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ABSTRACT

The phasedown of coal for electricity generation is considered vital to meeting global climate targets. Many countries have pledged to stop using coal, with some as early as 2030. While the United States has no target currently in place, several states do. In this paper, we examine the feasibility of phasing down U.S. coal-generated electricity given the existing fleet of power plants. In particular, we take consumption as given and evaluate how prioritizing natural gas generation over that of coal would change emissions and operating costs. To do this, we develop a replacement algorithm based on transmission regions and marginal cost comparisons. Using our preferred scenarios, we find that between 66 and 94 percent of coal generation could be replaced immediately, reducing electricity sector carbon dioxide (CO_2) emissions between 18 and 29 percent – equivalent to between 5 and 8 percent of total U.S. energy related emissions. The cost range is between \$49 and \$92 per ton of CO_2, where benefit-cost ratios are favorable in some scenarios considering local pollutant co-benefits alone. Despite the command-and-control nature of prioritizing natural gas generation, we find it relatively cost effective even in comparison to a Pigouvian tax. We examine sensitivity of the results to transmission regions, replacement cost conditions, natural gas pipeline capacity, and alternative fuel prices.

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1 Introduction

There is no shortage of research showing that the threat of climate change is growing increasingly severe. Plans for addressing the problem call for a significant reduction in greenhouse gas (GHG) emissions, often citing the coming years as critical to ensure the world is on track to meet the internationally agreed upon target of limiting warming below 2 degrees, or even 1.5 degrees, Celsius above preindustrial levels. The need to phasedown coal for electricity generation is a central part of any such plan. The replacement of coal with other sources of energy for electricity generation—renewables and even natural gas—is considered a near-term priority because coal has the highest carbon dioxide (CO_2) emissions rate and is associated with greater emissions of local pollutants that adversely affect human health. Indeed, many U.S. states and other countries already have coal bans in place or have set targets for a phaseout.[1] At a national level, the United States signed a 2021 United Nations agreement that calls upon all countries to accelerate "efforts towards the phasedown of unabated coal power" (COP26 2021) but was a notable non-signatory to a more stringent pledge among 45 countries to "transition away" from their own coal-fired electricity generation (U.K. Government 2021).[2]

The first part of this paper considers an important yet understudied question: How feasible is it for the United States to eliminate coal for electricity generation in the short-term—that is, using existing sources of electricity generating capacity and the existing grid? From a technological perspective, the answer hinges on a comparison between current coal generation and spare natural gas capacity, as coal and natural gas are the two main sources of dispatchable generation. Figure 1 provides an initial motivation. Based on a comprehensive data set of hourly generation in the contiguous United States, the figure compares actual coal generation in 2022 with spare natural gas capacity averaged over all hours of the year, separately for six geographical transmission areas within the electricity grid (i.e., the North

[1] U.S. states that currently have some form of a moratorium on the construction of new coal-fired electricity generators or plans to phaseout coal-generated electricity are California, Hawaii, Maine, New York, Oregon, Texas, and Washington. For a continually updated list of countries with moratoriums, phaseout plans, or both see https://bloombergcoalcountdown.com.

[2] The Unites States has, however, joined all G20 nations in pledging to stop financing the construction of new unabated coal-fired power plants in other countries (G20 2021).

Atlantic Electric Reliability Corporation, or NERC, regions).[3] On average, spare natural gas capacity exceeds coal generation, and the margin is substantial in some regions. However, Figure 1 overstates the potential for a coal phasedown because electricity storage is currently minimal, meaning that coal generation must be compared with spare natural gas capacity hour by hour.

Figure 2 shows the spare natural gas capacity for each hour of the year in each region. The pattern of results indicates insufficient natural gas capacity during the summer months in all regions with the exception of the Northeast. The Midwest and Mid-Atlantic regions also have shortages for some hours earlier in the year during cold months. Nevertheless, across most hours of the year, there remains spare natural gas capacity compared to coal generation. While the figure indicates that fully replacing coal generation with spare natural gas capacity is not feasible, it does suggest potential for a substantial amount of replacement. In what follows, we develop a novel methodology based on observed market data to assess the amount of replacement that can be done in the short run.

Although suggestive, the naive comparisons in Figures 1 and 2 do not account for whether an existing natural gas unit with spare capacity is a plausible substitute source of generation for a coal-fired unit. The location of electricity generating units (EGUs) affects whether they operate in the same market, are subject to different transmission constraints, or both. And beyond the question of how much coal generation can be replaced in the short run are questions about the likely costs and benefits. The costs of imposing a shift from coal to natural gas will be based on a comparison between the marginal costs of generation from the particular EGUs that are substituting for one another. Substituting natural gas for coal generation will also reduce the emissions of CO_2 and local pollutants, with consequent benefits in the form of avoided climate damages and adverse health effects. These are all topics that our methodology afford an opportunity to evaluate.

While many studies examine the implications of how carbon taxes affect emissions in the electricity sector, we are aware of only one study that considers prioritizing natural gas over

[3] Later in the paper, in Section 3, we discuss in detail the data collection and preparation that underlie Figures 1 and 2.

coal generation in the United States.[4] Several factors may explain the absence of economics research on the topic. First, the immediate replacement of coal with natural gas generation is far from a marginal change because coal generation accounts for 20 percent of U.S. electricity generation (EIA 2023).[5] Typically, engineering and economic models are less well-equipped to deal with short-term, non-marginal changes to the status quo. Research that examines future trends in the electricity sector tends to focus on gradual transitions over decades, with a focus on entry and exit of EGUs. Second, economics research usually considers the consequences of policy instruments that change incentives (e.g., taxes or subsidies) rather than command-and-control approaches that may give preference to one technology or fuel over another. Finally, research on whether natural gas can or should serve as a bridge fuel to reduce emissions from coal has generally sounded a word of caution, resulting in a primary focus of research on the expansion of renewable sources of generation with the longer-term goal of phasing out all fossil fuels.

A greater understanding is nevertheless needed about the near-term feasibility of phasing down coal for U.S. electricity generation, along with the consequent emission reductions, costs and benefits. The United States has ambitious targets for reducing its GHG emissions by the end of the decade (i.e., 50-52 percent below 2005 levels by 2030), yet questions remain about whether federal policy is commensurate with the ambition. Knowing how far the United States can get with immediate substitutions away from coal in the coming years is therefore informative, especially in light of the growing number of states and countries that are coalescing around the phaseout of coal as a focal point for policy. Moreover, with our analysis, concerns about expansion of natural gas as a bridge fuel should be reduced because we focus on potential substitution with existing generation capacity and infrastructure, rather than a build out that can induce future lock in.

[4] Steinberg et al. (2018) minimize coal generation by changing the dispatch order such that coal units are dispatched only after all natural gas units subject to modeled transmission and ramping constraints. They consider only the eastern interconnection and find the potential for a 13 percent reduction in power sector emissions.

[5] U.S. coal generation, both in levels and as a share of total generation, has declined significantly from a high in 2007. But we might not expect it to fall to (near) zero without some form of market intervention, at least in the relative near-term. Reasons include the growing demand for electricity because of incentives for electrification, the growing amount of natural gas exports, and the way that dispatchable sources of generation are complements to increased reliance on renewable and intermittent sources of generation.

Beyond having policy relevance, this paper makes a methodological contribution to the literature on modeling electricity dispatch. Answering our primary research question requires a model of changes in short-run, hour-by-hour dispatch of electricity. Our approach is based on readily observable data on generation, emissions, costs, and transmission inter-connectivity of coal and natural gas EGUs operating on the U.S. electricity grid. The transparent and relatively straightforward methods contrast with primarily engineering models that operate as more of a "black box." While economic analyses also employ models of short-run dispatch (e.g., Dahlke 2019, Gonzales et al. 2023, Brown et al. 2023, Jha and Leslie 2024), our approach differs because we employ a replacement algorithm based on transmission constraints and revealed patterns of generation (what we refer to later as a revealed preference type of approach). Specifically, we identify potential substitute EGUs within the same geographical area and use different marginal cost thresholds based on observed patterns of generation to identify which units can feasibly replace generation from others. Rather than calibrate a model and simulate counterfactuals, we use the initial, observed equilibrium as the basis upon which to consider shifts that satisfy a range of observed patterns of dispatch and geographical assumptions. Our primary policy experiment is priority dispatch of natural gas generation over that of coal, but the framework can readily accommodate other policies as well. Indeed, we also consider carbon taxes in the electricity sector to examine relative cost effectiveness of priority dispatch.

Based on our preferred scenarios, we find broad scope for using spare capacity of natural gas units to replace coal generation. Priority dispatch means that we replace coal generation with that of natural gas when feasible, but continue to rely on coal generation when necessary to meet fixed demand for electricity. We estimate feasible replacement rates of coal generation in 2022 of between 66 and 93 percent. The corresponding range of estimates for CO_2 emissions reductions is 18 to 29 percent of the combined coal and natural gas emissions in the electricity sector. This equals between 5 and 8 percent of total U.S. energy related CO_2 emissions. The cost of reducing these emissions ranges from \$49 to \$92 per ton of CO_2, and this compares favorably with recent estimates of the social cost of carbon at \$185 and \$190 (Rennert et al. 2022; EPA 2023). We also quantify the benefits of avoided local pollution using an integrated assessment model (Clay et al. 2019; Holland et al. 2019) and find favorable benefit-cost ratios considering local pollution benefits alone. While the quantity of avoided emissions varies across the range of scenarios that we consider, our overall economic conclusion is robust across scenarios: the benefits exceed the costs of implementing priority dispatch of natural gas generation over that of coal.

The methods and findings herein contribute to several different strands of the literature at the interface of electricity markets and climate change. As mentioned previously, we develop a new approach for modeling changes in short-run grid dispatch, taking account of observed hour-by-hour patterns of generation. Directly related to climate policy, existing research examines coal phaseouts as part of the strategy to meet grid decarbonization goals (e.g., Kharecha et al. 2010; Jewell et al. 2019), yet these papers tend to focus on how costs and capacities must change rather than on what is feasible in the very short-run. In Europe, where some coal phaseout policies are in place, research has focused on forecasting the cost and emission consequences (e.g., Keles and Yilmaz 2020; Graupner and Bruckner 2022). The European Union has imposed priority dispatch of renewable sources of electricity generation for over a decade (Directive 2009/28/EC), and studies have examined the impact on electricity markets and emissions (Oggioni et al. 2014; Zhoa et al. 2020). More generally, studies have focused on benefit-cost analyses of coal phaseouts (e.g., Rauner et al 2020; Adrian et al. 2022). Our analysis is a complement to the extensive literature that employs long run models of the electricity sector with entry and exit to study various polices, along with the more short-run engineering type of models of grid dispatch.[6] Finally, we reinforce a findings in a recent study that compares a prescriptive policy (i.e., an emissions standard) with an economic incentive (i.e., a tax) for reducing emissions in the electricity sector, whereby the former can be quite close to the latter on an efficiency basis (Borenstein and Kellogg 2023).

The next section of the paper develops the conceptual framework for implementing priority dispatch, introducing how we account for geographic transmission constraints and feasible substitution based on generation cost comparisons. We also define the environmental and economic outcomes of interest. Section 3 describes our data collection and preparation. We

[6]Long run models include the U.S. Department of Energy's NEMS model, the National Renewable Energy Lab's (NREL) ReEDS model, and Resources for the Future's E4ST and Haiku models. The grid dispatch models include PLEXOS and ISO real-time dispatch models.

report the main results in Section 4, making comparisons across scenarios with different assumptions about geographic regions and marginal cost thresholds for feasible replacement. In Section 5, we use the same methodological approach to solve for equilibria at different carbon tax rates. These results enable an evaluation of cost-effectiveness of priority dispatch and, more generally, produce short-run marginal costs curves of electricity sector emissions using our short-run approach for dispatch. Section 6 considers robustness of the results to natural gas pipeline constraints, dynamic constraints about EGU ramping rates, and alternative fuel prices. Finally, Section 7 concludes with as summary of our main results.

2 Conceptual framework

This section describes our framework for modeling feasible and cost effective replacement of coal-fired generation with that of natural gas. The policy experiment we consider is priority dispatch of natural gas over coal generation. It is worth noting, however, than an alternative, though equivalent, way to conceptualize the policy experiment is a cap on coal generation, where our analysis solves for the lowest cap that is feasible with the existing set of generators. We then focus on how different assumptions about transmission affect the modeled equilibria, along with the overall change in generation costs, emissions, and net benefits.

2.1 A graphical illustration

We begin with a graphical illustration of our policy experiment. Because we are interested in the potential for natural gas to substitute for coal generation, we focus on net load, defined as total load (i.e., demand for electricity) minus generation from all other sources (i.e., nuclear, renewables, other). Figure 3 illustrates marginal cost curves of meeting net load with coal generation (MC_C from left to right) or with natural gas generation (MC_{NG} from right to left). The figure depicts a case where neither source of generation has enough capacity to meet all of net load. Assuming perfect competition (or at least cost minimization) the intersection of the two private marginal cost curves defines the equilibrium split of generation between sources Q^e. Also shown in Figure 3 is the social marginal cost curves of generation for each fuel (SMC_C and SMC_{NG}). Coal generation is depicted as having greater marginal external costs.

The experiment is to now introduce priority dispatch such that natural gas generation is dispatched even if it has higher private marginal costs than coal, and to dispatch only the lowest cost generation from either fuel to continue meeting net load. This shifts to a new equilibrium Q^m, which in this case is determined by the maximum capacity of natural gas generation, ensuring less coal generation.[7] The net private costs of instituting priority dispatch for natural gas is the gray shaded area, and the social net benefit is the green area minus the red area. Notice that the red area only exists when there is enough spare capacity of natural gas that has sufficiently high social marginal costs. In principle, the red triangle could be greater than the green, in which case instituting priority dispatch would decrease welfare. The first-best, efficient split between the two sources of generation occurs at the intersection of the two social marginal cost curves, because at this allocation total social costs are minimized. We now turn to a more formal setup to describe how we model various priority dispatch equilibria and estimate the relative magnitudes of areas indicated in the figure.

2.2 Model setup

We consider electricity generation separately for each hour of the year.[8] Let j denote coal units and i denote natural gas units. Each coal unit has an observed level of hourly generation $\bar{x}_j$, constant marginal generation costs c^x_j, and emissions rate z^x_j. Note that we employ the notational convention of using "bars" to denote quantities associated with the initial, observed equilibrium. Each natural gas unit has spare generation capacity $\bar{s}_i = m_i - \bar{g}_i$, where m_i is a natural gas unit's maximum generation capacity, and $\bar{g}_i$ is its observed hourly

[7]It is, of course, possible for there to exist enough natural gas capacity to fully replace coal generation, in which case the MC_{NG} curve would continue all the way to the left vertical axis.

[8]While we do not model dynamic considerations (or storage) that might affect generation and dispatch from hour to hour, we do discuss related issues later in the paper and the potential implications for our analysis.

generation. Natural gas units also have constant marginal generation costs c_i^g and emissions rates z_i^g.[9]

Given this simple setup, the aim is to solve for an alternative equilibrium in which natural gas units are given priority dispatch. This *modeled equilibrium* is characterized by generation x_j for all j coal units and additional generation g_{ij} for all i natural gas units, where the notation captures how much of unit i's new generation is replacing generation from coal unit j (this will be important for reasons discussed below). It follows that new generation from natural gas unit i is $g_i = \sum_j g_{ij}$. Hence the new equilibrium can be fully characterized with (X, G), where X is a vector of the remaining generation for all coal units, and G is a matrix summarizing the new generation and replacement mix across all natural gas units.

An important part of our analysis is consideration of which natural gas units have the potential to replace generation from a particular coal unit. We approach this question with a range of assumptions that seek to capture realistic replacement options across two dimensions: geographic transmission on the electricity grid, and feasible substitutes based on marginal cost comparisons.[10]

2.2.1 Replacement regions

We consider various geographic regions within which spare natural gas capacity can serve as a potential replacement for coal generation. These correspond to established transmission regions on the electricity grid. From broadest to narrowest scope, these include Interconnection, NERC regions, NERC subregions, and Balancing Authorities (BAs, with examples being the Independent System Operators, or ISOs). Figure 4 illustrates the different areas, showing how they correspond with 3, 6, 22, and 51 partitions of the contiguous U.S. electricity grid, respectively.

[9] Assume initially that the pollutant is CO_2 emissions, yet we will consider multiple pollutants further on in the paper.

[10] Although not considered initially, later in the paper we extend the analysis to account for potential natural gas pipeline capacity constraints.

2.2.2 Replacement cost thresholds

We consider a second dimension to refine which natural gas units can provide replacement generation to particular coal units within the same replacement region. This dimension is based on four different marginal cost thresholds. For a given threshold, natural gas units with costs above the threshold are eligible to be replacements. The least restrictive threshold, referred to as the *Unconstrained* threshold, allows any spare natural gas capacity within the same replacement area to replace coal generation, regardless of cost. A feature of this approach, however, is that coal generation can be replaced with lower cost natural gas generation, and this implies shifting to a new equilibrium with the added constraint of priority dispatch can be lower cost. Eliminating this possibility is part of the reason we consider alternative thresholds such that imposing priority dispatch (and therefore lowering emissions) cannot occur at a cost saving.

The other three thresholds are defined based on the marginal costs of units that are generating in the observed equilibrium. Natural gas units that have spare capacity and costs below the operational threshold are not considered as possible replacements, because the observed equilibrium indicates an unobserved constraint that prevents the natural gas unit from using its capacity. The idea is that any lower cost plant is not a feasible substitute because if it were, it would have been used in the observed equilibrium. This is analogous to revealed preference (RP) arguments from consumer theory, so we employ that language here, referring to the different scenarios as RP thresholds.

Our most stringent threshold, *RP Max Any*, sets the threshold at the highest observed hourly marginal cost of any coal or natural gas unit with positive generation within the replacement region. Formally, this means that, for any hour of the year, $g_{ij} > 0$ requires $c_i^g \geq \max\{\max\{c_j^x\}, \max\{c_i^g\}\}$ where the inner maximums are over all i and j such that $\bar{x}_j > 0$ and $\bar{g}_i > 0$. This threshold ensures that any spare natural gas capacity used for replacement must have higher costs than the market price.

The next two thresholds are less restrictive. We consider them in part because implementing priority dispatch is likely to impose non-marginal changes in generation that shift the relevant cost threshold from the initial equilibrium. *RP Max Coal* sets the threshold at the marginal cost of the highest cost coal generating unit with positive generation. Formally, this states that $g_{ij} > 0$ requires $c_i^g \geq \max\{c_j^x\}$ over all j such that $\bar{x}_j > 0$. This threshold is further motivated by the way that natural gas peaker units are often dispatched "out-of-merit" to satisfy local transmission requirements, and because of this, peaker units may not provide the most reliable threshold.

Our third threshold, and the one we emphasize most, *RP Own*, is more lenient and sets a threshold for each coal unit equal to that coal unit's marginal cost. This threshold assumes that any natural gas replacement generation must occur at a higher marginal cost than the coal generation it replaces—that is, $g_{ij} > 0$ requires $c_i^g \geq c_j^x$. An appealing feature of this threshold is that natural gas units are dispatched for replacement based on what we observe as least cost generation, but because they must be higher cost than the coal they replace, priority dispatch must always be costly.

2.3 Solving the model

Any potential new equilibrium (X, G) must satisfy several necessary conditions. First is a spare natural gas capacity constraint: $g_i \leq \bar{s}_i$ for all i. This means quite simply that natural gas units can only generate additional electricity up to their capacity. Second is a "keep the lights on" constraint: $x_j + \sum_i g_{ij} = \bar{x}_j$ for all j. This means that coal units may continue to generate electricity to the extent that feasible natural gas units do not have the capacity for replacement. The important implication is that net load remains at it observed level for for every hour of the year. Third is the feasibility constraint based on the assumed replacement region: Interconnection, NERC region, NERC subregion, or BA. Finally, we have the feasibility constraint based on the assumed replacement threshold (from least to most restrictive): Unconstrained, RP Own, RP Max Coal, or RP Max Any.

To implement natural gas priority dispatch, we solve a two-step optimization. The first step is to minimize coal generation among the feasible equilibria:

$$\mathcal{F} \equiv \underset{(X,G)}{\arg\min} \sum_j x_j \;\; s.t. \;\; (X, G) \;\; \text{feasible}, \tag{1}$$

where the feasibility constraint is defined as satisfying the four necessary conditions. The second step ensures cost minimization among both sources of generation:

$$\min_{(X,G)\in\mathcal{F}} \sum_j c^x_j x_j + \sum_i \sum_j c^g_i g_{ij}. \tag{2}$$

Together, equations (1) and (2) implement feasible priority dispatch of natural gas that first and foremost minimizes coal generation, and then conditional on satisfying that objective, minimizes overall generation costs. Note that the second step of the procedure is necessary because different combinations of feasible natural gas generation are likely possible to replace the same amount of coal generation.

Solving the two-step optimization is relatively straightforward. For each hour, define the set of 'contender' natural gas units to potentially replace generation from each coal unit. The contender natural gas units must have spare capacity, be within the assumed replacement region, and satisfy the assumed replacement cost threshold. Now order the coal units within a replacement region from high to low marginal costs, and the natural gas units within the same replacement region from low to high marginal costs. The procedure is then to loop through coal units from high to low, with a nested loop through natural gas units from low to high, replacing coal generation with spare capacity from contender gas units, keeping track of any used up spare capacity to replace generation at lower cost coal units. The result is an equilibrium at which no additional coal generation is feasible to replace, and total generation costs (coal and natural gas) are minimized.

2.4 Outcomes of interest

Given a solution satisfying (1) and (2), we have an equilibrium consisting of x_j for all coal units and $g_i = \sum_j g_{ij}$ for all natural gas units. There are several outcomes of interest based on comparisons between the observed and modeled equilibria. First is the amount of remaining coal generation:

$$\sum_j x_j = \sum_j \bar{x}_j - \sum_i g_i. \tag{3}$$

This expression will be positive to the extent there is insufficient natural gas capacity that is feasible.

Second is the change in generation costs:

$$\sum_i c_i^g g_i - \sum_j c_j^x (\bar{x}_j - x_j), \tag{4}$$

which is the difference between the costs of greater generation from natural gas and less from coal. As noted, the change in generation costs will always be positive for the revealed preference approaches, but it is possible for a cost savings using the unconstrained approach, which is one rationale for preferring the revealed preference approaches.[11]

Third is the change in emissions:

$$\sum_i z_i^g g_i - \sum_j z_j^x (\bar{x}_j - x_j). \tag{5}$$

We expect the change in emissions to be negative given that emission rates are typically lower for natural gas units.[12] While equation (5) is written for the change in emissions of one pollutant, we will consider multiple pollutants in our empirical analysis.

Fourth, we have the monetized value of the change in emissions:

$$\sum_j \phi_j^c z_j^x (\bar{x}_j - x_j) - \sum_i \phi_i^g z_i^g g_i, \tag{6}$$

where ϕ_j^c and ϕ_j^g are the constant marginal damages of emissions from each coal and natural gas unit, respectively. The expression applies for a single pollutant with marginal damages that can vary across units, as would be the case for local pollutants. It is nevertheless easy to see how the same expression can be modified to account for multiple pollutants and the case of CO_2, where the marginal damages are uniform across units.

Finally, we are interested in the overall net benefits of shifting from the observed to the modeled equilibria. This is obtained by subtracting (4) from (6), where the latter can

[11] Equation (4) makes clear how a cost savings would occur if the initial equilibrium has spare natural gas capacity with a lower marginal cost than that of generating coal units.

[12] Note that we are using average rather than marginal emission rates because changes in generation at each unit are likely to be non-marginal.

include climate damages from CO_2, health effects from local pollutants, or both. Although not described until later in the paper, we will compare the modeled equilibrium with priority dispatch to one with taxes, where the latter is a useful benchmark because it is cost effective and possibly maximizes net benefits (if emission taxes are set at the Pigouvian level).

3 Data collection and preparation

The analysis requires hourly generation, capacity, marginal cost, and emissions rates for coal and natural gas units. Our primary source of data is the U.S. Environmental Protection Agency's Continuous Emission Monitoring System (CEMS). CEMS includes data on most fossil fuel generating units with at least 25 MW of generating capacity. We focus on data for 2022, which is the most the most recent year with complete data at the time of writing. We consider all coal and natural gas units that report positive amounts of generation, emissions, or heat rates throughout 2022. We drop all cogeneration (combined heat and power) units. This yields a sample of 385 coal units and 2,550 natural gas units.

CEMS reports hourly gross generation for each unit, but we are interested in net power delivered to the grid.[13] To correct for this, we merge monthly EIA 923 data on annual net generation with CEMS data by power plant and technology type (coal plants and three types of natural gas plants) to construct a net-gross ratio for each plant by the technology type. The net-gross ratio is Winsorized at the 10th and 90th percentile, and any missing values are imputed at the mean for that technology type. Hourly net generation is then the product of the hourly CEMS gross generation and the net-gross ratio for the corresponding technology type.

We estimate capacity of each unit based on observed generation over the previous decade. This provides a realistic bound on production and only depends on CEMS data, which is advantageous because matching EIA and EPA data at the unit level is challenging. However, this approach may understate capacity for rarely utilized units. Following Holland et al. (2022), we begin with the 99th percentile of a unit's hourly observed CEMS gross generation

[13] These can differ because of electricity use inside the unit (e.g., for powering conveyor belts, pumps, and emissions control equipment) or because generation is reported for only a single cycle of a combined-cycle unit.

over the previous decade, and we then adjust by the 2022 net-gross ratio. If data are missing, we use nameplate capacity reported to EPA or EIA, adjusted again by the net-gross ratio.[14] We then define the expected capacity as 95 percent of this amount, holding back 5 percent for forced outages.

Table 1 reports the 2022 average hourly generation among coal and natural gas units broken out by Interconnection, NERC regions, and overall. Both coal and natural gas generation are greatest in the Southeast and Mid-Atlantic NERC regions. The overall hourly average generation is 86 and 143 GWh for coal and natural gas, respectively. The table also reports the estimated capacity for both coal and natural gas generators. The final column reports natural gas spare capacity, as the difference between capacity and generation. These estimates by NERC region compared with the coal generation correspond with the magnitudes shown in Figure 1. Over the entire year, we can see that there is far more spare natural gas capacity than coal generation in all NERC regions; however, limited electricity storage makes this naive comparison relatively informative about actual replacement potential.

Table 2 reports the average hourly CEMS emissions from coal and natural gas units. We report emissions of CO_2, along with the local pollutants sulfur dioxide (SO_2) and nitrogen oxides (NO_X). Consistent with regions having the largest generation (coal and overall), emissions are greatest is the Southeast and Mid-Atlantic. We calculate the emissions rate at each unit as the CEMS reported annual emissions over the reported annual net generation.

The marginal cost of generation at each unit equals the product of unit-level heat rates and fuel costs, plus technology-specific operation and management (O&M) costs.[15] We use monthly prices for coal and natural gas, where the former varies by coal region (e.g., Central Appalachia), and the latter by NERC region.[16] Figure 5 reports box plots for the marginal

[14]There are 37 units with missing data, and we get nameplate capacity for 33 from EPA and 4 from EIA.

[15]If a unit is missing CEMS data, we calculate plant-technology heat rates using EIA form 923. Variable O&M costs are from `https://www.eia.gov/outlooks/aeo/assumptions/`.

[16]Coal prices are from `https://www.eia.gov/coal/annual/xls/tableES4.xls`. We weight prices based on annual coal purchases at each plant (EIA 923). We include a delivery adder of $7.26 per ton (see `https://www.eia.gov/energyexplained/coal/prices-and-outlook.php`). For lignite plants, we use the annual average price by plant that includes delivery (EIA 923). For natural gas prices, we use EIA 923 data on the quantity and total costs of natural gas spot contracts. We regress total costs on quantity to obtain an estimate of the marginal cost of natural gas to power plants in a given NERC region and month.

generation costs and emission rates.[17] Coal units are reported separately for bituminous, sub-bituminous, and other coal. Natural gas units are reported separately for peakers, steam, and combined-cycle gas turbines (CCGT). The top left panel shows that the marginal costs of coal generation are on average less than that for natural gas, although the ordering is not complete, and bituminous units have a higher marginal cost than CCGT units. The other panels illustrate that coal units have substantially higher CO_2 emission rates, natural gas units have exceedingly low SO_2 emissions rates, and the two fuels are closer with respect to NO_X emissions.

We calculate marginal damages using two approaches depending on whether emissions are CO_2 or local pollutants. For CO_2 we consider different estimates of the social cost of carbon (SCC) (e.g., Rennert et al. 2022; US EPA 2023). We do not, however, assign a particular value; instead we consider a range of potential values to reflect the potential benefits of avoided CO_2 emissions that we compare to the estimated cost per ton of emissions reductions. To quantify the marginal damages of local pollutants, we use the AP3 model (Clay et al. 2019; Holland et al. 2019), which is a source-receptor matrix from county to county. AP3 uses annual average meteorological data to map the flow of emissions over space, chemistry to specify how primary pollutants affect ambient concentrations of secondary pollutants, epidemiology to translate pollution concentrations into increased mortality, and finally economics to assign dollar values of damages using estimates of the value of a statistical life.[18]

4 Results

We report our main results in this section. We begin with a particular scenario: replacement at the NERC region, and the RP Own cost threshold. This is one of our preferred scenarios, as we will discuss, and focusing on this particular case helps characterize the different types

[17] We provide additional information on the distribution of marginal costs and estimated unit capacities in Figure A.1 of the Supplementary Appendix. There we construct standard merit order curves (though we do not employ them in this way in our analysis) for coal and natural gas generation for each NERC region. The curves are also plotted on the same graph with the kernel density of net load within the same region.

[18] Not reported in this section are data collected and used for our analysis of natural gas pipeline capacity constraints. We discuss these data later in the paper when describing the analysis and reporting results.

of results across regions. We then proceed to the full set of comparative results across all scenarios.

4.1 NERC region replacement and the RP Own cost threshold

Table 3 makes comparisons between the observed 2022 generation and the modeled equilibrium with priority dispatch of natural gas. Panel A reports the average hourly reduction in coal generation across NERC regions and in total. The total reduction of 80.4 GWh is substantial, meaning that 93 percent of the observed coal generation is replaced with natural gas (see Table 1). The majority of coal generation in replaced by that from CCGT units, followed by peakers and then steam. Note that while cost minimization of new gas generation will tend to favor CCGT over steam and peaker units (see Figure 5), units with marginal costs lower than that for observed coal generation are deemed infeasible as replacement sources given the RP Own cost threshold. Panels B and C compare the 2022 observed capacity factors to those modeled with priority dispatch, where the capacity factor is defined as the mean hourly generation over the estimated capacity. The total average capacity factor for coal declines from 0.48 to 0.03, and the modeled capacity factors for natural gas increase but remain well below maximum levels, reaching 0.76 for CCGT and 0.31 for peaker and steam units.

Figure 6 illustrates where coal generation is being replaced and by how much. We report the annual reduction in terawatt hours (TWh) at the NERC subregion. Although the results are based on NERC region replacement, reporting the results at the NERC subregion provides greater resolution of where generation is changing. The greatest reductions occur in the north central region and Texas.

Despite the significant reduction in coal generation, it is important to keep in mind how some coal generation remains necessary in order to 'keep the lights on.' Table 4 reports in the first column the number of shortfall hours by NERC region and in total, that is, the number of hours in 2022 when coal generation exceeds spare capacity of natural gas subject to the RP Own cost threshold. In the Mid-Atlantic and Southeast, a shortfall occurs in every hour of the year (i.e., 8760 hours). In contrast, the number of shortfall hours is substantially lower in other regions, at 1,597 in the Midwest, 358 in Texas, 113 in the West, and zero in the Northeast. Also reported in the table are summary statistics on the magnitude of the shortfall hours measured in GWh, and the insight is quite different by this measure. The last column provides a sense of the shortfall magnitude as the ratio of the aggregate hourly shortfall over net load for all hours of the year. This implies, for example, that between 7 and 8 percent of net load must continually be met with coal generation in the Mid-Atlantic and Midwest, whereas the estimate is 5 percent for Texas and the West, and below 1 percent for the Southeast. The estimate is 2 percent for the U.S. total, meaning that coal is needed for just over 2 percent of net electricity generation in order to "keep the lights on."

Table 5 reports the environmental and cost implications of moving from the observed to the modeled equilibrium on an average hourly basis. The results are reported for each NERC region and each source of generation, where we combine results for coal but distinguish between different technologies for natural gas. The total net difference in CO_2 emissions is 48 thousand tons per hour, which is equivalent to a reduction of 29 percent in the combined coal and natural gas emissions in the electricity sector (see Table 2). The greatest reductions occur in the Southeast and Mid-Atlantic regions. Note that the mid-western states (Illinois, Ohio, Pennsylvania, and West Virginia) are part of the Mid-Atlantic NERC region. The Northeast is an outlier because it has virtually no coal generation to replace, so the change in emissions is nearly zero.

Comparable percentage changes for the reduction in SO_2 and NO_X emissions, based on net changes of 145 and 69 thousand pounds per hour, are 86 and 43 percent, respectively. But unlike CO_2 emissions, where the pollutant is uniformly mixed, the damages of SO_2 and NO_X depend on the specific location where the emissions occur. Using the marginal damage estimates from the AP3 model, Figure 7 illustrates the change in local pollution damages that arise because of natural gas priority dispatch. The estimates are annual avoided damages measured in 2020 dollars and reported at the county level. The economic benefits of emission reductions tend to be greatest in the Midwest and the Northeast.[19]

The bottom panel of Table 5 reports the change in electricity generation costs. It reports the decrease due to less coal generation and the increase due to more natural gas generation

[19] We also report in Supplementary Appendix Figure A.2 the distribution of local pollution damages at the observed 2022 equilibrium and the modeled equilibrium, where Figure 7 is the difference between the two.

across technology types, along with the net differences by NERC region and overall. The overall costs are on average just over \$2.3 million per hour, which translates into \$20.4 billion for the year. Costs are the greatest in the Midwest, followed by the Southeast and the West. The total cost is not fully informative when comparing across regions, however, because the change in quantities differs substantially. Hence a statistic of interest overall and across regions is the cost per ton of CO_2 reductions. This can be derived by taking the ratio of the numbers reported in panels D and A. The overall cost per ton, rounded to the nearest dollar, is \$49, with region specific estimates at \$26 for the Mid-Atlantic, \$91 for the Midwest, less than \$1 for the Northeast, \$23 for the Southeast, \$51 for Texas, and \$56 for the West. We will return to such cost per ton estimates in the next section when we consider a range of scenarios and comparisons with recent estimates of the SCC.

4.2 All scenarios

We now examine the effects of alternative assumptions about feasible replacement. Table 6 summarizes the main results for all 16 scenarios: 4 regions by × 4 marginal cost thresholds.[20] Panel A reports results for the RP Own cost threshold and all 4 replacement regions. The results for NERC region replacement simply repeat the ones discussed in the previous subsection. For each case, the table reports the reduction in coal generation, the reduction in CO_2 emissions, the total cost of replacement, and the economic value of the reduction in local pollution.

The rows in Panel A indicate that with less restrictive replacement at the Interconnection level, the amount of coal generation replaced increases, but not by much. This is not surprising given that the vast majority of coal generation is already replaced with assumed replacement at the NERC region. But the amount of coal replacement does decline more substantially if replacement is only allowed within NERC subregions, and it does so even more with replacement at the BA level. Nevertheless the overall amount of coal replaced

[20]We report in Supplementary Appendix tables more detailed results that include changes in generation at natural gas units of different types, changes in emissions, and changes in costs. In particular, the complete set of results across replacement regions are shown for the cost thresholds of RP Own, Unconstrained, RP Max Coal, and RP Max Any in Tables A.1, A.2, A.3, and A.4, respectively.

remains high, at 82 percent even with the assumption of BA replacement (i.e., 70.2 GWh of 86 GWh from Table 1).

Panels B, C, and D report parallel results for the alternative assumptions about the replacement cost thresholds: Unconstrained, RP Max Coal, and RP Max Any. One pattern to note is that within RP Max Coal and RP Max Any scenarios, the amount of coal replacement does not always decline with a more restrictive replacement region; in fact, it monotonically increases in the RP Max Any scenario. To see why, note that at the interconnection level, feasible plants must have higher costs than any plant with positive generation throughout the entire interconnection that is generating power in the observed equilibrium. This implies a relatively high threshold, reducing the amount of feasible natural gas units to replace coal. Conversely, with a more restrictive replacement region, the marginal cost threshold is weaker because there are fewer units over which the maximum costs are determined. It is the case, however, that the more stringent conditions on the marginal cost thresholds reduce the amount of coal generation that is replaced.

Figure 8 illustrates the results in a way that facilitates comparisons across scenarios. The top left panel reports the percent reduction in coal generation for each of the 16 scenarios. Variation based on the replacement cost thresholds is more substantial than that based on the replacement regions. Our preferred estimates are based on RP Own or RP Max Coal. As discussed previously, one reason is that the Unconstrained scenario admits the possibility for coal replacement at a cost savings, and RP Max Any is likely too restrictive of a requirement when the modeled responses are likely non-marginal changes. Additionally, our preferred assumptions about the replacement region are at the NERC level, as emphasized in the previous subsection, and NERC subregions. The rationale for favoring these regions is that Interconnections are quite large and that transmission is well-known to pass through balancing authorities. Consideration of all the scenarios nevertheless shows a wide range of results and sensitivity to different assumptions.

Based on these preferred scenarios, we find a reduction in coal generation that ranges between 66 and 93 percent. Moreover, the range of estimates for CO_2 emission reductions, based on these same scenarios, is from 18 to 29 percent of the combined coal and natural gas emissions in the electricity sector. These results on emission reductions, along with those for the other scenarios, are reported in the top right panel of Figure 8.

The cost estimates in Table 6 are a bit more subtle to interpret because the amount of coal being displaced differs in each scenario. This is why reporting the cost estimates on a per ton of CO_2 basis is helpful, as shown in the lower left panel of Figure 8. The preferred scenario estimates range between $49 and $92 per ton, and these provide the basis for simple benefit-cost comparisons of CO_2 emission reductions. The U.S. Environmental Protection Agency (EPA) recently updated estimates of the SCC for use in federal regulatory impact analysis, finding a value of $190 using the central discount rate scenario of 2 percent (US EPA 2023).[21] Moreover, another recent estimate in the literature puts the SCC at $185 (Rennert et al. 2022). Using these benchmarks, we find that implementing natural gas priority dispatch is likely to pass a benefit-cost test even if we only consider CO_2 emission reductions, that is, ignoring the benefits of reducing local pollutants. While the different scenarios that we consider are associated with different amounts of emission reductions, the benefit-cost comparisons on a per ton basis are favorable in most cases.[22]

Quantification of the benefits associated with the reduction of local pollutants provides even stronger evidence of positive net benefits. The last column of Table 6 reports the economic value of the reduction in local pollution using our estimates of the change in emissions and the damage estimates from the AP3 model. But again the change in emissions differs across scenarios. We therefore report results in the lower right panel of Figure 8 as a local pollution benefit-cost ratio. All of the scenarios using the RP Own cost threshold have ratios that exceed or are close to one, meaning in some cases that priority dispatch of natural gas would pass a benefit-cost test when ignoring CO_2 emissions and focusing only on local pollutants. All scenarios for RP Max Coal exceed .5, and even those for RP Max Any indicate that the benefits are roughly a quarter of the costs when focused only on local pollution. These results, combined with those for CO_2, indicate that replacing coal

[21] Estimates of the SCC are based on dollars per metric ton, whereas we use short tons throughout our analysis because those are the units in which CEMS reports emissions. The SCC estimates per short ton are approximately 10 percent lower based on the unit conversion.

[22] Even our highest estimate at $356 per ton, which is an outlier and associated with very little emission reductions (replacement at the Interconnection region and the RP Max Any cost threshold), is still below the upper-bound the 95-percent confidence interval of the Rennert et al. (2022) estimate of the SCC at $413.

with natural gas generation is likely to pass the benefit-cost test, even though the different scenarios indicate uncertainty about exactly how much emissions are likely to decline.

5 Pigouvian tax comparisons

The policy of priority dispatch for natural gas is largely a command-and-control approach because it mandates dispatch of one source of generation over another. We now compare this approach with a carbon tax, which is typically a more favored instrument among economists because it is less prescriptive and more incentive based. The analysis is useful for two reasons. First, the results provide a way to evaluate the cost effectiveness of priority dispatch when compared to the costs of an emissions-equivalent carbon tax. Second, using our revealed preference methodology, solving for the total costs of abatement at different carbon tax rates provides a novel approach for estimating the short-run marginal costs of reducing CO_2 emissions in the electricity sector.

We solve for equilibria with carbon taxes in a way that enables direct comparison with those for priority dispatch. A key feature is to maintain the same feasibility conditions when moving from the observed equilibrium to a modeled equilibrium with imposition of a carbon tax. Let τ denote the per unit tax on CO_2 emissions, which can be set at any level, and recall that z_j^x and z_i^g are the emission rates for all j coal and all i natural gas units.[23] Rather than the two step procedure used before, we use a single optimization problem to define the modeled equilibrium. This problem is agnostic about the source of generation. The objective is to minimize the aggregate, tax-inclusive costs of electricity generation:

$$\min_{(X,G)} \sum_j (c_j^x + \tau z_j^x) x_j + \sum_i \sum_j (c_i^g + \tau z_i^g) g_{ij} \;\; s.t. \;\; (X,G) \text{ feasible.} \tag{7}$$

The key feature is that we start from the observed equilibrium and allow replacement generation—which can be from either coal or natural gas units—that satisfy the feasibility conditions. In this case, however, we focus only on the RP Own cost threshold scenario. As described previously, this is one of the preferred scenarios along with RP Max Coal,

[23]Setting the tax equal to the SCC is one possibility that we return to below. This would be the efficient policy ignoring the damages of local pollution.

but the latter is no longer warranted with a tax that admits the possibility of replacing generation from either coal or natural gas to either coal or natural gas.

Implementation of the minimization problem in (7) is relatively straightforward with some modification of the procedure described previously in Section 2.3. Once again, begin by defining the set of 'contender' units for potential replacement at each unit with observed generation. The difference here is that coal and natural gas units both could be replaced and could do the replacing. Then order all units (coal and natural gas) from high to low based on their tax-inclusive marginal costs. Loop through all units from the high to low, with a nested loop from low to high, replacing generation with spare capacity from contender units, keeping track of any used spare capacity to replace generation at the higher cost units. Note that when using the RP approach, this means that replacement occurs only if there is spare capacity at a unit with lower tax-inclusive marginal costs, but higher tax-exclusive marginal costs. The result is an equilibrium with minimized tax-inclusive costs satisfying the assumed feasibility conditions.

Figure 9 traces out the CO_2 emission reductions and costs of implementing carbon taxes at different rates. We report the results on an annual basis and consider the four different replacement region assumptions. To be clear, the costs represent the additional generation costs associated with reducing emissions using a carbon tax, where different points on the curves are labeled as corresponding to particular tax rates. That is, these curves represent minimized total cost curves of reducing emissions. There is very little difference between the BA and NERC subregion scenarios, and as expected, costs are lower with replacement at the NERC and Interconnection levels.

We also indicate (with dots) on the figure the priority dispatch solution corresponding with each replacement region and the RP Own cost threshold. In all cases, the solution lies relatively close to the carbon tax curve. The vertical distance down to the corresponding curve indicates how much more costly it is to achieve the same emissions reduction with priority dispatch than it does with a cost-effective carbon tax. With replacement at the NERC and NERC subregion, the increased costs are \$1.49 and \$2.5 billion per year, which is equivalent to higher costs of 7 and 11 percent, respectively.[24] While the costs are certainly higher, the relatively modest differences are due to the way that when pricing CO_2 emissions, natural gas generation is usually less costly than coal, because of the latter's higher emission rates. Where the carbon tax differs more substantially is with respect to the possibility of also replacing relatively high-emitting natural gas units.

Another observation to make about Figure 9 is the high carbon tax rates necessary to implement emissions reductions consistent with priority dispatch. We determine the equivalent carbon tax using the same vertical drop to the curve and solving for the carbon tax at that point. The tax rates for NERC and NERC subregion replacement are $284 and $306, respectively.[25] These rates are above estimates typically employed for the SCC, as discussed previously, and this suggests that priority dispatch may imply inefficiently high emissions reductions when accounting for only CO_2. Nevertheless, because the cost curves become quite steep at costs above $150 and $200 per ton, an efficient policy is likely to imply emissions reductions that are not substantially lower.

The use of the RP cost thresholds to model short-run grid dispatch in response to policy interventions provides a novel methodological approach. When combined with a carbon tax at different rates, the results can be illustrated as short-run marginal cost curve of emissions reductions in the U.S. electricity sector.[26] This raises the question of how our estimates compare with those of alternative approaches, noting that there are few comparable short-run estimates in the literature. We make two comparisons. Using an hourly dispatch model, Dahlke (2019) finds that carbon prices of $25 and $50 per ton induce short-run emissions reductions in the U.S. electricity sector of 17 and 22 percent, respectively. Our approach produces comparable estimates at $25 of 13 and 10 percent reductions for NERC and NERC subregion replacement, and at $50 of 21 and 17 percent reductions. The second comparison is to the U.S. Energy Information Administration's National Energy Modeling System (NEMS) that reports a 14 percent reduction in electricity sector emissions in the

[24] The comparable percentage cost increases for Interconnection and BA replacement are 17 and 11 percent, respectively.

[25] The comparable carbon tax rates for Interconnection and BA replacement are $172 and $259.

[26] We report these marginal cost curves in Figure A.3 of the Supplementary Appendix. In effect, they are rescaled versions of Figure 9, where the vertical axis in the carbon tax rate and the horizontal axis is the percentage reduction in CO_2 emissions.

same year as implementation of a $25 carbon tax (EIA 2022). In both cases, our estimates are quite close to the others, though slightly less, building confidence in our methodology for analyzing changes in short-run dispatch.

Finally, we compare the welfare gains between two alternative policies: priority dispatch of natural gas generation and implementation of a first-best Pigouvian tax. Taxes are set to internalize the unit-specific marginal damages from local pollution (SO_2 and NO_X) and the SCC. We show results with different assumptions about the SCC (i.e., $0, $50, $100, and $150) and the transmission region (i.e., NERC and NERC Subregion), continuing to focus on the RP Own cost threshold. The first column of Table 7 shows how the first-best reduction in coal generation is increasing in the SCC, as greater values implies a larger tax. The second column shows the reduction in coal generation with natural gas priority dispatch, which is invariant to the SCC, and the quantities match those in Panel A of Table 6. The third column shows the average hourly welfare gain of moving form the observed to the first-best equilibrium. For example, assuming a SCC of $50 and replacement at the NERC region, the welfare gain is $3.4 million per hour, or just under $30 billion for the year. The final column reports the the welfare gain with priority dispatch as percentage of the first-best welfare gain. While the magnitude is relatively low with a SCC of zero, the percentage quickly increases, reaching 96 percent with a SCC of $150 and NERC Region replacement. Hence priority dispatch is very close to a first-best policy instrument with values of the SCC near those based on the most recent evidence (Rennert et al. 2022; US EPA 2023). A similar result holds with replacement at the NERC subregion, but in this case, priority dispatch creates a welfare loss with a SCC of zero.

6 Additional considerations

In this section, we briefly discuss results related to additional considerations about our modeling approach: natural gas pipeline capacity, dynamic effects, and alternative fuel prices.

6.1 Pipeline capacity

The above estimates imply a large, short-run increase in generation from natural gas units. This raises a question about whether existing natural gas pipelines are able to deliver the requisite quantities of fuel. To examine the issue, we consider pipeline capacity constraints for the distribution of natural gas. In particular, within replacement areas, we place an upper bound on the amount of new natural gas generation that can be turned on:

$$\sum_i \sum_j \gamma_i g_{ij} \leq SparePipe, \tag{8}$$

where the left-hand is the amount of natural gas needed (i.e., the product of a generators heat rate γ_i and new generation summed over all generators), and the right-hand side is the amount of spare pipeline capacity available for electricity generation within the replacement area. This inequality becomes an additional constraint for a feasible allocation discussed in Section 2.3.

To implement this constraint, we collect data on natural gas consumption for electricity, home heating, and all other uses. Data are by state and month from 2010 to 2022.[27] We use U.S. Census population data to allocate natural gas consumption to counties that we then aggregate back up to a NERC region (we also consider NERC subregions). We define monthly spare pipeline capacity as the difference between the maximum observed consumption over this time period and observed consumption in each month in 2022. Unlike electricity, natural gas can be stored within a pipeline over days or weeks. We allocate the monthly spare pipeline capacity across hours in order to minimize the expected natural gas shortage. In particular, we define hourly *SparePipe* as a weighted partition of the monthly spare pipeline capacity based on the expected demand for coal to natural gas replacement. The weights we use are the minimum of observed coal generation and spare natural gas capacity for each hour.[28]

We find that accounting for natural gas pipeline capacity has relatively modest effects on our results. Part of the reason is that in places where pipeline capacity is known to

[27] These data are available at `https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm`.

[28] The minimum reflects the way that the amount of coal to natural gas replacement in any hour will be either the amount of coal generation or the amount of spare natural gas capacity, with the actual amount being the minimum of the two.

be tight, such as the Northeast, there is exceedingly little coal generation to replace. We report the comparative results for replacement at the NERC and NERC subregion level in Figure A.4 of the Supplementary Appendix. These results also assume the RP Own cost threshold. We consider this threshold rather than other preferred assumption of RP Max Coal because it is associated with replacement of more coal generation, meaning that pipeline capacity is likely to be more binding. Focusing on NERC replacement, the percentage of coal generation replaced decreases from 94 to 82 percent, and the percentage of CO_2 emissions reduced decreases from 29 to 26 percent. Despite less replacement, the cost per ton and local pollution benefit-cost ratios are even more favorable, as the high cost natural gas units are the ones the drop out with the pipeline capacity constraint. The cost per ton of CO_2 decreases from $49 to $44 and the local pollution benefit-cost ratio increases from 1.1 to 1.2.

6.2 Dynamic considerations

All of our preceding analysis has been carried out on an hour-by-hour basis without taking account of dynamic considerations that can be important for the ways that power plants operate. In particular, electricity generating units face ramping constraints that limit their ability to increase or decrease generation over short periods of time, e.g., from hour to hour. Knowing these dynamic constraints exist, one might wonder whether our modeled equilibria are feasible in the sense of satisfying plausible ramping constraints. We investigate this issue in three ways, all of which point to the fact that our straightforward hour-by-hour solution method is not creating what seems like implausible generation profiles within EGUs.

We continue to focus on the baseline scenario of replacement at the NERC region and the RP Own cost threshold. Given that this scenario produces greater shifts in generation than the other RP scenarios, a finding of plausible generation profiles would be expected to carry over to the others. First, we consider how much of the reduction in coal generation is coming from units that are completely shut down versus those that simply reduce generation. Among the 385 coal units, 110 units are shut down entirely, and these units account for 23 percent of the reduction in coal generation. The remainder of the reduction, just over 75 percent, is due to other coal units curtailing generation, but not shutting down completely.

The other two summary statistics that we produce relate directly to ramping rates. Following Holland et al. (2022), we calculate unit-specific ramping constraints using the CEMS generation data. In particular, for each unit, we use adjacent hours to calculate the distribution of ramping rates (up and down) over the previous decade. We then define the maximum ramp-up rate as the 99th percentile of the distribution and the maximum ramp-down rate as the 1st percentile of the distribution. Focusing on the reduction in coal generation, we find that our modeled equilibrium has ramp down violations of less than 0.3 percent when measured as either the number of hourly observations or the quantity of generation reduced.[29] This indicates that the hour-to-hour reductions at coal units is generally well within range of observed reductions. Focusing now on the increase in natural gas generation, the equilibrium has ramp up violations of 2.8 percent when measured as the number of hourly observations, and only 1.4 percent when measured in terms of new generation.[30] Combined, these results indicate that the hour-by-hour approach is not producing results that would change in a meaningful way even if one were to add the significant complexity of a dynamic model that explicitly takes account of ramping constraints.

6.3 Alternative fuel prices

We have assumed throughout throughout that coal and natural gas prices are given. We now examine how alternative fuel prices are likely to affect the results. In doing so, we do not simply adjust marginal cost of EGUs to reflect different fuel prices because our approach relies on an observed equilibrium based on actual market prices.[31] Instead, we replicate the analysis using a different year for purposes of comparison. We consider 2019 because it is the most recent pre-Covid year, and fuel prices differ meaningfully from 2022. In particular, the annual generation-weighted coal and natural gas prices were 49 and 60 percent lower in 2019. The observed equilibrium in 2019 also has coal generation at 70 percent of that for natural gas, compared to 60.9 percent in 2022.

[29] The percentage of ramp up violations for coal units is also less than 0.3 percent, measured in terms of hours or quantity generation.

[30] The percent of ramp down violations for natural gas units is 3.0 and 1.5 when measured by hour and generation, respectively.

[31] Referring back to Figure 3, it straightforward to see that different fuel prices will affect both the initial equilibrium and the cost of replacing coal generation with that of natural gas.

We report the full set of results for implementing natural gas priority dispatch in the Supplementary Appendix, while summarizing here the main differences with respect to the preferred scenarios.[32] With the RP Own cost threshold, along with NERC and NERC subregion replacement, there is very little difference between years in terms of the percentage of coal generation that is replaced and CO_2 emissions that are reduced. With the RP Max Coal threshold, however, the amount of coal replaced and emissions reduced are substantially lower, approximately half on a percentage basis. The reason is that natural gas prices are relatively lower than coal prices in 2019 making the RP Max Coal feasibility threshold more difficult to satisfy for natural gas replacement units.

More substantial differences between years relate to the cost estimates. We previously reported for 2022 a range of cost estimates per ton of CO_2 from \$49 to \$92. The comparable range is from \$9 to \$49 in 2019. The reason for the differing results is that costs are determined by the difference between coal and natural gas prices, and the gap between fuels is less in 2019: \$1.33 per mmBtu compared to \$4.22 in 2022.[33] We find the same pattern of lower costs in 2019 when comparing the benefit-cost ratios for local pollution. The range of estimates among the preferred scenarios for 2022 is from 0.6 to 1.1, and it increases to a range of 1.1 to 6.8 for 2019, meaning that implementing priority dispatch in 2019 would pass a benefit-cost test based on avoided damages from local pollutants only.

Finally, we acknowledge a limitation of the analysis within a year because, in our model, fuel prices are not endogenous to changes in demand for coal and natural gas. The increase in demand for natural gas would affect prices in the short-run, and our analysis does not capture this effect. Nor does it capture the fact that coal prices would decline. In these respects, our analysis is likely to provide an underestimate of the costs assuming the increase in natural gas prices would have a larger effect. Nevertheless, we conjecture that the benefit-cost comparisons, which are quite favorable, even across years with very different prices, would not change qualitatively even if price adjustments were taken into account.

[32]We report analogs to the key figures and tables in Appendix Figures A.5 and A.6 and Table A.5.

[33]These price gaps are generation-weighted averages. Capacity also matters for our analysis, and the gaps remain similar by this metric, with differences of \$1.20 and \$3.82 for 2019 and 2022, respectively.

7 Conclusion

The phasedown of coal for electricity generation is considered vital for reducing CO_2 emissions in sufficient quantities to meet global climate targets. Compared to other sources of energy, the burning of coal is also associated with higher emissions of local pollutants that adversely affect human health. Many nations have pledged to phaseout coal for electricity, and while the United States has no such target in place, several states do. This paper examines the feasibility, costs, and benefits of immediately reducing U.S. coal-generated electricity given the existing fleet of power plants. In particular, we take consumption in 2022 as given and evaluate how prioritizing dispatch of natural gas generation over that of coal would change emissions and operating costs.

The results suggest broad scope for reducing coal generated electricity and net emissions with favorable benefit-cost comparisons. Based on preferred scenarios, we find that 66 to 94 percent of coal generation could be replaced immediately while still satisfying electricity demand. The net effect on CO_2 emissions is a reduction of 18 to 29 percent of the combined coal and natural gas emissions in the electricity sector. This quantity translates to between 5 and 8 percent of all U.S. energy-related CO_2 emissions in 2022, according to the EIA's estimate of 5,472 million tons. Recent estimates find that the current suite of policies in the United States, inclusive of the Inflation Reduction Act, will fall short of the nation's 2030 commitment by between 12 and 18 percent (Bistline et al. 2023). This may necessitate the need for consideration of additional policies, and the near term phasedown of coal generated electricity may be one such candidate.

We examine sensitivity of these results to geographical transmission constraints, replacement cost conditions, natural gas pipeline capacity, and alternative fuel prices between 2019 and 2022. While the different scenarios are associated with different quantities of coal replacement and emissions reductions, the economic conclusions are robust across scenarios: replacing coal generation with that of natural gas is likely to always pass a benefit-cost comparison. The cost range of our preferred scenarios is \$49 to \$92 per ton of CO_2, which compares favorably with current estimates of the SCC. Moreover, benefit-cost ratios in some cases are near or exceed unity considering local pollutant co-benefits alone.

Beyond the policy relevance of these empirical findings, the paper makes a methodological contribution to the modeling changes in short-run dispatch of electricity among generators. We develop a replacement algorithm based on replacement regions and marginal cost comparisons. The approach uses the observed equilibrium as a starting point, upon which policy induced changes must satisfy revealed-preference type conditions that rationalize the initial equilibrium. We use the approach with a primary focus on modeling priority dispatch of natural gas, but we also consider implementation of carbon taxes. By comparing these two policies, we find that despite the command-and-control nature of priority dispatch, it is relatively cost effective in comparison to Pigouvian taxes. Additional results of the analysis, owing to the way that emission reductions are cost minimized with a carbon tax, are marginal cost curves for short-run emission reductions on the U.S. electricity grid using our approach. These provide estimates with a straightforward and transparent method to complement others in the literature, and the methods can be used to evaluate other policies in future research.

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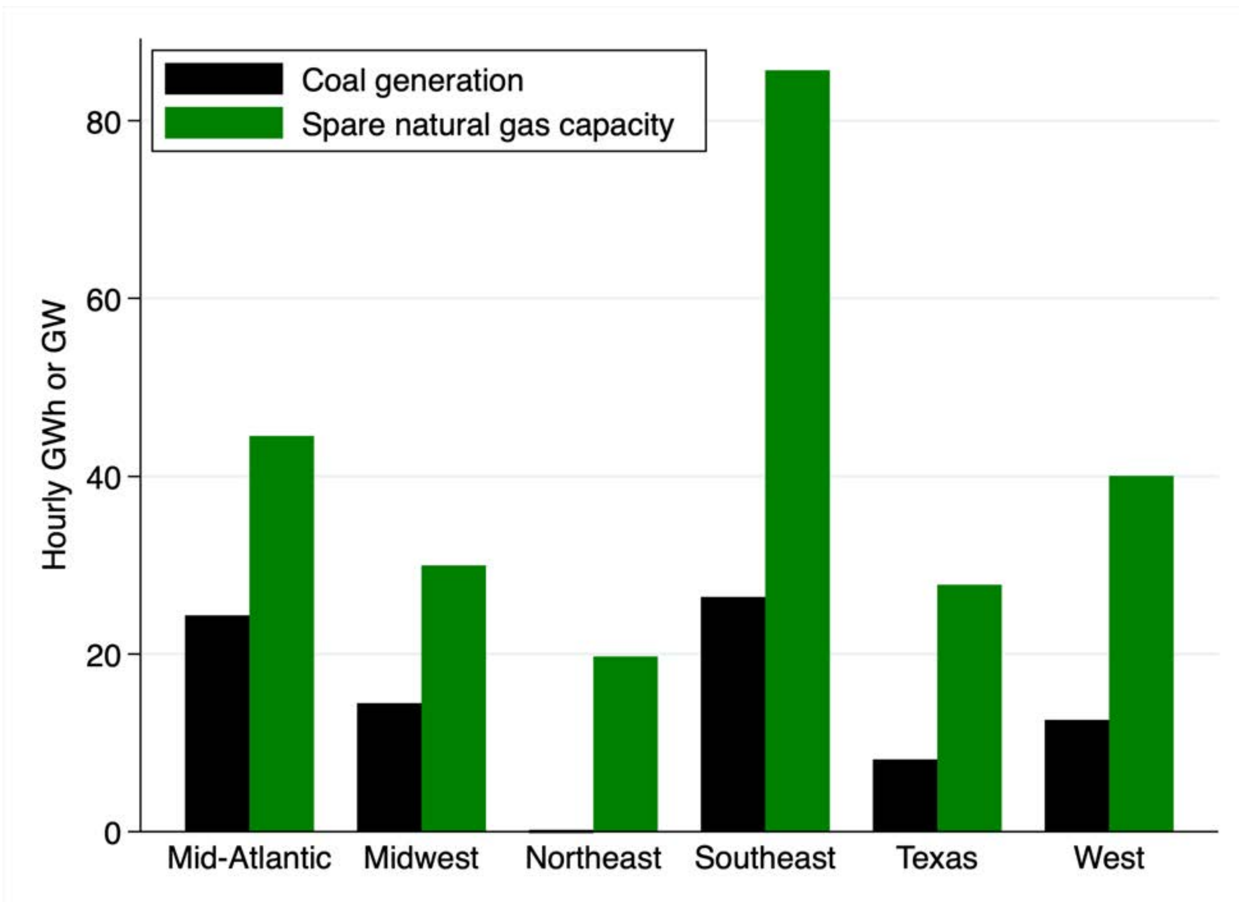


Figure 1: Annual hourly average coal generation and spare natural gas capacity in the six NERC regions for 2022. Coal generation is reported in GWh per hour, and spare natural gas capacity is reported in GW, making the units comparable.

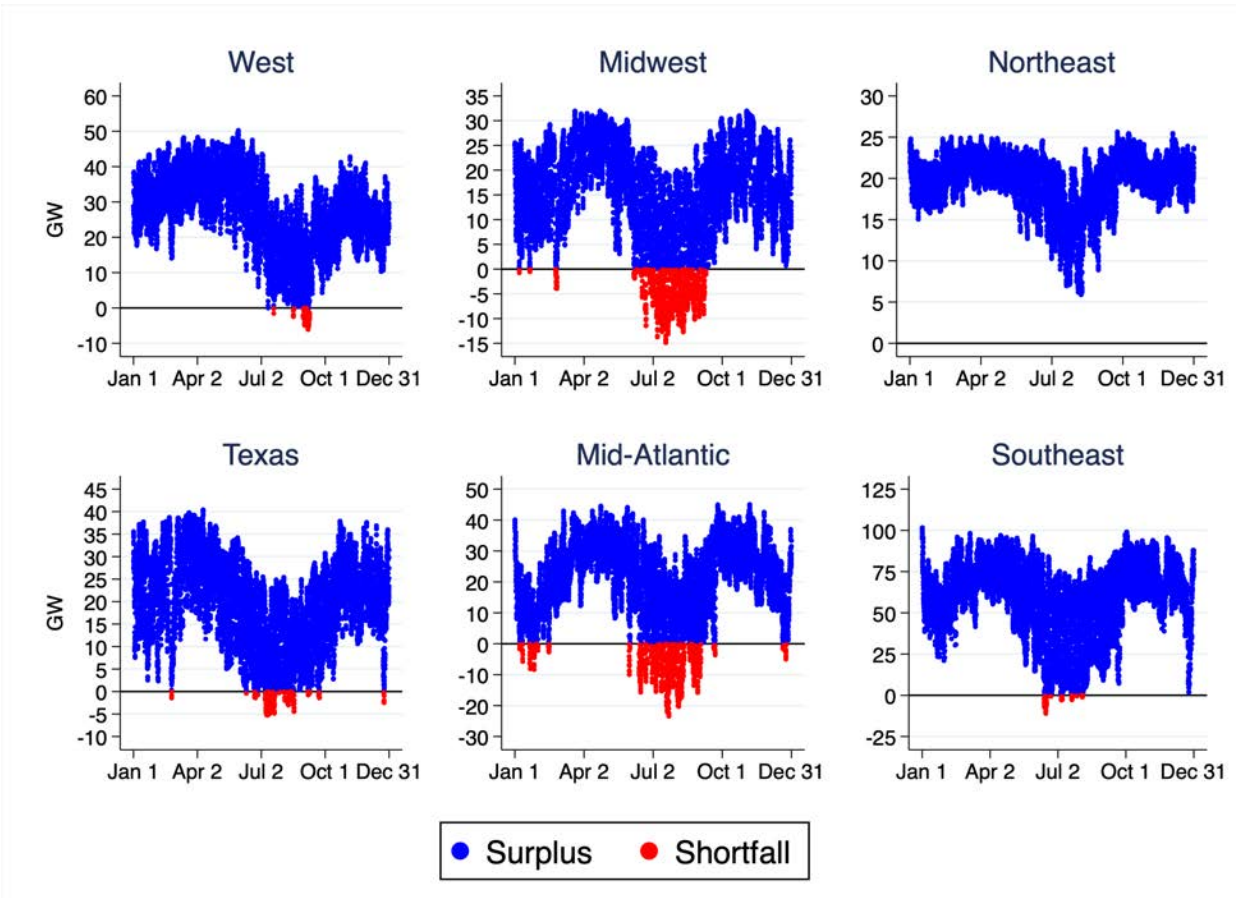


Figure 2: Hourly surplus or shortfall of natural gas capacity in the six NERC regions for 2022. Points represent hourly spare natural gas capacity measured in GW minus coal generation measured in GWh per hour. Surplus occurs when the difference is positive, and shortfall occurs when the difference is negative.

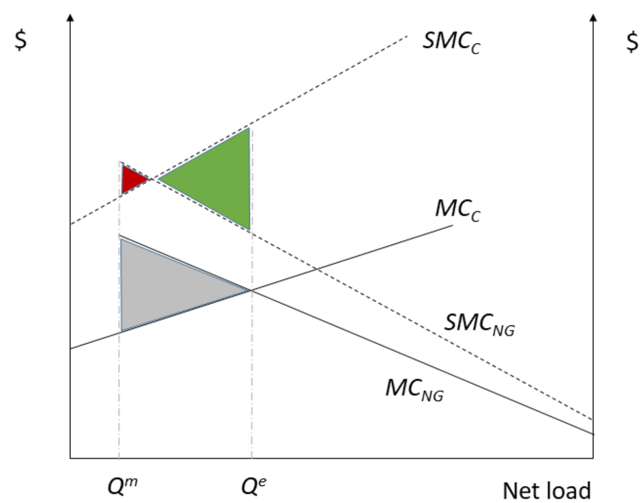


Figure 3: The impacts of priority dispatch of natural gas generation over coal generation. The initial equilibrium split between sources of generation is Q^e, and the modeled equilibrium is Q^m. Net private costs are the gray area, and net social benefits are the green minus red.

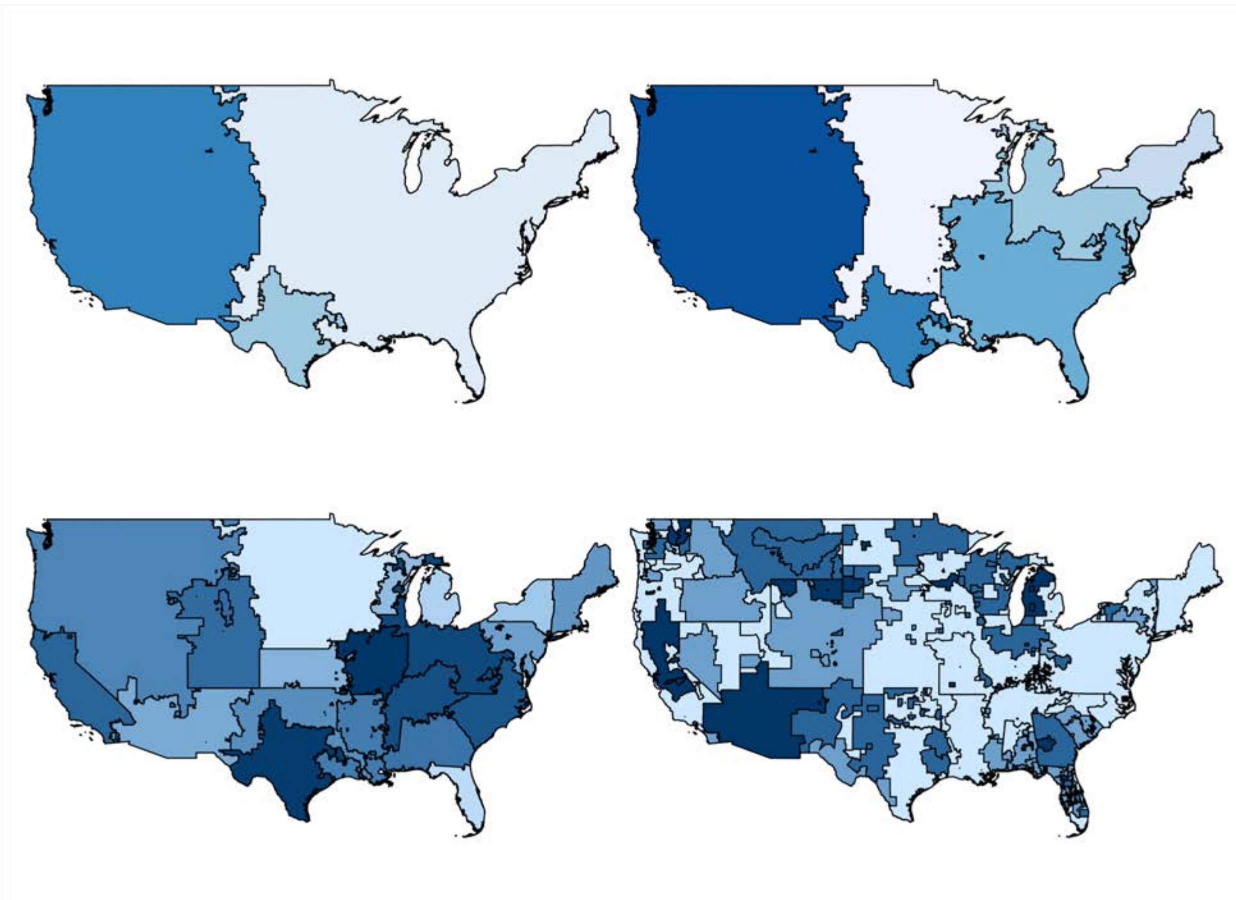


Figure 4: Replacement regions. Top left is Interconnections of which there are 3, top right is NERC regions of which there are 6, bottom left is NERC subregions of which there are 22, and bottom right is Balancing Authorities (e.g., ISOs) of which there are 51.

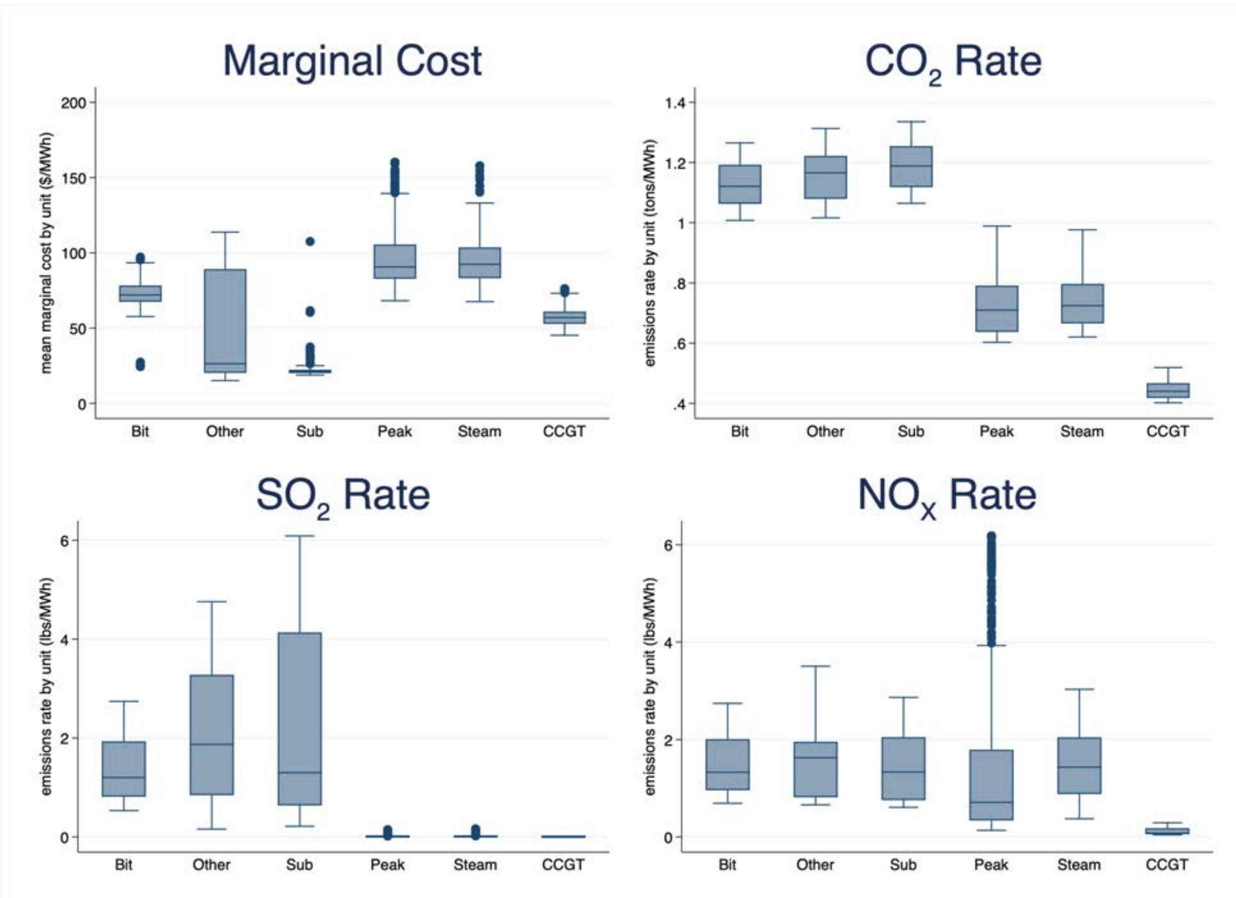


Figure 5: Marginal costs of electricity generation and emissions rates at generating units by type. Box plots show the median, interquartile ranges, adjacent values, and outside values, averaged across months. Coal units are bituminous (Bit), subbituminous (Sub), and Other. Natural gas units are Peak, Steam, and CCGT.

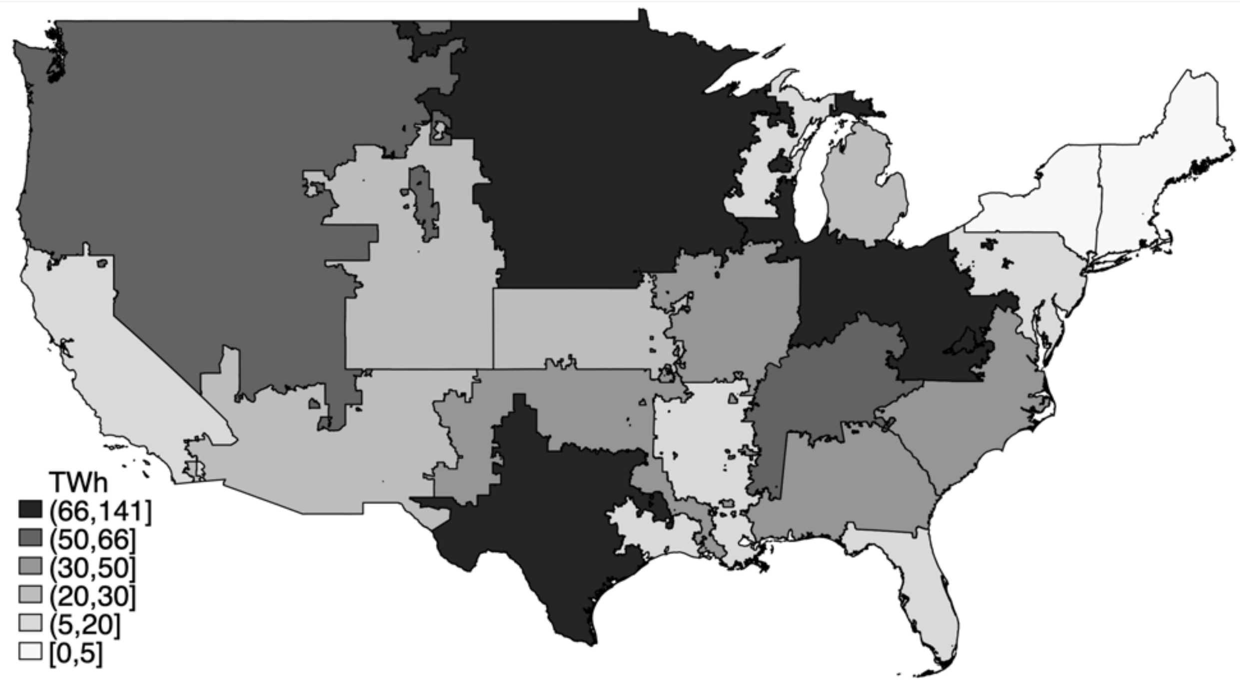


Figure 6: Annual reduction in coal generation. Reductions reported in TWh. Replacement is assumed at the NERC Region with the RP Own cost threshold. Reductions are nevertheless reported at the NERC subregion to provide greater resolution of where generation changes the most.

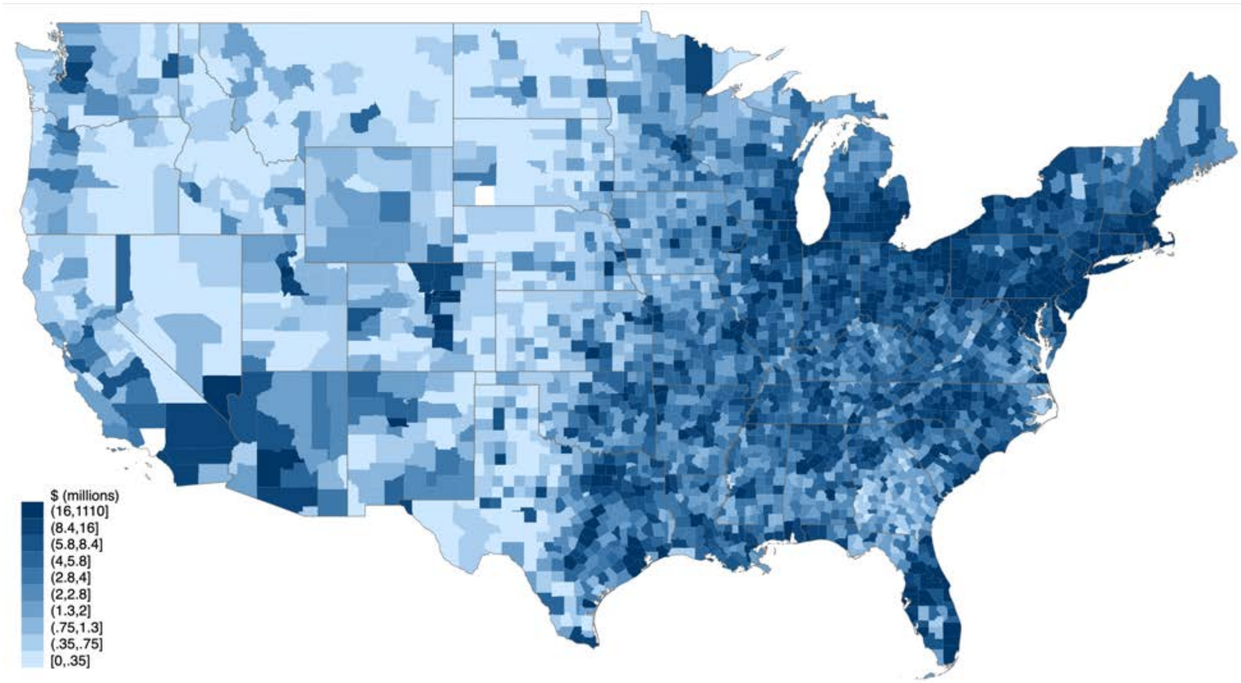


Figure 7: Change in local pollution damages. The difference between the observed and the modeled equilibrium assuming NERC region replacement and the RP Own cost threshold. Avoided damages are reported on an annual basis at the county level in millions of 2020 dollars.

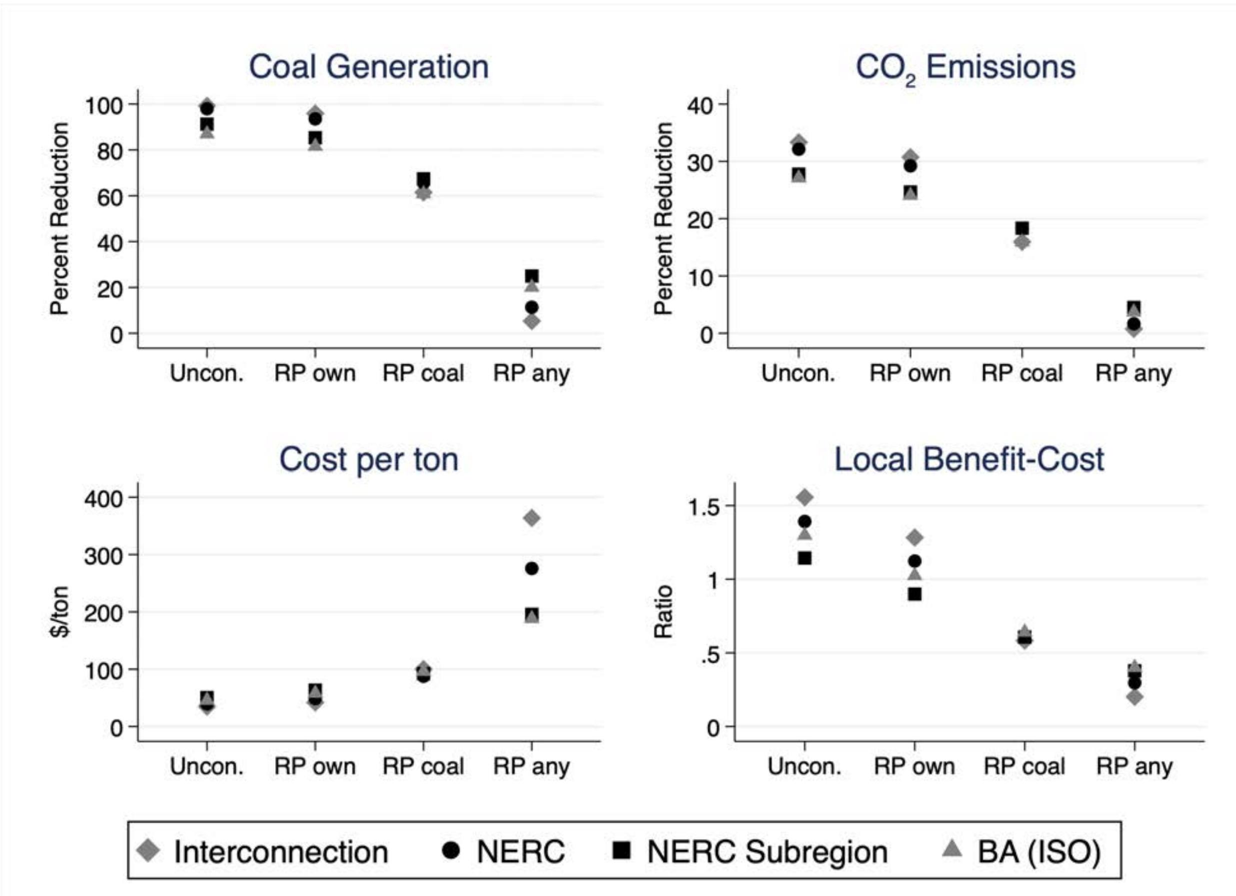


Figure 8: Comparison of results across all 16 scenarios. The top panels report the percentage reduction in coal generation and CO_2 emissions in the electricity sector. The bottom panels report the estimated cost per ton of CO_2 and the local pollution benefit-cost ratio. The scenarios are all 4 replacement regions and all 4 replacement cost thresholds. The preferred scenarios are NERC and NERC subregion replacement and the RP Own cost and RP Max Coal cost thresholds.

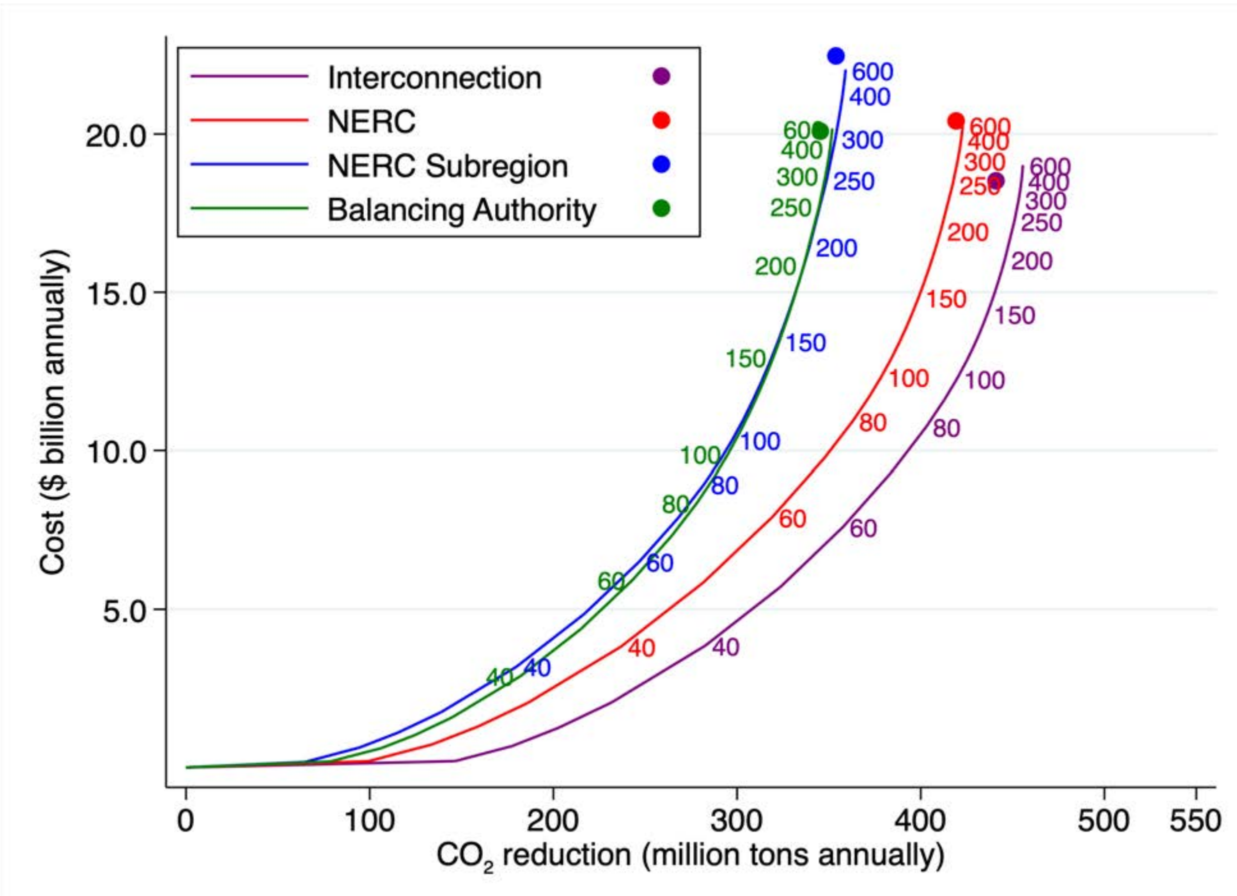


Figure 9: Minimized cost of reducing electricity sector CO_2 emissions. The cost is the minimized total cost of reducing emissions from coal and natural gas units. The curves trace out the loci of different carbon tax rates, some of which are indicated. All curves assume the RP Own cost threshold and results are shown separately for different replacement regions. The corresponding dots indicate the reduction in CO_2 emissions and costs associated with implementing priority dispatch of natural gas generation.

Table 1: Average hourly generation and capacity of coal and natural gas units by Interconnection, NERC region, and total

	Coal		Natural gas		Spare
Region	Generation	Capacity	Generation	Capacity	Capacity
East	65.3	146.0	105.1	284.9	179.9
Mid-Atlantic	24.4	55.9	26.6	71.1	44.5
Midwest	14.5	28.6	8.1	38.1	30.0
Northeast	0.0	0.4	9.3	29.0	19.7
Southeast	26.4	61.0	61.1	146.8	85.7
Texas	8.1	13.3	16.4	44.2	27.8
West	12.6	20.5	21.5	61.6	40.1
All	86.0	179.8	142.9	390.7	247.7

Notes: Generation is measured in GWh per hour, and capacity is measured in GW. Spare capacity is natural gas capacity minus generation. East represents the entire Eastern Interconnection, which is an aggregate of its four NERC regions. All is an aggregate of the three Interconnections.

Table 2: Average hourly emissions by Interconnection, NERC region, and total

	Coal			Natural gas		
Region	CO_2	SO_2	NO_X	CO_2	SO_2	NO_X
East	73.1	132.8	88.6	48.3	1.5	23.2
Mid-Atlantic	27.1	47.4	28.3	11.9	0.2	3.6
Midwest	16.6	30.5	22.6	4.2	0.1	4.4
Northeast	0.0	0.0	0.1	4.5	0.5	1.8
Southeast	29.4	54.8	37.6	27.6	0.8	13.4
Texas	9.4	20.8	9.5	7.7	0.1	4.6
West	14.6	14.3	21.6	10.0	0.1	3.1
All	97.1	167.8	119.7	65.9	1.7	30.9

Notes: CO_2 is measured in thousands of tons. SO_2 and NO_X are measured in thousands of pounds. East represents the entire Eastern Interconnection, which is an aggregate of its four NERC regions. All is an aggregate of the three Interconnections.

Table 3: Changes in mean hourly generation and capacity factors assuming NERC region replacement and the RP Own cost threshold.

	Coal	CCGT	Steam	Peaker
Panel A: Change in Generation				
Mid-Atlantic	-20.3	7.1	3.0	10.3
Midwest	-13.9	7.0	3.3	3.5
Northeast	-0.0	0.0	0.0	0.0
Southeast	-25.6	15.7	2.7	7.2
Texas	-8.0	6.8	0.8	0.4
West	-12.5	11.5	0.2	0.9
All	-80.4	48.2	10.0	22.3
Panel B: Observed capacity factors in 2022				
Mid-Atlantic	0.44	0.63	0.07	0.08
Midwest	0.51	0.38	0.13	0.09
Northeast	0.08	0.44	0.13	0.15
Southeast	0.43	0.61	0.20	0.09
Texas	0.61	0.49	0.13	0.08
West	0.62	0.48	0.12	0.09
All	0.48	0.55	0.14	0.09
Panel C: Modeled equilibrium capacity factors				
Mid-Atlantic	0.07	0.82	0.47	0.48
Midwest	0.02	0.87	0.46	0.34
Northeast	0.00	0.44	0.13	0.15
Southeast	0.01	0.78	0.38	0.26
Texas	0.01	0.72	0.22	0.17
West	0.00	0.76	0.14	0.16
All	0.03	0.76	0.31	0.31

Notes: Generation is reported in GWh. Capacity factors are mean hourly generation divided the estimated capacity. Differences my not sum to zero because of rounding.

Table 4: Hourly counts and magnitudes of shortfalls in spare natural gas capacity assuming NERC region replacement and the RP Own cost threshold

NERC Region	Shortfall (Hours)	Median (GWh)	Mean (GWh)	Max (GWh)	Short/Net load Ratio
Mid-Atlantic	8,760	2.7	4.0	26.7	0.076
Midwest	1,597	1.1	3.3	16.6	0.075
Northeast	0	.	.	.	0.000
Southeast	8,760	0.5	0.8	17.5	0.009
Texas	358	1.9	2.4	7.0	0.053
West	113	2.9	3.3	8.8	0.051
Total	8,760	3.3	5.6	52.9	0.023

Notes: Shortfall is the number of hours in which hourly coal generation exceeds spare natural gas capacity given the RP Own cost threshold. For the aggregation in Total, the count in the number of hours when there is a shortfall in at least one region. The Median, Mean, and Max are summary statistics across shortfalls within a region or for the national aggregation. The Short/Net Load Ratio is the magnitude of the aggregate hourly shortfall over the net fossil load averaged over all hours of the year.

Table 5: Average hourly effects on emissions and costs assuming NERC region replacement and the RP Own cost threshold

	Coal	CCGT	Steam	Peaker	Net
Panel A: Change in CO_2					
Mid-Atlantic	-22.7	3.1	2.2	7.2	-10.2
Midwest	-16.0	3.2	2.3	2.4	-8.1
Northeast	-0.0	0.0	0.0	0.0	-0.0
Southeast	-28.8	6.6	1.8	5.1	-15.2
Texas	-9.3	3.0	0.6	0.3	-5.5
West	-14.6	5.0	0.1	0.6	-8.9
All	-91.5	20.9	7.0	15.7	-47.9
Panel B: Change in SO_2					
Mid-Atlantic	-32.4	0.0	0.1	0.1	-32.1
Midwest	-27.4	0.0	0.0	0.1	-27.3
Northeast	-0.0	0.0	0.0	0.0	-0.0
Southeast	-53.5	0.1	0.1	0.2	-53.2
Texas	-18.8	0.0	0.0	0.0	-18.7
West	-13.8	0.1	0.0	0.0	-13.7
All	-145.9	0.2	0.3	0.4	-145.0
Panel C: Change in NO_X					
Mid-Atlantic	-22.9	0.6	3.7	9.5	-9.0
Midwest	-20.8	1.1	5.2	3.6	-10.9
Northeast	-0.1	0.0	0.0	0.0	-0.1
Southeast	-36.3	1.6	4.9	7.3	-22.4
Texas	-9.5	1.0	1.0	0.6	-6.8
West	-21.2	0.8	0.1	0.2	-20.0
All	-110.7	5.1	15.1	21.3	-69.2
Panel D: Change in generation costs					
Mid-Atlantic	-1223.3	353.2	269.0	865.4	264.4
Midwest	-283.7	402.8	291.1	325.7	735.9
Northeast	-1.9	2.2	0.5	0.0	0.8
Southeast	-1263.9	859.1	253.7	704.0	552.9
Texas	-166.4	339.4	70.1	38.4	281.6
West	-310.5	695.6	18.2	91.6	494.9
All	-3249.6	2652.4	902.6	2025.1	2330.5

Notes: CO_2 is measured in thousands of tons. SO_2 and NO_X are measured in thousands of pounds. Costs are measured in thousands of 2020 dollars.

Table 6: Aggregate hourly results by differing replacement regions and cost thresholds

Replacement level	Coal gen.	CO_2	Cost	Local Damages
Panel A: RP Own				
Interconnection	-82.4	-50.3	2114.5	-2713.1
NERC	-80.4	-47.9	2330.5	-2618.4
SubRegion	-73.4	-40.4	2565.1	-2306.0
BA (ISO)	-70.2	-39.4	2293.4	-2350.3
Panel B: Unconstrained				
Interconnection	-85.3	-54.6	1899.5	-2956.5
NERC	-84.2	-52.6	2076.6	-2891.4
SubRegion	-78.5	-45.5	2293.5	-2624.2
BA (ISO)	-74.8	-44.4	2034.4	-2642.2
Panel C: RP Max Coal				
Interconnection	-52.9	-26.1	2614.9	-1524.4
NERC	-56.5	-30.0	2633.8	-1627.0
SubRegion	-57.9	-30.1	2777.2	-1687.2
BA (ISO)	-52.3	-26.1	2507.6	-1607.5
Panel D: RP Max Any				
Interconnection	-4.6	-1.3	462.8	-93.4
NERC	-9.8	-2.7	749.8	-222.5
SubRegion	-21.5	-7.4	1441.7	-545.3
BA (ISO)	-17.3	-6.1	1142.8	-457.9

Notes: Generation is reported in GWh, CO_2 emissions in thousands of tons, and costs and local damages in thousands of 2020 dollars.

Table 7: Average hourly comparison between a Pigouvian tax (accounting for climate and local pollution damages) and priority dispatch

	Change in coal generation		Welfare Gains	
SCC	First best	RP Own cost	First best vs Observed	% First best captured by RP Own cost
Panel A: NERC				
0	-34.0	-80.4	1,930	14.9
50	-62.9	-80.4	3,418	78.4
100	-70.8	-80.4	5,521	91.9
150	-74.6	-80.4	7,776	96.0
Panel B: NERC Subregion				
0	-30.1	-73.4	1,532	-16.9
50	-52.4	-73.4	2,751	64.0
100	-60.9	-73.4	4,452	84.9
150	-65.2	-73.4	6,300	92.1

Notes: Change in generation is reported in GWh, and the welfare gain is reported in thousands of 2020 dollars.

Supplementary Appendix for

On the Feasibility, Costs, and Benefits of an Immediate Phasedown of Coal for U.S. Electricity Generation

Stephen P. Holland   Matthew J. Kotchen   Erin T. Mansur
Andrew J. Yates

This file contains supplementary figures and tables. They are included in the order referenced in the main text. The figures and tables included are the following :

- Figure A.1 through A.6
- Tables A.1 through A.5

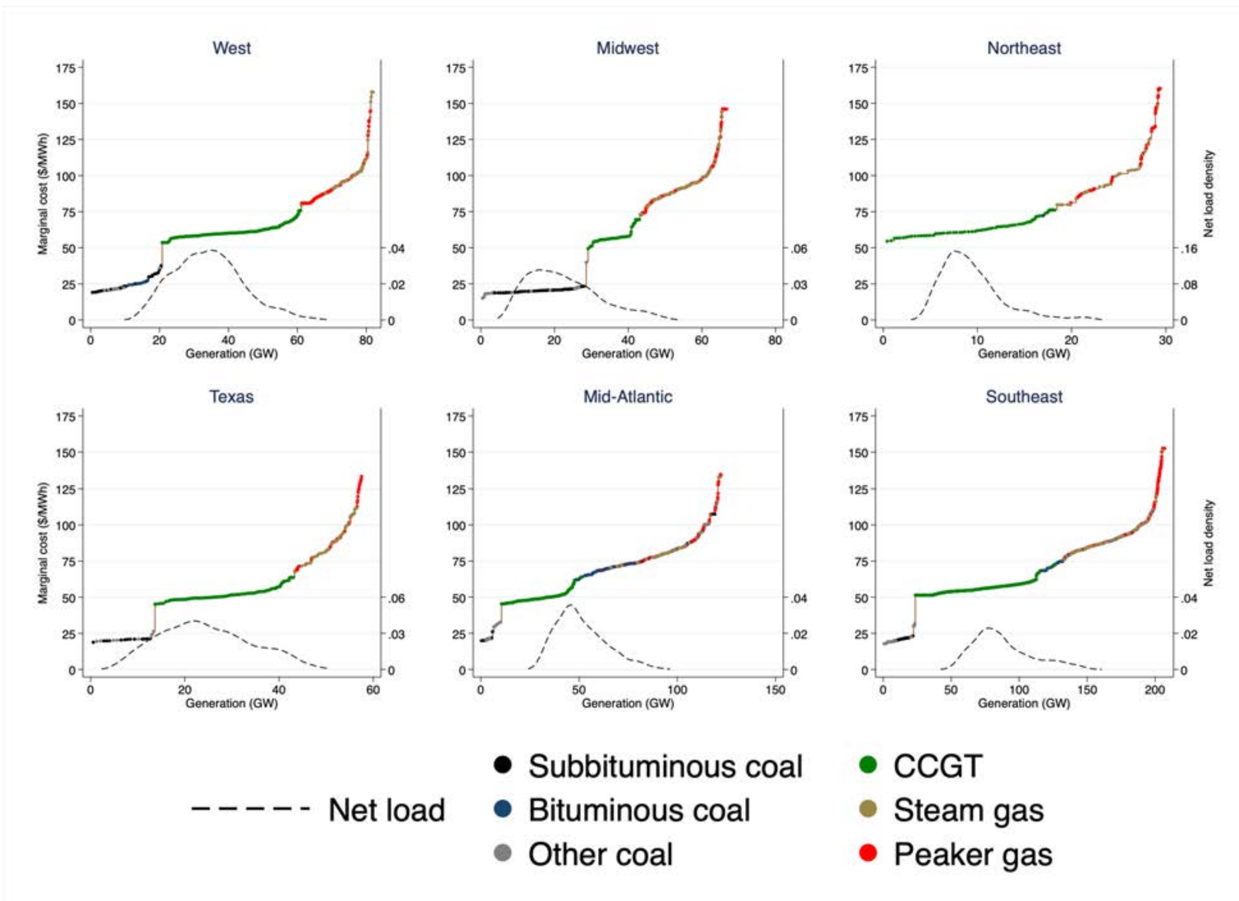
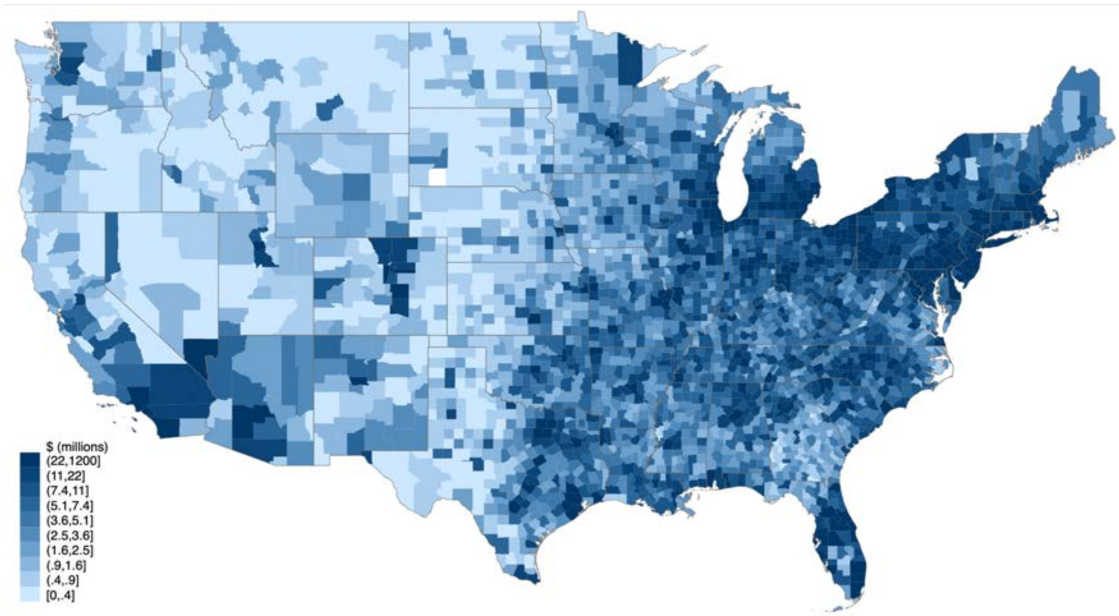


Figure A.1: Standard merit order curves and distribution of net load for each NERC region. The merit order curves show marginal cost and estimated capacity for each generating unit ordered by marginal cost. As described in the main text, net load is consumption net of other generation sources and equals required fossil generation. The kernel density illustrates hourly net load.

Observed



Modeled

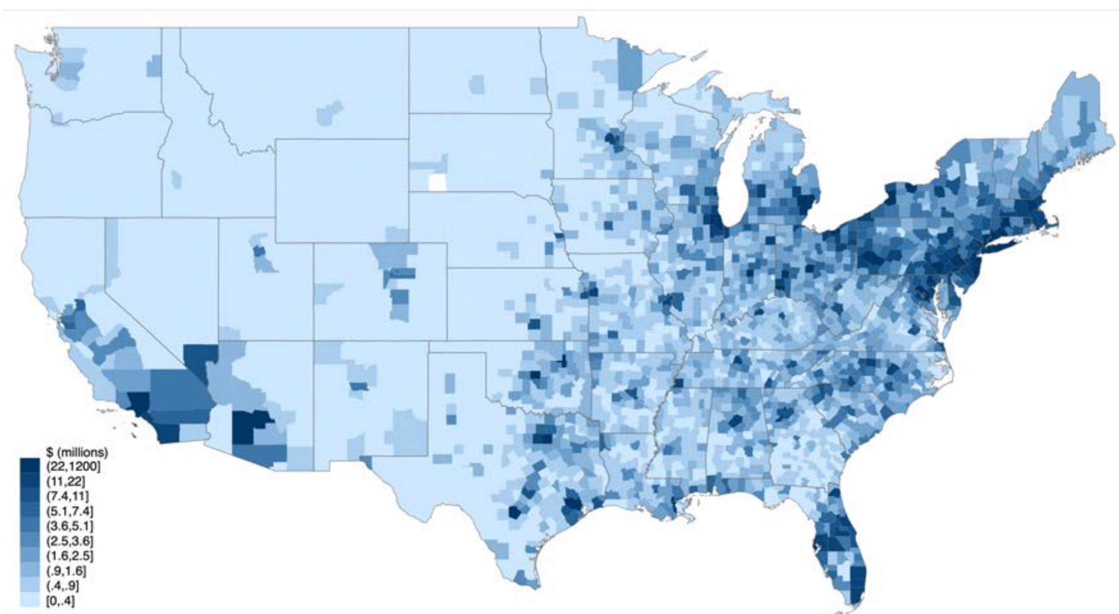


Figure A.2: Distribution of local pollution damages. The top panel shows annual damages at the county level in 2020 dollars based on the observed pattern of generation. The bottom panel shows the distribution of damages with priority dispatch of natural gas with replacement at the NERC region with the RP Own cost threshold. Figure 7 is the difference between the top and bottom panels.

Table A.1: The change in generation, emissions, and costs at different replacement regions – RP Own cost threshold

Replacement level	Coal	CCGT	Steam	Peaker	Net
Panel A: Generation					
Interconnection	-82.4	55.3	8.5	18.7	0.0
NERC	-80.4	48.2	10.0	22.3	0.0
SubRegion	-73.4	33.3	7.0	33.0	0.0
BA (ISO)	-70.2	34.2	11.2	24.7	0.0
Panel B: CO_2 emissions					
Interconnection	-93.7	24.0	6.0	13.4	-50.3
NERC	-91.5	20.9	7.0	15.7	-47.9
SubRegion	-83.6	14.6	5.0	23.6	-40.4
BA (ISO)	-79.9	15.1	7.8	17.6	-39.4
Panel C: SO_2 emissions					
Interconnection	-149.1	0.2	0.3	0.4	-148.2
NERC	-145.9	0.2	0.3	0.4	-145.0
SubRegion	-132.8	0.1	0.3	0.6	-131.8
BA (ISO)	-132.0	0.2	0.3	0.4	-131.1
Panel D: NO_X emissions					
Interconnection	-113.1	5.6	12.3	19.7	-75.5
NERC	-110.7	5.1	15.1	21.3	-69.2
SubRegion	-99.8	4.0	10.3	33.5	-52.1
BA (ISO)	-95.0	4.2	18.0	24.1	-48.7
Panel E: Costs					
Interconnection	-3403.7	3002.1	778.5	1737.6	2114.5
NERC	-3249.6	2652.4	902.6	2025.1	2330.5
SubRegion	-2960.6	1844.7	636.3	3044.8	2565.1
BA (ISO)	-2851.2	1872.6	987.9	2284.1	2293.4

Notes: Generation in GWh, CO_2 emissions in thousand tons, SO_2 and NO_X emissions in thousands of pounds, and costs in thousands of dollars.

Table A.2: The change in generation, emissions, and costs at different replacement regions – Unconstrained cost threshold

Replacement level	Coal	CCGT	Steam	Peaker	Net
Panel A: Generation					
Interconnection	-85.3	64.1	7.5	13.7	0.0
NERC	-84.2	57.5	8.5	18.2	0.0
SubRegion	-78.5	42.0	6.9	29.6	0.0
BA (ISO)	-74.8	43.3	10.5	21.0	0.0
Panel B: CO_2 emissions					
Interconnection	-96.9	27.9	5.1	9.2	-54.6
NERC	-95.7	25.0	5.8	12.3	-52.6
SubRegion	-89.3	18.2	4.8	20.8	-45.5
BA (ISO)	-85.0	19.0	7.2	14.5	-44.4
Panel C: SO_2 emissions					
Interconnection	-156.2	0.3	0.3	0.2	-155.4
NERC	-154.9	0.3	0.2	0.2	-154.2
SubRegion	-144.1	0.2	0.3	0.4	-143.2
BA (ISO)	-141.5	0.2	0.2	0.3	-140.8
Panel D: NO_X emissions					
Interconnection	-117.2	6.6	10.8	10.9	-88.9
NERC	-116.2	6.0	12.5	14.8	-82.8
SubRegion	-107.0	4.5	10.0	28.4	-64.1
BA (ISO)	-101.6	5.0	17.5	17.5	-61.7
Panel E: Costs					
Interconnection	-3451.4	3493.4	653.0	1204.5	1899.5
NERC	-3412.7	3135.7	751.9	1601.8	2076.6
SubRegion	-3264.4	2282.1	602.1	2673.6	2293.5
BA (ISO)	-3097.1	2336.2	913.8	1881.5	2034.4

Notes: Generation in GWh, CO_2 emissions in thousand tons, SO_2 and NO_X emissions in thousands of pounds, and costs in thousands of dollars.

Table A.3: The change in generation, emissions, and costs at different replacement regions – RP Max Coal cost threshold

Replacement level	Coal	CCGT	Steam	Peaker	Net
Panel A: Generation					
Interconnection	-52.9	19.8	10.1	23.0	0.0
NERC	-56.5	25.3	9.5	21.8	0.0
SubRegion	-57.9	22.6	7.1	28.2	0.0
BA (ISO)	-52.3	16.8	10.0	25.5	0.0
Panel B: CO_2 emissions					
Interconnection	-60.4	8.7	7.7	17.9	-26.1
NERC	-64.8	11.2	6.9	16.7	-30.0
SubRegion	-66.6	10.0	5.3	21.2	-30.1
BA (ISO)	-59.9	7.5	7.1	19.2	-26.1
Panel C: SO_2 emissions					
Interconnection	-92.4	0.1	0.4	0.7	-91.3
NERC	-101.4	0.1	0.3	0.6	-100.4
SubRegion	-105.9	0.1	0.3	0.7	-104.8
BA (ISO)	-99.9	0.1	0.3	0.6	-99.0
Panel D: NO_X emissions					
Interconnection	-73.2	2.0	15.9	34.2	-21.1
NERC	-80.8	2.9	14.4	27.1	-36.4
SubRegion	-80.4	2.9	10.8	34.7	-32.0
BA (ISO)	-73.8	2.5	16.0	31.2	-24.1
Panel E: Costs					
Interconnection	-1923.2	1154.5	998.3	2385.4	2614.9
NERC	-1861.9	1436.9	889.7	2169.0	2633.8
SubRegion	-1931.0	1257.2	671.6	2779.4	2777.2
BA (ISO)	-1841.8	941.4	899.5	2508.5	2507.6

Notes: Generation in GWh, CO_2 emissions in thousand tons, SO_2 and NO_X emissions in thousands of pounds, and costs in thousands of dollars.

Table A.4: The change in generation, emissions, and costs at different replacement regions – RP Max Any cost threshold

Replacement level	Coal	CCGT	Steam	Peaker	Net
Panel A: Generation					
Interconnection	-4.6	0.0	1.4	3.2	0.0
NERC	-9.8	0.0	2.3	7.4	0.0
SubRegion	-21.5	0.2	4.7	16.5	0.0
BA (ISO)	-17.3	0.8	2.8	13.7	0.0
Panel B: CO_2 emissions					
Interconnection	-5.4	0.0	1.3	2.8	-1.3
NERC	-11.4	0.0	2.2	6.5	-2.7
SubRegion	-24.9	0.1	3.9	13.5	-7.4
BA (ISO)	-20.0	0.3	2.5	11.1	-6.1
Panel C: SO_2 emissions					
Interconnection	-9.6	0.0	0.0	0.3	-9.2
NERC	-18.8	0.0	0.1	0.5	-18.2
SubRegion	-40.5	0.0	0.2	0.8	-39.5
BA (ISO)	-32.3	0.0	0.1	0.7	-31.5
Panel D: NO_X emissions					
Interconnection	-5.6	0.0	2.7	13.8	10.9
NERC	-13.1	0.0	4.2	24.1	15.3
SubRegion	-28.3	0.0	8.4	34.4	14.6
BA (ISO)	-25.6	0.1	5.3	29.5	9.2
Panel E: Costs					
Interconnection	-180.7	0.0	166.0	477.5	462.8
NERC	-458.6	0.0	273.1	935.3	749.8
SubRegion	-889.6	11.8	486.4	1833.2	1441.7
BA (ISO)	-765.3	45.0	305.0	1558.2	1142.8

Notes: Generation in GWh, CO_2 emissions in thousand tons, SO_2 and NO_X emissions in thousands of pounds, and costs in thousands of dollars.

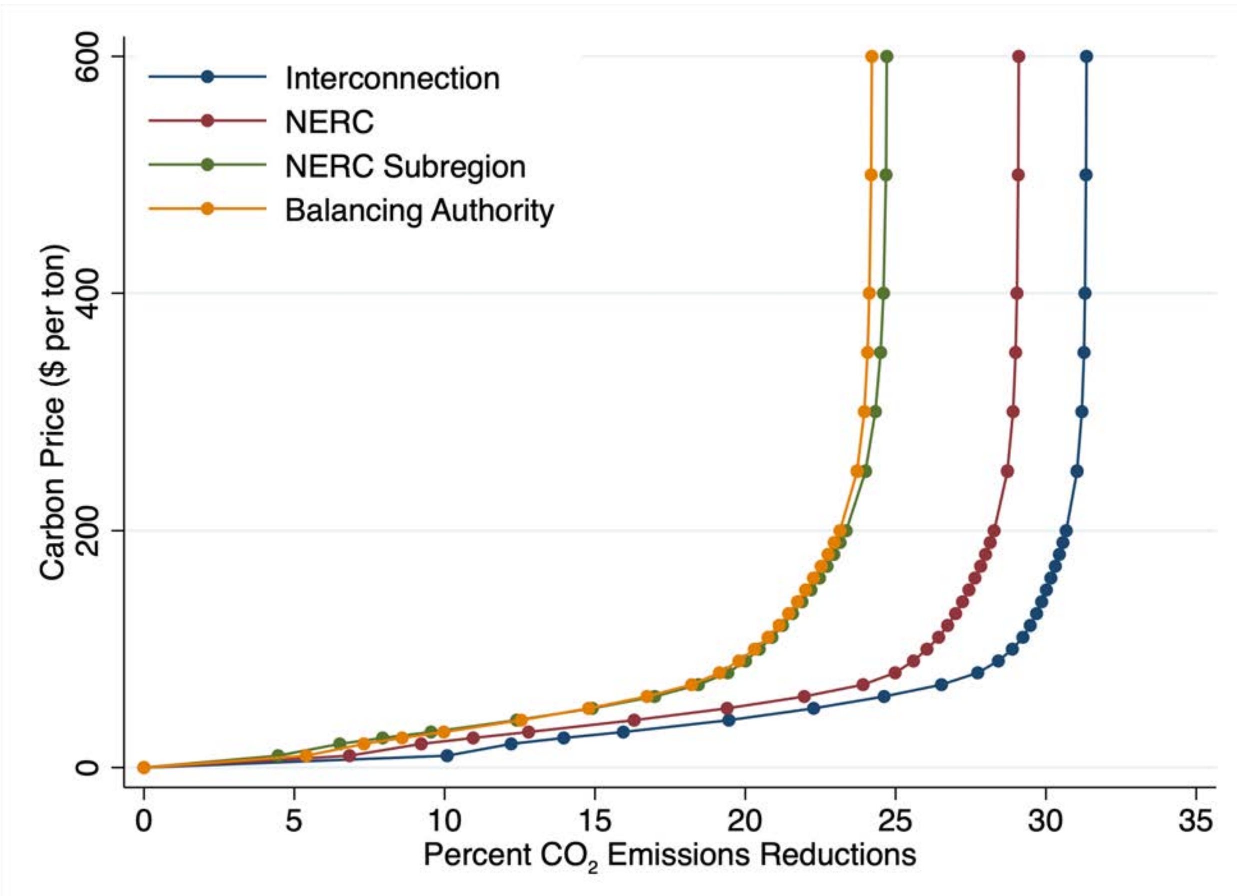


Figure A.3: Marginal costs of emissions reductions from the electricity sector. The curves represent the marginal costs of reducing emissions as a percentage of the 2022 baseline. All curves are based on the RP Own cost threshold and are shown for each replacement region. Marginal costs are reported as the equivalent carbon tax rate.

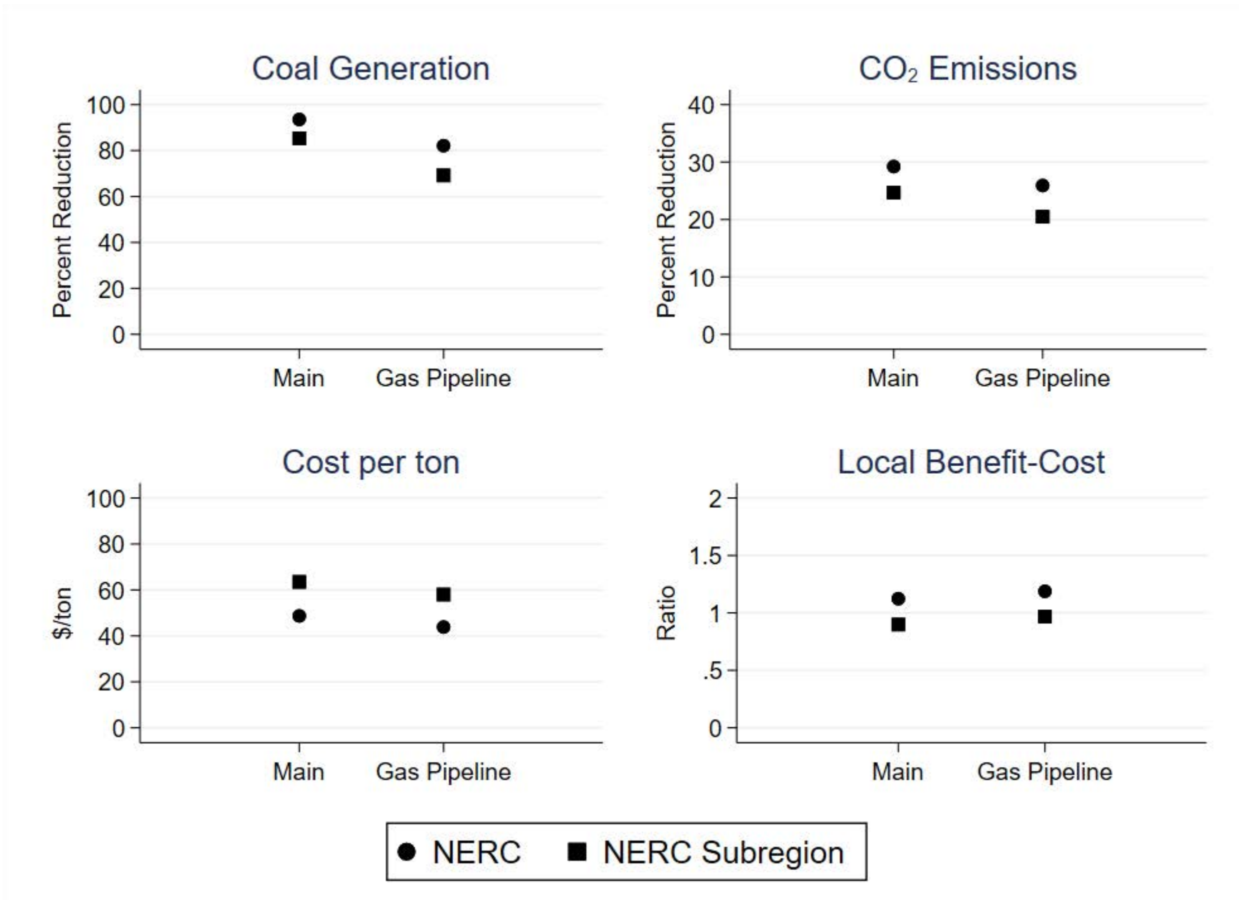


Figure A.4: The effect of adding natural gas pipeline constraints. The figure compares results for NERC and NERC subregion replacement assuming the RP Own cost threshold, with and without the natural gas pipeline constraint. Those labeled Main are identical to those in Figure 8 for the corresponding scenario, and those labeled Gas Pipeline include the constraint.

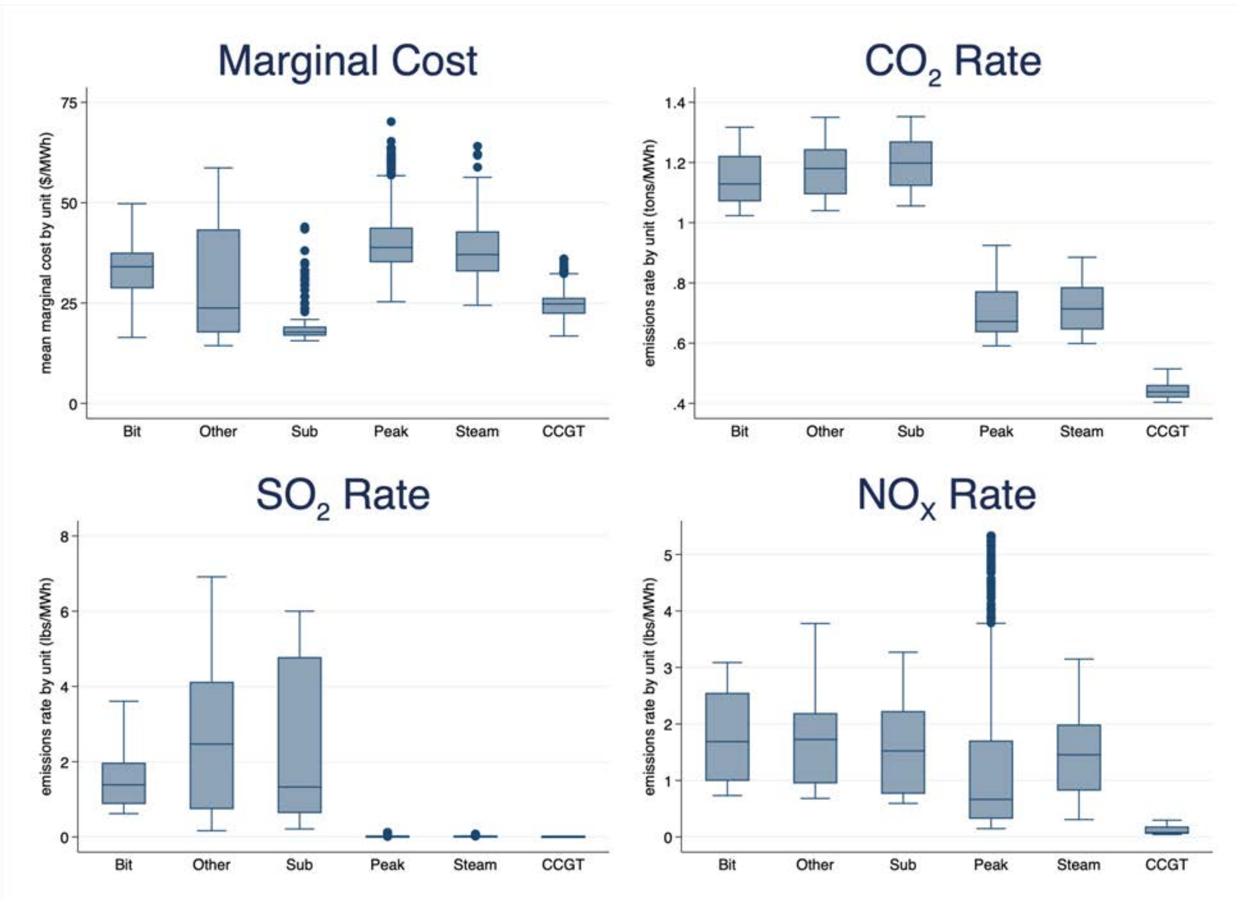


Figure A.5: Year 2019 marginal costs of electricity generation and emissions rates at generating units by type. This figure is the 2019 analog of Figure 5 reported in the main text for 2022. Box plots show the median and interquartile ranges, averaged across months.

Table A.5: Year 2019 aggregate hourly results by differing replacement regions and cost thresholds

Replacement level	Coal gen.	CO_2	Cost	Local Damages
Panel A: RP Own				
Interconnection	-94.7	-55.0	380.2	-3298.2
NERC	-92.9	-52.8	473.4	-3198.3
SubRegion	-82.2	-42.9	620.4	-2769.7
BA (ISO)	-77.3	-41.0	565.8	-2774.6
Panel B: Unconstrained				
Interconnection	-98.2	-61.1	247.9	-3636.0
NERC	-96.6	-58.6	358.4	-3549.6
SubRegion	-87.4	-49.7	462.7	-3195.7
BA (ISO)	-83.5	-48.5	412.0	-3183.6
Panel C: RP Max Coal				
Interconnection	-21.0	-9.1	534.1	-590.6
NERC	-27.6	-11.8	583.2	-617.8
SubRegion	-36.8	-16.7	631.4	-1130.6
BA (ISO)	-32.0	-14.5	516.3	-877.4
Panel D: RP Max Any				
Interconnection	-1.9	-0.6	103.7	-67.7
NERC	-4.8	-1.8	124.0	-88.8
SubRegion	-16.8	-6.5	380.5	-488.3
BA (ISO)	-13.2	-5.3	286.5	-319.9

Notes: This table is the 2019 analog of Table 6 reported in the main text for 2022. Generation is reported in GWh, CO_2 emissions in thousands of tons, and costs and local damages in thousands of 2020 dollars. The 2019 average hourly coal generation is 99.6 GWh per hour. The average hourly emissions of CO_2 is 112.0 thousand pounds from coal units and 64.8 from natural gas units, for a combined CO_2 emissions rate of 176.8 thousand pounds per hour.

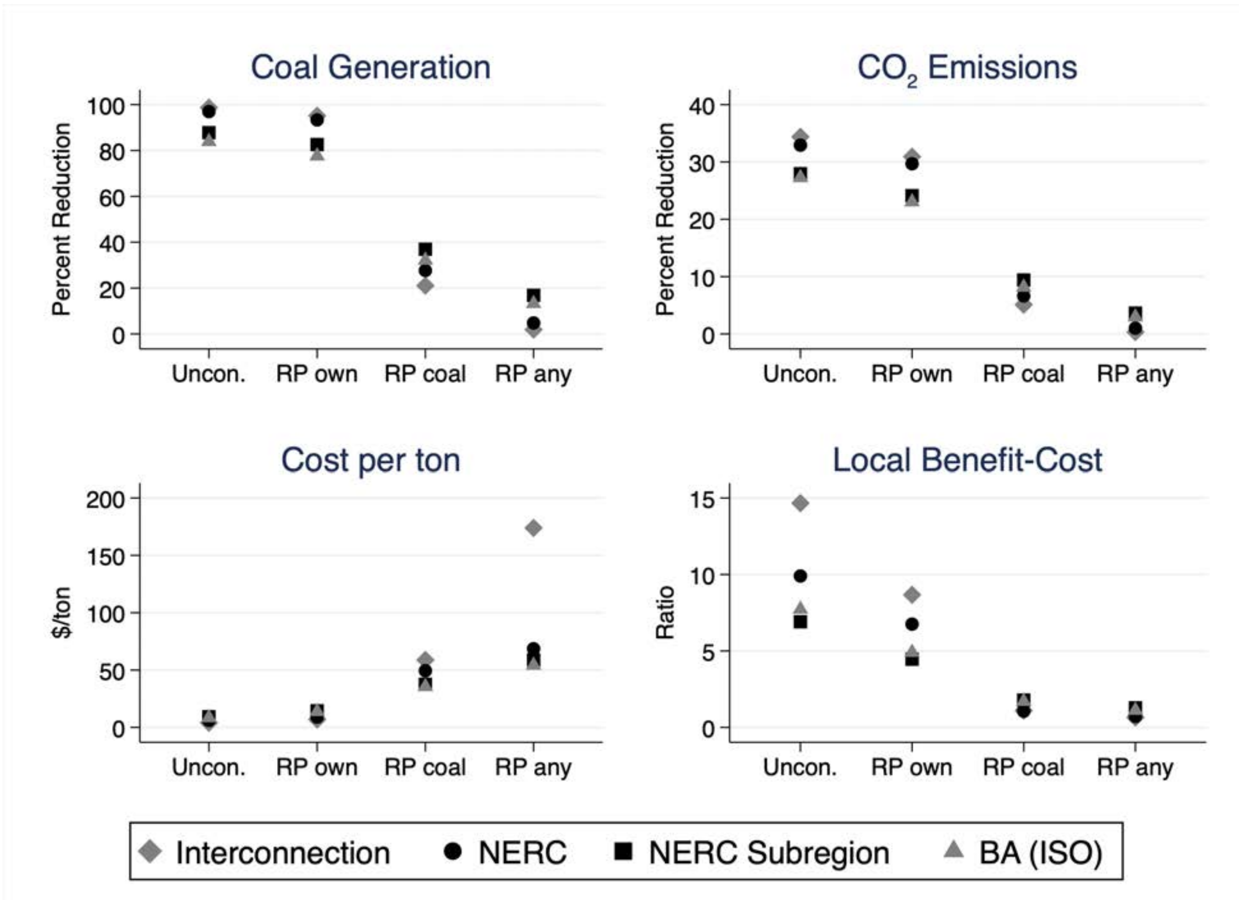


Figure A.6: Year 2019 comparison of results across all 16 scenarios. This figure is the 2019 analog of Figure 8 reported in the main text for 2022. The top panels report the percentage reduction in coal generation and CO_2 emissions. The bottom panels report the estimated cost per ton of CO_2 and the local pollution benefit-cost ratio.