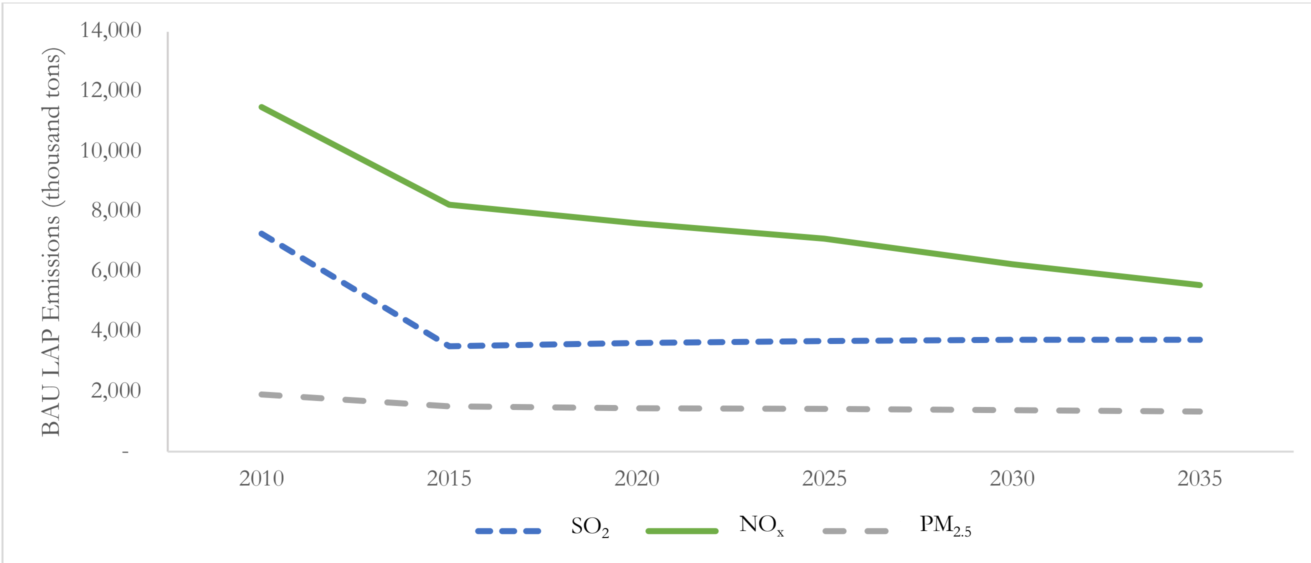

Figure C.3: SO_2, NO_x, and $PM_{2.5}$ emissions over time in the business as usual scenario.

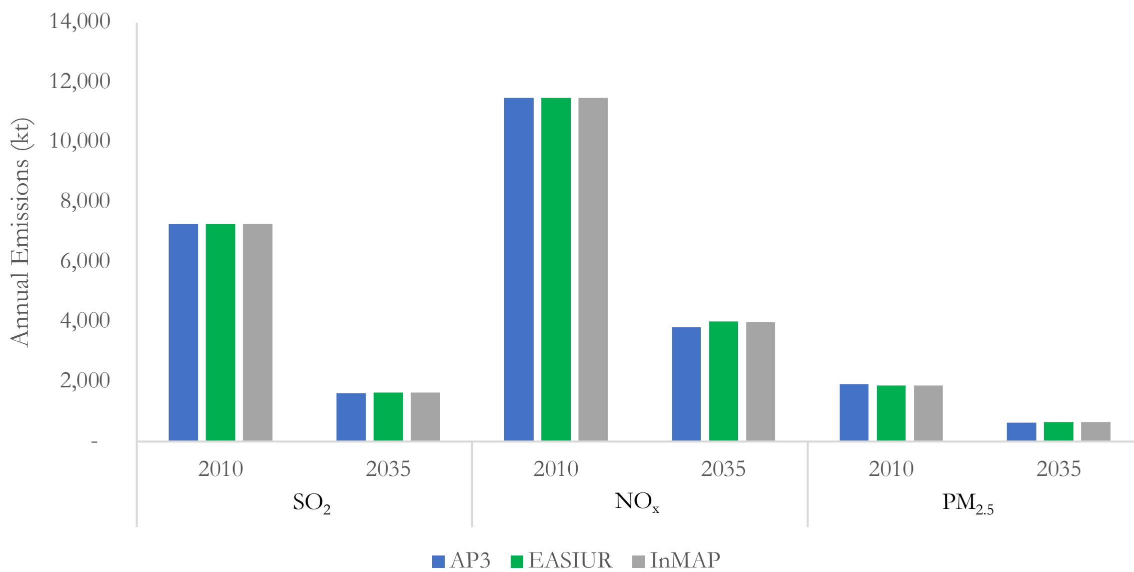

Figure C.4: Emissions of SO_2, NO_x, and $PM_{2.5}$ in 2010 and 2035 under AP3, EASIUR, and InMAP derived national LAP tax trajectories.

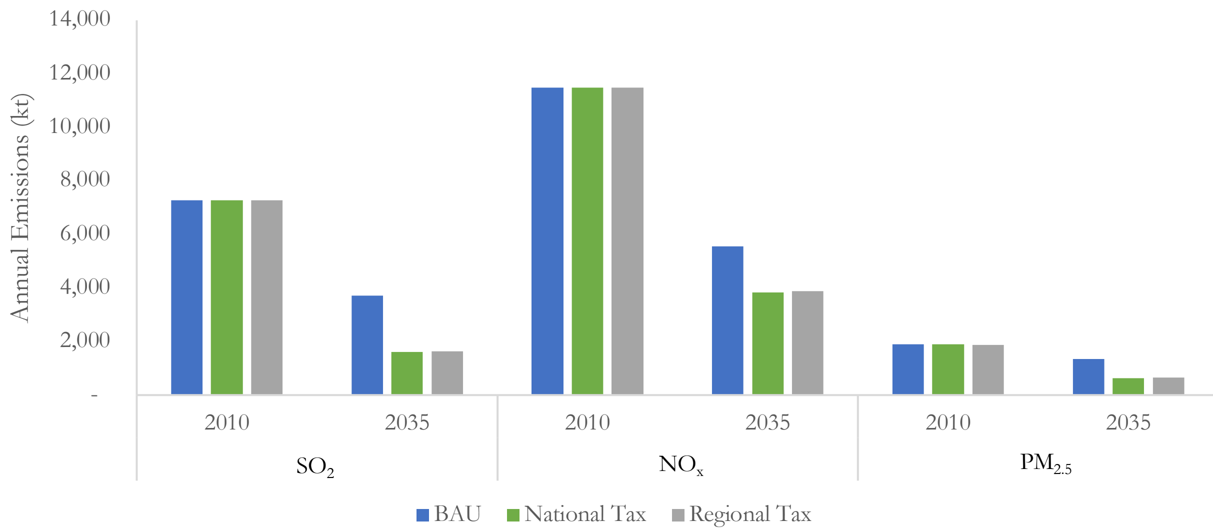

Figure C.5: Annual emissions of SO_2, NO_x, and $PM_{2.5}$ in 2010 and 2035 under BAU, a national tax, and a regional tax derived from AP3.

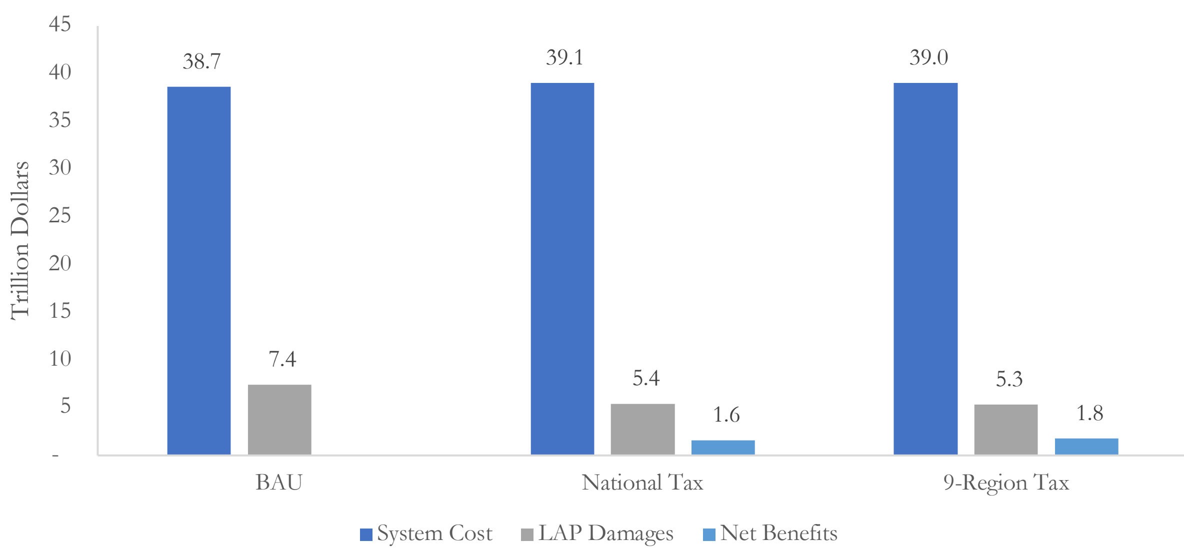

Figure C.6: Present value of cumulative system cost to meet energy demand (blue) and cumulative damage from LAP emissions (grey), net benefits (purple) from 2010-2035 using AP3 damages.

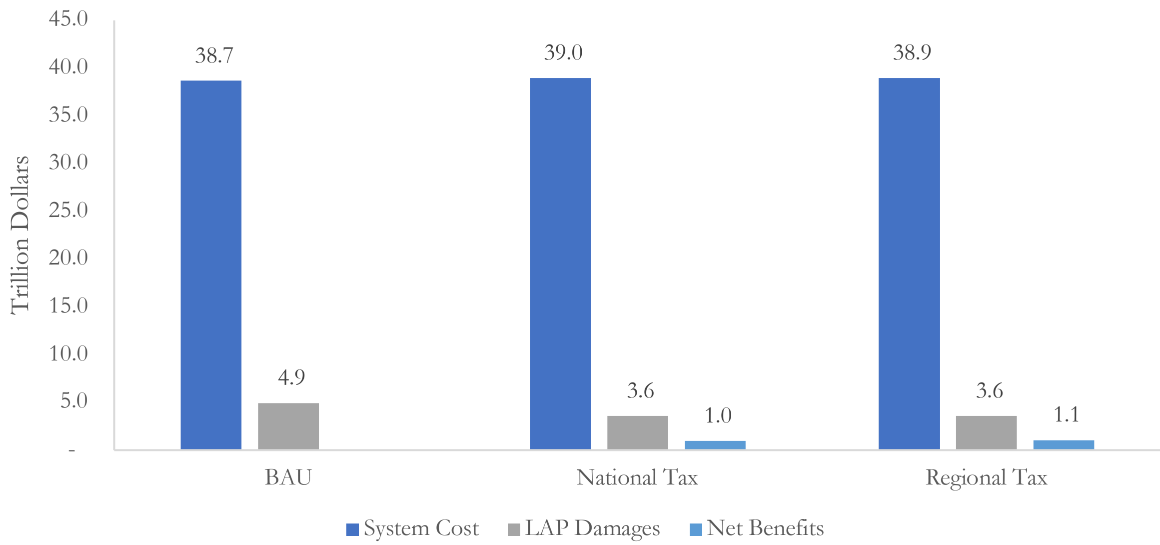

Figure C.7: Cumulative system cost to meet energy demand (blue), cumulative damage from LAP emissions (grey), net benefits (purple) from 2010-2035 using EASIUR damages and tax rates.

Table C.1: 2010 national damages by integrated assessment model and pollutant species in dollars per ton.

	NO_x	SO_2	$PM_{2.5}$
AP3	19,888	29,153	110,667
EASIUR	7,755	16,877	110,262
InMAP	10,300	18,147	93,189

Table C.2: Regional emissions of SO_2, NO_x, and $PM_{2.5}$ in 2035 under the AP3 uniform national tax and 9-region tax scenarios.

	SO_2 2035 kt		NO_x 2035 kt		$PM_{2.5}$ 2035 kt	
Region	National	9-region	National	9-region	National	9-region
New England	102	101	124	124	36	36
Middle Atlantic	253	233	429	381	67	64
E. North Central	344	330	564	534	109	106
W. North Central	220	223	373	387	69	71
South Atlantic	148	139	480	460	98	97
E. South Central	91	96	248	257	48	50
W. South Central	320	366	952	1,073	107	117
Mountain	66	80	361	406	35	42
Pacific	72	64	295	265	70	68
Total	1,616	1,632	3,826	3,888	640	651

Table C.3: kiloton difference between National and 9-region SO_2 emissions by region. Negative values indicate a decrease in emissions under 9-region tax policy.

Region	Commercial	Electric	Industrial	Refinery	Residential	Upstream	Transportation
New England	0	0	0	0	0	0	0
Middle Atlantic	0	0	0	-15	0	-5	0
E. North Central	0	0	-1	-10	0	-3	0
W. North Central	0	0	3	0	0	0	0
South Atlantic	0	0	0	-7	0	-3	0
E. South Central	0	0	6	0	0	0	0
W. South Central	0	0	1	30	0	12	4
Mountain	0	1	2	6	0	3	0
Pacific	0	0	-1	-5	0	-2	0

Table C.4: kiloton difference between National and 9-region NO_x emissions by region. Negative values indicate a decrease in emissions under 9-region tax policy.

Region	Commercial	Electric	Industrial	Refinery	Residential	Upstream	Transportation
New England	0	0	0	0	0	0	0
Middle Atlantic	0	0	-2	-18	0	-27	0
E. North Central	0	1	-1	-12	0	-16	-1
W. North Central	0	2	7	0	0	-1	6
South Atlantic	0	-2	4	-8	0	-13	0
E. South Central	0	0	6	0	0	-2	5
W. South Central	0	0	17	38	0	56	9
Mountain	0	1	8	8	0	14	14
Pacific	-1	-3	-6	-6	0	-14	0

Table C.5: kiloton difference between National and 9-region $PM_{2.5}$ emissions by region. Negative values indicate a decrease in emissions under 9-region tax policy.

Region	Commercial	Electric	Industrial	Refinery	Residential	Upstream	Transportation
New England	0	0	0	0	0	0	0
Middle Atlantic	0	0	0	-3	0	-1	0
E. North Central	0	0	0	-2	0	-1	0
W. North Central	0	0	1	0	0	1	0
South Atlantic	0	0	0	-1	0	-1	0
E. South Central	0	0	0	0	0	2	0
W. South Central	0	0	1	5	0	3	1
Mountain	0	1	1	1	0	5	0
Pacific	0	0	0	-1	0	-1	0

In 2035 there were only small differences in sectoral emissions by region when comparing the national and regional tax policy scenarios. For instance, when comparing the national tax and regional tax scenarios, regional emissions of SO_2 were the same in the commercial, electric, and residential sectors, and transportation sector emissions increased by only 4 kt in the West South Central region (see Table C.3). There were also some small changes in SO_2 emissions by region across scenarios in the refinery and upstream sectors. In the refinery sector, SO_2 emissions decreased under the regional scenario by between 5-15 kt in the Middle Atlantic, East North Central, South Atlantic, and Pacific regions. Additionally, refinery sector emissions increased by 6 kt in the Mountain region and 30 kt in West South Central region. NO_x emissions across the national and regional tax scenarios in 2035 were also similar across regions. In Table C.4, we illustrate the difference in regional NO_x emissions between the regional and national tax scenarios in 2035. As shown in Table C.4, the largest decreases in 2035 NO_x emissions occurred in the refinery sector in the Middle Atlantic and East North Central regions. There was an increase in NO_x emissions across scenarios of 38 kt in the West South Central region and 8 kt in the Mountain region. Regional $PM_{2.5}$ emissions differences in 2035 across the regional and national tax scenarios were smaller than the regional differences observed in NO_x and SO_2. In Table C.5, we show that across regions and scenarios that there was less than a 1 kt change in $PM_{2.5}$ emissions in the commercial, electric, industrial, residential, and transportation sectors. In any region, the refinery and upstream $PM_{2.5}$ emissions changed by less than 5 kt across tax scenarios. What we can take away from these data is that the small changes in emissions across the national and regional tax policies were mostly driven by changes in the refinery and upstream sectors. Additionally, the fact that there were only small modeled differences across regions by sector when comparing the national and regional tax scenarios suggests that there may be a relatively small increase in net-benefits in implementing a regional tax policy over a national tax policy.