4-1-2018

Electric sector policy, technological change, and U.S. emissions reductions goals: Results from the EMF 32 model intercomparison project

John E. Bistline
Electric Power Research Institute

Elke Hodson
U.S. Department of Energy

Charles G. Rossmann
Southern Company

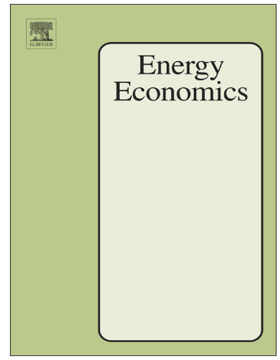
Jared Creason
U.S. Environmental Protection Agency

Brian Murray
Duke University

See next page for additional authors

Authors
John E. Bistline, Elke Hodson, Charles G. Rossmann, Jared Creason, Brian Murray, and Alexander R. Barron

Accepted Manuscript



Electric Sector Policy, Technological Change, and U.S. Emissions Reductions Goals: Results from the EMF 32 Model Intercomparison Project

John E. Bistline, Elke Hodson, Charles G. Rossmann, Jared Creason, Brian Murray, Alex Barron

PII: S0140-9883(18)30137-3
DOI: doi:10.1016/j.eneco.2018.04.012
Reference: ENEECO 3982

To appear in:

Received date: 10 October 2017
Revised date: 20 March 2018
Accepted date: 1 April 2018

Electric Sector Policy, Technological Change, and U.S. Emissions Reductions Goals: Results from the EMF 32 Model Intercomparison Project

John E. Bistline[a], Elke Hodson[b], Charles G. Rossmann[c], Jared Creason[d], Brian Murray[e], Alex Barron[f]

Abstract

The Energy Modeling Forum (EMF) 32 study compares a range of coordinated scenarios to explore implications of U.S. climate policy options and technological change on the electric power sector. Harmonized policy scenarios (including mass-based emissions limits and various power-sector-only carbon tax trajectories) across 16 models provide comparative assessments of potential impacts on electric sector investment and generation outcomes, emissions reductions, and economic implications. This paper compares results across these policy alternatives, including a variety of technological and natural gas price assumptions, and summarizes robust findings and areas of disagreement across participating models. Under a wide range of policy, technology, and market assumptions, model results suggest that future coal generation will decline relative to current levels while generation from natural gas, wind, and solar will increase, though the pace and extent of these changes vary by policy scenario, technological assumptions, region, and model. Climate policies can amplify trends already under way and make them less susceptible to future market changes. The model results provide useful insights to a range of stakeholders, but future research focused on intersectoral linkages in emission reductions (e.g., the role of electrification), effects of energy storage, and better coverage of bioenergy with carbon capture and storage (BECCS) can improve insights even further.

Keywords: climate policy; energy-economic modeling; model intercomparison; market-based environmental policy; technology; electric sector

[a] Electric Power Research Institute, 3420 Hillview Avenue, Palo Alto, CA 94304, USA. To whom correspondence should be addressed. Email: jbistline@epri.com. Phone: 650-855-8517.
[b] U.S. Department of Energy, 1000 Independence Avenue, Washington, DC 20585, USA, elke.hodson@hq.doe.gov
[c] Southern Company, 600 N. 18th Street, Birmingham, AL 35203, USA, cgrossma@southernco.com
[d] U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, Mail Code 6207J, Washington, DC 20460, USA, creason.jared@epa.gov
[e] Duke University, Energy Initiative and Nicholas Institute for Environmental Policy Solutions, Box 90335, Durham, NC 27708, USA, bcmurray@duke.edu
[f] Smith College, 44 College Lane, Northampton, MA 01063, abarron@smith.edu

1. Introduction

Technological change and evolving regulatory landscapes at state, federal, and international levels have generated significant transformations in the U.S. electric power sector in recent years. Previous studies have examined questions related to electric sector climate policies (e.g., Wiser et al., 2017; White House, 2016; Fiertz and Lawson, 2016; McKibbin et al., 2014; Fischer and Newell, 2008) and technological innovation (e.g., Creutzig et al., 2017; EIA, 2016a; Cole et al., 2016; Sanchez et al., 2015; Shearer et al., 2014), but few studies have analyzed a range of policies, technologies, and market conditions across a diverse set of energy-economic models. The Energy Modeling Forum (EMF) 24 study (Clarke et al., 2014; Fawcett et al., 2014) was the most recent large-scale multi-model comparison using U.S. energy models. With rapid changes in emerging technologies, lower natural gas prices, and uncertainty about future policy directions, an updated analysis is needed to allow stakeholders to take stock of model assessments of alternate market and planning scenarios and to understand how expectations about the power sector's future have shifted in the last few years.

This study brings together 16 state-of-the-art analytical models of the U.S. electric sector and economy. Comparing insights across models, scenarios, and technological assumptions can inform the design of U.S. power-sector policy and tradeoffs between environmental ambition and economic outcomes. Motivating questions driving this work include:

- How do market-based climate policies transform the electricity sector, and how do policy impacts compare with impacts of key uncertainties such as technological costs, fuel costs, and economic growth?
- How does policy stringency affect emissions and technology pathways in the electricity sector? Which policies appear consistent with near- and long-term emissions reduction targets?
- What are the electricity price impacts and system costs of different approaches?

These comparisons help to identify robust insights across models and possible planning environments, but also highlight areas of disagreement to guide research needs (both for technologies and analysis). It has long been a conclusion of the modeling community that these models are best used for insights into the design of policies and future research questions, instead of tools to offer quantitative forecasts of policy impacts (Huntington et al., 1982).

Questions also remain about whether expected policy and technological trajectories will allow the U.S. to reach its stated greenhouse gas emissions reduction goals, or whether new technological advances (e.g., in availability, cost, and performance) and policy support (e.g., on regional or federal levels) will be required. These disagreements can be clarified by critically examining the assumptions and dynamics behind models used to make statements about possible electric sector futures.

Perhaps the most significant changes in electric sector model projections since the last major U.S. model intercomparison of technology and climate policy strategies for the U.S. electric power sector (the EMF 24 study, see Fawcett et al., 2014) are updated forecasts for variable renewable energy costs and natural gas prices, which are lower than previous estimates. Despite this rapid technological progress, uncertainty remains about future costs and how these changes will translate into market outcomes;

sophisticated energy-economic models are required to evaluate these potential outcomes. This uncertainty is reflected in analyst claims about future wind and solar generate shares, with some suggesting that variable renewable energy will comprise nearly all energy demand even without supporting policies and others claiming that these technologies will not be deployed without subsidies.

Another motivation for this study is the shift in state and federal policies from economy-wide market-based approaches to regulatory ones with partial sectoral or geographical coverage. Many existing (e.g., the Regional Greenhouse Gas Initiative) or previously issued (e.g., Clean Power Plan) U.S. regulations focus on the power sector, which raises questions about the economic and environment impacts of this sectoral emphasis and the implications for electric sector planning and technology strategy.

The EMF 32 model intercomparison project explores these questions by assessing results from 16 models across six standardized climate policy scenarios, which are discussed in Section 2. Modeling teams provide a range of outputs related to energy system impacts, emissions, and economic metrics. Murray et al. (2018) provide an introduction to the EMF 32 study and papers in the *Energy Economics* special issue, and Creason et al. (2018) synthesize technological insights from EMF 32. In addition to updated assumptions about technologies and markets, this study differs from EMF 24 in the increased number and breadth of participating models (EMF 24 included 9 models) and greater detail on implications for the power sector and specific technological categories. Another important function of the EMF 32 analysis is to identify research and analysis needs based on the evolving technology and policy landscapes, which are summarized in Section 4.

2. Description of Policy Sensitivities

2.1. Scenario Design

The scenarios in the EMF 32 study explore a range of sectoral approaches to U.S. federal climate policy with an emphasis on market-based, technology-neutral instruments. Due to the large number of possible combinations of policy scenarios and technological sensitivities, this study develops a tractable set of scenarios for all participating models.

Table 1. EMF 32 scenario matrix and number of models submitting data for each scenario. Sensitivities span alternate assumptions about technologies (columns) and policies (rows).

Technology Sensitivities

Policy Sensitivities	Reference AEO '16 Assumptions	Natural Gas Low	Natural Gas High	End-Use EE Costs Low	End-Use EE Costs High	Nuclear Lifetimes Low	Renew. Energy Costs Low	Electricity Demand High
Reference	16	14	15	6	6	12	10	12
Power Sector National Mass Based Cap ("Mass Cap")	13	7	9	3	3	6	7	7
Power Sector Carbon Tax $25 @5% ("$25 Tax, 5%")	11	4	5	2	2	3	4	4
Power Sector Carbon Tax $50 @5% ("$50 Tax, 5%")	11	4	5	2	2	3	4	4
Power Sector Carbon Tax $25 @1% ("$25 Tax, 1%")	10	4	4	2	2	3	4	3
Power Sector Carbon Tax $50 @1% ("$50 Tax, 1%")	11	4	4	2	2	3	4	3

Six policy variants are explored in this study: 1. Reference (i.e., business-as-usual) scenario with existing on-the-books policies only; 2. National mass-based cap-and-trade on the power sector; 3. Power-sector-only carbon tax starting in 2020 of $25 per metric ton CO_2 increasing at 5% per year; 4. $50 electric-only tax at 5%; 5. $25 electric-only tax at 1%; 6. $50 electric-only tax at 1%.[1] The levels of the mass-based cap are chosen to align with aggregate levels from EPA's final Clean Power Plan Regulatory Impact Analysis (EPA, 2015). Tax trajectories span a range of proposed starting values and escalation rates, though these policy scenarios are necessarily stylized due to the variety of assumptions about timing, stringency, and provisions of proposed policies. Detailed scenario assumptions are described in Table 2 and tax trajectories are shown in Figure 14 in Appendix A. All technological and natural gas price sensitivities run by participating models are plotted for each of the policy variants shown in the following figures to test whether insights about policy impacts are robust to variations across models, technological costs, and fuel prices.

[1] Note that these scenarios are not intended to reflect specific federal administrative or legislative policy proposals but instead represent stylized sectoral policies.

For all scenarios, it is assumed that international climate policies for countries other than the U.S. reflect current commitments without additional climate policies beyond those levels in the future. These scenarios assume no new international or domestic offsets.

Table 2. EMF 32 policy scenario assumptions. Detailed scenario assumptions and tax trajectories are shown in Appendix A.

Policy Scenario	Description
Reference	The reference scenario approximates the Energy Information Administration's 2016 Annual Energy Outlook (AEO) reference scenario without EPA's Clean Power Plan. It assumes a "business-as-usual trend estimate" with all other on-the-books federal and state policies, including state-level renewable mandates, federal production tax credit for wind, and federal investment tax credit for solar. AEO 2016 fuel prices and demand projections are assumed.
Power Sector Mass-Based Cap ("Mass Cap")	The national power sector mass cap scenario is extrapolated from the EPA's final Clean Power Plan Regulatory Impact Analysis for the rate-based approach (EPA, 2015), which results in emissions caps of 1,891, 1,754, 1,644 million metric tons of CO_2 in the years 2020, 2025, and 2030, respectively, from the electricity sector. From 2030 to 2050, this scenario applies a constant mean annual reduction in power sector emissions of 1.8% based the average annual reduction from 2020 to 2030. Full banking and borrowing of emissions allowances between 2020 to 2030 is allowed (to reflect the policy target as a decadal average), but such temporal flexibility is limited between 2030 and 2050. Overall, the mass cap reaches 55% below 2005 levels by 2050.
Power Sector Only CO_2 Tax Trajectories ("$X Tax, Y%")	These scenarios model two initial tax rates ($25 and $50 per metric ton of CO_2 in 2010 U.S. dollars) and two rates of annual increase over inflation (1% and 5%), for a total of four tax trajectories (Figure 14 in Appendix A). The $X tax is imposed beginning in 2020 and increased Y% annually through 2050. To the extent feasible, models assume that the carbon tax is anticipated. In years after 2050, the carbon tax rate is held constant at its 2050 level. The tax is applied only to power sector fossil CO_2. Tax credits are applied to biomass CO_2 sequestered geologically with carbon capture technology. Coal and gas units that deploy carbon capture and storage pay a tax on uncaptured emissions only.

2.2. Modeling Teams

These comparisons employ a range of models with different characteristics, which reflects alternate assumptions about the future planning environment, decision-making processes, system dynamics, and technological cost and performance assumptions. Table 3 lists key characteristics of the 16 models participating in the EMF 32 study.[2] For instance, some models assume perfect foresight in their intertemporal optimization of management decisions (e.g., DIEM, NEMS, NewERA, US-REGEN), whereas other models use recursive-dynamic formulations or other approaches with more myopic decision-making (e.g., FACETS, GCAM, ReEDS, ReEDS-USREP).

[2] Some models have additional capabilities and versions that are not used in this analysis. Refer to individual model documentation for details. In the "Covered Sectors" column, "demand" refers to structural models of end-use demand and not stylized representations of energy efficiency or demand response.

Table 3. Overview of key characteristics of participating models in the EMF 32 study. More detailed model comparisons are provided in Creason et al. (2018).

Model Name	Covered Sectors	Number of U.S. Regions	Supporting Organization(s)
AMIGA3	Electricity, other energy supply, 100 IO sectors	6	Argonne National Laboratory
DIEM	Electricity, other energy supply, non-energy, demand	48	Duke University
E4ST_v6	Electricity	6,670	Resources for the Future; Cornell
ENERGY_2020	Electricity, other energy supply, non-energy, demand	24	Systematic Solutions
EPSA-NEMS	Electricity, other energy supply, demand	22	OnLocation
FACETS	Electricity, other energy supply, demand	41	KanORS-EMR; SEE
GCAM-USA	Electricity, other energy supply, demand	51	Pacific Northwest National Laboratory
Haiku	Electricity	26	Resources for the Future
MARKAL_NETL	Electricity, other energy supply, demand	9	National Energy Technology Laboratory
NEMS_AEO2016	Electricity, other energy supply, demand	22	Energy Information Administration
NewERA	Electricity, other energy supply, non-energy, demand	61	NERA Economic Consulting
NewERAele	Electricity	61	NERA Economic Consulting
ReEDS	Electricity	134	National Renewable Energy Laboratory
ReEDS-USREP	Electricity, other energy supply, non-energy, demand	134	National Renewable Energy Laboratory; MIT
RHG-NEMS	Electricity, other energy supply, demand	22	Rhodium Group
US-REGEN	Electricity	48	Electric Power Research Institute

Comparing variations across models (i.e., intermodel comparisons) along with variations across scenarios for the same model (i.e., intramodel comparisons) offer a variety of plausible outcomes that account both for alternate scenario and model assumptions as well as for alternative model structures.

2.3. Limitations of the Analysis

Readers should keep in mind the following limitations when interpreting model results:

- This study includes alternate policy and technology scenarios, not forecasts or predictions (Weyant, 2017).[3]
- Many additional sources of uncertainty and implementation details are not explored in this analysis and are left for future work. These unknowns become more pronounced over longer timescales, making out-year results particularly uncertain (Barron et al., 2018).
- Assumptions about technological costs/performance and markets are not fully harmonized across models. Differences in model structures prevent such harmonization, especially for variable renewable energy (NREL, 2017).
- There is an underrepresentation of interactions between the electric power sector and other sectors, which may be especially important for aggressive policies that have more prominent general equilibrium effects (Barron et al., 2018). In particular, economy-wide decarbonization strategies likely entail extensive electrification of end uses, such as transportation, industrial production, and household services such as heating and air conditioning (Bistline and de la Chesnaye, 2018; White House, 2016; Williams et al., 2014; Clarke et al., 2014), and few models capture details of consumer adoption or potential changes in load shapes.
- Not all models included in this synthesis completed all scenarios, which means that some conclusions may reflect sampling biases rather than robust insights, especially for scenarios with few reporting models (Tavoni and Tol, 2010).
- The scenario design was locked down in late 2016, so the runs do not reflect more recent changes in federal or state policies. As noted in Table 2, the reference scenario does not assume implementation of the Clean Power Plan.

Notwithstanding these caveats and uncertainties for future exploration, many clear insights emerge from this analysis, as described in the following sections.

[3] Models used for energy and climate policy analysis are not designed for forecasting specific economic variables. Economic predictions involve considerable uncertainty due to long time horizons, human behavior, technology, evolving policies, and difficult-to-forecast conditions such as interest rates, economic growth, factor prices, and population. Instead, models provide illustrative comparisons of one economic projection (the reference scenario) with another (the policy scenario).

3. Results

3.1. Effect of Policy Scenarios on Individual Technologies

In nearly all scenarios and all models, there is high agreement that future coal generation will decrease from historical levels. As shown in Figure 1, most models project flat or declining coal generation under reference policy conditions, though a significant amount of coal capacity remains online without further policy (Figure 16 in Appendix B).[4] Under reference policy conditions with certainty about no additional climate policies or performance standards, almost all models show less coal generation over time and no new builds. This outlook differs considerably from planning a decade ago (EIA, 2007) or even EMF 24 (Clarke et al., 2014), which envisioned new coal builds in the absence of climate policy. Such differences are driven primarily by changing expectations about natural gas prices (Bistline, 2015; Burtraw et al., 2012) and lower wind and solar costs (Cole et al., 2016).

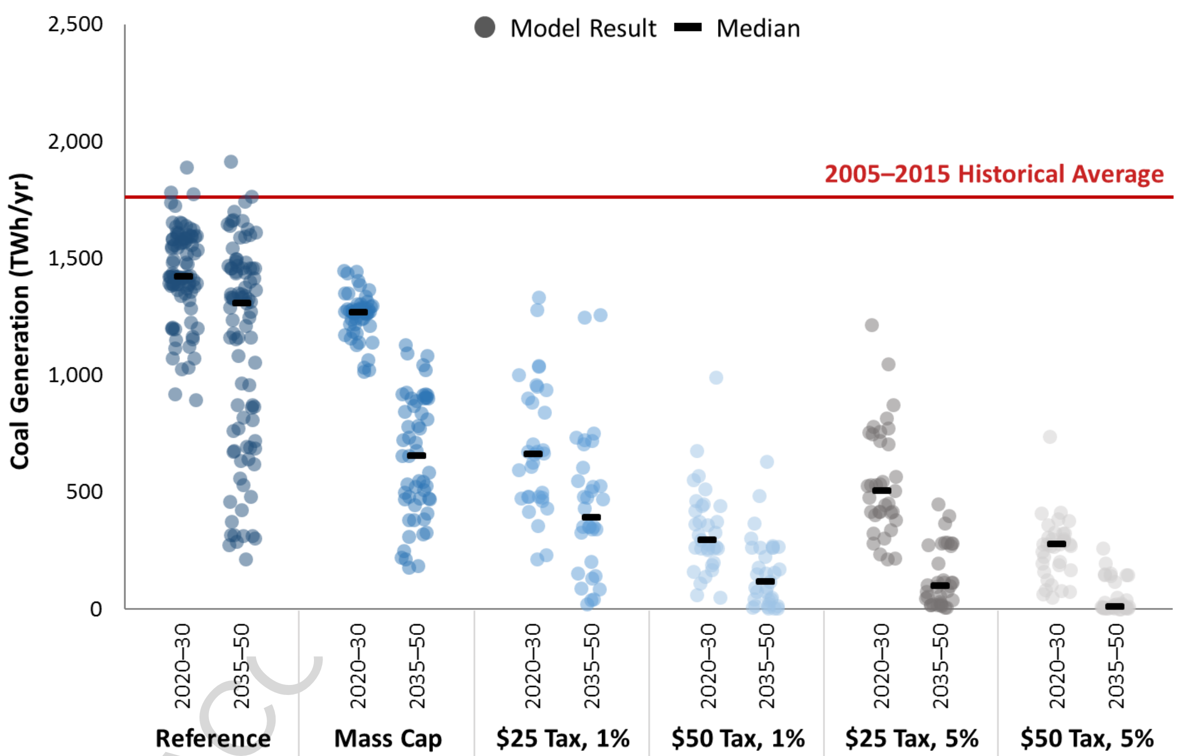


Figure 1. Annual coal generation (TWh/yr) for all models and technology scenarios, grouped by policy scenario and time period. Generation is the sum of all U.S. coal units without and with carbon capture. Historical average generation comes from EIA (2016b).

Assumptions about implementation of the Clean Air Act (CAA) § 111(b) CO_2 performance standards for new fossil units were not harmonized across models. Roughly half of the participating models included

[4] Note how the number of scenarios vary across policy cases, which reflects differences in the number of scenarios submitted across models (see Table 1). Figure 15 in Appendix B illustrates how these qualitative insights hold when variations across models and policies are examined under the reference technological scenario only. Lower coal generation in the reference case largely corresponds to the low natural gas price scenario.

these standards, though many teams reported that these constraints were not binding. However, for the models that allowed new coal additions without carbon capture, coal investments were observed only in the high gas price sensitivity and were less than 10 GW nationally.

The downside risk for coal generation is larger under the policy scenarios than the reference, as many tax scenarios drive coal generation to near-zero levels by midcentury. As the highest CO_2 emissions intensive resource, coal is the most responsive fuel to carbon taxes imposed on those emissions, and even the least stringent tax trajectory ($25 rising at 1% per year) lowers coal generation by more than 50% on average below current levels by 2050. More stringent carbon tax policies lead to lower coal generation (Figure 1) and higher capacity retirements (Figure 16 in Appendix B).

In the carbon tax scenarios, relative costs of low-carbon technologies suggest that the availability of new carbon capture and storage (CCS) technologies applied to coal generation does not markedly alter these trends under most conditions, as shown in Figure 1. Many models indicate that least-cost low-carbon scenarios involve CCS-equipped gas generation rather than CCS-equipped coal, as discussed in Section 3.2 (Figure 7). These findings imply that the transition away from coal generation in the U.S. power sector is likely to continue, barring coal-specific CCS advances, substantially higher natural gas prices, or direct subsidization of coal use. These results differ considerably from previous model intercomparison studies, which indicated increased coal use in reference scenarios and coal with CCS under carbon pricing scenarios (e.g., Figures 4 and 15 in Clarke et al., 2014).

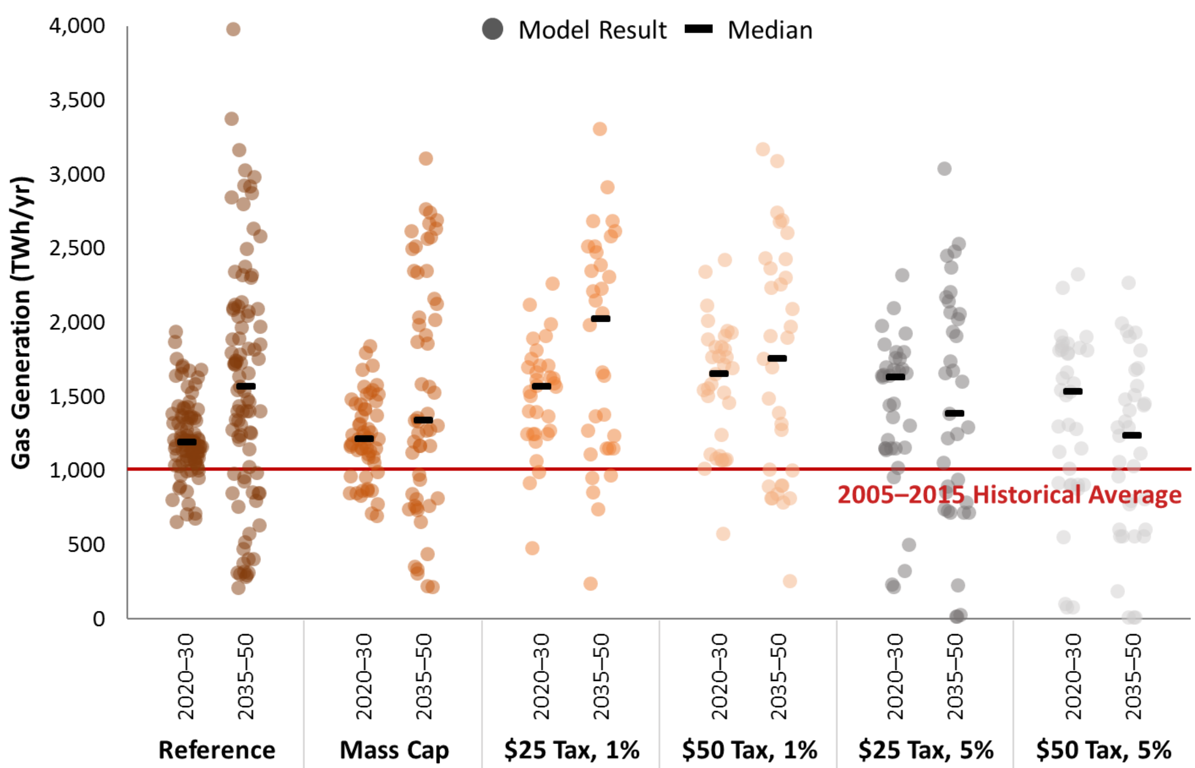


Figure 2. Annual natural gas generation (TWh/yr) for all models and technology scenarios, grouped by policy scenario and time period. Generation is the sum of all U.S. gas units without and with CCS.

In contrast to coal, generation from natural-gas-fired units is likely to increase relative to historical values in the reference (i.e., no-policy) case. Natural gas generation is expected to rise over time under the reference scenario, with 2035–2050 values higher than 2020–2030 values.[5] Variation in gas generation is significant across models, technological sensitivities, and gas prices, as some models exhibit a more than doubling of gas generation above the 2005–2015 historical average through 2050 while others anticipate more modest growth.[6]

Under the CO_2 policy sensitivities, most models indicate that gas generation will likely increase over the 2005–2015 historical average. However, the medians for the CO_2 policy scenarios are not appreciably different from the median in the reference scenario. Gas generation increases most in the $25 tax scenarios. Relative price effects from the carbon tax are smaller for gas than for coal owing to the lower carbon intensity of gas, which is roughly half of coal on a CO_2 combustion emissions per output basis. Nevertheless, tax scenarios with the higher escalation rates (5% per year) are stringent enough to decrease gas generation below reference levels in the long run for many models.

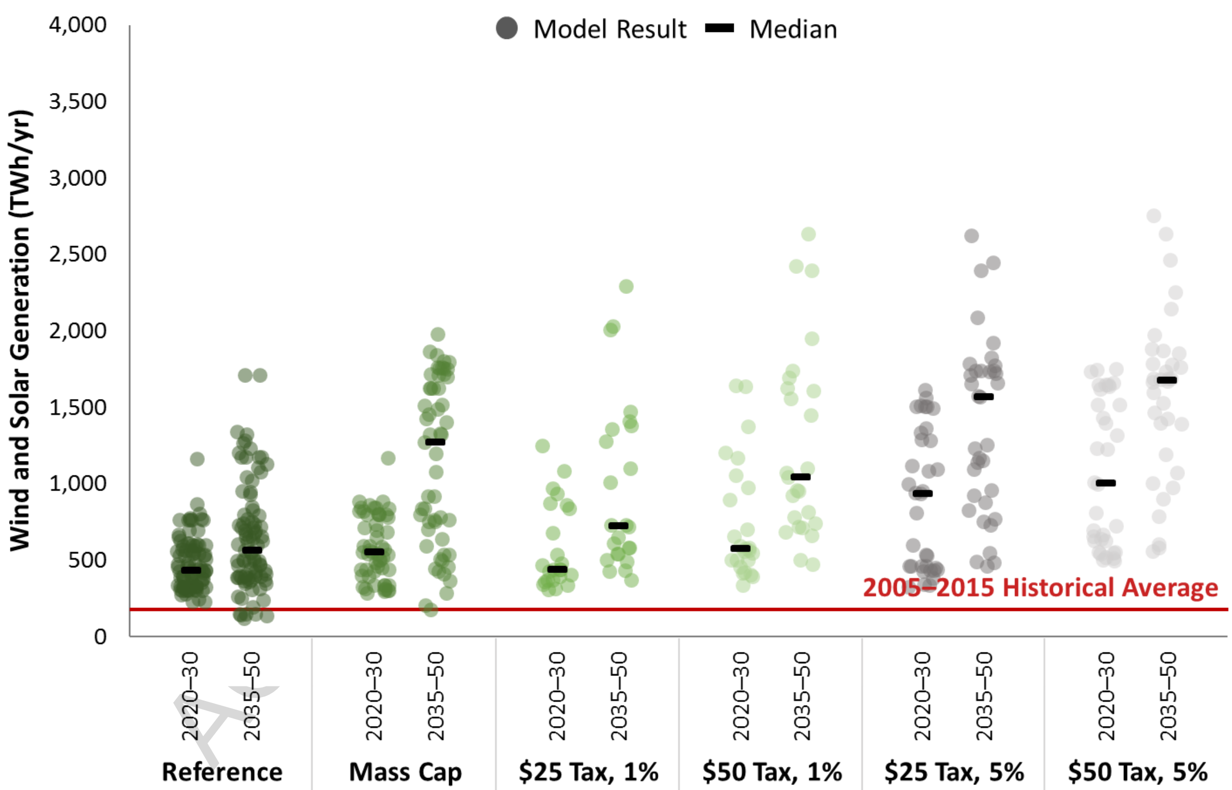


Figure 3. Annual wind and solar generation (TWh/yr) for all models and technology scenarios, grouped by policy scenario and time period. Generation is the sum of all U.S. solar and wind technologies (i.e., not including hydropower, geothermal, or biomass). While the 2005–2015 average is 179 TWh/yr, 2017 generation from wind and solar was approximately 330 TWh/yr.

[5] Exceptions in Figure 2 are scenarios with high gas prices, represented in the lowest points in each scenario.
[6] Agreement is higher for total gas capacity (Figure 17 in Appendix B), as many scenarios exhibit capacity growth even when generation changes are more modest.

Levels of wind and solar generation are expected to increase significantly from current values under all scenarios, though the magnitude varies based on the policy environment and model-specific cost-effectiveness relative to substitute technologies. Variable renewable deployment increases over time as costs fall and is highest for the stringent carbon tax cases, especially policies with higher escalation rates (Figure 3), since variable renewable resources face no carbon tax and will further benefit from any increase in electricity price caused by the tax on other generators. Wind and solar generation by 2050 are higher than previous model intercomparison studies, though the qualitative trends are similar across policy scenarios (Clarke et al., 2014).

Figure 4 shows the wide range in projections of the total share of wind and solar as a fraction of generation nationally (top panel) and regionally (bottom panel). The national results are qualitatively similar to Figure 3 with the generation fraction increasing with higher carbon taxes over time (reaching as high as 60% of national generation by 2050 with the \$50/t-CO_2 tax scenario and 5% escalation rate). Underlying national results are significant differences at the regional level (Fell and Linn, 2013), as shown in the bottom panel of Figure 4. Regional heterogeneity means that some grids have near-zero levels of variable renewables in some scenarios (e.g., the Southeastern U.S.) and others have almost 60% even without carbon policies (e.g., the West). Drivers of regional differences include renewable resource bases, technology costs, existing fleet mixes, market regimes, load shapes, and regulations.

Another area of agreement across models and scenarios is that the generation share of wind is likely to exceed solar absent future technological surprises (Figure 5). Drivers of this split include relative cost declines, capacity factors, and changes in marginal value at higher levels of deployment (e.g., Bistline, 2017; Gowrisankaran et al., 2016; Hirth, 2013).[7] Models suggest that a majority of wind capacity will likely be onshore and that solar will largely come from utility-scale photovoltaic (PV) capacity. Figure 19 in Appendix B shows how wind and solar generation are typically higher under scenarios with higher gas prices. It is important to note that, under alternate cost assumptions where solar capital costs are roughly 50% lower than wind, some models show that solar generation can significantly exceed wind generation, but other models still indicate wind generation dominating across the range of costs examined in this study (Figure 5).[8]

[7] Note that the relative competitiveness of wind and solar depends strongly on relative cost and value declines across time and cumulative penetration (Figure 5 in Appendix B).

[8] Here, the low-renewable cost scenario is based on NREL's Annual Technology Baseline costs from 2016, where solar capital costs are roughly 50% lower than onshore wind after 2030.

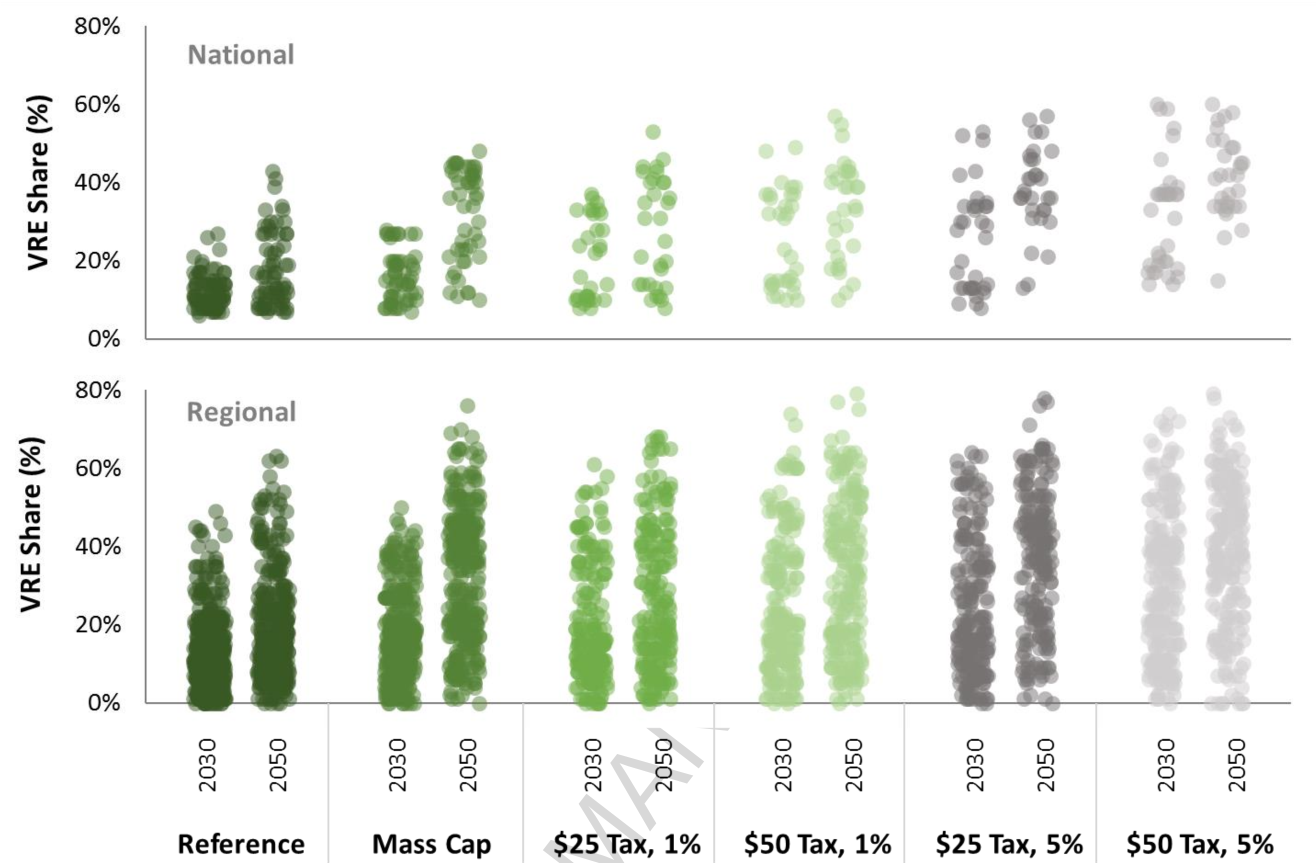


Figure 4. Variable renewable energy (wind and solar) generation share (% of in-region generation) by year and scenario. The top panel shows national results (where individual points represent outputs from different models), and the bottom panel shows regional results (where points represent different model and different regions).

Note that model representations of variable renewable technologies and complementary flexibility options vary across models (Santen et al., 2017; Sullivan et al., 2014). Temporal and spatial resolution decisions in model construction may materially affect their ability to represent these technologies, which may understate deployment of specific assets and overstate others. For instance, capturing drivers and impacts of higher-than-anticipated cost reductions for solar and storage would increase deployment (*ceteris paribus*), but there are also questions about whether models are adequately representing endogenous value deflation at higher penetrations (i.e., declining economic value of added capacity), which would decrease deployment (Blanford et al., 2018).

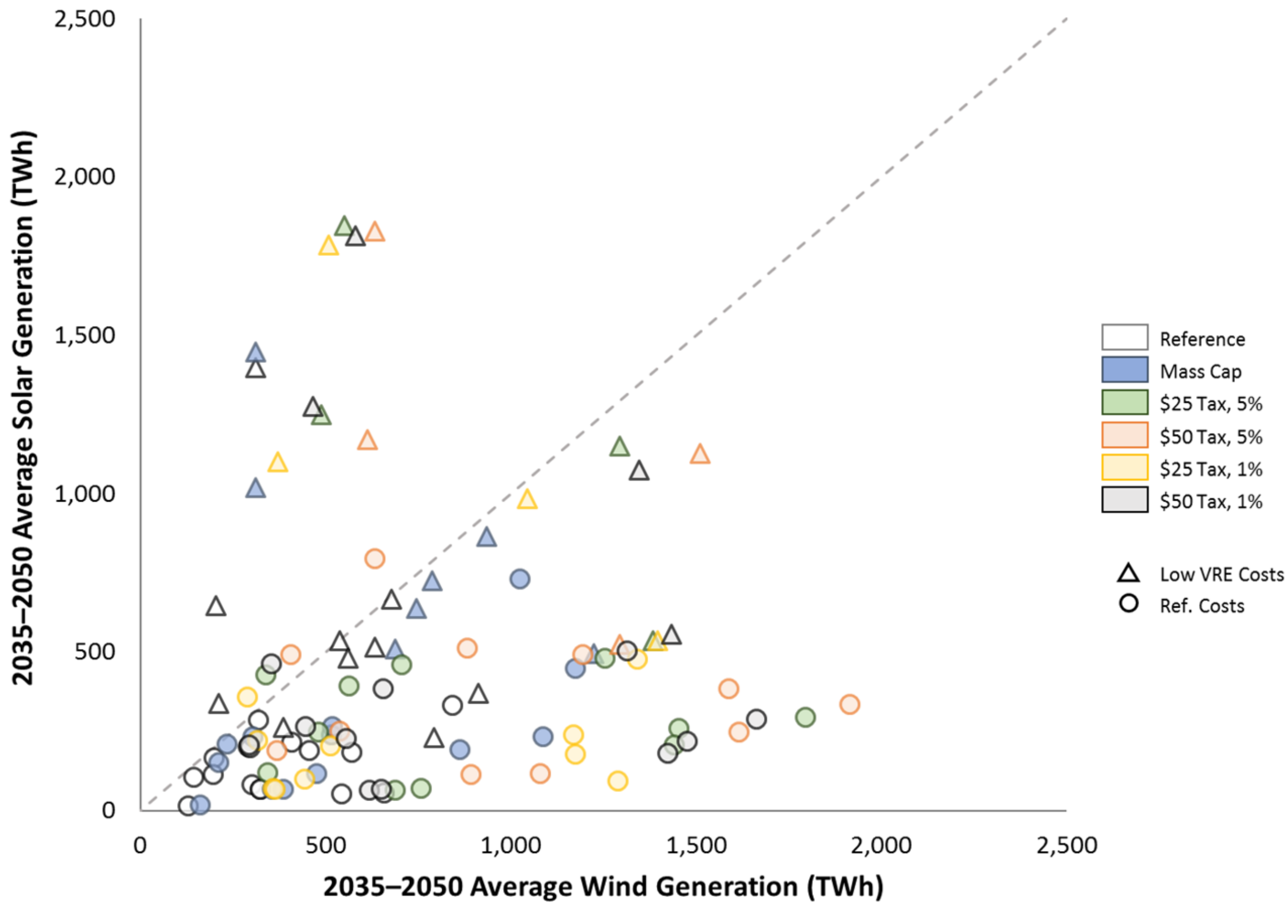


Figure 5. Comparison of average annual U.S. wind and solar generation (TWh/yr) between 2035–2050 with reference and lower wind and solar costs. Points represent individual model runs with colors corresponding to the policy scenarios. Reference wind and solar cost scenarios are represented by circles and lower-cost scenarios by triangles. Values above (below) the dotted line indicate higher solar (wind) generation for a given model and scenario.

Generation from existing and new nuclear plants depends on the policy environment but is not as sensitive as other technologies (Figure 6). Without additional policy, nuclear generation remains close to current levels through 2030 with planned uprates for existing units approximately offsetting retirements. However, nuclear retirements increase across many models after 2030 under the reference policy scenario, and models disagree about the extent of potential impacts. Under the carbon tax scenarios (even at the lower price trajectories that begin at $25), revenues to nuclear plants increase, which lowers the downside risk of premature retirements for existing facilities and incents investments in new nuclear plants in some models. New nuclear capacity installations generally occur later in the time horizon and only under the scenarios with higher CO_2 tax escalation rates.[9] The extent of nuclear

[9] Note that several models include new investments in nuclear capacity and uprates for existing plants (both endogenous and exogenous) in the reference, which are reflected in Figure 6. Since the study was conducted in late 2016, several companies have announced plans to stop or forego new construction.

deployment under climate policy scenarios is lower in this study relative to previous model intercomparisons, as most models in EMF 34 rely more heavily on renewables and gas with CCS under low-carbon scenarios (Clarke et al., 2014).

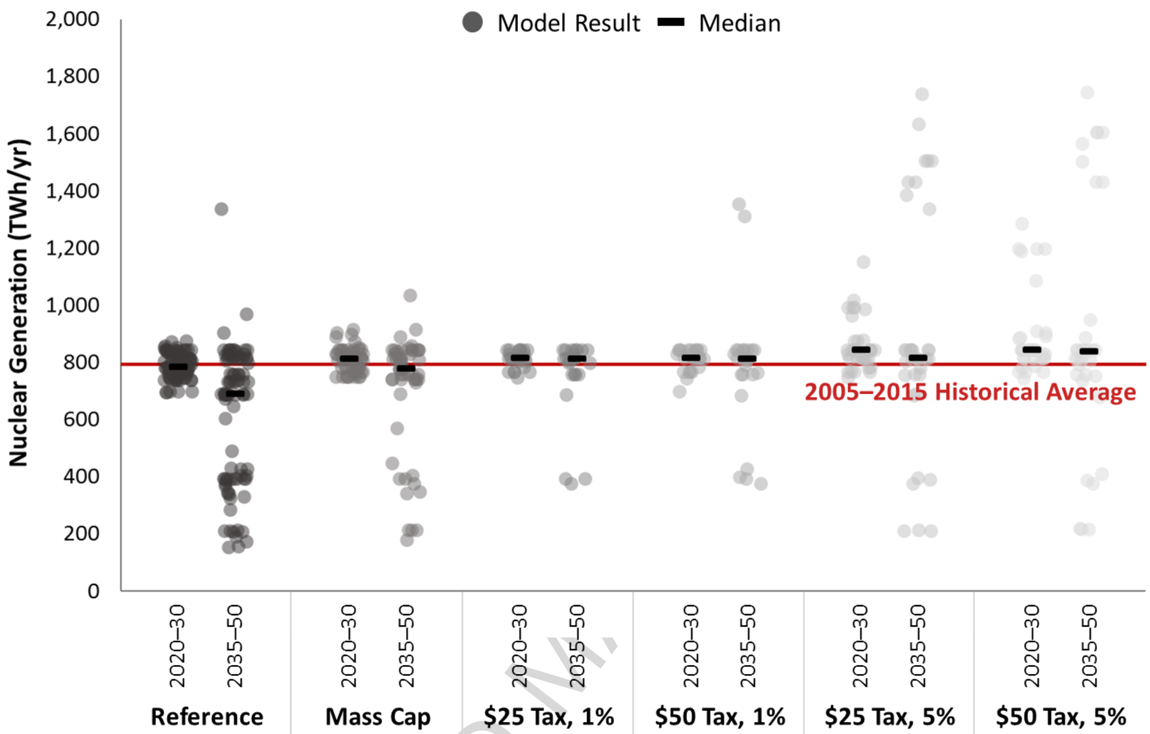


Figure 6. Annual nuclear generation (TWh/yr) for all models and technology scenarios, grouped by policy scenario and time period. Generation is the sum of all existing and new U.S. nuclear generation.

For scenarios with early nuclear retirements, Figure 18 in Appendix B shows how the generation mix that replaces nuclear depends strongly on the policy environment. Without additional policies, nuclear retirements generally lead to more gas generation (and more limited increases in wind, coal, and solar generation) after 2030 depending on the region-specific marginal technology. Early nuclear retirements also lead to higher CO_2 emissions across all scenarios, but these emissions impacts are much smaller under the CO_2 tax scenarios, where lower-carbon-intensity technologies are more likely to be on the margin. Under the mass-based cap where emissions are constrained, nuclear retirements are accompanied by additional reductions in coal generation.

3.2. Effect of Policy Scenarios on Decarbonization Pathways

The evolution of the electric sector absent further CO_2 policy entails two technological shifts, as shown in the first column of Figure 7. First, coal-to-gas switching occurs for most models, though the extent of coal retirements by 2050 depends on expectations for the gas price path combined with costs of maintaining units (see Appendix B). Second, variable renewable deployment (specifically wind) increases over time; however, lower natural gas prices in the reference limit national penetration without continued policy support or more aggressive cost declines for variable renewables. Figure 20 in

Appendix B shows relative generation from natural gas and renewables in 2035–2050 under different policy and technology assumptions.

Under the \$25 and 50/t-CO_2 tax scenarios with 5% escalation, near-term emissions reductions are achieved through redispatch toward existing natural gas capacity, minimizing the share of generation from coal by 2030 (though some models lean heavily on wind and energy efficiency as well). As shown in Figure 9, the median rate of near-term capacity additions across all models is similar to the historical rate in all but the most stringent tax scenarios. Post-2030 mitigation takes place on the investment margin (i.e., changes in new capacity) and varies based on model-specific cost and performance assumptions, which underscores the importance of technological changes in shaping long-run transformation pathways (Creason et al., 2018).

2050 generation portfolios are diverse under many policy scenarios owing to regional heterogeneity, supply-curve-like system dynamics (e.g., upward-sloping fuel supply curves, decreasing marginal value of variable renewables), sunk costs, different function attributes and system needs (e.g., energy, capacity, flexibility), and other model-specific factors. Models vary in their treatment of technology-specific cost and value profiles, and portfolio mixes reflect differences in how dispatchable (e.g., natural gas generators) and non-dispatchable (e.g., wind, solar PV) options are assessed relative to total system benefits and costs (Creason et al., 2018).

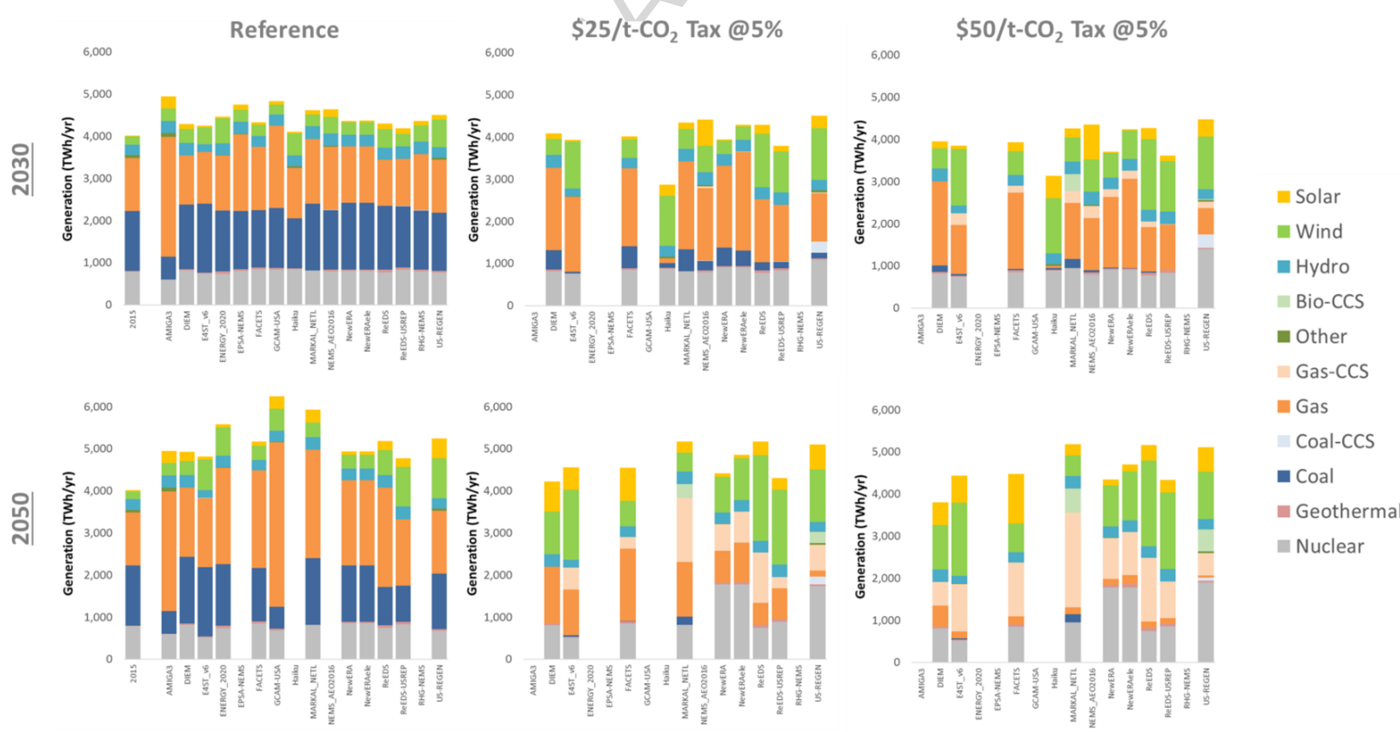


Figure 7. National generation (TWh/yr) by technology under different years (rows) and policy scenarios (columns). Individual bars represent different models. 2015 generation shown on left. Note how models omit some policy scenarios and/or have time horizons that do not extend to 2050.

Comparisons across models indicate disagreement about load growth over time in the reference and policy scenarios. Total generation in Figure 8 tends to increase in the reference, though growth through 2050 varies from the model average by almost 1,500 TWh across models (almost 40% of current generation levels). Demand tends to decrease under the power-sector-only taxes for most trajectories and models, but the degree of feedback with end uses and representation of endogenous energy efficiency also varies across models. Note that, unlike the sectoral policies examined here, studies that examine stringent economy-wide cap scenarios (e.g., 80% reduction in all greenhouse gas across all sectors) typically entail considerable electrification of end uses in addition to offsetting price-responsive demand.[10] Higher load growth under deep decarbonization scenarios is consistent with other studies (Bistline and de la Chesnaye, 2018; White House, 2016; Williams et al., 2014; Clarke et al., 2014). In contrast, the partial coverage of the power-sector-only policies increases electricity prices relative to other fuels and induces end-use fuel switching. For instance, Figure 21 in Appendix B.1 illustrates how electricity demand decreases across nearly all models, sectors, and carbon pricing scenarios.

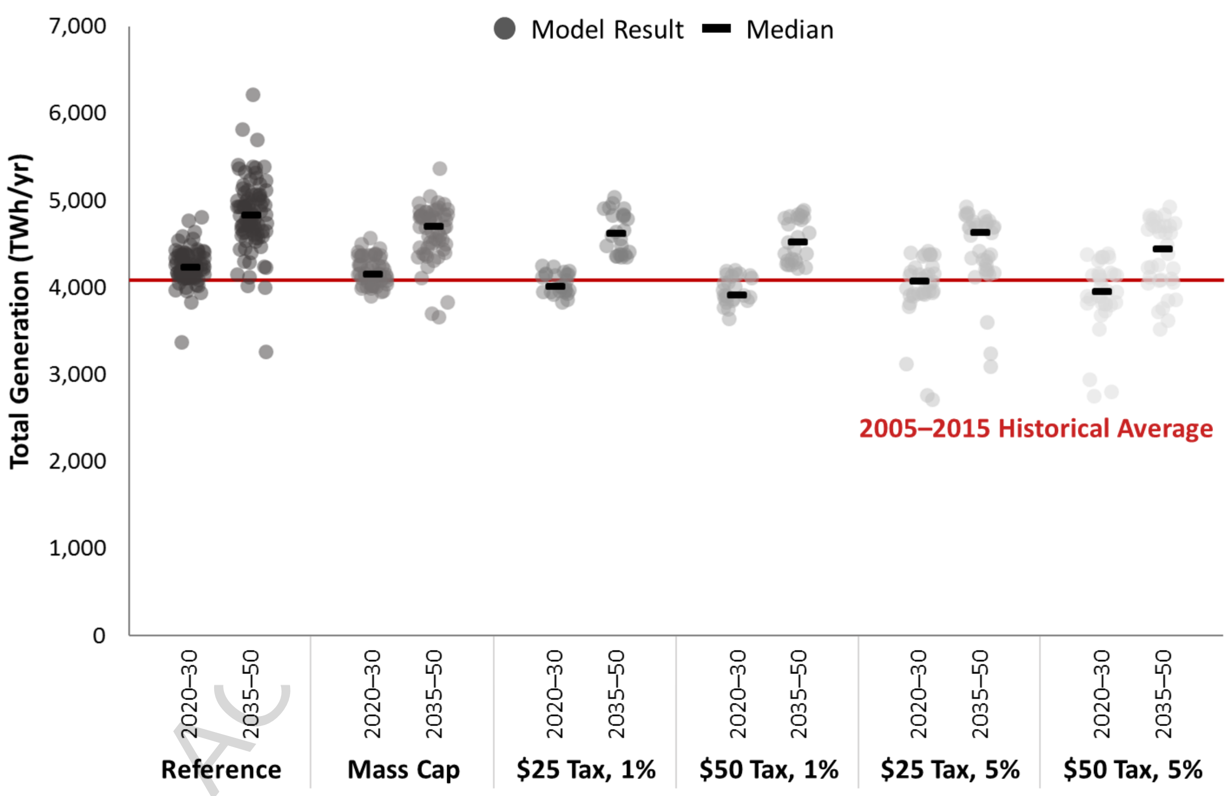


Figure 8. Total U.S. electricity generation (TWh/yr) for all models and technology scenarios, grouped by policy scenario and time period. All scenarios refer to power-sector-only policies.

[10] Economy-wide CO_2 pricing has countervailing impacts on electricity load growth due to induced energy efficiency (which *ceteris paribus* lowers demand) and electrification of end uses (which increases demand). The total impact on load is ambiguous and depends on factors like the policy design, overall stringency, and technological assumptions (Clarke et al., 2014; Fawcett et al., 2014).

Annual installations of new capacity provide one metric for measuring the rate of sectoral transformation across scenarios. The oversupply of capacity in many regional grids, measured through metrics like reserve margins, suppresses wholesale prices and leads to slower-paced near-term investments relative to the 2005–2015 average. Most models and scenarios suggest an inflection point after 2030 toward higher investment, as deployment and mitigation strategies transition from fuel switching (from existing coal to gas) toward new capital investments. Annual additions are higher under more stringent policy scenarios, both due to higher capital turnover of carbon-intensive plants and to higher variable renewable deployment (which has lower output per unit of installed capacity).

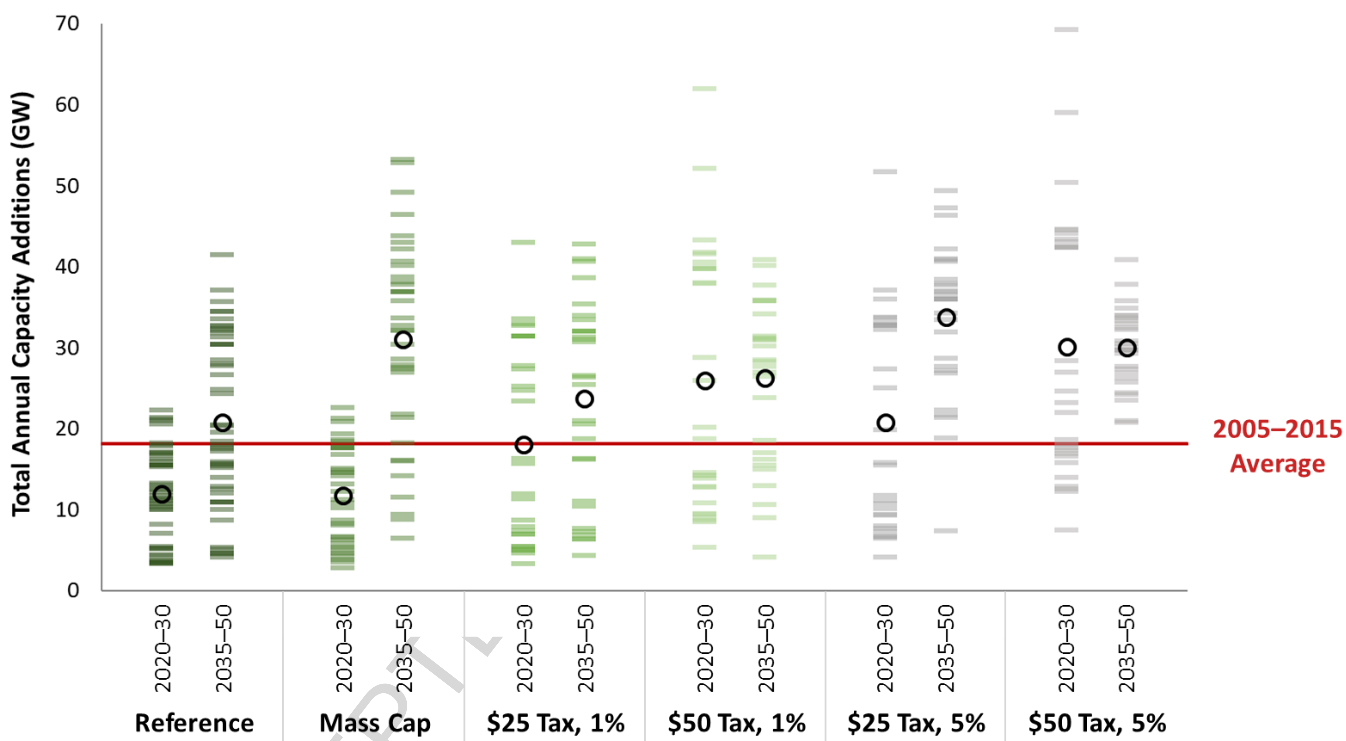


Figure 9. Total annual capacity additions (GW/yr) for all models and technology scenarios, grouped by policy scenario and time period. Dashes represent individual model outputs, and circles represent averages for given policies.

3.3. Effect of Policy on Emissions Outcomes

How close are emissions under reference trajectories (i.e., the current business-as-usual without the Clean Power Plan or increased state ambitions beyond on-the-books policies) to stated short- and long-run emissions reduction targets? Under the Obama administration's Clean Power Plan (soon to be re-proposed), EPA estimated that electric sector emissions would decrease nationally by approximately 32% relative to 2005 levels (EPA, 2015).

With respect to the national Clean Power Plan goals, models suggest that reference trends are likely to meet early emissions targets but that 2030 targets are significantly less likely to be met if current technological cost and demand projections hold.[11] Figure 10 indicates that emissions trajectories vary significantly by model, as 2030 reductions are between 9 and 30% below 2005 levels under reference technological assumptions (this range increases to 2–37% under alternate technological assumptions). Despite increasing renewable deployment and coal-to-gas switching, further emissions reductions in the reference case face headwinds from demand growth, declining marginal returns from pursuing gas/renewable strategies, and nuclear retirements.

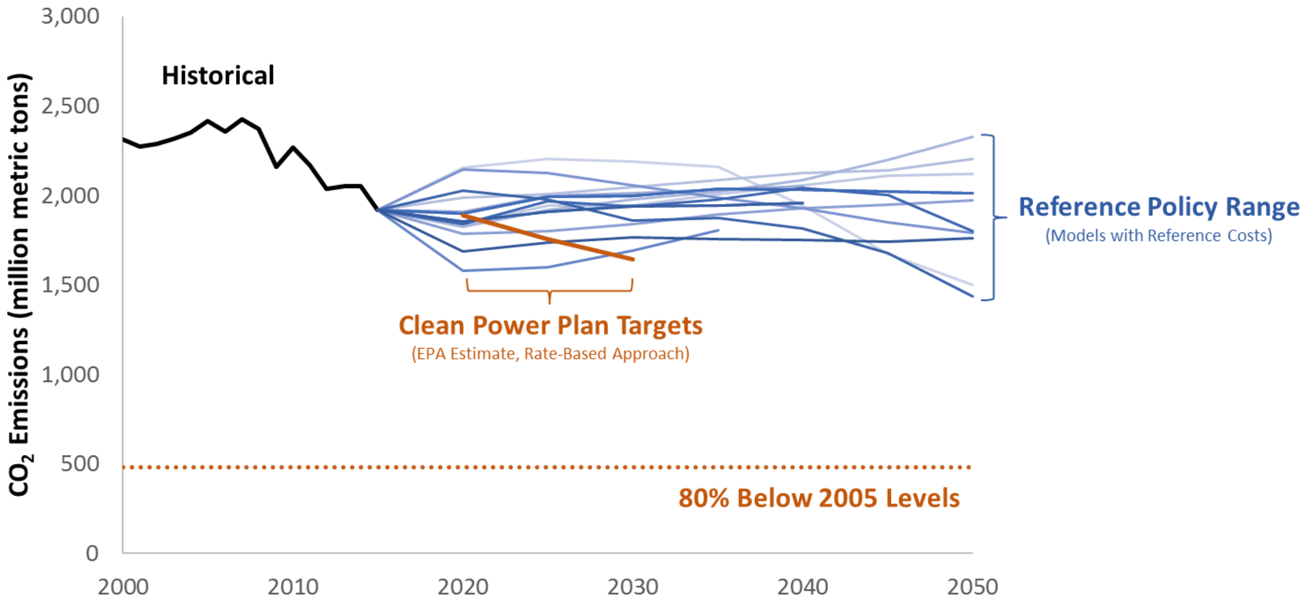


Figure 10. Historical and projected U.S. electric sector CO_2 emissions (million metric tons) across models (2000–2050) under reference policy conditions. Lines represent individual models. Values are shown for the reference technological scenario only.

Figure 11 underscores how technological and market trends alone are unlikely to reach identified longer-run emissions targets, though short-run goals may be met without additional policy in some cases. This figure illustrates the relative impacts of levels and trajectories for market-based CO_2 policies on power sector emissions over time.

Which CO_2 tax trajectories would be likely to achieve the emissions objectives of proposed Clean Power Plan, Nationally Determined Contribution (NDC), and notional 2050 80% goal?[12] Model results suggest that, with a carbon tax starting in 2020, there is a high likelihood that the 2030 reduction goals would be exceeded under all stringencies studied here. Because the 2050 goal is economy-wide, power-sector-

[11] Emissions calculations include electric sector emissions only and do not account for emissions changes in other sectors, including upstream emissions in fuel production. Also, regional variation in investments and dispatch lead to important differences in reference emissions.

[12] On June 1, 2017, the President of the United States announced that the country "will withdraw from the Paris climate accord… but begin negotiations to reenter either the Paris Accord or a really entirely new transaction…" The scenarios in this paper examine greenhouse gas emissions from the electricity sector and place those emissions in context by comparing them to the range of emissions that would have been required under the original U.S. NDC submission. Although the original intent of this analysis was to inform policymakers efforts to meet the U.S. NDC goal, the analysis is equally informative for policymakers' efforts to reach any future mitigation targets.

only carbon taxes cannot achieve the target (Barron et al., 2018). For the narrower question of how much the electricity sector reduces emissions by 2050, models show less agreement which depends largely on the tax trajectory, specifically the growth rate over time. Very few models reach an 80% reduction under the 1% tax escalation cases even with optimistic technological assumptions, but median model emissions for the 5% escalation cases are well below 80%.

The most stringent tax trajectories lead to net negative emissions in the power sector in the models that employ bioenergy with carbon capture and storage (BECCS), which on net can remove CO_2 from the atmosphere. These power sector reductions are especially beneficial under stringent economy-wide policies due to higher abatement costs in other sectors of the economy. Combined with electrification, very low or net negative power sector emissions are a common feature of decarbonization strategies (e.g., Muratori et al., 2016; Krey et al., 2014; Azar et al., 2013), which means that scenarios meeting an 80-by-50 target for the power sector alone are unlikely to be low enough to meet emissions reductions consistent with economy-wide targets.

Despite its significance in global integrated assessment model scenarios of stringent temperature targets, BECCS has received comparatively little treatment in analyses of U.S. deep decarbonization scenarios. Only two models participating in this study include the option for BECCS investments; however, both models that include BECCS (MARKAL_NETL and US-REGEN) indicate that it will play a role under the tax cases with 5% escalation rates (Figure 7). BECCS and other negative emissions technologies are notable for the significant revenue streams they would receive from captured CO_2 under carbon-constrained scenarios, which other categories of low-carbon technologies (e.g., nuclear, renewables, gas with CCS) would not. For instance, assuming a biomass emissions factor of 0.09 t-CO_2/MMBtu, carbon-neutral feedstock, heat rate of 12 MMBtu/MWh, and a 90% capture rate, a BECCS unit would receive a \$210 subsidy for each MWh it generated under the \$25/t-CO_2 tax at 5% in 2050 (i.e., approximately a \$X/MWh subsidy for a \$X/t-CO_2 tax). Such CO_2 sequestration subsidies are many times the revenues from electricity sales in typical models, which means that BECCS may be economically competitive even with high capital and operating costs.

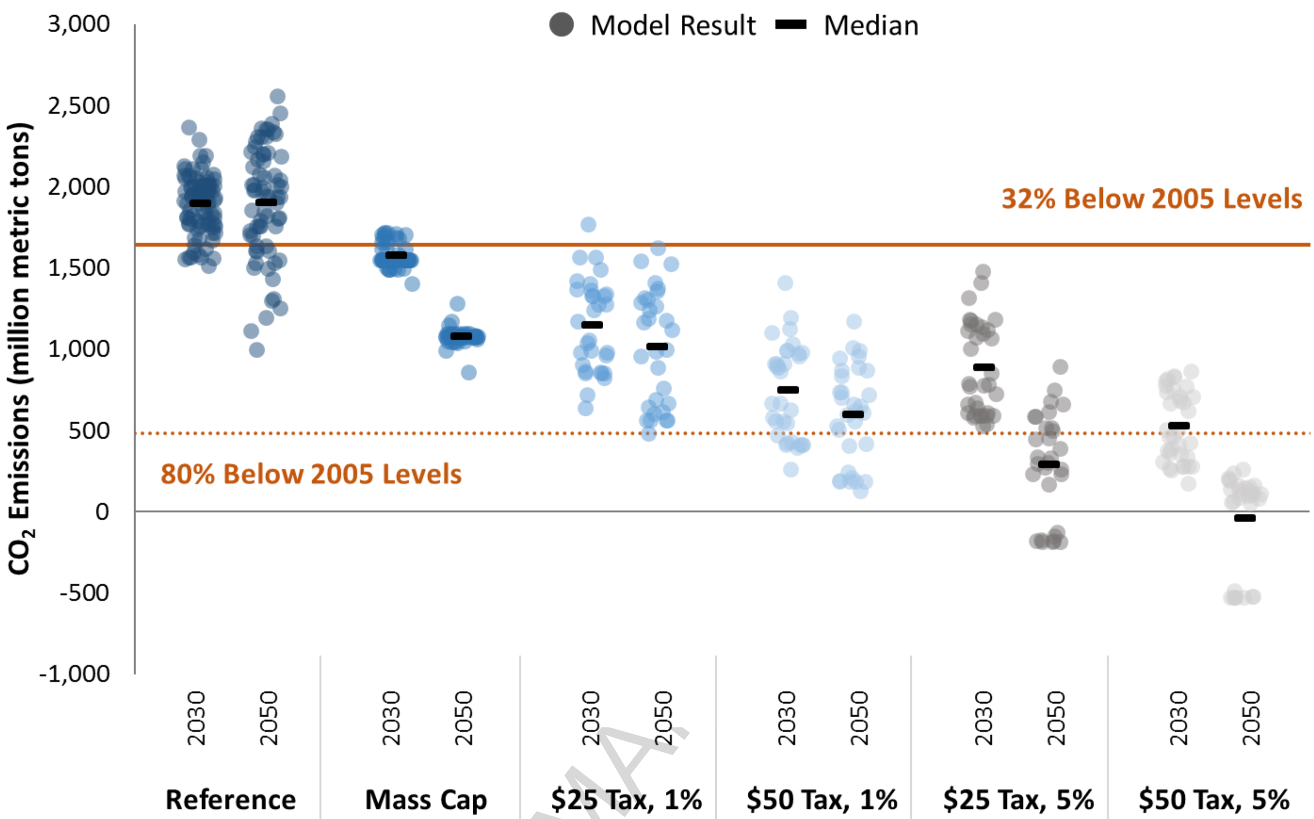


Figure 11. U.S. electric sector CO_2 emissions (million metric tons) for all models and technology scenarios, grouped by policy scenario and time period. All scenarios refer to power-sector-only policies.

Note how the variation in emissions outcomes across models and technological sensitivities does not differ considerably across policy scenarios in Figure 11.[13] As in the EMF 24 modeling exercise (Fawcett et al., 2014), model differences in CO_2 pathways are smaller if initial model conditions in the reference scenario are considered.

While the primary goal of climate policy is to reduce greenhouse gas emissions and the associated impacts on human society and the environment, these policies also produce significant benefits by reducing other forms of pollution from fossil fuels. Fossil fuel use generates pollution associated with resource extraction (e.g., Alvarez et al., 2012; Epstein et al., 2011), fuel handling (e.g., Jha and Muller, 2017), combustion (e.g., Muller et al., 2011; National Research Council, 2010), and waste disposal (e.g., Lemly, 2015; Lemly and Skorupa, 2012). In particular, the co-benefits of reductions in particulate matter (i.e., $PM_{2.5}$), nitrogen oxides (NO_x), and sulfur dioxide (SO_2) as a result of climate policy have been widely studied.

[13] The notable exception is for the mass-based cap scenario, where cumulative emissions targets are specified as part of the scenario construction. Emissions in 2030 above (below) the cap indicate borrowing (banking) of emissions allowances to lower compliance costs through temporal ("when") flexibility (Bistline and de la Chesnaye, 2018). Figure 22 in Appendix B shows how these cap scenarios employ banking across most models and scenarios.

Consistent with relatively flat coal use, SO_2 emissions from the electricity sector remain relatively flat in the reference case, as shown in Figure 23 in Appendix B. Reference case SO_2 emissions break down into two distinct groups based on model calibration. The lower estimates more closely match 2016 SO_2 emissions from the electricity sector of 1.5 Mt SO_2 (EPA, 2017a). Under the mass cap, some models show near-zero reductions in SO_2 by 2030 (for cases where the cap is non-binding in the short term), while others show larger responses with a median reduction of 24%. All carbon tax scenarios show significant reductions in SO_2. The median reduction in SO_2 under a $25@1% tax is 64% in 2030, and carbon prices greater than this level reduce SO_2 emissions to near zero in most models.

Nitrogen oxide emissions (NO_x) are also relatively constant in the reference case (Figure 24 in Appendix B). As with SO_2, some models under the mass cap show near-zero reductions in NO_x by 2030, while others show larger responses with a median reduction of 24%. Because NO_x is emitted by both coal and gas-fired facilities, it might be expected to reduce by smaller amount than SO_2, but most models also show strong reductions in NO_x. The median reduction in NO_x under a $25 at 1% tax is 50% in 2030, while a $50 at 5% trajectory reduces emissions by 91%.

The health benefits of reductions in SO_2 and NO_x are often substantial, with the short-term health benefits often similar in magnitude to, or greater than, the near-term abatement costs (e.g., Woollacott, 2018; Buonocore et al., 2016; Thompson et al., 2014; West et al., 2013; Nemet et al., 2010).

3.4. Effect of Policy on Economic Outcomes

The effect of alternative power-sector-only CO_2 tax trajectories on emissions is shown in Figure 12. Such visualizations provide first-order approximations for marginal abatement cost functions, and the reference-scenario-based metric partially controls for differences in baseline emissions across models (as opposed to using 2005 levels).[14] Even when technological and market uncertainties are taken into account (the "Reference Technology" points), models exhibit significant variation in emissions abatement for the same CO_2 tax trajectories. The technological sensitivities indicate that many developments increase abatement for a given CO_2 price (e.g., lower renewables costs), but other market uncertainties may decrease abatement for a given price (e.g., higher gas prices).

[14] Note that the scenarios depicted in Figure 12 use different initial CO_2 taxes and escalation rates, as discussed in Table 2.

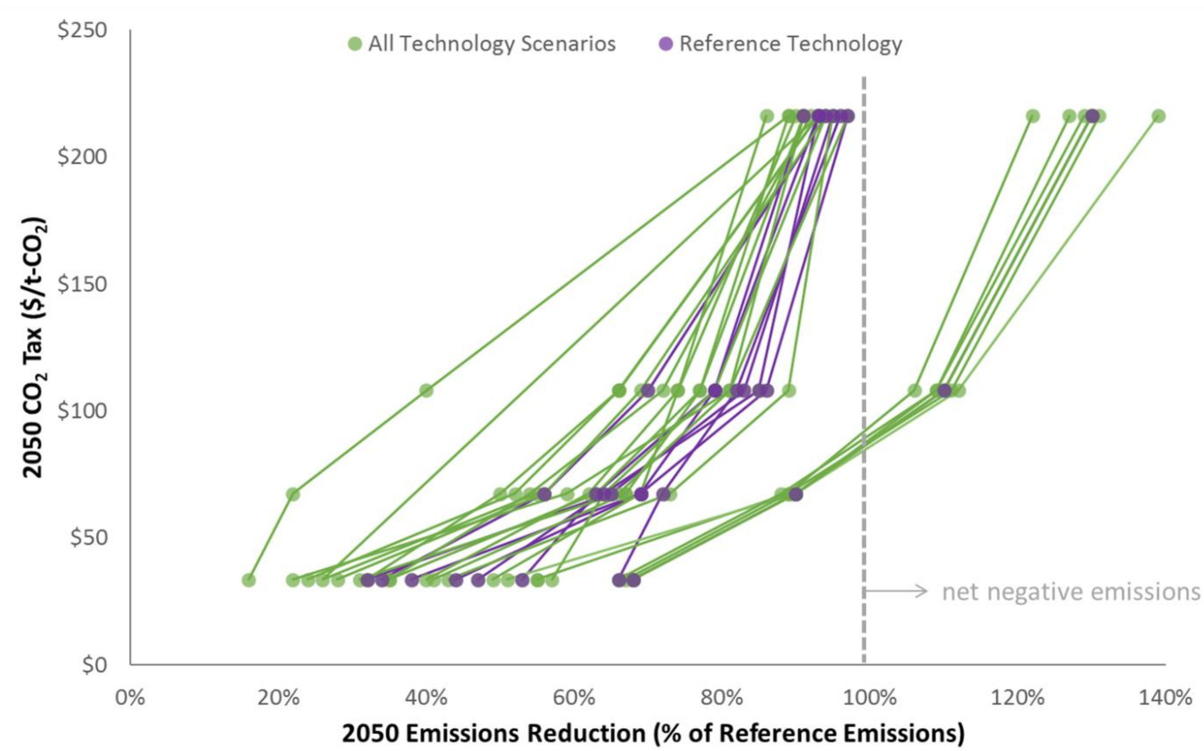


Figure 12. 2050 electric sector CO_2 emissions reduction (% reference) for different 2050 tax levels ($/t-$CO_2$). Lines represent individual model runs. Purple values are for "Reference Technology" assumptions, and green values show the full variation in outcomes across all scenarios.

It can be challenging to compare economic and environmental outcomes across scenarios with drastically different assumptions (especially for price-based instruments that do not generally result in similar emissions paths), and comparing scenarios across models with different emissions levels further exacerbates these difficulties. Figure 13 compares economic and emissions outcomes across models and scenarios by plotting cumulative CO_2 reductions relative to the reference scenario against the net present value (NPV) of incremental electric sector costs,[15] assuming a 5% real discount rate. Individual models and scenario assumptions in these figures loosely correspond to efficiency frontiers with higher emission reductions coming at greater sectoral costs.

An important limitation of these results is that, given the partial equilibrium structure of many participating models, an NPV metric that only covers electric sector costs provides an incomplete portrait of the economic impacts of policies. These scenarios would be expected to affect other sectors, consumer welfare, and monetized impacts of emissions. For instance, if revenue generated by market-based policies (either from a carbon tax or the sale of allowances under a cap) were used to lower preexisting taxes on capital and labor, the efficiency frontier would shift down and to the right, which means that overall costs to the economy would be lower (Barron et al., 2018).

[15] Total electric sector costs include capital, fuel, operations, and maintenance expenditures. Note how these values represent a small component of total costs for models with energy system or economy-wide scopes. Using an aggregated NPV-based metric removes the time component of calculations and helps to standardize outputs across models with different time horizons.

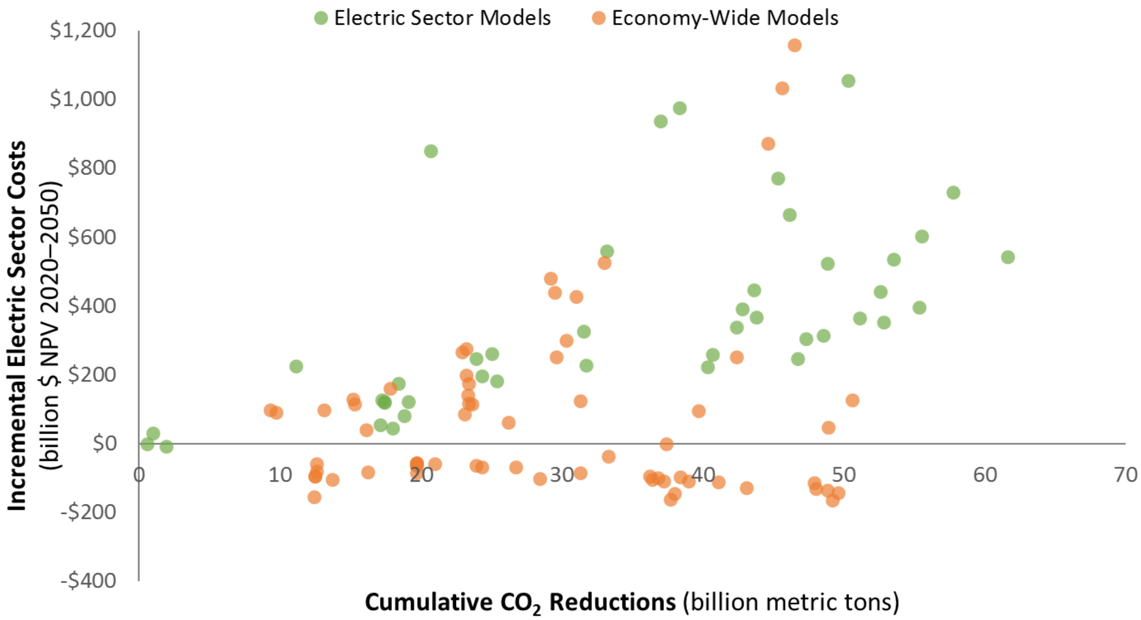


Figure 13. Comparison of cumulative CO_2 reductions (billion metric tons) and incremental electric sector costs (billion $ NPV 2020–2050) relative to the reference scenario. Dots represent individual model runs. Green circles show electric-sector-only models, and orange values show economy-wide models. The average NPV under reference scenarios is $2.77 trillion.

Figure 13 illustrates that, although increases in cumulative abatement generally create incremental electric sector costs, there are many models that suggest relatively low power sector economic impacts across scenarios. Almost all of these low- or negative-cost scenarios are associated with economy-wide models that that represent other sectors in addition to the power sector. The partial coverage of the power-sector-only policies induce end-use fuel switching and ultimately shift costs and emissions to other sectors. For instance, Figure 21 in Appendix B.1 illustrates how electricity demand decreases across nearly all models, sectors, and carbon pricing scenarios. Cost and emissions leakage beyond the regulated segment is a broader concern for policies with only partial geographical or sectoral coverage. Additionally, some models rely extensively on the adoption of energy efficiency measures, which reduce capital and fuel costs in the power sector while reducing demand and emissions. The actual cost-effectiveness of energy efficiency measures *ex post* (versus expected *ex ante*) is a source of great debate in the energy economics literature (Fowlie et al., 2015), which may add to the uncertainty of results here driven by energy efficiency measures. However, the most significant cost reductions come through the advanced technological scenarios. Technological substitution possibilities (e.g., cost assumptions) are a major driver of economic impact assessments, and these scenarios underscore how technological progress reduces economic impacts across policy environments, especially under the most stringent policy scenarios.[16]

[16] It should be noted that these social costs are accompanied by social benefits, principally in the form of reduced climate damages from CO_2 and in improved welfare from reductions in conventional air pollution (e.g., SO_2 and NO_x). As noted above, short-term health benefits are often similar in magnitude to, and often greater than, the near-term abatement costs.

4. Research Needs

Most of the power sector models used in this study have a strong research foundation and have been used extensively in policy and technology assessment of the energy sector. That said, all models are abstractions and require exclusive choices on structure, scope, technology options and costs, and expectations of future demand and market conditions for fuel inputs. These modelers' choices create uncertainty in model projections and can identify areas where further research may reduce these uncertainties (Morgan, 2015). An important function of the EMF 32 analysis is to identify future research and analysis needs, which are summarized in this section.

The two most significant omissions in the technological coverage of the power sector are energy storage and bioenergy with carbon capture and storage (BECCS). Costs of battery storage have been falling rapidly in recent years, but it is unclear how this pace will continue in the future or how much developments will translate into changes in the power sector and beyond (Kittner et al., 2017). However, many capacity planning models do not capture storage investments endogenously, and models that do represent storage simplify technological characteristics of its operations (Cole et al., 2017). These simplifications are often motivated by computational requirements of multidecadal capacity planning and dispatch problems, which require tradeoffs between spatial resolution, temporal resolution, treatment of end uses, and uncertainty (Santen et al., 2017). Future work should prioritize computationally efficient methods for incorporating storage in capacity planning models.

Likewise, as discussed in Section 3.3, BECCS is underrepresented in participating models in this study, especially given its significance for deep decarbonization scenarios. There is a disconnect between global integrated assessment model scenarios of stringent temperature targets, where negative emissions technologies like BECCS are prominent features (Krey et al., 2014), and strategies suggested by U.S. decarbonization analyses with national models, where BECCS has received relatively little treatment. The 2 of 16 models participating in this study that include BECCS indicate that it will play a role under the tax cases with 5% escalation rates (Figure 7). BECCS and other negative emissions technologies are notable for the significant revenue streams they would receive from captured CO_2 under carbon-constrained scenarios, which other categories of low-carbon technologies (e.g., nuclear, renewables, gas with CCS) would not. Future efforts should incorporate BECCS and other negative emissions options and investigate their relative roles under alternate policy scenarios, especially for economy-wide decarbonization scenarios with high abatement costs in non-electric sectors.

Other future research needs based on this analysis include:

- **Cross-sectoral impacts of increasingly integrated energy systems:** Few models are capable of representing deep decarbonization scenarios and interactions across sectors (e.g., electrification) and hourly load shape impacts while still maintaining a sufficient degree of planning and operational detail in the power sector.

- **Value of a full technological portfolio (and costs of limited one):** The results of these model comparisons of climate policies are broadly consistent with the EMF 24 study in that emissions reduction goals can be met through many different technological pathways, and costs are higher when options are more limited (Clarke et al., 2014). The specific mix of technologies differs in this study based on updated costs and model representations of generation options and other technologies. Models of the power system under low-carbon futures are increasingly required to balance appropriate levels of temporal, spatial, and technical complexity with computational demands to accurately capture and evaluate economic and technical dimensions of energy transitions. Future work to understand the relative roles of low-carbon technologies should systematically evaluate tradeoffs in electric sector and energy system models between the accuracy of simplifications and computational tractability (Bistline et al., 2017).

- **Drivers of retirements of the existing coal and nuclear fleet:** Model results suggest that carbon policy can drive retirements of these two generation sources in opposite directions – increasing coal retirements and decreasing nuclear ones. Future work should explore these drivers systematically and in greater depth. It would be useful to understand retirement implications of policy approaches that provide subsidies for "clean" technologies rather than taxing "dirty" ones, as each provide different entry, exit, and utilization incentives for generators (Paul et al., 2015). Nuclear plants are now feeling market pressure from low natural gas prices and renewable generation subsidies that are together keeping power prices low. For instance, the state of New York passed a law in 2017 to provide subsidies for nuclear generation in the form of "Zero Emission Credits" or ZECs issued per MWh of nuclear power generated (New York Senate Bill S. 6651). Additionally, coal-fired electric generation is more exposed than other technologies to regulatory risk from internalizing currently unpriced negative externalities (Muller et al., 2011; Epstein et al., 2011; NRC, 2010), which suggests that a thorough assessment of drivers and impacts of coal retirements should include a broader range of policy sensitivities not related to CO_2 emissions.

- **Role of energy storage and other flexibility options:** Since the value of dispatchable assets on the grid grows as the share of non-dispatchable resources such as wind and solar increases. Additionally, states are increasingly exploring approaches to integrate not only generation-side resources but also distributed energy resources, efficiency, and flexible demand. It is increasingly important for models to assess potential roles of balancing and flexibility options such as energy storage, combustion turbines, and demand-side management. This modeling requires not only detailed temporal resolution and chronology to capture operational detail but also multi-decadal time horizons to evaluate potential impacts on investments. Modeling challenges are compounded by the complexity of possible cost and revenue streams for these technologies, which are not likely to be captured endogenously within any single model. The role of storage and flexibility is important not only for low-carbon scenarios but also for potential impacts on revenues of more inflexible units like existing coal and nuclear under less stringent policy environments.

- **Ex-post analysis of model intercomparisons and backcasting exercises:** The EMF 32 study provides a snapshot about the current state of knowledge and analysis about power sector futures; however, further insights may be gained with more analysis. Future work should use this study to understand best practices and ex-post techniques for improving model development and utilization. Such analyses should evaluate how model architectures and assumptions affect results and areas where model projections are consistently out of line with observed outcomes to identify areas for improvement.

- **Greater range of technological sensitivities:** Favorable and unfavorable technological surprises may emerge, but model results indicate that many general insights will hold nevertheless. Technological and market surprises may provide unexpected benefit but also could bring new challenges, which are important for decision-makers to understand. For instance, realized wind and solar costs have been lower than many past projections (Cole et al., 2016), which suggests that a broader range of low-cost sensitivities for these technologies should be explored.

- **Consistent approaches to electricity price comparisons:** In compiling this study, we found it challenging to compare electricity price impacts across models given a lack of comparability in reporting (e.g., retail versus wholesale prices) and model structures (e.g., different geographical resolutions). This is unfortunate as regional electricity price changes are the most politically salient price impact for policies in this sector. Further work to create apples-to-apples comparisons of electricity price impacts and total system costs (including accounting for changes across sectors given different model structures) would be of great use.

5. Discussion

For the electric sector policy-related scenarios and technological sensitivities considered here, models suggest that future climate policies have the potential to be the leading determinant of the extent and pace of future electric sector transformations and emissions trajectories in the United States. Existing environmental regulations, cost reductions of low-carbon technologies, and energy market trends alone are unlikely to reach emissions reductions targets identified in recent U.S. policy declarations (especially for more ambitious mid- to long-run goals), but these baseline trends may reduce the cost of adopting policies to achieve emission reduction targets. The near-term power sector transformation comes primarily in the form of substitution of natural gas and renewables for coal generation, a trend that has already started without a national policy in place, but would be amplified considerably if the types and levels of carbon pricing policies studied here were enacted. More stringent long-run policies lead to a broader range of investments in renewables, gas, carbon-capture-equipped units, and nuclear (with the mix depending on cost assumptions and economic value of different technologies).

The policy-induced outcomes are more pronounced after 2030 due to rising policy stringency, though subject to much greater uncertainty (Barron et al., 2018). Emissions, new capacity deployment, and generation shares exhibit wider variation across models and scenarios between 2035 and 2050 than they do prior to 2030. This reflects greater uncertainty about technological and market developments but also the dynamics of investment and capital stock turnover. When viewing individual policy scenarios, models can vary greatly in terms of their generation responses; for example, a \$25/t-CO_2 tax (rising at 1% annually) reduces coal generation anywhere from 20 and 90% by 2035 depending on the model. Although previous model intercomparison projects have suggested variation in generation responses, this study suggests higher variable renewable energy and natural gas shares than multi-model studies from even a few years ago (Fawcett et al., 2014). These variations depend on the type of model (i.e., perfect foresight versus recursive dynamic), technological cost assumptions, regional specificity, whether they incorporate endogenous energy efficiency responses, and other factors.

Technological strategies and electric sector deployment depend jointly on the policy environment and technological developments over time. Results across models largely agree that trends of coal-to-gas substitution and renewables deployment are likely to continue, but the extent varies by model and scenario. There is robust agreement across models that coal's generation share is the most sensitive to the policy context due to relative price effects of a carbon tax on higher-carbon-intensity fuels. However, the pace and extent of decreases in coal generation and the composition of replacement capacity depends on policy, market uncertainties (e.g., gas prices), technological costs, and region. For natural gas generation, variation of 2050 generation is significant, as models span the range from nearly no gas generation to almost 4,000 TWh (roughly the same as total generation in 2015). For nuclear generation, carbon taxes can reduce the likelihood of retirements for existing nuclear plants since they are an emissions-free resource at the point of generation.

The carbon tax trajectories examined here appear to reduce emissions at relatively modest costs (with models showing incremental electric sector costs between -\$200 to +\$1,200 billion net present value through 2050), though cost impacts vary across policy scenarios and models and are sensitive to technology cost assumptions. However, the power-sector-only policies addressed here do not necessarily align with economy-wide deep decarbonization pathways either in the level of total electricity generation or the pace of capacity deployment. While these models generally project the least-cost approach for the power sector to respond to carbon pricing policies, including in some instances energy efficiency investments, they largely ignore options in the rest of the economy. In fact, these power-sector-only policies lead to greater increases in electricity prices relative to other fuels and decreases in electricity consumption across nearly all sectors and carbon pricing scenarios (as shown in Figure 21 discussed in Appendix B.1). Economy-wide decarbonization strategies, however, likely entail extensive electrification of end uses, such as transportation, industrial production, and household services such as heating and air conditioning (Bistline and de la Chesnaye, 2018; White House, 2016; Williams et al., 2014; Clarke et al., 2014). These economy-wide decarbonization strategies would likely increase electricity consumption, generation, and the nature and pace of capacity build-outs over time relative to power-sector-only policies.

Acknowledgments

The authors would like to thank Qiuzi Chen, Stuart Cohen, James McFarland, Steve Rose, Martin Ross, Kate Shouse, Nadejda Victor, and two anonymous reviewers for their helpful feedback. The views and opinions expressed in this paper are those of the authors alone and do not necessarily state or reflect those of DOE, Duke University, EPA, EPRI, Smith College, or Southern Company, and no official endorsement should be inferred.

Bibliography

Alvarez, R.A., Pacala, S.W., Winebrake, J.J., Chameides, W.L., Hamburg, S.P. (2012). "Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure." *Proceedings of the National Academy of Sciences* **109:6435–6440**.

Azar, C., Johansson, D.J.A., Mattsson, N. (2013). "Meeting Global Temperature Targets – The Role of Bioenergy with Carbon Capture and Storage." *Environmental Research Letters* **8**.

Barron, A.R., Fawcett, A.A., Hafstead, M.A.C., McFarland, J.R., Morris, A.C. (2018). "Policy Insights form the EMF 32 Study on U.S. Carbon Tax Scenarios." *Climate Change Economics* **9(1):1840003**.

Barron, A. (2018). "Time to Refine Key Climate Policy Models." *Nature Climate Change* (forthcoming).

Bistline, J.E., de la Chesnaye, F. (2018). "Banking on Banking: Does 'When' Flexibility Mask the Costs of Stringent Climate Policy?" *Climatic Change* **144(4):597–610**.

Bistline, J.E., Shawhan, D., Blanford, G., de la Chesnaye, F., Mao, B., Santen, N. (2017). *Systems Analysis in Electric Power Sector Modeling: Evaluating Model Complexity for Long-Range Planning*, EPRI Technical Report #3002011365 (EPRI, Palo Alto, CA).

Bistline, J.E. (2017). "Economic and Technical Challenges of Flexible Operations under Large-Scale Variable Renewable Deployment." *Energy Economics* **64:363–372**.

Bistline, J.E. (2015). "Electric Sector Capacity Planning under Uncertainty: Climate Policy and Natural Gas in the U.S." *Energy Economics* **51:236–251**.

Blanford, G., Merrick, J., Bistline, J.E., Young, D. (2018). "Simulating Annual Variation in Load, Wind, and Solar by Representative Hour Selection." *The Energy Journal* **39(3)**.

Buonocore, J.J., Lambert, K.F., Burtraw, D., Sekar, S., Driscoll, C.T. (2016). "An Analysis of Costs and Health Co-Benefits for a U.S. Power Plant Carbon Standard." *PLOS ONE* **11:e0156308**.

Burtraw, D., Palmer, K., Paul, A., Woerman, M. (2012). "Secular Trends, Environmental Regulations, and Electricity Markets." *The Electricity Journal* **25(6):35–47**.

Clarke, L., Fawcett, A., Weyant, J., McFarland, J., Chaturvedi, V., Zhou, Y. (2014). "Technology and U.S. Emissions Reductions Goals: Results of the EMF 24 Modeling Exercise." *The Energy Journal* **35:9–31**.

Cole, W., Frew, B., Mai, T., Sun, Y., Bistline, J., Blanford, G., Young, D., Marcy, C., Namovicz, C., Edelman, R., Meroney, B., Sims, R., Stenhouse, J., Donohoo-Vallett, P. (2017). *Variable Renewable Energy in Long-Term Planning Models: A Multi-Model Perspective*, NREL/TP-6A20-70528 (National Renewable Energy Laboratory, Golden, CO).

Cole, W., Mai, T., Logan, J., Steinberg, D., McCall, J., Richards, J., Sigrin, B., Porro, G. (2016). *2016 Standard Scenarios Report: A U.S. Electricity Sector Outlook*, NREL/TP-6A20-66939 (National Renewable Energy Laboratory, Golden, CO).

Creason, J., Bistline, J., Hodson, E., Murray, B., Rossmann, C. (2018). "Effects of Technology Assumptions on US Power Sector Capacity, Generation and Emissions Projections: Results from the EMF 32 Model Intercomparison Project." *Energy Economics* (forthcoming).

Creutzig, F., Agoston, P., Goldschmidt, J.C., Luderer, G., Nemet, G., Pietzcket, R.C. (2017). "The Underestimated Potential of Solar Energy to Mitigate Climate Change." *Nature Energy* **2:17140**.

Electric Power Research Institute (2017). *US-REGEN Model Documentation*, EPRI Technical Update #3002010956 (EPRI, Palo Alto, CA).

Epstein, P.R., Buonocore, J.J., Eckerle, K., Hendryx, M., Stout III, B.M., Heinberg, R., Clapp, R.W., May, B., Reinhart, N.L., Ahern, M.M., Doshi, S.K., Glustrom, L. (2011). "Full Cost Accounting for the Life Cycle of Coal." In *Ecological Economics Reviews* (edited by Costanza, Limburg, and Kubiszewski).

Fawcett, A., Clarke, L., Rausch, S., Weyant, J. (2014). "Overview of EMF 24 Policy Scenarios." *The Energy Journal* **35:33–60**.

Fell, H., Linn, J. (2013). "Renewable Electricity Policies, Heterogeneity, and Cost Effectiveness." *Journal of Environmental Economics and Management* **66:688–707**.

Fiertz, C., Lawson, A. (2016). *Insights from a Comparative Analysis of Clean Power Plan Modeling*, Center for Climate and Energy Solutions.

Fischer, C., Newell, R. (2008). "Environmental and Technology Policies for Climate Mitigation." *Journal of Environmental Economics and Management* **55:142–162**.

Fowlie, M., Greenstone, M., Wolfram, C. (2015). *Do Energy Efficiency Investments Deliver? Evidence from the Weatherization Assistance Program*, NBER Working Paper No. 21331.

Gowrisankaran, G., Reynolds, S., Samano, M. (2016). "Intermittency and the Value of Renewable Energy." *Journal of Political Economy* **124(4):1187–1234**.

Hirth, L. (2013). "The Market Value of Variable Renewables: The Effect of Solar and Wind Power Variability on their Relative Price." *Energy Economics* **38:218–236**.

Huntington, H., Weyant, J., Sweeney, J. (1982). "Modeling for Insights, Not Numbers: The Experiences of the Energy Modeling Forum." Omega **10(5):449–462**.

Jha, A., Muller, N. (2017). *Handle with Care: The Local Air Pollution Costs of Coal Storage*. National Bureau of Economic Research Working Paper No. 23417 (NBER, Cambridge, MA).

Kittner, N., Lill, F., Kammen, D. (2017). "Energy Storage Deployment and Innovation for the Clean Energy Transition." *Nature Energy* **2:17125**.

Krewski, D., Jerrett, M., Burnett, R.T., Ma, R., Hughes, E., Shi, Y., Turner, M.C., Pope, C.A., Thurston, G., Calle, E.E., Thun, M.J., Beckerman, B., DeLuca, P., Finkelstein, N., Ito, K., Moore, D.K., Newbold, K.B., Ramsay, T., Ross, Z., Shin, H., Tempalski, B. (2009). "Extended Follow-Up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality." *Res. Rep. Health Eff. Inst.* **5-114**.

Krey, V., Luderer, G., Clarke, L., Kriegler, E. (2014). "Getting from Here to There – Energy Technology Transformation Pathways in the EMF 27 Scenarios." *Climatic Change* **123:369–382**.

Lemly, A.D. (2015). "Damage Cost of the Dan River Coal Ash Spill." *Environmental Pollution* **197:55–61**.

Lemly, A.D., Skorupa, J.P. (2012). "Wildlife and the Coal Waste Policy Debate: Proposed Rules for Coal Waste Disposal Ignore Lessons from 45 Years of Wildlife Poisoning." *Environmental Science and Technology* **46(16):8595–8600**.

Lepeule, J., Laden, F., Dockery, D., Schwartz, J. (2012). "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-up of the Harvard Six Cities Study from 1974 to 2009." *Environ. Health Perspect.* **120:965–970**.

McKibbin, W.J., Morris, A.C., Wilcoxen, P.J. (2014). "Pricing Carbon in the U.S.: A Model-Based Analysis of Power-Sector-Only Approaches." *Resource and Energy Economics* **36(1):130–150**.

Morgan, M.G. (2015). "Our Knowledge of the World is Often Not Simple: Policymakers Should Not Duck that Fact, But Should Deal with It." Risk Analysis **35(1):19–20**.

Muller, N., Mendelsohn, R., Nordhaus, W. (2011). "Environmental Accounting for Pollution in the United States Economy." *American Economic Review* **101(5):1649–1675**.

Muratori, M., Calvin, K., Wise, M., Kyle, P., Edmonds, J. (2016). "Global Economic Consequences of Deploying Bioenergy with Carbon Capture and Storage (BECCS)." *Environmental Research Letters* **11:095004**.

Murray, B., Creason, J., Hodson, E., Rossmann, C., Bistline, J. (2018). "Introduction to EMF 32." *Energy Economics* (forthcoming).

National Research Council (2010). *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use* (The National Academies Press, Washington, DC).

Nemet, G.F., Holloway, T., Meier, P. (2010). "Implications of Incorporating Air-Quality Co-Benefits into Climate Change Policymaking." Environ. Res. Lett. **5:01400**.

National Academies of Sciences (2017). *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon* (The National Academies Press, Washington, DC).

National Renewable Energy Laboratory (2017). *Variable Renewable Energy in Long-Term Planning Models: A Multi-Model Perspective*, NREL/TP-6A20-70528 (NREL, Golden, CO).

Paul, A., Palmer, K., Woerman, M. (2015). "Incentives, Margins, and Cost Effectiveness in Comprehensive Climate Policy for the Power Sector." *Climate Change Economics* **6:1550016**.

Rose, S., Turner, D., Blanford, G., Bistline, J., de la Chesnaye, F., and Wilson, T. (2014). *Understanding the Social Cost of Carbon: A Technical Assessment*, EPRI Technical Update #3002004657 (EPRI, Palo Alto, CA).

Sanchez, D.L., Nelson, J.H., Johnston, J., Mileva, A., Kammen, D.M. (2015). "Biomass Enables the Transition to a Carbon-Negative Power System across Western North America." *Nature Climate Change* **5:230–234**.

Santen, N., Bistline, J., Blanford, G., de la Chesnaye, F. (2017). *Systems Analysis in Electric Power Sector Modeling: A Review of the Recent Literature and Capabilities of Selected Capacity Planning Tools*, EPRI Technical Report #3002011102 (EPRI, Palo Alto, CA).

Shearer, C., Bistline, J., Inman, M., Davis, S. (2014). "The Effect of Natural Gas Supply on U.S. Renewable Energy and CO_2 Emissions." *Environmental Research Letters* **9(9):094008**.

Sullivan, P., Eurek, K., Margolis, R. (2014). *Advanced Methods for Incorporating Solar Energy Technologies into Electric Sector Capacity-Expansion Models: Literature Review and Analysis*, NREL/TP-6A20-61185 (NREL, Golden, CO).

Tavoni, M., Tol, R.S.J. (2010). "Counting Only the Hits? The Risk of Underestimating the Costs of Stringent Climate Policy." *Climatic Change* **100:769–778**.

Thompson, T.M., Rausch, S., Saari, R.K., Selin, N.E. (2014). "A Systems Approach to Evaluating the Air Quality Co-Benefits of U.S. Carbon Policies." Nat. Clim. Change **4:917–923**.

Wiser, R. et al. (2017). "Assessing the Costs and Benefits of U.S. Renewable Portfolio Standards." *Environmental Research Letters* **12(9)**.

U.S. Energy Information Administration (2016a). *Annual Energy Outlook 2016 with Projections to 2040* (EIA, Washington, DC).

U.S. Energy Information Administration (2016b). *Electric Power Annual Interactive Data* (Table 3.1.A). Available at: https://www.eia.gov/electricity/annual/xls/epa_03_01_a.xlsx.

U.S. Energy Information Administration (2007). *Annual Energy Outlook 2007 with Projections to 2030* (EIA, Washington, DC).

U.S. Environmental Protection Agency (2017a). *Regulatory Impact Analysis for the Clean Power Plan Final Rule*, EPA-452/R-15-003 (EPA, Research Triangle Park, NC).

U.S. Environmental Protection Agency (2017b). U*ser's Manual for the Co-Benefits Risk Assessment (COBRA) Screening Model, Version 3.* Developed by Abt Associates for U.S. Environmental Protection Agency, Climate Protection Partnerships Division, State and Local Climate and Energy Programs (Washington, DC).

U.S. Environmental Protection Agency (2015). *Air Markets Program Data – Clean Air Markets*, available online at https://ampd.epa.gov/ampd/.

West, J.J., Smith, S.J., Silva, R.A., Naik, V., Zhang, Y., Adelman, Z., Fry, M.M., Anenberg, S., Horowitz, L.W., Lamarque, J.-F. (2013). "Co-Benefits of Mitigating Global Greenhouse Gas Emissions for Future Air Quality and Human Health." *Nat. Clim. Change* **3:885–889**.

Weyant, J. (2017). "Some Contributions of Integrated Assessment Models of Global Climate Change." *Review of Environmental Economics and Policy* **11(1):115–137**.

White House (2016). *United States Mid-Century Strategy for Deep Decarbonization* (White House, Washington, DC). Available at: https://unfccc.int/files/focus/long-term_strategies/application/pdf/us_mid_century_strategy.pdf.

Williams, J., Haley, B., Kahrl, F., Moore, J., Jones, A., Torn, M., McJeon, H. (2014). *Pathways to Deep Decarbonization in the United States*, U.S. Report of the Deep Decarbonization Pathways Project of the Sustainable Development Solutions Network and the Institute for Sustainable Development and International Relations.

Woollacott, J. (2018). "The Economic Costs and Co-Benefits of Carbon Taxation: A General Equilibrium Assessment." *Climate Change Economics* **9(1):1840006**.

Appendix A: Scenario and Model Assumptions

As described in Section 2.1, the policy sensitivities for this study examine four tax trajectories that are applied to the power sector only. Figure 14 shows that these taxes are assumed to start in 2020 at either \$25 or \$50/t-CO_2 and escalate at either 1% or 5% per year. For context, the social cost of carbon with 3% discount rate developed by the U.S. Government Interagency Working Group (IWG) is most similar to the \$50/t-CO_2 tax with 1% escalation, starting slightly lower at \$43/t-CO_2 in 2020 but ending slightly higher at \$71/t-CO_2 in 2050.*

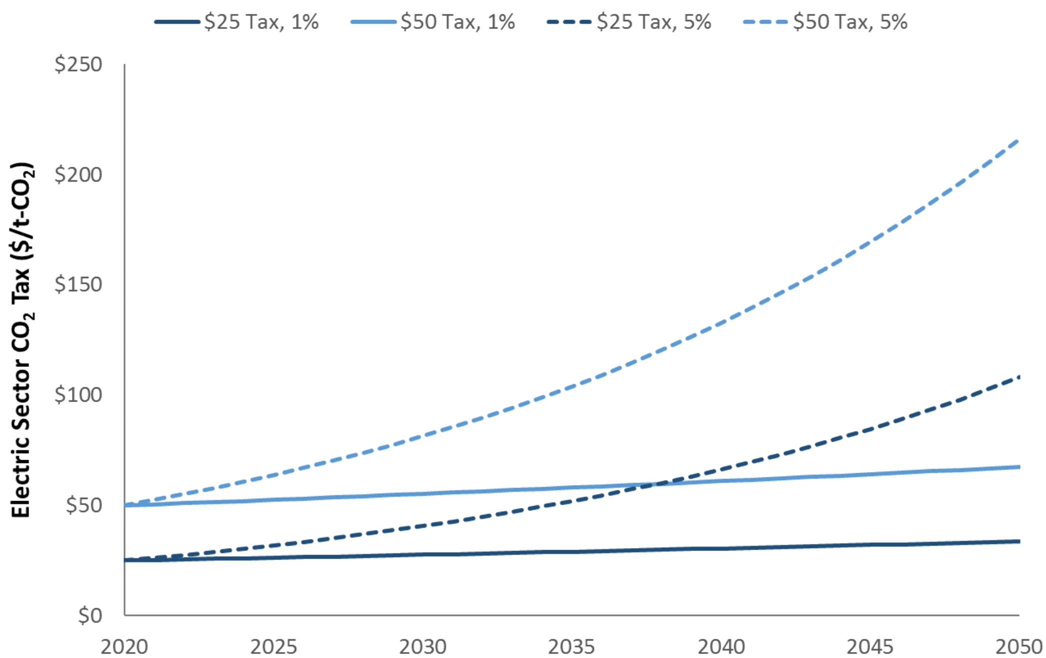


Figure 14. Electricity sector tax trajectories (\$ per metric ton CO_2) over time. Starting value and escalation rates for the CO_2 tax are shown above.

As described in Creason et al. (2018), there are many differences across models: structure, foresight, demand response, price feedbacks with other economic sectors (e.g., gas prices), assumptions (e.g., tech cost/performance, financing), geographical scope (e.g., Lower 48 only, all U.S., linkages with other countries), spatial and temporal resolution, and grid representations (e.g., transmission expansion).

* Note that Rose et al. (2014) identify consistency, comparability, and uncertainty issues with the IWG approach utilizing three models. NAS (2017) also found the multi-model approach problematic and recommended an alternative framework. The IWG values were withdrawn from federal regulatory use and replaced with alternative guidance for monetizing changes in greenhouse gases through the Executive Order "Promoting Energy Independence and Economic Growth" on March 28, 2017.

Appendix B: Additional Model Results

B.1. Technological Outputs

Figure 15 illustrates how the qualitative insights about coal generation in Section 3.1 across models and policies also hold when examined under the reference technological scenario only (Figure 1 plots values across technological sensitivities as well). Although there is disagreement about the magnitude, models suggest that there is significant disagreement about the amount of coal generation approaching midcentury without additional CO_2 policy, as shown in Figure 16.

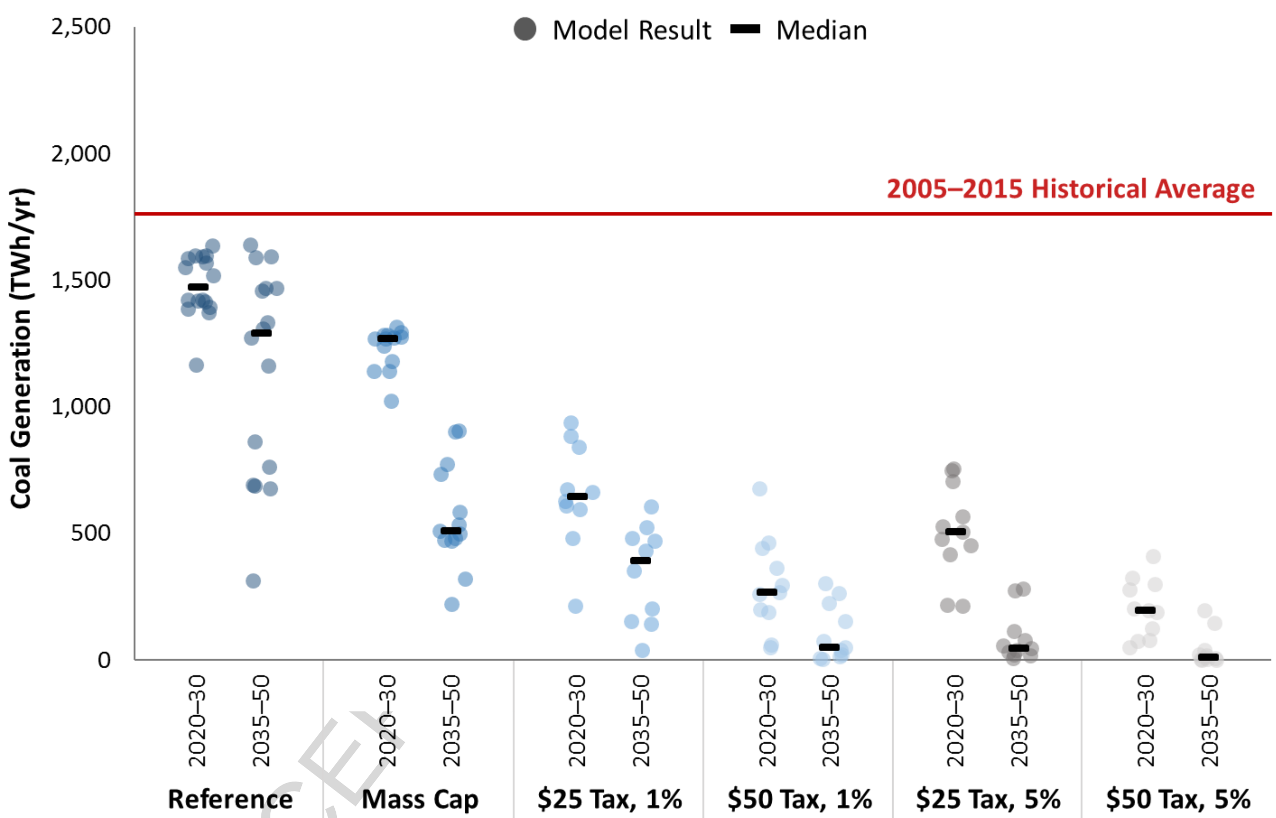


Figure 15. Annual coal generation (TWh/yr) for all models and technology scenarios, grouped by policy scenario and time period. Generation is the sum of all U.S. coal units without and with CCS. Values shown for the reference technological scenario only. Historical average generation from EIA (2016b).

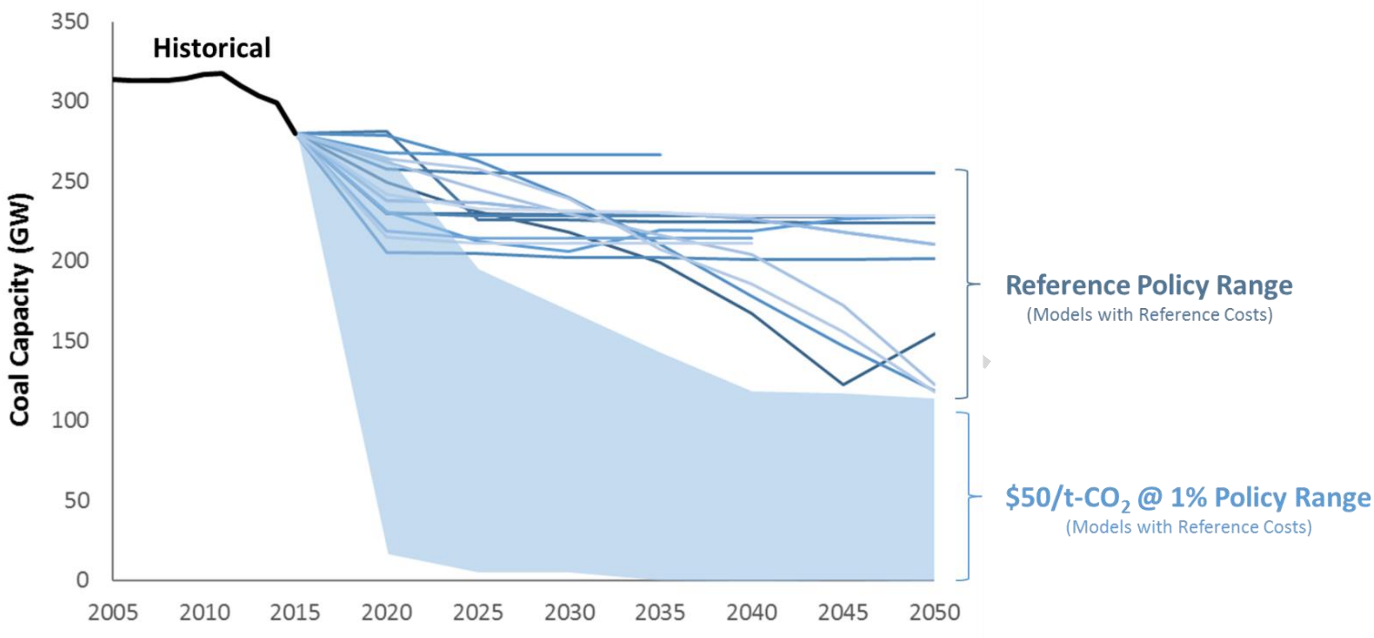


Figure 16. Coal capacity (GW) by model and time under alternate policy scenarios. Values shown for the reference technological scenario only.

Note that there are many unresolved market uncertainties that may influence the near- and long-term competitiveness of coal, including gas prices, rising operation and maintenance costs, refurbishment costs, and additional environmental policies. Many features that may impact coal costs are stylistically mimicked or are absent from capacity expansion models, such as cycling-related commitment costs and local transmission congestion, which are difficult to capture given the structures of these models (Santen et al., 2017). Coal-fired generation is more exposed than other technologies to regulatory risk from internalizing currently unpriced negative externalities (Muller et al., 2011; Epstein et al., 2011; NRC, 2010). These caveats should inform interpretation of the results and directions for future work.

Although Figure 2 indicates significant variation in gas generation across models and scenarios, models agree more about total gas capacity, as shown in Figure 17 in Appendix B. Scenarios principally exhibit increases in gas capacity over time, even though dispatch of these assets varies significantly by region and scenario. Gas assets are used to provide energy, capacity, and flexibility in models and, under certain conditions, may have a high system value even with modest generation.

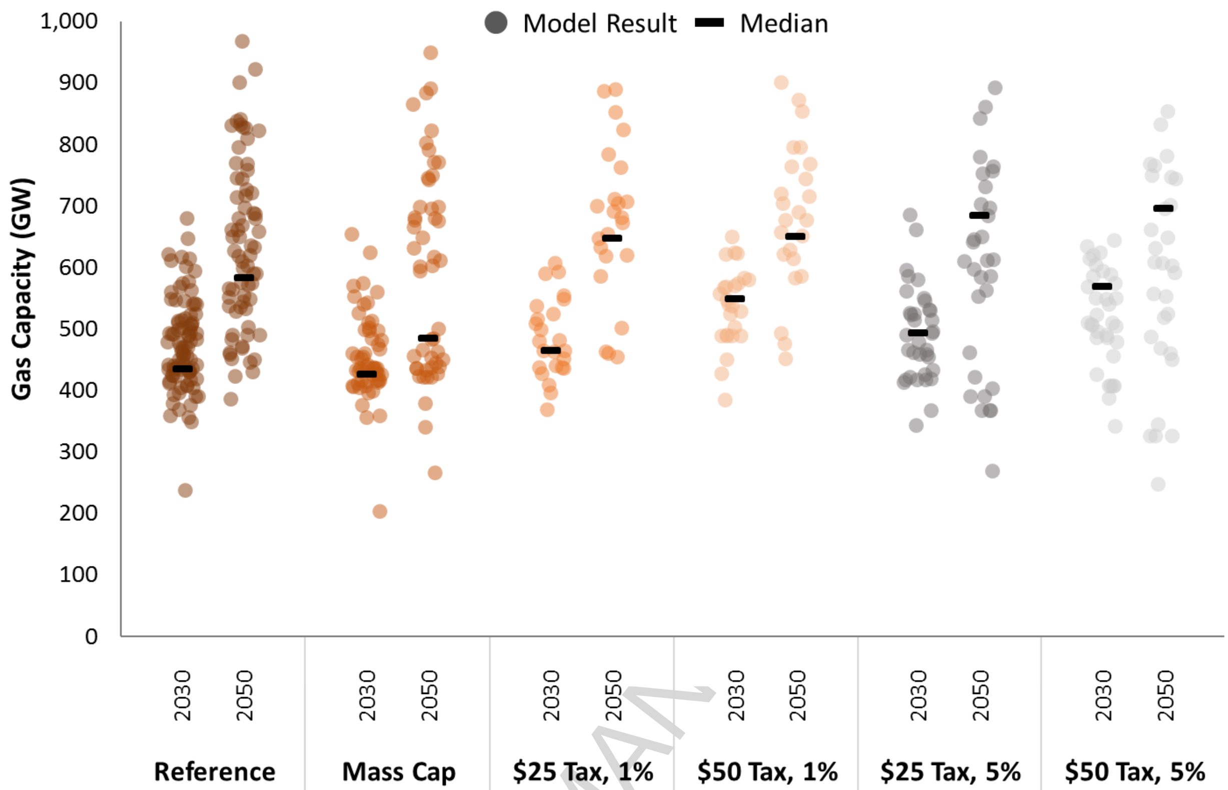


Figure 17. Total natural gas capacity (GW) for all models and technology scenarios, grouped by policy scenario and time period. Capacity is the sum of all U.S. gas units without and with CCS.

The low nuclear lifetime scenario assumes that existing units retire after 60-year lifetimes and do not receive license renewals thereafter. Under reference policy conditions, early nuclear retirements lead to increases primarily in natural gas generation after 2030 with smaller increases in wind, coal, and solar (Figure 18). The region-specific marginal technology depends on the policy conditions, which differs across models. Note that replacement capacity needs are generally higher than displaced nuclear capacity owing to nuclear's high capacity factors (unlike generation where total changes across all technologies are roughly zero). All scenarios indicate that early nuclear retirements lead to increases in CO_2 emissions and system costs, though the magnitudes of these impacts differ across models and scenarios. Policies that price CO_2 emissions exhibit smaller emissions increases with earlier nuclear retirements, though these scenarios also decrease the likelihood of early nuclear retirements due to higher revenues in wholesale power markets to these units (Figure 6).

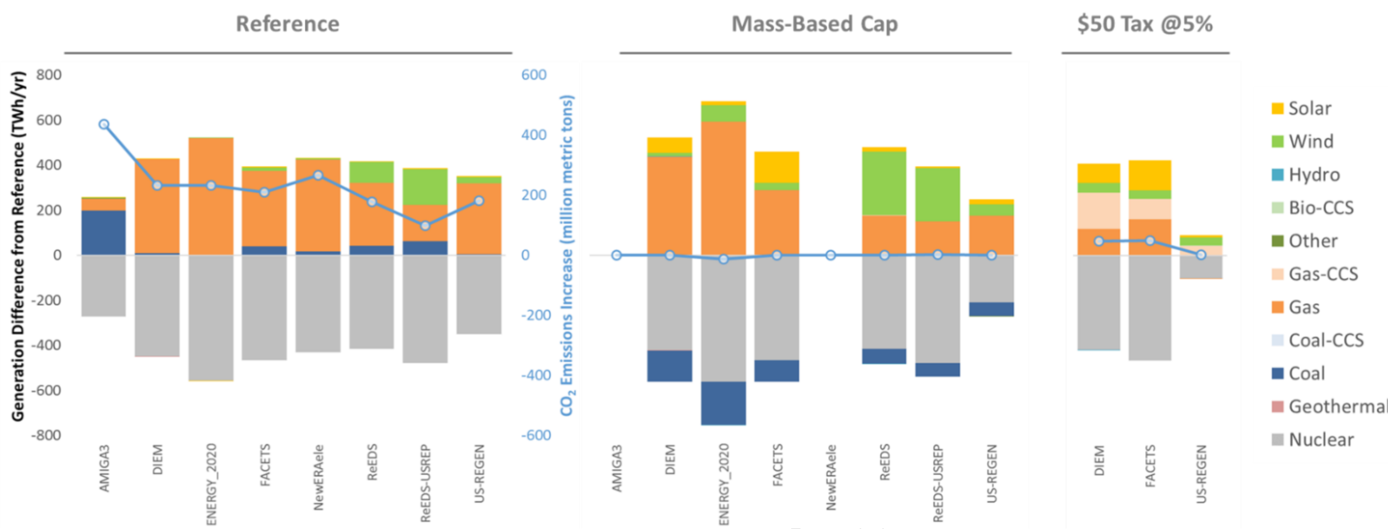


Figure 18. Generation difference (TWh/yr) between the low nuclear lifetime scenario and reference in 2050 by technology under different policy scenarios (left axis). Individual bars represent different models. The change in 2050 CO_2 emissions (million metric tons) is shown in the blue line (right axis).

Figure 19 shows the relative economic competitiveness of wind and solar across different policy contexts and different natural gas price scenarios. Although there are some models and scenarios where solar generation exceeds wind, many models suggest that wind is more economically competitive nationally owing to its higher capacity factors and less severe value erosion at high penetration levels.

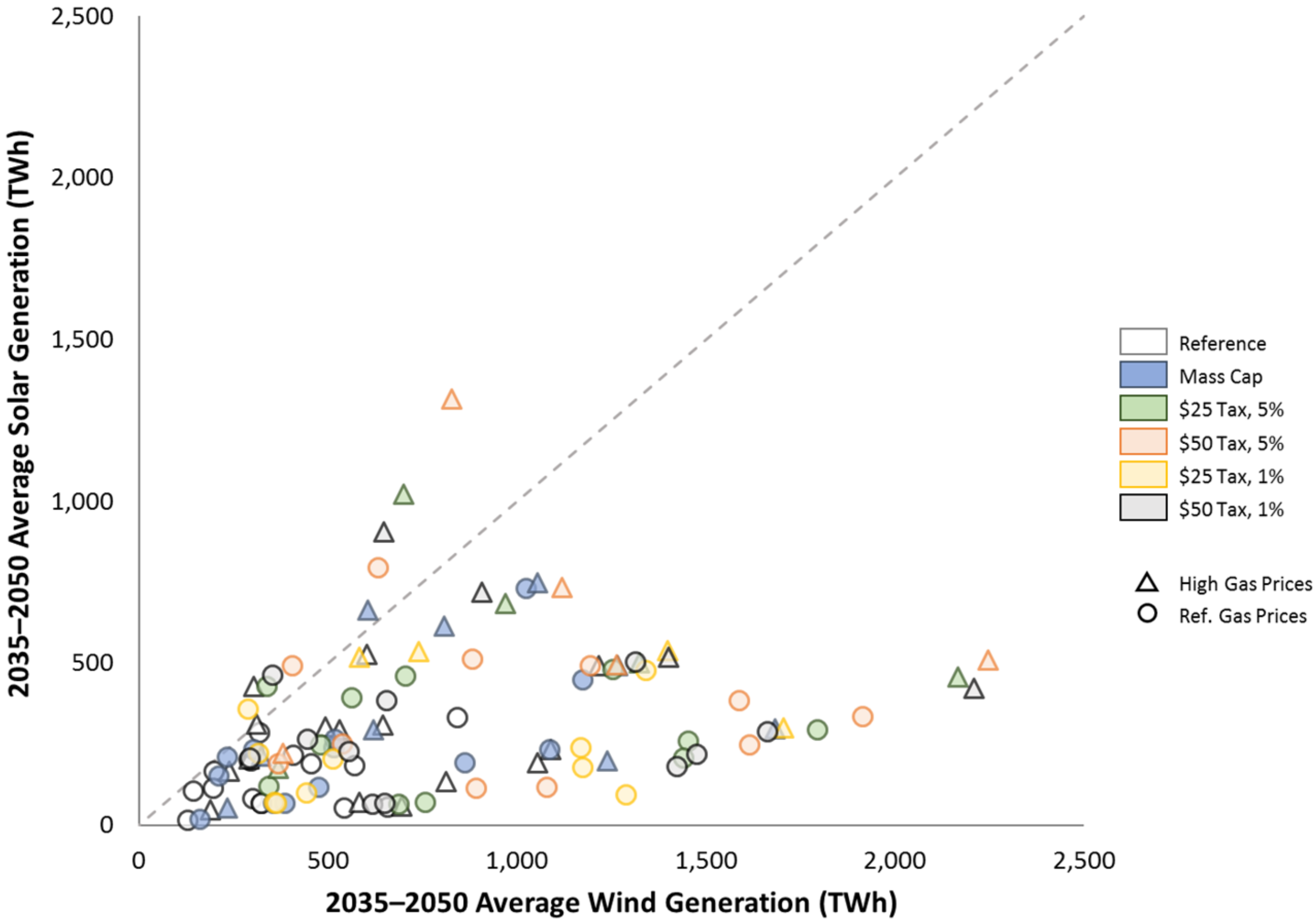


Figure 19. Comparison of average annual U.S. wind and solar generation (TWh/yr) between 2035–2050. Points represent individual model runs with colors corresponding to the policy scenarios. Reference natural gas price scenarios are represented by circles and high gas prices by triangles. Values above (below) the dotted line indicate higher solar (wind) generation for a given model and scenario.

Figure 20 compares total variable renewable generation with gas generation across models and scenarios in this study. Although perhaps complementary from a system perspective given cost structures and functional attributes, gas and renewables show little evidence across these scenarios of being complementary goods in an economic sense (i.e., demand for one good increases as the price of another decreases). Many models and scenarios suggest that renewables and gas compete on the build margin, and market shares differ considerably across regions.

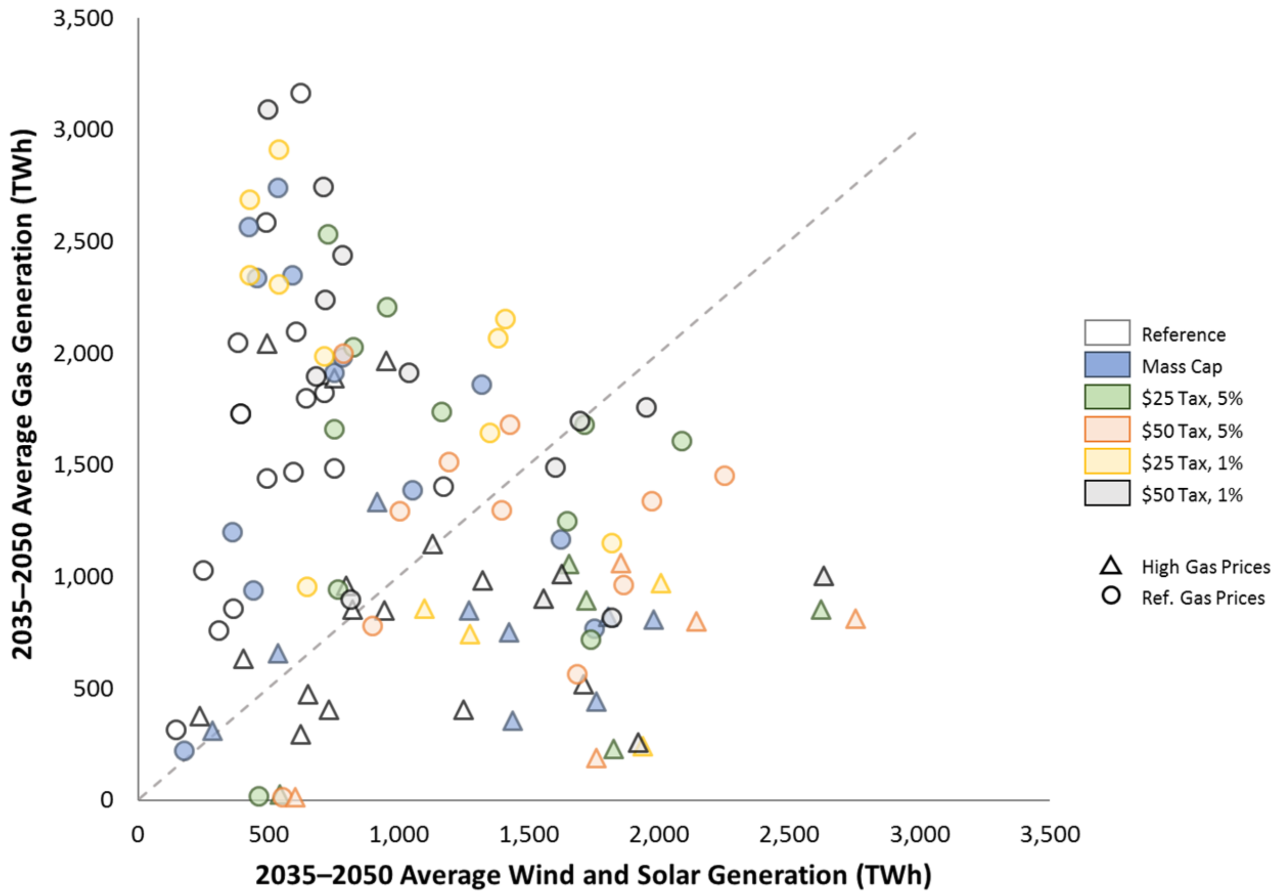


Figure 20. Comparison of average annual U.S. variable renewable and gas generation (TWh/yr) between 2035–2050 with reference and high gas prices. Points represent individual model runs with colors corresponding to the policy scenarios.

EMF 32 scenarios focus on electric-sector-only carbon pricing, and this limited sectoral coverage could work against the electrification that is expected to be incentivized under economy-wide decarbonization strategies, though the ability of current models to capture electrification and end-use decisions may vary (Barron, 2018). To evaluate these potential impacts using the participating EMF 32 models with detailed representations of end-use demand (Table 3), Figure 21 shows changes in electricity demand in the policy scenarios relative to the reference across the residential, commercial, industrial, and other sectors. Electricity demand decreases across nearly all sectors and scenarios, though the magnitude of change varies by sector, model, year, and policy stringency. More stringent power-sector-only policies lead to greater increases in electricity prices relative to other fuels, which leads to greater declines in electricity demand. Models differ in their translation between wholesale and retail prices, which accounts for some of the response heterogeneity.

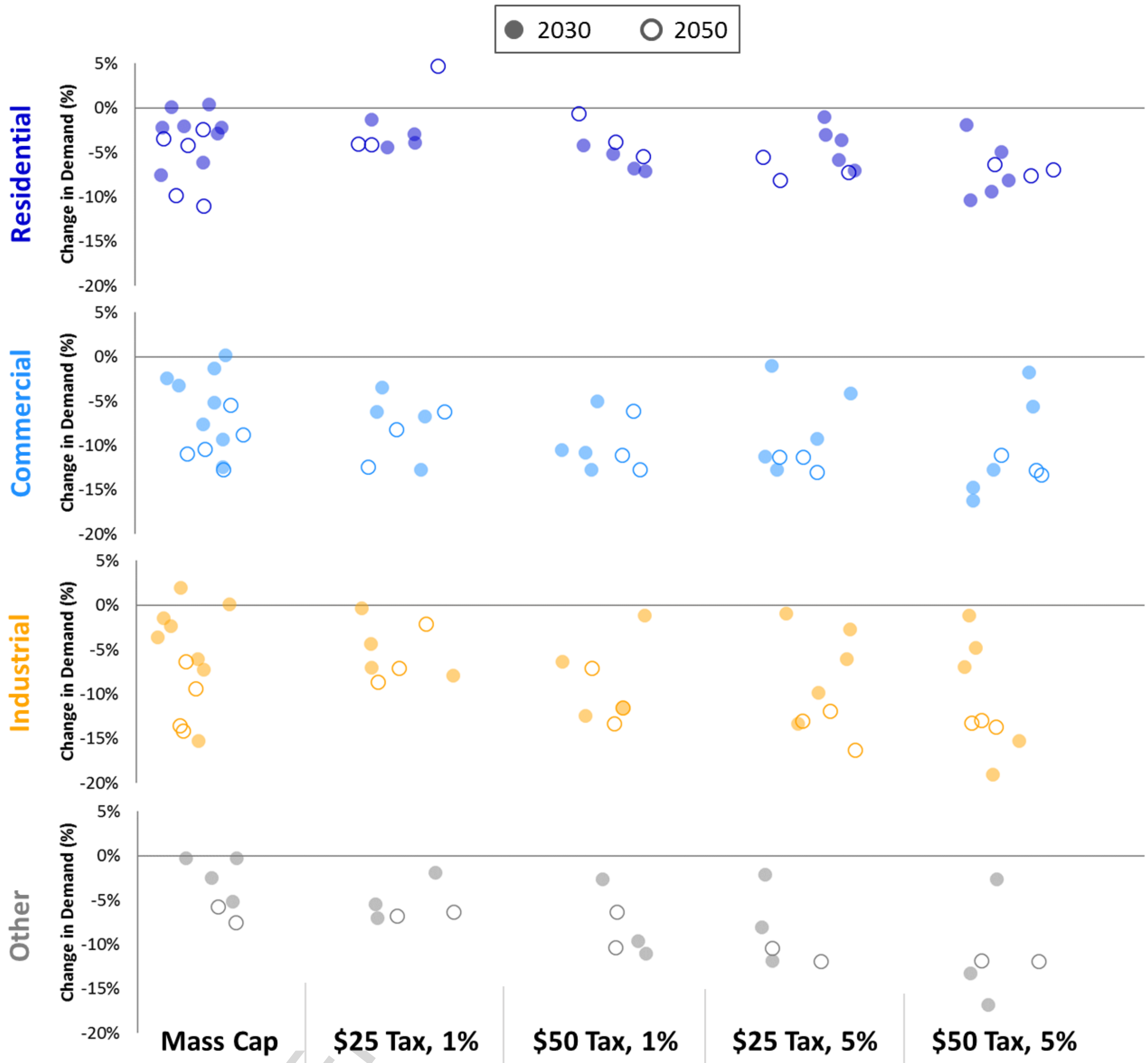


Figure 21. Change in sectoral electricity demand (% of reference) under the policy scenario relative to the reference. Solid (hollow) points show 2030 (2050) values.

B.2. Emissions

Figure 22 shows emissions over time for the mass-based cap. Emissions trajectories indicate that banking emissions allowances is the least-cost strategy for most models and scenarios, where emissions reductions are "front loaded" in early compliance periods (creating a reserve of credits when abatement is relatively cheap) and emissions are above the cap in later periods as the bank is drawn down. Banking is an especially valuable form of "when" flexibility "when expectations of higher marginal abatement costs in the future outweigh discounting and capital stock effects, which encourage early effort when costs are comparably low" (Bistline and de la Chesnaye, 2018). In this case, fuel switching from coal to gas is an especially low-cost emissions reduction strategy in the early 2020s. The use of banking in power-sector-only cap-and-trade policies is qualitatively similar to economy-wide deep decarbonization strategies, though the drivers behind these trends and magnitudes of their impacts differ (Bistline and de la Chesnaye, 2018; Fawcett et al., 2014). Note that the net atmospheric impact will also include changes in non-CO_2 greenhouse gas emissions and uncapped emissions in other sectors (e.g., upstream emissions in fuel production).

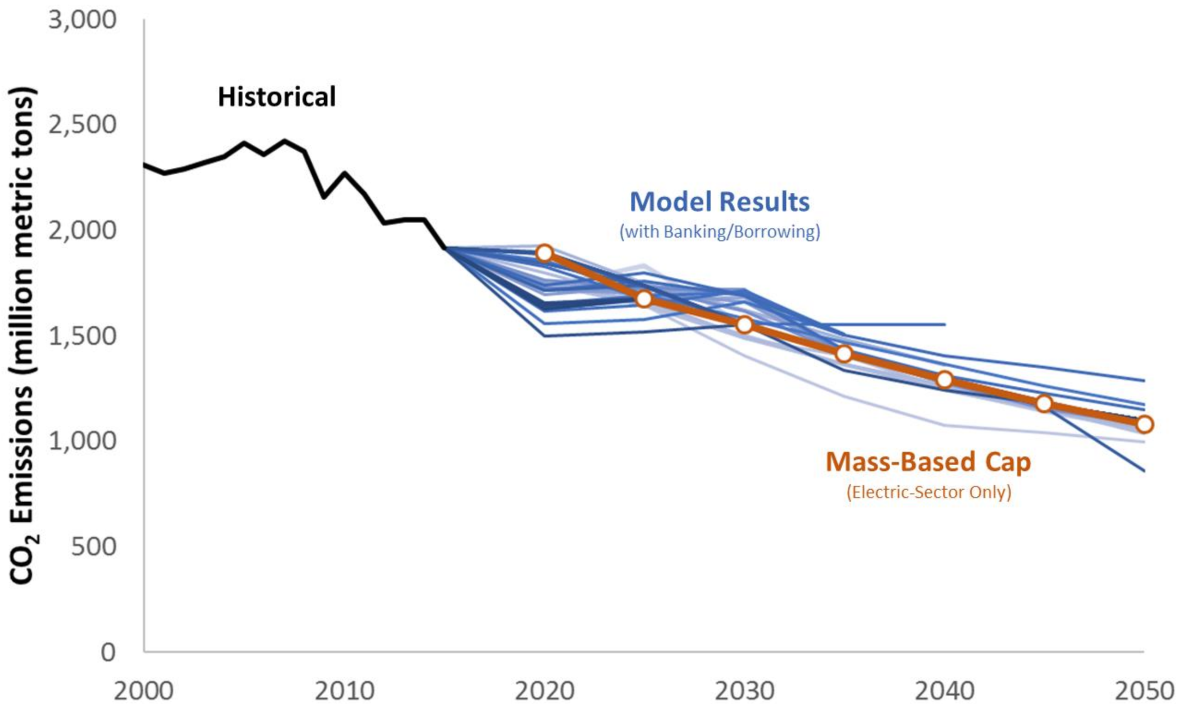


Figure 22. Historical and projected U.S. electric sector CO_2 emissions (million metric tons) across models (2000–2050) under mass-based policy conditions. Blue lines represent individual models, and the orange line shows the cap value (i.e., without banking and borrowing).

Figure 23 and Figure 24 show SO_2 and NO_x emissions (respectively) across the policy scenarios.

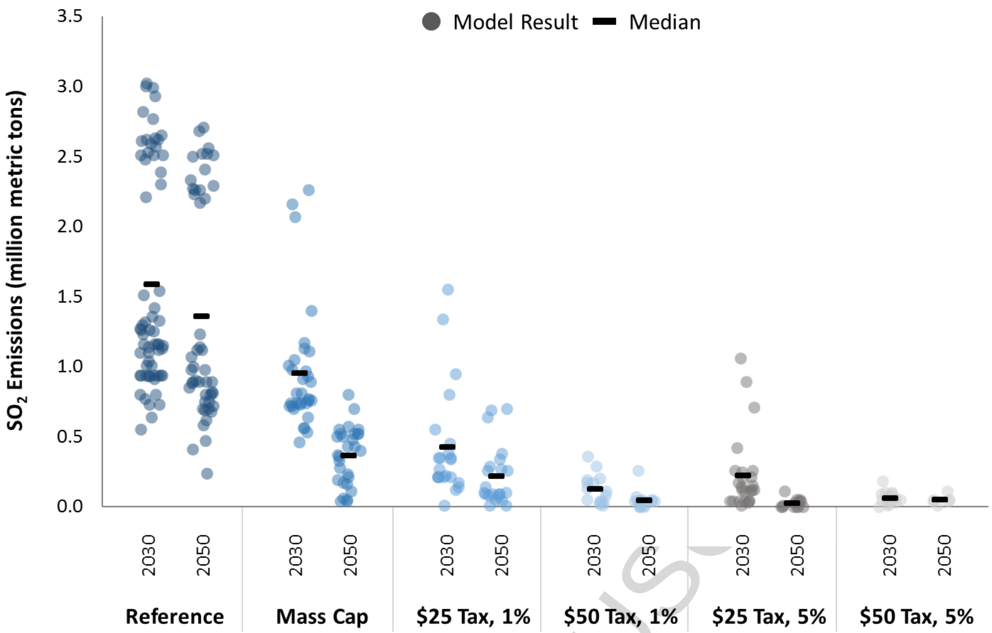


Figure 23. U.S. electric sector SO_2 emissions (million metric tons) for all models and technology scenarios, grouped by policy scenario and time period. All scenarios refer to power-sector-only policies.

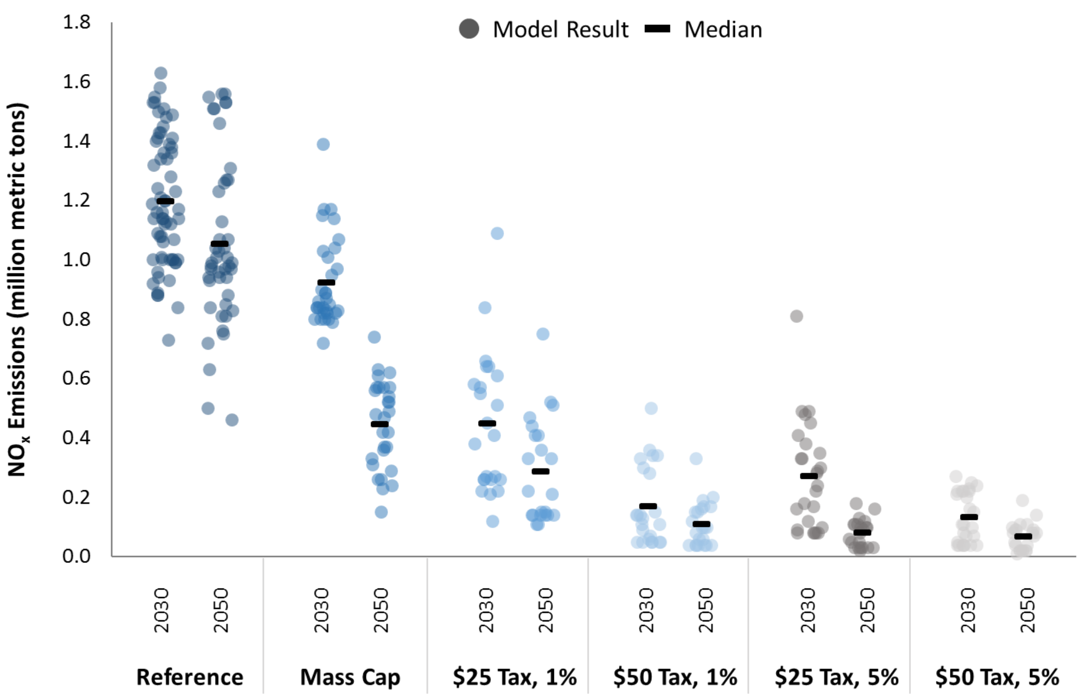


Figure 24. U.S. electric sector NO_x emissions (million metric tons) for all models and technology scenarios, grouped by policy scenario and time period. All scenarios refer to power-sector-only policies.

Highlights

- EMF 32 compares electric sector policy and technology scenarios for 16 U.S. models
- Technology change lowers costs, but long-run emissions targets require policy
- Declines in coal use are expected to continue and would accelerate with CO_2 pricing
- Most models and scenarios suggest generation from gas and renewables will rise
- Research needs include cross-sector linkages, battery storage, bioenergy with CCS