

Power System Decarbonization: A Comparison Between Carbon Taxes and Forcing Coal Power Plant Retirements

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Abstract—The U.S. power system faces a 2035 decarbonization target, though the exact pathway to the target remains unclear. Policy instruments, like carbon taxes and forcing coal plants to retire through various mechanisms, could help achieve the target. It is critical to analyze and compare decarbonization policies as different policies lead to different costs, emissions pathways, and political challenges. In this paper, we explore the ramifications of adopting alternative decarbonization policies. We assume a particular carbon tax to be the benchmark policy and compare it to alternative carbon tax and forced coal retirement policies in terms of emissions and costs. We use a power system dispatch model that co-optimizes unit commitment, energy, and frequency regulation capacity to simulate system evolution over multiple years, including retirements and renewables/storage expansion, under each policy. Our case study highlights the trade-offs between policies. We find that, counter-intuitively, higher carbon taxes do not always achieve lower emissions due to the complexity of dispatch, resulting profits and retirements, and the addition of renewables/storage. In contrast, forced coal retirements result in lower power system costs but higher emissions than the benchmark policy, with a large range of possible outcomes across different retirement cases.

Index Terms—Carbon tax, decarbonization, economic dispatch, energy policy, power plant retirement.

I. INTRODUCTION

UNITED States power systems are experiencing transitions towards a cleaner future, with policy-makers pushing to accelerate this transition. The Biden administration set a 2035 electricity decarbonization target, a crucial step towards economy-wide net-zero emissions by 2050 [1], but the pathway to the target remains uncertain. Many scientists and economists have proposed carbon taxes as a policy tool, arguing that carbon taxes are the most cost-effective way to achieve emissions reductions in not only power systems but also various economic sectors [2], [3]. However, an economy-wide carbon tax

faces many political obstacles. Alternative policy tools are also being explored. Forcing coal plant retirements are one example; environmental policies that could, in practice, accelerate the retirement of coal power plants include carbon pollution standards on fossil power plants [4] as well as environmental regulations such as Mercury and Air Toxics Standards set by the U.S. Environmental Protection Agency (EPA). We refer to these policies by the name “forced coal retirements” hereafter. Inevitably, existing coal power plants would have to go through significant retrofits such as carbon capture or retire early to meet decarbonization targets as coal power plants are recognized as one of the largest emitting sources in the U.S. [5], [6].

In power systems, carbon taxes are usually applied on the generation side, meaning that power plant operators must pay for their carbon emissions. This would generally change the merit order of energy dispatch and cause fuel switching from coal to natural gas, and/or from fossil fuels to lower-emitting alternatives such as renewables. Furthermore, emissions paths towards decarbonization are also affected by the changes in the generation fleet. Under carbon taxes, fossil fuel plants face increased operation costs along with less energy production, which can lead to unprofitable operations and retirements.

On the other hand, forced coal retirements are more straightforward. The importance of coal retirements in achieving power system decarbonization is discussed in many studies. For example, [5] pointed out the necessity of retiring fossil fuel plants in the absence of substantial investments in carbon-capture technology or fuel switching. The author investigated the implications of establishing “retirement deadlines” for fossil fuel plants and found that about 15% of existing fossil-fuel plants in the U.S. would need to retire early to meet U.S. decarbonization targets. Inspired by this work, we wish to compare the power systems impacts of forced retirements to those of carbon taxes. Unfortunately, it is not clear how best to determine which coal power plants should retire and when. Therefore, it is important to understand the range of possible impacts of forced coal retirements on power systems. Overall, it is critical that policymakers have information on how power systems would respond to different policies as policies may increase costs, lead to different emissions pathways, and present political challenges.

In this paper, instead of finding an optimal carbon tax or retirement plan, we aim to better understand and compare the impacts of carbon taxes and forced coal retirements on emissions and

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costs of power systems. Specifically, we assess the performance of a benchmark decarbonization policy (i.e., a specific carbon tax) and investigate the differences in outcomes between the benchmark policy and alternative ones. Equivalently, we ask the question: “How much worse are the alternative policies when the benchmark one is unavailable?” To address this research question, we formulate a simulation model using iterative optimization over multiple years, and in each time step, we co-optimize unit commitment, energy, and frequency regulation capacity, with plant retirement decisions made based on net profit. We then evaluate the resulting emissions paths and costs for each policy. Rather than quantitative forecasts, we aim to obtain qualitative comparisons and insights into the trade-offs associated with different pathways towards decarbonization. Therefore, we use a generic test system, rather than trying to model a specific power system. Additionally, we recognize that renewable energy and energy storage are driving many recent developments in power systems. Renewable energy is becoming cost competitive and rapidly expanding, while storage could provide arbitrage and ancillary services. Report [7] shows that about 75% of installed battery storage in U.S. is providing frequency regulation. Hence our assessment also incorporates renewables expansion and incrementally increasing storage capacity for frequency regulation. We note that renewables and energy storage not only affect emissions but also have significant impacts on grid reliability, stability, and resilience, as described in [8].

A number of existing papers have studied the impacts of carbon taxes on power systems through simulation studies leveraging power systems optimization models. For example, [9], [10], [11] studied emissions, costs, and other market outcomes in power systems under different carbon taxes. Unlike our study, they focus on specific power systems and do not include a multi-year analysis of generator profits and retirements. Ref. [12], [13] included long-term analysis but focused on least-cost capacity expansion and investment decisions. More work has included carbon taxes in efforts to develop novel expansion planning models [14], [15] or dispatch models [16], or to evaluate the impacts of energy storage and renewable energy in power systems [17].

As for forced coal retirements, many prior works studied coal retirements via statistical methods [18], [19], or integrated assessment models [20], [21]. However, these models cannot capture the impacts of coal retirements on power system operations, or vice versa. Ref. [22] studied how renewables affect coal plants economics via market-equilibrium models. There are relatively fewer works that assessed the impacts of forced coal retirements through power systems optimization models. For example, [23] evaluated the interaction between coal retirements and wind penetration. Ref. [24] examined the changes in dispatch order considering several coal retirement scenarios. Some work includes coal retirements as part of their planning models [25], [26], [27].

In parallel to these efforts, some work compared the performance of carbon taxes and other policies that promote renewable energy in power systems [9], [28], or investigated the effectiveness of carbon taxes used with other complementary policies [29]. However, to our best knowledge, no work has

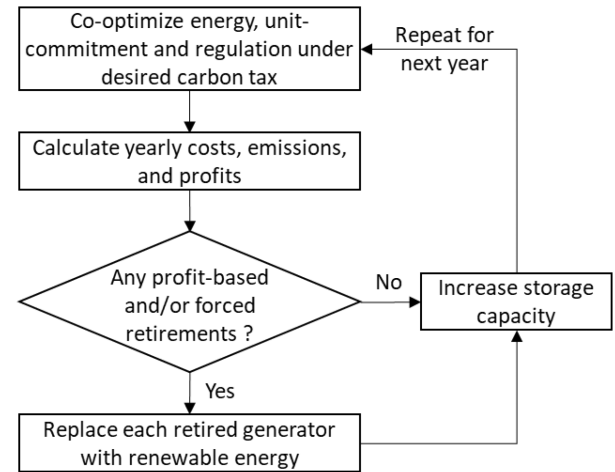


Fig. 1. Simulation of multi-year power system operation under carbon taxes or forced coal retirements.

investigated and compared the performance of carbon taxes and forced coal retirements.

In summary, this paper contributes to the existing literature by 1) providing a qualitative understanding of the impacts of two different decarbonization strategies; 2) providing a method of comparing these strategies in terms of emissions paths and cost outcomes in power systems via an optimization model capturing unit commitment, economic dispatch, and reserve (regulation) scheduling; and 3) providing a qualitative understanding of how decarbonization strategies and renewable/storage expansion interact and lead to long-term changes in the generation fleet.

The rest of the paper is organized as follows. Section II presents our methods including the policy scenarios, simulation model, and test system set-up. Section III presents the results including sensitivity analyses. Section IV concludes.

II. METHODS

In this section, we present our methods to investigate the outcomes of carbon taxes and forced coal retirements in power systems. Our approach leverages the framework developed in our prior work [30], which allows us to simulate the operation of a power system over multiple years. We summarize the steps of this simulation process in Fig. 1. We first use an optimization model to co-optimize energy dispatch, unit commitment, and frequency regulation capacity under the desired carbon tax, if applicable. The model is run for four representative hours in a year, representing different typical load levels in each of the four seasons. The seasonal results are used to calculate yearly costs, emissions, and profits, and retirement decisions are made based on profits and forced retirement plans at the end of each year. Following any retirement, we add renewable energy to replace each retired generator. Then, we increase energy storage capacity and repeat the simulation for next year. After running the simulation for 11 years, we evaluate the effects of each policy. The following subsections describe the policy scenarios, simulation approach, and test system set-up.

TABLE I
POLICY SCENARIOS

policies	carbon tax	forced coal retirements
no-policy	\$0/ton	no
benchmark	\$50/ton	no
alternative - low tax	\$10/ton	no
alternative - high tax	\$100/ton	no
alternative - forced retirements	no	yes

A. Policy Scenarios

We designed a total of five policy scenarios, consisting of a no-policy scenario, three different carbon tax scenarios (benchmark, low tax, and high tax) and one forced coal retirement scenario, which contains a large set of cases. These scenarios are listed in Table I. Scenarios combining both policies are included as sensitivity analysis.

We assume that a carbon tax of \$50/ton is the benchmark policy. Estimates of the social cost of carbon in the literature range from a few dollars to hundreds of dollars per ton [31], [32], [33]. We note that \$50/ton may not be the optimal carbon tax, and that the U.S. government is likely to adopt a higher estimate in the near future [34]. However, this is not a problem for our analysis; our goal is not to prove this is optimal or to quantitatively explore how the optimal tax affects dispatch, but to qualitatively analyze the differences in outcomes between the benchmark and alternative policies. The range of carbon taxes considered in our scenarios approximately matches the range in existing carbon pricing systems [35].

In practice, the decision to retire a coal plant is often a function of its age (amongst other factors). However, here, we use a test network with stylized generators (described in Section II-C) for which we do not have generator age information. Therefore, we enumerate a large set of retirement cases, in which each coal generator is forced to retire in each simulation year. This allows us to understand the range of outcomes resulting from all possible forced coal retirements plans. Our model does not include non-operational factors that affect coal retirements, such as decommissioning costs and social costs, because they do not affect the dispatch of the system. We refer readers to [5], [36] for more discussion and analysis of other costs and social factors related to coal retirements.

B. Power System Simulation

1) *Optimization Model:* To simulate power system operations, we use a single-period optimization model, which is an extension of the model first developed in [37] and extended in [30]. The model determines energy dispatch, unit commitment, and regulation capacities for four representative hours in a year, over 11 years. Here, we have extended the optimization model to include carbon taxes and forced coal retirements.

U.S. Independent System Operators (ISOs) typically co-optimize energy dispatch, unit commitment, and ancillary services that ensure system reliability [38], [39]. Frequency regulation is one of many ancillary services. It is used to correct both deviations in system frequency resulting from supply-demand

mismatch and deviations in inter-area tie line flows. While frequency regulation is not always included in the co-optimization problem, a generator's ability to provide frequency regulation is affected by its dispatch level and vice versa [40], and so generators must make offering decisions that take into account these interdependencies. Instead of modeling these offering decisions, we simply assume frequency regulation is co-optimized by the ISOs, which is consistent with assuming the generators' offers are optimal. It is important to capture this as energy storage providing frequency regulation affects generator dispatch and unit commitment [30].

Additionally, including unit commitment in the formulation enables a better representation of individual unit operations. Though we do not include multi-period unit commitment constraints such as ramp limits and minimum up/down time since we use only a single-period optimization formulation, we do model generators' minimum output limits, which can greatly affect a generator's operation especially when it participates in both the energy and ancillary services markets [41]. Subsequently, unit commitment constraints can have significant effects on system prices, generator profits, and retirements.

The optimization formulation, a mixed-integer quadratic program (MIQP), is as follows.

$$\begin{aligned} \underset{x}{\text{minimize}} \quad & \sum_{g \in \mathcal{G}} \left((\alpha_g p_g^2 + \beta_g p_g + \gamma_g u_g) (C_g^f + E_g T) \right. \\ & \left. + C_g^{\text{vm}} p_g + C_g^r r_g \right) + \sum_{s \in \mathcal{S}} C_s^r r_s \end{aligned} \quad (1)$$

$$\text{s.t.} \quad \sum_{g \in \mathcal{G}_i} p_g - D_i - \sum_{s \in \mathcal{S}_i} p_s^{\text{load}} = \sum_{j \in \mathcal{I}} p_{i,j}^f \quad \forall i \in \mathcal{I} \quad (2)$$

$$p_{i,j}^f = B_{i,j}(\theta_i - \theta_j) \quad \forall (i,j) \in \mathcal{L} \quad (3)$$

$$p_g + r_g \leq P_g^{\text{max}} u_g \quad \forall g \in \mathcal{G} \quad (4)$$

$$p_g - r_g \geq P_g^{\text{min}} u_g \quad \forall g \in \mathcal{G} \quad (5)$$

$$0 \leq r_g \leq R_g^{\text{max}} u_g \quad \forall g \in \mathcal{G} \quad (6)$$

$$0 \leq r_s \leq R_s^{\text{max}} \quad \forall s \in \mathcal{S} \quad (7)$$

$$\sum_{s \in \mathcal{S}} r_s + \sum_{g \in \mathcal{G}} r_g \geq R^{\text{req}} \quad (8)$$

$$p_s^{\text{load}} = \delta_s r_s \quad \forall s \in \mathcal{S} \quad (9)$$

$$-P_{i,j}^{\text{f,max}} \leq p_{i,j}^f \leq P_{i,j}^{\text{f,max}} \quad \forall (i,j) \in \mathcal{L} \quad (10)$$

$$\theta_i = 0 \quad \forall i = \text{ref} \quad (11)$$

$$u_g : \text{binary} \quad \forall g \in \mathcal{G} \quad (12)$$

$$u_g = 0 \quad \forall g \in \mathcal{G}^{\text{retire}}, \quad (13)$$

where the decision variables that comprise x are the power output p_g of all generators $g \in \mathcal{G}$, the regulation capacities $r_g \forall g \in \mathcal{G}$ and r_s for all energy storage units $s \in \mathcal{S}$, the unit commitment status $u_g \in \{0, 1\} \forall g \in \mathcal{G}$, the storage-induced load $p_s^{\text{load}} \forall s$, the voltage angles θ_i for all buses $i \in \mathcal{I}$, and the power flows $p_{i,j}^f$ for all lines $(i,j) \in \mathcal{L}$.

The objective function (1) sums the generation and regulation costs. The generation costs include fuel costs, carbon emissions costs, and variable operation and maintenance (O&M) costs. We assume heat rate curves are quadratic with coefficients α_g, β_g and γ_g for each generator g . We multiply γ_g by u_g to ensure there are no fuel or emissions cost when a generator is not committed. Fuel costs are obtained by multiplying the fuel price C_g^f by the heat rate curve. Emissions costs are obtained by multiplying the carbon emissions rate E_g by the carbon tax T and the heat rate curve. The variable O&M costs are assumed to be linear with respect to generation, with unit cost C_g^{vm} . Likewise, regulation costs for both generators and energy storage units are assumed to be linear with respect to regulation capacities, with unit cost C_g^r and C_s^r , respectively. Though carbon emissions can change when generators provide regulation, we do not model these changes in emission/costs.

Constraint (2) enforces power balance, where D_i is the demand at bus i , $\mathcal{G}_i$ is the set of generators at bus i , and $\mathcal{S}_i$ is the set of energy storage units at bus i . Constraint (3) is the DC power flow equation, where $B_{i,j}$ is the i, j -th entry of the susceptance matrix. Constraints (4) and (5) enforce maximum P_g^{max} and minimum P_g^{min} generation limits. We assume regulation procurement is symmetric, i.e., a generator must be able to provide the same amount of up and down regulation capacity. Constraints (6) and (7) limit generators and energy storage units to provide regulation below their maximum regulation capacity R_g^{max} and R_s^{max} , respectively. Constraint (8) ensures the system's regulation requirement R^{req} is fulfilled. Constraint (9) models energy storage inefficiency losses as a storage-induced load. As in [42], we assume losses increase linearly with regulation capacity, with coefficient δ_s . We do not model the state of charge of energy storage units because we assume that the regulation signal is approximately energy neutral and storage-induced losses are compensated by generation. This means that, in each hour, the state of charge starts and ends at approximately the same value (e.g., half-full). Constraint (10) limits power flows below their maximum levels $P_{i,j}^{\text{f,max}}$. Constraint (11) sets the voltage angle at the reference bus to zero. Constraint (12) requires that the unit commitment variables be binary. Constraint (13) sets the unit commitment statuses of retiring generators to be zero, where $\mathcal{G}^{\text{retire}}$ is the subset of generators that are forced to retire and/or retire because of negative profits.

2) *Yearly Costs, Emissions, and Profits:* At the end of each year, we use the results of the four optimization model runs to compute the costs, emissions, and profits. Each generator's yearly profits are calculated using the dispatch results and resulting energy and regulation prices.

For each generator g at bus i , its hourly operation costs are $y_g^{\text{op}} = (\alpha_g p_g^2 + \beta_g p_g + \gamma_g u_g) C_g^f + C_g^{\text{vm}} p_g + C_g^r r_g$, its hourly carbon emissions are $y_g^{\text{em}} = (\alpha_g p_g^2 + \beta_g p_g + \gamma_g u_g) E_g$, its hourly carbon tax payments are $y_g^{\text{ct}} = y_g^{\text{em}} T$, and its hourly revenue is $y_g^{\text{rv}} = \pi_i^e p_g + \pi^r r_g$, where π_i^e is the energy price at bus i and π^r is the regulation price, which are the shadow prices (Lagrange multipliers) of the nodal power balance constraints (2) and regulation requirement constraint (8), respectively. Because shadow prices are not well-defined for MIQPs, the prices are

obtained by fixing the binary variables to their optimal values and solving the resulting quadratic program [43]. The hourly operational profit of generator g is $y_g^{\text{pt}} = y_g^{\text{rv}} - y_g^{\text{op}} - y_g^{\text{ct}}$.

Seasonal generator costs, emissions, and operational profits are computed by multiplying the results from the representative hour for a particular season by the number of hours in a season (2190). Then, the yearly results are the summation of the four seasonal results. A generator's yearly overall profit is its yearly operational profit minus its fixed yearly O&M costs C_g^{fm} . System-wide operation costs, emissions, carbon tax payments, and profits are computed by summing the results across all generators. Total system costs are the sum of the system-wide operation costs and carbon tax payments.

3) *Retirements:* We retire generators only at the end of each year. Profit-based retirements occur when a generator's overall profit becomes negative. However, we allow only one profit-based retirement each year; when multiple generators become unprofitable we retire the most unprofitable one. We explored retiring more than one generator per year, but this does not significantly affect the overall findings of our paper, so we do not include those results here. Forced retirement decisions are based on the retirement case; rather than making them a function of the outputs of the simulation, we explore all possible cases.

4) *Adding Renewables and Storage Capacity:* We assume all new generation is renewable generation because renewables represent the majority of generation expansion [44]. There is no renewable energy at the beginning of the simulation, but we add renewable energy (e.g., wind or solar) in place of retired generators to ensure that there is enough energy capacity to meet demand. Specifically, we add sufficient renewable energy to match its expected generation (i.e., physical capacity times capacity factor) with the capacity of the retired generators. For example, if a 50 MW generator retires, we add 150 MW of wind capacity assuming a 33% capacity factor. We model renewables as dispatchable generators, where P^{max} is set to its expected generation, $P^{\text{min}} = 0$, and $E_g = 0$. We assume renewable generators can provide both energy and regulation capacity. When providing regulation capacity, renewables are dispatched below their expected generation to enable increases in generation in response to regulation signals. Although upfront renewable energy costs, such as investment and installation costs, affect installed renewable capacity, we do not include them in our framework since they do not affect power system operations. Finally, we add energy storage capacity at the end of each year, with details described in Section II-C.

We acknowledge that the four representative hours do not fully capture renewable intermittency and its impacts on renewable expansion and system reliability. Therefore, we performed additional simulations over a year (8,760 h), with a load profile varying in approximately the same range. Renewables are still added based on a 30% average capacity factor, but they are dispatched with hourly capacity factor ranges of approximately 10% to 60%. These supplementary results, provided in a Github repository [45], show that load curtailment up to 1.8% of total load is necessary in certain hours (in practice, this could be mitigated with demand response or energy storage [46]). However, the overall findings and conclusions for the four hour and 8,760 h

TABLE II
INDIVIDUAL GENERATOR PARAMETERS

Gen	Bus	$P^{\max}$ MW	$P^{\min}$ MW	a MMBtu MW ²	b MMBtu MW	c MMBtu	C_s^{fm} \$/ MW-yr
Coal1	1	55	8	0.054	7.23	84.50	4500
Coal2	1	55	17	0.025	8.50	70.35	5000
Coal3	1	70	18	0.015	8.90	74.02	5000
Coal4	2	70	16	0.036	7.55	55.21	5000
Coal5	3	80	39	0.009	6.85	120.87	6000
Coal6	2	90	38	0.000	8.40	75.98	7000
CC1	2	45	19	0.076	4.15	88.30	800
CC2	3	50	27	0.002	6.30	110.47	1000
CC3	2	75	41	0.011	5.43	110.90	1500
CT1	1	35	30	0.000	9.61	-0.79	800
CT2	1	35	29	0.000	9.59	1.35	800
CT3	2	35	31	0.000	8.44	5.53	800
CT4	3	40	12	0.000	10.70	-13.64	800
CT5	3	40	12	0.000	7.58	60.22	800
CT6	2	55	25	0.000	9.86	2.01	700
Oil	2	20	15	0.000	5.87	72.06	0

TABLE III
GENERATOR TYPE-SPECIFIC PARAMETERS

Type	C^{f} \$/ MMBtu	$R^{\max}$ %/P ^{max}	C^{r} \$/ MW	C^{vm} \$/ MWh	E ton MMBtu
Coal	3	2	10	4	0.095
CC	4	5	6	2	0.053
CT	4	8	4	1	0.053
Oil	10	8	4	1	0.073
RE	0	6	1	0	0

simulations are qualitatively similar. Therefore, for the sake of clarity and ease of interpretation, we present results only from the four hour simulation in this paper.

5) *Scenario Evaluation*: We evaluate the performance of each policy scenario at the end of an 11-year simulation by analyzing the resulting emissions, power system operation costs, and carbon tax payments. We investigate two emissions metrics: 11-year cumulative emissions and emissions at the end of year 11.

C. Test System Set-up

We use the modified IEEE 9-bus system we used in prior work [30]. The line limits are raised to 1000 MW to avoid transmission congestion. Therefore, the energy prices are the same system-wide. The seasonal system loads are 500, 750, 600, and 700 MW each year; we assume the load consumption is inelastic with respect to changes in electricity prices and does not change year to year to better isolate the effects of policies. To capture the impacts of renewable generation on regulation capacity needs, the system regulation requirement R^{req} is set to 3% of expected renewable generation plus 5% of system load [47].

The generators used in our test system are picked to resemble the generation mix in PJM. Initially, there are 6 coal, 3 natural gas combined cycle (CC), 6 natural gas combustion turbine (CT), and 1 oil generator, with a total of 850 MW power capacity. The generators' bus location, upper and lower generation limits, heat rate characteristics, and yearly fixed O&M costs are listed in Table II. The heat rate curves are based on real data obtained from the EPA CEMS database [48]. Generator type-specific parameters, including those for added renewables (RE), are listed in Table III. We estimated the fuel prices and emission rates based on [49], regulation costs based on [50], and O&M costs based on [51]. Since we have 6 coal generators, we consider a total of 60 cases in the forced coal retirement scenario (we do not force them to retire at the end of the last year).

We add one energy storage (ES) resource to bus 7. Energy storage capacity is set to a percentage of the system regulation

requirement R^{req} (which increases with expected renewable generation, as described above), and we increase the percentage by 5% each year, i.e., in year 10 energy storage capacity is 50% of R^{req} . In Section III-C1, we perform a sensitivity analysis on the energy storage capacity increase rate. We set its regulation cost C_s^{r} to 1 \$/MW and its loss parameter δ_s to 0.038 based on [42].

III. RESULTS

In this section, we first present the results of the benchmark carbon tax scenario to explain how emissions outcomes are affected by the carbon tax. We then compare the emissions, dispatch, cost, and retirement results of the benchmark carbon tax scenario and other policy scenarios, in order to understand the trade-offs between the benchmark and alternative policies. Finally, we describe the results of a number of sensitivity analyses. Our input data, code, and full results are available on GitHub [45].

A. Results of the Benchmark Carbon Tax

Fig. 2 displays the yearly emissions, generation, and regulation capacity from each type of generator under each carbon tax scenario. Comparing the top row (\$0/ton, no policy) to the third row (\$50/ton), we can assess the impact of the benchmark carbon tax. The benchmark carbon tax leads to a significant reduction in emissions over the 11 years, with a reduction of over 89% by the end of year 10 compared to year 0 emissions. Three main changes in the system contribute to the emissions reduction. First, the \$50/ton carbon tax makes coal generators the most expensive generation resource. Together with their high regulation costs, coal generators become less profitable or unprofitable. As a result, coal retirements begin at the end of year 0 and all six coal generators retire in the first six years. Second, the entrance of low-cost renewables into the market not only makes up for generation from retired coal generators but also displaces some generation from gas generators. This, in turn, drives down the prices of both energy and regulation, causing five natural gas generators to retire over the remaining five years. Third, growing energy storage capacity enables the system to fulfill its increasing regulation requirement (due to growing renewables) without relying on fossil-fuel generators. As a result, natural gas generators, which were previously the main source of regulation capacity, are replaced in the ancillary services market by energy storage.

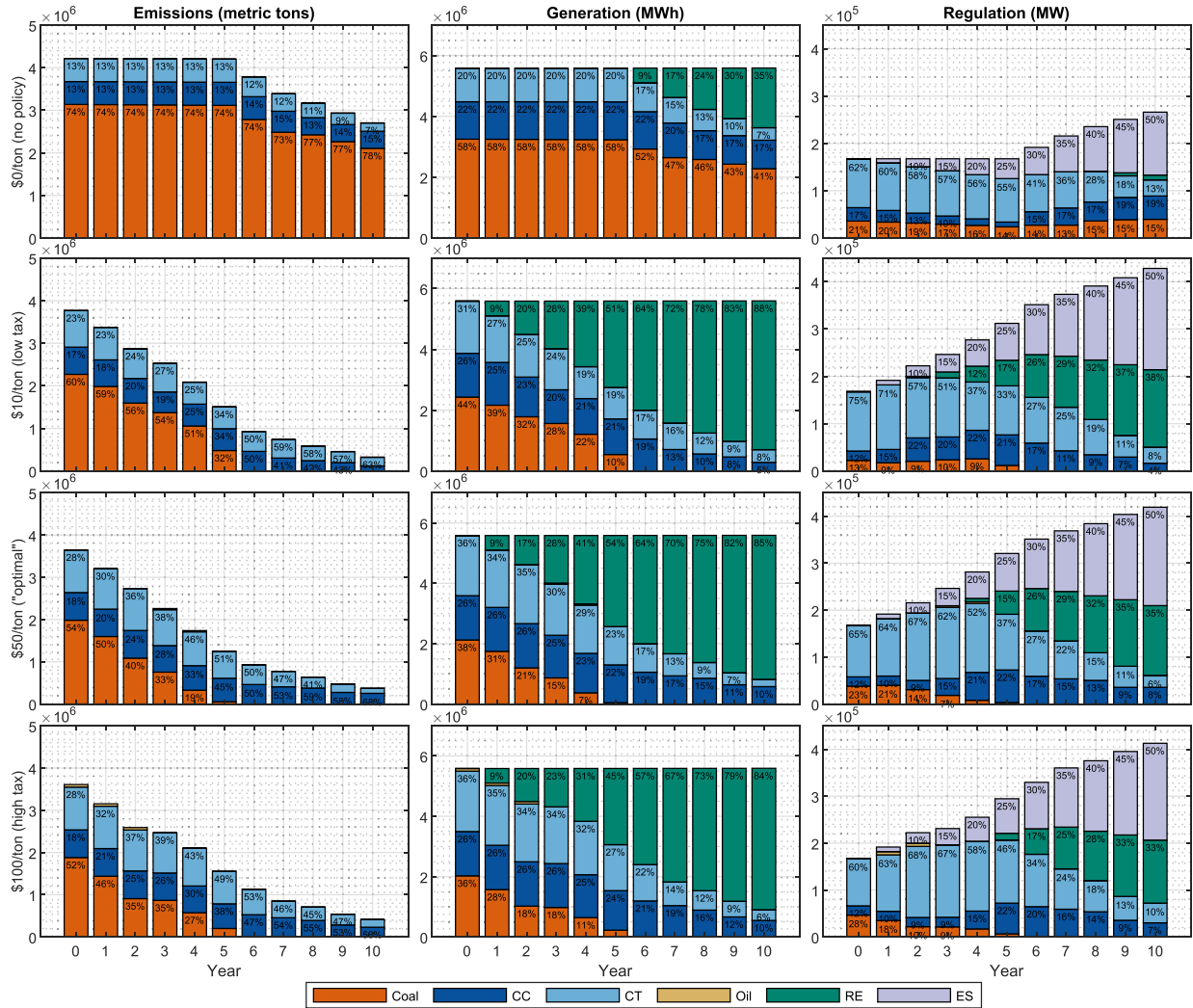


Fig. 2. Yearly system emissions, generation, and regulation capacity from each type of generator under carbon taxes.

B. How Much Worse are the Alternative Policies?

1) *Outcomes of the Alternative Carbon Taxes:* Fig. 2 also shows the results of the low carbon tax (\$10/ton, second row) and the high carbon tax (\$100/ton, fourth row) policy scenarios. All three non-zero carbon taxes lead to significant emissions reductions, with similar fuel switching from coal to natural gas and renewables, and similar growth in the system regulation requirement due to growing renewables. The generation shift from coal to natural gas is faster with higher carbon taxes, but by year 10, the results of all of the carbon tax scenarios are similar, with around 85% of generation by renewables. Across all scenarios, most renewable generation is used; the highest yearly curtailment is only 6%.

Fig. 3 explores the yearly system emissions. Specifically, Fig. 3(a) shows the emission paths associated with each carbon tax, Fig. 3(b) shows emissions versus system operation costs, Fig. 3(c) shows emissions versus carbon tax payments, and Fig. 3(d) shows emissions versus total system costs, where the grey lines connect points associated with the same year for easy comparison. Table IV further summarizes the cumulative

TABLE IV
CUMULATIVE (AVERAGE YEARLY) COSTS, PAYMENTS, AND EMISSIONS, ALONG WITH EMISSIONS AT THE END OF YEAR 10, UNDER CARBON TAXES

	System operation costs	Carbon tax payments	System emissions	Emissions at end of year 10
	10 ⁸ \$		10 ⁶ metric ton	
\$0/ton	19.33 (1.76)	0.00 (0.00)	41.20 (3.70)	2.70
\$10/ton	11.43 (1.04)	1.92 (0.17)	19.20 (1.70)	0.32
\$50/ton	11.80 (1.07)	9.01 (0.82)	18.00 (1.60)	0.37
\$100/ton	12.65 (1.15)	19.11 (1.74)	19.10 (1.70)	0.41

and average yearly operation costs, carbon tax payments, and emissions, and the emissions at the end of the simulation horizon (i.e., at the end of year 10).

Fig. 3(a) shows that overall the emissions paths under the benchmark and alternative non-zero carbon taxes are similar. This is a result of similar retirements. Table V gives the sequence of generator retirements in each carbon tax scenario. In our test system, all three carbon taxes raise coal generation costs enough

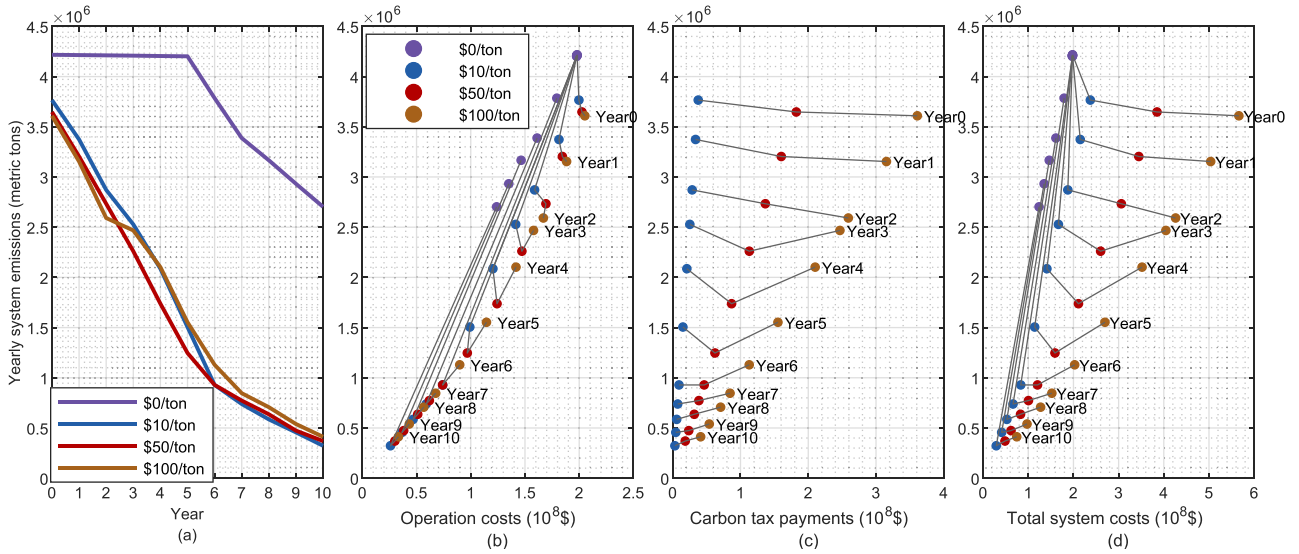


Fig. 3. Yearly system emissions (a) per year, (b) per operation costs, (c) per carbon tax payments, and (d) per total system costs under carbon taxes.

TABLE V
SEQUENCE OF GENERATOR RETIREMENTS UNDER EACH CARBON TAX SCENARIO

Year	0	1	2	3	4	5	6	7	8	9	10
\$0/ton						Coal1	CT6	CC1	CT2	CT1	Coal2
\$10/ton	Coal1	Coal3	Coal2	Coal4	Coal5	Coal6	CC2	CT5	CT4	CC1	CT3
\$50/ton	Coal1	Coal2	Coal4	Coal5	Coal6	Coal3	CT5	CT2	CC1	CT1	CC3
\$100/ton	Coal2	Coal3	Oil	Coal1	Coal6	Coal5	Coal4	CT1	CC1	CT4	CT6

to cause a profit-based coal generator retirement at the end of year 0, all coal generators to retire over the next five to six years, and retirements of natural gas generators in the remaining years. However, the generators retire in slightly different orders. In contrast, in the no-policy scenario, the growing energy storage capacity is used to gradually replace regulation provided by fossil-fuel generators, which also changes energy dispatch. As a result, several generators experience reductions in profit and, eventually, Coal1 retires at the end of year 5. This can also be seen in the top row of Fig. 2; there is little emissions reduction until year 6. Without a carbon tax, some natural gas generators retire before coal generators.

Fig. 3(a) also shows some counter-intuitive results. It is expected that higher carbon taxes lead to more emissions reductions, which is consistent with our results from year 0 to year 2. However, after year 4, the high-tax scenario (\$100/ton) has the highest yearly emissions of all of the non-zero carbon tax scenarios. Moreover, after year 6, the low-tax scenario (\$10/ton) has the lowest yearly emissions of all of the non-zero carbon tax scenarios. As shown in Table IV, the benchmark scenario (\$50/ton) leads to the lowest 11-year cumulative emissions. These results are specific to our test system, but highlight how counter-intuitive results may arise when discrete generator retirements significantly change the resource mix and economics of the power system.

In this case, the emissions associated with the high-tax scenario become the highest because the oil generator, instead of

a coal generator, retires at the end of year 2, resulting in less emissions drop from year 2 to year 3 as seen in Fig. 3(a). The oil generator is usually not committed because it has the highest fuel price and smallest power capacity. In practice, such a generator is a “peaker plant”, only turning on a small number of hours in a year to supply peak demand. Such plants would retire if not compensated to provide capacity and/or paid extremely high energy prices during peak periods. Here, we have set its fixed yearly O&M costs to zero so that it does not retire if not committed at all. Under carbon taxes, it is cheaper to commit the oil generator than a coal generator in some hours; Fig. 2 shows a small amount of oil generation in the non-zero carbon tax scenarios, especially in the high-tax scenario. However, in the high-tax scenario, the oil generator (rather than a larger coal generator) runs at a loss and retires. As a result, fewer renewables are added in year 3 in the high-tax scenario than in the other non-zero carbon tax scenarios. This can also be seen in Fig. 2; in the high-tax scenario, the share of coal generation and emissions do not change much from year 2 to year 3. Consequently, the high-tax scenario has the highest emissions after year 4. Similarly, the low-tax scenario emissions become lower than the benchmark scenario emissions after year 6 because the generator that retires in the benchmark scenario (CT5) is smaller than the generator that retires in the low-tax scenario (CC2), and so it is replaced with fewer renewables.

Fig. 3(b) shows that yearly operation costs are generally higher under higher carbon taxes. This is because carbon taxes

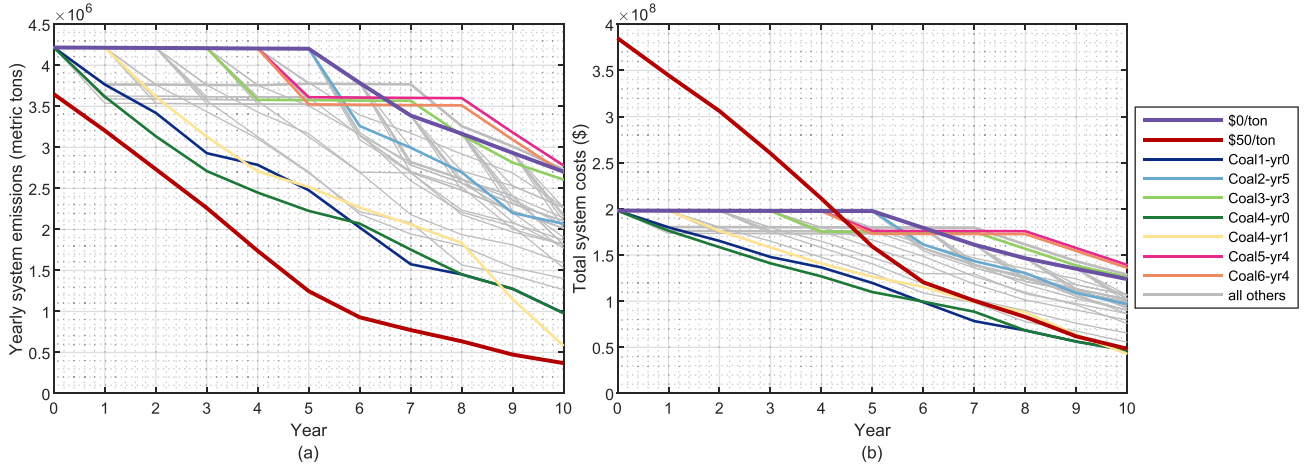


Fig. 4. Range of outcomes for forced coal retirements: (a) yearly system emissions and (b) total system costs, compared those of the benchmark policy (\$50/ton carbon tax) and the no-policy scenario (\$0/ton carbon tax).

make it cost effective to dispatch generators with lower emissions rates but higher operation costs (e.g., natural gas and oil generators). Comparing the operation costs in the no-policy scenario (\$0/ton) to the non-zero carbon tax scenarios, the no-policy scenario has lower operation costs in year 0 but higher costs in all subsequent years. Cumulative operation costs are much lower under non-zero carbon taxes as shown in Table IV. This is because operation costs decrease as more and more zero-marginal-energy-cost renewables replace fossil fuel generators.

Fig. 3(c) shows that carbon tax payments increase when carbon taxes increase. Since emissions are similar across carbon taxes scenarios, the differences between the carbon tax payments are approximately proportional to the differences between the carbon taxes. Similar to operation costs, the carbon tax payments, as well as the differences between them, drop as fossil-fuel generators retire.

Fig. 3(d) shows the yearly total system costs, i.e., the sum of the operation costs in Fig. 3(b) and the carbon tax payments in Fig. 3(c), but not the upfront costs such as investment and installation costs. The system costs associated with low-tax scenario, benchmark scenario, and the high-tax scenario become lower than the costs associated with the no-policy scenario in year 2, year 5, and year 7, respectively. The cumulative total system costs associated with the low-tax scenario, benchmark scenario, and the high-tax scenario are 30% lower, 7% higher, and 64% higher than those associated with the no-policy scenario.

All in all, we find that the choice of carbon tax (between \$10 and \$100/ton) does not significantly affect the emissions path, but does significantly change the total systems costs, with higher carbon taxes leading to higher total system costs inclusive of carbon tax payments. We note this finding is specific to our simulation set-up, which allows one profit-based retirement per year and replaces retired capacity with renewables. We will investigate the sensitivity of our results to these assumptions in Section III-C2.

2) *Outcomes of Forced Coal Retirements:* To explore the possible range of outcomes of forced coal retirements, we enumerate a set of retirement cases by forcing each of the six coal generators to retire at the end of each year (a total of 60 possible

TABLE VI
CUMULATIVE (AVERAGE YEARLY) COSTS AND EMISSIONS, ALONG WITH EMISSIONS AT THE END OF YEAR 10, UNDER FORCED COAL RETIREMENTS

	System operation costs	System emissions	Emissions at end of year 10
	$10^8 \$$	10^6 metric ton	
\$0/ton	19.33 (1.76)	41.20 (3.70)	2.70
\$50/ton	11.80 (1.07)	18.00 (1.60)	0.37
Coal1-yr0	12.96 (1.18)	26.90 (2.44)	0.98
Coal2-yr5	18.28 (1.66)	38.48 (3.50)	2.07
Coal3-yr3	19.14 (1.74)	39.71 (3.61)	2.61
Coal4-yr0	12.70 (1.15)	25.88 (2.35)	0.98
Coal4-yr1	14.06 (1.28)	28.29 (2.57)	0.58
Coal5-yr4	19.90 (1.81)	41.44 (3.77)	2.78
Coal6-yr4	19.71 (1.79)	40.91 (3.72)	2.69

cases). As the results of the no-policy scenario show, the first profit-based retirement (Coal1) happens at the end of year 5 so we do not force Coal1's retirement after year 5 (i.e., we eliminate 5 cases). For cases in which other coal generators are forced to retire after year 5, we allow two retirements: the forced one plus a profit-based one if applicable. Both retirement decisions are made at the end of the year, and so the forced retirement does not affect the profit-based retirement in the same year.

Fig. 4 compares the yearly system emissions and total system costs under the forced coal retirement cases to those of the benchmark policy (\$50/ton carbon tax) and the no-policy scenario (\$0/ton carbon tax). Some retirement cases result in very similar emissions and cost trends. We label seven representative cases, where, e.g., "Coal1-yr0" means Coal1 is forced to retire at the end of year 0, and use grey lines for all others. For each of these seven cases, the cumulative and average yearly system operation costs (which are equivalent to the total system costs since there are no carbon tax payments) and emissions, along with emissions at the end of year 10, are given in Table VI, and the sequences of generator retirements are given in Table VII.

Fig. 4(a) shows that the benchmark policy is more effective than forced coal retirements in reducing emissions. Amongst all the forced coal retirement cases, Coal4-yr0 and

TABLE VII
SEQUENCE OF GENERATOR RETIREMENTS UNDER REPRESENTATIVE FORCED COAL RETIREMENT CASES (BOLD = FORCED RETIREMENT)

Year	0	1	2	3	4	5	6	7	8	9	10
Coal1-yr0	Coal1	CC1	Coal2	CT2	CT6	Coal3	Coal4	CT1	CT5	CT3	Coal5
Coal2-yr5						Coal1,2	CT6	CT4	Coal3	CT5	Coal4
Coal3-yr3				Coal3				Coal1	CT6	CT4	CT5
Coal4-yr0	Coal4	Coal1	Coal2	CC1	CT6	CT1	CT2	Coal3	CT5	CT3	Coal5
Coal4-yr1		Coal4	Coal1	Coal2	CC1	CT2	CT6	CT1	Coal6	Coal5	CT4
Coal5-yr4					Coal5				Coal1	CT6	CC1
Coal6-yr4					Coal6				Coal1	CT6	CC1

Coal5-yr4 have the lowest and highest cumulative emissions, respectively, which are 44% and 130% higher than that of the benchmark policy. At the end of year 10, Coal4-yr1 and Coal5-yr4 have the lowest and highest emissions, respectively, which are 57% and 651% higher than that of the benchmark policy.

The emissions outcomes under forced coal retirements are worse than those under the benchmark policy for a number of reasons. First, forced coal retirements do not discourage coal generation or prioritize coal retirements. In the forced coal retirement cases, some natural gas generators are operated near their minimum mainly to provide regulation, and some become unprofitable and retire before coal generators. Second, while non-zero carbon taxes induce profit-based retirements in each year as shown in Table IV, forced coal retirements do not always induce profit-based retirements in each subsequent year as shown in Table VI. We find that retiring Coal1 or Coal4 always induces retirements in each subsequent year (e.g., Coal1-yr0 and Coal4-yr1). However, retiring the other coal generators does not, though retirements often pick up towards the end of the horizon (e.g., Coal3-yr3 and Coal5-yr4). This is because the energy costs of Coal1 and Coal4 are higher than those of the other coal generators and so they are usually operated near their minimum. When they are retired, renewables not only replace the generation from the retired generators but also some generation from the remaining generators (recall that renewables are sized to match their expected generation with the capacity of the retired generators). However, retiring less expensive coal generators that are operated near their maximum (e.g., Coal5) and replacing them with renewables does not have as large an effect on the remaining generators.

Fig. 4(b) shows that the yearly total system costs of the benchmark policy start very high since they include both operation costs and carbon tax payments. However, they decrease quickly and eventually become less than those of nearly all of the forced coal retirement cases by year 10. The benchmark policy has higher cumulative system costs than all forced coal retirement cases. Specifically, its total system costs are 4.3% higher than those of the highest-cost forced retirement case (Coal5-yr4) and 39% higher than those of the lowest-cost forced coal retirement case (Coal4-yr0), but these costs include carbon tax payments that represent government revenue.

C. Sensitivity Analysis

We next explore the sensitivity of our results to several of our assumptions.

1) *Energy Storage Capacity Growth Rate*: The amount of energy storage capacity affects system dispatch and so different energy storage capacity growth rates can lead to different sequences of retirements. We varied the growth rate of energy storage capacity from 1% to 10% of R^{req} per year at 1% increments. Sample results are shown in Fig. 5. Overall, the emissions paths follow similar trends to those in Fig. 3(a). In the no-policy scenario, higher growth rates lead to earlier emissions reductions resulting from earlier retirements as storage reduces the amount of regulation provided by fossil fuel generators. In the non-zero carbon tax scenarios, the growth rate affects which carbon tax achieves the most emissions reductions. Unlike in Fig. 3(a), in some cases, we see periods in which emissions level out. For example, with a 1% growth rate, the emissions under the benchmark policy and in the low-tax scenario are almost flat after year 6 because there are no more retirements. This is because natural gas generators remain profitable by providing regulation since there is limited energy storage capacity. However, in the high-tax scenario the profit from regulation does not outweigh the effective cost of energy, and so natural gas generators continue to retire.

2) *Without Profit-Based Retirements or Renewables Expansion*: Significant reductions in emissions occur because we allow profit-based retirements in each year, and because we replace retired capacity with renewables. Therefore, we ran sensitivities without profit-based retirements and without renewables expansion. First, without profit-based retirements, carbon taxes and forced coal retirements still induce changes to dispatch, which changes year to year due to storage capacity expansion and, in the case of forced coal retirements, renewables expansion. Although emissions reductions are not as significant as with profit-based retirements, carbon taxes are still more effective at reducing emissions than forced coal retirements. This is because, with carbon taxes, high-emissions generators are dispatched less. With forced coal retirements, even though renewables are added, high-emission generators may still be dispatched if less expensive than other fossil-fuel generators. Second, without renewables expansion but with profit-based retirements, the emissions paths under all policies are “flatter” because prices change more gradually without low-cost renewables and fossil-fuel generator profits decrease more slowly, resulting in years without retirements. Carbon taxes still result in lower emissions than forced coal retirements. The differences between the results under different carbon taxes are more distinct, and higher carbon taxes always lead to lower emissions, both cumulatively and yearly. Eventually, there are enough retirements

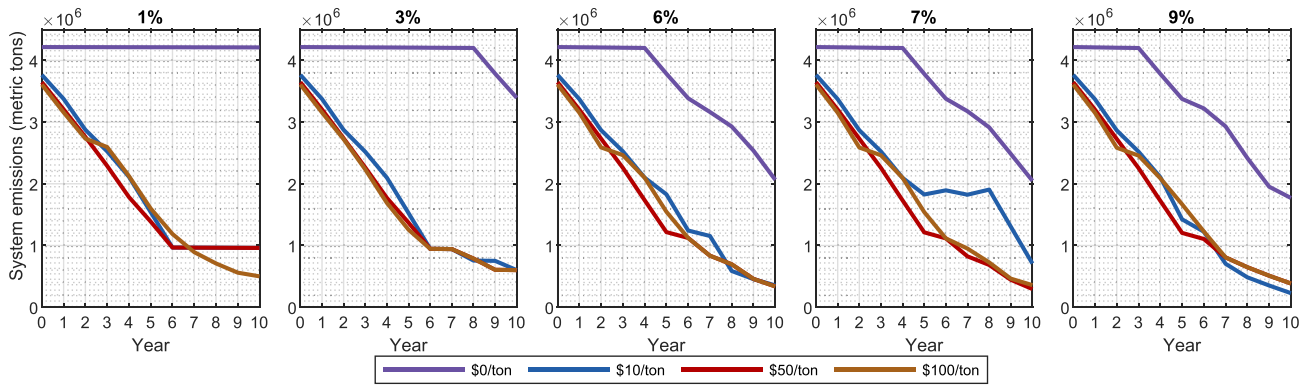


Fig. 5. Yearly system emissions per year under carbon taxes, with different energy storage capacity growth rates. Previous results assumed 5% per year.

that the system can no longer meet the demand and/or fulfill the system regulation requirement without adding new generation.

3) *Different Benchmark Policy*: Recognizing that a \$50/ton carbon tax may not be the actual optimal policy, we performed a sensitivity analysis varying the benchmark policy (from \$0/ton to \$100/ton) and compared the results to those of the forced coal retirements cases. Results show that the differences in emissions reductions between the different benchmark policies and forced coal retirements vary only slightly because the emissions paths associated with all carbon taxes are similar as shown in Fig. 3(a). However, the differences in total system costs between different benchmark policies and forced coal retirements vary significantly since the costs include payments to the government that are directly related to the carbon tax, as shown in Fig. 4.

4) *Combining Carbon Tax With Forced Coal Retirements*: We performed a simulation exploring the simultaneous adoption of both policies. The results show that combining carbon taxes with forced coal retirements can achieve lower emissions. Because carbon taxes already induce one profit-based fossil-fuel plant retirement every year of our simulation, forcing a coal generator to retire allows one additional generator to retire. Here we show the results of two combined policies as examples: combining a \$10/ton carbon tax with Coal6-yr4 (referred to as 10-Coal6-yr4) and combining a \$100/ton carbon tax with Coal1-yr2 (referred to as 100-Coal1-yr2). Fig. 6 shows the emissions pathways under these two combined policies, as compared to the emissions pathways associated with carbon taxes alone.

In combined policy 10-Coal6-yr4, because Coal6 is forced to retire in year 4 (instead of year 5 as in the \$10/ton carbon tax scenario), the emissions pathway takes a steeper turn after year 3, resulting in the lowest emissions. Because one additional generator retired, the carbon tax payments and operation costs are slightly lower than those under the \$10/ton carbon tax alone. In contrast, combined policy 100-Coal1-yr2 results in an emissions pathway that lies under the pathway of the benchmark carbon tax. This is expected because Coal1 is forced to retire earlier (in the same year as the oil unit) so that the emissions pathway does not take a turn after year 2 as it does in the \$100/ton carbon tax scenario. Similarly, the operation costs and carbon tax payments are lower under the combined policy than under the \$100/ton carbon tax alone. However, if the \$100/ton carbon tax

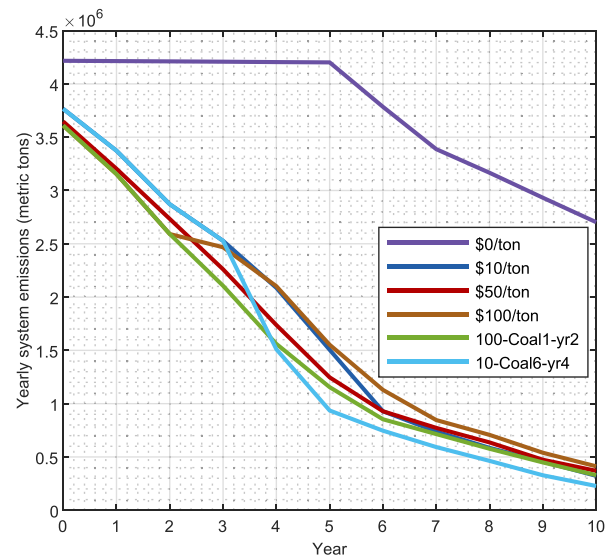


Fig. 6. Yearly system emissions per year under combined policies.

is combined with forced coal retirements later than year 2, the combined policy results in higher emissions than the benchmark policy.

These results suggest that combining carbon taxes with forced coal retirements could potentially further reduce emissions compared to adopting only one policy. However, the complex interaction of renewable/storage expansion, the dispatch process, and resulting profits and retirement decisions could still cause unexpected emissions results, i.e., a higher carbon tax could still result in higher emissions. This suggests that the carbon tax level and retirement decisions should be carefully examined to achieve desired outcomes. We refer interested readers to a more comprehensive discussion of combining and sequencing energy and environmental policies in [52].

IV. CONCLUSION

In this paper, we compared carbon taxes and forced coal retirements as decarbonization strategies in power systems. We used an optimization model to simulate the operation of a test

system over an 11-year horizon to obtain emissions pathways and associated costs.

Our results highlight the trade-offs between emissions reductions and costs when benchmark versus alternative policies are adopted. For carbon taxes, counter-intuitively, a higher carbon tax does not always achieve more emissions reductions because of the complexity in dispatch, resulting profits and retirements, and the addition of renewables and storage. This suggests that an alternative carbon tax could potentially achieve similar emissions reductions to a benchmark carbon tax, assuming unprofitable generators are continually retired and retired capacity is replaced by renewables. In contrast, forced coal retirements result in higher emissions and lower total system costs than carbon taxes, but without the potential for government revenue. However, we see a very large range of emissions pathways and cost outcomes across all forced retirement cases indicating specific coal retirements decisions can have a significant impact on whether resulting emissions pathways are somewhat close to or very distant from the benchmark policy's pathway.

The sensitivity analysis shows that the energy storage capacity growth rate does not qualitatively change the emissions pathways in the long term, but could affect which carbon tax achieves the most emissions reductions. The sensitivity analysis also shows that renewables expansion accelerates profit-based retirements and emissions reductions, and without renewables expansion emissions pathways under different carbon taxes are more distinct, with higher carbon taxes achieving higher emissions reductions.

There are numerous avenues for future work. First, our model captures the intermittency of renewables only indirectly through frequency regulation capacity. Future work could incorporate a simulation of intrahour operations. Second, we include only operation costs in our assessment; other costs, incentives, or regulations could affect the system evolution. Future work could develop more comprehensive models of the economic, political, and regulatory factors affecting capacity expansion and retirements.

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