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Accounting for Climate and Air Quality Damages in Future U.S. Electricity Generation Scenarios

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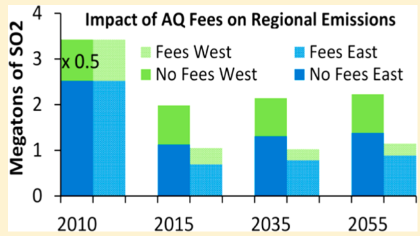
Ⓢ *Supporting Information*

ABSTRACT: The EPA-MARKAL model of the U.S. electricity sector is used to examine how imposing emissions fees based on estimated health and environmental damages might change electricity generation. Fees are imposed on life-cycle emissions of SO_2, nitrogen oxides (NO_x), particulate matter, and greenhouse gases (GHG) from 2015 through 2055. Changes in electricity production, fuel type, emissions controls, and emissions produced under various fees are examined. A shift in fuels used for electricity production results from \$30/ton CO_2-equivalent GHG fees or from criteria pollutant fees set at the higher-end of the range of published damage estimates, but not from criteria pollutant fees based on low or midrange damage estimates. With midrange criteria pollutant fees assessed, SO_2 and NO_x emissions are lower than the business as usual case (by 52% and 10%, respectively), with larger differences in the western U.S. than in the eastern U.S. GHG emissions are not significantly impacted by midrange criteria pollutant fees alone; conversely, with only GHG fees, NO_x emissions are reduced by up to 11%, yet SO_2 emissions are slightly higher than in the business as usual case. Therefore, fees on both GHG and criteria pollutants may be needed to achieve significant reductions in both sets of pollutants.



■ INTRODUCTION

Electricity production in the U.S. is influenced by many factors, but not all consequences of electricity generation are considered when planning capacity expansions. The emission of pollutants from electricity generating plants affects both local air quality and global climate. For example, the Natural Research Council Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption estimated damages (the monetary value of adverse effects of pollution) associated with criteria pollutants (NO_x, SO_2, and particulate matter (PM)) from electricity generation in the U.S. in 2005 at \$62 billion from coal plants and \$740 million from natural gas plants.[1] Here we examine how incorporating damages associated with air quality and climate into the cost of electricity would impact the way in which electricity is generated in the U.S. and the amount of associated emissions produced. We consider the interplay between fees on greenhouse gases (GHG) and criteria pollutants, since prior studies have suggested policies targeting GHG mitigation may lead to reductions in levels of conventional air pollutants, and vice versa.[2,3]

Several studies have investigated negative health and environmental externalities associated with electricity generation. Krupnick and Burtraw[4] provide a critical review of damage estimates for electricity that were developed through the mid 1990s, including early work for the ongoing ExternE[5] project. Burtraw and Krupnick[6] further examine various policy alternatives that incorporate damage estimates. Burtraw et al.[7] and the Interagency Working Group on the Social Cost of Carbon[8] both studied the external cost of CO_2 emissions. The Stern[9] review concludes that the benefits of action to avoid climate change and the related externalities outweigh the costs. Levy et al.[10] model damages from coal fired power plants in the U.S. and Muller et al.[11] estimated U.S. air pollution damages from all sectors. Several of these studies suggest that the damages they report could be applied as fees on emissions as a means of internalizing externalities.

Incorporating damages into the cost of electricity is expected to encourage practices that reduce externalities. Markets with associated externalities are not efficient unless the damage costs are internalized or the externalities are otherwise considered during decision making.[12] According to economic theory, the most efficient policies to internalize damages are directed at the externality, such as a fee on emissions rather than a fee on electricity. Emissions fees are expected to lower emissions rates, reducing negative effects on air quality and in turn on human health and welfare. By considering policies based on damages instead of emission caps or technology goals, the overall social welfare cost related to electricity will decrease because externality costs are lowered, even if fees cause an increase in electricity prices.

Previous studies have assessed the potential impacts of incorporating externalities into energy systems outside the U.S. The MARKAL (MARKet ALlocation) model is an economic-optimization model that finds the least cost way to satisfy specified energy demands over multiyear time horizons.[13] Nguyen[14] used MARKAL to model the effect of emissions fees

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on electricity generation in Vietnam and found that although the cost of electricity production increased by 2.6¢/kWh, external costs of 4.4¢/kWh were avoided. Rafaj and Kypreos[15] used MARKAL to model the effects of including estimated externality costs in the price of electricity on the global electricity mix. In their study, electricity demand was reduced, a different mix of generating technologies was used, and emissions control technologies were installed. Rafaj and Kypreos[15] found that when fees were added to help internalize externalities for global regions, the increase in electricity price is larger for regions relying on coal-based technology. Klaassen and Riahi[16] performed a similar study using the MESSAGE-MACRO model to consider internalizing criteria pollutant externalities from the global energy system. They saw reduced electricity demand and use of fossil fuels and increased production from renewable sources, concluding that adding fees to help internalize criteria pollutant externalities can also reduce GHG emissions.

While previous studies have examined this approach for other countries or the global electricity system, to our knowledge, the impact of adding damage-based emissions fees on the suite of fuel types and technologies used to generate electricity, and their associated emissions, has not been studied in detail for the future U.S. electricity system. Banzhaf et al.[17] used coupled models to determine the level of emissions at which emissions fees are equal to marginal damages, but they only considered emissions of SO_2 and NO_x in 2010. Here we use the U.S. Environmental Protection Agency's (EPA) MARKAL energy systems model to investigate scenarios in which damages from criteria pollutants and GHG are accounted for in electricity generation decisions by applying emissions fees equal to damages estimated in the prior literature. MARKAL is extended to account not only for emissions from direct fuel combustion but also for emissions occurring during upstream stages of the electricity production life cycle: resource extraction, equipment manufacturing, and transportation. The study considers the interplay of GHG and criteria pollutant fees and examines differences in responses across U.S. regions with different pre-existing emissions control requirements. This approach does not reflect a perfect internalization of all possible external damages but illustrates the concept of introducing damage-based fees to reduce external costs.

■ MATERIALS AND METHODS

MARKAL Model. The MARKAL energy systems model is used to compare future electricity generation scenarios. MARKAL determines the least cost way to satisfy future end-use demand for electricity within specified constraints including constraints on generating technologies, fuel supplies, and emissions.[13] It is used with the U.S. Environmental Protection Agency's (EPA) 9-region database which describes the U.S. energy system, including electricity, transportation, residential, commercial, and industrial sectors. Conservation technologies are included, so demand can be met by using more efficient end-use devices or by generating more electricity.

EPA Database. The EPA U.S. 9 region database (EPAUS9r_2010_v1.3)[18,19] is used as a basis for all scenarios considered. The database represents the U.S. energy system for the years 2005−2055 in 5 year increments and uses a system-wide 5% discount rate, augmented by technology specific hurdle rates that reflect noneconomic or behavioral barriers to new investment. While other sectors are also represented in the database, this study focuses on the electricity system. The database includes the projected demand for electricity services in each of the nine census regions in the U.S. as well as the currently installed generation capacity, by type, in each of these regions.[20] Resources and energy are traded and transported between regions through modeled pipelines, transmission lines, and import and export parameters. This trade is constrained by the cost of transportation as well as upper bounds on commodity exports.

The database includes several traditional and advanced electricity generation technologies that are in use or available to install. Fuel types used include solar, wind, hydro, geothermal, municipal solid waste, biomass, nuclear, oil, natural gas, and seven different types of coal (see the Supporting Information (SI) for more detail). The new generation technologies available for coal are integrated gasification combined cycle (IGCC) and pulverized coal steam. Natural gas generation methods include combined cycle, steam, and combustion turbine. All coal and natural gas technologies have the option of applying carbon capture and storage (CCS). The existing coal steam plants have the option of applying controls on NO_x, SO_2, and PM. The SO_2 controls are flue gas desulphurization (FGD), and the optional PM controls are a cyclone, an electrostatic precipitator, or a fabric filter. To control NO_x, the residual coal steam plants can use low NO_x burners either alone or in combination with either selective noncatalytic reduction (SNCR) or selective catalytic reduction (SCR). Residual control technologies on existing generation are also included in the model. FGD, NO_x, and PM controls are standard for natural gas and new coal-fired power plants. Controlled emission rates are from the Inventory of U.S. Greenhouse Gas Emissions and Sinks,[21] eGRID,[22] and the Documentation of EPA Modeling Applications.[23] A fixed lifetime is specified for all methods of electricity generation; hurdle rates ranging from 15 to 25% are applied to approximate barriers to investing in new technologies.[18]

Fuel supply curves in the EPA database are based on the National Energy Modeling System (NEMS) outputs used for the Energy Information Administration's (EIA) 2010 Annual Energy Outlook (AEO) report.[24] The cost of electricity production covers steps from fuel extraction to transportation to end-use. Costs include capital equipment and financing, operation and maintenance, and fuel costs. The capital cost for solar is derived from the assumptions used in the 2010 AEO[24] and declines over time, but the capital cost for wind, which is derived from assumptions in the 2008 AEO,[25] stays roughly constant throughout the time period. Availability factors for wind[26] and solar[27] are differentiated by region, season, and time of day. The fuel costs of coal and natural gas increase with time. Data on existing power plants including capacity, lifetime, availability, and operating costs come from EIA Forms 860, 767, 759/906, and Form 1.[28] The EPA obtained estimated cost and efficiency for new electricity generating units (EGUs) from the 2010 AEO.[24]

The EPA database also includes predicted demand for electricity services for all years modeled. EPA MARKAL treats demand by specifying an end use demand for a service such as lighting and then providing a range of technologies to fulfill the demand (e.g., a selection of light bulbs). The types, cost, and efficiency of the end use technologies are derived from the AEO.[24] Demand for the commercial sector is derived from the NEMS Commercial Sector Demand module output.[26] Most of the demand data for the industrial sector come from the

Manufacturing Energy Consumption Survey database.[29] Demand in the residential sector is derived from AEO Table A4: Residential Sector Key Indicators and Consumption.[24]

State renewable portfolio standards referenced from the 2010 AEO[24] are aggregated to the nine regions in the database by weighting each state's requirements by their portion of the region's historic electricity generation. There are no GHG regulations represented in the current database. The database also includes emissions constraints based on existing or pending regulations. The Cross State Air Pollution Rule (CSAPR) is represented by placing an upper bound on SO_2 and NO_x emissions from EGUs in the eastern U.S. Although the CSAPR has been overturned,[30] the limits in the model are expected to approximate eventual regulations limiting emissions from EGUs. The Mercury and Air Toxics Standard (MATS) is not represented in these cases, but scrubbers that are installed under the CSAPR regulations will also approximate some effects of MATS.[31] All emissions are also capped at historical levels from the U.S. EPA Clean Air Markets Division's database[32] and are limited to comply with the Clean Air Act Amendments.[20] Existing coal-fired EGUs are also constrained to use at least one NO_x control method in 2020 and beyond. While emissions are constrained to historical levels, the method of achieving these levels is not specified, so utilization of control technologies in the model does not necessarily match historical use.

Electricity generation emissions in the EPA database generally include only direct combustion emissions. For this study we added emissions from other life cycle stages. Transportation of materials, land use changes, disposal of worn out materials, and electricity use in equipment production are among the emissions sources upstream of generation.[33] GHG, SO_2, NO_x, and PM_{10} upstream emissions are introduced for all electricity generating technologies as described in the SI.

Damages. We consider a range of damage estimates from the literature to assign fees to criteria pollutant emissions. The primary midrange fees applied are based on the marginal damage estimates from Hidden Costs of Energy,[1] hereinafter referred to as NRC2010. These values consider emissions throughout the entire U.S., with damages specific to EGU emissions. The criteria pollutant damages are estimated in NRC2010 using the Air Pollution Emission Experiments and Policy (APEEP) model. APEEP, described and evaluated in the technical appendix to Muller and Mendelsohn,[34] is a reduced-form integrated assessment model that uses source-receptor matrices to rapidly estimate the contribution of emissions from individual EGUs to ambient concentrations in each county in the contiguous U.S. County level concentrations are multiplied by the population of each county to determine exposure. Damages are calculated based on U.S. population ca. 2000 and are not recalculated for predictions of future population. To estimate health effects, NRC2010 compared these exposure levels to concentration response functions from peer reviewed health studies[35−37] and then monetized the corresponding effects to determine damage estimates. The value of a statistical life (VSL) used is approximately \$6 million, which NRC2010 applied uniformly to all lives lost. The value of market goods was determined by market price, and the value of illness was derived from nonmarket valuation literature.[34] To calculate marginal damages, NRC2010 used APEEP to estimate total damages due to all sources in the model. From these baseline emissions, an additional ton of pollution was added from one source at a time and total damages were recomputed; the marginal damage is the difference. This was repeated for each pollutant and each source. The majority of the damages from criteria pollutants are due to human health effects, specifically premature mortality associated with chronic exposure to $PM_{2.5}$.[35] Other health effects include chronic bronchitis,[36] and respiratory and cardiovascular hospitalization.[37] Environmental externalities include changes in crop and timber yields and reduced visibility.[38−41]

Table 1 compares the NRC2010 damage estimates to other recent values published in the literature. The estimates shown

Table 1. Marginal Damage Estimates Presented in the Literature (Values Converted from Original Units to Year 2005 USD/Metric Ton Pollutant)

source	NRC 2010	NRC 2010[1]	Muller and Mendelsohn 2007[34]	Fann et al. 2009[42]
fuel type/sector	coal EGUs	natural gas EGUs	average for all sources	average for EGUs
SO_2	6000	13 000	1500	80 000
NO_x	1700	2300	370	15 000
$PM_{2.5}$	9800	33 000	2700	
$PM_{10-2.5}$	470	1800	440	

here are chosen because they represent the range of values found in the literature.[1,10,11,34,42,43] There are a few primary reasons for the range of damage estimates given in Table 1. Marginal damage estimates can be 50% higher if the VSL is applied uniformly[11] as in Fann et al.[42] and NRC2010 as opposed to differentiating based upon age[34] as was done in Muller and Mendelsohn.[34] Another important factor is which sources are considered. The study by Muller and Mendelsohn[34] considered all sources of emissions while NRC2010[1] and Fann et al.[42] focused on EGUs alone, and NRC2010 further separated coal and natural gas units. The NRC2010 and Muller and Mendelsohn[34] studies use the APEEP model to relate emissions to concentrations, with source-receptor relationships estimated on an annual average basis for PM, and as a summer season average for ozone. In both studies the APEEP model was run using the EPA's 2002 National Emission Inventory.[44] Fann et al.[42] use the Community Multiscale Air Quality (CMAQ) Response Surface Model (RSM) to relate sector-specific emissions reductions to concentration changes. CMAQ simulates processes involved in the formation, transport, and destruction of $PM_{2.5}$ and ozone, and the RSM shows the change in concentration within nine urban areas. Baseline emissions in Fann et al.[42] were determined by projecting the 2001 National Emissions Inventory to the year 2015. Variations in population exposure also contribute to the differences across damage estimates. Muller and Mendelsohn[34] considered damages in urban and rural areas separately, whereas Fann et al.[42] only considered effects in urban areas. Since mortality from $PM_{2.5}$ is a significant component of the damage estimates, the choice of the corresponding concentration−response functions is also important. NRC2010 and Muller and Mendelsohn[34] used Pope et al.[35] and Woodruff et al.[45] to relate $PM_{2.5}$ exposure to mortality; Fann et al.[42] used Laden et al.[46] Fann et al.[47] discusses the strengths and weaknesses of using each concentration−response relationship to develop damage estimates.

The fees used for direct combustion and upstream emissions of GHG are set at \$30/ton CO_2-equivalent (CO_2-e). This value is chosen to represent the central tendency of the damage

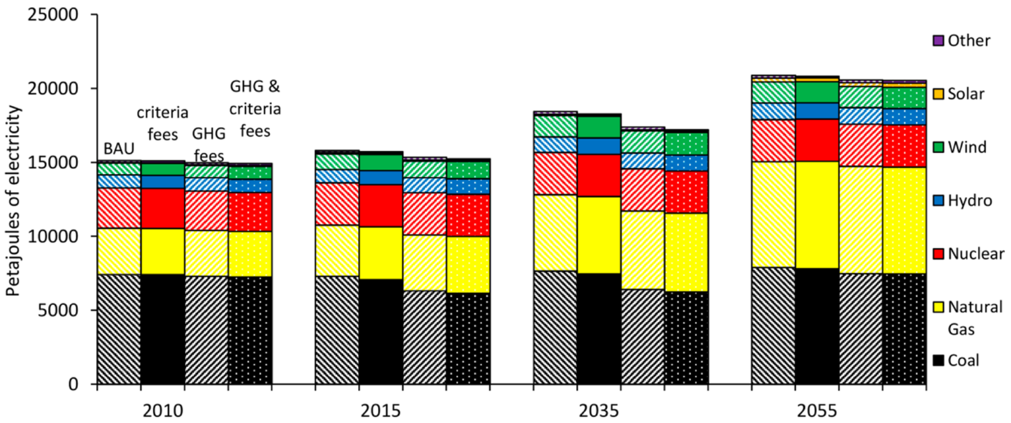

Figure 1. Electricity production by fuel type in four cases: BAU, life cycle criteria pollutant fees, life cycle GHG fees, and life cycle criteria pollutant and life cycle GHG fees. "Other" includes oil, biomass, waste, and geothermal generation.

estimates in the literature.[1,7] There are large discrepancies in the estimated value of damages from GHG. NRC2010[1] found that almost all variation stems from differences in assumptions of discount rate and the magnitude of damages from climate change, especially whether unlikely but catastrophic effects were considered. Emissions of CO_2 are assumed to dominate the direct combustion emissions of GHG. For upstream emissions, the GHG fee is also applied to methane emissions from production of natural gas and landfill gas. Methane emissions are converted to CO_2-e on a mass basis using a factor of 21.

The damage estimates described above are internalized as fees on emissions. These fees are applied in the years 2015 through 2055. All of the fees are applied per metric ton of pollutant emitted and all monetary values in the paper are given in year 2005 USD adjusted using the GDP deflator. The NRC2010 values are used as the midrange fees for criteria pollutants. Distinct fees are applied to emissions from coal and natural gas fired power plants corresponding to the national average of the separate damage values provided by NRC2010. For upstream emissions and biomass combustion emissions, the damages per ton are the same for each generation type and are determined by an average of the coal and natural gas combustion damage estimates from NRC2010. In addition to examining the effect of fees based on the midrange NRC2010 estimates, sensitivity cases use Muller and Mendelsohn's[34] values as lower estimates and Fann et al.'s[42] values as higher estimates. In these sensitivity cases, the same fees are applied to both combustion and upstream emissions regardless of generation type. In separate cases, fees are considered on criteria pollutants only, GHG emissions only, and both criteria pollutants and GHGs. In the cases presented here, fees are applied to full life cycle emissions. We also examined the impact of only applying fees to direct combustion emissions, with results shown in the SI.

Due to uncertainty in the predicted cost and supply of natural gas, a sensitivity analysis was run to represent the fuel supply curves predicted for natural gas in the 2012 AEO,[31] which correspond to increased supply and lower gas prices than the 2010 AEO forecast used in the EPA MARKAL database. This modification is modeled by adding a subsidy of $1 million/petajoules ($1.09/thousand cubic feet) on natural gas in the MARKAL database for all model years, approximating the price difference between the 2012 and 2010 AEO projections. Sensitivity analysis was also conducted to investigate the influence of the system-wide discount rate and hurdle rates for selected electricity generating technologies, with results presented in the SI.

RESULTS

Figure 1 shows the electricity generation by fuel type in four cases: business as usual (BAU) with no fees added, life cycle fees on criteria pollutants based on NRC2010 damage estimates, life cycle fees on GHG, and life cycle fees on criteria pollutants and GHG. In the BAU case, the amount of generation from coal remains relatively constant, but as total generation increases by 36% the percentage from coal declines from 48% in 2010 to 37% in 2055. Natural gas generation increases significantly, with its contribution increasing from 20% in 2010 to 33% in 2055. With little change in absolute generation from nuclear power, its contribution drops from 18% to 13%. The share from hydropower drops from 6% to 5%. Finally, the absolute amount of generation from solar, geothermal, and wind increases over time, with wind playing the largest role and contributing 7% of generation in 2055. We also considered versions of the BAU case with different discount rates, with results presented in the SI. In general the model results are not very sensitive to the system-wide discount rate, but a lower hurdle rate leads to an increase in the use of the corresponding technology, as expected.

When midrange fees are applied to the criteria pollutant life cycle emissions, there are only slight changes to the total electricity use and generation mix. More significant changes result when only GHG fees are applied. There is up to 7% less total electricity generated with GHG fees in place compared to the BAU case, and up to 16% less electricity generated from coal. There is up to 9% more generation from natural gas, 7% more from wind, and up to 13% more from hydro. When GHG fees and midrange criteria pollutant fees are combined, limited additional reductions in electricity generation and coal use occur, with up to 7% less total electricity and 18% less electricity from coal than in the BAU case. However, combination of fees leads to expansion of natural gas and wind use, with increases of up to 10 and 11% compared to BAU, respectively.

Figure 2 shows emissions of SO_2 and NO_x from each of the four main cases. Emissions are divided into those from the eastern and western U.S., as these two regions have distinctly different emissions regulations. Figure 2 also shows results for national total emissions from application of criteria pollutant fees based on low and high damage estimates, which are

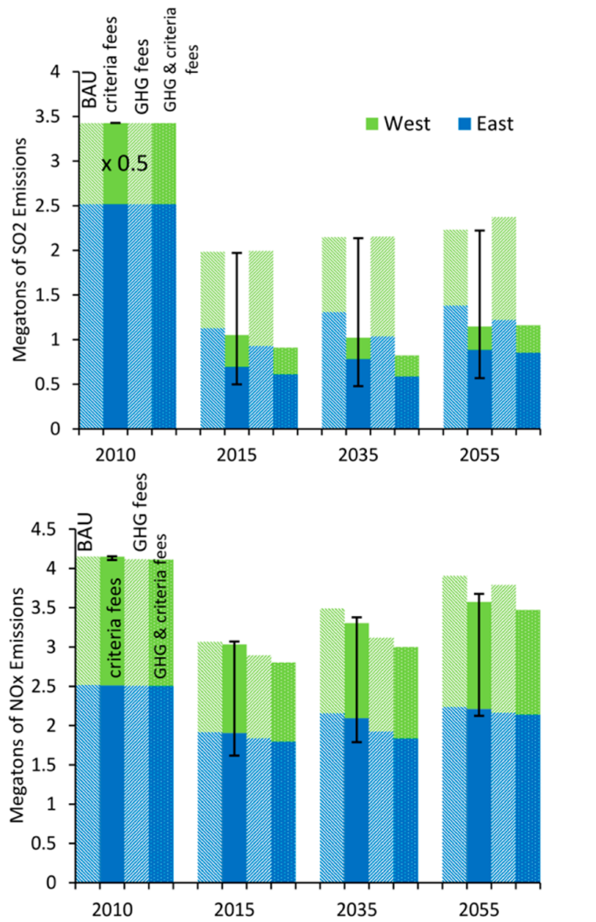

Figure 2. Emissions of SO_2 and NO_x from electricity generation in eastern and western regions of the U.S. For the criteria fees case, the end points of the "error bars" represent national total emissions with high and low criteria pollutant fees in place. (Note that error bars are used for convenience in the display, but are not meant to connote a statistical distribution.)

discussed in the next section. PM changes are typically small when fees are applied to criteria pollutants, GHG or both; results for PM are shown in the SI.

In the BAU case, emissions control technologies are applied to EGUs due to existing regulations, so that by 2035 total SO_2 and NO_x emissions are respectively 78 and 27% lower than in 2005. In the BAU case, the model applies few new controls on SO_2 until 2015, after which 65−70% of the electricity generation from coal has FGD technologies applied. Most coal plants have both low NO_x burners and SNCR equipment in place in all years. Control technologies selected in the BAU case are expected to differ somewhat from those applied in the real world due to the model's simplified treatment of costs and constraints.

When midrange fees are applied to criteria pollutant life cycle emissions, there are only slight changes to the electricity mix, as shown in Figure 1, but the changes in emissions are more substantial. Reductions in SO_2 and NO_x emissions are due to increased application of control technologies. As shown in Figure 2, nationwide SO_2 emissions are 47−53% lower in the case with midrange criteria pollutant fees than in the BAU case. With midrange criteria pollutant fees, 87% of coal plants across the country have FGD controls after 2020 and every plant has at least one NO_x control and typically two. SO_2 emissions in the western region are 70% lower than in the BAU case, while those in the eastern region are 36−42% lower. NO_x emissions are reduced by up to 10% overall, and in the western region are as much as 21% lower than in the BAU case. The regional discrepancy in additional reductions occurs because more controls are installed in the eastern region prior to application of fees.

When fees are applied to GHG emissions alone, without criteria pollutant fees, the NO_x emissions are lower than in the BAU case for all years due to a reduction in the use of coal to generate electricity. NO_x emissions are as much as 11% less than in the BAU case. As shown in Figure 2, the SO_2 emissions are actually slightly greater than in the BAU case due to a reduction in the number of SO_2 controls applied, with a difference of 6% by 2055. As the capacity factor at certain coal plants is reduced with the GHG fee, investment in FGD is no longer warranted at those locations (see SI on page S4).

Combining GHG fees with midrange criteria pollutant fees results in additional reductions in criteria pollutant emissions. NO_x emissions are reduced as much as 14% from the BAU case and 12% compared to the case with fees on criteria pollutants alone due to the combined use of control technologies and a reduction in coal use. SO_2 emissions are as much as 63% lower than the BAU case and 22% lower than the midrange criteria pollutant fee case. With GHG fees combined with criteria pollutant fees, 86% of generation from coal goes through FGD emissions controls after 2020. This is a slightly lower percentage than in the case with only criteria pollutant fees because more reductions are achieved through reduced coal combustion.

Figure 3 shows GHG emissions for the four main cases we considered. As in Figure 2, results are also shown for cases with

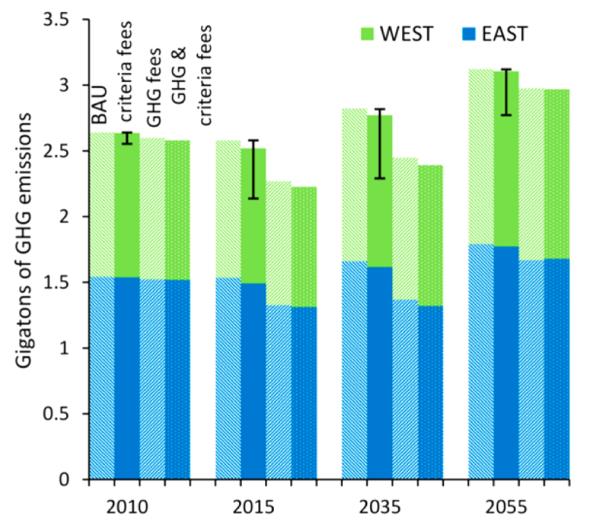

Figure 3. Lifecycle GHG emissions (in CO_2-e) in four different cases. For the criteria fees case, the end points of the error bars represent the total emissions with high and low criteria pollutant fees. (Note that error bars are used for convenience in the display, but are not meant to connote a statistical distribution.)

criteria pollutant fees based on low and high damage estimates. In the BAU case, GHG emissions increase over time, but more slowly than total electricity generation as technologies with lower emissions contribute a larger portion of the electricity. When midrange criteria pollutant fees are applied without including GHG fees, there is a slight decrease of at most 2% in

GHG emissions relative to levels in the BAU case. When fees are only applied to GHG emissions, those emissions are as much as 14% less than in the BAU case. The maximum impact of GHG fees on GHG emissions occurs about 20 years out, and declines in the later years due to increased electricity demand that is not fully satisfied using low GHG intensity generation. Finally, the combination of fees on GHG and midrange fees on criteria pollutants leads to slightly lower GHG emissions than GHG fees alone, with reductions of up to 16% compared to the BAU case.

SENSITIVITY ANALYSIS

High Damage Estimates. One of the largest sources of uncertainty in the results shown above is the value of the external damages. To investigate how robust our findings are to this uncertainty, sensitivity cases are considered using fees based on high and low estimates of damages. For SO_2 and NO_x, respectively, the high criteria pollutant damages shown in Table 1, which are from Fann et al.[42] are approximately 13 and 9 times higher than the NRC2010 estimates for coal-fired power plants, and 6 and 6.5 times higher than the NRC2010 estimates for gas-fired plants. As shown in the SI (Figure S1) when criteria pollutant fees are set to correspond to these higher damage estimates, changes to the electricity system are much more pronounced than with midrange criteria pollutant fees. Compared to the midrange fees, high life cycle criteria pollutant fees lead to as much as 23% less electricity generated from coal. There is up to 5% less total electricity compared to the midrange fees, and there are increases in natural gas and wind power of up to 21% and 11%, respectively. Thus the electricity mix can be altered by criteria pollutant fees alone, if the fees are high enough.

More emissions reductions are seen with high fees on criteria pollutants, including reductions in GHG emissions. There is up to 18% less CO_2 generated with high fees on criteria pollutants than with the midrange fees (Figure 3). Fifteen to twenty-five percent fewer FGD controls are applied with the high fees than with the midrange fees and the scrubbers are implemented more slowly, in part because reduction in coal use also reduces emissions. There is also some switching from high to low sulfur coal, as shown in the SI (Figure S6). The NO_x emissions are as much as 49% lower than with midrange fees, and there is up to 54% additional reduction in SO_2 emissions (Figure 2).

Low Damage Estimates. The low damage estimates given in Table 1 for SO_2 and NO_x are from Muller and Mendelsohn[34] and are respectively about one-fourth and one-fifth as large as those presented in NRC2010 for coal plants. Correspondingly, when only low criteria pollutant fees are applied the magnitude of changes to the generating system is significantly smaller than when midrange fees are applied. As shown in the SI (Figure S1), there is very little change from the BAU case in total electricity generation or the mix of generating technologies. As shown in Figure 2, SO_2 emissions are nearly the same as the BAU case and more than double those in the midrange fee case. FGD is installed on only 67% of the units across the country. With low fees, NO_x emissions are up to 8% lower than in the BAU case, whereas with midrange fees NO_x emissions were reduced by up to 12%. The GHG emissions levels are close to those for the median fee case.

Low Natural Gas Prices. In the cases in which natural gas is given a subsidy of \$1 million/petajoule to represent the AEO 2012[31] forecast of lower natural gas prices, some electricity generation is shifted from coal to natural gas, but the effect on emissions is small. With the subsidy, natural gas use is increased by up to 5% in the BAU case (without fees) and by up to 6% in the case with midrange fees applied to criteria pollutants compared to the same fees without the subsidy. There are slightly lower GHG and SO_2 emissions (2% and 4% respectively) with low natural gas prices and criteria pollutant fees due to less coal combustion. In the case without fees, GHG, SO_2, and NO_x emissions show very little change with low natural gas prices.

DISCUSSION

These results suggest that imposing criteria pollutant fees at levels that correspond to low to midrange damage estimates would have little effect on total electricity production, the generation mix, or GHG emissions, but would substantially reduce criteria pollutant emissions through implementation of control technology. In contrast, criteria pollutant fees based on upper range damage estimates not only reduce criteria pollutant emissions but also affect the amount and method of electricity production as well as GHG emissions. When GHG fees of \$30/ton CO_2-e are applied without criteria pollutant fees, total electricity generation, generation from coal, and GHG and NO_x emissions are all reduced, but not SO_2 emissions. When GHG fees are combined with midrange criteria pollutant fees, the electricity portfolio is changed the most from the BAU case and both GHG and criteria emissions are reduced more than in the other cases.

The model determines which technologies to use based on relative prices of available options. In the EPA MARKAL database, FGD controls for coal-fired power plants have typical cost-effectiveness of \$2,000−4,000/ton. Therefore, many coal plants have FGD controls installed with midrange fees of \$6,000/ton, but not with low fees of \$1,500/ton. Cost-effectiveness estimates for both SNCR and low-NO_x burners in the EPA MARKAL database are as low as \$1,100/ton, which is higher than the low fees for NO_x of \$370/ton but cheaper than the midrange fees of \$1,700/ton. Depending on conditions for a particular EGU, cost effectiveness of SCR in the database can be as much as \$9,000/ton, which is still cheaper than high-end NO_x fees at \$15,000/ton. Similar comparisons can be made between generating technologies if fees expressed in \$/ton are expressed in \$/MWh for specific units. As one example, EPA MARKAL estimates that electricity generated at a certain existing coal plant costs about \$10/MWh while a new wind turbine nearby would produce electricity that costs about \$70/MWh. With GHG and midrange criteria pollutant fees, the coal plant would have an additional cost imposed of \$76/MWh.

Some technologies that are available in the model are never used in the cases presented here. CCS is an optional control technology but is not utilized in any of the scenarios, as the GHG fee of \$30/ton is less than the cost of CCS in the MARKAL database, which is about \$140/ton. Neither integrated gasification combined cycle (IGCC) plants nor new pulverized coal plants are used. Although coal is relatively inexpensive, the capital costs of new coal plants are too high for them to be selected for capacity expansion when other options are available.

While natural gas price projections are shifting rapidly, the results of our study are not highly sensitive to these forecasts. Natural gas use increases with time in all cases and its use increases over the BAU scenario when high criteria pollutant fees, GHG fees, or both are in place. Reducing the effective price of natural gas by \$1 million/petajoule does increase

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natural gas use and decrease coal use, but the decrease in emissions from this change is small compared to the impact of fees. Thus, while less expensive natural gas may help to reduce air pollution, fees are still needed to minimize externalities from electricity generation.

Some of the results shown here support key conclusions of previous studies for the U.S. and other areas. Burtraw et al.[3] found that in the U.S. in 2010, a GHG fee would lead to health benefits in addition to the climate benefits. Rive[2] found that meeting the Kyoto protocol in Europe reduced the emissions controls needed to meet air quality policy targets. Here we see similar results for the interaction of GHG and criteria pollutant emissions fees in the U.S., and the impact of internalizing GHG damages alone generally reduces criteria pollutants excluding a slight increase in SO_2 emissions in some cases. In their global scale assessment, Klaassen and Riahi[16] found that application of fees on criteria pollutants could also reduce GHG emissions. We found this to be true as well for the U.S., but the GHG emissions reductions were small except when high criteria pollutant fees were applied. Thus, while the potential for coreductions of GHG and criteria pollutant emissions is evident, maximizing such benefits may require judicious design of emissions control strategies.

Further work is warranted to reconcile and refine damage estimates for criteria pollutants as well as GHGs. In particular, the APEEP model used to develop the NRC2010 and Muller and Mendelsohn[34] damage estimates uses a reduced form source-receptor model that represents annual (PM) or seasonal (ozone) average conditions and omits more detailed representation of atmospheric chemistry and transport processes. Though developed more directly from a process-based model, the Fann et al.[42] damage estimates are also limited in that they are derived only for impact in relatively densely populated urban areas. Damage-based fees could also be modified for future years based on population growth projections, baseline health status, and changes in personal income, or varied to reflect regional differences in damage estimates. Future work should include updated representation of regulations, including the MATS and regional GHG limits. Further, the model could be refined to include opportunities to directly reduce upstream emissions through controls or changes in production methods at upstream stages. In this study, upstream emissions were only modified through shifts at the electricity generation stage. Finally, the version of MARKAL used here models inelastic end-use demand, so that all reduction in electricity demand comes from more efficient end-use devices. Future work with a fully elastic model would be needed to assess how end-use demand might change if fees increase the price of electricity.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

Supporting Information includes additional results in figures and values and sources of life cycle emissions used. This material is available free of charge via the Internet at http://pubs.acs.org/.

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Notes

The authors declare no competing financial interest.

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