



# ASSESSING U.S. CLIMATE POLICY OPTIONS

*A report summarizing work at RFF as part of the inter-industry U.S. Climate Policy Forum*

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**Resources for the Future (RFF)** is an independent, nonpartisan think tank that, through its social science research, enables policymakers and stakeholders to make better, more informed decisions about energy, environmental, and natural resource issues. RFF researchers have been engaged in climate change research and analysis for over 20 years. They are recognized, called-upon experts in the analysis and design of climate change policies and have played an influential role in advancing intellectually credible and politically sensible approaches to this challenging problem.

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November 2007

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# FOREWORD

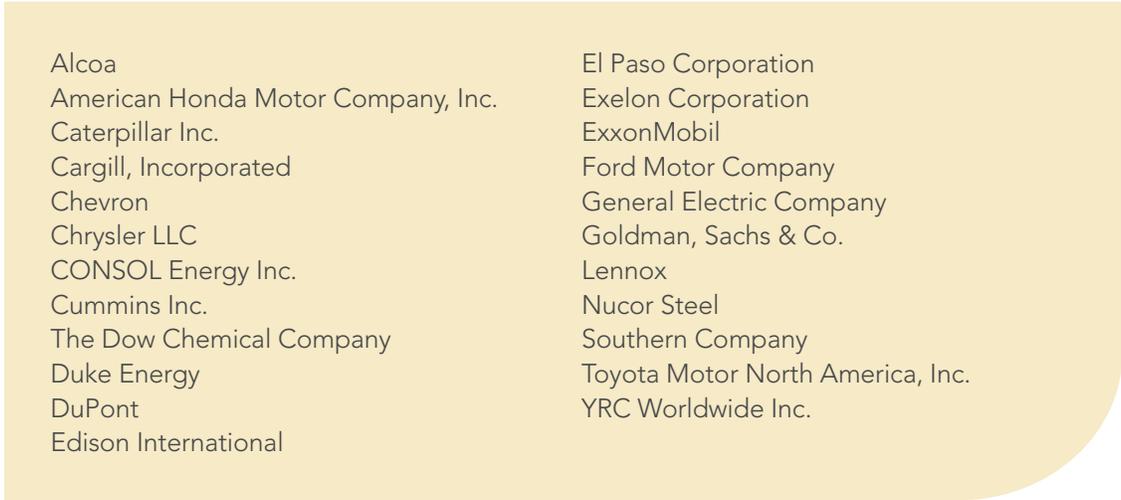
## ***From the Participants***

We are a few of the many companies that could be significantly affected by future efforts to manage the challenging risks of global climate change. We have a deep interest in finding effective approaches and in playing a constructive role. We therefore welcomed the opportunity to join with colleagues from across a wide spectrum of U.S. industry and with the world-class economists at Resources for the Future (RFF) in a frank and detailed exploration of the many issues that arise in designing effective climate policies for our nation to address this global issue. This report by RFF scholars summarizes the fruits of that exploration and the insights that emerged from months of lengthy discussion and detailed analyses. We hope this report informs policymakers and others engaged in policy discussions regarding these extremely complex issues. This hope motivated the entire project.

We entered into this process with a diverse set of views—and our views have remained diverse. Some of us, for example, support or do not oppose policy measures to limit greenhouse gas (GHG) emissions in the United States; others instead emphasize policy measures to stimulate investment in new technology; some support both of these; and still others have not taken a policy position. Our purpose was neither

to reach consensus on nor to advocate for any particular policy direction. Instead, it was to learn from each other and to enhance the policy-relevance of the information provided in this report by contributing our diverse perspectives and real-world expertise. Although our input helped identify which topics became the subjects of these issue briefs, and our comments on the substance of the briefs contributed to their revision, readers should not attribute to any of us support or opposition toward particular policy options or statements based on this report.

We thank our colleagues at RFF for providing a forum to articulate concerns and questions about climate policy, for the independence and depth of their analyses, and for their enthusiasm for engaging a diverse set of views. This has been a useful and informative process for us. We believe it exemplifies constructive, thoughtful, and participatory engagement. This collaborative spirit is essential if our country is to reach consensus on a common strategy for addressing GHG concerns and the serious energy, environmental, and economic challenges that lie ahead.



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# PREFACE

The threat of climate change is motivating efforts around the world to curb greenhouse gas (GHG) emissions. Within the United States, emission-reduction policies are being debated at the local, state, regional, and federal levels, but the scale of the undertaking—in terms of the number of sources, magnitude of emissions, and time span involved—is unprecedented in the history of U.S. environmental regulation. Most would agree that an effective domestic climate policy must be one that elicits the investments needed to profoundly transform the country's energy producing and using infrastructure, while at the same time doing no serious harm to the economy or unfairly burdening particular regions, industries, or households. In attempting to craft such a policy in a context where domestic efforts must ultimately be accompanied by global action, decision-makers and stakeholders are navigating largely uncharted waters.

As a participant in the domestic policy debate, Resources for the Future (RFF) has provided ideas and analysis concerning effective, least-cost strategies to limit GHG emissions for more than a decade. As Congressional momentum for action on climate policy began to build in 2004, the demand for thoughtful, objective input on critical design issues increased significantly. Moreover, as legislators became aware of the complexity of the policy challenge they asked for ever more complete and sophisticated analyses—analyses that required a thorough understanding of the impact GHG-reduction efforts would have on producers and consumers in every sector of the U.S. economy.

To meet this need, RFF organized the U.S. Climate Policy Forum in May of 2006. The Forum brings RFF researchers together with business leaders from 23 companies that represent a broad spectrum of the U.S. economy, including automobiles and heavy equipment; electricity generation; oil, gas, and coal; transport; agriculture; and chemicals, as well as large energy consumers and financial services. The Forum's objective is to provide legislators with well-vetted, detailed policy options; important criteria for policy assessment; and well-articulated concerns (specifying the strengths and weaknesses of different approaches), from which effective federal policy might be crafted.

It was not the goal of the U.S. Climate Policy Forum to reach consensus and advocate on behalf of a specific course of action; many other organizations are filling that role. Rather, the Forum was designed to provide a process for informed dialogue on policy options and to foster a common understanding of the implications of different choices. The various issue briefs collected in this document present empirical facts, rest on a foundation of economic analysis, and attempt to be comprehensive and objective with respect to the policy issues they address. Rather than provide a single policy prescription, they aim to explain and assess a wide range of available options and to inform future policy-design decisions.

This report represents the culmination of the U.S. Climate Policy Forum process. It was written by independent RFF scholars (who retained all editorial control) and informed by a year-long dialogue with Forum participants who provided feedback and recommended areas of focus. Based on needs and priorities identified in consultations with Senate and House members and staff, former staff from relevant executive-branch agencies, corporations, and NGOs, the report is designed—first and foremost—to present information objectively and to focus on those aspects of federal policy design that are most important. In addition, the document aims to convey information in an accessible and modular fashion: accordingly, each issue brief can be read without further introduction as a stand-alone piece concerning a specific topic. The overview that precedes the issue briefs is intended to serve as both introduction and road map to the larger document: it provides essential context and summarizes key points from each of the issue briefs.

We believe that vigorous debate informed by independent analysis is critical to moving significant public policy efforts forward, and hope that this report serves to facilitate progress as federal climate policy discussions continue in the months and years ahead.

Raymond J. Kopp  
William A. Pizer

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Senior Fellows, Resources for the Future



## EXECUTIVE SUMMARY

Climate change is a century-scale, global challenge that will require a global response. A global response, however, emerges from national policies in leading countries. In the United States, there is a growing debate about federal legislation that would begin to tackle the problem without doing serious harm to the economy or unfairly burdening particular regions, industries, and consumers. Crafting such legislation requires thoughtful, objective input on critical design issues. To meet this need, RFF organized the U.S. Climate Policy Forum in May 2006. The Forum's objective is to provide legislators with well-vetted, detailed policy options; important criteria for policy assessment; and well-articulated concerns (specifying the strengths and weaknesses of different approaches). The 15 issue briefs collected in this report were written by RFF researchers and informed by frank discussions with 23 companies drawn from across the broad spectrum of the U.S. economy. Collectively, they attempt to provide a foundation of common understanding from which effective federal policy might be crafted. The Forum has not sought to reach consensus or advocate a particular course of action.

Throughout the analyses and discussions that follow, a key theme has been the need for policies that combine a long-term strategy for managing environmental risk with the ability to adjust, over time, to new information and developments. Addressing climate change will also require significant resources, with perhaps 1 percent or more of annual global output devoted to stabilizing atmospheric concentrations of greenhouse gases (GHGs).

These two observations motivate current interest in policies that—by placing a rising price on GHG emissions—attach a tangible market value to avoiding or reducing those emissions. Reliance on a pricing mechanism as the core element of domestic climate policy promises lower overall costs to the economy

because it creates incentives to exploit the cheapest emissions-reduction options wherever they exist. Given that considerable resources will be required to address climate risks even with efficient policies, the arguments for avoiding strategies that add to cost by unnecessarily restricting flexibility are compelling. Reliance on a pricing mechanism also provides flexibility over time because the aggressiveness of the policy can be adjusted relatively easily in the future by changing a primary parameter: the emissions price.

In some areas—particularly in the electricity and transportation sectors—additional policies are likely to be implemented to promote lower-carbon technologies. Broader energy policy decisions—particularly those that affect natural gas supply, nuclear waste, the siting of renewable energy projects, electricity grid infrastructure, and energy efficiency—will also have important consequences for efforts to reduce GHG emissions. These policies can act as complements to a pricing policy, possibly reducing the cost of achieving a particular emissions goal. However, they can also work against an otherwise efficient pricing policy—raising costs at best and creating conflicting incentives at worst.

The 15 issue briefs that comprise this report aim to elucidate the important questions that confront legislators and regulators as they seek to develop effective policy responses to address climate change. Their key themes can be framed as a series of questions, which are summarized below. Of these questions, the first five concern the core design of an emissions pricing mechanism, while the last three explore the rationale for additional policies to address specific technology opportunities (and often unique features) in key sectors:

- What is an appropriate, overall GHG emissions objective for the United States at this time? While a logical starting point for answering this question involves weighing the



global cost and benefit of stabilizing atmospheric GHG concentrations at different levels, efforts to define a goal for domestic policy must also confront capital, technological, and institutional constraints, along with the United States' ability to engage, coordinate with, and motivate other major economies and emitting nations.

- What sectors of the economy should be covered by a single emissions pricing policy and where in the supply chain should energy-related carbon emissions be regulated?
- How much emphasis should be placed on providing certainty about future GHG emissions versus providing certainty about the trajectory of future GHG prices?
- Given that the impacts of a federal GHG pricing policy are likely to vary considerably across regions, industries, and consumers, how should the distributional consequences of such a policy be addressed? Specifically, how should revenues (in a tax system) or the asset value represented by emissions allowances (in a cap-and-trade program) be distributed back to society?
- How will the policy address international competitiveness concerns?
- To what extent should a domestic climate policy create additional requirements and/or incentives (beyond the GHG price signal) for accelerated technology development and deployment?
- What role do additional policies in the electricity sector—including performance standards, renewable energy portfolio standards, energy efficiency programs, and incentives for carbon dioxide (CO<sub>2</sub>) capture and storage—play alongside a CO<sub>2</sub> pricing policy? How can emissions allowances or tax revenues be allocated in an equitable fashion given the varied forms of regulation and patterns of fuel use that characterize the electricity sector in different regions of the country?
- Given that significantly reducing the GHG contribution from the transportation sector will require much higher

emissions prices and longer lead times than achieving similar reductions from other sectors, what is the role for vehicle fuel-economy standards, renewable or low-carbon fuel requirements, and other technology-forcing policies—either alongside or in place of a single GHG-price policy? How might these policies be designed in more or less cost-effective ways?

These questions can provide a framework for devising a climate policy from scratch, or they can help to unpack and illuminate the core elements of existing proposals. Specifically, they can help policymakers and stakeholders understand how and whether a given proposal covers key bases, how it might be improved, and whether its various elements fit together in a sensible way. As efforts to reach consensus on a federal climate policy intensify, this kind of critical thinking by all parties to the debate, including the broader public, is increasingly important.



## OVERVIEW

### The Basic Structure of Federal Climate Change Policy

The policy debate concerning U.S. action to address climate change is increasingly active and complicated, with a suite of proposals being considered at the federal level even as new initiatives emerge at the state, regional, and international levels. The issue briefs compiled in this report are intended to provide a guide through that debate and, in particular, to help policymakers at the federal level identify the various advantages and disadvantages of different legislative proposals. We take the position that while state-level and international activities are important—especially in terms of their eventual intersection with federal policy—it is necessary to start with an understanding of the basic questions that are central to designing an effective national policy.<sup>1</sup>

► **In thinking about the architecture of a domestic policy, two important and potentially competing design criteria must be balanced. The first is the desire to establish a clear vision of the future and provide enough policy certainty going forward that key actors in the economy—especially those faced with making long-term investment decisions—can plan effectively and adjust smoothly to greenhouse gas (GHG) constraints. Second, the policy architecture must be sufficiently flexible to evolve over time.** No domestic program adopted in the next five or even ten years is going to solve the climate change problem once and for all. Rather, it will be necessary to revisit U.S. policy at intervals and to respond to new information and developments in climate science, mitigation technologies, and international commitments. This places a premium on policies that are both capable of being modified over time without significant economic disruption and robust enough to drive the emissions reductions and technology innovation needed to produce environmentally significant results in a relevant timeframe. Policies that lock in particular actions, technologies,

or political interests—for example, narrow subsidies that do not gradually phase out—may be difficult to adjust and ultimately more costly; therefore, the arguments for such policies, along with the potential for unintended consequences over the long-term, must be evaluated carefully.

Over time, a key factor in the evolution of U.S. climate policy will be the choices made and actions taken by other nations, particularly nations with large economies and significant emissions of greenhouse gases. Without concerted global action, U.S. policies alone cannot substantially alter climate outcomes. Further, to be cost-effective—and achieve global benefits at the lowest cost—national policies will need to be coordinated, if not connected. In this context, adopting a domestic policy architecture that offers the specific ability to coordinate and adjust both carbon dioxide (CO<sub>2</sub>) prices and technology incentives is particularly valuable.<sup>2</sup>

► **Underlying this report is an assumption that establishing a price path for CO<sub>2</sub> and other GHG emissions—either through a tax or tradable permit program—will be a core element of future U.S. climate policy.** A pricing strategy is appealing because it responds to the need for both policy clarity and flexibility—making it possible, on the one hand, to predict prices and emissions over reasonable timeframes with a reasonable degree of certainty while also facilitating smooth adjustments over time. There are other compelling economic arguments for taking this assumption as a starting point. As a means of addressing climate-change risks, GHG reductions are equally valuable wherever they occur—but they are not equally costly. From an economic perspective, this means that costs to society can be reduced by implementing a policy that achieves cheaper emissions reductions without any trade-off in environmental benefit. Setting a price on GHG emissions sends a transparent signal to everyone engaged in emissions-producing activities—including direct emitters as well as downstream consumers of emissions-producing products—about the value of reducing emissions. Those who can reduce emissions cheaply will do so, while those who cannot will face a common CO<sub>2</sub> price.

<sup>1</sup> There is obviously an important role for state action in policy areas that present potentially inexpensive emission-reduction opportunities and that have typically been addressed at the state level—examples would include building codes and utility demand-side management programs. A distinct and important question is now emerging about whether and how federal legislation might “pre-empt” state efforts to regulate—on the basis of climate concerns—in areas beyond their traditional role. On the one hand, a patchwork of state regulation creates additional costs. Further, state actions will not affect national emissions if there is a national cap: in that case, additional emissions reductions in one state as a result of state- or region-specific policies will lead to lower allowance prices and higher emissions in other states (assuming, as current federal proposals do, that there are no constraints on emissions trading between states). On the other hand, states may wish to pursue more aggressive targets in a way that prevents other states from benefiting and/or states may wish to exercise greater control over how and where mitigation occurs. Economic principles suggest it would not be efficient for states to pursue separate policies, but offer little guidance in terms of how policymakers might weigh efficiency considerations against other, competing interests and states’ rights.

<sup>2</sup> This report focuses on policies that aim to mitigate GHG emissions. Additional domestic policy concerns and international considerations apply in the case of policies aimed at spurring investment in adaptation and possible geo-engineering options for reducing climate-change risk.

The alternative to a single price policy is a more traditional approach to government regulation in which emissions abatement requirements or technology standards and incentives are applied to various GHG sources, such as power plants, factories, cars, and households. While this type of strategy is feasible, evidence suggests it could be much more expensive. Studies that compare the costs of traditional regulation to the costs of market-based approaches have typically found substantial differences: for example, a recent study by economists at RFF suggests that the costs of limiting U.S. GHG emissions through traditional regulatory approaches could be ten times higher than achieving the same result through a pricing policy.<sup>3</sup> Given that the costs of addressing climate change are likely to be far from trivial under any circumstances—the cost of an efficient policy has been estimated at 1 percent or more of GDP over many years—maximizing economic efficiency should be a primary consideration for policymakers. (By comparison, the total cost of existing environmental regulation in the United States has been estimated at 2 percent of GDP.)

In fact, recent interest in market-based policies has probably had less to do with academic arguments about economic efficiency and more to do with the experience accumulated through real-world emissions trading programs, starting with the U.S. Acid Rain program in the 1990s and continuing with subsequent broad-based trading programs for both sulfur dioxide and nitrogen oxides in the United States and, as of 2005, for large industrial sources of CO<sub>2</sub> in Europe. Of the climate-policy proposals debated in Congress, the great majority feature a cap-and-trade style approach to limiting GHG emissions. The alternative of a carbon tax has not featured as prominently in the current debate, but the larger trend toward establishing a single CO<sub>2</sub> price appears well established.

► **Strong arguments are often made for additional public support and incentives to accelerate the transition to climate-friendly technologies, particularly in the electric power and transportation sectors where a large volume of emissions are concentrated and where market problems may exist. These arguments are well supported by economic theory in the case of research and development. In the case of technology deployment, however, policies that are not carefully designed to address a specific market problem tend to raise costs relative to a simple CO<sub>2</sub> pricing policy.** Public spending on research and development, for example, is typically viewed as necessary to capture the broad public benefits that arise

from new knowledge: because these benefits cannot be fully appropriated by individual firms, private-sector incentives for basic R&D typically fail to reflect the full societal benefits generated by those investments. Uncertainty about future policy commitments may further dilute incentives for private-sector investments in developing new technology.

Broadly speaking, technology deployment policies find support in economic arguments where there are information problems that impede the market response to price incentives, spillovers from learning associated with new technology investments, network effects for large integrated energy systems, and incomplete insurance markets for managing liabilities associated with new-technology investments. In these cases, technology deployment policies can lower the cost associated with achieving a given emissions-reduction target. Often, however, such policies are driven by other interests, including enthusiasm for particular technologies (renewables, biofuels, carbon capture and storage, hybrid vehicles, hydrogen, etc.), a desire to avoid imposing explicit costs in the form of higher energy prices, and a desire to shift costs to the general taxpayer via subsidies. Policies created largely for these reasons, rather than to address market problems, typically raise the overall cost to the economy of reaching the environmental goal compared to a simple pricing policy centered on an emissions tax or permit trading program.

► **For a given economic cost in aggregate, the distribution of costs across businesses and consumers—and over time—can vary considerably.** Most discussions of cost focus on aggregate economic impacts, such as changes in the cost of energy and loss of GDP. However, the distribution of impacts across different industries, regions of the country, and demographic groups can vary considerably. Competitive industries with high energy costs, regions of the country that depend on more carbon-intensive fuels, and households that have higher energy expenditures and lower incomes, are all at greater risk.

There is also a temporal dimension to costs. Many policies currently under discussion propose to achieve relatively modest near-term reductions that lead gradually to significantly deeper reductions in the future, coupled with the flexibility to move emissions-reduction obligations over time. With the predictability and flexibility afforded by this type of approach, businesses can adjust their investments and households can save now to offset higher burdens in the future. In this way, costs should be smoothed out over time. Without predictability and flexibility—or if the

3 Pizer, W. et al., 2006. Modeling Economywide versus Sectoral Climate Policies Using Combined Aggregate-Sectoral Models, *Energy Journal* 27(3), 135-168. For further discussion of these issues, see Issue Brief #5: Taxes versus Tradable Permits.

policy generates inaccurate expectations that lead to poor investment decisions—costs are likely to be higher in the future. Alternatively, unexpected, positive developments could lead to lower costs in the future.

► **Additional technology policies—including policies designed to overcome barriers to zero- and low-carbon energy sources—can be economically efficient (that is, they may lower the overall costs to society of achieving long-term environmental goals) only as complements to, rather than substitutes for, a pricing policy.** Implementing public R&D investments, traditional performance standards for stationary sources or equipment, tradable portfolio standards for electricity generation or fuels, or subsidies alongside a broader pricing policy may be justified if the aim is to address other market problems while the CO<sub>2</sub> price encourages emissions reductions. The same is true for policies that address natural gas supply, nuclear waste, the siting of renewable energy projects, electricity grid infrastructure, and efficiency, where the status quo may or may not achieve an adequate balancing of costs and benefits. Used in place of a CO<sub>2</sub> price to achieve a given emissions-reduction target, such policies will almost certainly result in higher overall costs compared to a broad-based emissions tax or cap-and-trade program.

As a substitute for policies that effectively price CO<sub>2</sub> emissions, for example, performance standards for energy-using equipment reduce the energy-related costs of using that equipment. The effect of lower energy costs may or may not be to cause consumers to increase their use of more efficient equipment, but certainly such standards don't serve to encourage less use. (To give a concrete example: fuel-economy standards reduce the per-mile cost of driving, thus they don't encourage consumers to use their vehicles less.) In effect, low-cost opportunities to reduce emissions by simply reducing equipment use are foregone, implying higher-cost mitigation somewhere else. Also, regulations specific to a single sector will not balance the cost of whatever actions they require against potentially less costly abatement opportunities elsewhere in the economy; as a result, someone will almost certainly spend more than necessary to meet the overall target. Third, traditional regulation does not offer the same incentives for continual innovation over time as do policies that put a price on GHG emissions—once firms meet a standard, there is no incentive to exceed it. Over time, this again leads to higher costs.

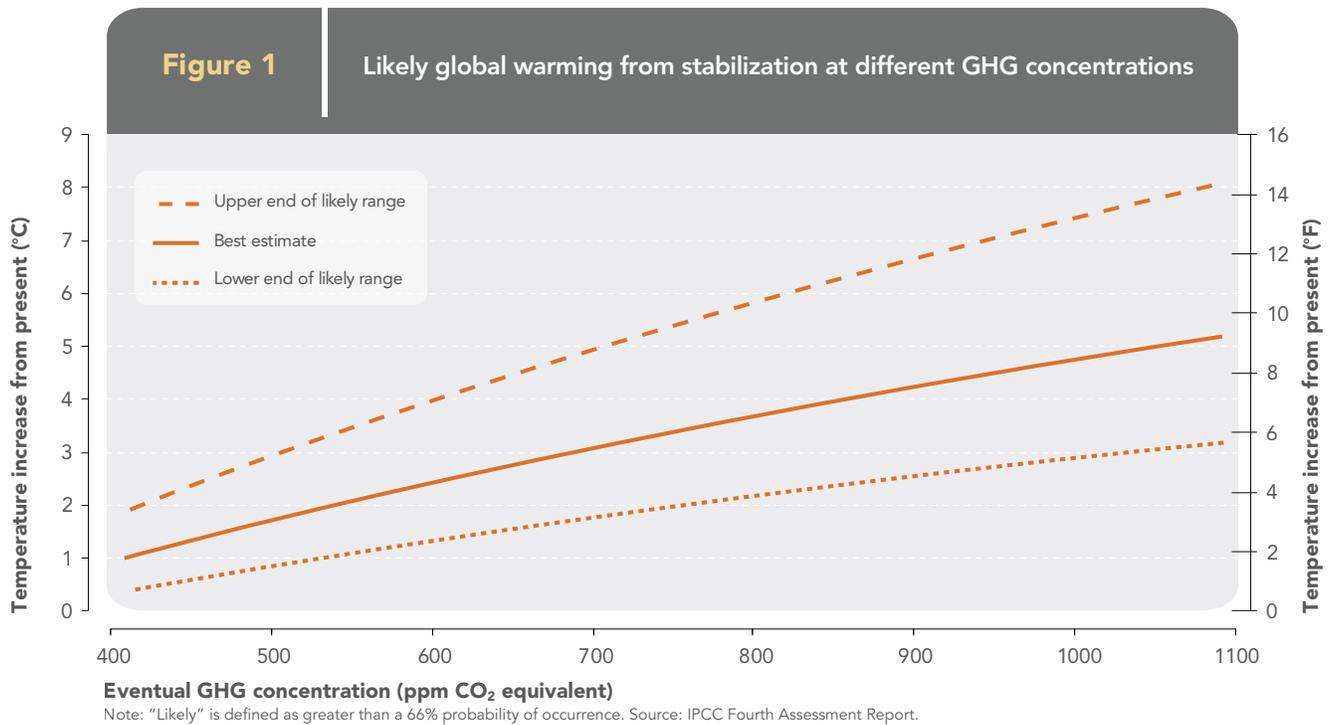
As a complement to CO<sub>2</sub> pricing, on the other hand,

technology policies may or may not lower costs or emissions, depending on the extent to which they address an existing market problem. In either case, it is important that policymakers understand the interaction between a broad-based pricing policy and narrower technology policies. If an emissions cap is in place, technology policies can, at best, only serve to reduce costs and will not produce additional emissions reductions. Similarly, under a tax or other price-setting mechanism, such policies can only serve to reduce emissions and will not lower the price.

► **Domestic climate policy should be viewed in the context of energy policy more broadly.** More than 80 percent of U.S. GHG emissions come from the combustion of fossil fuels. Reducing these emissions implies changing the energy sources used to power the U.S. economy toward increased reliance on zero- or low-carbon fuels. Policies that affect the availability, cost, and usability of natural gas, renewable resources, nuclear power, carbon capture and storage, and end-use efficiency improvements will have important consequences for the cost and success of climate policy. While this report focuses exclusively on the design of climate policy, policies implemented to address broader energy objectives can act to significantly support or undermine climate policy goals and to mitigate or exacerbate the economic impacts associated with achieving GHG reductions. Conversely, policies intended to address climate risks may simultaneously support or undermine broader energy policy goals. For example, climate policies that reduce oil consumption could yield energy-security benefits. On the other hand, climate policies that create additional demand for natural gas in the power sector—absent new supply opportunities—could drive up natural gas prices for industrial users and give rise to additional competitiveness concerns.

## Key Questions for the Design of U.S. Climate Policy

As an introduction to the more detailed issue briefs that follow, it is useful to consider a series of key questions that arise in putting together a comprehensive climate-policy package. These questions can be used to build up a proposal from scratch, or to “unpack” and understand the core elements of an existing proposal. Taken together they touch on, and provide a framework for organizing, important themes from all 15 issue briefs. The first five of these questions concern the core design of a mechanism to price emissions; the remaining three explore additional policies to address specific technology opportunities (and often unique features) in key sectors.



**1. What is an appropriate, overall domestic emissions objective for the United States at this time and how does that objective balance competing considerations and risks with regard to environmental protection, economic costs, technological development, institutional constraints, and global participation?** A fundamental challenge in designing a domestic climate change policy is defining an initial target emissions trajectory that will, over time and in conjunction with actions by other major emitters, achieve environmental objectives at an acceptable cost to the economy. Most global analyses designed to help answer this question start with the relationship between atmospheric GHG concentrations and temperature change, work backwards from different atmospheric stabilization targets to investigate their implications for emissions, CO<sub>2</sub> prices, and economic output, and then contemplate a reasonable balance of costs and objectives.<sup>4</sup> To select an appropriate national-level, emissions-reduction goal, policymakers will need to consider the relationship between domestic action and future technology development, broader action by other major emitting nations, and longer-term emissions trends at the global level. As a

starting point, it is useful to examine—as we do in Issue Brief #2—what trajectory for U.S. emissions and carbon prices would be consistent with the results obtained from global analyses of cost-effective paths to different stabilization scenarios.<sup>5</sup>

Figure 1 is based on the synthesis report of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC). It summarizes current understanding of the relationship between atmospheric concentrations of GHGs and likely changes in global average surface temperature (where “likely” is defined as corresponding to a probability range of 67 percent or higher). In the context of current emissions trends, which—if continued—would result in atmospheric GHG concentrations (in CO<sub>2</sub>-equivalent terms) of 1,000 parts per million (ppm) by volume or more by the end of this century, stabilizing GHG concentrations in the 450–650 ppm CO<sub>2</sub>-equivalent range would significantly reduce the magnitude of expected warming and associated risks to human welfare and ecological integrity.<sup>6</sup> Stabilization at 1,000 ppm implies long-term

<sup>4</sup> An entirely different approach is to assign economic value to climate change impacts and then compute the value of mitigation. Such an approach can generate a wide range of results depending not only on the valuation, but also rather critically on how effects over time are discounted. For example, William Nordhaus estimates mitigation benefits of \$6.40 per ton CO<sub>2</sub>, while Nicholas Stern estimates benefits at \$85 per ton. Some of the findings from this literature are summarized in Issue Brief #3 on costs.

<sup>5</sup> Issue Brief #2 on U.S. Climate Mitigation in the Context of Global Stabilization examines the first part of this question; Issue Brief #3 on Assessing the Costs of Domestic Regulatory Proposals examines the second part, as well as the benefit estimates in the preceding note.

<sup>6</sup> Here and throughout, we discuss GHGs and GHG concentrations in carbon-dioxide equivalent (CO<sub>2</sub>e) terms. This means that when discussing various stabilization targets we include the atmospheric concentration of carbon dioxide plus the effect of other greenhouse gases that enter the atmosphere as a result of human activities, where those other gases are converted to a global warming-equivalent volume of carbon dioxide. Expressed in terms of carbon dioxide concentrations only, the same stabilization targets

warming of as much as 3–8°C relative to present conditions, whereas stabilization at 450–650 ppm reduces the range of predicted temperature change to 0.5–4.5°C.

Translating stabilization targets of 450–650 ppm into emissions scenarios, CO<sub>2</sub> prices, and economic costs requires models of economic activity and emissions. Considerable analysis has been done on 650 ppm scenarios, with results that suggest achieving stabilization at this level will require global emissions to flatten out over the next several decades and CO<sub>2</sub> prices to reach \$5–\$30 per metric ton by 2030 and \$20–\$90 per ton by 2050—assuming global participation and efficient policies.<sup>7</sup> The model scenarios point to significant technology shifts, including increased reliance on systems that capture and store CO<sub>2</sub> emissions from coal-fired power plants, nuclear power, renewable energy, and energy efficiency. The costs incurred to achieve stabilization (again assuming efficient policies and global participation) in these 650 ppm scenarios generally amount to a reduction of less than 1 percent of GDP compared to the business-as-usual forecast over the next decade. Less is known about the economic impact of achieving more aggressive stabilization targets, but these scenarios generally involve significantly higher costs and require global emissions to begin declining in the next decade or sooner. The IPCC estimates that global stabilization in the 450–550 ppm range could be achieved at a cost of less than 3 percent of world economic output and with CO<sub>2</sub> prices below \$100 per ton in 2030 (again, assuming global participation and efficient policies).

Detailed analyses of various scenarios for limiting U.S. GHG emissions over the next two decades produce cost and carbon-price estimates that are roughly consistent with the results obtained in global analyses.<sup>8</sup> The more aggressive domestic policy scenarios assume that emissions through 2030 are limited to roughly 1990 levels; the less aggressive scenarios assume emissions roughly stabilize at current levels or even increase slightly over the same timeframe. Modeled costs in all scenarios are less than 1 percent of forecast GDP for 2015. Costs reach almost 2 percent of GDP in the more aggressive scenarios by 2030, but remain below one-half of 1 percent of GDP under the less stringent scenarios.<sup>9</sup> Carbon prices range from \$15 to \$100 per ton CO<sub>2</sub> and are therefore

comparable to the carbon-price estimates obtained when modeling cost-effective global stabilization scenarios in the 450–650 ppm range. Importantly, all of these estimates are for the near- to medium-term timeframe. Considerable uncertainty exists about the longer-term costs of achieving these targets. On the one hand, deeper reductions will be required as we approach the mid-century mark; on the other, capital stocks will have had more time to adjust and promising technologies may have emerged in that timeframe.

The question frequently arises, of course, how any domestic emissions target can be environmentally meaningful—or indeed worth incurring costs to achieve—absent full international participation in emissions-reduction efforts. More to the point, how can U.S. policymakers choose a domestic target while consensus on an appropriate global objective is still lacking and while other major emitting countries have yet to adopt their own emissions-reduction commitments? While acknowledging that broader international participation and a clear roadmap to achieving global reductions will eventually be necessary to address climate risks, at least four different kinds of considerations can provide justification for near-term U.S. action and can help inform the selection of appropriate domestic targets.

First, a serious policy commitment by the United States is likely to have a significant effect on the actions of other major emitting nations (and may even represent a necessary precondition for establishing broader participation, especially on the part of some developing countries). The European Union, for example, has announced a 2020 target of reducing emissions 20 percent below 1990 levels—and has indicated it will increase the reduction target to 30 percent below 1990 levels if other countries take comparable action. One way to approach the design of domestic policy is by asking what scale of reduction commitments we seek in other countries to achieve a globally meaningful result. Second, domestic policy can stimulate international actions more directly by recognizing offset credits associated with verifiable emissions-reduction projects undertaken in developing countries.<sup>10</sup> In fact, it is likely that international offsets will play a role in meeting domestic targets, especially if those targets are relatively aggressive. Thus, one could imagine defining the objectives for a U.S. program in terms of the emissions reductions we seek to achieve domestically plus some volume we expect to pursue in poorer countries.

A third option is to consider what emissions price we want

are typically 50 to 100 ppm less.

<sup>7</sup> Here and elsewhere, prices are in current (2005–2006) dollars unless specifically indicated otherwise.

<sup>8</sup> It is important to recognize that available models provide only a stylized representation of the likely economic impacts of different policies. As policies diverge from a simple economy-wide CO<sub>2</sub> pricing regime (implemented through either a cap-and-trade system or an emissions tax), overall costs could rise significantly.

<sup>9</sup> The total cost of all existing U.S. environmental regulation is around 2 percent of GDP, according to estimates by the Bureau of Economic Analysis and the U.S. Environmental Protection Agency (EPA). The sulfur dioxide (acid rain) trading program is estimated to cost around 0.01 percent of GDP. Over the time period that most of these regulations have been introduced and implemented (that is, over the past 40 years), average household income has grown at an average annual rate of 1.3 percent while median household income has grown at an annual average rate of 0.7 percent.

<sup>10</sup> Issue Brief #15 discusses international offsets in some detail.

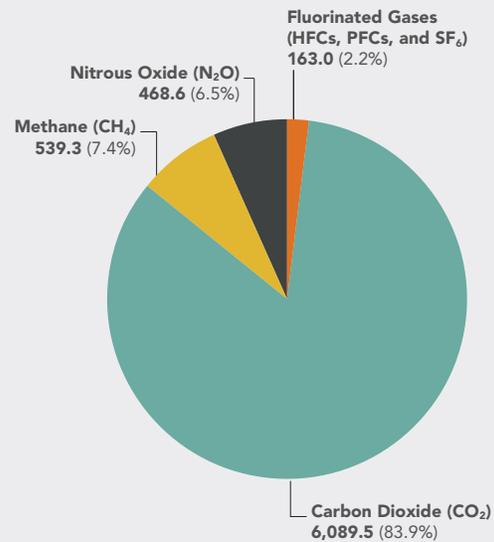
to encourage in other countries, rather than what level of emissions reductions. That is, we can design a domestic policy to produce an emissions price consistent with a particular stabilization target and encourage other countries to seek a similar price. It will arguably be easier to converge toward a globally harmonized carbon price, and to develop some confidence in the feasibility of attaining a given stabilization target, once the United States has achieved political consensus on a pricing policy. Finally, a fourth argument can be made on the basis of technology considerations. Significant emissions reductions in the future—in the United States and in other countries—will depend on significant technology developments. Absent effective market incentives in the world's most advanced economies, the technology developments needed to achieve substantial global reductions and lower abatement costs to globally affordable levels will be unlikely to materialize. Accordingly, an important consideration for domestic policy is how effectively it will encourage necessary long-term technology advances.

In the end, the choice of an appropriate, initial goal for U.S. climate policy must balance multiple considerations and objectives, including the need to achieve meaningful environmental benefits, motivate broader international participation, minimize costs to the domestic economy, address competitiveness concerns, and promote low-carbon technology development and deployment (including technology transfer to developing countries).

**2. What sectors of the economy should be covered by a single carbon price and where in the energy supply chain should energy-related CO<sub>2</sub> emissions be regulated?** From the standpoint of maximizing economic efficiency, policymakers should try to cover as many emissions sources as possible with a single policy and a single emissions price. This approach expands the pool of low-cost emission reduction opportunities that can be exploited to achieve a given policy target, thereby minimizing overall costs to the economy. Equally important, this approach addresses the risk that a market-based policy will create incentives to shift emissions to sources that are not covered under the policy. For example, if households and small businesses are excluded from an emissions cap imposed on the electric power sector, these end-users may shift some of their energy consumption away from electricity and toward increased use of primary fuels (such as oil and natural gas) for space conditioning and water heating. While such shifts may, in some cases, produce gains in energy efficiency they represent a form of emissions “leakage” and will undermine the achievement of environmental objectives since emissions, rather than being

**Figure 2**

2005 U.S. GHG Emissions:  
7,260.4 MMTCO<sub>2</sub>e



reduced, merely shift from regulated to unregulated sources. Nonetheless, arguments are often made for treating some sectors differently—either by regulating them via a separate policy mechanism or by excluding them completely. In some sectors, the economic impacts of GHG regulation may be more severe or there may be a desire to create regulations tailored to specific sector needs. The latter reflects the view that different sectors and sources face different hurdles that may be best addressed through different policies, with the government choosing technologies or performance improvements rather than firms doing so in response to market signals. All of these arguments tend to run counter to conventional economic thinking and to more than a decade of research that suggests broad, market-based policies can substantially reduce costs relative to targeted regulatory approaches.

Tied up with the question of program coverage is the question of where to regulate energy-related CO<sub>2</sub> emissions. In contrast to most conventional air-pollutant emissions, energy-related CO<sub>2</sub> emissions can be effectively regulated anywhere in the fossil-fuel supply chain based on a simple calculation involving fuel carbon content and through-put. It should be noted that the same is not true for non-energy-related CO<sub>2</sub> emissions and for other (non-CO<sub>2</sub>) GHGs; however, these collectively constitute a much smaller share of overall emissions.

Figure 2, which shows the breakdown of U.S. GHG emissions in 2005 by gas, shows that CO<sub>2</sub> emissions dominate the overall emissions inventory. Because fossil-fuel combustion accounts for 95 percent of economy-wide CO<sub>2</sub> emissions, the climate-policy debate typically focuses on how to address this portion of the emissions pie.<sup>11</sup> A policy that focused on large downstream emitters would cover just over half of all of CO<sub>2</sub> emissions from fossil-fuel combustion.<sup>12</sup> Small emitters—mobile sources, households, and small businesses—would necessarily be excluded from such an approach. In contrast, an upstream program could cover virtually all energy-related CO<sub>2</sub> emissions by focusing on fossil-fuel producers, processors, or distributors and by calculating the compliance obligation based on the volume of fuel processed or delivered and its carbon content.<sup>13</sup> Hybrid program designs, in which some fuels or sources are regulated upstream while others are regulated downstream, are also possible.

Two additional observations concerning the choice of where to regulate are important. First, while past tradable permit programs have typically allocated free permits or allowances to regulated sources, there is no reason why CO<sub>2</sub> permits or allowances cannot be allocated to other entities in the fossil-fuel supply chain that are directly or indirectly affected by regulation. In other words, decisions about how to allocate permits or allowances need not be tied to decisions about which entities will be required to submit permits or allowances under a trading program. This distinction is important because stakeholders, if they fail to understand it, will tend to assume that decisions about where to regulate also constitute de facto decisions about how to distribute permits with a likely asset value, in aggregate, on the order of tens of billions of dollars per year (we return to this point below).

A second important point is that the decision about where to regulate—whether upstream or downstream—generally does not change the economic burden imposed on different entities in the fossil-fuel supply chain.<sup>14</sup> The price signal generated by an emissions tax or trading program is passed forward and backward between upstream and downstream entities and achieves the same ends regardless of where it is actually imposed. Important caveats may apply in situations

where products are not competitively priced (as, for example, in regulated utility markets). Finally, the point of regulation does affect which entities bear the administrative burden of demonstrating compliance under a tradable permits program.<sup>15</sup>

**3. How much emphasis should be placed on providing certainty about future GHG emissions versus certainty regarding the future cost of the policy?** A particularly contentious issue in the debate over the design of a federal cap-and-trade program for U.S. GHG emissions is whether total emissions should be strictly capped (that is, limited), as has traditionally been the case in existing programs of this type. The alternative is to make additional allowances available when the market price of allowances reaches a pre-determined maximum. This mechanism, which is frequently termed a “safety valve,” trades emissions certainty in favor of cost certainty—effectively, it means that the level of the emissions cap is not fixed but rather becomes contingent on a maximum price. Coupled with a mechanism to create a price floor—which could involve the government either (a) re-purchasing allowances if the price reaches a specified minimum, (b) specifying a minimum price in allowance auctions, or (c) tightening future emissions caps in response to persistently low prices—trading programs can, to a large extent, mimic the price certainty of a tax.<sup>16</sup> Disagreements about whether a cap-and-trade policy should include a safety valve are often intense because they pit two fundamental concerns—protecting the environment and protecting the economy—against each other.

Because climate impacts ultimately hinge on the long-term accumulation of global emissions, the case for choosing price certainty over emissions certainty is strongest in the early years of a U.S.-only policy. Over longer horizons and with broader global efforts, fixed emissions targets can be increasingly advantageous as they are more closely tied to actual environmental outcomes (for example, stabilizing atmospheric GHG concentrations at a particular level). This suggests that if a safety valve is used, it may be more valuable in the short run.

11 We devote an entire issue brief (Issue Brief #14) to the topic of regulating “nontraditional” emissions—both process CO<sub>2</sub> emissions and other gases. Much of this category of emissions consists of fugitive emissions from land-use changes that would be difficult to capture outside of an offset program (see also Issue Brief #13 on agriculture).

12 The distribution of source size and potential for regulation is discussed in Issue Brief #1.

13 Under an upstream program, adjustments would have to be made for imported and exported fuels, sequestered emissions such as carbon capture and storage, and uses of fossil fuels that do not result in emissions. Note that the European Union Emissions Trading Scheme currently accounts for emissions on the basis of fuel volume and carbon content and not through direct emissions monitoring, even though emissions are regulated at the combustion source rather than upstream.

14 This is analogous to the observation that it does not generally matter whether employer or employees pay income and payroll taxes—the effect on the eventual wage paid by the employer and received by the employee end up being the same.

15 In a well-designed program administrative costs are likely to be small in a relative sense, compared to allowance prices and the cost of reducing emissions. However, these administrative costs—which include the transaction costs associated with buying and selling allowances, establishing internal management structures, hedging to manage price volatility in allowance markets, investing in the equipment needed to monitor emissions or fuel use, and possibly providing external verification—can still amount to a nontrivial sum in absolute terms. According to one firm with dozens of regulated facilities, administrative costs under the EU ETS can run hundreds of thousands of dollars per facility, a number that is likely to be even higher for firms with fewer facilities.

16 An emissions tax tends to come with the presumption that the revenues it generates can be used for broad social purposes, such as cutting other taxes or engaging in valuable social spending. By contrast, the assumption that has, at least until recently, accompanied most tradable permit programs is that most emissions permits will be given away for free. These issues are discussed more extensively in Issue Brief #5.

A number of other cost-containment mechanisms have been proposed as alternatives to a safety valve; in most cases these aim to provide similar benefits (in terms of limiting economic impacts and allowance-price volatility), even as they shift the balance back toward greater environmental certainty. Many of these proposals involve allowance banking and borrowing: for example, businesses could borrow allowances from the government in one year and pay them back in a future year, with interest. This would tend to stabilize allowance prices in response to short-term fluctuations in demand and supply, but would not affect long-term drivers of CO<sub>2</sub> price such as expectations about future targets, technologies, and energy demand. Of course, such expectations might still be subject to substantial uncertainty given the potential for politically motivated adjustments to longer-term targets and other program parameters. (For example, if borrowing resulted in an acute shortfall of allowances in some future year, the political pressure to increase allowance budgets—at least temporarily—could be intense.)

A more recent proposal for reducing economic risk in connection with a domestic GHG cap-and-trade program involves a distinct government agency charged with balancing environmental and economic objectives and given the authority to intervene in markets by buying and selling allowances (and possibly in other ways). In principle, this concept could represent an attractive compromise, one that reassures private industry while promising greater environmental integrity. In practice, however, neither objective would be well served if such an agency is poorly designed, if its interventions are badly executed, or if statutory constraints tie its hands. It is worth noting that the Federal Reserve Board, which provides something of a model for this idea, was established only in response to a financial crisis nearly 100 years ago. Moreover, its performance was widely criticized during many decades of its existence. Notwithstanding these pitfalls, the concept of a “carbon Fed” is sufficiently promising that it merits further exploration.

In the often heated debate about cost-containment mechanisms, it is also important that policymakers not lose sight of the larger objective: to implement a well-designed program with broad coverage of emissions sources and clear rules concerning targets, trading, compliance, and flexibility. Such a program will deliver the most environmental benefit at the lowest cost and should serve as the starting point for any discussion of additional mechanisms for enhancing cost certainty.

**4. How should the distributional consequences of an emissions pricing policy be addressed? Specifically, how should revenues (in a tax system) or the asset value represented by emissions allowances (in a cap-and-trade program) be distributed back to society?** Under the original U.S. Acid Rain trading program, as under most of the trading programs that have followed since, the great majority of allowances has been distributed gratis (at no cost) to directly regulated entities. This need not be the case, however: permits can be given to entities other than those that are directly regulated under the program (including, for example, households or state governments). Regulated firms then buy allowances from allowance recipients. Moreover, allowances need not be given away at all: they can be sold or auctioned by the government, which can then retain and re-distribute resulting revenues for other purposes.<sup>17</sup>

The likely market value of emissions allowances in many proposals is not trivial, amounting to tens if not hundreds of billions of dollars annually (with similar revenue arising from a comparable carbon tax). This overall allowance value is not an indication of the overall cost of the program to the economy; rather, it represents a transfer from those who directly or indirectly pay for allowances in the form of higher fossil energy prices to those who hold allowances (whether those holders are taxpayers, in the case where government auctions allowances, or private-sector entities, in the case where government distributes allowances for free to selected firms).

Economic efficiency argues for the government selling allowances and using the revenue to cut other taxes. By some estimates, this approach could produce net economic gains as lower labor and capital taxes will encourage more employment and investment; in any case, it reduces the net burden imposed on the economy. Indeed, even if allowance revenues are not used to cut other taxes, they can fund valuable government expenditures that otherwise require an increase in taxes.<sup>18</sup> At the same time, this economically efficient solution could have undesirable distributional properties, imposing very different cost burdens on different sectors of the economy and different regions of the country depending on the fuels they use and their ability to pass through costs. By contrast, arguments for a free allocation are typically premised on the need to address distributional concerns by targeting free allowances to those sectors, firms, and regions that would otherwise be most adversely affected by the policy.

<sup>17</sup> See Issue Brief #6 on Allocation.

<sup>18</sup> An obvious risk is that the government would use allowance revenues in wasteful ways. If this is likely, it would argue against auctioning allowances.

Any free allocation that changes in response to future business developments—such as one that continually updates firm-level shares of the total allowance pool based on production output—must be carefully scrutinized in terms of its incentive properties. Updating allocation methodologies can produce inefficient outcomes by creating incentives that promote excess production, discourage the retirement of inefficient facilities, or—depending on the specifics of the methodology—encourage continued investment in high-emitting technologies. While these incentive properties might be desirable in some cases—for example, to promote continued domestic production in industries that might otherwise be motivated to move their operations overseas—they might produce perverse outcomes in other instances (for example, a new entrant allocation that would unnecessarily encourage coal-fired power plants over lower-emitting alternatives).

In the end, decisions about how to allocate allowances or tax revenues, both within and between sectors, are deeply political in nature as they involve the re-distribution of significant wealth and require a careful balancing of competing claims. Policymakers will need to weigh a wide range of concerns and objectives: the desire to reward leaders versus help laggards, for example, or to accommodate new entrants without over-accommodating them in ways that creates perverse incentives to continue investing in higher-emitting sources. At a macro-economic level, additional trade-offs exist between equity and efficiency.<sup>19</sup> That is, policymakers must weigh the merits of using free allowances to compensate entities that will otherwise bear a disproportionate share of the economic burden of the policy against the overall efficiency benefits that could be realized by using allowance revenues to reduce other taxes. At the same time, policymakers will have to address the concern that an overly generous free allocation could result in unjustified windfall gains for some firms and industries.

**5. How should the policy address international competitiveness concerns?** A chief concern surrounding most proposals for a mandatory GHG reduction policy is that pricing emissions will adversely affect the competitiveness of U.S. businesses and may encourage businesses to move their operations overseas. This would obviously undermine the ability to achieve stated environmental goals, along with public support for the policy. A variety of strategies have been proposed to address these concerns.

The simplest involves starting with a modest “first step” domestically while linking more aggressive future targets to international progress. This approach recognizes that the potential for competitive distortions depends on the degree of disparity that exists between the scope and stringency of climate policies in the United States and the policies that exist in other nations. The idea would be to limit economic costs until similar efforts are underway among key trading partners. The argument against this approach is an obvious environmental one: it delivers less environmental benefit, weaker incentives for technology development, and less pressure for international participation.

Other strategies involve singling out especially vulnerable industries for special treatment. Identifying these sectors can be challenging, however: evidence suggests a need to focus on both the energy intensity of domestic producers and the level of international competition they face. Typically, industries that make primary, bulk-produced products (iron and steel, aluminum, cement, and glass) are the most vulnerable to competition from overseas suppliers. Once vulnerable industries have been identified, at least four options exist for addressing competitiveness concerns related to a GHG policy. The simplest is to exclude those operations from the policy altogether; however, this is also the most inefficient response since completely excluding an activity means forgoing possibly inexpensive mitigation opportunities that would not drive production overseas. A second option is to limit emissions from these sources using traditional, tailored forms of regulation that might be less likely to create similar competitiveness concerns. Again, however, this solution is likely to be inefficient and potentially costly. A third approach would be to use free allowances to compensate industries for higher energy-related costs (in this case, the free allocation would need to be tied to continued domestic production). The challenge would be to specify an allocation formula that adequately offsets regulatory costs without over-subsidizing production and without unfairly advantaging some firms relative to others, or U.S. firms in general relative to their foreign competitors.

The last option would be to implement additional policies that directly target imports (and/or exports) of goods to the United States, rather than attempting to adjust the impacts of the GHG policy on domestic producers. The idea would be to regulate energy-intensive, bulk commodity goods imported from countries that lack comparable CO<sub>2</sub> policies on the basis of embedded CO<sub>2</sub> content and in a manner that parallels the price impacts of domestic regulations. This approach would have the dual advantage of directly addressing

<sup>19</sup> The trade-off exists if one assumes that government will use revenues from allowance sales or emissions taxes wisely. If used to support wasteful public spending, there would be no efficiency gain from recycling allowance revenues and likely a loss.

competitiveness concerns while also creating incentives for other countries to adopt comparable policies. Its key downside is the potential to provide cover for unwarranted and inefficient forms of protectionism that, in addition to their immediate costs, would hinder the long-term economic development and technology transfer needed to achieve global progress in addressing climate change. In the end, a combination of strategies may be necessary to address the competitiveness concerns of different stakeholders. Among these, excluding a sector completely or using alternate, traditional regulation tend to have the most costly consequences for the rest of the economy (assuming the overall emissions goal is held constant).

**6. To what extent should a domestic climate policy create additional requirements and/or incentives (beyond the GHG price signal) for accelerated technology development and deployment?**

Alongside the debate about how to price emissions, policymakers must confront an additional set of questions concerning the appropriate government role in technology development. At one end of the spectrum are those who believe the private sector—once motivated by a price on GHG emissions—is best positioned to make R&D and technology investments. At the other end of the spectrum are those who see a much greater role for government.<sup>20</sup> As noted at the outset, a relatively clear economic case can be made for government involvement in research and development, both basic and applied. That said, the best approach to managing such investments is far from clear, especially in the case of applied research. U.S. Department of Energy program offices, a new public agency, a new quasi-public corporation, and/or private research consortia could all be used to manage an increased public budget for applied energy research—each has advantages and disadvantages in terms of fostering effective management and performance, providing stable funding, degree of insulation from politics, and public accountability.

The case for public investment becomes less clear moving from research to technology deployment, a frequent target of additional policies and regulation—particularly in the electricity and transportation sectors, as discussed below. On one hand, legitimate market imperfections can justify public support for technology deployment. On the other hand, technology deployment policies often go well beyond this initial motivation in practice (if such a motivation existed in the first place)—in ways that imply substantial costs and efficiency losses beyond those incurred by the CO<sub>2</sub> pricing policy alone.

Nevertheless, such policies continue to have strong political appeal, perhaps in large part because their costs tend to be less explicit and/or fall more heavily on the general taxpayer, and because they provide a more visible means to promote popular technologies.<sup>21</sup>

Different technology deployment policies make different trade-offs with respect to risk, cost burden, and relative efficiency. They can be used to guarantee quantitative outcomes (via standards) or fix the price of new technologies (via subsidies). Subsidies can be structured as fee-bates to shift the financing burden from the taxpayer to lower-performing technologies. Policies that allow greater flexibility, typically in the form of crediting, banking, and trading, will tend to lower costs.

One way to evaluate technology policies as potential complements to a common CO<sub>2</sub> price is to consider the following questions: Does the policy address a market problem distinct from reducing CO<sub>2</sub> emissions and thereby provide additional, otherwise un-priced benefits? Or, are there other aspects of the policy that make it more appealing and therefore worth incurring higher costs? Are the higher costs reasonable for the volume of emissions reductions and other public benefits achieved? Is the policy as flexible and cost-effective as possible, given other key features and constraints? If the answer to these questions is yes, the benefits of the additional policy under consideration are more likely to outweigh its costs.

**7. How can climate policies be designed to address equity concerns and confront multiple technology challenges in the electricity sector, given the considerable variation in resource portfolios and regulatory structures that characterizes this industry?**

The electric power industry represents one of the largest and most concentrated sectors for GHG emissions, and one where international competitiveness concerns generally do not apply.<sup>22</sup> With only 3,000 facilities that together account for 33 percent of U.S. GHG emissions, any long-term climate solution must deal with the challenge of transforming the nation's power sector. Complicating this challenge is the fact that the electricity industry is enormously diverse, with different regions of the country relying on a different combination of fuels and generation technologies—and hence characterized by different CO<sub>2</sub>-emissions profiles—and being governed by different regulatory structures. This variation has important implications for the use of complementary policies and for the design of a CO<sub>2</sub> pricing policy itself.<sup>23</sup>

Given the importance of the electric power industry, it is

20 These broad questions are discussed in more detail in Issue Briefs #9 and #10, which cover research, development, and demonstration and technology deployment, respectively.

21 For more information on biofuel policies, see Issue Brief #13 on climate change and agriculture.

22 Of course, electricity users often face international competition. Hence the competitiveness issues discussed previously in this overview may be very relevant for electricity-consuming sectors.

23 For a longer discussion of topics specific to the electricity sector, see Issue Brief #11.

perhaps not surprising that numerous complementary policies—in addition to a CO<sub>2</sub> pricing policy—have been proposed for this sector. These range from increased public support for basic research and development to additional technology policies, including direct subsidies, performance standards for new facilities, portfolio standards for existing facilities, and energy efficiency programs. These policies need to be evaluated carefully because while some may resolve various market problems others can lead to more costly solutions than are otherwise necessary. For example, carbon capture and storage may be a critical technology that does not benefit from adequate incentives under a broad-based CO<sub>2</sub> price because of long-term policy uncertainty and the additional liabilities associated with underground storage and other unfamiliar aspects of the technology. While additional incentives may be justified by these and other considerations, it remains the case that additional incentives for carbon capture and storage and other climate-friendly technologies in the electric sector must be carefully monitored to avoid creating imbalances with other abatement opportunities.

In the context of an emissions trading program, special complexities arise with respect to allocating allowances within the power generation sector. In general, the electricity industry as a whole should be able to pass through a large fraction of the cost associated with GHG regulation (including the cost of both mitigating emissions and purchasing necessary allowances) as electricity prices rise to reflect emissions costs. This means that if a free allocation is meant to offset regulatory cost burdens, the bulk of any free allocation should go to electricity users and only a relatively small share of the allowances associated with electricity-related CO<sub>2</sub> emissions needs to be given to electric power generators. In different regions of the country, however, the way in which emissions costs are passed through and the consequences of free allocation to generators will be very different depending on whether electricity markets are competitive or regulated. In regulated regions, generators are traditionally protected by rules that guarantee a rate of return on investments and could expect to be allowed to pass through all costs. At the same time, regulators are likely to ensure that the value of any free allowances allocated to generators in regulated regions will be passed on to consumers by way of reducing the price impact of the CO<sub>2</sub> policy. In competitive regions, the price of electricity is set by the marginal generator—which will rise to reflect the opportunity cost of CO<sub>2</sub> allowances regardless of any free allocation generators receive. Here, the degree to which individual generators can pass through emissions costs depends on their emissions profile compared to the marginal generator. Thus, in competitive regions, free allocation can be used to

offset those emissions costs that are not passed through and are borne by generators. The possibility also exists, however, that free allocation to some generators in competitive regions will more than offset costs and result in increased profits.

These and other considerations have led to a variety of proposals for handling allocation in the electric sector, including proposals that establish a greater role for auctions.<sup>24</sup> At a minimum, many current proposals now envision any free allocation that exists in the early years of program implementation will be phased out over time. Such a phase-out aligns with the underlying notion that free allocation is supposed to compensate for unequal regulatory burdens—burdens that eventually become more evenly distributed as existing capital depreciates and new investments are made. Some have proposed that free allowances be allocated to load-serving entities instead of generators, with the idea that this could lead to more consistent outcomes—in terms of the impact on retail electricity prices—across regulated and competitive regions alike. Allocation to load-serving entities could be based on a variety of measures including electricity consumption, population, or emissions by generators in a state or region. Still other proposals include allocations to end-users, including both large industrial users as well as state governments who could then use allowance assets to address local issues.

**8. What are possible approaches to address emissions in the transportation sector, where achieving reductions comparable to those in other sectors might otherwise require significantly higher carbon prices and longer lead times? How do available policy options compare in terms of the emissions reductions they achieve, the costs they impose, the distribution of those costs, and their short- and long-term effects on different drivers of transport-sector emissions, including vehicle fuel economy, fuel carbon content, and vehicle miles traveled?** As in the electric power sector, numerous additional policies have been proposed to reduce GHG emissions and advance other policy objectives in the transportation sector. It is unclear whether this interest in additional sector-specific policies stems from transportation's large share of overall emissions (28 percent of the U.S. total, including 16 percent of the U.S. total from light-duty vehicles alone), from the historic regulation of light-duty vehicle fuel economy, or from the observation that under a typical carbon pricing policy, transport-sector emissions are unlikely to decline very much. Regardless, various policies have been proposed to directly address two of the three

<sup>24</sup> In the Northeast states' Regional Greenhouse Gas Initiative, states are required to auction at least 25 percent of available allowances and use the revenue to support energy efficiency programs. Several RGGI states have decided to auction 100 percent of available allowances.

factors that drive overall GHG emissions from this sector: the fuel-economy of new vehicles and net GHG emissions from the production and use of different transportation fuels. The remaining factor is vehicle miles traveled, which has increased by 25 percent over the last decade for light-duty as well as larger vehicles. There are few policy alternatives to a carbon price for delivering incentives to reduce travel demand.<sup>25</sup>

As in the electric power sector, the use of additional policies (beyond a GHG price) will tend to raise the overall cost of reducing emissions unless those policies are addressing additional market problems. In the case of fuel economy standards, the concern is frequently voiced that consumers do not adequately value fuel economy, thereby justifying the existing CAFE (Corporate Average Fuel Economy) program and creating momentum to strengthen current standards.<sup>26</sup> Recent changes in the CAFE standard for light trucks offer some guidance for making the overall program more cost-effective and could be applied to cars. Meanwhile, additional program reforms (such as trading across fleets and manufacturers, a safety valve mechanism, and/or shifting to a feebate program) could improve efficiency even further.

Fuel requirements, such as a renewable fuels standard or low-carbon fuel standard, by contrast, represent a relatively new policy approach for addressing transport-sector GHG emissions.<sup>27</sup> In their most flexible form, fuel standards specify an average life-cycle emissions rate per gallon that must be met in aggregate, and are designed to achieve that rate as cost-effectively as possible. Nonetheless, both fuel standards and vehicle efficiency standards should be evaluated carefully to ensure that they do not go too far in creating higher mitigation costs in a narrow area of activity when cheaper emission-abatement opportunities exist elsewhere.<sup>28</sup>

In contrast to the electric power sector, where additional policies (such as a renewable portfolio standard) are typically viewed as complementary to a carbon pricing policy, fuel and vehicle performance standards in the transport sector are sometimes viewed as potential substitutes for including the sector in a unified GHG pricing policy, particularly since any policy that can be portrayed as raising the price of gasoline tends to be politically unpopular. The argument is also often made that demand for transportation fuel is relatively inelastic

at the level of price signal contemplated in most current GHG cap-and-trade proposals; therefore, excluding the transportation sector from an economy-wide CO<sub>2</sub> price would not be expected to have the effect of foregoing a significant quantity of emissions abatement. Nevertheless, over time excluding transport sector emissions from a broader pricing policy and relying instead on fuel and vehicle standards is likely to be increasingly inefficient, as CO<sub>2</sub> prices rise and the potential impact of higher fuel prices on vehicle miles traveled could become more important. Equally important, distinct transportation policies such as low-carbon fuel requirements and vehicle fuel economy standards do not trade-off CO<sub>2</sub> mitigation opportunities across sectors.

## Understanding Current Policy Proposals

More than a dozen legislative proposals to address climate change had been introduced in the first session of the 110th Congress as of September 2007. A few of these draft bills propose to tax GHG emissions, a greater number would establish an economy-wide GHG cap-and-trade program, and two propose cap-and-trade programs that cover only the electric power sector. In addition, the House and Senate have each passed energy bills that provide a variety of technology incentives in the electricity and transportation sectors, and elsewhere. To highlight the range of policy options already on the table, and to demonstrate how the design questions discussed in this report can be used to understand the differences between competing proposals, we summarize key aspects of the various bills now under discussion at the federal level.<sup>29</sup>

## Emissions Targets

All the economy-wide cap-and-trade proposals put forward in the 110th Congress specify emissions targets out to 2030, and most extend out to 2050. Over this time period, all envision reducing U.S. GHG emissions below current levels. Proposed targets for 2030 range from reducing emissions to roughly 1990 levels (Bingaman-Specter, S. 1766; Udall-Petri draft) to achieving 25–40 percent reductions below 1990 levels (Sanders-Boxer, S. 309; Kerry-Snowe, S. 485; Waxman, H.R. 1590). The bills that cover only emissions from electric power generation aim to return that sector's emissions to 1990 levels by sometime in the 2020–2030 timeframe. Under current proposals, likely emissions prices in 2030 generally range from \$30 to \$100 per ton CO<sub>2</sub>. The two tax proposals that have

<sup>25</sup> For a more complete discussion see Issues Brief #12 on the transportation sector.

<sup>26</sup> This same concern does not typically extend to commercial modes of transport—primarily trucking, shipping, and aviation—where energy users more clearly value fuel economy. This is presumably why the overwhelming focus of transportation policy debates is on strategies for improving light-duty vehicle fuel economy, rather than addressing energy use by other modes of transportation.

<sup>27</sup> A national renewable fuel standard was part of the Energy Policy Act of 2005; more recently, a low-carbon fuel standard has also been proposed in California.

<sup>28</sup> In the case of policies designed to promote biofuels, it will also be important to consider impacts on land use, water, and other commodity markets. These issues are discussed in Issue Brief #13, which examines a host of issues relevant to climate change and agriculture.

<sup>29</sup> As various proposals for federal legislation continue to be debated, updated information on the key features of current bills will be available at <http://www.rff.org/climatechangelegislation>.

been introduced in the House of Representatives—Stark (H.R. 2069) and Larson (H.R. 3416)—set price rather than quantity targets for U.S. emissions. Based on the modeling results discussed in Issue Brief #3, HR 3416 should achieve 1990 emission levels by 2030 (if not sooner) since it proposes to tax GHG emissions at more than \$130 per metric ton CO<sub>2</sub> in that timeframe. H.R. 2069, meanwhile, might or might not ever reduce U.S. emissions to 1990 levels: it does not account for inflation, and so—in real terms—the carbon price under this legislation is unlikely to ever exceed \$60 per metric ton CO<sub>2</sub>.<sup>30</sup>

Reducing U.S. emissions to 1990 levels or below by 2030 could be consistent with achieving a global stabilization goal of 550 ppm CO<sub>2</sub>-equivalent (CO<sub>2</sub>e) if other nations follow suit by adopting similar targets—it may even be consistent with achieving a more protective stabilization target if other countries take comparable action relatively quickly. A domestic target of 1990 emission levels or below in 2030 may also be justified, however, even in the context of a less protective global stabilization goal (say 650 ppm CO<sub>2</sub>e), if it is paired with substantial reliance on offset projects in developing countries to demonstrate compliance.<sup>31</sup> Action by other countries would still be required over the next several decades, but a tough domestic target paired with international offsets and a less demanding global stabilization target would allow for greater delay in implementing reductions on the part of developing countries. Without substantial use of international offsets, a program designed to reduce domestic emissions substantially below 1990 levels by 2030 would be expected to produce emissions prices at the higher end of the range noted above (i.e., on the order of \$100 per ton CO<sub>2</sub>e), the same target with substantial use of offsets would likely result in prices at the lower end of the range (i.e., approximately \$30 per ton CO<sub>2</sub>e).

### Program Coverage and Point-of-Regulation

Current legislative proposals adopt three main approaches to the issue of program coverage and point-of-regulation. The electric-sector cap-and-trade bills regulate CO<sub>2</sub> emissions only and impose the compliance obligation at the point of emissions—in other words, on electricity generators. Because they are limited to one sector, these bills would cover roughly one third (34 percent) of total U.S. GHG emissions.<sup>32</sup> The two tax proposals that have been introduced also regulate only CO<sub>2</sub> emissions, but provide economy-wide coverage by taxing fossil-fuel producers (coal mines, petroleum refiners,

and natural gas processors or pipeline operators) and importers on the basis of fuel carbon content. These bills would effectively cover roughly 80 percent of total U.S. GHG emissions. The remaining economy-wide cap-and-trade bills would all regulate the six major GHGs listed in the Kyoto Protocol—carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), nitrous oxide (N<sub>2</sub>O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF<sub>6</sub>)—but for practical reasons would probably exclude fugitive emissions of methane and nitrous oxide. As a result, these bills could cover up to 85 percent of total U.S. GHG emissions.

Among the economy-wide cap-and-trade bills, only the Udall-Petri draft takes an entirely upstream approach to regulating emissions from fossil-fuel use. The Bingaman-Specter proposal (S. 1766) adopts a hybrid approach, regulating natural gas and oil upstream (specifically, the compliance obligation would fall on natural gas processors, petroleum refiners, and importers of both fuels), while regulating coal emissions downstream at large industrial facilities that burn coal—mainly electric generating units. Because virtually all downstream coal users are large emitters, this approach essentially covers all CO<sub>2</sub> emissions from fossil-fuel combustion. Therefore, both of these bills would likely capture 85 percent of total U.S. GHG emissions under a single pricing policy.

A different type of hybrid approach is proposed in Lieberman-McCain (S. 280), which regulates transportation fuels upstream at the petroleum refiner and natural gas and coal emissions downstream at large emitters (above 10,000 metric tons of emissions per year). Because this bill does not cover emissions from primary energy use in the residential or agricultural sectors, it would miss 6 percent of total U.S. GHG emissions, as well as any emissions from small sources in the manufacturing and commercial building sectors.<sup>33</sup> The Lieberman-Warner draft uses a similar approach. Other bills do not specify whether regulation would be upstream or downstream. A fully downstream program focused on large CO<sub>2</sub> emitters and includable sources of other GHGs would cover slightly less than half of total U.S. GHG emissions.

### Cost vs. Emissions Certainty

By their nature, tax bills provide the most certainty about emissions prices—generally they do not even set specific quantity targets. The Stark proposal (H.R. 2069) attempts to combine near-term price certainty with a long-term emissions target: it calls for a tax that rises continually until U.S. CO<sub>2</sub> emissions fall to 80 percent below 1990 levels. As noted

<sup>30</sup> Indeed, at an annual nominal inflation rate of 2 percent per year—historically a low rate—the carbon tax would max out at \$50–60 per metric ton CO<sub>2</sub> in real terms after about 50 years and decline after that.

<sup>31</sup> For example, a 2030 emissions cap set at 25 percent below 1990 levels could be viewed as a commitment to cap U.S. emissions at 1990 levels plus finance additional reductions (equal to 25 percent of domestic 1990 emissions) in developing countries.

<sup>32</sup> CO<sub>2</sub> accounts for nearly all electricity sector GHG emissions.

<sup>33</sup> Issue Brief #1 provides additional detail about the size distribution of various emission sources and likely coverage of downstream programs.

previously, however, this target is unlikely to be achieved because the proposed rate of increase in the emissions tax does not account for inflation. Nevertheless, H.R. 2069 illustrates how a tax proposal might attempt to combine near-term price certainty with a long-term emissions target. Current cap-and-trade proposals, meanwhile, fall along a spectrum in terms of the relative emphasis they place on cost vs. emissions certainty. The Bingaman-Specter bill (S. 1766) and Udall-Petri draft include a safety-valve mechanism to provide cost certainty; in both proposals, the safety-valve price starts at \$12 per metric ton of CO<sub>2</sub> and escalates 5 percent (above inflation) thereafter.<sup>34</sup> By adjusting the rate of escalation such that the safety-valve price eventually exceeds the possible cost of reductions needed to achieve a given emissions target, this type of proposal could be designed to favor price certainty in the near term and emissions certainty in the long term. Other bills use allowance borrowing to address cost and price-volatility concerns. Under this approach, the aggregate amount of emissions allowed over time should remain (essentially) unchanged,<sup>35</sup> but firms can borrow against future emission-reduction requirements to meet short-term compliance needs and make up the difference later. Both Lieberman-McCain (S. 280) and the Lieberman-Warner draft allow regulated entities to borrow up to 15 percent of their total compliance obligation, limiting the borrowing period to five years. Compared to a safety valve, borrowing provisions obviously place a stronger emphasis on maintaining emissions certainty: firms can re-shuffle their emissions profile over time to smooth out short-term supply-demand imbalances and associated price volatility, but eventually aggregate emissions from all firms still have to meet the cap.<sup>36</sup>

Another approach to balancing cost vs. emissions certainty is proposed in the Lieberman-Warner draft legislation, which would create a regulatory body with discretionary power to adjust the number of allowances in circulation and/or the rate at which firms can borrow. Even as it sought to manage price volatility and other market concerns, this new government entity would presumably also operate under some obligation to ensure that long-term environmental goals are met. The concept of a Federal Reserve-like entity to oversee allowance markets is a relative new one and deserves further consideration.<sup>37</sup> Ordinary cap-and-trade proposals that do not include provisions for borrowing or a safety valve provide the greatest emission certainty—examples include the Kerry-

Snowe (S. 485) and Waxman (H.R. 1590) bills—but leave much greater uncertainty about compliance costs.

### Allowance Allocation and Revenue Distribution

Cap-and-trade programs and carbon tax legislation tend to take widely different approaches to allowance allocation and revenue distribution. The two tax proposals introduced in the 110th Congress direct receipts from emissions taxes into the general fund of the U.S. Treasury. The Stark bill (H.R. 2069) does not attempt to dictate the subsequent use of these funds whereas the Larson bill (H.R. 3416) specifies that new revenues are mostly to be used to provide payroll tax rebates, with a declining portion reserved for R&D support and transition assistance to vulnerable industries.

Current cap-and-trade proposals typically specify a blend of free and auctioned allocation, though they rarely allow revenue from any auction to go to the general fund of the U.S. Treasury. The share of allowances to be auctioned ranges from 24 percent of the cap (Bingaman-Specter, S. 1766) up to 80 percent (Udall-Petri draft), with remaining allowances to be allocated for free to various stakeholders.<sup>38</sup> Among recently introduced proposals with detailed provisions concerning this issue, several leave decisions concerning the distribution of allowances available for free allocation to regulatory administrators. Some bills, including S. 1766 and the Feinstein-Carper electric-power sector bill (S. 317), start with a smaller auction but gradually move towards auctioning most allowances. Proceeds from auctioning allowances are used to fund technology R&D (several bills), guaranteed loan provisions (Lieberman-McCain, S. 280), transition assistance (S. 280, S. 1766), engagement with developing countries (Udall-Petri draft), adaptation measures (several bills), debt reduction (Udall-Petri draft), and other measures.

Free allowance allocation to industry ranges from 53 percent in S. 1766 to 20 percent in the Udall-Petri draft. S. 280 specifies that allowances given away for free—the amount is unspecified—must go to regulated entities who surrender allowances; other bills—S. 1766 is example—distribute free allowances to industries that are not directly regulated to reduce cost impacts on these industries. Most of these bills do not specify in advance how free allowances are to be distributed to individual firms within a sector; however, the two bills that are limited to the electric sector provide specific direction on these issues. Specifically, Alexander-Lieberman (S. 1168) distributes free allowances on the basis of historic heat

<sup>34</sup> This \$12 figure is expressed in 2012 dollars; it translates to about \$11 in current (2006) dollars.

<sup>35</sup> Actually, aggregate emissions over a given time period will tend to fall because borrowing provisions generally charge a rate of interest on borrowed allowances to prevent strategic manipulation.

<sup>36</sup> Arguably, the distinction between a safety valve and borrowing begins to blur if safety-valve allowances are drawn from future auctions as they are sold and if, as borrowing occurs, there is some natural feedback to future adjustments in the cap.

<sup>37</sup> This idea is discussed in greater length in Issue Brief #5, which compares different approaches to regulation, including taxes and tradable permits.

<sup>38</sup> S. 1766 also sets aside 14 percent of available allowances for direct technology incentives and 9 percent for state governments. This might be viewed as equivalent to auctioning a 23 percent share of allowances with the revenues being directed to particular purposes.

input, while Feinstein-Carper (S. 317) provides for an updating allocation based on electricity output (existing nuclear generators are excluded).

### Provisions to Address International Competitiveness Concerns

Several current legislative proposals—including Bingaman-Specter (S. 1766), the Udall-Petri draft, as well as the Stark tax proposal (HR 2069)—can be said to address competitiveness concerns by adopting less aggressive emission-reduction targets (Udall-Petri) or emissions prices (H.R. 2069) than competing proposals, or by including a safety valve that limits costs (S.1766).

Some current proposals also include more targeted provisions to address competitiveness concerns in specific industries. Most cap-and-trade bills, for example, direct free allowances to industries that face competitive pressure. Bingaman-Specter also includes provisions that allow the President, starting in 2020, to require that importers of carbon-intensive goods—iron, steel, aluminum, or cement, for example—submit allowances for a product’s embedded carbon content if the country of origin does not have a climate policy comparable to that of the United States. This mechanism not only creates incentives for major trading partners to implement GHG-reduction policies, it also seeks to address the problem of emissions leakage. The Lieberman-Warner draft legislation contains similar provisions.

### Technology Provisions

All of the current climate-policy proposals before Congress make some provision for technology research, development, demonstration, and deployment. In addition to specific technology mandates for the electricity and transportation sectors, which are discussed in the next two sections, a variety of technology provisions are included in the proposed climate legislation and the energy and tax bills now being debated by Congress. Among the climate change policy proposals, the Larson emissions tax bill directs one-sixth of revenues—up to \$10 billion annually—to a newly created Energy Security Trust Fund that would support research and development for clean energy technologies. The Lieberman-McCain cap-and-trade proposal would create a new Climate Change Credit Corporation, funded by allowance auctions, which would promote low-carbon technology deployment.

The separate energy bills passed by the House and Senate include a variety of technology provisions and thus highlight a broad spectrum of options for addressing technology

development and deployment. The energy bill passed by the House would create an Advanced Research Projects Agency-Energy (ARPA-E) within the Department of Energy. This agency would be modeled after DARPA at the Department of Defense with the similar aim of supporting cutting-edge research in high-risk, high-return technologies.<sup>39</sup>

Both the House and Senate energy bills also aim to increase energy efficiency by promoting the deployment of more efficient lighting technologies through measures such as advanced procurement, efficiency standards for light bulbs, and technology prizes. In addition, these bills would amend the Energy Policy and Conservation Act to expedite rulemakings on efficiency standards and to update standards for a variety of devices, including consumer appliances and space heating and air conditioning products.

The House energy bill includes provisions designed to promote international technology transfer. Specifically, it authorizes \$200 million for the U.S. Agency for International Development to promote clean and energy-efficient technologies; in addition, it provides funding to support a Clean Energy Technology Exports Initiative. The House bill also establishes a government corporation called the International Clean Energy Foundation that would make grants to promote and advance GHG-reducing technologies and projects outside the United States.

### Additional Policies for the Electric Power Sector

Many of the climate-related policy proposals currently before Congress include a Renewable Portfolio Standard (RPS)—that is, a requirement that electric generators produce a minimum percentage of electricity using renewable energy technologies. The Kerry-Snowe bill would establish a 20 percent RPS for 2021, phased in 5 percent at a time in four-year increments. This proposal also creates an energy efficiency performance standard for retail electricity suppliers that requires suppliers to reduce electricity use by 9 percent by 2021. The Sanders-Boxer and Waxman bills contain similar renewable portfolio and energy efficiency requirements. The House energy bill includes a 15 percent RPS for 2020 that must be met by new renewable generation (i.e., facilities placed in service since 2001), with energy efficiency projects eligible to fulfill about one-quarter of the total RPS requirement. The House energy tax bill extends through 2012 the production tax credit for renewable energy technologies (including wind, biomass, geothermal, marine, hydrokinetic, and qualified hydropower), although it places a limit on the production

<sup>39</sup> An ARPA-E agency was included in the America COMPETES Act (H.R. 2272) which was signed into law by the President on August 9, 2007.

credit for new facilities that start operations after 2008. The energy bill passed by the House includes support for research and development in renewable energy technologies for generating electricity, authorizing an average of more than \$200 million annually between 2008 and 2012 for marine, geothermal, and solar renewable energy technologies. The Senate energy bill also includes research and development support for marine, hydrokinetic, and offshore wind energy technologies. Both bills include funding for “smart grid” technology, with the House bill authorizing over \$2 billion in matching funds for related deployment efforts.

Finally, many bills currently before Congress support research, development, and demonstration efforts to advance geologic carbon capture and storage (CCS). Among the climate proposals, the Bingaman-Specter bill creates incentives for this technology by providing bonus allowances for CCS projects. The Lieberman-Warner proposal calls for the newly-created Climate Change Credit Corporation to use 20 percent of proceeds from auctioning allowances to support public-private partnerships aimed at commercializing CCS technology. The House and Senate energy bills both include extensive support for CCS, providing for federal research, development, and deployment support on the order of \$1.5 billion over a five-to-six year period starting in 2008.

Among the bills that propose to establish a GHG cap-and-trade program for the electric sector only, the Alexander-Lieberman legislation would create a New Source Performance Standard for CO<sub>2</sub> emissions from new electric generating units.

### **Additional Policies for the Transport Sector**

Several of the climate bills (e.g., Kerry-Snowe, Sanders-Boxer, etc.) have extensive provisions concerning vehicle and transportation standards, including requirements aimed at supporting a nationwide supply and distribution infrastructure for biofuels; a 35 percent credit for manufacturers who invest in energy-saving vehicle components; a \$3,000–\$3,150 tax credit for the purchase of new hybrid, flex-fuel, or plug-in hybrid vehicles; and a GHG emissions standard for new passenger vehicles (the proposed standard, which is specified in grams of CO<sub>2</sub> emissions per mile, is identical to the standard that has been adopted by California).

The energy bills that were passed in the summer of 2007 by both chambers of Congress include provisions designed to reduce GHG emissions from the transport sector. In particular, the Senate bill included provisions to raise Corporate Average

Fuel Economy (CAFE) standards for light-duty vehicles (passenger cars and light-duty trucks) to 35 miles per gallon (mpg) by 2020 (current standards equate to around 24 mpg) and to make the CAFE program more flexible by allowing credit trading among manufacturers. Both the Senate and House bills include measures to support new vehicle technologies: for example, the House bill includes loan guarantees for advanced vehicle battery manufacturing and grants for plug-in hybrid demonstration programs. The House also passed an energy tax bill that would establish a new tax credit—with a base amount of \$4,000—for consumers who purchase plug-in hybrid vehicles.

The Senate energy bill also includes a renewable fuel standard (RFS) that would mandate 36 billion gallons of renewable fuels by 2022, with 21 billion gallons of that total coming from advanced biofuels such as cellulosic ethanol, biodiesel, or biobutanol. Biofuels would be assessed and labeled based on lifecycle GHG emissions. Additional provisions would support the deployment of biofuel infrastructure; these include grants for installing fuel distribution facilities and support for research on the environmental and economic impacts of biofuels. The total funding authorization for renewable, low-carbon, and biofuels is more than \$1 billion. Although the House bill does not contain an RFS, it does include support for biofuels-related research and development, including studies on economic and technical feasibility, alternative infrastructure needs, and environmental impacts. Finally, the tax bill passed by the House extends the current production tax credit for biodiesel and creates a new production tax credit for cellulosic ethanol of 50 cents per gallon.

## **Remainder of the Report**

The remainder of this report consists of 15 issue briefs that explore in greater detail key issues related to the design of a mandatory federal climate policy for the United States. These issue briefs provide information on emissions sources, targets, and costs; program coverage and scope; price versus emissions certainty; allowance allocation; competitiveness impacts and responses; technology research and deployment; sector-specific issues surrounding electricity, transportation, and agriculture; the regulation of non-traditional GHGs; and offsets. While this overview has sought to draw out major themes and organize key points from the issue briefs around a series of questions, the briefs themselves provide a foundation for addressing the major questions policymakers will confront in designing federal climate legislation.





**ISSUE BRIEF 1**

**BY THE NUMBERS: GREENHOUSE  
EMISSIONS AND THE FOSSIL-FUEL  
SUPPLY CHAIN IN THE UNITED STATES**

**DANIEL S. HALL**



## BY THE NUMBERS: GREENHOUSE GAS EMISSIONS AND THE FOSSIL-FUEL SUPPLY CHAIN IN THE UNITED STATES

Daniel S. Hall

### SUMMARY

This issue brief presents information on greenhouse gas (GHG) emissions in the United States to provide background for the design of a domestic climate policy. It starts by detailing current U.S. GHG emissions, including breakdowns of emissions by greenhouse gas and by economic sector. Following that, patterns of production, distribution, and use of fossil fuels in the U.S. economy are examined to estimate the number of sources that would potentially be regulated under a domestic climate policy.

- Current, annual U.S. GHG emissions total more than 7 billion metric tons of carbon dioxide equivalent (CO<sub>2</sub>e) (emissions for 2005 totaled 7.26 billion metric tons CO<sub>2</sub>e). Emissions have been growing by about 1 percent per year since 1990. CO<sub>2</sub> is the primary greenhouse gas, accounting for more than four-fifths of U.S. GHG emissions; the remaining 16 percent is composed of methane, nitrous oxide, and various fluorinated gases.
- The sectors with the largest emissions are electricity generation (33 percent) and transportation (28 percent). The primary drivers of emissions in these sectors are coal-burning for electricity generation and oil use for transportation.
- Almost all U.S. CO<sub>2</sub> emissions are generated by the combustion of fossil fuels. Because CO<sub>2</sub> emissions from fossil fuels can be calculated directly and accurately based on the carbon content of the fuel, there is flexibility about *where* in the fossil-fuel supply chain to regulate CO<sub>2</sub> emissions. Although it is often assumed that regulation of CO<sub>2</sub> would occur “at the smokestack” (that is, at the point of emissions), the ability to calculate emissions based on carbon content means that regulation can be accomplished at any point from fossil-fuel production (“upstream”), to processing or distribution (“midstream”), to actual end use (“downstream”).
- There are typically fewer upstream producers, or midstream processors and/or distributors, than there are downstream users. This is particularly true for oil and natural gas, which have a very small number of processing and distribution facilities (that is, oil refineries and natural gas processors or pipeline distributors) and a very large number of end users (for example, automobiles and homes).
- Regulating CO<sub>2</sub> emissions at upstream or midstream entities would facilitate the inclusion of virtually all fossil-fuel emissions in a market-based (tax or cap-and-trade) climate policy. Such regulation would likely involve fewer than 3,000 sources: around 1,000 entities for coal (either coal mines or large coal-burning facilities); and another 500–700 each for oil and natural gas (including refineries, natural gas processors, and importers/exporters). A purely downstream approach that regulates only large stationary emitters (primarily electricity generators and industrial sources) would likely involve about 10,000

entities and cover about half of U.S. fossil-fuel emissions. Merging this approach with midstream coverage of transportation fuels (refineries and importers) would add the same 500–700 entities and net about another third of these emissions, thus covering 80 percent of U.S. fossil-fuel emissions (or about two-thirds of total U.S. GHG emissions). Issue Brief #4 on the scope and point of regulation provides further discussion on the policy issues surrounding where to regulate emissions.

- Emissions of non-CO<sub>2</sub> GHGs come from a variety of sectors and activities, and are often widely dispersed. Although smaller in percentage terms, non-CO<sub>2</sub> emissions are important in discussions of climate policy because they often account for a substantial share of projected near-term emission reductions. Options for including these gases in a climate policy are discussed further in Issue Briefs #14 and #15, on non-CO<sub>2</sub> gases and offsets respectively.

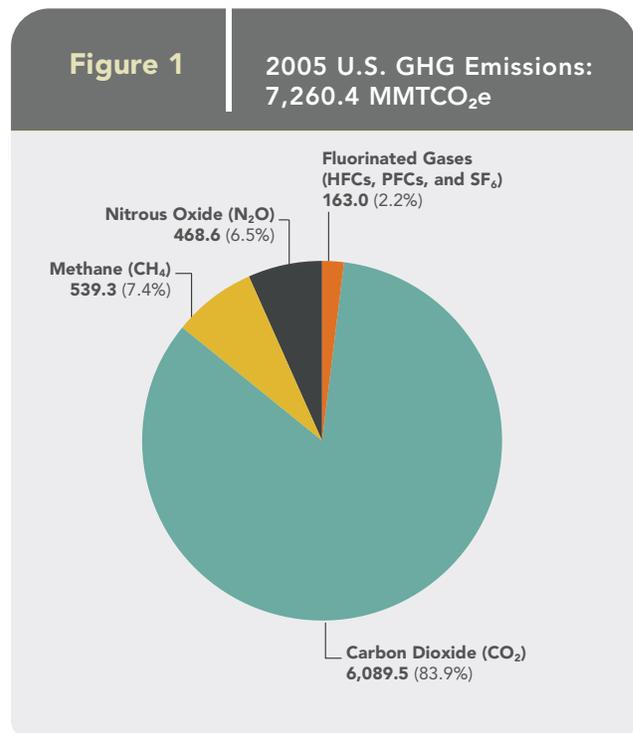
## U.S. Greenhouse Gas Emissions

The U.S. Environmental Protection Agency (EPA)<sup>1</sup> calculates that GHG emissions in the United States in 2005 totaled 7,260.4 million metric tons of carbon dioxide equivalent (MMTCo<sub>2</sub>e).<sup>2,3,4</sup>

Figure 1 shows U.S. GHG emissions in 2005, broken down by type of gas. Figure 2 depicts the trend in U.S. emissions since 1990.

U.S. CO<sub>2</sub> emissions have been growing on average at about 1.2 percent per year since 1990. Methane (CH<sub>4</sub>) emissions have fallen slightly (by about 0.8 percent annually) since

1990 while nitrous oxide (N<sub>2</sub>O) emissions rose slightly in the mid-90s but have since returned to 1990 levels. Emissions of hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF<sub>6</sub>)—referred to sometimes collectively as the fluorinated (F) gases, or the high global warming potential (GWP) gases—have risen at a 4 percent average annual rate since 1990.



1 Both the EPA and the Department of Energy's Energy Information Administration (EIA) release detailed reports on U.S. GHG emissions annually, most recently in April 2007 and November 2006 respectively. Reported emissions are similar in the two reports, but there are systematic differences. The most recent EIA study reports (preliminary) 2005 emissions of 7,147.2 MMTCo<sub>2</sub>e, about 1.6 percent lower than the current EPA report. Comparing reported annual emissions from previous years, the EPA estimates are consistently higher than those of EIA: for 2000–2004, the EPA figure is higher by 2.3 percent on average (165 MMTCo<sub>2</sub>e), with a range of 1.4–2.8 percent; for 1990 emissions—frequently used as a historical baseline—the EPA reports emissions of 6242.0 MMTCo<sub>2</sub>e, while the EIA reports 6112.8 MMTCo<sub>2</sub>e (a difference of 2.1 percent). The major difference in the methodologies employed by the two agencies is in accounting for nitrous oxide (N<sub>2</sub>O) emissions, especially from agricultural soil management; the higher EPA estimates for N<sub>2</sub>O emissions account for approximately 90 percent of the difference in emissions estimates reported by these two sources. There are also smaller—and approximately offsetting—differences in estimates for CO<sub>2</sub> and methane (CH<sub>4</sub>) emissions. The EPA reports higher industrial process CO<sub>2</sub> emissions (e.g., from iron and steel production), while the EIA estimates higher CH<sub>4</sub> emissions, primarily from landfills, natural gas systems, and manure management. This paper uses the EPA report, largely because it provides greater disaggregation for certain sectors. The annual EPA report is available at <http://epa.gov/climatechange/emissions/usinventoryreport.html> while the EIA report is available at <http://www.eia.doe.gov/environment.html>.

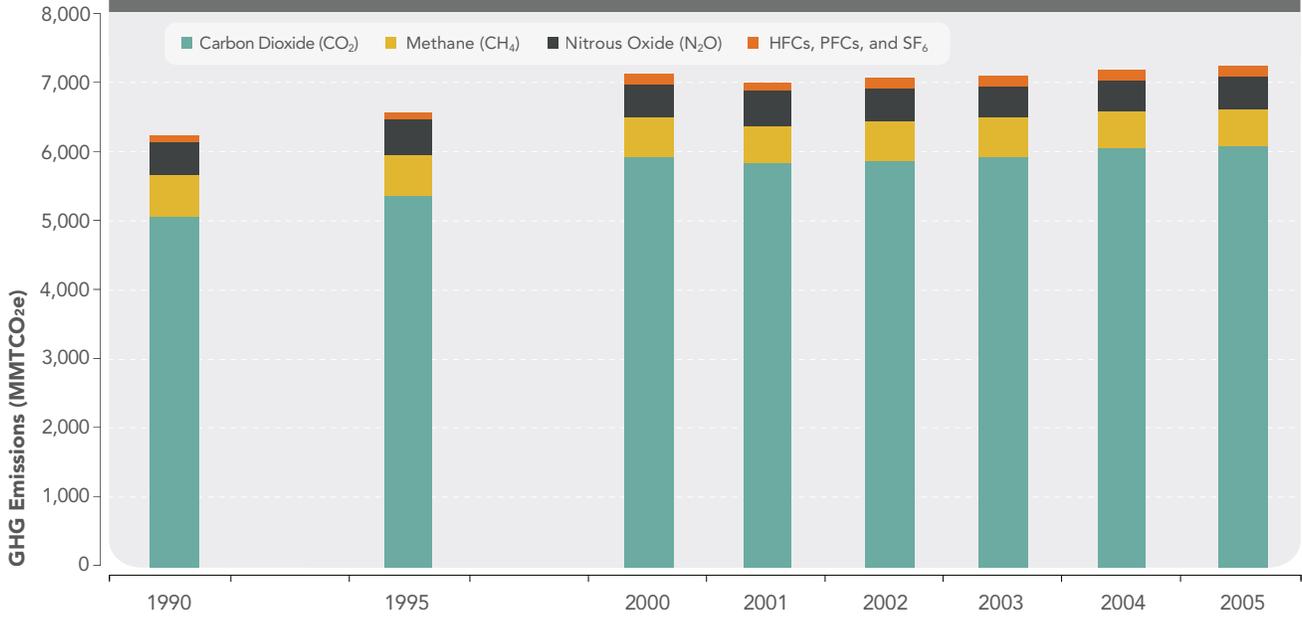
2 Several units are used to measure and report GHG emissions; this report uses one of the most common: million metric tons of CO<sub>2</sub> (Metric tons are spelled tonnes in British English.) Some studies report emissions in teragrams (Tg), which are identical to million metric tons (1 Tg = 1 MMT). Another common measure (used more frequently in Europe) is gigatonnes of carbon (GtC). One Gt = 1 billion metric tons = 1,000 MMT; including the conversion from carbon (C) to carbon dioxide (CO<sub>2</sub>), 1 GtC = 3.67 x 10<sup>3</sup> MMTCo<sub>2</sub>.

3 The use of CO<sub>2</sub>-equivalent (CO<sub>2</sub>e) units allows comparison between various GHGs based on their contribution to the warming effect of the atmosphere. CO<sub>2</sub>-equivalence is calculated by multiplying the weight of the gas by a factor called its global warming potential, or GWP. Carbon dioxide itself has a GWP of 1; the GWP for other gases depends on the strength of their warming effect and their residence time in the atmosphere. This means that there are different GWPs for different time horizons. The most commonly used GWPs are based on a 100-year time horizon. Methane, for example, has a 100-year GWP of 21; thus 1 metric ton of methane emissions is reported as 21 tCO<sub>2</sub>e emissions. The GWPs used in the EPA emissions report are the 100-year GWPs from the Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report; these are also the factors required for international reporting under the UN Framework Convention on Climate Change. An updated set of 100-year GWPs was published in the IPCC Third Assessment Report; some studies—including the EIA emissions report—use these in reporting. Although the two sets of GWPs are very similar, their differences may partially account for small differences in reported emissions among various sources.

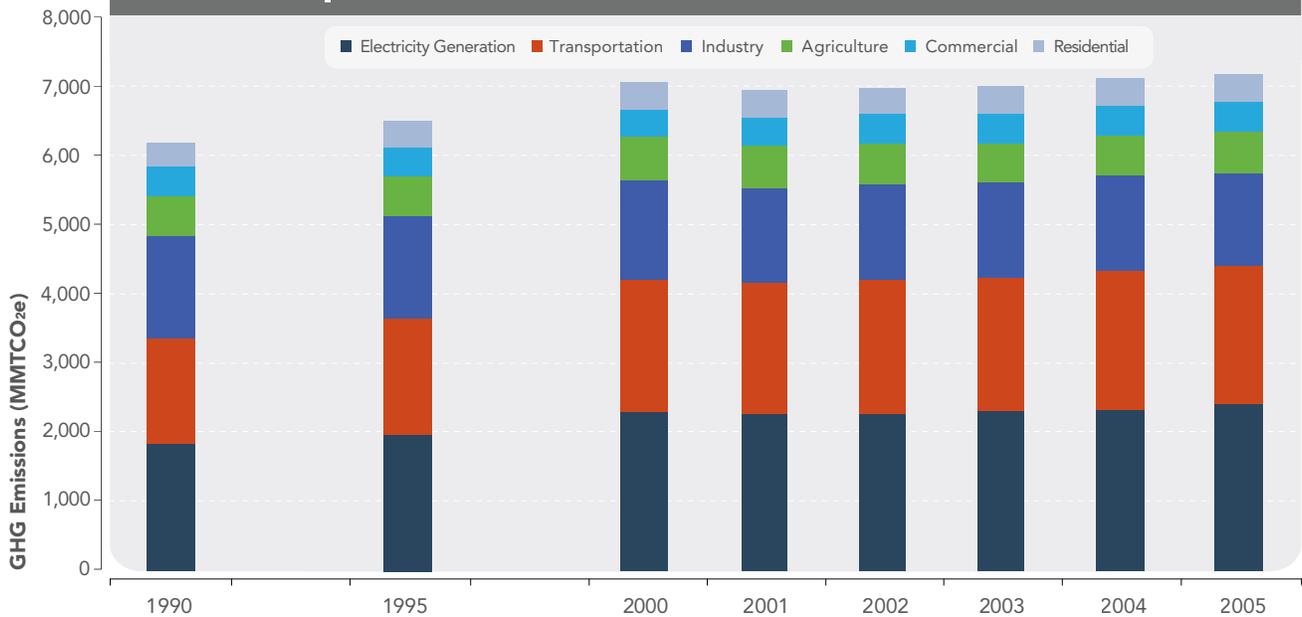
4 Estimates of uncertainty are included for all emissions in Annex 7 of the EPA report. The 95 percent confidence interval (CI) for total U.S. emissions is 7,170.3–7,635.0 MMTCo<sub>2</sub>e, or -1 percent to +5 percent of the central estimate of 7,260.4 MMTCo<sub>2</sub>e. By gas, the uncertainty is smallest in percentage terms for CO<sub>2</sub> emissions (-2 percent to +5 percent), with progressively higher uncertainties for the fluorinated gases (-6 percent to +16 percent), methane (-10 percent to +16 percent), and nitrous oxide (-16 percent to +24 percent). In general, uncertainties tend to be lower when emissions arise from centralized production activities (as with fossil fuels or the fluorinated gases) and/or are associated with smaller numbers of point sources (as with most CO<sub>2</sub> process emissions); these uncertainties are typically within +/-10 percent. Higher uncertainties are frequently associated with emissions from distributed activities (e.g., methane from natural gas systems) and/or fugitive sources (such as landfill methane or nitrous oxide from agricultural soils), and can be +/-40 percent. While smaller sources tend to have higher relative uncertainties, the largest source of absolute uncertainty is the largest source of emissions: fossil-fuel combustion accounts for 80 percent of U.S. GHG emissions (5,751 MMTCo<sub>2</sub>e), and, with a 95 percent CI of -2 percent to +5 percent, has an absolute uncertainty of about 400 MMTCo<sub>2</sub>e. Thus, this source of emissions accounts for most of the uncertainty in the overall emissions estimate.

**BY THE NUMBERS:** GREENHOUSE GAS EMISSIONS AND THE FOSSIL-FUEL SUPPLY CHAIN IN THE UNITED STATES

**Figure 2** U.S. Greenhouse Gas Emissions, 1990-2005



**Figure 3** U.S. GHG Emissions by Sector



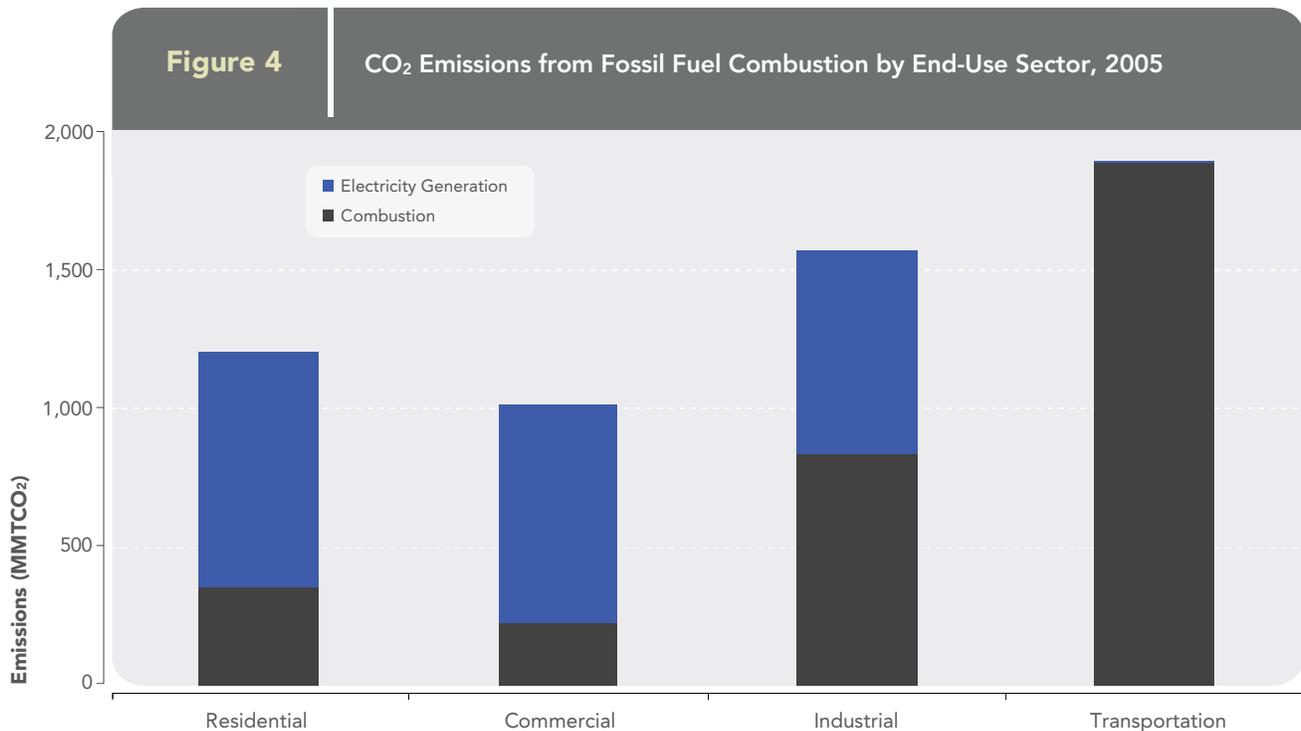


Figure 3 shows these same emissions totals again, but broken down by economic sector rather than gas. Electricity generation accounts for one-third of total emissions.<sup>5</sup> Transportation is the second-largest category, accounting for 28 percent of U.S. GHG emissions. Industry accounts for about 19 percent of total emissions. Agriculture, the commercial sector, and the residential sector each account for 5–8 percent of total emissions. Electricity generation and transportation have accounted for the majority of emissions growth since 1990, with emissions from these sectors growing at an average annual rate of about 1.8 percent. Emissions from primary energy consumption in the residential and commercial sectors, by contrast, have grown more slowly—at average annual rates of 0.5 percent and 0.2 percent, respectively. Agricultural emissions have remained essentially unchanged since 1990, with growth averaging just 0.1 percent per year. Industrial emissions, meanwhile, have declined by almost 0.6 percent per year since 1990.

The following sections look in more detail at emissions of specific gases, starting with CO<sub>2</sub> and then moving to non-CO<sub>2</sub> GHGs.

<sup>5</sup> Note that emissions from the electric power sector vary regionally across the United States, e.g., the southeastern U.S. tends to have more coal-fired generation and hence larger electric-sector emissions. This point is discussed in greater detail in Issue Brief #11 on the electricity sector.

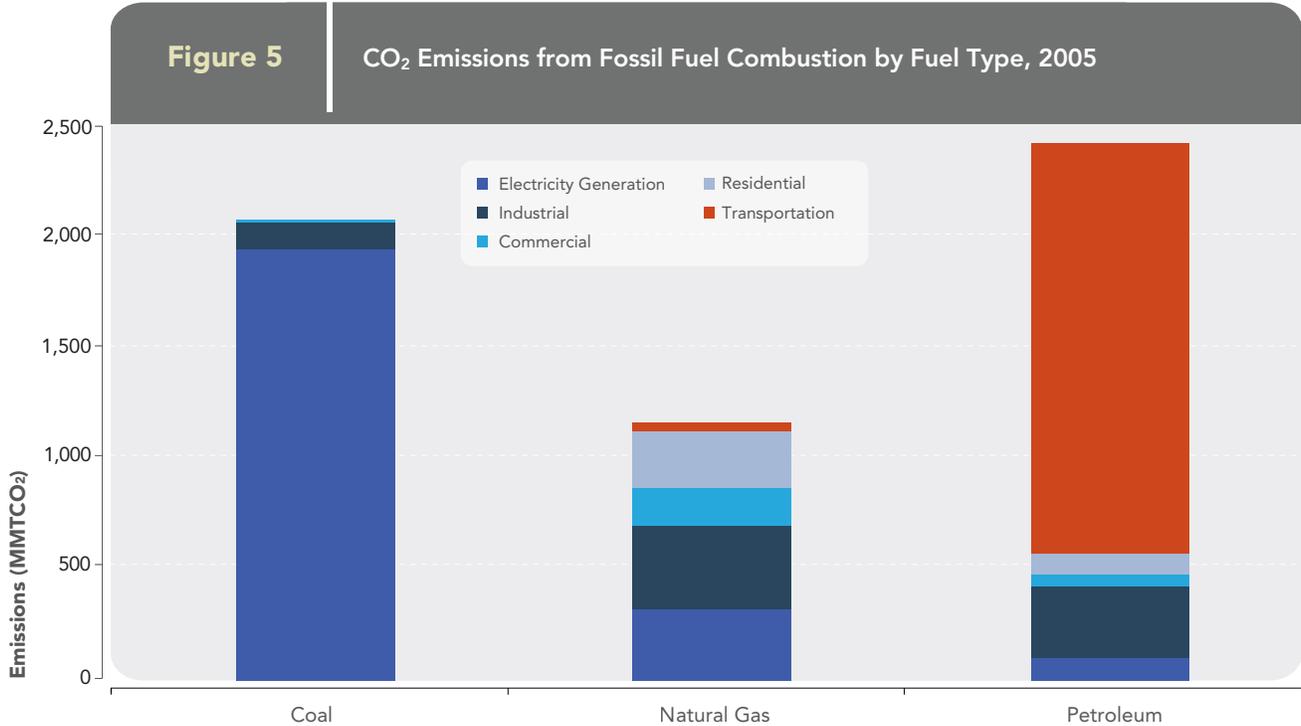
### Carbon Dioxide Emissions

Emissions of CO<sub>2</sub> constitute about 84 percent of total U.S. GHG emissions. Of this emitted CO<sub>2</sub>, the vast majority (5,751 MMTCO<sub>2</sub>, or 94.4 percent) comes from the combustion of fossil fuels. Figure 4 breaks these emissions down by sector for the year 2005, with total emissions from electricity generation (at 2,381 MMTCO<sub>2</sub>) apportioned to end-use sectors. Among end-use sectors (that is, after apportioning the electric-sector contribution), transportation accounts for the largest single share of U.S. fossil-fuel emissions—about 31 percent of the total. Industry accounts for approximately 26 percent of fossil-fuel emissions;<sup>6</sup> residential and commercial energy users account for 19.8 percent and 16.7 percent, respectively.

Figure 5 shows fossil-fuel emissions by fuel type with different colors indicating sector and with electricity emissions again distributed among end-use sectors. This breakdown reveals that petroleum use—with total annual CO<sub>2</sub> emissions of 2,487 MMT—accounts for the largest share of emissions among fuels, with most emissions coming from dispersed use of fuels for transportation, rather than from operational emissions at large facilities. Emissions from coal total 2,094 MMTCO<sub>2</sub>, almost entirely from electricity generation. Emissions from

<sup>6</sup> Agricultural emissions are included with industrial sector emissions in Figures 4 and 5.

**BY THE NUMBERS:** GREENHOUSE GAS EMISSIONS AND THE FOSSIL-FUEL SUPPLY CHAIN IN THE UNITED STATES



the use of natural gas are spread relatively evenly between electricity generation, industry, and commercial and residential users, with 1,170 MMTCO<sub>2</sub> emitted in 2005.

The pie chart in Figure 6 disaggregates transportation sector emissions. Passenger vehicles (cars and light-duty trucks) account for almost two-thirds (61 percent) of CO<sub>2</sub> emissions from transportation. Of these emissions, the vast majority—around 90 percent—come from household vehicle use, with commercial use comprising the remainder.<sup>7</sup> Shipping makes up about a quarter of emissions, mostly from trucks. Aircraft are the other significant contributor, with about 10 percent of total transportation emissions.

Although much smaller contributors than fossil-fuel combustion, other sources of CO<sub>2</sub> within the economy account for approximately 4.7 percent of total U.S. GHG emissions. Figure 7 breaks these emissions out by source, indicating that nearly half come from non-energy uses of fossil fuels where some of the carbon is stored

in a product and some is emitted. Emissions can occur during the manufacture of some products, such as plastics and rubber, or over a product's lifetime, as occurs with transportation lubricants or industrial solvents. The industrial sector accounts for most other non-energy CO<sub>2</sub> emissions, particularly process emissions from cement manufacture and iron and steel production.

**Non-CO<sub>2</sub> Greenhouse Gas Emissions**

Non-CO<sub>2</sub> gases compose about 16 percent of U.S. GHG emissions as measured in CO<sub>2</sub>-e terms based on their 100-year GWP. Although smaller than the contribution from CO<sub>2</sub> in percentage terms, non-CO<sub>2</sub> emissions are important in discussions of climate policy because they often account for a substantial share of projected emissions reductions, particularly in the near term.<sup>8</sup> The potential for including non-CO<sub>2</sub> emissions in a mandatory federal market-based program varies. Some are fugitive emissions that might only be included as offsets (for example, methane emissions from

<sup>7</sup> This percentage was calculated from an EIA report on household vehicle energy use, based on 2001 survey data from the U.S. Department of Transportation. (EIA, 2005. *Household Vehicles Energy Use: Latest Data & Trends*, DOE/EIA-0464(2005), EIA: Washington, DC. Available at [http://www.eia.doe.gov/emeu/rctcs/nhts\\_survey/2001/index.html](http://www.eia.doe.gov/emeu/rctcs/nhts_survey/2001/index.html) and accessed on August 16, 2007.)

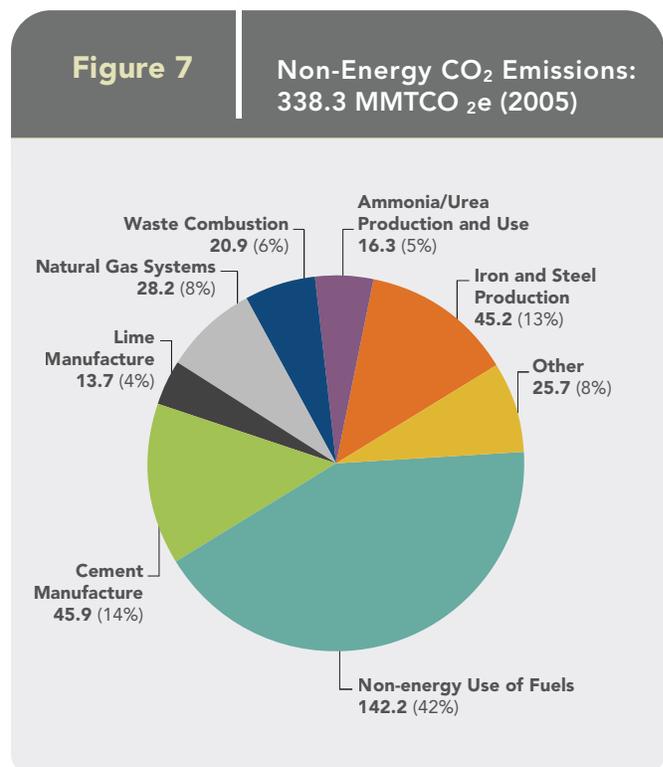
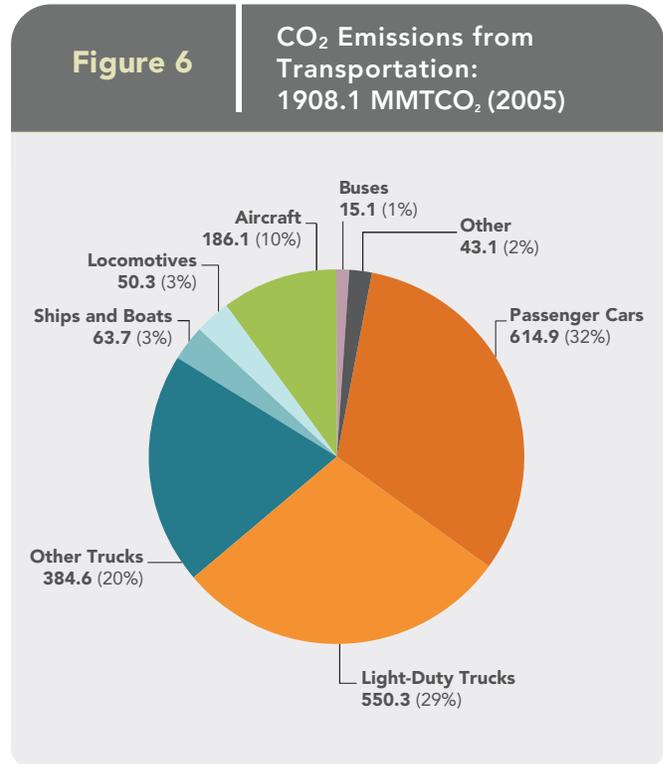
<sup>8</sup> For example, an EIA analysis from March 2006 that considered a range of cap-and-trade proposals found that with modest near-term GHG permit prices (\$8–\$24 (2004 dollars) per tCO<sub>2</sub>e in 2020), reductions in other GHGs (i.e., those besides energy-related CO<sub>2</sub>) would account for 25–55 percent of total emissions reductions in 2020, despite composing only about 6 percent of regulated emissions in the reference scenario. (EIA, 2006. *Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals*, SR/OAIF/2006-01, EIA: Washington, DC.)

landfills and nitrous oxide emissions from agricultural soil management); others, especially industrial gases, could be included relatively easily.<sup>9</sup>

The next three figures depict sources of emissions of the three major types of non-CO<sub>2</sub> GHGs: methane, nitrous oxide, and the fluorinated gases. Methane emissions fall broadly into three categories: waste, agriculture, and fossil-fuel sources. Landfills and wastewater treatment account for about 30 percent of methane emissions. Another 30 percent comes from agricultural activities; most of this is from the digestive gases of livestock, particularly ruminant animals (cattle, sheep, goats, etc). Various fossil-fuel systems account for just over one-third of methane emissions. Natural gas systems account for the largest portion of this share, largely as a result of fugitive emissions from throughout the natural gas system (production, processing, transmission, and distribution). Coal mining and petroleum systems also contribute methane emissions, principally from production activities (coal seams and oil field operations).

Nitrous oxide is produced naturally in soils through the microbial processes of nitrification and de-nitrification. These processes are amplified by agricultural activities—such as fertilization, which adds mineral nitrogen to soils—which produce more than three-fourths of anthropogenic N<sub>2</sub>O emissions. Nitrous oxide is also formed as a byproduct of ordinary combustion processes, with emissions determined by fuel characteristics; combustion parameters, such as temperature and air-fuel ratio; and pollution control equipment. Emissions are also influenced by the processes used in catalytic converters to control nitrogen oxides, carbon monoxide, and hydrocarbon emissions, making mobile sources—particularly passenger vehicles—the second-largest contributor to nitrous oxide emissions (although emissions from this source have been falling since the late 1990s as improvements have been made in vehicle pollution-control technology).

The fluorinated gases (HFCs, PFCs, and SF<sub>6</sub>) account for the smallest share of CO<sub>2</sub>-e emissions, although they have very high GWP and are growing more quickly than other non-CO<sub>2</sub> GHGs. Most emissions from this group of gases are associated with their use as substitutes for ozone depleting substances (ODSs). Under the Montreal Protocol and the 1990 Amendments to the Clean Air Act, the United States is phasing out the use of ODSs. Unfortunately, the HFCs and PFCs that are being used instead—while they do not deplete



<sup>9</sup> See Issue Briefs #14 and #15, on nontraditional GHGs and offsets, for further discussion of policy options for these types of emissions.

Figure 8

Methane (CH<sub>4</sub>) Emissions: 539.3 MMTCO<sub>2</sub>-e (2005)

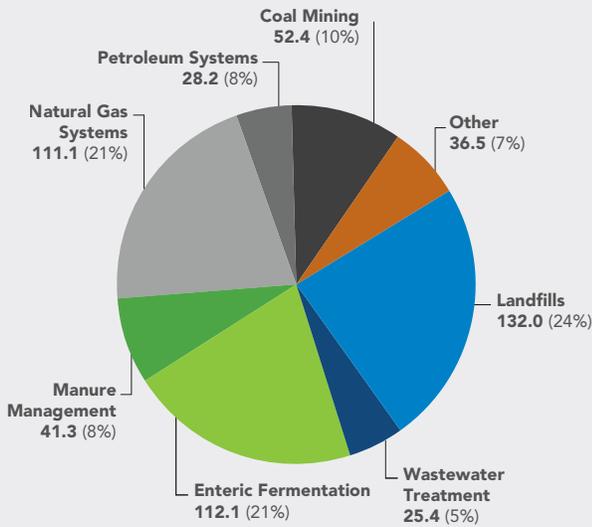
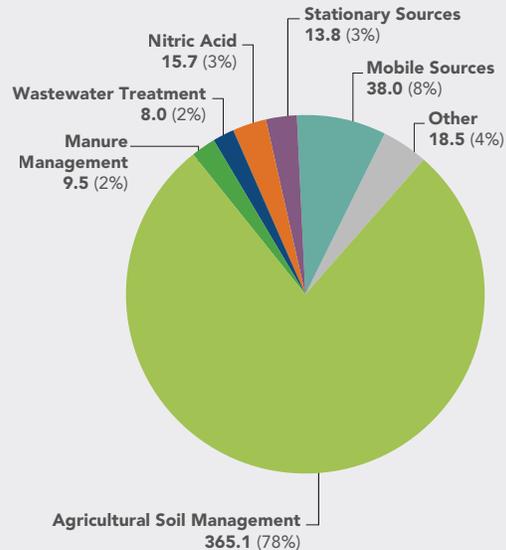


Figure 9

Nitrous Oxide (N<sub>2</sub>O) Emissions: 468.6 MMTCO<sub>2</sub>-e (2005)



the ozone layer—are potent greenhouse gases.<sup>10</sup> As shown in Figure 10, the bulk of HFC and PFC emissions come from the use of fluorinated gases for refrigeration and air conditioning; many of these emissions result from accidental leakage, particularly in smaller mobile systems such as motor vehicle air conditioners and refrigerated transport units. Smaller contributions also come from the use of fluorinated gases as aerosol propellants and as solvents in some industrial processes. Emissions of ODS substitutes have risen steadily in the last few years and are projected to continue increasing. On the other hand, emissions related to HCFC-22 production are falling, as this gas was a temporary substitute for some ODSs, but is now itself being phased out in the United States. Other emissions arise from production and use of SF<sub>6</sub>, a gas that serves as an insulator and interrupter in equipment that transmits and distributes electricity. Most SF<sub>6</sub> emissions are fugitive releases, such as leaks from gas-insulated substations through equipment seals or releases during servicing or disposal activities. Emissions from these activities have been gradually falling since 1990 due to increased SF<sub>6</sub> prices and growing awareness of the environmental impact of the gas.

## Number and Type of Carbon Dioxide Sources

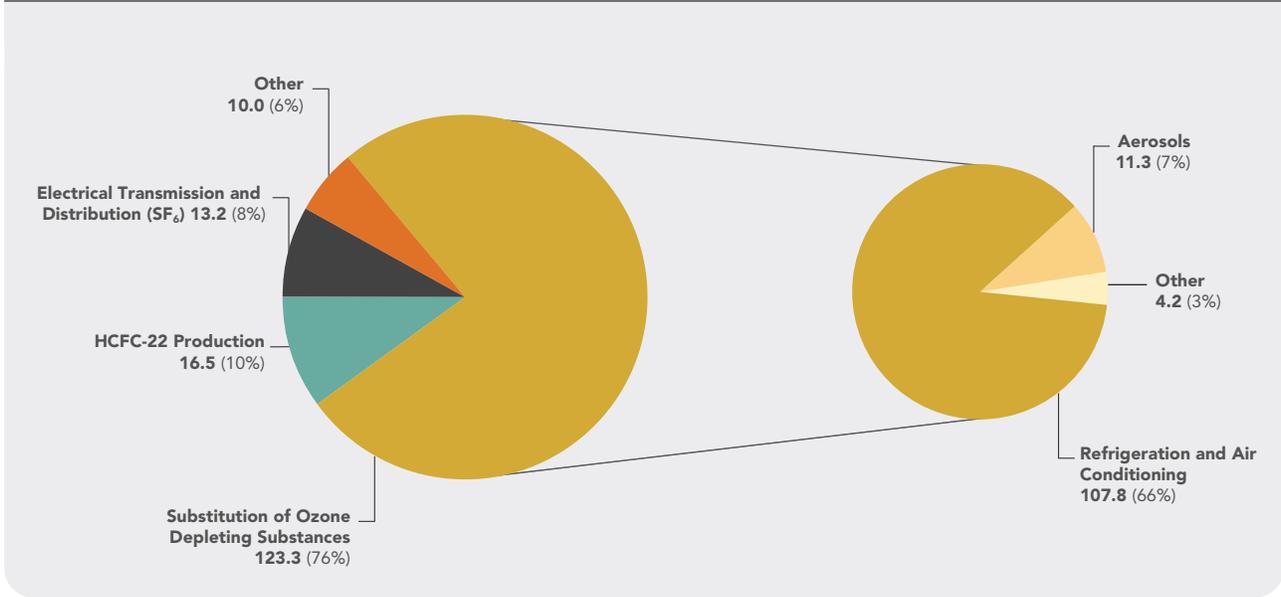
The remainder of this issue brief examines in some detail the number of facilities involved in different stages of fossil-fuel production, processing, distribution, and use. As noted at the outset, this information is relevant because—unlike other types of emissions—CO<sub>2</sub> from fossil-fuel combustion can be directly and accurately estimated by multiplying the carbon content of the fuel by the volume of fuel consumed. This calculation can be performed at any point after fuels are produced, giving policymakers the flexibility to regulate emissions at different points in the fossil-fuel supply chain.

We emphasize data on the number, size, and type of facilities involved at different stages because it may be impossible to directly regulate very large numbers of small sources—such as homes and cars—without a high cost in terms of measuring, monitoring, and verifying emissions. By contrast, moving regulation upstream to facilities that supply these small sources may allow regulators to capture the vast majority of emissions throughout the economy while monitoring a much smaller number of facilities. Except where particular constraints exist, the market signal to reduce emissions—via a

<sup>10</sup> Most of the ODSs being phased out by the Montreal Protocol are also potent GHGs.

**Figure 10**

**Emissions of Fluorinated Gases: 163.0 MMTCO<sub>2</sub>-e (2005)**



price on CO<sub>2</sub> emissions—would be transmitted to virtually all downstream users.<sup>11</sup> The latter point is important: the United States will only achieve the most emission reductions at the lowest cost to the economy if all actors in the chain of energy supply and use face the same incentive to reduce emissions.

In the discussion that follows, we distinguish between upstream, midstream, and downstream facilities or sources. Upstream facilities are fuel-production operations, such as coal mines, or natural gas and oil producers. Midstream facilities are intermediate fuel processors, including oil refiners, transporters, and pipeline operators. Downstream entities are end-users of fuel and include the facilities where emissions actually occur, such as electric power generators, industrial users, or households and automobiles.<sup>12</sup> As noted above, emissions can be calculated for upstream, midstream, or downstream facilities based on the carbon content of the fuel that is produced, processed, or consumed, rather than being directly measured (at the downstream smokestack). The next three sections discuss the number and size of upstream,

midstream, and downstream facilities, respectively.

### Upstream Facilities

Upstream facilities include both producers and importers of fossil fuels. Figures 11 and 12 show the distribution of U.S. producers of fossil fuels. In the case of coal, about 500 mines account for 95 percent of U.S. production, while the top 1,000 mines account for 99.5 percent of production. In total, there are about 1,400 coal mines in the United States.<sup>13</sup> By contrast, there are more than 15,000 companies producing crude oil and natural gas domestically. As with coal, however, production is concentrated among the largest companies: the top 500 producers account for 90–93 percent of U.S. production.<sup>14</sup>

In addition to production facilities, upstream regulation would have to account for imports. Coal imports are very small relative to domestic production—less than 3 percent.<sup>15</sup> Natural gas imports are larger, making up about one-fifth of U.S. consumption.<sup>16</sup> Most of these are pipeline imports from

11 See Issue Brief #4 on scope and point of regulation for further discussion of constraints that may exist on the ability to pass costs from upstream suppliers to downstream users.  
 12 Note that the same facility could confront different compliance obligations depending on the point of regulation. For example, if CO<sub>2</sub> were regulated at midstream based on fuel input, an oil refinery would be responsible for submitting allowances or paying taxes on the carbon content of its refining throughput as well as its direct emissions. Under downstream regulation based on actual emissions, the same refinery would be responsible only for its own direct emissions.

13 EIA Coal Production Data Files, 2005. Available at <http://www.eia.doe.gov/cneaf/coal/page/database.html>. Accessed August 16, 2007.  
 14 EIA, 2006. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2005 Annual Report, Appendix A, Operator Level Data*, DOE/EIA-0216(2005), EIA: Washington, DC.  
 15 EIA, 2007. *Quarterly Coal Report October–December 2006*. DOE/EIA-0121 (2006/04Q). EIA: Washington, DC. Coal imports were on average about 2.3 percent of domestic production from 2001–2006. Coal exports were about 4.2 percent of U.S. production from 2001–2006.  
 16 EIA, 2007. *U.S. Natural Gas Imports and Exports: Issues and Trends 2005*, EIA: Washington, DC. Exports of natural gas from the U.S. represent less than 4% of domestic production, with most of this being pipeline

Figure 11

Distribution of U.S. Coal Production (2005)

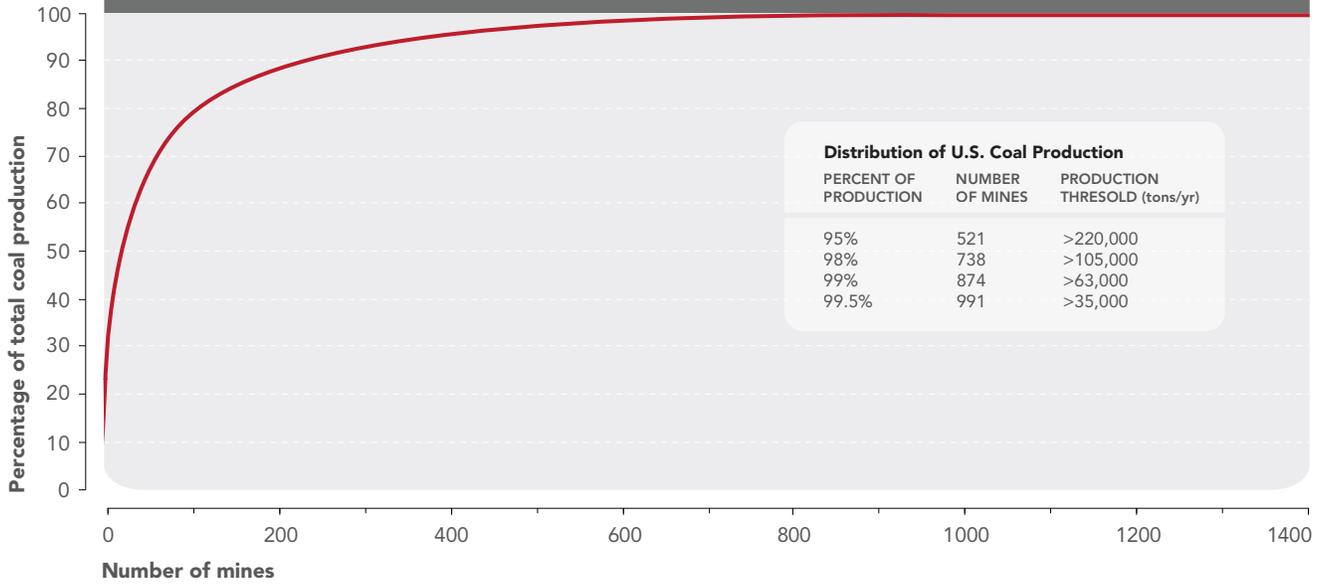
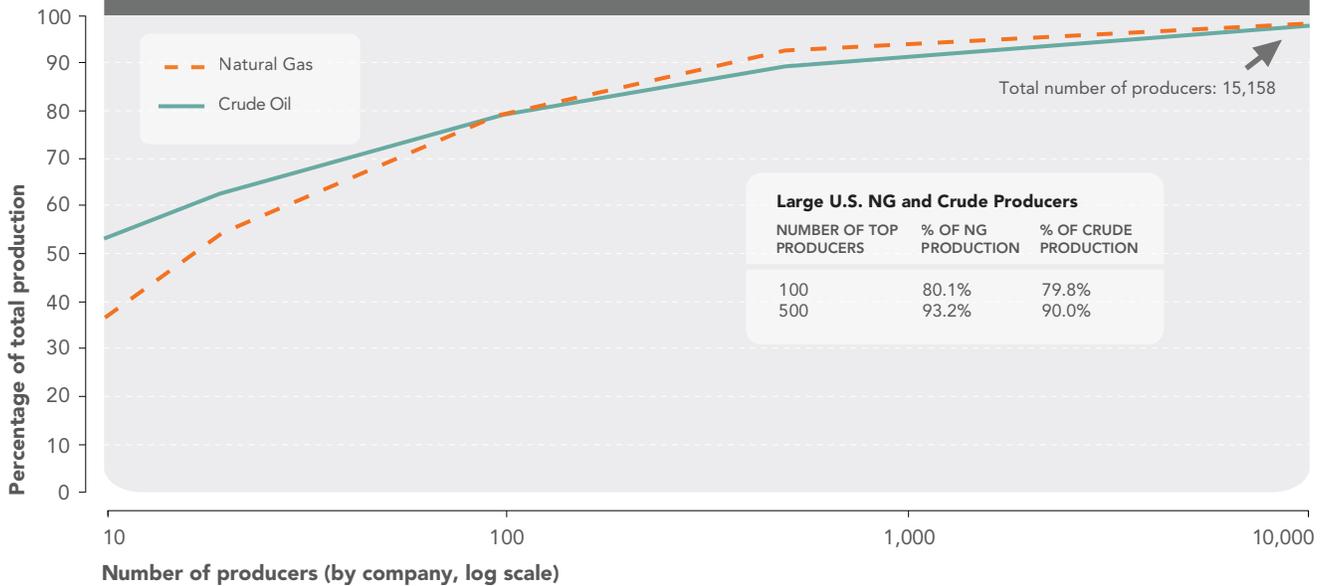
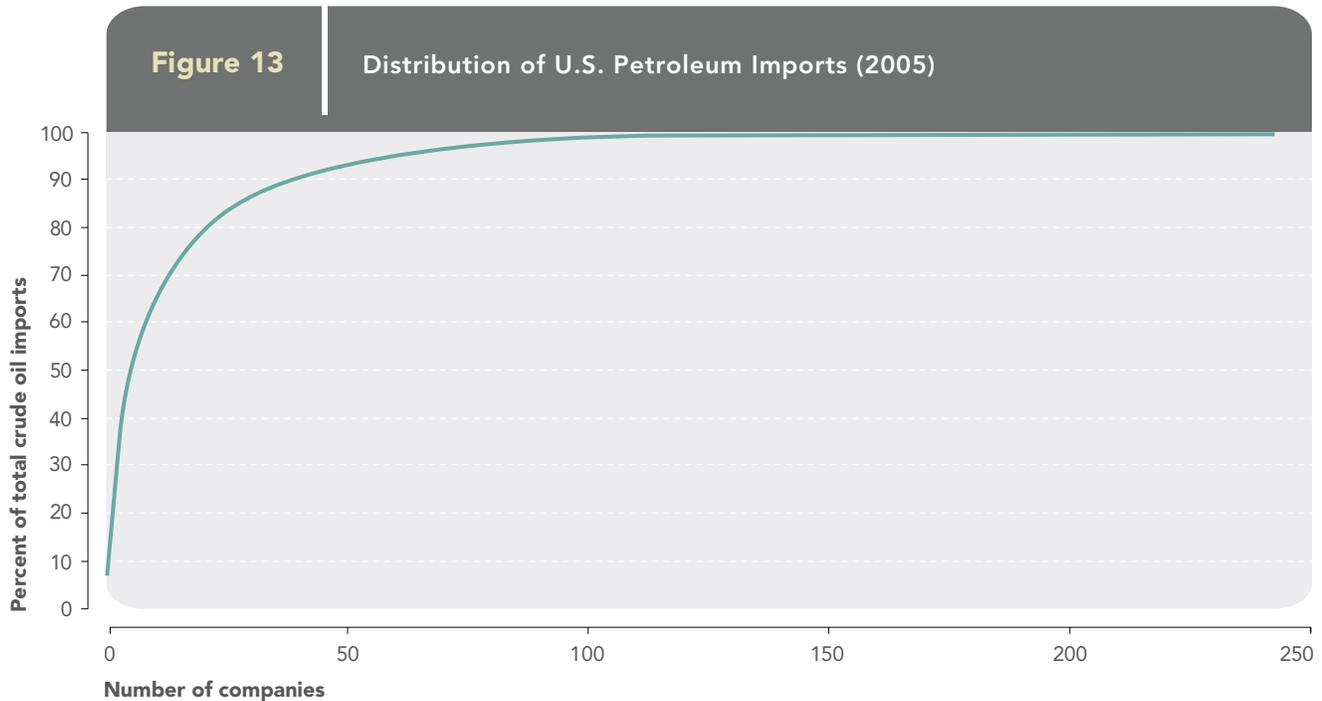


Figure 12

Distribution of U.S. Natural Gas and Crude Oil Production (2005)





Canada and Mexico, with the last 15 percent of imports (3 percent of total U.S. natural gas supply) being liquid natural gas (LNG). Slightly more than 100 companies are involved in natural gas pipeline import/export.<sup>17</sup> Five companies imported LNG to the U.S. in 2005.<sup>18</sup> Unlike coal or natural gas, imports exceed U.S. production in the case of petroleum. Figure 13 shows the distribution of U.S. petroleum imports—both crude and refined—by company; less than 250 companies account for all imports, with about 100 companies making up 99 percent of the total.<sup>19</sup>

### Midstream Facilities

Although in theory, transmission facilities could be regulated (whether oil and gas pipelines or coal shippers), most proposals for midstream regulation focus on processors. Further, the emphasis is on oil and natural gas, since coal is typically not processed between production and use.

Figure 14 shows U.S. crude oil refining capacity as of January 1, 2006 for the approximately 150 refineries in operation at

that time.<sup>20</sup> This figure depicts capacity rather than actual throughput because firm-level data on throughput are not available. Because the utilization of operable capacity for refineries has averaged over 90 percent for the last five years, however, capacity data provide a reasonable proxy for throughput.<sup>21</sup> Imports of refined petroleum products, which composed about 25 percent of total U.S. petroleum imports in 2005, would also need to be regulated in a midstream system.<sup>22</sup> Figure 13 includes these refined products; although a detailed breakdown is not given, the figure indicates that fewer than 250 companies import petroleum products, whether refined or crude.

Natural gas processing plants are in some respects analogous to oil refining facilities, although they receive less attention. Processing plants take raw natural gas from the wellhead and process it into standard pipeline-quality natural gas, removing oil, water, natural gas liquids (NGLs), and contaminants (such as sulfur). Figure 15 shows processing capacity for the approximately 570 natural gas processing facilities in the

exports to Canada and Mexico.  
 17 U.S. Dept. of Energy, Authorizations to import/export natural gas, 2005. <http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders-2005.html> Accessed August 24, 2007.  
 18 EIA, 2007. *U.S. Natural Gas Imports and Exports: Issues and Trends 2005*, EIA: Washington, DC.  
 19 Figure 13 data from the EIA, *Company Level Imports of Petroleum*, 2005. [http://www.eia.doe.gov/oil\\_gas/petroleum/data\\_publications/company\\_level\\_imports/cli\\_historical.html](http://www.eia.doe.gov/oil_gas/petroleum/data_publications/company_level_imports/cli_historical.html) Accessed August 16, 2007.

20 EIA, 2006. *Refinery Capacity Report 2006*, EIA: Washington, DC. [http://www.eia.doe.gov/oil\\_gas/petroleum/data\\_publications/refinery\\_capacity\\_data/refcap\\_historical.html](http://www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcap_historical.html) Accessed August 16, 2007.  
 21 EIA, 2007. *EIA Petroleum Navigator*, U.S. Total Weekly Inputs, Utilization & Production. The average weekly percent utilization of refinery operable capacity from August 2002 to July 2007 was 90.5 percent. File available at [http://tonto.eia.doe.gov/dnav/pet/pet\\_pnp\\_wiup\\_dc\\_nus\\_w.htm](http://tonto.eia.doe.gov/dnav/pet/pet_pnp_wiup_dc_nus_w.htm) Accessed August 27, 2007.  
 22 EIA, 2007. *EIA Petroleum Navigator*, *U.S. Weekly Imports & Exports*. Imports of petroleum products (i.e., all non-crude oil imports) were 24.8% of total 2005 imports. File available at [http://tonto.eia.doe.gov/dnav/pet/pet\\_move\\_wkly\\_dc\\_NUS-200\\_mbbldp\\_w.htm](http://tonto.eia.doe.gov/dnav/pet/pet_move_wkly_dc_NUS-200_mbbldp_w.htm) Accessed August 27, 2007.

continental United States.<sup>23,24</sup> Natural gas imports would also have to be accounted for under a midstream system, since pipeline and LNG imports are rarely processed by U.S. processing facilities. As noted previously, about 100 companies are involved in importing natural gas.

### Downstream Sources

There are a much larger number and variety of downstream fossil-fuel users compared to either midstream or upstream fuel producers or processors. In addition to traditional large point sources of emissions, such as electric generating units or manufacturing plants, downstream sources include much smaller fuel users such as commercial buildings, automobiles, and home furnaces. There are an enormous number of these small sources in the U.S. economy, including nearly 200 million personal vehicles in the United States.<sup>25</sup> Out of the almost 110 million households in the country, nearly 70 million use natural gas; fuel oil or liquid propane gas (LPG) are used in about 9 million each; and kerosene is used in about 3 million.<sup>26</sup> There are fewer commercial buildings—under 5 million—about half of which use natural gas; another half million each use fuel oil or propane.<sup>27</sup> All told there are roughly 300 million small downstream sources in the U.S. economy, primarily homes and personal vehicles.

The remainder of our discussion focuses on large downstream sources and, in particular, on downstream sources in the electric utility and industrial sectors. These sectors accounted for just over half (52 percent) of total U.S. GHG emissions in 2005 (see Figure 3). Legislative proposals that opt for regulating downstream sources typically target these large emitters; if emissions from small sources are included, they are typically regulated upstream or midstream (for example, through crude oil producers/importers or refiners).

Figure 16 depicts the distribution of CO<sub>2</sub> emissions from the electric power sector.<sup>28</sup> Emissions are presented by facility for the approximately 3,000 facilities in the United States that use fossil-fuel-based generation.<sup>29</sup> The 800 largest emitting facilities account for 95 percent of electric power sector emissions. Nearly two-thirds of all fossil-fuel generating

facilities emit more than 10,000 metric tons annually; together these large facilities account for more than 99.9 percent of electric utility emissions. Of the roughly 3,000 fossil-fuel-based electric generating facilities in the United States, around 900 burn coal. Given that electricity generation accounts for more than 90 percent of U.S. coal use (see Figure 5), it would appear that the number of upstream facilities for coal (coal mines) is roughly equal to the number of downstream facilities (coal-burning electric generating units). Finally, note that these data do not include electricity generation at industrial- and commercial-sector plants.<sup>30</sup>

The other major category of large downstream sources consists of industrial facilities, particularly manufacturing. Manufacturing accounts for 84 percent of energy-related CO<sub>2</sub> emissions in the industrial sector.<sup>31</sup> (The rest arise from agriculture, construction, fisheries, forestry, and mining.) The discussion below summarizes information about energy-related CO<sub>2</sub> emissions from manufacturing.

According to the U.S. Census Bureau, which conducts a nationwide economic survey every five years, the U.S. manufacturing sector in 2002 consisted of approximately 350,000 establishments employing more than 14 million people.<sup>32</sup> EIA reports that direct CO<sub>2</sub> emissions from the manufacturing sector in 2002 were approximately 860 MMTCO<sub>2</sub>.<sup>33</sup> (This total includes emissions from on-site fossil-fuel-based electricity generation, but does not include net electricity purchases from the electric power sector.) EIA provides data for about 30 different categories of manufacturing operations,<sup>34</sup> which together account for more than 90 percent of manufacturing sector energy-related CO<sub>2</sub> emissions, but does not provide any information about the distribution of emissions across individual facilities. To obtain a rough estimate of the distribution of manufacturing emissions sources by size, we use data from the Census Bureau economic survey, which provides disaggregated data on manufacturing employment, with firms grouped by number of employees.<sup>35</sup> Assuming emissions within each manufacturing category are proportional to employment, we develop an estimate of the distribution of emissions among firms. Thus, for example, if there are 8 firms in the largest employment size group of a particular type of manufacturing, and they account for 30 percent of employment within that manufacturing category, we

23 EIA, 2006. *Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market*. EIA: Washington, DC. Although Alaska has four natural gas processing plants with more than 8 billion cubic feet per day of combined processing capacity (about 12 percent of the U.S. total), almost none of the natural gas extracted in Alaska enters any transmission system. Rather, it is re-injected into reservoirs.

24 Figure data provided on request by EIA.

25 EIA, 2005. *Household Vehicles Energy Use: Latest Data & Trends*, DOE/EIA-0464(2005). EIA: Washington, DC.

26 EIA, 2001. *2001 Residential Energy Consumption Survey, Housing Characteristic Data Tables HC1: Housing Unit Characteristics*. EIA: Washington, DC.

27 EIA, 2006. *2003 Commercial Building Energy Consumption Survey, Building Characteristic Tables, Table B22: Energy Sources, Number of Buildings*. EIA: Washington, DC.

28 EIA, *Form EIA-906 and EIA-920 Databases*, [http://www.eia.doe.gov/cneaf/electricity/page/eia906\\_920.html](http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html) Accessed August 16, 2007.

29 "Facilities" are defined by unique EIA plant identification numbers. In practice this means that a facility is considered the sum of all the generating units at a physical plant location.

30 Note that on-site industrial electric generation is included in the discussion of the industrial sector that follows.

31 EIA, 2006. *Energy-Related Carbon Dioxide Emissions in U.S. Manufacturing*, DOE/EIA-0573(2005), EIA: Washington, DC.

32 Data on number of establishments and employee size came from U.S. Census Bureau, 2002 Economic Census. Data retrieved with American FactFinder.

33 EIA, 2006. *Energy-Related Carbon Dioxide Emissions in U.S. Manufacturing*, DOE/EIA-0573(2005), EIA: Washington, DC.

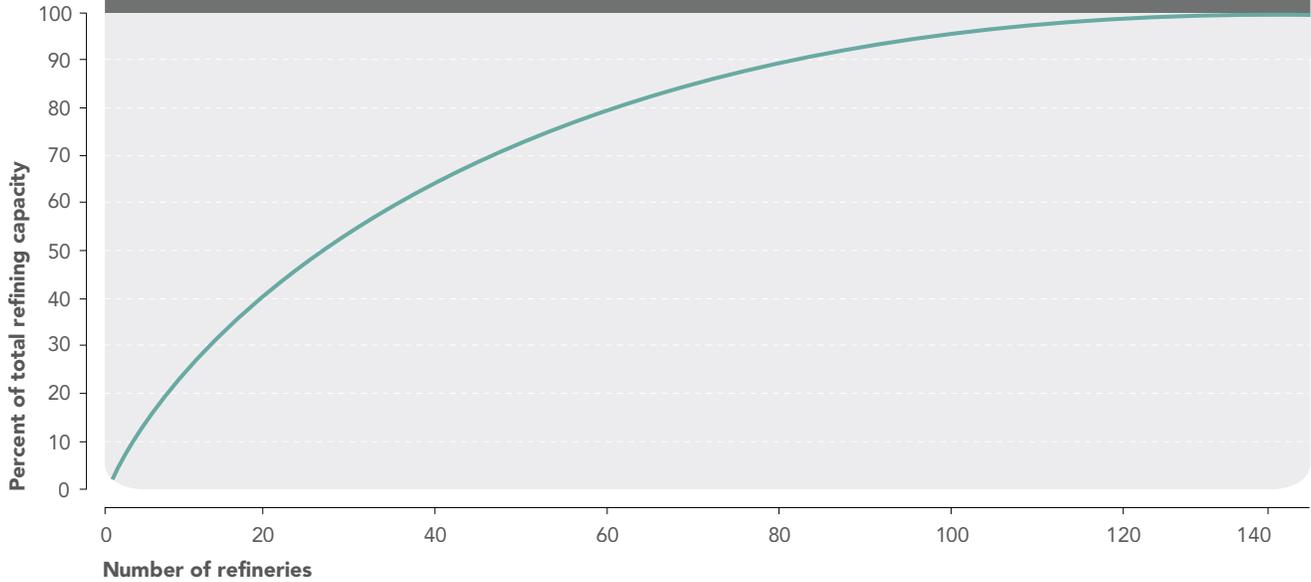
34 Manufacturing operations are categorized by the North American Industrial Classification System (NAICS).

35 Employment data are also categorized by NAICS, and are reported using ten employment size divisions, ranging from establishments with one to four employees to those with 2,500 employees or more.



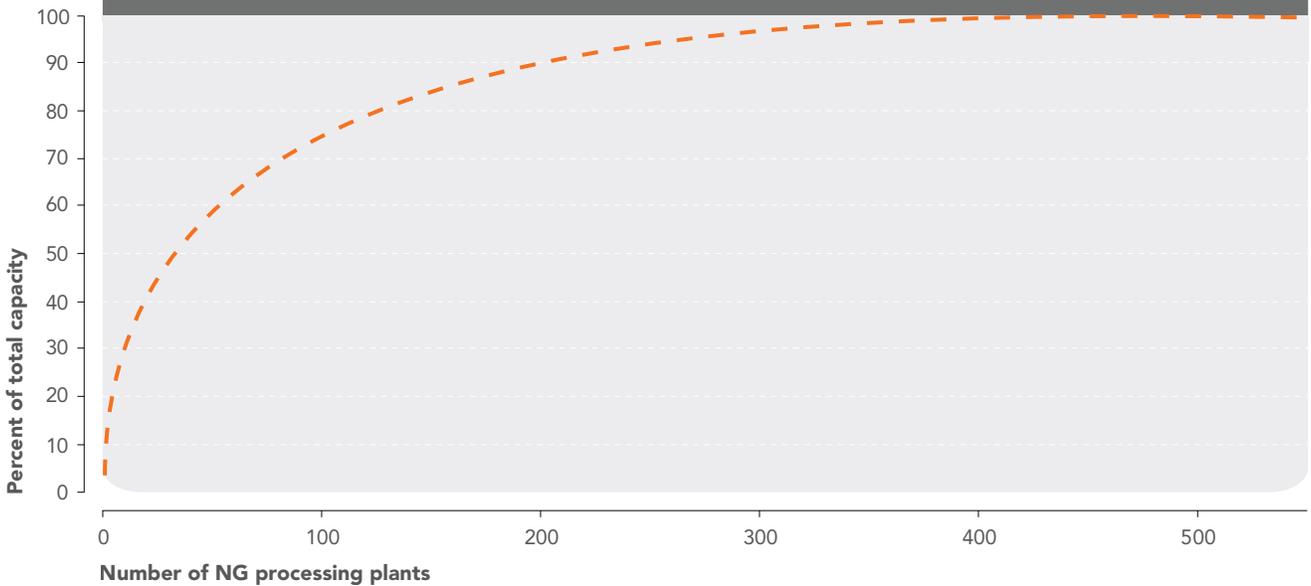
**Figure 14**

**Distribution of U.S. Refining Capacity  
(2006, Atmospheric Crude Oil Distillation)**



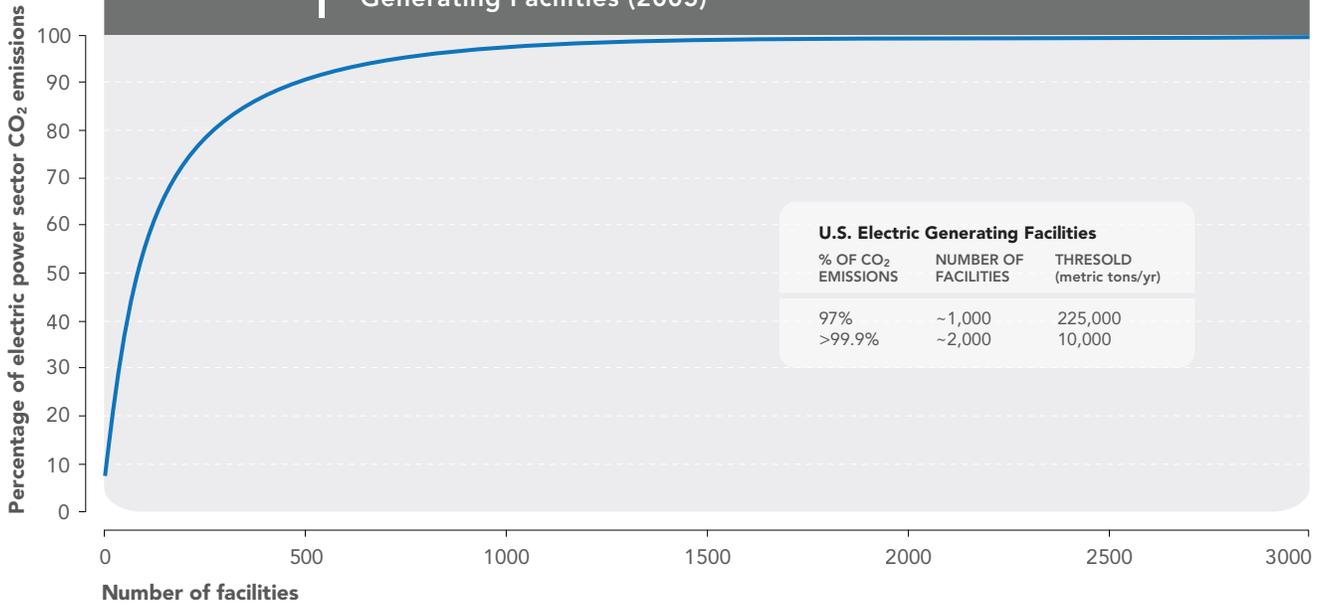
**Figure 15**

**Distribution of U.S. Natural Gas Processing Capacity  
(2006, Lower 48 States)**



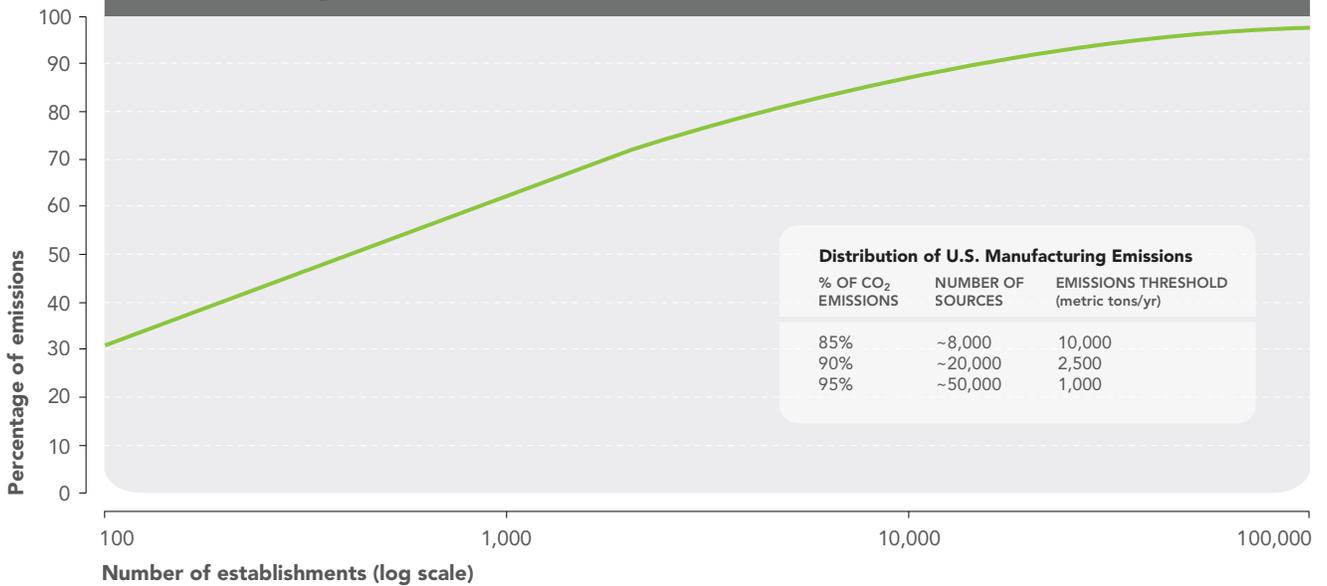
**Figure 16**

**Distribution of CO<sub>2</sub> Emissions from Electric Power Sector Generating Facilities (2005)**



**Figure 17**

**Distribution of Energy-Related CO<sub>2</sub> Emissions from U.S. Manufacturing in 2002 (estimate based on employment as a proxy emissions measure)**



assume they account for 30 percent of the energy-related CO<sub>2</sub> emissions reported by EIA for that type of manufacturing.<sup>36</sup> The resulting estimate of emissions distribution is very rough, but should be sufficient to provide policymakers with a useful approximation of the number of manufacturing sources that might be involved in domestic regulation.

Figure 17 shows the result of this analysis. It suggests that the 10,000 largest firms account for around 85 percent of manufacturing CO<sub>2</sub> emissions. Achieving coverage of more than 95 percent of manufacturing emissions would likely involve more than 50,000 sources.

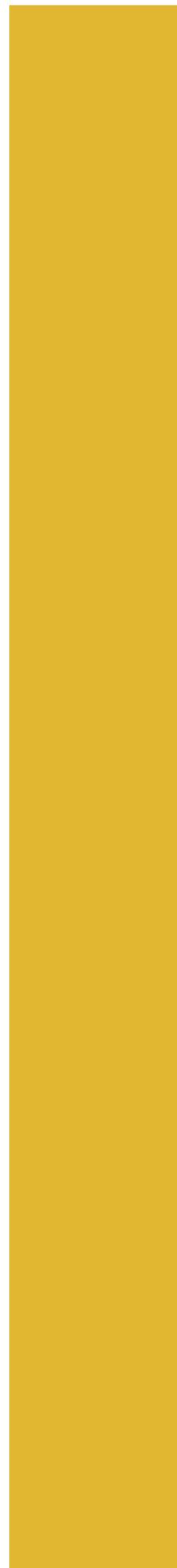
## Conclusion

As suggested at the outset, regulating a relatively small number of upstream or midstream facilities—fewer than 3,000—would capture the vast majority of economy-wide CO<sub>2</sub> emissions and pass incentives for mitigation to a much larger number of downstream emission sources (paying attention to certain constraints). Focusing only on downstream regulation, the analysis presented here suggests that a system covering the 10,000 largest sources might capture about half of national CO<sub>2</sub> emissions (all electric generation emissions and most manufacturing CO<sub>2</sub> emissions). A third option would be a hybrid system, which would regulate large downstream sources while also capturing emissions from smaller downstream sources (such as cars and buildings) by regulating on the basis of fuel throughput at midstream or upstream entities. This approach could work well for regulating CO<sub>2</sub> emissions from the transport sector, where a small number of refineries and importers serve virtually the entire sector.

When regulating some types of sources (such as wellheads in an upstream system or industrial facilities in a downstream system) it will likely be necessary to establish cut-offs, whereby smaller entities are excluded. The figures in this section help provide a sense of the trade-off between increasing coverage on the one hand and limiting the number of regulated facilities—and associated administrative costs—on the other.<sup>37</sup> For some categories of sources, such as oil refineries and coal mines (or coal-burning electric generating units), there are few enough facilities that they could all be included.

<sup>36</sup> The approximately 30 categories for which EIA details emissions comprise around 70,000 establishments, or about 20 percent of all manufacturing establishments. This analysis divides these manufacturing establishments into roughly 300 bins (30 categories by 10 employment size groups). The other 280,000 establishments—accounting for less than 9 percent of manufacturing energy-related CO<sub>2</sub> emissions—are included in the analysis in an “all others” category with the same 10 employment size divisions.

<sup>37</sup> Note that the relative contribution to overall emissions from small sources could change under long-term regulation depending on the stringency of emissions targets and program coverage. This is discussed in further detail in Issue Brief #4 on scope and point of regulation.





**ISSUE BRIEF 2**

**U.S. CLIMATE MITIGATION  
IN THE CONTEXT OF  
GLOBAL STABILIZATION**

**RICHARD G. NEWELL AND DANIEL S. HALL**



## U.S. CLIMATE MITIGATION IN THE CONTEXT OF GLOBAL STABILIZATION

Richard G. Newell  
and Daniel S. Hall

### SUMMARY

This issue brief examines recent studies of long-term scenarios for stabilizing atmospheric concentrations of greenhouse gases (GHGs) to understand whether and how near-term U.S. climate policy can translate into environmentally significant climate outcomes. Specifically, the focus is on modeling analyses that have attempted to quantify the emissions reductions necessary to achieve a defined set of stabilization targets. The scenarios analyzed include information on the path of emissions reductions, changes in technology, and prices for emissions needed to reach different stabilization levels. As such, they provide insight on the near-term actions—particularly with regard to carbon prices and technology developments—that would be consistent with achieving long-term environmental objectives.

The broad picture given by the model scenarios can help inform near-term policy. Although the models differ in their details, several messages emerge.

- Given current estimates of the relationship between GHG concentrations and global temperature change, stabilizing atmospheric concentrations of carbon dioxide (CO<sub>2</sub>) at 450–650 parts per million (ppm) by volume significantly reduces the expected change in global average surface temperature and associated impacts relative to baseline projections for increased GHG concentrations.

- Most modeling scenarios for cost-effectively achieving a 550 ppm CO<sub>2</sub> (670 ppm CO<sub>2</sub>-e<sup>1</sup>) stabilization target show U.S. and global emissions leveling off over the next several decades, with a slight initial rise in emissions that peaks by 2020–2040, and a declining trajectory thereafter. Stabilizing at lower concentration levels would require that emissions start declining sooner; while a less protective (higher concentration) target would allow for a longer period of continued emissions growth and/or slower decline.
- To cost-effectively stabilize atmospheric CO<sub>2</sub> at about 550 ppm, most models require that global carbon prices rise to \$5–\$30 per metric ton of CO<sub>2</sub> in the next 20 years, increasing to \$20–\$90 per metric ton by 2050, and continuing to rise thereafter. These modeling scenarios assume an idealized, flexible, comprehensive, least-cost approach to reducing emissions. Costs could therefore be significantly higher in the context of real-world policy where countries set different levels and trends of policy stringency, do not cover all sectors, do not include all GHGs, or employ relatively costly policy instruments. For example, limiting mitigation to CO<sub>2</sub> (rather than all GHGs) could roughly double the CO<sub>2</sub> prices needed to achieve a given stabilization goal.

- The more stringent the stabilization target, the higher the CO<sub>2</sub> price required to achieve it and vice versa. Models suggest

<sup>1</sup> CO<sub>2</sub> equivalence is a means of measuring the total concentration of all GHGs, not solely CO<sub>2</sub>.

that the global carbon price levels needed for stabilization at 450 ppm CO<sub>2</sub> (530 ppm CO<sub>2</sub>e) could be 3–14 times higher by 2050 than the price levels needed to stabilize at 550 ppm, assuming emissions reductions are implemented cost-effectively. Likewise, a less stringent 650 ppm CO<sub>2</sub> (830 ppm CO<sub>2</sub>e) target could be achieved with CO<sub>2</sub> prices that are 50–75 percent lower than the prices modeled for a 550 ppm target, since considerably less action would be required relative to baseline expectations.

- Although the models show differing degrees of utilization for different technology strategies, all of them indicate that achieving the requisite emissions abatement will necessitate reductions in both overall energy use (through efficiency and conservation) and in the carbon intensity of remaining energy use (through greater reliance on low- or non-carbon resources such as nuclear power, fossil-fuel systems with carbon capture and storage, and renewable electricity and biofuels). Scenarios that assume higher rates of baseline economic growth require pushing harder on each of these technological fronts to achieve a given stabilization goal, with commensurately higher emissions prices.
- Concerted global action including all large emitters will be required in the medium and long term to cost-effectively stabilize atmospheric GHG concentrations. Nonetheless, delaying reductions by developing countries in the near term would not significantly impede the prospects for CO<sub>2</sub> stabilization at levels of about 550 ppm or higher. However, if the stabilization target is close to current levels (450 ppm) flexibility is considerably reduced, and early participation by developing countries becomes essential if much higher costs are to be avoided.

## Background on Modeling Efforts

This issue brief focuses on results from two modeling exercises: an analysis of stabilization scenarios developed for the federal government's inter-agency Climate Change Science Program (CCSP) and the Stanford Energy Modeling Forum's EMF-21 study. Although both modeling efforts incorporated non-CO<sub>2</sub> GHGs and included non-CO<sub>2</sub> emissions reductions in their scenarios, we confine the discussion that follows to CO<sub>2</sub> emissions. In all scenarios, CO<sub>2</sub> remains the largest contributor among the GHGs. Further, because it is closely tied to fossil-fuel use, focusing on CO<sub>2</sub> provides insight into how the energy sector might change to achieve alternative stabilization targets.

## CCSP Modeling Scenarios

The CCSP study<sup>2</sup> examines different scenarios for stabilizing long-term atmospheric concentrations of the major GHGs: CO<sub>2</sub>, methane (CH<sub>4</sub>), nitrous oxide (N<sub>2</sub>O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF<sub>6</sub>).<sup>3</sup> Computer-based tools known as integrated assessment models were used to examine the GHG emissions trajectories that would be consistent with various stabilization targets and to explore the implications of those emissions trajectories for energy systems globally and in the United States. Working independently, three modeling groups (IGSM, MERGE, and MiniCAM<sup>4</sup>) produced results for the project, providing a range of estimates for emissions trajectories that would achieve different stabilization targets. All modeling teams explored scenarios in which long-term atmospheric GHG concentrations are constrained to the same levels, but the pathways taken to deliver these outcomes vary in terms of the timing and magnitude of emissions reductions, the trajectory of CO<sub>2</sub> prices, and the extent to which various energy technologies are used.

Each modeling team independently produced a baseline scenario representing a world in which there is no climate policy after 2012. They also produced four policy scenarios consistent with achieving four different environmental outcomes. These outcomes were defined in terms of long-term changes in the radiative forcing of the atmosphere<sup>5</sup> relative to pre-industrial times, but they were chosen to be approximately consistent with stabilizing CO<sub>2</sub> concentrations at 450, 550, 650, and 750 ppm by volume.<sup>6</sup> (Taking into account all GHGs based on their CO<sub>2</sub>-equivalent contribution to radiative forcing, the corresponding stabilization targets are approximately 530, 670, 830, and 980 ppm CO<sub>2</sub>e.<sup>7</sup>) For the policy scenarios, the modeling teams assumed there would be coordinated global action to reduce GHG emissions after 2012, implemented through the imposition of a common global price for GHG emissions. Conceptually, the emissions price can be thought of as arising from a GHG tax, a market-

2 See Clarke, L., J. Edmonds, H. Jacoby, H. Pitcher, J. Reilly, and R. Richels. 2006. *Synthesis and Assessment Product 2.1, Part A: Scenarios of Greenhouse Gas Emissions and Atmospheric Concentrations*. Draft for CCSP Review, December 6, 2006. Our figures are based on the accompanying database of scenario results from November 8, 2006, found at [http://www.sc.doe.gov/ober/CPDAC/database\\_scenarios\\_information.xls](http://www.sc.doe.gov/ober/CPDAC/database_scenarios_information.xls).

3 These are the six GHGs identified in Annex A of the Kyoto Protocol to the United Nations Framework Convention on Climate Change (UNFCCC).

4 The three models are the Integrated Global Systems Model (IGSM) of the Massachusetts Institute of Technology's Joint Program on the Science and Policy of Global Change; the Model for Evaluating the Regional and Global Effects (MERGE) of GHG reduction policies developed jointly at Stanford University and the Electric Power Research Institute; and the MiniCAM Model of the Joint Global Change Research Institute, which is a partnership between the Pacific Northwest National Laboratory and the University of Maryland.

5 Radiative forcing is a measure of the warming effect of the atmosphere; it is typically expressed in watts per square meter.

6 Predicted long-term concentrations of CO<sub>2</sub> varied slightly across the models because the actual long-term stabilization targets used for the analysis were expressed as the additional radiative forcing (or warming effect) from all GHGs—specifically 3.4, 4.7, 5.8, and 6.7 watts per square meter. Since the model outputs for different scenarios showed varying concentrations of non-CO<sub>2</sub> GHGs, final CO<sub>2</sub> concentrations varied slightly around these approximate stabilization targets.

7 We used the following relationship, as published in the IPCC Third Assessment Report, to express radiative forcing (r) in CO<sub>2</sub>-equivalent terms: CO<sub>2</sub>e = 280 exp (r/5.35).

based cap-and-trade system, or other policy that imposes a uniform cost per unit of GHG emissions. Results are available for 10-year time steps from 2000 to 2100.

The models used in the CCSP study had several common characteristics: all were global in scale, represented multiple geographic regions, could produce emissions trajectories and totals for the major GHGs, incorporated technology in sufficient detail to report which sources of primary energy were being used, were economics-based and thus could simulate the macroeconomic costs of stabilization, and looked forward until at least the end of the 21st century. The models also all used a least-cost approach to reducing emissions. This least-cost assumption is sometimes referred to as *where, when, and what* flexibility. That is, reductions are taken in all locations (*where*), during the entire time period (*when*), and across all GHGs (*what*) such that the total cost of achieving the target is minimized. This flexibility lowers the overall cost of stabilization by equalizing the marginal costs of mitigation across space, time, and type of GHG. In practice, however, the ability to implement policies that achieve least-cost reductions on a global scale may be compromised, for reasons discussed in the final section.

### EMF-21 Modeling Scenarios

The EMF-21 modeling project<sup>8</sup> was similar to the CCSP scenario analysis but included many more models. Nineteen modeling teams, including the three CCSP teams, evaluated atmospheric stabilization under two strategies: a CO<sub>2</sub>-only mitigation strategy, and a multi-gas mitigation strategy (where the multi-gas strategy included the other major GHGs). The radiative forcing target selected for this project was close to that of the second CCSP policy scenario, so the multi-gas strategy results are comparable to stabilization at 550 ppm CO<sub>2</sub> (650 CO<sub>2</sub>e).<sup>9</sup> EMF-21 modeling teams produced a baseline scenario and a policy scenario that achieved long-term stabilization. As in the CCSP scenarios, the participating EMF-21 models assumed global participation and *where-when-what* flexibility in terms of implementing least-cost emissions reductions, although they differed in the exact approach used to model this flexibility. Results are available for 25-year time steps from 2000 to 2100.

### 550 ppm CO<sub>2</sub> Stabilization Scenarios

In the next five sections, we discuss results from the CCSP and EMF-21 modeling analyses for a long-term stabilization target of approximately 550 ppm CO<sub>2</sub> (670 ppm CO<sub>2</sub>e). We focus on

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Scenarios that model a 550 ppm CO<sub>2</sub> stabilization target typically show U.S. (and global) emissions leveling off over the next several decades—with a slight initial rise in emissions that peaks by 2020–2040, and declining emissions thereafter.

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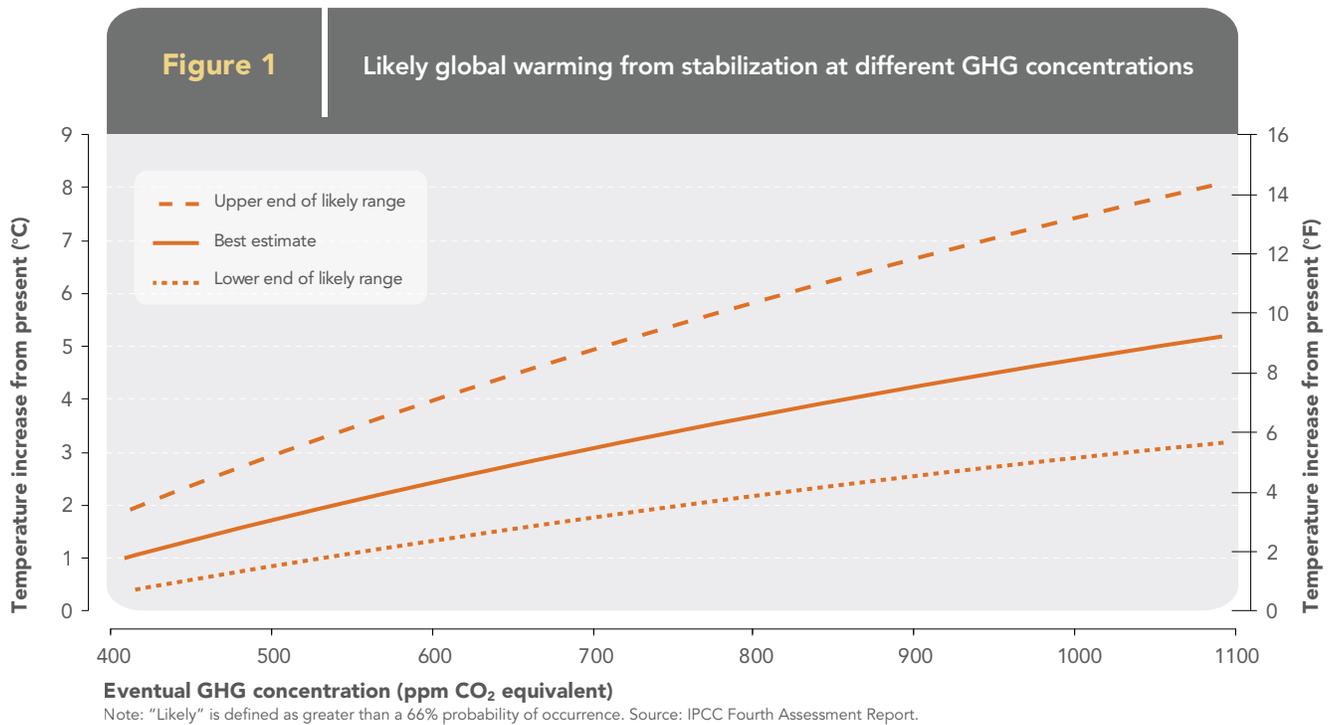
the 550 ppm CO<sub>2</sub> target level because it has received much attention in the literature. Any stabilization target, or indeed even the choice of an ultimate objective for climate policy—be it based on atmospheric GHG concentrations, emissions price, risk management, technology development, or some other objective—is ultimately a sociopolitical decision.

There are several reasons we focus our discussion on CO<sub>2</sub>. First, it is the most important GHG: as a result, no model achieves stabilization without reducing CO<sub>2</sub> emissions. Second, the strong link between CO<sub>2</sub> and energy use implies that any effective climate policy must produce fundamental changes to the energy system. Finally, the modeling results we use provide technological detail about the character of CO<sub>2</sub> reductions that is not present for the non-CO<sub>2</sub> gases. For example, the models report whether CO<sub>2</sub> reductions are achieved through expanded use of nuclear power or from carbon capture and storage, but they do not report whether methane reductions come from landfills or pig farms.

Nonetheless, it is worth noting that the role of the non-CO<sub>2</sub> GHGs, while smaller, is important in these models. In the CCSP modeling, for example, non-CO<sub>2</sub> gases make up 25–30 percent of the total baseline radiative forcing in 2050, while reductions in non-CO<sub>2</sub> gases by 2050 account for 20–40 percent of the overall change in radiative forcing needed to

<sup>8</sup> See Multi-Greenhouse Gas Mitigation and Climate Policy, F. C. de la Chesnaye, and J. P. Weyant, eds. *The Energy Journal*, Special Issue (2006).

<sup>9</sup> As with CCSP, the actual target was expressed in terms of increased radiative forcing relative to pre-industrial times—specifically, 4.5 watts per square meter.



limit warming to a level consistent with stabilization at 550 ppm CO<sub>2</sub>. We discuss the importance of other GHGs in the context of cost-effective stabilization further in the final section.

We also focus on results up until mid-century. A 2050 timeframe is near enough to provide some confidence that the model outputs are realistic, yet sufficiently long term to be informative and relevant for exploring how near-term policy and technology decisions could influence the achievement of long-term goals.<sup>10</sup> Modeled projections of carbon prices, emissions trajectories, and energy and technology developments can provide useful insight into the policy interventions that could be necessary to achieve different stabilization paths.

In the final section, we explore other mitigation scenarios. How do results change if a different stabilization target is chosen? If actual policies as implemented do not resemble the least-cost approach used for modeling, how might costs change? What if the technological options are broader or more constrained than assumed?

## Atmospheric Concentrations and Temperature Change

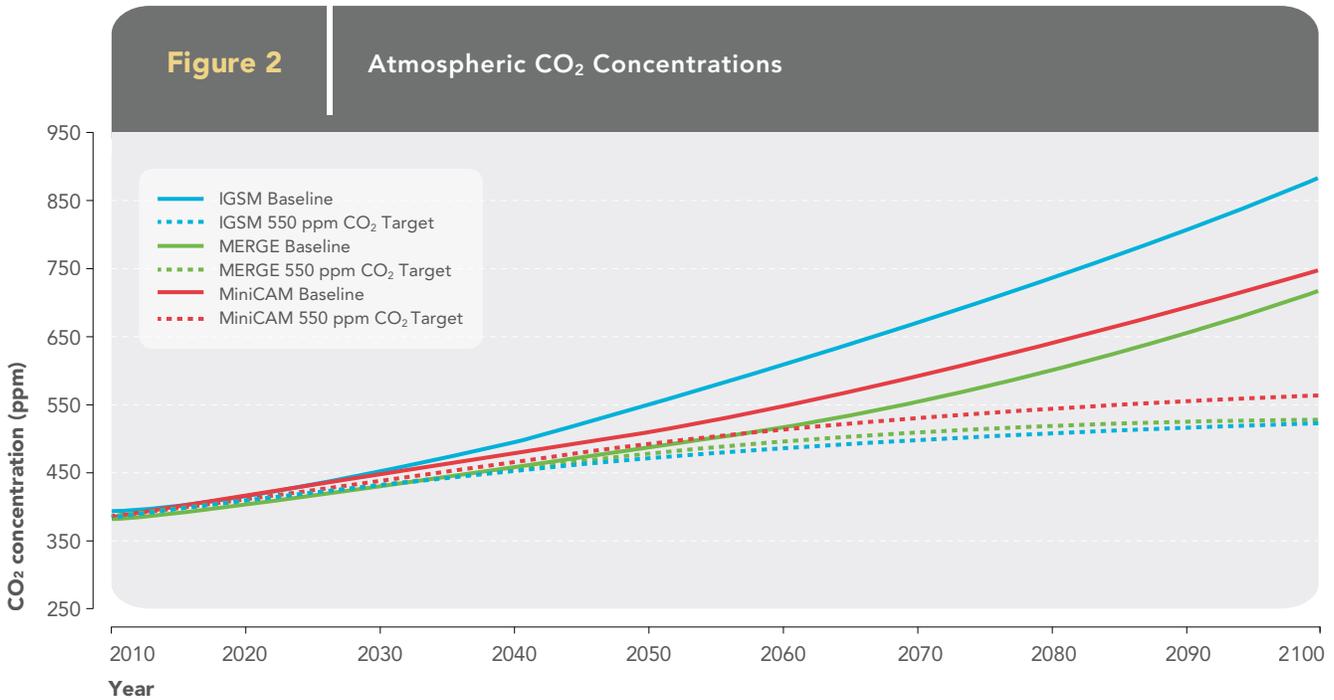
The pre-industrial concentration of CO<sub>2</sub> in the atmosphere was 280 ppm; the current level is 380 ppm CO<sub>2</sub>. Other major GHGs contribute approximately 70 ppm CO<sub>2</sub>e to present GHG concentrations, bringing existing concentrations of the six main GHGs in the atmosphere to about 450 ppm CO<sub>2</sub>e. Other anthropogenic activities (including aerosol emissions and land-use changes) have a net cooling effect (negative radiative forcing) such that the current net forcing effect from anthropogenic sources is approximately equal to 380 ppm CO<sub>2</sub>e.<sup>11</sup> About 2–3 ppm CO<sub>2</sub>e are currently added to the atmosphere each year, and this amount has been growing. The temperature response to a change in atmospheric GHG concentrations is called climate sensitivity. The recently released Fourth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC)<sup>12</sup> states,

The equilibrium climate sensitivity is a measure of the climate system response to sustained radiative forcing. It is not a projection but is defined as the

<sup>10</sup> Issue Brief #3, focusing only on economic impacts, only looks out to 2030 where there is greater confidence in those estimated impacts.

<sup>11</sup> See Figure SPM.2 (p. 4) of IPCC, 2007. *Climate Change 2007: The Physical Science Basis. Summary for Policymakers*. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Geneva: IPCC.

<sup>12</sup> *Ibid.*, p. 12.



global average surface warming following a doubling of carbon dioxide concentrations. It is *likely* to be in the range 2 to 4.5°C with a best estimate of about 3°C, and is *very unlikely* to be less than 1.5°C.<sup>13</sup>

Figure 1 shows the range of long-term warming (in degrees Celsius and Fahrenheit) that would be expected at different GHG stabilization levels based on the IPCC’s current estimate of likely climate sensitivity. Changes in global average surface temperature are relative to present conditions; thus, the range of warming impacts shown is additional to the approximately 0.8°C (1.4°F) of warming that is estimated to have already occurred relative to pre-industrial conditions.

Figure 2 shows baseline CCSP projections for atmospheric CO<sub>2</sub> concentrations, along with concentrations for scenarios that achieve stabilization at about 550 ppm CO<sub>2</sub>. It also shows that baseline projections from the CCSP reach atmospheric concentrations of 710–880 ppm CO<sub>2</sub> (930–1390 ppm CO<sub>2</sub>e) by 2100, depending on the model. Moreover, because the baseline case assumes no effort to achieve stabilization, concentrations would continue rising beyond 2100 in these

scenarios. Looking back to Figure 1, a concentration of 900 ppm CO<sub>2</sub>e would likely produce an eventual temperature increase of about 2.5°–7°C (5°–12°F). At 1100 ppm CO<sub>2</sub>e, the likely temperature increase would be about 3°–8°C (6°–14.5°F), relative to current temperatures. Warming would continue beyond these ranges in the baseline scenarios until stabilization is achieved. Stabilization around 550 ppm CO<sub>2</sub> (670 ppm CO<sub>2</sub>e) would likely result in 2°–5 °C (3°–9°F) of warming, with a best estimate of 3°C (5.5°F).

## U.S. CO<sub>2</sub> Reductions

Scenarios that model a 550 ppm CO<sub>2</sub> stabilization target typically show U.S. (and global) emissions leveling off over the next several decades—with a slight initial rise in emissions that peaks by 2020–2040, and declining emissions thereafter (Figures 3 and 4). The three CCSP models follow this pattern, with projected emissions in the MERGE model peaking higher and earlier and emissions in the other two models being relatively flat (the IGSM emissions path falls slightly, then rises slightly, then falls slightly again but essentially remains constant). Also note the significant divergence in projected baseline emissions—we return to this point below. There is a wider spread of trajectories among the 16 models in the EMF-21 study. Figure 4 shows that the median EMF-21 result

<sup>13</sup> “Likely” is defined in the IPCC report (p. 4) as corresponding to a greater than 66 percent probability of occurrence, while “very unlikely” corresponds to a less than 10 percent probability of occurrence.

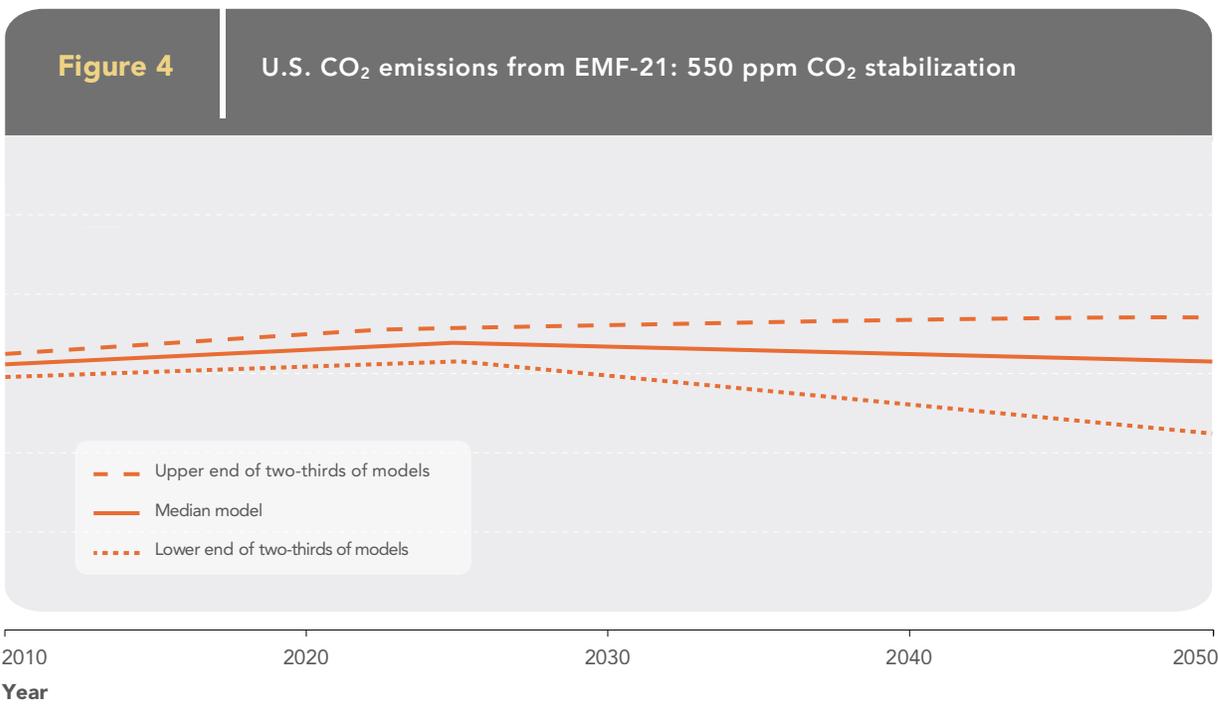
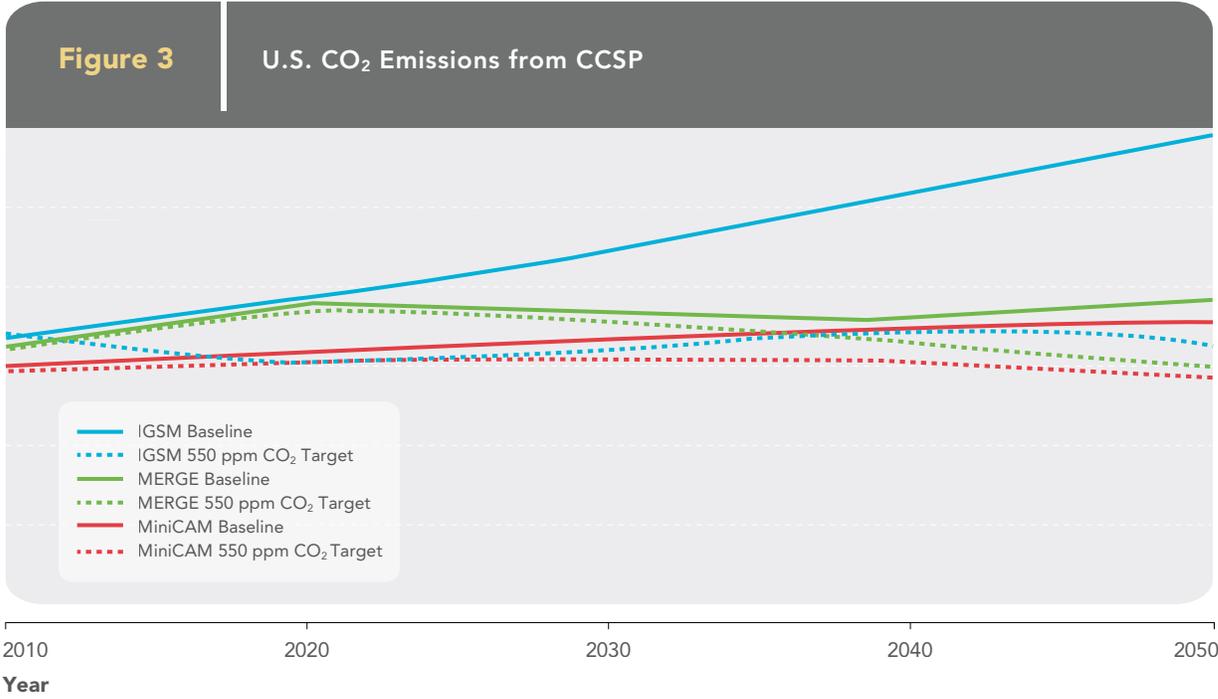
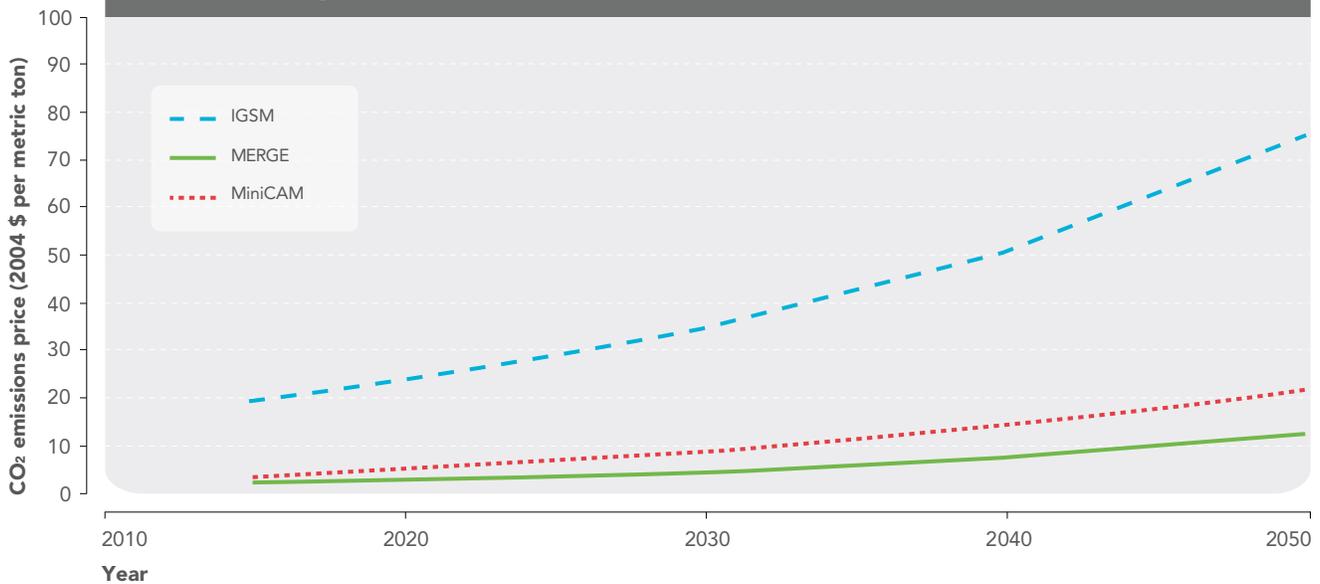


Figure 5

CO<sub>2</sub> emissions price from CCSP: 550 ppm CO<sub>2</sub> stabilization



has U.S. emissions rising slowly for the next two decades and falling slowly thereafter to achieve the 550 ppm CO<sub>2</sub> target. The figure also shows U.S. emissions trajectories for the upper and lower ends of two-thirds of the EMF-21 modeling results (the top line omits the 17% of results that show higher emissions, while the bottom line omits the lower 17% of model results, for a total of one-third).

### Prices for CO<sub>2</sub> Emissions

Most model projections for stabilizing CO<sub>2</sub> show CO<sub>2</sub> prices rising gradually through mid-century and beyond. To achieve stabilization at about 550 ppm, most models project that CO<sub>2</sub> prices will need to rise to \$5–\$30 per metric ton by 2025, increasing to \$20–\$90 per metric ton by 2050, and continuing to rise thereafter. However, a few models predict prices outside these ranges for cost-effective stabilization at 550 ppm CO<sub>2</sub> (see Figures 5 and 6 below).<sup>14</sup>

### Shifts in Energy Technologies

Here we describe the changes in energy technology projected to be necessary, based on the CCSP results, to achieve CO<sub>2</sub>

stabilization at 550 ppm. Model projections include changes in both the type and amount of fuels used and the energy technologies deployed. The stabilization scenarios show a trend toward lower overall energy use, reduced use of fossil fuels, and increased use of renewable electricity and biofuels, nuclear energy, and fossil-fuel-based electricity production with carbon capture and storage. Figure 7 summarizes projected changes in U.S. primary energy use in 2050. Changes are shown for a 550 ppm CO<sub>2</sub> climate policy relative to baseline projections across all major energy technologies in both absolute and percentage terms (for example, according to the IGSM results, commercial biomass production in 2050 is 250 percent higher in the stabilization case than in the baseline forecast).

One of the major changes projected in the 550 ppm stabilization scenarios is a downward shift in total energy use relative to the baseline.<sup>15</sup> The models project that overall energy consumption will be approximately 5–20 percent lower under a climate policy designed to achieve stabilization at 550 ppm, with larger reductions anticipated from models (such as IGSM) that project higher baseline energy use (see Figure

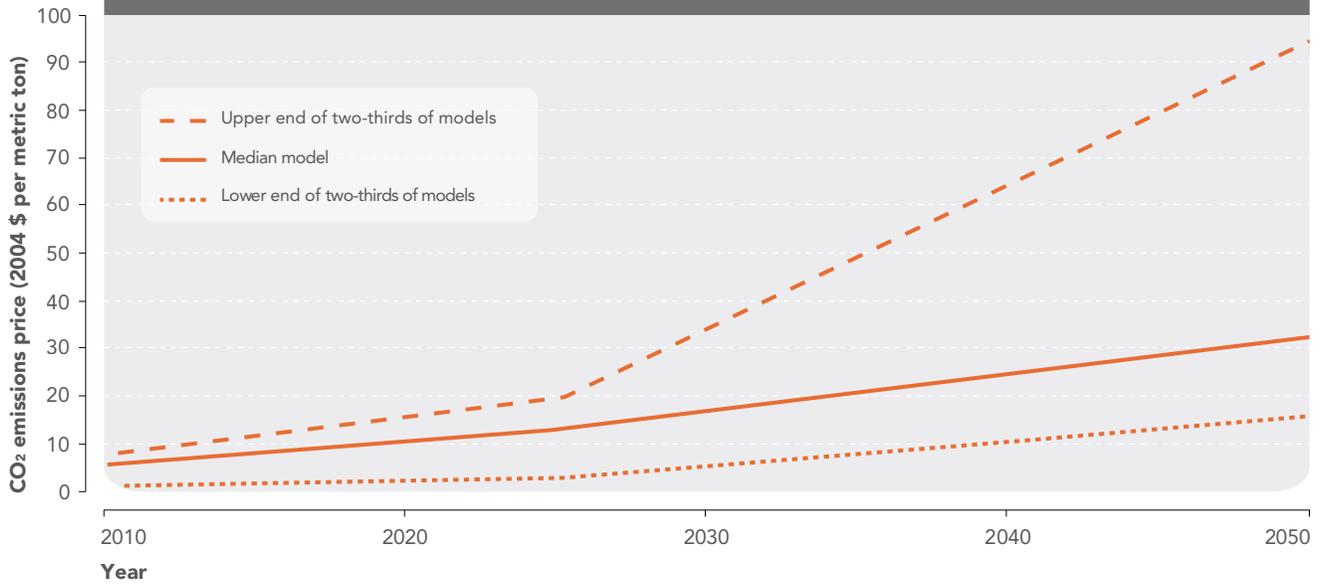
<sup>14</sup> Note that the model with higher prices in Figure 5, IGSM, is also the model with the highest baseline emission level in Figure 3. The consistency of this relationship is discussed in Issue Brief #3 concerning mitigation costs.

<sup>15</sup> This shift is depicted on the positive side of the ledger in Figure 7, where it is reported as an “energy reduction.” The rationale is that reductions in the use of carbon-intensive energy sources must be matched by increased use of lower-carbon technologies, reduced energy use, or some combination of both.



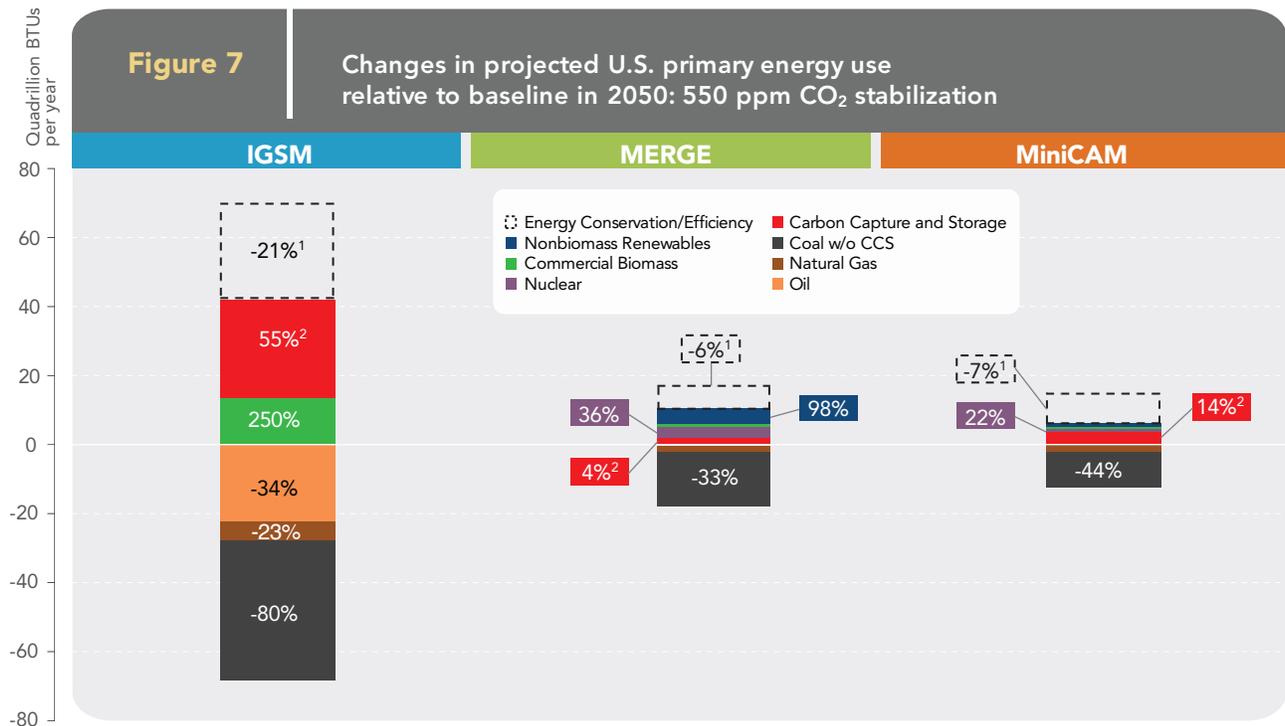
**Figure 6**

CO<sub>2</sub> emissions price from EMF-21: 550 ppm CO<sub>2</sub> stabilization



**Figure 7**

Changes in projected U.S. primary energy use relative to baseline in 2050: 550 ppm CO<sub>2</sub> stabilization



Percentage changes are relative to baseline projections for each technology, except as noted.

<sup>1</sup> Percentage change in total primary energy use relative to baseline projection. <sup>2</sup> Percentage increase in CCS relative to projected total coal use in baseline scenario.

4). Baseline projections of energy use are primarily driven by assumptions about economic growth. For example, the IGSM model assumes an average annual GDP growth rate of about 2.7 percent from 2010 to 2050, while MERGE and MiniCAM assume growth rates of 1.6–1.7 percent per year. The IGSM baseline projection for U.S. GDP in 2050 is therefore about 50 percent higher than the MERGE or MiniCAM projection.

Stabilization also implies significant changes to the remaining energy mix. Conventional coal use in the United States is significantly lower under the 550 ppm stabilization scenario than in the baseline in all three CCSP models. Note that the projected reduction in total coal use (both with and without carbon capture and storage) is similar across the three models—around 25–30 percent or 10–15 quadrillion Btus (quads), relative to baseline projections. All models shift some of this coal into plants with carbon capture and storage. The IGSM model projects the largest shift, with a major drop in conventional coal use and a large increase in carbon capture and storage. Specifically, the IGSM projection for 2050 shows the equivalent of about 800 coal-fired power plants using capture and storage, each with 500 megawatts (MW) net capacity (see Table 1). The other two models project much more modest increases in carbon capture and storage, equivalent to 50–100 new plants with this technology.

One of the major changes projected in the 550 ppm stabilization scenarios is a downward shift in total energy use relative to the baseline. The models project that overall energy consumption will be approximately 5–20 percent lower under a climate policy designed to achieve stabilization at 550 ppm.

Type of facility	Facility capacity	Facilities per quad
Coal-fired power plant	500 megawatts	28
Natural gas base load power plant <sup>1</sup>	100 megawatts	142
Nuclear power plant	1,000 megawatts	12
Wind farm	100 megawatts	380
Ethanol plant	100 million gallons/year	150
Oil refinery	100,000 barrels/day	5

<sup>1</sup>Note that natural gas has many uses as a primary fuel apart from electricity generation

The MERGE and MiniCAM models project very little change in oil use, relative to the baseline, in the 550 ppm stabilization scenario, whereas the IGSM model shows a significant reduction in oil use (projected consumption is 33 percent below the baseline case, implying a reduction equal to about half of current U.S. oil use). There is significant substitution of biofuels for oil in the IGSM model: much of the “commercial biomass” reported in Figure 7 for IGSM consists of biomass-based liquid fuels for use in the transportation sector (i.e., biofuels). Assuming, for purposes of illustration, that the biofuels contribution is all ethanol, this implies a 30-fold increase in ethanol production from current levels, to more than 160 billion gallons per year.<sup>16</sup>

The MERGE and MiniCAM models project significant growth in electricity production using non-fossil technologies in the 550 ppm scenario, whereas IGSM does not. Specifically, both models project an increase in nuclear generation that equates to about 20–40 additional 1,000 MW nuclear power plants. MERGE also projects that electricity production from non-biomass renewable resources (e.g., wind, solar, geothermal) will double by 2050 under a 550 ppm stabilization policy, relative to the baseline forecast. The model does not make projections concerning the specific mix of renewable technologies used to supply this increase, but if wind generation is assumed to account for most of it, these results imply approximately 1,500 new wind sites at 100 MW capacity each.

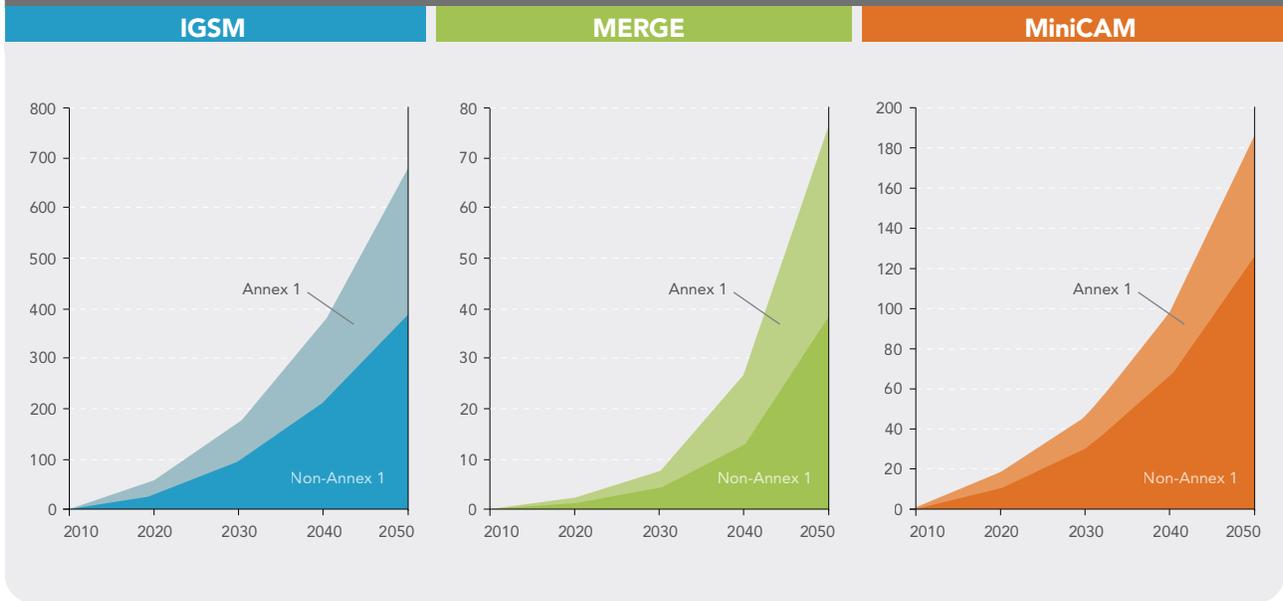
Figure 7 presents primary energy consumption in quads per year. Table 1 below indicates how many facilities are implied by each additional quad of primary energy input, assuming

<sup>16</sup> In reality, not all commercial biomass use will consist of biofuels and even the biofuels component will likely include a mix of fuels besides ethanol, such as biodiesel. Although the CCSP analysis does not provide a detailed breakdown of these results, this simple illustration provides some sense of the potential scale of biofuels production under a stabilization policy.



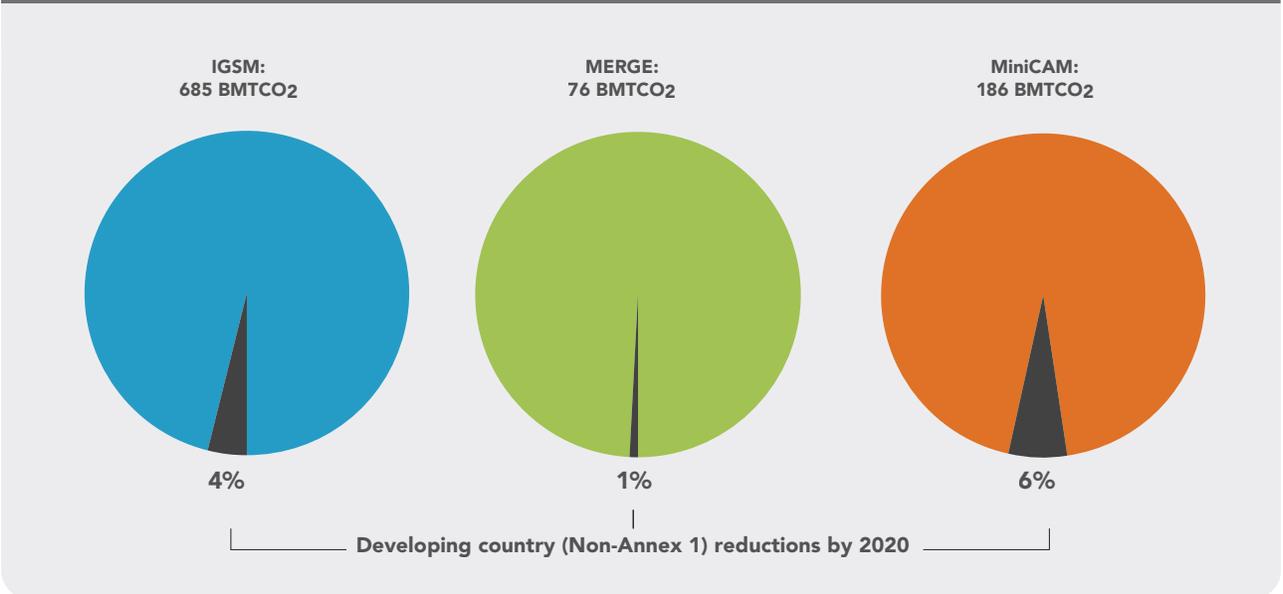
**Figure 8**

Cumulative CO<sub>2</sub> emissions reductions: 550 ppm CO<sub>2</sub> stabilization



**Figure 9**

Global cumulative reductions by 2050 to achieve 550 ppm(v) CO<sub>2</sub> stabilization, billion metric tons (BMT) of CO<sub>2</sub>



**Table 2** Comparison of carbon prices under alternative modeling scenarios

Modeling study	Scenario	Price in 2025 (\$/metric ton CO <sub>2</sub> )	Price in 2050 (\$/metric ton CO <sub>2</sub> )
CCSP <sup>1</sup>	450 CO <sub>2</sub> (530 CO <sub>2</sub> e)	40-95	140-250
	550 CO <sub>2</sub> (670 CO <sub>2</sub> e)	5-30	10-75
	650 CO <sub>2</sub> (830 CO <sub>2</sub> e)	1-10	5-30
EMF-21 <sup>2</sup>	All 6 GHGs	13 (3-20)	30 (15-95)
	CO <sub>2</sub> reductions only	26 (6-37)	55 (25-150)

1 Ranges shown are based on the results from three models.  
 2 Median results for the 550 ppm CO<sub>2</sub> (650 ppm CO<sub>2</sub>e) case are shown with the upper and lower two-thirds of model results in parentheses.

representative facility sizes and capacity utilization factors.<sup>17</sup> For example, a 1-quad increase in the use of nuclear power translates into roughly 12 new 1,000-MW nuclear power plants. Values for coal-fired power plants apply to plants with carbon capture and storage if one interprets the facility capacity as net output, after accounting for the energy penalty associated with carbon capture. Finally, 1 quad of oil use per year equals about 0.47 million barrels of oil per day.

## The Importance of Global Participation

The model scenarios described in this paper assume cost-effective global efforts to reduce GHG emissions starting in 2012, whereas—in reality—political constraints may delay action in some countries. Particular concern has been expressed that developing countries—the “non-Annex I” countries<sup>18</sup>—do not have commitments under the Kyoto Protocol. As shown in Figure 8, it is clear from the CCSP modeling that concerted global action including all large emitters will be required in the medium and long term to cost-effectively stabilize GHG concentrations (note also the wide range of required reductions, depending on estimated baseline emissions). In fact, emissions reductions (relative to baseline) in non-Annex I countries account for

more than half of total reductions by 2050 under cost-effective stabilization. Results from the three models also indicate, however, that near-term reductions by non-Annex I countries—that is, reductions that occur by 2020—account for only 1–6 percent of the cumulative reductions needed through 2050 to achieve the 550 ppm CO<sub>2</sub> stabilization target (see Figure 9). This suggests that it would be feasible to make up for near-term delays in reducing emissions from some countries—as long as those countries eventually participate. Note also that there is a distinction between where reductions occur and *who pays* for those reductions.

## Sensitivity of Results to Alternative Mitigation Scenarios

As discussed previously, these modeling exercises assume that emissions reductions are achieved in a least-cost manner. For a variety of reasons, however, the ability to achieve this ideal may be compromised. If mitigation efforts are not comprehensive, whether in terms of country participation or the GHGs and sectors covered, the cost of achieving a given stabilization target increases. Models also have to make assumptions about the availability of low-carbon alternatives and the pace of technology development in the future. If carbon-reducing technologies advance more quickly than modeled, the costs of mitigation will be lower; conversely, if technology advances more slowly, costs will be higher. This section briefly explores the sensitivity of the modeling results to different assumptions concerning the choice of stabilization targets, policy coverage, and technology availability.

First, the CCSP modeling also included, in addition to the 550 ppm CO<sub>2</sub> stabilization scenarios discussed earlier, scenarios that achieved stabilization at around 450 ppm CO<sub>2</sub> (530 ppm CO<sub>2</sub>e) and 650 ppm CO<sub>2</sub> (830 ppm CO<sub>2</sub>e). In Table 2, we compare CO<sub>2</sub> prices in these scenarios to the results for the 550 ppm scenarios. Note that modeled CO<sub>2</sub> prices are 3–14 times higher in the 450 ppm scenarios than in the 550 ppm scenarios. By contrast, carbon prices are 50–75 percent lower in the less stringent 650 ppm scenarios. The EMF-21 modeling exercise compared the costs of a climate policy that included all six major GHGs, as discussed earlier, to the costs of a policy that achieved the same reductions in radiative forcing by reducing CO<sub>2</sub> emissions alone. The results provide insight on the value of flexibility in a multi-gas strategy. As shown in Table 2, the carbon prices needed to achieve stabilization at 550 ppm CO<sub>2</sub> in the EMF-21 scenarios roughly double if non-CO<sub>2</sub> gases are not included in the mitigation strategy.

17 The capacity utilization factor for a given plant or facility is the ratio of actual output to maximum rated output. The capacity factors assumed in Table 1 are as follows: 0.8 for coal, 0.8 for natural gas base-load, 0.9 for nuclear, 0.3 for wind, 0.8 for ethanol, and 0.9 for oil.

18 The term “Annex I” originates from the U.N. Framework Convention on Climate Change, which called for the countries listed in Annex I to take initial responsibility for limiting GHG emissions. Annex I is limited to the world’s more developed countries, including Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, European Economic Community, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, Ukraine, United Kingdom of Great Britain and Northern Ireland, and the United States of America. When the Kyoto Protocol was negotiated, all the countries that agreed to emissions reduction targets (listed in Annex B of the Protocol) were Annex I countries. The only Annex I countries that did not agree to targets were Belarus and Turkey. Two Annex I countries, the United States and Australia, agreed to targets but have not ratified the Protocol.

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Flexibility—in terms of where reductions take place, when reductions are taken, what gases are included, and which technologies are available for mitigation—is an important determinant of cost.

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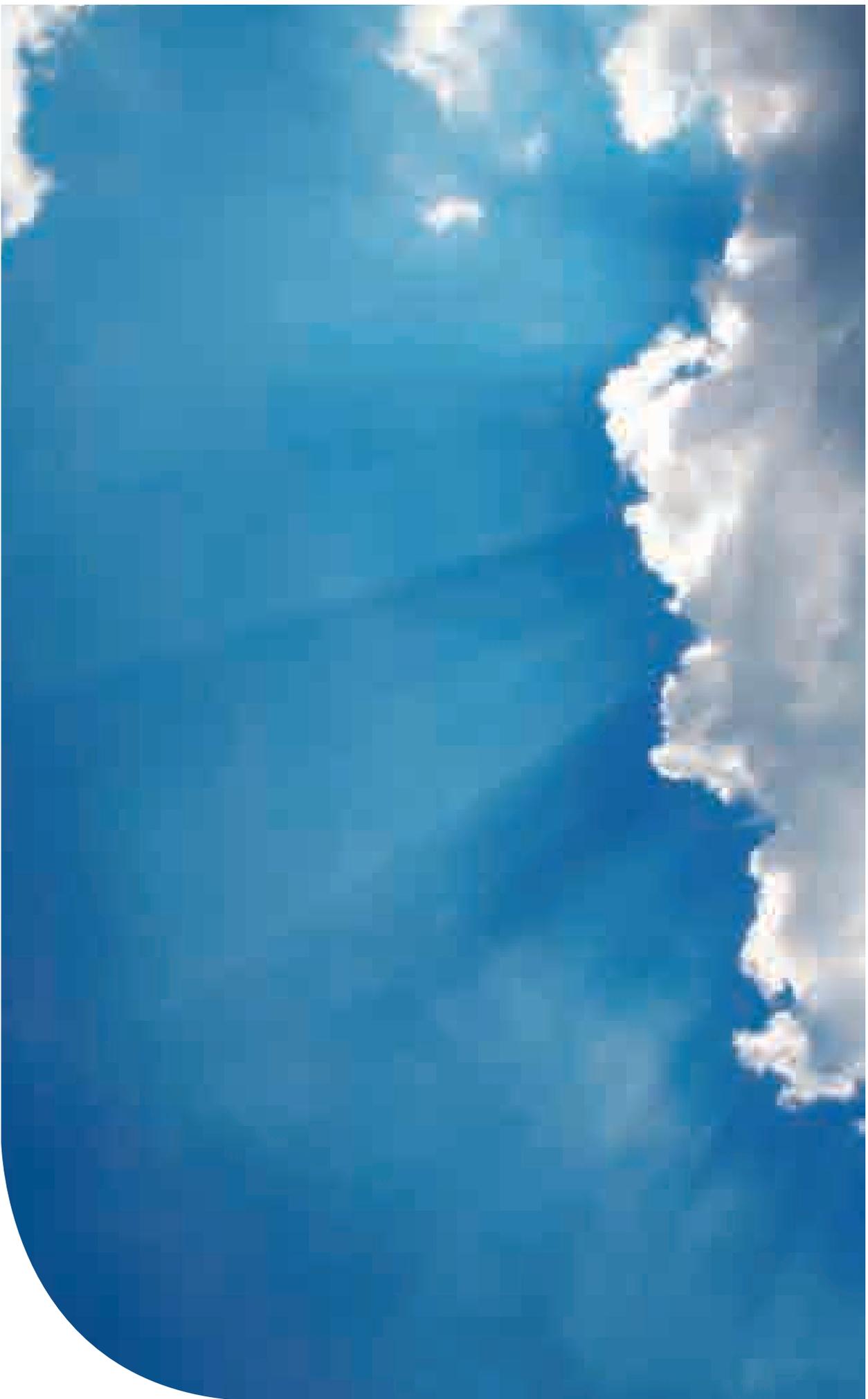
Other modeling studies have investigated scenarios that make different assumptions concerning technology development, policy effectiveness, and country participation. For example, the MERGE model was recently used to evaluate the costs of mitigation under scenarios in which there is not global participation and with alternative technology assumptions.<sup>19</sup> For the technology scenarios, researchers examined scenarios where nuclear power and carbon capture and storage were not available to mitigate GHG emissions in the future. They found that this would not have a large impact on CO<sub>2</sub> prices in the near term (over the next 20 years), but that medium- and long-term CO<sub>2</sub> prices would have to more than double to achieve stabilization if these technologies were unavailable.

The same study also examined the impacts of country participation and policy design by exploring scenarios in which non-Annex I countries do not participate in GHG mitigation efforts until 2050 while Annex I countries set annual reduction targets. In the parlance defined earlier, these alternative scenarios constrain *where* and *when* flexibility by confining reductions to developed (Annex I) countries and by imposing, in those countries, constant annual percent reduction targets that cannot be traded across time. Results from these scenarios suggest that if a relatively stringent stabilization target is chosen (equivalent to the 450 ppm CO<sub>2</sub> target from CCSP), the key to controlling costs is to include all countries in the policy. Achieving the more stringent target without the participation of non-Annex I countries

becomes much more expensive. On the other hand, delaying reductions from developing countries to 2050 had a smaller impact on the CO<sub>2</sub> prices if a less stringent stabilization target (equivalent to the 550 ppm CO<sub>2</sub> target from CCSP or EMF-21) was chosen. The primary driver of CO<sub>2</sub> prices in scenarios with less stringent stabilization targets was whether countries had binding annual reduction targets. Without flexibility to trade reductions across time, the near term prices necessary to achieve stabilization rose dramatically. This happens because the cost-effective profile of emissions reduction opportunities falls by an accelerating amount over time, rather than declining by a constant annual amount (note the curvature in Figure 8, reflecting an acceleration in reductions); this acceleration is particularly strong in the MERGE model.

More generally these studies show that flexibility—in terms of where reductions take place, when reductions are taken, what gases are included, and which technologies are available for mitigation—is an important determinant of cost.

<sup>19</sup> Richels, R., T. Rutherford, G. Blanford, L. Clarke. 2007. *Managing the Transition to Climate Stabilization* Working Paper 07-01, AEI-Brookings Joint Center for Regulatory Studies.





**ISSUE BRIEF 3**

**ASSESSING THE COSTS OF  
REGULATORY PROPOSALS IN  
REDUCING U.S. GREENHOUSE  
GAS EMISSIONS**

JOSEPH E. ALDY

## ASSESSING THE COSTS OF REGULATORY PROPOSALS FOR REDUCING U.S. GREENHOUSE GAS EMISSIONS

Joseph E. Aldy

### SUMMARY

Reducing greenhouse gas (GHG) emissions requires costly changes in behavior for firms and individuals. Various ways exist to measure these costs, but most economic analyses focus on changes in gross domestic product (GDP), prices, employment, and sometimes disaggregated impacts on particular sectors. Two recent studies by the Energy Information Administration (EIA) and the Massachusetts Institute of Technology (MIT) provide insights into the range of costs associated with recent proposals for limiting U.S. GHG emissions over the next several decades.<sup>1</sup> This issue brief further emphasizes impacts in 2015 both because nearer-term modeling results are more reliable, and hence more informative, and because this timeframe is most relevant for the current policy debate.

- A single measure of program stringency—average annual emissions allowed over the 2010–2030 timeframe—is used to facilitate comparisons across different regulatory scenarios. The studies reviewed here consider regulatory proposals that would limit average annual GHG emissions over the 20-year modeling period to actual emissions in the years 1992 and 1996 and forecast emissions for the years 2007, 2008, and 2015. To estimate costs for achieving these emissions limits, all of the studies assume a perfectly efficient, economy-wide cap-and-trade program.

<sup>1</sup> Specifically, we discuss results for the period 2010–2030, because this timeframe matches the available data from EIA and because of the inherent difficulty and uncertainty associated with modeling economic impacts over longer time horizons. This is in contrast to Issue Brief #2, where use of an extended (2010–2050) timeframe is appropriate in discussing longer-term environmental outcomes.

- The carbon dioxide (CO<sub>2</sub>)-equivalent price associated with GHG allowances increases over time in all analyses. In 2015, carbon prices are estimated at \$10 per metric ton CO<sub>2</sub> for the least stringent target and \$50 per metric ton for the most stringent target. By 2030, the least stringent target yields a carbon price of \$15 per metric ton, and the most stringent target \$100 per metric ton.<sup>2</sup>
- Energy prices increase along with CO<sub>2</sub> prices. Electricity prices increase 6–32 percent in 2015 relative to projected business-as-usual electricity prices for that year.
- The near-term GDP and employment impacts of the regulatory scenarios analyzed are modest. Modeled energy price increases are estimated to reduce overall economic output in 2015 by three-tenths to seven-tenths of 1 percent below the business-as-usual GDP forecast. Under the 2007 and 2015 average annual emissions cases, manufacturing employment is estimated to be 0.6–1.0 percent less than the business-as-usual employment forecast. This occurs against a backdrop of 2.9 percent annual growth in GDP and a baseline annual rate of decline in manufacturing employment of one-half of 1 percent over the same period.

The modeling analyses reviewed here show that the United States will bear costs in mitigating GHG emissions, but that these aggregate costs will be small in the context of overall trends. It is worth noting, however,

<sup>2</sup> All price and GDP data in this issue brief are presented in year 2005 dollars.

that all of these analyses assume a regulatory approach that produces cost-effective, economy-wide emissions abatement. Failure to promote least-cost abatement across all emissions sources could increase the costs of a domestic emissions mitigation policy.

## Introduction

Moving the United States off its current GHG emissions trajectory will require policies to change the behavior of firms and individuals. Changing behavior—such as inducing greater investment in and consumption of more energy-efficient and lower-carbon goods and services—imposes costs as firms and individuals take actions and make investments they would not otherwise undertake. A well-designed climate change policy achieves its goal by changing behavior and lowering GHG emissions in a manner that minimizes the disruption to the economy and the costs borne by firms and consumers. This issue brief examines the cost of domestic policies for reducing CO<sub>2</sub> and other GHG emissions based on existing analyses by EIA and MIT that attempt to model the economic impacts of various national emissions-mitigation scenarios.<sup>3</sup>

To provide a basis for understanding and comparing results across different analyses, we begin by reviewing common measures of cost and their key determinants. We then examine recent modeling results for different levels of emissions caps that roughly correspond to the range of targets contained in current legislative proposals. The issue brief concludes with a short discussion intended to put these cost estimates in context and comment on important cost-related issues that lie beyond the scope of existing models.

## Measures of Cost

Various measures of cost may prove informative in the design and implementation of a domestic climate change policy. This section briefly describes the most commonly used cost measures: change in the prices of energy- and emissions-intensive goods, change in economic output (GDP), and change in employment. The section concludes with a brief comment on the sectoral and demographic distribution of costs.

### Energy-Price Changes

A cap-and-trade program or tax on GHG emissions will increase the cost of electricity, gasoline, and other fuels consumers buy, as well as the cost of emissions-intensive goods. It does not matter whether emissions allowances in a cap-and-trade program are auctioned or freely given away; energy prices will increase.<sup>4</sup> These price increases can be translated to costs to households in considering likely impacts on household budgets. Energy price increases are likely to be of particular interest to those concerned about the effects of a climate change policy on the competitiveness of U.S. industry.

### GDP Changes

By changing the behavior of individuals and firms and by inducing them to reallocate their resources, a domestic regulatory regime for limiting GHG emissions will cause economic output to grow more slowly than it would without the policy. These impacts, quantified as GDP, are typically measured relative to a no-policy, business-as-usual forecast. Thus, the costs of GHG regulation generally do not produce absolute reductions in output (GDP) from current levels—rather, they result in lower output than would be expected in the future, absent regulation.

### Employment Changes

Higher prices for energy- and emissions-intensive goods can reduce the rate of employment growth through several channels. First, slower growth in the economy will slow the rate of job creation. Second, an increase in energy prices effectively increases the costs of virtually all goods, and this reduces the buying power of workers' wages. Effectively lower real wages could reduce the incentive for some individuals to work.

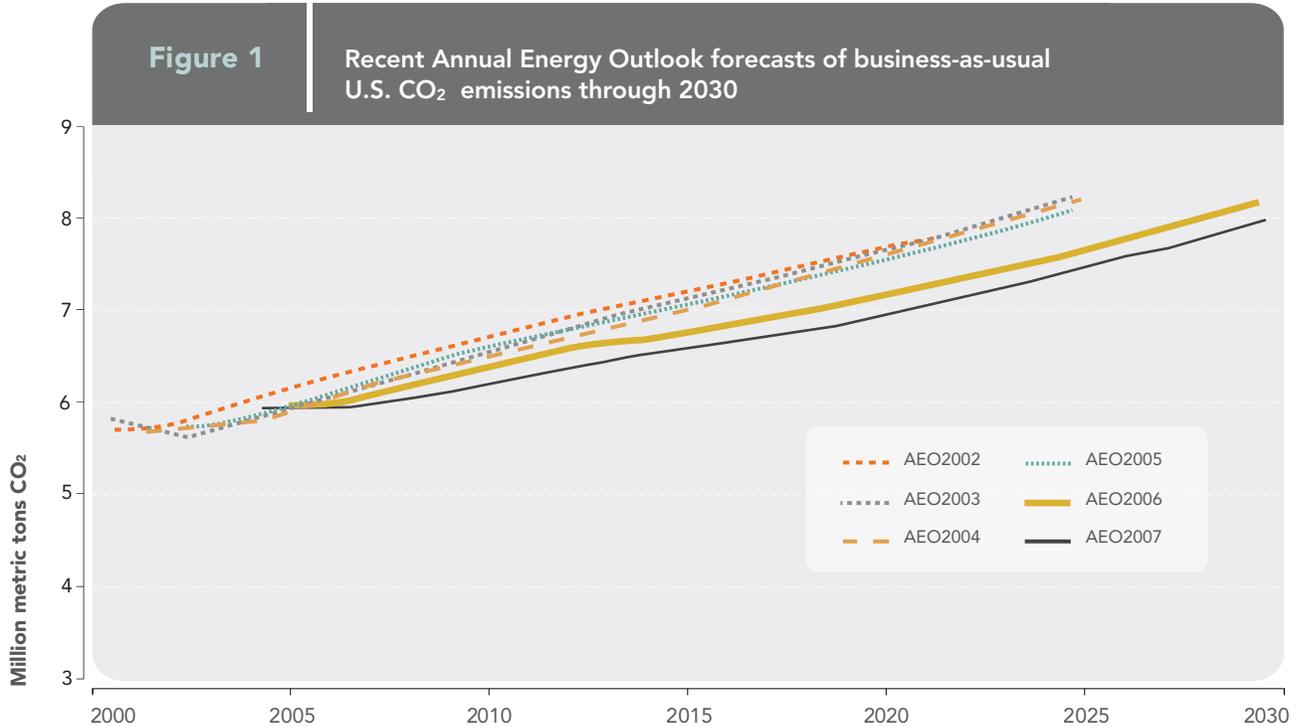
### Distribution of Costs

Climate policies could yield fairly modest changes in aggregate economic output or employment but impose substantial costs on specific industries or demographic groups. For example, output in emissions-intensive industries could decline much more than the average for U.S. industry as a whole, and low-income households could be more adversely affected by higher energy prices than typical households.<sup>5</sup>

<sup>3</sup> We focus on the EIA and MIT results as these have been the only analyses to consider a range of emissions-reductions targets consistent with recent U.S. policy proposals. Other studies, discussed in Issue Brief #2, have modeled scenarios that assume U.S. participation in a cost-effective global effort to stabilize atmospheric GHG concentrations at various levels.

<sup>4</sup> Electricity price increases may vary with the share of allowances auctioned versus freely allocated in states that have not deregulated their electricity markets and still require public utility commissions to set retail electricity rates.

<sup>5</sup> Industry-specific impacts are discussed in more detail in Issue Brief #7, which addresses competitiveness concerns.



## Key Determinants of Cost in Domestic Regulatory Programs

The cost of any effort to constrain GHG emissions in the U.S. economy will be a function of several factors, including the stringency of the policy relative to the business-as-usual emissions path, what opportunities exist for energy efficiency and fuel switching, which emissions sources are covered, whether emissions offsets are allowed under the policy, and how revenues from a carbon regulatory regime are used.

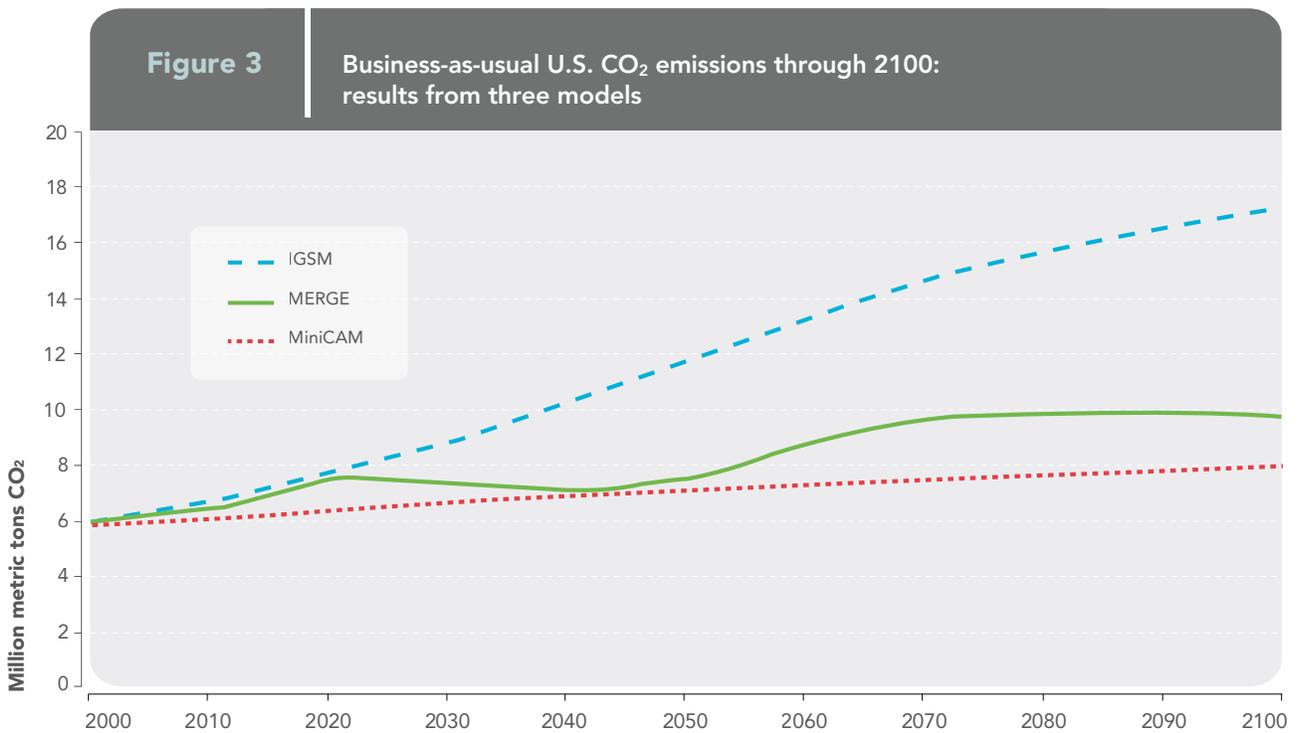
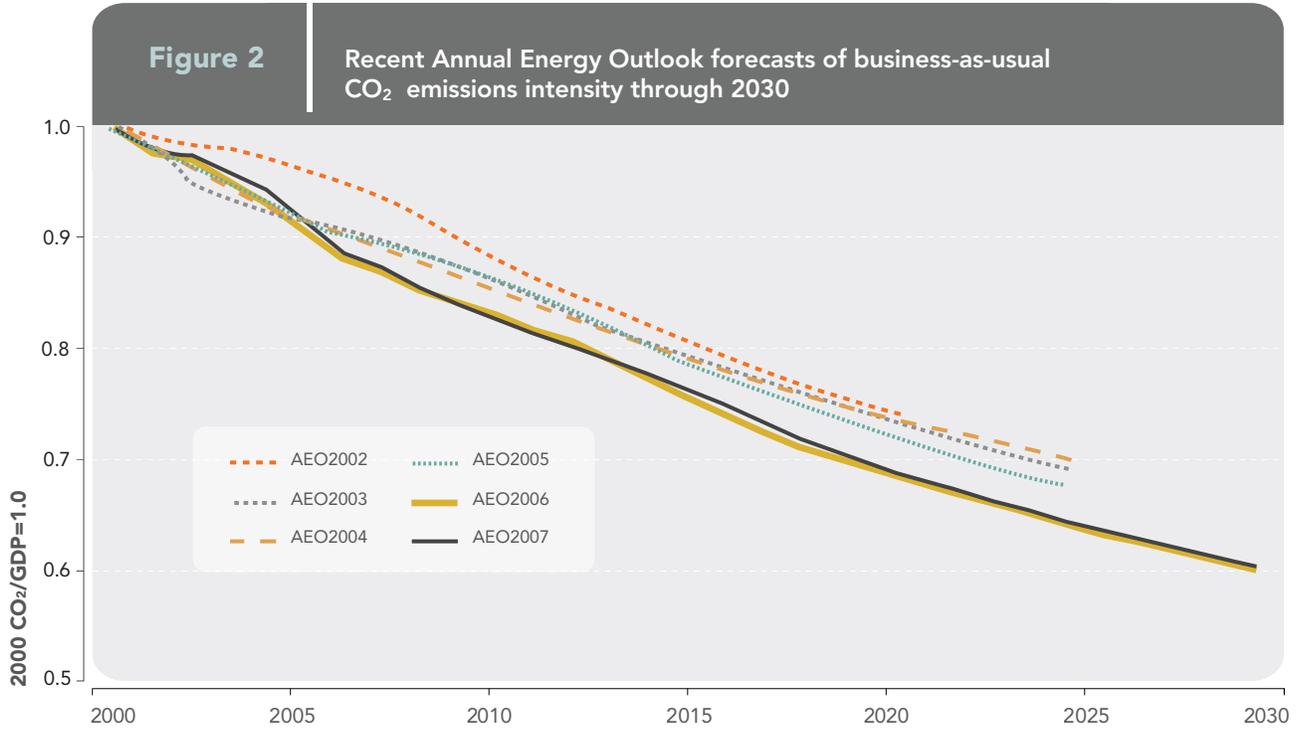
Abating GHG emissions imposes costs on society because individual consumption and firm investments must be changed to produce a shift away from the business-as-usual emissions path. Evaluating the cost of any GHG-reduction policy requires an explicit comparison between business-as-usual emissions and expected emissions under the new policy. Emissions forecasts, in turn, are driven by a variety of factors, including the rate of economic growth, population growth, and the effect of higher prices on the energy intensity of economic output and the carbon intensity of energy consumption.

EIA produces forecasts of business-as-usual CO<sub>2</sub> emissions as a part of its Annual Energy Outlook (AEO) report. Due primarily to a recent increase in energy prices, EIA's 2006 and 2007 AEO

reports have estimated lower business-as-usual emissions for the next 20-plus years than forecasts published earlier this decade (Figure 1). Specifically, EIA's current forecast for U.S. CO<sub>2</sub> emissions in 2010 shows a 7 percent increase over year 2000 emissions; by 2020, forecast emissions are 20 percent above year 2000 levels. These forecasts reflect an assumption that the emissions intensity of the economy—defined as the ratio of CO<sub>2</sub> emissions to GDP (see Figure 2)—will continue to decline. Specifically, the emissions intensity of the U.S. economy is forecast to decline 17.6 percent between 2000 and 2010 and 31 percent between 2000 and 2020, with an annual rate of change of 1.7 percent over the 2000–2030 timeframe. These more recent business-as-usual forecasts suggest that the estimated costs of achieving a given quantitative emissions cap or intensity-based target could be lower now than under the pre-2006 forecasts.

To complement the EIA forecasts, the U.S. Climate Change Science Program recently commissioned three models to estimate business-as-usual CO<sub>2</sub> emissions for the United States through 2100. Figure 3 presents results obtained from Pacific Northwest National Laboratory's MiniCAM model, Manne and Richel's MERGE model, and MIT's IGSM model (which includes the EPPA model reviewed below).<sup>6</sup>

<sup>6</sup> For more information about these models, refer to: <http://www.pnl.gov/gtsp/research/minicam.stm> (MiniCAM); <http://www.stanford.edu/group/MERGE/> (MERGE); and <http://web.mit.edu/globalchange/www/if.html> (IGSM).



The cost of moving from business as usual to a new, lower emissions path depends on the rate and magnitude of the required change. EIA studies of the economic impacts of implementing the Kyoto Protocol, for example, found high costs because, under some scenarios, the Protocol would have required dramatic emissions reductions over a relatively short period of time—such as reducing U.S. emissions 7 percent below 1990 levels by 2010. Policies that aim to take advantage of the natural timing of consumer and firm decisions—particularly those that allow dramatic emissions reductions to be delayed until the capital stock adjusts and new technologies are developed—can reduce the costs of achieving a particular long-term goal.

In general, the easier it is to switch to low- and zero-carbon energy sources, the lower the costs of mitigating CO<sub>2</sub> emissions. For example, a key driver of abatement costs in the electricity sector will be the cost of natural gas relative to coal. This is because switching from coal to natural gas—which generates 40 percent lower CO<sub>2</sub> emissions per unit of primary energy supplied than coal—is an important near-term mitigation strategy *if* additional natural gas is available at a reasonable price. Over time, the cost of abatement will also reflect the potential for nuclear and renewable sources of power to substitute for all fossil fuels in electricity generation, as well as the potential for carbon capture and storage technology to be incorporated in fossil-fuel generation plants. The scope for investment in energy-efficiency improvements also influences the estimated cost of mitigating emissions.

Program coverage is another important factor in determining costs. Most models assume that all sources in a given region are equivalently covered by an emissions trading program and produce cost estimates consistent with an economy-wide program. In reality, many policies, especially those focused only on large emitters, will exclude some fraction of mitigation opportunities. Sector-specific approaches have also been proposed—for example, emissions from electricity generation could be regulated separately from transportation sector emissions. The estimated costs of a fragmented and/or non-price policy<sup>7</sup> would be higher than model estimates of an integrated, economy-wide trading program because a fragmented and/or non-price policy generally precludes or limits the ability to substitute cheaper abatement options for more expensive forms of mitigation wherever those options exist.<sup>8</sup>

The inclusion of alternative compliance mechanisms will also influence program costs. For example, many policies propose using offsets—emission-reduction credits generated by sources not covered under an overall emissions cap—either domestically or internationally. Projects that reduce emissions from uncovered sources would be allowed to generate emissions abatement credits that could be used by covered sources to satisfy their obligations under either a cap-and-trade or tax regime. Allowing offsets typically lowers the estimated cost of achieving a particular emissions target for covered sources, but the availability, quality, and transaction costs associated with offsets are highly uncertain.<sup>9</sup> In many cases, modeling analyses of programs with offsets make alternative ad hoc assumptions to examine the sensitivity of cost estimates to various possibilities. In the discussion that follows, we focus on direct U.S. GHG emissions without considering the impact of offset provisions for either domestic biological sequestration or international projects.

A final issue in analyzing regulatory cost concerns the use of revenues from an emissions tax or from the sale of emission allowances under a cap-and-trade policy. Some program designs can generate revenues that would allow the government to offset existing taxes. For example, if the government implemented an emissions tax to stimulate private-sector emissions abatement, then revenues from the tax could allow taxes on labor or capital to be reduced in a revenue-neutral manner.<sup>10</sup> In some models, these changes can have aggregate consequences by increasing the overall efficiency of the tax system; that is, reducing taxes on labor or capital will increase the supply of those factors, raising GDP. Most economic modeling analyses show that such revenue recycling can reduce some, but not eliminate all, of the costs of an emissions tax or cap-and-trade program. In the discussion that follows, we ignore revenue-recycling effects.

## Overview of Major Domestic Regulatory Proposals

In the 109<sup>th</sup> Congress, a dozen bills were drafted that would impose mandatory climate-change regulations on part or most of the U.S. economy. As of the summer recess of the 110<sup>th</sup> Congress, in August 2007, more than a half-dozen cap-and-trade proposals had been introduced in the Senate, and several more in the House. Several bills have also proposed a tax on GHG emissions. It is beyond the scope of this issue brief to provide a detailed review of each of these proposals,

7 We use the term “non-price policy” to refer generically to traditional forms of regulation such as performance standards, technology mandates, etc. For further discussion of different regulatory approaches, see Issue Brief #5.

8 The cost implications of different policy-design decisions—such as program coverage and scope, flexibility, reliance on price signal vs. traditional regulation, etc.—are discussed in Issue Briefs #4, #5, and #10.

9 See Issue Brief #15 on offsets.

10 See further discussion in Issue Brief #5 (on different regulatory strategies) and Issue Brief #6 (on allocation).

## Abating GHG emissions imposes costs on society because individual consumption and firm investments must be changed to produce a shift away from the business-as-usual emissions path.

but this section will highlight a few key elements common to several of them.<sup>11</sup>

In the Senate, specific legislative cap-and-trade proposals have been introduced by Senators Bingaman and Specter, Boxer and Sanders, Feinstein and Carper, Kerry and Snowe, Lieberman and McCain, and Alexander (co-sponsored with Lieberman); on the House side, Congressmen Udall and Petri and Waxman have sponsored bills. All proposals except for the Feinstein-Carper and Alexander-Lieberman bills, which focus on the electricity sector, address all six important types of GHGs<sup>12</sup> across all or a large part of the U.S. economy. Congressmen Stark and Larson have each proposed bills to establish an economy-wide tax on the carbon content of fossil fuels.

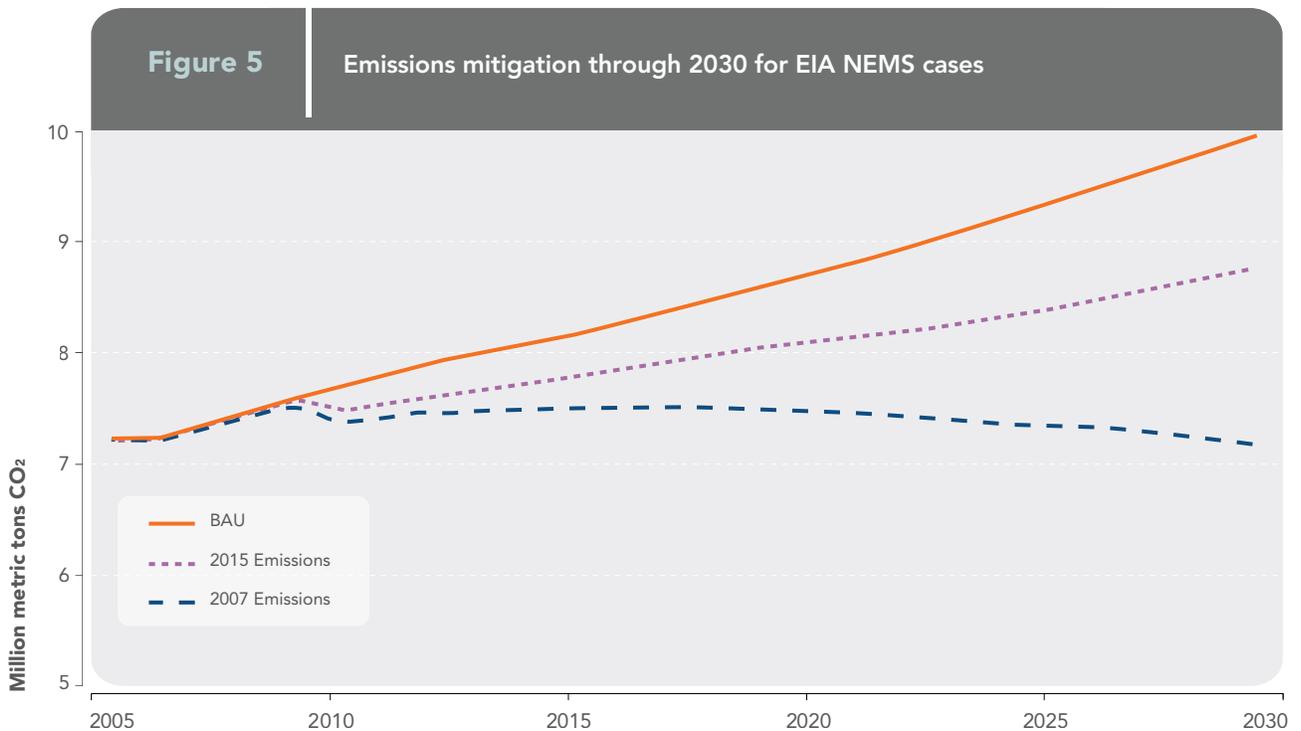
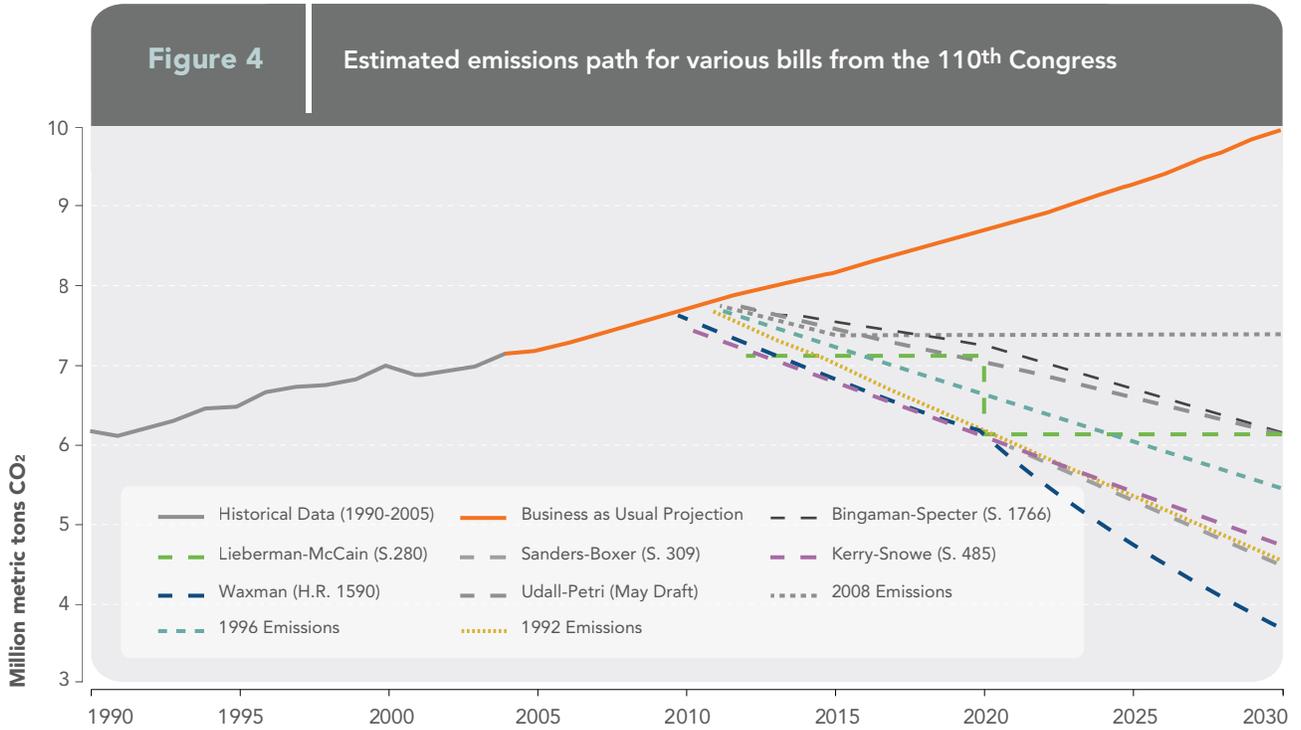
Current cap-and-trade proposals would institute emissions targets starting between 2011 and 2020, and run out through at least 2050. Some bills propose emissions targets in the form of a cap that declines by a fixed percentage every year; others would establish new targets every 10 years. Earlier versions of the Bingaman-Specter bill set emissions targets based on a declining carbon-intensity objective; by contrast, the current version of the bill calls for reducing emissions to 2006 levels by 2020 and 1990 levels by 2040. The Sanders-

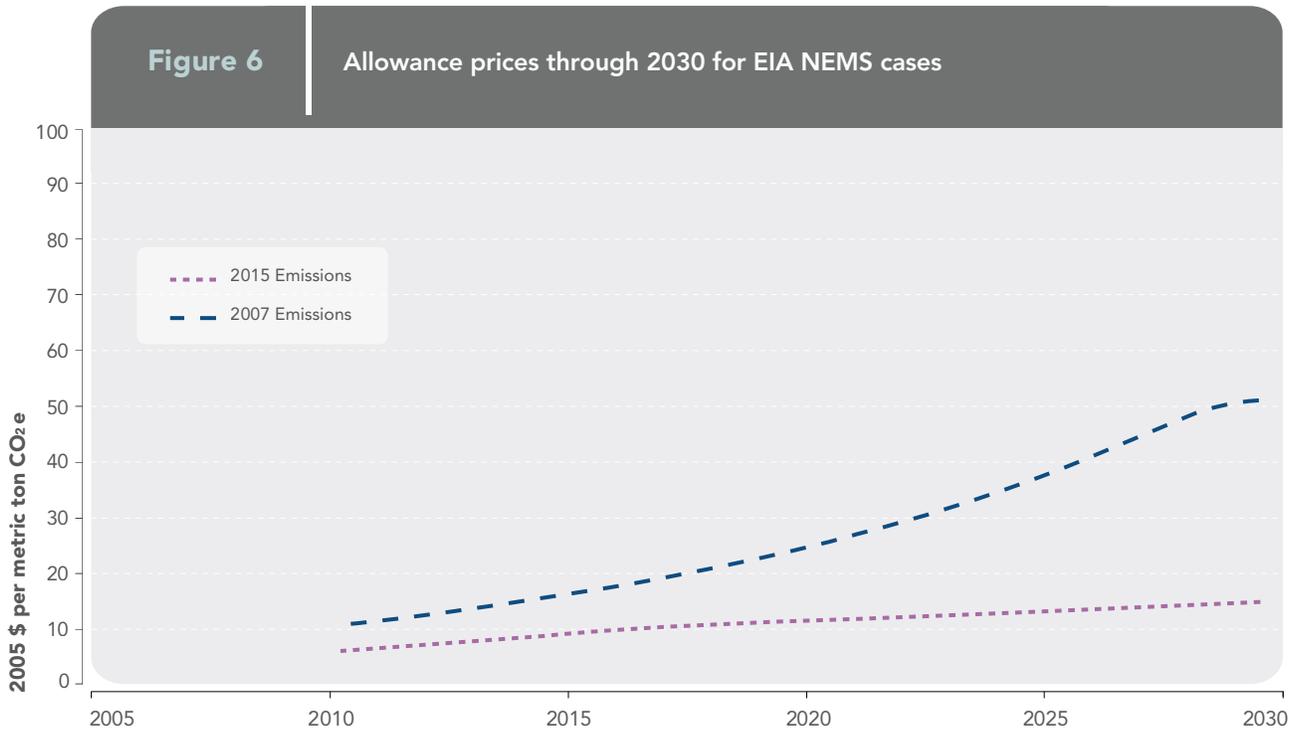
Boxer proposal sets a long-term goal of stabilizing the atmospheric concentration of CO<sub>2</sub> at 450 parts per million. The Bingaman-Specter and Udall-Petri proposals include a “safety valve” mechanism designed to provide cost certainty and limit the potential for adverse economic impacts. Both bills would provide regulated firms the opportunity to purchase an unlimited number of additional allowances at a predetermined price; this price would rise each year at a known rate to provide a steadily stronger incentive for emissions abatement over time. The starting price of the safety valve in recent proposals that contain this feature has ranged from about \$7 to \$12 per metric ton of CO<sub>2</sub>, and the proposed rate of increase in this price for future years has been set at 5 percent per year. The current Bingaman-Specter legislation specifies that this annual increase is in addition to inflation—that is, the safety valve price rises 5 percent per year in real rather than nominal terms.

Current legislative proposals also vary in how they account for offsets, especially from agricultural and forestry activities, and in terms of the rules they propose for banking and borrowing emissions allowances. The different emissions trajectories implied by these proposals through 2030 are presented in Figure 4. Actual U.S. emissions under these targets in any given year will depend on the extent that various cost-containment measures—such as banking and borrowing, offsets, or a safety valve—are employed by regulated firms. In addition, emissions will depend on which sources are included and excluded from the policy (the targets in the figure all assume economy-wide coverage). The Lieberman-McCain legislation proposes a step-like emissions path in which targets are lowered once every ten years, while other proposals employ emissions targets that change annually. The dashed lines in the figure refer to emissions scenarios modeled by the MIT Joint Program on the Science and Policy of Climate Change (“Assessment of U.S. Cap-and-Trade Proposals,” April 2007, Report no. 146). These dashed lines provide a basis for comparing modeling results to policy proposals currently under consideration. The MIT 2008 emissions scenario lies above the Bingaman-Specter and Udall-Petri emissions paths; the MIT 1996 emissions scenario achieves a 2030 emissions target similar to that proposed by McCain-Lieberman; and the most ambitious MIT scenario, in which annual average emissions for 2010–2030 are equal to 1992 emissions, is similar to the Kerry-Snowe and Sanders-Boxer emissions paths.

<sup>11</sup> Additional bills by Senators Lieberman and Warner, and by Congressman Dingell, were under discussion as this issue brief went to press. Updated information on current Congressional proposals is available at: [www.rff.org/climatechangelegislation](http://www.rff.org/climatechangelegislation).

<sup>12</sup> The relevant types of greenhouse gases covered by these proposals include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.





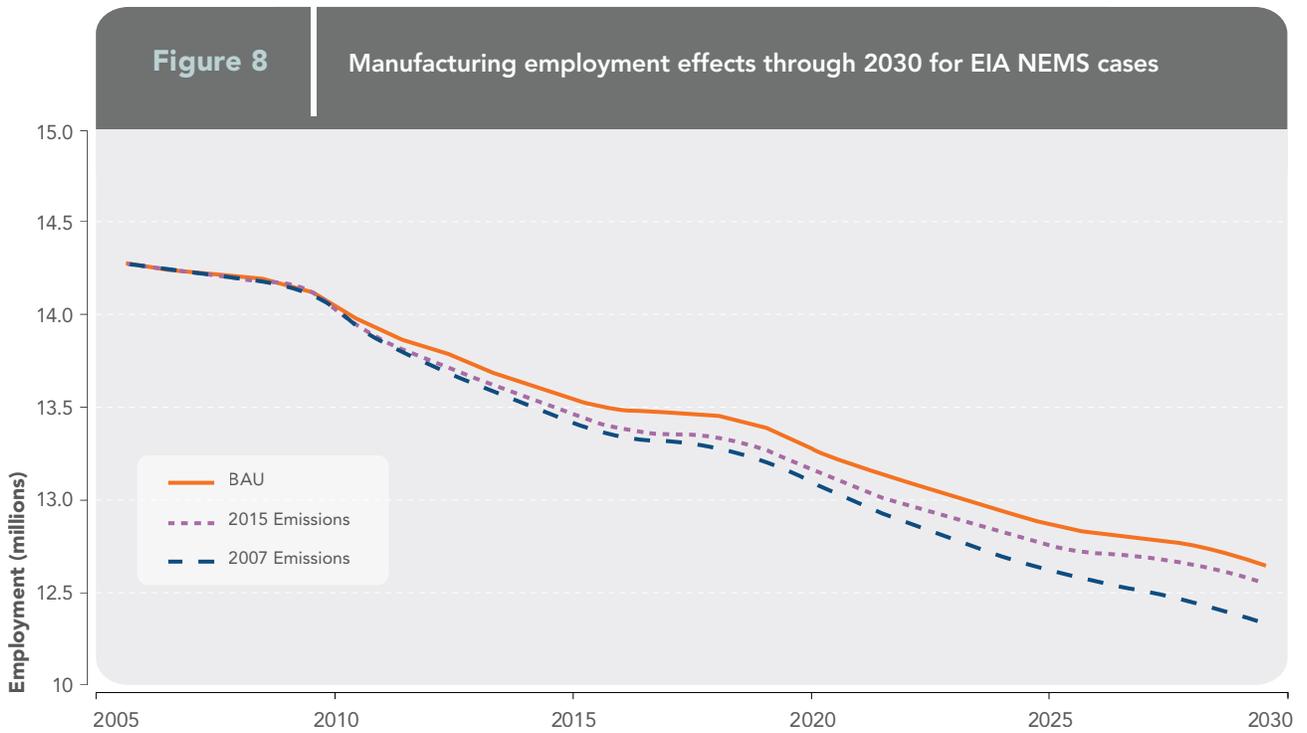
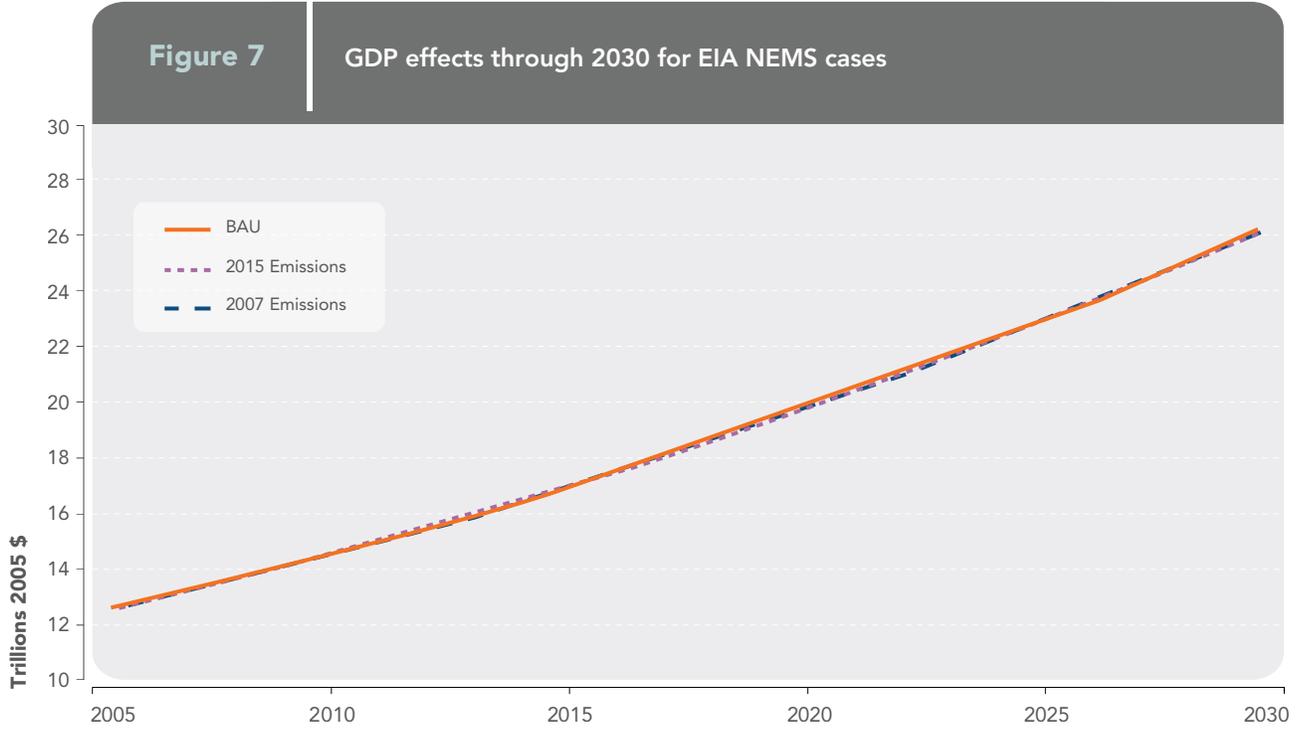
## Results from Several Recent Economic Modeling Analyses

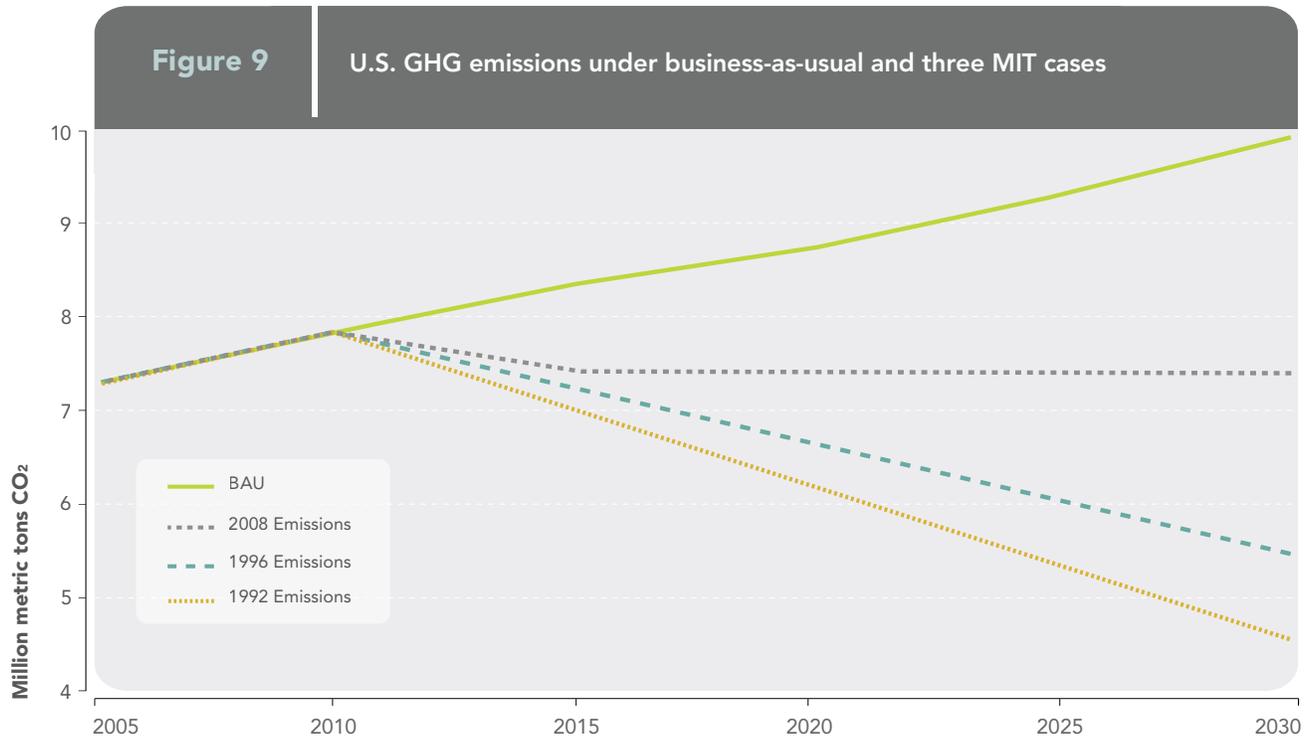
Numerous models have been developed to assess the economic impacts of cap-and-trade programs and emissions taxes. The EIA National Energy Modeling System (NEMS) model represents the U.S. energy system and economy in one-year periods and is better oriented to assess short-term economic impacts. NEMS is typically run for 20–25 years into the future. We also present results from the MIT EPPA model, which runs in five-year periods, accounts for all types of GHG emissions, and is better designed to evaluate the longer-term effects of policies. Recent MIT analyses of three “representative” policy scenarios (the dashed lines in Figure 4) run through 2050.

EIA has used the NEMS model to evaluate mitigation policies assuming different GHG cap levels and safety-valve prices (“Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals,” March 2006, SR/OIAF/ 2006-01). The resulting cost estimates show the effect of imposing

carbon prices<sup>13</sup> that result in average annual GHG emissions equal to year 2015 and 2007 forecast emissions over the 2010–2030 time period. The 2015 emissions scenario is based on EIA’s modeling of emissions targets that reflect an annual reduction in the emissions intensity of the overall economy (metric tons per dollar of GDP output) of 2.6 percent per year between 2010 and 2019 and 3.0 percent per year thereafter, coupled with a safety valve price that starts at a little less than \$9 per metric ton of CO<sub>2</sub> in 2010 (measured in 2005 dollars). The 2007 emissions scenario reflects more ambitious emissions targets—corresponding to a 3.0 percent annual reduction in emissions intensity between 2010 and 2019 and a 4.0 percent per year reduction between 2020 and 2030—and a safety valve price starting at more than \$30 per metric ton of CO<sub>2</sub> in 2010. Figure 5 shows the emissions pathways for the business-as-usual, 2015 emissions, and 2007 emissions scenarios. The first policy scenario slows emissions growth, while the second begins by slowing growth and then yields a decline in absolute emissions below current levels.

<sup>13</sup> Throughout this issue brief, we use the terms “carbon price” or “price per metric ton of CO<sub>2</sub>” to refer to the allowance price that would apply to all GHGs included in the policy based on a conversion to CO<sub>2</sub>-equivalent emissions.





Emissions reductions relative to the business-as-usual reference case are driven by the implementation of a cap-and-trade program coupled with a safety valve price that increases over time. Figure 6 shows allowance prices (in dollars per metric ton of CO<sub>2</sub>) over the 2010–2030 period for these two cases. By 2015, allowance prices range from \$9 to \$16 per metric ton, and increase to \$14–\$50 per metric ton in 2030. The faster growth in allowance prices in the 2007 emissions case reflects the much more substantial deviation from business-as-usual emissions achieved under this scenario over time.

Figure 7 shows that macro-economic impacts—in terms of change in forecast GDP—are very small at the CO<sub>2</sub> emissions and price levels modeled in the EIA NEMS scenarios. Specifically, the estimated reduction in overall GDP in these two cap-and-trade cases is between one-fifth and three-fifths of 1 percent below the business-as-usual forecast for 2030. This reduction is small compared to underlying economic trends which, according to NEMS, project an approximate doubling of economic output from 2005 to 2030—as a result the lines in Figure 7 are barely distinguishable. Modeled impacts on aggregate, economy-wide employment are similarly small: in the 2007 emissions case, total non-farm employment in 2030 is reduced by 700,000 jobs compared to

the business-as-usual case, but this impact is minimal relative to a forecast increase of nearly 40 million jobs between 2005 and 2030.

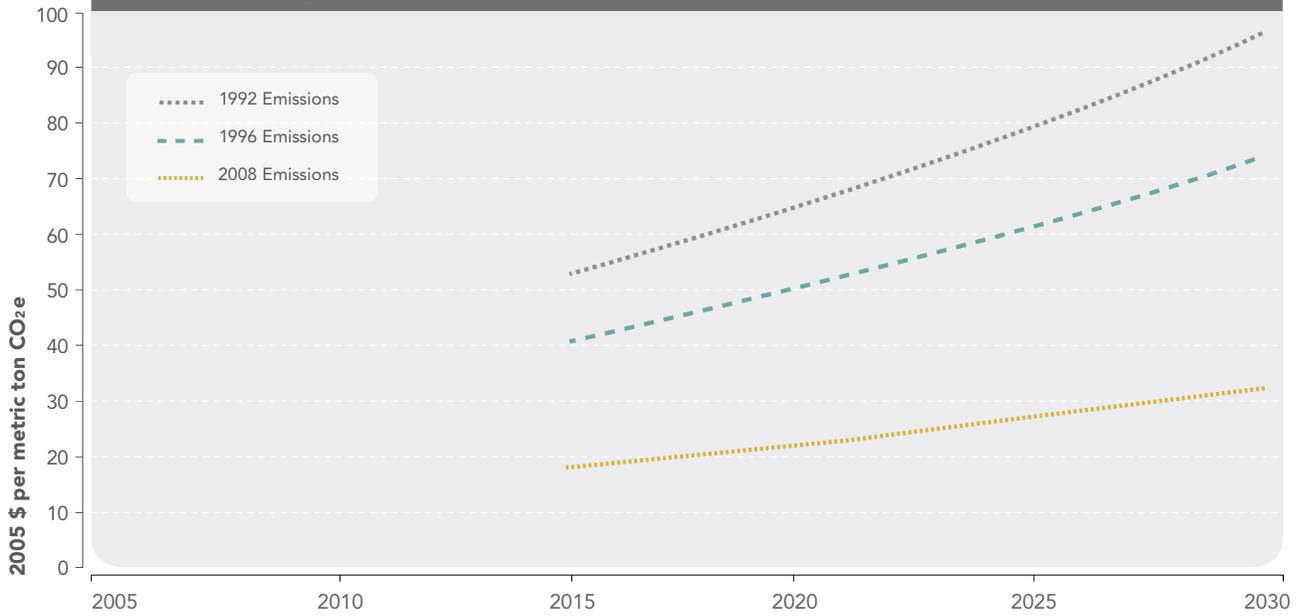
Estimated impacts on aggregate GDP and employment, however, can mask sector-level changes in consumption and production that are more significant. In other words, the policies being analyzed can produce shifts within the economy that are not immediately visible in overall national-level results. The cap-and-trade programs actually spur an additional \$10–\$20 billion of investment in 2030 compared to the business-as-usual case, and consumption losses equal the decline in GDP. Nearly half of estimated job losses by 2030 as a result of GHG regulation occur in the manufacturing sector; thus, as shown in Figure 8, impacts on manufacturing employment specifically are more significant than impacts on overall non-farm employment.

### MIT EPPA Model

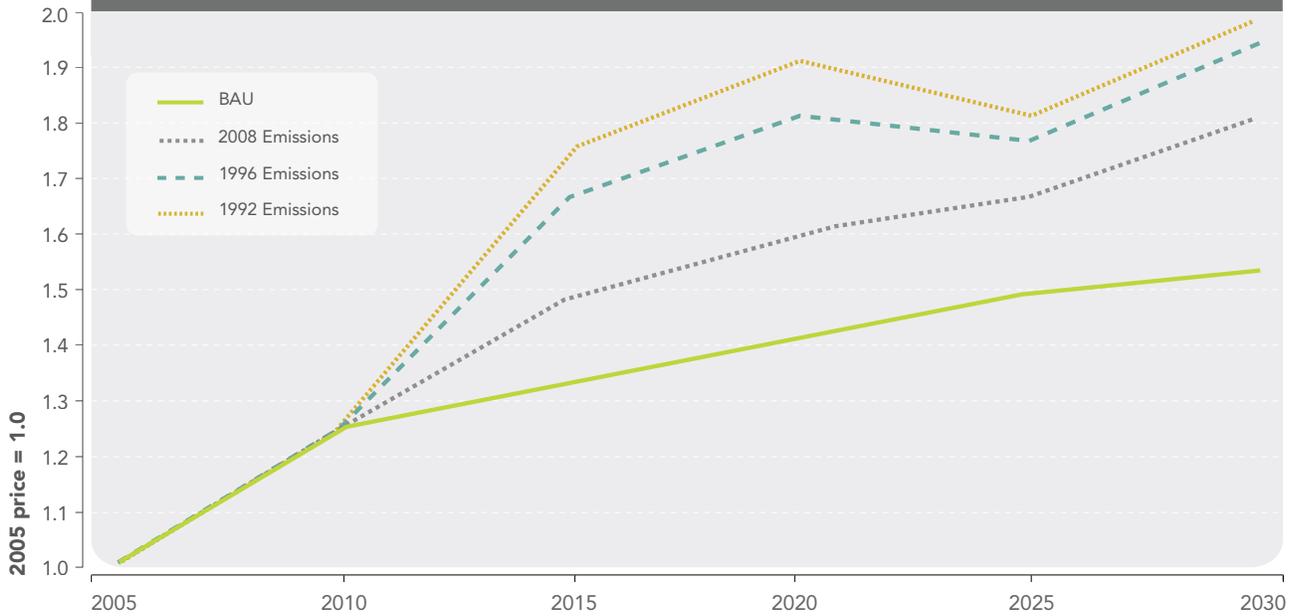
The MIT modeling group recently evaluated three emissions scenarios represented by the dashed lines in Figures 4 and 9.<sup>14</sup> The top line represents average annual GHG emissions equal to 2008 emissions over the 2010–2030 time period. We refer

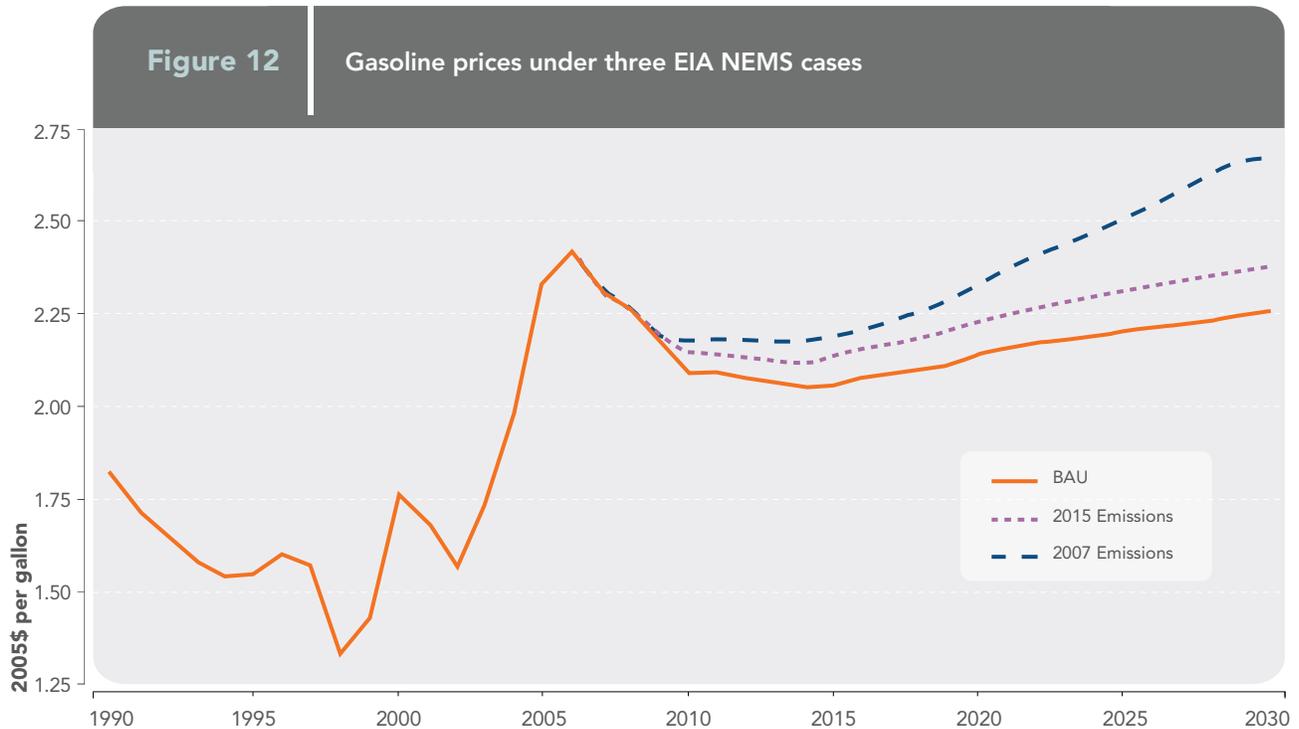
<sup>14</sup> To facilitate comparisons with the EIA results, we have relabeled the MIT cases which are denoted by cumulative emissions in billion metric tons (bmt) allowed over the 2012–2050 time period. The 2008 emissions case corresponds to MIT's 287 bmt case, the 1996 emissions case corresponds to MIT's 203 bmt case, and the 1992 emissions case corresponds to MIT's 167 bmt case.

**Figure 10** U.S. allowance prices under three MIT cases



**Figure 11** Forecast U.S. electricity prices for three MIT cases compared to business as usual





to the second dashed line as the 1996 emissions scenario; this emissions path is similar in stringency to the Lieberman-McCain proposal. The third dashed line, representing the 1992 emissions scenario, is similar to the most ambitious proposals put forward to date in Congress, such as the Sanders-Boxer, Kerry-Snowe, and Waxman bills. These emission targets yield the economy-wide allowance prices presented in Figure 10.

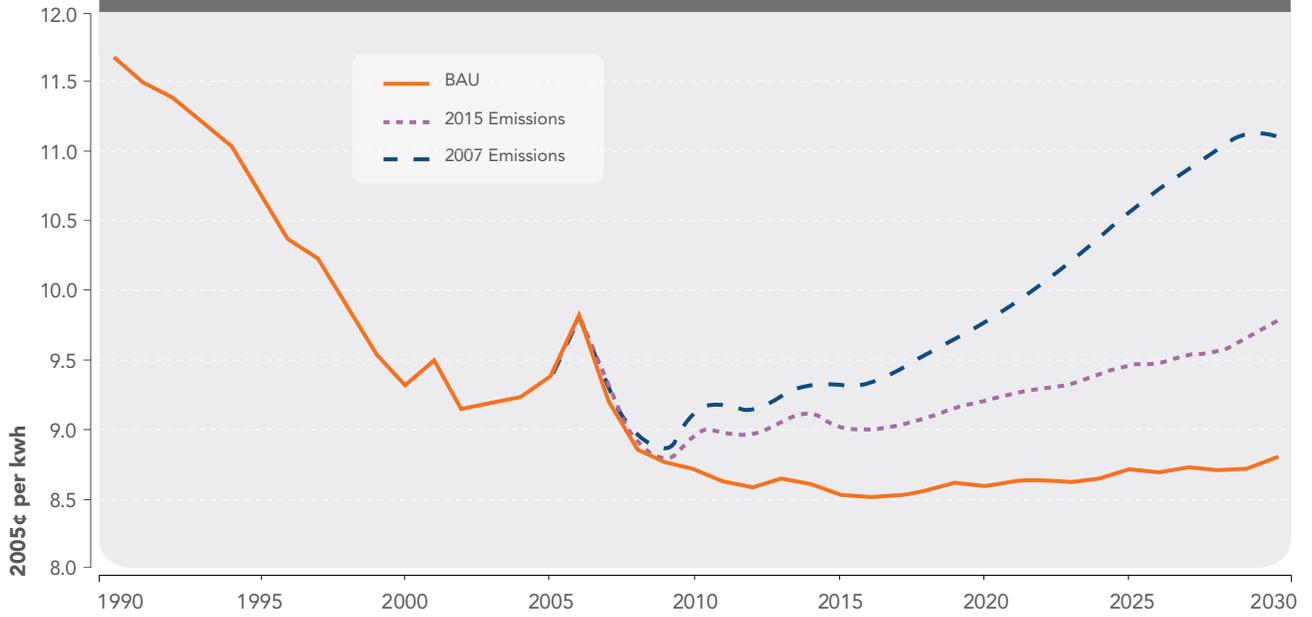
Not surprisingly, near-term (2015-2020) allowance prices for the MIT 2008 emissions case are similar to the EIA 2007 emissions case. As shown in the original MIT analysis, maintaining the target for an additional 20 years through 2050 increases the allowance price over time. The more stringent MIT 1996 and 1992 emissions cases yield much higher allowance prices. As in the EIA NEMS scenarios, however, the macro-economic GDP impacts, relative to the business-as-usual forecast, are small (in other words, a graph of the MIT results for overall GDP would produce virtually indistinguishable lines, as in Figure 7). In percentage terms, estimated GDP impacts for 2015 range from two-tenths to seven-tenths of 1 percent. Consumption falls more than GDP, as the cap-and-trade policies stimulate additional investment relative to business as usual. In 2030, GDP in the most ambitious 1992 emissions case is \$144 billion below the business-as-usual forecast, but consumption is nearly \$400

billion below business as usual. Again, sector-level impacts are somewhat more significant as can be seen in Figure 11, which illustrates the modeled impact on electricity prices. The MIT model does not produce estimates of employment impacts.

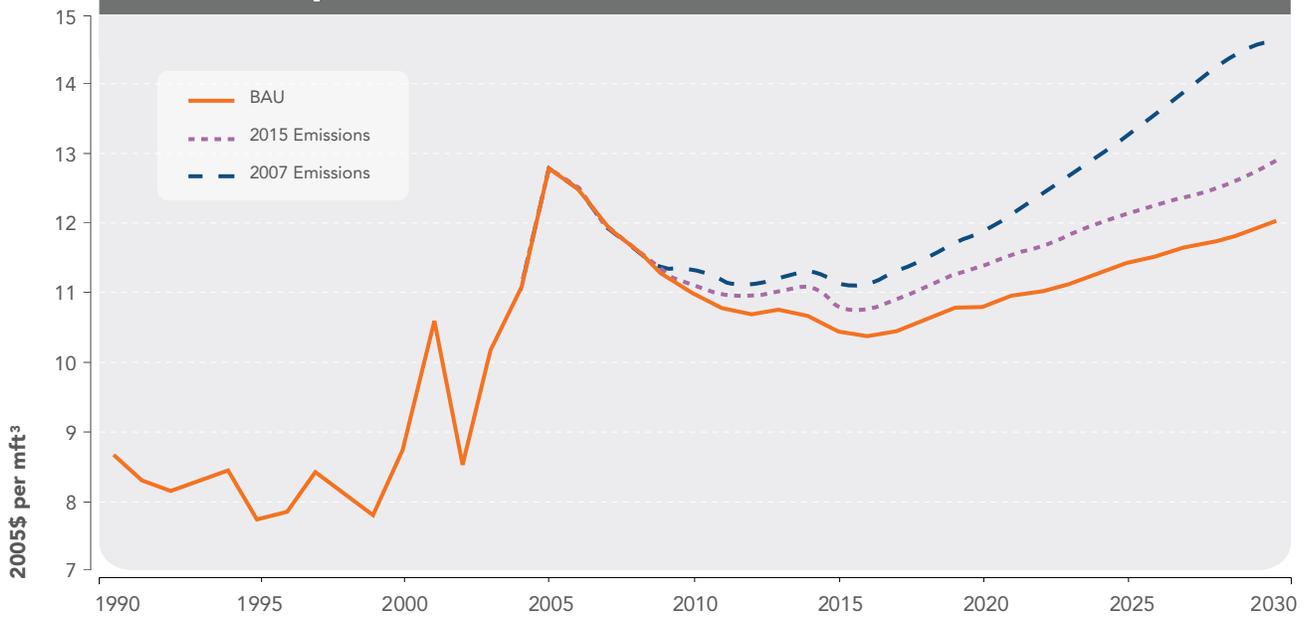
## Putting Costs in Context

Economists assess the efficiency of policies by comparing the cost of the last incremental effort (marginal cost) with the benefit of that last unit of effort (marginal benefit). A policy is efficient—that is, it maximizes net monetized benefits to society—when the benefit and cost of the last incremental effort are the same. It is beyond the scope of this issue brief to evaluate recent analyses of the benefits of reducing GHG emissions, but a brief comparison of recent cost estimates with efforts to estimate the benefits of an efficient policy can be instructive. William Nordhaus of Yale University has modeled the benefits and costs of climate change policy for several decades. In his most recent analysis of climate change policy, he finds that the optimal price on GHG emissions (in 2005 dollars) starts at \$6.40 per metric ton of CO<sub>2</sub> in 2007 and increases steadily over time to more than \$80 per metric ton of CO<sub>2</sub> in 2050 and about \$200 per metric ton in 2100. Richard Tol conducted a recent survey of the relevant economic literature and found that most estimates of the benefits of

**Figure 13** Electricity prices under three EIA NEMS cases



**Figure 14** Natural gas prices under three EIA NEMS cases



mitigating GHG emissions do not exceed \$14 per metric ton of CO<sub>2</sub>-equivalent in the near term. The recent *Stern Review: The Economics of Climate Change* arrives at larger estimates for the benefits of mitigating emissions, on the order of \$85 per metric ton of CO<sub>2</sub>.

In the political arena, of course, debate tends to focus on energy-price impacts, rather than on abstract notions of cost and benefit. To provide context for that discussion, Figures 12–14 illustrate price impacts for gasoline, electricity, and natural gas in the three EIA cases relative to both the business-as-usual forecast and actual price trends since 1990. These figures show that the modeled policies cause a change in energy prices that is not insignificant, but that is considerably more gradual than the energy price spikes experienced in recent years.

A final prism through which to view the costs of domestic policy options is in relation to the costs being incurred by other countries that are trying to limit GHG emission. The European Union launched its Emissions Trading Scheme (EU ETS) in 2005. The program covers most large point sources of CO<sub>2</sub> emissions, such as power plants and industrial boilers. In the first 18 months of Phase I of the ETS (2005–2007), allowance prices ranged between \$10 and nearly \$30 per metric ton of CO<sub>2</sub>. During the summer of 2007, EU ETS allowances for 2008 traded at about \$19–\$21 per metric ton

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Based on an array of cost measures, the modeling analyses reviewed here indicate that a modest policy designed to ramp up over time (either through more stringent emissions caps or an increasing emissions tax) would not adversely affect the U.S. economy.

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CO<sub>2</sub> (about \$26–\$29 per metric ton at current exchange rates). These allowance prices are similar to those estimated over the next two decades by EIA (for its 2007 emissions scenario) and by MIT (for its 2008 emissions scenario).

## Important Cost-Related Issues and Questions Outside the Scope of the Models

It is important to note that most efforts to model cost are optimistic to the extent that they assume efficient policies and cost-effective abatement. Thus, for example, all the studies summarized here implicitly assume zero transaction costs for trading. They further assume that all cost-effective abatement opportunities are pursued and realized throughout the economy. This emphasis on complete *where, when, and what* flexibility may not accurately describe the actual implementation of a cap-and-trade program. In addition, it ignores the costs incurred by firms (and borne by shareholders and consumers) for monitoring emissions, engaging in trading (or submitting tax payments), and other related administrative costs. These costs could be a substantial share of compliance costs, depending on firm size (small firms have fewer emissions over which to spread their fixed costs) and on the nature of required monitoring technology (continuous emissions monitors, such as on power plant smokestacks, are relatively expensive, whereas monitoring fuel use and applying emissions factors is relatively cheap).

In the real world, of course, the idealized conditions described above may not obtain. Moreover, policies as actually proposed and eventually implemented may differ from the policies modeled. The aggregated nature of available energy-economy models, both across time and across industries, inevitably requires that a number of simplifying assumptions be made in the modeling process. For example, most models cannot account for the Lieberman-McCain proposal's use of a size threshold (10,000 metric ton CO<sub>2</sub>-equivalent per year) to determine whether a facility is covered by the cap-and-trade program. Models that account for offsets typically have to make ad hoc assumptions about the cost and supply of offsets outside the modeled program. Finally, a variety of other components in many current policy proposals, such as technology programs and supply regulations, would have effects on the economy and on energy markets that are distinct from setting an emissions cap and cannot be readily captured by the models. Incorporating all these factors may influence predicted economic impacts, although it is not immediately clear whether more detailed

modeling of a given policy would tend to increase or reduce associated cost estimates.

An important source of uncertainty in interpreting model results relates to how labor markets are likely to respond to higher energy prices. Some of the high costs that have been estimated for domestic climate change policies over the past 10 years are largely driven by an assumption that labor supply is quite responsive to energy prices. In some models, energy price increases resulting from the imposition of a cap-and-trade program or emissions tax reduce the effective real wage of workers, causing a reduction in labor supply. Economists continue to disagree about the magnitude of this effect—a smaller labor response to higher energy prices would lower the costs of domestic climate change policy (but also diminish the benefits of using revenues from such a policy to lower payroll taxes), whereas a greater labor response would increase costs. In other models, an increase in energy prices is assumed to have recessionary effects. Similar disagreement exists among economists as to whether such recessionary effects, which have occurred in the past after large, unexpected price increases, would hold for the kind of gradual, expected price increases that would be associated with a GHG reduction policy.

Another important driver of future costs that is difficult to predict with confidence concerns technology responses to higher energy prices and, in particular, the impacts of a likely increase in R&D investments. Several recent climate-change policy proposals have set emissions caps through at least 2050. In some models, the economy experiences large costs because of the stringency of the emissions caps that are assumed to apply in the distant future—especially relative to current forecasts of business-as-usual emissions 40+ years out. These models do not include detailed characterizations of the R&D process. Over this kind of timeframe, one might reasonably expect more rapid development of low-carbon and zero-carbon technologies in response to credible domestic climate change policies. Accelerated progress in developing and deploying climate-friendly technologies would in turn lower the costs of a given climate change policy, so long as related R&D efforts do not draw too much capital away from other important and productive investments that promote economic growth.

Finally, two further questions are relevant in a discussion of cost, but are outside the scope of the models presented here. The first relates to the fact that most models used to evaluate climate change policy do not explicitly model uncertainty; the

second concerns the interaction of state and federal policy. With respect to uncertainty, several current policy proposals include program elements that are expressly designed to address concerns about cost certainty. Examples include the safety valve in the Bingaman-Specter and Udall-Petri proposals and the borrowing provisions in the Lieberman-McCain proposal. Additional analyses that can account for the effects of uncertainty may show the benefits of such mechanisms in maintaining reasonable costs and illustrate the potential use of safety valve or borrowing provisions in a future policy regime.

Any federal policy to limit GHG emissions is likely to co-exist, at least in the early years of implementation, with a number of state and regional climate initiatives. Examples include the Regional Greenhouse Gas Initiative in the Northeast and mid-Atlantic states and California's adoption of state-level emission-reduction targets. Potential interactions between these efforts and a federal program are not accounted for in most modeling analyses of domestic climate change policy. The incremental cost of a national GHG mitigation policy may be lower than would be indicated by modeling analyses that fail to account for state efforts because emissions reductions would occur in those states even in the absence of the national policy.

## Conclusion

Implementing a domestic cap-and-trade program or tax on GHG emissions will impose costs on the U.S. economy. Based on an array of cost measures, the modeling analyses reviewed here indicate that a modest policy designed to ramp up over time (either through more stringent emissions caps or an increasing emissions tax) would have seemingly manageable effects on the U.S. economy as a whole, although adverse impacts in certain sectors may occur. Energy prices would increase, but with only modest effects on GDP and employment. Additional analysis can highlight sectoral, demographic, and regional impacts that may be important but that are obscured by aggregated national-level analysis. It is also important to recognize that available models provide only a stylized representation of the likely economic impacts of different policies—some of the details in various proposals that are not accounted for in the models could have a significant impact on overall costs.



**ISSUE BRIEF 4**

**SCOPE AND POINT OF  
REGULATION FOR PRICING  
POLICIES TO REDUCE FOSSIL-  
FUEL CO<sub>2</sub> EMISSIONS**

**WILLIAM A. PIZER**

**4**

## SCOPE AND POINT OF REGULATION FOR PRICING POLICIES TO REDUCE FOSSIL-FUEL CO<sub>2</sub> EMISSIONS

William A. Pizer

### SUMMARY

This issue brief examines the choice of what emissions to include—and where to regulate them—under a tax or tradable allowance policy to reduce fossil-fuel carbon dioxide (CO<sub>2</sub>) emissions. A companion brief (Issue Brief # 14) examines options for regulating non-CO<sub>2</sub> greenhouse gases (GHGs) and non-fossil CO<sub>2</sub> emissions. Several points emerge from this discussion:

A regulatory program that establishes a price on CO<sub>2</sub> emissions—either through a tax or tradable permit system—will achieve the most reductions at the least cost when it covers as many emissions as possible under a single program with one price. Broader coverage also mitigates the tendency for emissions to shift to uncovered sources over time, raising the profile of any excluded emissions sources (that is, leakage).

- The argument for a broad-based, single-price program is grounded in cost considerations. Other policies, however, are often proposed instead of, or in addition to, a pricing policy. These proposals are often motivated by a desire to pursue more popular technologies, to guarantee certain technology outcomes or emissions-reducing actions within a sector, and to shield some fossil-energy users from higher energy prices.
- A program to price CO<sub>2</sub> emissions that focused on large emission sources (for example, sources that emit over 10,000 metric tons of CO<sub>2</sub> annually) could cover

just over half of U.S. GHG emissions by regulating roughly 13,000 facilities. A program focused solely on the electricity sector would cover roughly one-third of U.S. emissions and involve 2,000–3,000 facilities.

- An upstream tax or emissions-trading program could effectively cover almost all fossil-energy CO<sub>2</sub> emissions by regulating approximately 3,000 entities, including refineries, natural gas pipelines or processors, coal mines, and importers.
- While regulatory programs for other forms of pollution have traditionally focused on emitters, the unique nature of CO<sub>2</sub> emissions makes it possible to regulate effectively at any point in the fossil-fuel supply chain. The vast majority of CO<sub>2</sub> emissions result from the combustion of fossil fuels. Because these emissions do not depend on the combustion technology used or on other operating parameters, and because there is limited opportunity to reduce emissions other than by burning less fuel, downstream emissions can be calculated with relative ease and accuracy based on the quantity of fuel produced or processed and its carbon content. Thus, fuels can be regulated as a proxy for emissions at any point in the chain from production to processing to distribution and final consumption. Important adjustments must be made for imported and exported fossil resources and fuels, sequestered emissions (including carbon capture and storage), or uses of fossil fuels that do not result in emissions.

- A concern frequently raised about upstream regulation of CO<sub>2</sub> emissions is that fossil-fuel users will respond more strongly to direct incentives for reducing emissions than they will to higher fossil-fuel prices. There is a psychological appeal to this logic, but basic economic theory and business pressure to minimize cost argue against it.
- While existing tradable permit programs have traditionally allocated free permits to regulated sources, there is no reason why CO<sub>2</sub> permits cannot be allocated to other actors throughout the fossil-fuel supply chain that are directly or indirectly affected by regulation. Decisions about how to allocate permits or allowances need not be tied to decisions about which entities will be required to submit permits or allowances under a trading program.
- For a *given* set of design choices concerning permit allocation and program coverage, the decision about where to regulate does not generally change the economic burden imposed on different actors in the fossil fuel supply chain. Important caveats may apply in situations where products are not competitively priced (as, for example, in regulated utility markets). In addition, point of regulation does affect which entities bear the administrative burden of demonstrating compliance under a tradable permits program (in a well-designed program, however, administrative costs should be relatively small).

## Key Choices

A high-level question that arises early in designing a market-based climate-change mitigation policy for the United States is how to define the scope of economic activities regulated under the policy, particularly with respect to fossil energy CO<sub>2</sub> emissions. Entities involved in generating emissions that are covered by a market-based policy (including entities upstream and downstream of the entity that is actually regulated) face a common incentive to reduce emissions; entities involved with the production of emissions that are not covered do not. This issue brief outlines the basic motivations for including and excluding various emissions sources, along with different regulatory options for including sources in a market-based emissions-reduction program.

## Motivation

A principal motivation for market-based policies—taxes or tradable permits—is that they encourage the most reductions

at the lowest cost compared to other policy architectures.<sup>1</sup> Among market-based policies, those that include more emissions sources can deliver larger reductions at even lower costs. Broader coverage implies more opportunities—including possibly very cost-effective opportunities—to reduce emissions. Broad coverage also avoids the tendency for emissions to shift over time to sources that are not covered under the trading program. This is referred to as emissions leakage. Finally, broad coverage may satisfy a desire for fairness—that is, ensuring everyone is part of the policy—though it is worth noting that this desire could also be satisfied by a less-efficient, sector-by-sector approach (and is, in any case, a much more subjective goal).

Reducing GHG emissions enough to limit future climate impacts could eventually cost the world economy as much as 1–3 percent of gross product according to recent assessments by the Intergovernmental Panel on Climate Change (IPCC) and other studies.<sup>2</sup> All of these studies assume cost-effective global efforts to reduce emissions in which all emission sources face the same market price for CO<sub>2</sub>. If future mitigation efforts focus on a smaller number of sources or use less-efficient policies, costs could rise significantly—perhaps by a factor of ten.<sup>3</sup> A sector-by-sector approach that tackles various emissions sources with distinct policies risks precisely this outcome.<sup>4</sup> Even though such an approach may “cover” all emissions, it does not do so in a way that encourages least-cost reductions across all sectors.<sup>5</sup>

Distinct from the issue of cost is the concern that, over time, excluding some fuels and sources from regulation could gradually encourage leakage as CO<sub>2</sub> prices rise. A program that only covered electricity-related emissions, for example, could encourage households and businesses to shift to direct use of fossil fuels.<sup>6</sup> While policies with partial coverage may not create significant leakage problems in the short run because the price incentive is not sufficiently high, this may change over time as policies evolve to achieve deeper reductions and incentives for regulated sources to avoid emissions rise

1 Alternate, technology-based regulations are discussed in a companion issue brief on technology deployment options.  
 2 See companion issue brief on costs and Intergovernmental Panel on Climate Change, 2007. *Report of Working Group III, Summary for Policymakers*.  
 3 See Pizer, W. et al., 2006. Modeling Economywide versus Sectoral Climate Policies Using Combined Aggregate-Sectoral Models, *Energy Journal* 27(3): 135-168. The authors find that mitigation costs double when only electricity and transportation are included, and increase by a factor of ten when standards for fuel economy and renewable portfolios are used in those sectors.  
 4 Consider, for example, the suite of actions being considered in California under AB32, <http://www.arb.ca.gov/cc/ccea/ccea.htm>.  
 5 Sector-by-sector regulations lead to higher costs for three reasons. First, absent emissions pricing of some sort in all sectors, there will not be an efficient balance of conservation and mitigation. Second, it is unlikely marginal costs will be balanced, leading to expensive reductions in one sector while cheaper abatement opportunities go unrealized in another. Third, absent emissions pricing, there will be a weaker incentive to innovate. See Issue Briefs #10 and #5 on technology deployment policies and different forms of regulation, respectively, for additional details.  
 6 There is already anecdotal evidence, for example, that high oil and gas prices are encouraging some households to consider switching to coal. See Howe, Peter, 2005. Fuel prices usher in new coal age. *Boston Globe*, October 24.

accordingly. These two points suggest that including as many sources as possible under a single program is an important design objective for market-based emission-reduction policies. At the same time, there is often pressure to exclude various sectors and emissions sources from these policies—for different reasons. Emissions from some sources may be small and/or expensive to mitigate, administrative costs for including some sources may be high, and international competitiveness concerns may argue for exempting some firms or sectors, particularly if they compete with overseas producers that do not face similar carbon constraints (competitiveness impacts and potential responses are discussed in Issue Briefs #7 and #8). Some sectors may prefer to be regulated separately in order to seek a more tailored—and perhaps less onerous—result. In addition, tailored approaches might be appealing because they more directly promote popular technologies or emissions-reducing activities and result in less obvious price increases for end users. Finally, some sectors may be sufficiently vocal and recalcitrant that their inclusion in a mandatory regulatory program is simply considered not worth the political effort.

There is also the view that different sectors or sources face different hurdles that are best addressed through distinct policies. Passenger vehicles require fuel economy standards, aircraft require aircraft regulations, power plants require power plant standards, etc. This line of thinking tends to ignore a basic tenet of market-based policies: that, given an aggregate emissions objective, the private sector is best suited to determine the least-cost combination of measures required to achieve that objective. Instead, this view assumes government can design a cheaper approach through targeted regulation. Economists tend to find the latter argument unconvincing: decades of research suggest that broad, market-based policies can substantially reduce costs relative to targeted regulatory approaches.<sup>7</sup>

A desire to minimize costs and avoid leakage problems provides the primary motivation for thinking carefully about what to include in a uniform market-based policy as society pursues gradually deeper emissions reductions. Whether exclusion means that some sources are covered by a separate policy, or are simply excluded from regulation completely, may matter for leakage, but not for our central conclusion about costs—indeed, the largest unnecessary costs arise not from excluding some sources but from addressing them with poorly designed, inflexible regulation.

7 See Stavins, R. forthcoming. *Market-Based Environmental Policies: What Can We Learn From U.S. Experience (and Related Research)? Moving to Markets in Environmental Regulation: Lessons from Twenty Years of Experience*, eds. Jody Freeman and Charles Kolstad. New York: Oxford University Press.

### Deciding what Sources to Include— the Traditional Approach

The traditional approach for regulating air emissions is to focus on emitters; this is the model used in the Acid Rain trading program, the NO<sub>x</sub> budget and SIP call programs, and the EU Emissions Trading Scheme.<sup>8</sup> In this model, emitters are required to surrender allowances in proportion to their measured emissions. A fixed number of allowances are issued, thereby effectively limiting total emissions from covered sources while still giving individual emitters the flexibility to trade allowances and implement the most cost-effective compliance strategy.

Under the traditional approach, program coverage is generally limited to relatively large sources because the administrative burden of monitoring emissions and allowance obligations (or collecting a tax) on increasingly smaller sources quickly becomes prohibitive. In practice, two models for applying this approach to CO<sub>2</sub> emissions have emerged: one model focuses solely on the electricity sector, the other focuses more broadly on large emitters (those that emit, for example, more than 10,000 tons of CO<sub>2</sub> annually and/or sources in certain energy-intensive sectors).

The electricity-only model for CO<sub>2</sub> has appeared in a variety of market-based U.S. climate policy proposals, first as part of an effort to develop multi-pollutant regulations for power plants earlier this decade,<sup>9</sup> and more recently as the basis of the multi-state Regional Greenhouse Gas Initiative that is currently being implemented in the Northeast.<sup>10</sup> Part of the appeal of this approach is that the electricity sector has considerable experience with emissions trading; in addition, a growing number of companies within this sector have begun to support greenhouse gas regulations so as to achieve some measure of investment certainty. Applied in the United States, an electricity-only climate policy would cover about one-third of overall emissions and involve 2,000–3,000 sources.

In contrast, the EU Emissions Trading Scheme adopts the large source model, regulating electricity generators as well as large industrial sources. Applied domestically, this approach would cover about half of U.S. emissions and involve perhaps 13,000 sources.<sup>11</sup>

8 See <http://www.epa.gov/airmarkets/progreps/arp/s02.html>, <http://www.epa.gov/airmarkets/progreps/nox/index.html>, and <http://ec.europa.eu/environment/climat/emission.htm>. See also Ellerman, A.D. and B. Buchner, 2007. *The European Union Emissions Trading Scheme: Origins, Allocation, and Early Results*, *Review of Environmental Economics and Policy* 1(1):66-87.

9 Proposed policies would have covered SO<sub>2</sub>, NO<sub>x</sub>, mercury, and CO<sub>2</sub> in one program. See various legislative analyses at [http://www.epa.gov/air/oaq\\_caa.html/](http://www.epa.gov/air/oaq_caa.html/). Interestingly, the policies never proposed to allow trading across pollutants, something that economists have suggested for some time.

10 See [www.rggi.org](http://www.rggi.org) and Burtraw, D., D. Kahn, and K. Palmer, 2006. *CO<sub>2</sub> Allowance Allocation in the Regional Greenhouse Gas Initiative and the Effect on Electricity Investors*, *Electricity Journal* 19(2), 79-90.

11 Data on numbers of sources are discussed at greater length in Issue Brief #1 on emissions and emission sources.

### Alternative Regulatory Approaches that Provide Broader Coverage

An alternative to the traditional smokestack-oriented approach is to regulate upstream—that is, to regulate the production, processing, or distribution of fossil fuels.<sup>12</sup> Entities that initially produce (or process / transport) a fossil fuel in the United States would be required to surrender allowances in proportion to the carbon content of the fuels they handle. As with the traditional model, a fixed number of allowances are issued so as to limit the total volume of CO<sub>2</sub> ultimately released by the combustion of fossil fuels. In contrast to traditional regulatory programs, where emitters face both a fuel price and an emissions price, the price of emissions under an upstream system would be bundled with fuel prices.

For most conventional air pollutants, an upstream approach would have serious drawbacks. First, most of these emissions can be addressed through end-of-pipe pollution controls. Second, downstream emissions of these pollutants are not a simple function of the properties of the fuel consumed—rather, eventual emissions depend on a variety of factors including the type of combustion technology and post-combustion pollution controls used. Thus accurate measurement is only possible at or near the actual emissions source. CO<sub>2</sub> emissions from fossil-fuel combustion are different. The only end-of-pipe control option for these emissions is carbon capture and storage—a technology that, if applied, would be readily amenable to a post-combustion crediting scheme. Moreover, the carbon content of fuels is easily measured at any point in the supply chain and provides an accurate proxy for eventual CO<sub>2</sub> emissions. In fact, the EU program regulates on the basis of fuel use rather than actual emissions measurement.<sup>13</sup>

It should be noted that an upstream program requires a few critical adjustments to avoid perverse incentives: imports of fossil fuels must be covered and exports must be credited. In addition, CO<sub>2</sub> capture and storage must be credited. Further, any uses of fossil fuels as feedstocks (for example, in the manufacture of plastics or road asphalt) that do not result in emissions need to be credited. All of these adjustments, however, are relatively straightforward.

Because of this flexibility in choosing the point of regulation for CO<sub>2</sub> emissions, a variety of approaches have been

proposed, some of which regulate all emissions upstream and some of which use a hybrid model in which certain sectors or fuels are regulated upstream, while others are regulated midstream or downstream. The advantage of an upstream approach is that it provides broad emissions coverage while regulating a relatively small number of entities. Emissions from hundreds of millions of vehicles, households, and small businesses can be effectively captured by a program that regulates a few thousand petroleum refineries, natural gas pipelines or processors, and coal mines. As noted at the outset, broad coverage under a single regulatory program is often an important policy design objective because it will produce emissions reductions at lower cost.

A common concern about regulating fossil energy producers instead of end-use emitters is that this approach weakens incentives for mitigation. The logic goes that fuel producers can do little to reduce emissions (other than sell less fuel) and hence will not respond to regulation, whereas end users—who are actually in a position to change behavior and reduce emissions—will respond less strongly to regulation if the costs of emitting are simply bundled with fuel prices. While this view may seem intuitively reasonable, however, economic theory and the pressure to minimize costs and maximize profits argue strongly against it.

In fact, economic theory argues that the decision about where to regulate should have little or no bearing on the incentives faced by different entities under a market-based program. After all, the basic premise of market-based policies is that price drives behavioral change. If upstream fuel suppliers are regulated, they will pass emissions costs to downstream end-users in the form of higher fuel prices.<sup>14</sup> Higher prices will encourage end users to reduce their consumption of fossil fuels. Because reducing fuel use is, in most cases, the only real option for reducing energy-related CO<sub>2</sub> emissions, an incentive to reduce emissions is an incentive to reduce fuel use and vice versa. (The exception, of course, is post-combustion carbon capture and storage, but this technology is likely to be an option only for large point-source emitters, such as electric power generators and can be addressed with a crediting program.) While there are strong reasons to believe that theory holds up in practice on this point, we return to the question of whether upstream regulation is just as effective as downstream regulation at delivering emission-reduction incentives below.

<sup>12</sup> This approach has some parallels to the lead phase-down program in which refineries were regulated based on the lead content of the gasoline they produced, rather than vehicle emissions being regulated directly. The key difference is that lead was an additive in gasoline, not an intrinsic part of the fuel itself.

<sup>13</sup> That is, CO<sub>2</sub> emissions are not directly measured in the EU ETS. Rather, fuel use is measured and emission factors are applied. See Kruger, J. and C. Egenhofer, 2006. Confidence through compliance in emissions trading markets, *Sustainable Development Law and Policy* 6(2), 2-13 (Climate Law Special Edition).

<sup>14</sup> It is also possible that regulating CO<sub>2</sub> would lead to lower prices for fossil-fuel producers (versus increases for end users). Empirical evidence suggests this is likely to be a very small effect; see, for example, Energy Information Administration (2007), *Energy Market and Economic Impacts of S.280, the Climate Stewardship and Innovation Act of 2007*, and other studies, showing a minimal impact on fossil-fuel producer prices.

Table 1

Summary of the three broad regulatory models policymakers can consider in designing a market-based regulatory program for limiting CO<sub>2</sub> emissions.

	Potential coverage <i>(as percent of total U.S. CO<sub>2</sub> emissions from fossil-fuel combustion)</i>	Likely number of sources	Examples
Emissions sources / fossil fuel users	Electric power plants and large manufacturing facilities; ~50% of U.S. emissions	2,000–3,000 sources in the electric power sector; 10,000 sources in manufacturing	Acid rain program, EU ETS, Feinstein-Carper S. 317 (110 <sup>th</sup> Congress)
Fossil fuel manufacturers / distributors	Entire economy / nearly 100% of U.S. emissions	3,000 coal mines, refineries, natural gas processors / pipelines	Lead phase-down in gasoline; Bingaman S.A.868 (109 <sup>th</sup> Congress)
Hybrid <i>(some emissions sources covered directly; others covered via regulation of fuel distributors)</i>	Likely scenario for this approach would cover electric power, large manufacturing facilities, and transportation ~75% of U.S. emissions	13,000 downstream sources plus around 150 refineries	Lieberman-McCain S. 280 (110 <sup>th</sup> Congress).

**To summarize:** policymakers face a unique set of choices and opportunities when regulating energy-related CO<sub>2</sub> emissions compared to conventional air pollutants. As with most programs designed for the latter, policymakers can focus regulation on emitters. In the case of CO<sub>2</sub> this will necessarily mean focusing on large point sources and excluding numerous small emissions sources because it would be too expensive to monitor their emissions and verify compliance. As a result, this approach would fail to capture as much as half of U.S. emissions. Instead, policymakers have the option to regulate fossil-fuel producers and distributors on the basis of the fuel they deliver into the energy system for eventual sale to end-users. This approach provides an opportunity to cover the great majority of emissions from small sources—including vehicles, households, and small businesses—by focusing on a much smaller number of upstream entities. Several design considerations are relevant in comparing these approaches:

- Coverage.**  
More coverage in a single market-based system lowers cost and reduces potential for emissions leakage.
- Number of regulated facilities and their ability to manage compliance with a market-based program.**  
Fewer regulated facilities mean lower administrative costs; more sophisticated management means a more efficient market.
- Equity and fairness.**  
This objective does not require a single economy-wide program, but does suggest that no sector or area of

emissions-related activity should be exempt from the effort to mitigate emissions. While economics can shed light on the magnitude and distribution of cost burdens, it is not helpful in establishing what is fair.

- Durability.**  
How well will a particular policy configuration work in the future as societal objectives evolve? Except to note that broad coverage may become more important as society seeks deeper emissions reductions in the future, economic analysis offers little clear guidance.

## 2. Questions Concerning Allocation and the Distribution of Cost Burdens

Because past tradable permit programs have awarded most free allowances to directly regulated entities, the issue of allowance allocation is often explicitly or implicitly bound up with discussions about where to regulate. The critical point here, however, is that any free allocation of allowances need not be tied to the question of which entities will be required to surrender allowances. This point is important because if one assumes a direct connection between free allocation and point of regulation, the decision about where to regulate becomes tied to the distribution of potentially billions of dollars worth of assets. This would potentially distort a design choice that should be based primarily on maximizing program coverage and other considerations. A related point is that the burden of regulation—that is, whose fortunes diminish as a result of emissions constraints—does not necessarily fall on

the economic actors that are being directly regulated. Entities that are required to submit allowances or pay an emissions tax under a market-based regulatory system can usually pass some if not most of these costs forward (to their customers) or back (to their suppliers). More generally, point of regulation does not affect the distribution of associated cost burdens, with some important caveats, for reasons discussed in more detail below.

While it is somewhat obvious that allowances in a cap-and-trade system do not *need* to be freely allocated to regulated entities, this was the approach generally taken, as noted above, in all the fully operational emissions-trading programs that exist today.<sup>15</sup> Despite historic precedents, however, recent climate proposals show a growing interest in auctioning significant numbers of allowances, rather than giving them away. And in a few cases, recent proposals would give free allowances to businesses that are not directly regulated.<sup>16</sup> Why?

This change in thinking about allocation reflects a more sophisticated understanding of what happens when a price is put on CO<sub>2</sub> emissions associated with fossil-fuel use. First, users of fossil fuels face higher production costs as fuel prices rise to reflect the carbon price signal. Second, demand for fossil fuels can drop as a result of higher prices and/or underlying fossil-fuel prices can fall, shifting some of the cost of regulation onto fossil-fuel producers.<sup>17</sup> Third, prices for products made with fossil fuels—especially electricity—may rise shifting some of the cost burden onto consumers.<sup>18</sup> In the latter case, higher market prices for electricity may benefit non-fossil electric generators that do not face higher fuel or emissions costs under a CO<sub>2</sub> trading program, such as nuclear or renewable electricity producers.<sup>19</sup> Even mostly fossil-fuel based companies can benefit, however, if they can pass most of their emissions costs on to consumers and have simultaneously received an allocation of free allowances. In that case, the asset value of free allowances can exceed, perhaps substantially, the actual cost burden imposed on allowance recipients under the regulatory program. This phenomenon was observed in some European electricity markets where, in response to the EU ETS, a close correlation

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A desire to minimize costs and avoid leakage problems provides the primary motivation for thinking carefully about what to include in a uniform market-based policy as society pursues gradually deeper emissions reductions.

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emerged—not only between wholesale electricity prices and allowance prices, but also between the stock value of some power companies and allowance prices. That is, stock prices for some power companies rose with higher allowance prices and fell with lower allowance prices.<sup>20</sup> Because these companies could pass most of the opportunity cost of using allowances through to consumers in the form of higher prices and because they had been given free allowances to start with, they were actually better off when allowance prices were high. Evidence from the EU ETS, perhaps more than any other recent development, has changed current thinking about allocation and provoked a more nuanced approach to the question of who should receive free allowances.<sup>21</sup>

The issue of allocation is discussed at length in a companion issue brief (Issue Brief #6) on that topic (as well as in Issue Brief #11 concerning the electricity sector) but two relevant points are worth making here. First, there is a trend toward moving free allocation away from regulated emitters and toward a more nuanced notion of burden, taking into account the ability of regulated firms to pass emissions costs forward or back. Second, the fact that costs can be passed forward and back along the energy supply chain generally implies that the

15 That is, the Acid Rain trading program, the NOx Budget Program and SIP Call, and the EU ETS. See references in footnote 7.

16 Many states in the Regional Greenhouse Gas Initiative propose auctioning all permits; among the half-dozen cap-and-trade proposals in the 110<sup>th</sup> Congress, free allocation accounts for between 50 and 85 percent of initially available allowances and is, in many cases, phased out over time.

17 As noted in an earlier footnote, the principle impact on upstream suppliers is lower demand; prices received by fossil-fuel producers are not estimated to change much in response to near-term climate regulations.

18 We discuss the many issues surrounding electricity in Issue Brief #11. The question of whether other sectors can pass through costs, especially where firms face international competition, is the subject of a pair of issue briefs on competitiveness impacts and policy options (Issue Briefs #7 and #8).

19 This benefit to nuclear and renewable generators can be viewed as an appropriate reward for cleaner generation. More generally, questions of fairness and equity are extremely subjective; here we try to simply note where burdens exist, not where they should exist.

20 See Sijm, J. K. Neuhoff, and Y. Chen. 2006. CO<sub>2</sub> cost pass-through and windfall profits in the power sector. *Climate Policy* 6(1), 49-72.

21 See revised allocation recommendations by the National Commission on Energy Policy, <http://www.energycommission.org/site/page.php?report=32>.

distribution of economic burden is the same, regardless of who is regulated—the emitter, the fuel distributor, or the fuel producer. That is, requiring either producers or distributors of fossil fuels to surrender allowances based on the carbon content of the fuels they handle generally raises the price of those fuels by the value of associated allowance. Thus, the outcome is the same as in a system where the downstream end user has to buy emissions allowances to satisfy a direct compliance obligation.

One caveat to this observation that the point of regulation does not really matter, except in terms of emissions coverage and administrative complexity, relates to the structure of markets along the fossil-fuel supply chain.<sup>22</sup> In some cases, long-term fuel supply contracts may not allow for a price adjustment in response to a new upstream allowance requirement. In the case of western coal, the market power of railroads may affect the ability of western suppliers to pass along higher prices associated with upstream CO<sub>2</sub> regulation to eastern utilities without some of that price increase being captured by the railroad. Finally, pipeline companies with regulated tariff rates that do not own the fuel they transport may not be easily able to pass through the cost of CO<sub>2</sub> allowances. While none of these obstacles is insurmountable, especially over time, they serve to underscore two points. First, the basic notion that point of regulation does not affect the distribution of regulatory cost burdens depends on a central assumption: that prices are set by a competitive market. Second, where this is not the case, policymakers will need to address or work around impediments to cost pass-through to ensure that incentives for reducing emissions under a tradable permits system are properly transmitted up and down the energy supply chain.

The choice of where to regulate does, of course, affect the distribution of cost burdens in one obvious way: administrative costs related to a tradable permits program will fall largely on the entities that are being directly regulated.<sup>23</sup> Regulated businesses have to obtain and surrender allowances (or pay taxes), and document fuel carbon content or emissions to demonstrate compliance. While small relative to either the cost of allowances or the cost of reducing emissions, these administrative costs could be burdensome to small businesses. Perhaps more burdensome for some businesses will be the need, under a tradable permit system, for some sophistication in managing permit holdings in advance of

compliance: permits or allowances are market assets that can rise and fall in value (sometimes quite dramatically). Managing them in an intelligent way to minimize compliance costs can require a variety of financial market skills quite different from those required to comply with ordinary environmental regulations (to some extent, such skills will also be required of businesses that are indirectly impacted by the regulation, even if they are not directly involved in handling allowances themselves).<sup>24</sup> While there is no shortage of external financial market expertise that could (and eventually will) be brought to bear to help companies navigate carbon permit markets, matching everything up can take time. Recent proposals that seek as a first step to cap only electric-sector emissions may be motivated by this concern. Electric utilities have experience with emissions trading under other regulatory programs so proponents of this approach may be weighing the desire for knowledgeable participants against the competing desire for greater coverage. Of course, any future expansion of a utility-only program to cover more sources would eventually require firms in other sectors to acquire similar expertise.

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Policymakers have the option to regulate fossil-fuel producers and distributors on the basis of the fuel they deliver into the energy system for eventual sale to end-users. This approach provides an opportunity to cover the great majority of emissions from small sources—including vehicles, households, and small businesses—by focusing on a much smaller number of upstream entities.

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22 The general point that regulating at different points does not affect “who really pays” was established decades ago in the context of tax policy. See Musgrave, R. A. and P. B. Musgrave, 1980, *Public Finance in Theory and Practice*. McGraw-Hill: New York.

23 There is also the burden on regulators; but again, for market-based policies this is typically small. An office of 100 operates the current U.S. acid rain trading program.

24 This was recently discussed in the context of the EU ETS. See Kambayashi, S. 2007. Lightly carbonated: European companies are not yet taking full advantage of carbon markets. *Economist*, August 2. Lack of experience in managing allowance holdings has likely contributed to the volatility observed in a number of trading programs during the early phases of implementation. As such, it provides a further argument for cost-containment mechanisms; see Issue Brief #5 on various forms of regulation.

## Lingering Issues

A few final points concerning the scope of a market-based CO<sub>2</sub> program and point of regulation do not fit neatly into the discussion so far: these include the idea of expanding the range of covered sources over time and recent proposals for regulating “load-serving entities” in the power sector.

Taking the first issue (expanding program coverage over time), one option clearly is to start with emission sources that are relatively easy to regulate and include additional sources over time—such an expansion would likely be necessary if more stringent targets are to be met over time. This was basically the model used for the EU ETS. While focusing initially on the largest sources and on sources that have experience with trading programs has some appeal, for the reasons noted above, this approach raises a tricky practical question: How easy is it to create the necessary political momentum to add smaller and perhaps more resistant sources *after* the largest and most amenable sources are in? A related question is whether it might be possible to create a hybrid program that adds numerous small sources by regulating a small number of upstream fuel distributors *after* a program initially focused on large downstream emitters is implemented. If either outcome is unlikely, there may be a stronger argument for including more sources from the outset by using an upstream approach. Although it may be tempting to choose whatever regulatory approach seems most politically expedient in the interests of initiating a mandatory policy without further delay, policymakers should keep in mind that the core architecture of the program is important for its long-term environmental success. A program that cannot evolve to deliver needed emissions reductions at a reasonable cost could be a serious handicap over time. On the other hand, if a phased expansion of the program over time seems likely to be more feasible politically than starting with a broad-based approach there may be little reason to hold up progress with sources that are ready to go.

A somewhat related question is whether recent proposals to regulate load-serving entities in the electric power sector—versus power generators or other entities further upstream—are appropriate for cap-and-trade programs at the state or regional level. This approach is being considered in California as a response to serious concerns about leakage.<sup>25</sup> California imports 20 percent of its electricity so failure to address the emissions associated with power imports creates the distinct potential for out-of-state emissions to rise once constraints

are imposed within California. A proposed solution is to make the companies that procure wholesale electricity for sale in the California market responsible for the emissions associated with that electricity regardless of where it is generated. There are some potential problems with this approach. One is that it runs the risk of double counting emissions if another jurisdiction selling power to California enacts a similar regulatory program for limiting CO<sub>2</sub> emissions. In that case, California would need to work with the exporting state to ensure that emissions are not double-counted and double-charged—once when they occur and again when the power is sold into California. A second problem is the difficulty of accurately assigning emissions between buyers and sellers in a competitive wholesale market (discussed in Issue Brief #11 on the electricity sector). In general, regulating load-serving entities would seem to be a poor model for covering electric-sector emissions at the national level, where leakage is not a problem and where wholesale competition is more important.<sup>26</sup>

Just as starting with a narrow program may be appropriate if coverage can be expanded over time, locating the point of regulation for electric-sector emissions at the load-serving entity may make sense in the context of a state or regional program, provided this does not interfere with implementing a more appropriate program architecture at the federal level. The risk is that momentum and familiarity may carry early decisions for some time, even if much better options exist.

<sup>25</sup> This approach has been proposed by the California Public Utilities Commission; see [http://www.cpsc.ca.gov/static/energy/electric/climate+change/\\_index.htm](http://www.cpsc.ca.gov/static/energy/electric/climate+change/_index.htm).

<sup>26</sup> A different question is whether load-serving entities might receive free allocations—this question is likewise discussed in Issue Brief #11.





**ISSUE BRIEF 5**  
**EMISSIONS TRADING  
VERSUS CO<sub>2</sub> TAXES VERSUS  
STANDARDS**

IAN W.H. PARRY AND WILLIAM A. PIZER



## EMISSIONS TRADING VERSUS CO<sub>2</sub> TAXES VERSUS STANDARDS

Ian W.H. Parry and  
William A. Pizer

### SUMMARY

Much attention has focused on the design of a trading program for carbon dioxide (CO<sub>2</sub>) emissions, but a more fundamental question is whether emissions trading is really the best regulatory model. In particular, are there potential advantages or disadvantages to a CO<sub>2</sub> tax versus a cap-and-trade program? What about more traditional forms of regulation? This issue brief compares and contrasts these policy approaches, and offers the following observations:

- There are many similarities between CO<sub>2</sub> taxes and tradable allowances or permits. Both reduce emissions by associating a uniform price with emitting activities at any point in time, leading to efficient, low-cost emission reductions. Both can be administered on upstream fossil-fuel producers (based on the carbon content of fuels) to capture economy-wide emissions, or on downstream emitters to capture emissions from large sources. And both can incorporate incentives for carbon sequestration and other offset activities.
- Taxes generally fix the price of emissions, and leave the annual level of emissions uncertain; in contrast, tradable permits generally fix the level of emissions, and leave the price uncertain. Because climate change hinges on the long-term accumulation of global emissions, a predictable price tends to have advantages—for both the environment and the economy—over fixing the level of U.S. emissions for a short time horizon of several years. Over longer horizons, as nations converge on a common target for stabilizing atmospheric greenhouse gas (GHG) concentrations and as international participation in global emission-reduction efforts grows, fixed emissions targets become increasingly advantageous.
- Taxes generally raise government revenue, while tradable permits—at least traditionally—have not. New government revenue, if used to cut other taxes or provide valuable public goods, generates additional economic benefits that are not achieved under a traditional system of tradable permits in which the majority of permits or allowances is allocated for free to regulated entities. On the other hand, the allocation of free permits or allowances under an emissions-trading regime can be tailored to address concerns about an otherwise unequal distribution of regulatory cost burdens across firms and regions.
- These traditional differences between a tax and trading policy are easily blurred in a hybrid emissions trading system where some allowances are auctioned to raise government revenue and where banking and a safety valve (or perhaps borrowing) stabilize prices. Recent proposals for a Federal Reserve-like body to monitor allowance markets address this same issue.
- A few differences between these two types of policies are more immutable. For example, emissions trading does require additional institutions, though experience

suggests that these institutions are likely to arise quickly and for the most part inexpensively. Another difference is that a CO<sub>2</sub> tax tends to reframe the debate in terms of revenue and fiscal policy.

- Traditional forms of regulation—technology and performance standards—represent an alternative to emissions trading or CO<sub>2</sub> taxes, but can be much more costly because they do not allow the flexibility to shift efforts toward the cheapest mitigation opportunities. As a complement to emissions trading or CO<sub>2</sub> taxes, however, flexible standards can address possible additional market failures and potentially lower costs.

## Similarities Between CO<sub>2</sub> Taxes and Emissions Trading Programs

A CO<sub>2</sub> tax imposed upstream in the fossil-fuel supply chain (with rates reflecting the amount of CO<sub>2</sub> that will be emitted when the fuel is later combusted in automobiles, during electricity generation, and so on) minimizes the number of entities subject to the tax and therefore has administrative advantages. Roughly speaking, the tax would be passed forward into the price of coal, natural gas, and petroleum products and therefore ultimately into the price of electricity and other energy-intensive goods. These higher energy prices would encourage the adoption of fuel- and energy-saving technologies across the economy and promote switching from carbon-intensive fuels like coal to natural gas and renewable fuels. In these regards, a CO<sub>2</sub> tax closely resembles an upstream emissions-trading system, where the price of allowances is passed forward in the form of higher fuel prices.

Neither policy has to be implemented upstream: CO<sub>2</sub> taxes and emissions-trading programs can be implemented anywhere in the chain from fossil-fuel production (upstream) to ultimate fuel combustion (downstream).<sup>1</sup> Upstream programs, however, are typically more efficient—in the sense that they lead to lower costs per ton of emissions reduced—because they can encompass virtually all emissions sources with minimal administrative burden, thereby maximizing low-cost mitigation opportunities. In contrast, downstream programs necessarily exclude small sources, as does the European Union's Emissions Trading Scheme (EU ETS). And either a tax or tradable-permit program, upstream or downstream, can—via offset and crediting programs—incorporate

incentives for downstream carbon capture and storage at industrial facilities, for forestry expansion on farmland, and for other downstream activities.

## Potential Advantages of a CO<sub>2</sub> Tax

Carbon taxes have several advantages over traditional emissions-trading systems, but as discussed later, some of these advantages can be partly captured through modifications to the cap-and-trade approach.

One potentially important advantage of a CO<sub>2</sub> tax is that it establishes a well-defined price for emissions of CO<sub>2</sub> and other greenhouse gases. The price may rise over time, but it is known. In contrast, allowance or permit prices under a cap-and-trade system can be volatile because the supply of allowances is fixed, whereas demand will vary considerably at different points in time. Changes in energy demand, fuel-price fluctuations (like, spikes in natural gas prices), and a variety of other factors can cause demand for allowances to fluctuate significantly. Price volatility in allowance markets may in turn deter both long-term capital and R&D investments in low-carbon technologies that have high up-front costs. The long-term payoffs of making such investments will be very uncertain if the future price of CO<sub>2</sub> is unknown.

Moreover, it typically makes economic sense to allow nation-wide emissions to vary on a year-to-year basis because prevailing economic conditions affect the costs of emissions abatement. This flexibility is inherent in a CO<sub>2</sub> tax because firms can choose to abate less and pay more tax in periods when abatement costs are unusually high, and vice versa in periods when abatement costs are low. Traditional cap-and-trade systems do not provide this flexibility because the cap on economy-wide emissions has to be met, whatever the prevailing abatement cost. Intuitively, imposing strict limits makes economic sense only if (1) we are rapidly approaching a threshold in atmospheric greenhouse gas concentrations beyond which there is a risk of dangerous and extremely costly climate change impacts and (2) strict emissions limits can be globally enforced. It is worth noting that most trading programs do allow banking—that is, firms can save unused allowances for use in future compliance periods—and thus provide some flexibility, especially if initial targets are sufficiently generous for a long enough time to allow a bank to emerge. The topic of borrowing is discussed below.

Another potentially important advantage of CO<sub>2</sub> taxes is that they directly raise revenues for the government, whereas under past emissions trading systems, the government has

<sup>1</sup> See Issue Brief #4 on scope and point of regulation. That issue brief discusses issues related to upstream versus downstream regulation.

traditionally given away free allowances. At current emissions levels, for example, a tax of \$10 per ton of CO<sub>2</sub> on all greenhouse gases would raise about \$70 billion of revenue per year for the federal government, or about 9 percent of federal personal income taxes. This extra revenue could be used to lower the rates of other taxes, such as those on individual income, thereby producing important benefits for the economy. (Such a “tax swap” was implemented by the United Kingdom in conjunction with its 2001 climate change levy, and was proposed in the 110<sup>th</sup> Congress by Representative John Larson (D-CT) in H.R. 3416.) Income taxes cause a variety of distortions in the economy. For example, by taxing away some of the returns to working and saving, income taxes deter some people from joining the labor force and encourage others to consume too much of their income. Income taxes also induce a bias away from ordinary spending towards items that are deductible from taxes (owner-occupied housing and employer-provided medical insurance, for example). These economic distortions could be reduced if CO<sub>2</sub> tax revenues were used to lower income taxes.

Even if the revenue from a CO<sub>2</sub> tax is not used to cut other taxes, it could still flow to a variety of important uses—including to fund energy R&D; support climate-change adaptation efforts; or provide assistance to stakeholders, communities, and/or low income families adversely affected by the policy. Weighing against this revenue-raising advantage is the risk that the government will spend the additional revenue on programs that cost more than the benefits they provide, thereby in effect increasing the societal cost of the CO<sub>2</sub> tax relative to the cost of a comparable cap-and-trade program with free allowance allocation.

Aside from possible differences in economic efficiency, revenue to the government (and its potential uses) is likely to have different distributional consequences—in terms of costs and benefits to various individuals and firms in the economy—than a free distribution of allowances. Under the latter approach, benefits flow primarily to the recipients of free allowances—typically businesses and their shareholders and/or regions of the country with higher emissions. Revenues that flow to government as the result of a tax can be redistributed more broadly across the population: for example, to lower tax rates for all income groups. Critical questions, therefore, include the degree to which the burden of a market-based CO<sub>2</sub> program is broadly spread across society (or, conversely, concentrated among a particular group of carbon-intensive businesses or regions) and how the government could, and would, spend any tax revenues.

Finally, emissions trading systems require new institutions to function effectively; that is, they require smoothly running markets where firms can buy and sell permits or allowances and obtain information about permit prices now and in the future. Experience with existing trading programs, such as the U.S. SO<sub>2</sub> trading program, has shown that these institutions can arise quickly and for the most part inexpensively. Some emissions-trading markets have witnessed exceptional volatility during their inception. For example, allowance prices in the U.S. NO<sub>x</sub> budget program skyrocketed in the wake of uncertainty about whether Maryland, a net supplier of allowances, would enter the program on time. In the EU ETS, permit prices crashed spectacularly after emissions data pointed to an excess of CO<sub>2</sub> permits rather than the expected shortage.

## Hybrid Trading Schemes

The problem of allowance price volatility under a cap-and-trade system can be partly addressed by cost-containment mechanisms, such as a “safety valve,” coupled with allowance banking. With a safety valve, firms can buy an unlimited number of additional permits from the government at a pre-determined, possibly escalating price. The safety valve essentially functions as a cap on permit prices; it is most likely to be triggered when demand for permits and abatement costs are high. Allowance banking allows firms to hold over some allowances, in periods when the demand for permits is slack because abatement costs are low, for use in future periods when permit prices are expected to be higher again. In effect, this mechanism creates a floor under permit prices.

As an alternative to a safety valve or price cap mechanism, allowance borrowing has recently entered the U.S. policy debate. Legislation introduced in the 110<sup>th</sup> Congress by Senators McCain and Lieberman would allow firms to borrow up to 25 percent of their allowance obligation in a given year for up to five years (paying 10 percent interest annually). Borrowed allowances would be deducted from the allowance pool available in future years. Coupled with somewhat clear expectations about future prices, this mechanism could provide flexibility similar to a tax. Without clear expectations about future prices, however, borrowing would tend to dampen short-term volatility while leaving the market open to fluctuations based on longer-term expectations about the cap and prices.

The second potential advantage of a tax—that it raises revenues for government—can also be achieved by a cap-and-trade program if allowances are auctioned instead of

being distributed for free (conversely, the revenue-generating properties of a CO<sub>2</sub> tax could be offset by including rebates or exemptions). Although auctioning 100 percent of allowances would mimic the revenue advantages of a CO<sub>2</sub> tax, partial auctions or—as suggested by the recent U.S. Climate Action Partnership proposal—a gradual transition to auctions, offer a spectrum of possibilities.

## Potential Disadvantages of a CO<sub>2</sub> Tax

CO<sub>2</sub> taxes have several practical disadvantages. One is simply political resistance to new taxes; for example, despite a major effort, the first Clinton administration failed to enact an energy tax motivated on environmental grounds. Nonetheless, a CO<sub>2</sub> tax should not be ruled out entirely on this basis: it is always difficult to predict what policies may or may not be viable in the future, especially under different political leadership and likely greater public awareness of, and concern about, both global warming and the federal debt.

Another concern (noted earlier) is that revenues from a CO<sub>2</sub> tax (or auctioned allowances) might be spent inefficiently or even wasted. This could occur, for example, if revenues go toward special interests, rather than substituting for other taxes or addressing important social needs. In principle, legislation accompanying a CO<sub>2</sub> tax could specify how the new revenue must be used, thereby avoiding the risk that it would be dissipated among competing special interest groups. This approach would require political will, as would—more generally—any effort to pursue a fiscally focused climate policy in which environmental objectives are pursued in a manner that maximizes broader public-good objectives. A shift in focus to a policy approach motivated by revenue and fiscal considerations, as well as by environmental concerns, could have important implications—not only in terms of the jurisdiction of agencies and Congressional committees, but also in terms of the broader debate. At first blush, it might appear that such a shift could increase the political difficulty of achieving desired environmental objectives. On the other hand, a more transparent airing of the energy price implications of a trading program or carbon tax—and of the offsetting social benefits that could be achieved by re-directing revenues raised by the policy for other public purposes—could help to build better understanding of, and deeper support for, the policy among the public and some private-sector stakeholders.

Of course, policymakers may wish to compensate the industries most affected by the carbon regime or ease the transition for firms and workers facing adjustments. Compensation can be provided in a straightforward way under an emissions-trading regime by granting free allowances to particular firms or groups.<sup>2</sup> Compensation can also be provided under a CO<sub>2</sub> tax regime, although legislatively, this is more complex.

Finally, policymakers may wish to reduce emissions in a gradual fashion by setting progressively more stringent targets each year, perhaps because atmospheric CO<sub>2</sub> concentrations are already judged to be dangerously high, or because steady progress on emissions reductions more effectively communicates America's seriousness about tackling climate change to the international community. A traditional cap-and-trade system with no safety valve is best tailored to achieving defined emissions targets; in contrast, progress on emissions reductions is less certain under a CO<sub>2</sub> tax because emissions will vary from year to year with economic conditions. A cap-and-trade program with a safety valve represents a potential compromise between these approaches: the safety valve limits allowance prices and emissions-abatement costs, but the trigger price for the safety valve can be steadily increased over time, providing more certainty about emissions levels over the longer term.

## What About Recent Proposals for Federal Reserve-like Oversight of Carbon Markets?

In July 2007, a new proposal emerged in Congress for government oversight of carbon markets via a new body, much like the Federal Reserve. Like the Fed, this body could intervene in response to unexpectedly high (or low) prices or to curb excessive price volatility.<sup>3</sup> The basic idea is that this type of oversight would deliver some of the market-stabilizing benefits of a safety valve while providing greater confidence in the achievement of longer-run emissions goals. Although this proposal does not eliminate the trade-off between price and emissions certainty, it introduces an additional nuance into the current debate about cap-and-trade proposals with and without explicit cost caps.

At the same time, empowering an outside agency to intervene in the market poses risks. Designed or operated poorly, such oversight could exacerbate volatility. For

<sup>2</sup> See Issue Brief #6 for a longer discussion of the allocation issue.

<sup>3</sup> See <http://www.senate.gov/-warner/pressoffice/statements/20070802a.htm> and <http://www.nicholas.duke.edu/institute/carboncosts/>.

example, consider a provision that requires prices to remain above a particular threshold for a period of time before intervention occurs. As permits trade above the threshold, it becomes increasingly likely that the government will intervene to lower prices. At that point, allowance buyers begin waiting for the intervention—who wants to buy now if prices are going to be lower in the future? As demand falls, prices drop, the likelihood of intervention recedes, and therefore prices begin to rise again. In this scenario, the prospect of intervention could have the perverse effect of *increasing* price volatility and market instability. Alternatively, if interventions are quantitatively limited, the most valuable role of the outside agency—addressing a truly exceptional shortage—is compromised.

In sum, the idea of an independent oversight body for future carbon markets is likely to be the subject of additional discussion and elaboration as Congress debates different climate policy proposals going forward. On the one hand, this approach may provide additional opportunities to fine tune the balance between emissions and cost uncertainty in a tradable permit program. At the same time, however, the implications of such a mechanism must be carefully evaluated and important design questions considered in terms of minimizing any additional political or market risks associated with potential intervention.

## Is There Any Role for Traditional Regulation?

From a cost-effectiveness standpoint (that is, in terms of minimizing cost per ton of emissions reduction achieved), market-based instruments like CO<sub>2</sub> taxes and emissions trading systems, applied to all emissions sources, are typically superior to traditional regulation. (Examples of traditional regulation include facility-specific pollution-control requirements, limits on emissions per kilowatt-hour of electricity generation, fuel economy requirements imposed on new vehicles, or regulations on fuels). Under market-based policies, the marginal cost of abatement is equalized across all sectors of the economy, across all firms within a sector, and across all opportunities for abatement. The least expensive abatement options are implemented first, such as substituting less carbon-intensive fuels for more carbon-intensive fuels, adopting energy-efficient technologies, and conserving energy at the household level by, for example, driving less and reducing residential heating and cooling loads.

Nonetheless, traditional regulations—such as technology standards that dictate the use of a particular technology or manner of operations, and performance standards that limit emissions generated per unit of economic output or activity—are frequently proposed as alternatives or complements to emissions taxes or tradable permits.<sup>4</sup> The cost of such regulations is often less visible: emissions control requirements or performance standards raise the cost of certain goods and activities, resulting in price increases and income reductions that are not obviously tied to CO<sub>2</sub> emissions. Traditional regulation can also modify specific behavior directly, without appealing to incentives, and target preferred technologies or mitigation actions. No money is exchanged in the form of taxes paid or allowances traded—changes in behavior are simply required by law. While some view these features of traditional regulation as advantageous, they come at the cost of higher—perhaps much higher—costs.<sup>5</sup> Thus, while imposing sector- or source-specific requirements might appear to reduce the cost of emissions abatement (by avoiding effects on energy prices completely or by reducing demand for allowances and hence lowering allowance prices), the total cost to society—taking into account the less transparent costs of traditional regulation—is likely to be higher than if the same overall result were achieved with a market-based program only.

Unlike market-based instruments, performance or technology standards typically do not impose an economywide carbon price and therefore fail to meet the conditions for efficiently distributing the burden of emissions reductions across different firms, households, and mitigation options. In contrast to minimum performance standards that must be met by every facility or product, *tradable* performance standards offer some ability to equalize marginal costs. Facilities or products that beat the standard cheaply generate credits used to offset excess emission rates at facilities or by products that miss the standard, achieving the standard on average at a lower cost. However, even tradable performance standards often overlap coverage in some areas, exclude coverage in other areas, and always fail to provide proper incentives for conservation. For example, tradable performance standards for the power sector and efficiency standards for appliances would overlap, as would a tradable fuel-economy standard for cars and a renewable or carbon-based fuel standard for gasoline. In the case of industrial facilities, where facility output is not

<sup>4</sup> See, for example, recent proposals in California (<http://www.arb.ca.gov/cc/ccea/ccea.htm>) and the bill introduced by Senators Sanders and Boxer (S. 309, <http://www.sanders.senate.gov/news/record.cfm?id=269618>).

<sup>5</sup> One estimate found that using fuel economy standards for light-duty vehicles and a renewable portfolio standard in the electricity sector would cost ten times as much as an economywide tradable permit system. See Pizer, W. et al., 2006. Modeling Economywide versus Sectoral Climate Policies Using Combined Aggregate-Sectoral Models, *Energy Journal* 27(3), 135-168.

easily defined on a consistent basis, it would be difficult as a practical matter to develop output-based performance standards that could be applied to a diverse population of sources.

Finally, performance standards do less to promote conservation than market-based instruments. Both types of regulation lead to emissions reductions, the cost of which raise the price of emissions-intensive goods, like motor fuel and electricity. Market-based instruments like taxes and emissions trading, however also associate a cost with the remaining emissions that *do* occur, further raising the price of these goods. While this may seem like a bad thing for consumers, it is precisely that price increase that encourages the right amount of conservation—such as driving less or using less electricity. For example, vehicle fuel-economy standards reduce emissions per mile traveled, but do not generate incentives to reduce driving (on the contrary, drivers of more efficient vehicles face lower costs per mile traveled and hence weaker incentives to reduce driving). While avoiding the increase in fuel prices that would accompany a cap-and-trade program or emissions tax might seem desirable on the surface, pursuing the same carbon-reduction objectives via product performance standards means higher costs and lower income somewhere else.

While economic analyses reach uniformly negative conclusions about the cost-effectiveness of traditional regulations as an *alternative* to emissions taxes or tradable permits, for the reasons discussed above, an economic argument can be made for performance standards as a *complement* to a market-based carbon regime, either to address additional market failures and/or because the price incentive for reducing CO<sub>2</sub> emissions under the market-based regime does not reflect the full value of those reductions to society. Examples of market failures that might be amenable to traditional regulatory approaches include the possibility that purchasers may undervalue more energy-efficient vehicles or appliances, or that efforts to develop new technologies may generate substantial public benefits (in the form of new knowledge) that are not appreciated by the firm conducting the research.<sup>6</sup> Finally, the inability to price greenhouse-gas reductions appropriately may arise from political opposition to higher energy prices and/or concerns about the international competitiveness of energy-intensive industries.

<sup>6</sup> The latter point is discussed at length in Issue Briefs #9 and #10, concerning technology policy.

## Conclusion

Significant differences exist between emissions taxes and trading programs. In particular, emissions taxes will generate revenue and set prices, whereas trading programs have traditionally distributed most allowances for free and fixed emissions. Recent proposals for emissions-trading programs with allowance auctions and safety valves (and other mechanisms), however, suggest that many of the key features of a CO<sub>2</sub> tax can be partly included in a trading program. The same is not true for a tax: it is not possible to create fixed emissions limits without resorting to emissions allowances or permits. And whereas tax revenues can be redistributed, industry stakeholders have frequently responded to carbon-tax proposals by seeking exemptions or voluntary agreements in lieu of taxes. Politically, this represents a very different challenge than adjudicating competing claims for allowance allocations. Many other program design questions—such as point of regulation and whether to include offsets and other crediting mechanisms—have always applied equally to emissions taxes and trading systems.

What, then, are the fundamental differences between the major policy options? Emissions-trading programs do require additional institutions: markets, brokers, and information tools to function effectively and manage risk. These institutions tend to arise quickly and inexpensively but there is generally some risk of excess volatility, especially in the early phases of implementation. A tax approach does tend to reframe the traditionally environmental issue as, at least partially, a revenue issue—with attendant political, jurisdictional, and institutional consequences. Of course, similar issues are likely to arise in connection with revenue-generating allowance auctions. All this suggests that designing a CO<sub>2</sub>-reduction policy is more usefully viewed as a matter of selecting different program features along a continuum than as a simple dichotomous choice between taxes and tradable allowances. In that selection process, trade-offs must be made between emphasizing certainty about prices versus certainty about emissions and between raising revenue versus compensating some stakeholders through the free distribution of allowances.

The comparison between a market-based approach (whether taxes or tradable allowances) and traditional regulation is much simpler. While there is possibly an economic rationale for traditional regulations as a *complement* to a market-based policy when other market failures exist (or when the emissions price under a market-based system is constrained for political or other reasons to be less than its social value), there is no economic rationale for such regulations as an *alternative* to, or

substitute for, market-based programs. Traditional regulation is always more expensive because it: (1) generally fails to trade low-cost reductions off against high-cost reductions, (2) tends to provide overlapping incentives for reductions from some types of sources while excluding others, and (3) often fails to provide proper incentives for conservation. Nonetheless, the

desire to pursue preferred technologies or mitigation activities and to reduce the obvious price impact on energy end-users (even recognizing that the result is likely to be higher costs elsewhere) often means that substantial support exists for traditional types of regulation in some sectors of the economy.

	CO <sub>2</sub> tax	Cap and trade	Traditional regulation <i>(e.g., source-specific emissions standards)</i>
<b>Certainty over CO<sub>2</sub> price or cost?</b>	Yes. The tax establishes a well-defined price.	No. But price volatility can be limited by design features, such as a safety valve (price cap) or borrowing.	No.
<b>Certainty over emissions?</b>	No. Emissions vary with prevailing energy demand and fuel prices.	Yes, in its traditional form (over capped emissions sources). No, with the use of additional cost containment mechanisms.	No; regulating the rate of emissions leaves the level uncertain.
<b>Efficiently encourages least-cost emissions reductions?</b>	Yes.	Yes.	No, but tradable standards are more efficient than non-tradable standards.
<b>Ability to raise revenue?</b>	Yes. Results in maximum revenue generation compared to other options (assuming cap-and-trade alternative includes substantial free allocation of allowances).	Traditionally—with a largely free allocation—no. Growing interest in a substantial allowance auction suggests opportunity to raise at least some revenue now and possibly transition to a complete auction that generates maximum revenue in the future.	No.
<b>Incentives for R&amp;D in clean technologies?</b>	Yes. Stable CO <sub>2</sub> price is needed to induce innovation.	Yes. However, uncertainty over permit prices could weaken innovation incentives.	Yes and no. Standards encourage specific technologies, but not broad innovation.
<b>Harm to competitiveness?</b>	Yes, though if other taxes are reduced through revenue recycling, competitiveness of the broader economy can be improved.	Yes (as with a tax), but giving firms free allowances offsets potentially harmful effects on profitability.	Somewhat. Regulations increase the cost of manufacturing but, unlike taxes or tradable permits, do not raise the price of fossil energy.
<b>Practical or political obstacles to implementation?</b>	Yes. New taxes have been very unpopular.	Yes. Identifying a reasonable allocation and target is difficult.	Yes. Setting the level of the standard is difficult.
<b>New institutional requirements?</b>	Minimal.	Yes, but experience with existing trading programs suggests that markets (for trading permits and exchanging information across firms and time periods) arise quickly and relatively inexpensively.	Minimal (unless tradable).



**ISSUE BRIEF 6**  
**ALLOWANCE ALLOCATION**

**RAYMOND J. KOPP**

## ALLOWANCE ALLOCATION

Raymond J. Kopp

### SUMMARY

This issue brief provides an overview of concepts and policy decisions related to the allocation of emissions allowances or permits under a cap-and-trade program for limiting greenhouse gas (GHG) emissions.

Allocation decisions distribute the wealth embodied in emissions allowances and therefore have economic impacts that can affect the net cost of the program to individual stakeholders and to society as a whole. Allocation decisions do not, however, affect the environmental performance of the program—that is, they do not change the overall level of emissions reductions achieved by the policy.

- Allowances associated with a cap-and-trade system represent an asset with potentially considerable monetary value, perhaps \$100 billion or more annually. The value of these allowances or permits is not a measure of the cost associated with meeting the cap, but rather a wealth transfer from those who pay higher energy or emissions prices under the cap-and-trade program to those who hold allowances.
- While the U.S. Acid Rain program allocated sulfur dioxide (SO<sub>2</sub>) allowances gratis (for free) to regulated entities (in that case, electric utilities), cap-and-trade systems need not adopt this approach. Permits can be allocated gratis to entities other than those that are directly regulated under the program (including, for example, households or state government). Moreover, allowances need not be allocated gratis: they can be sold by the government, which can retain resulting revenues for other purposes.
- Allocation decisions can affect both the efficiency (overall cost of meeting the cap) and the equity (distribution of the cost) of a cap-and-trade program. Generally, auctioning allowances and using the revenues to lower taxes, or offset particularly distorting taxes, increases efficiency and lowers the overall cost of the program to society. Awarding free allowances to certain stakeholders can address distributional concerns, but can sacrifice some efficiency.
- Allocation can alter economic incentives and the behavior of firms. For example, an output-based, updating approach could award free allowances to firms on the basis of output. For example, free allowances could be distributed to firms within the electric-power sector on the basis of their share of total sector-wide electricity output. Because this approach rewards firms for producing a larger share of output, free allowances will act as an output subsidy, effectively incentivizing firms to produce more. This outcome may or may not be desirable depending on the sector and the policy goals being pursued.
- Allocation to new entrants and retiring sources can be dealt with in a number of ways. However, care must be taken to ensure that the allocation methods used do not alter forward incentives for investment and retirement in ways that may

not be immediately obvious but that lead to suboptimal technology choices (either in terms of encouraging new investments in carbon-intensive technologies or delaying the retirement of uneconomic facilities).

- Arguments for free allocation are typically rooted in equity concerns: the desire to compensate sectors or regions that will otherwise bear a disproportionate share of the cost of regulation, or to blunt immediate impacts on the competitiveness of U.S. firms. As the economy adjusts to GHG constraints over time, these arguments become less compelling while the potential for economic distortions as a result of free allocation tends to grow, making it prudent to phase out free allocation in favor of auctioning allowances.

## Overview of Discussion

While many important design features must be addressed in setting up a cap-and-trade system for greenhouse gas emissions, allocation has emerged as a critical challenge in the policy debate. This is unquestionably due to the enormity of the financial assets at stake: under current proposals, tens of billions of dollars per year—perhaps \$100 billion dollars or more per year—could be divided up and given away under an emissions trading program. While allocation decisions are first and foremost distributional decisions (who gets what), two key economic concerns are relevant: (1) the risk of unintended consequences from tying allocations to some change in behavior, and (2) using allocation to mitigate costs imposed on particularly vulnerable sectors, households, or regions.

## Cap-and-Trade Systems Change Prices and Create Wealth and Obligations

Cap-and-trade systems simultaneously change prices and create assets and liabilities. Entities that are directly regulated under the cap—including producers and processors of fossil fuels in an upstream system—face new liabilities in the form of the obligation to surrender allowances. Matching those liabilities are the new assets created in the form of emissions allowances. These allowances can be given to entities at no charge (whether those entities are directly regulated or not) or held by the government and auctioned. Energy prices downstream of regulated entities will typically adjust to reflect the opportunity cost of surrendering associated allowances, which in turn is a function of carbon dioxide (CO<sub>2</sub>) content.

Importantly, however, the method by which allowances are allocated will have no impact on the performance of the cap-and-trade system in terms of its ability to achieve targeted emissions reductions.

The wealth embodied in allowances can be substantial. If an economywide cap-and-trade program were instituted in the United States and allowance prices were in the range of \$10 per ton of CO<sub>2</sub>-equivalent (CO<sub>2</sub>e), the total value of allowances circulating under the program would be approximately \$50 billion dollars annually. At higher prices on the order of \$25/ton CO<sub>2</sub>e (akin to expected prices on the European Union CO<sub>2</sub> market for 2008–2012), the value of allowances would be more than \$100 billion dollars annually, or slightly less than 1 percent of U.S. GDP.

The value of all allowances is *not* a measure of the economic cost of the regulatory program. Rather, allowance value reflects a *transfer* from those paying higher energy or emissions costs as a result of the cap-and-trade program to whatever entities initially receive the allowances (note that the receiving “entity” can be U.S. taxpayers, if allowances are auctioned to raise money for the federal treasury). What, then, is the cost of the regulatory program itself? It is the sum of the cost associated with each ton that has to be reduced to meet the emissions cap. In turn, the price of allowances depends on the cost of the marginal—or last, most expensive—ton reduced. A quick numerical example may be helpful here: suppose the economy generates ten tons of emissions before we impose a cap of seven tons. The three tons that must be reduced cost \$1, \$5, and \$10, respectively. Here the cost of the program is \$16 (\$1 + \$5 + \$10). The *marginal* cost of the last, most expensive ton is \$10; this sets the market price of allowances in our cap-and-trade program. Finally, the total value of the seven allowances will be \$70: 7 tons x \$10/ton. There is generally no simple relationship between program costs and the value of the allowances, though for the CO<sub>2</sub> policies currently under consideration in the U.S. Congress, costs are significantly smaller than the value of the allowances.

## Allowance Allocation Options

Allowance allocation can affect two important economic dimensions of a cap-and-trade program: efficiency and equity. Efficiency refers to the overall economic cost of meeting the emissions cap, while equity refers to the distribution of that cost across all sectors and households in the economy. Generally, pursuing equity objectives means sacrificing some efficiency. Several approaches can be used to determine the initial allocation of allowances under an emissions trading program.

Allowances can be given for free to entities that are especially affected by the policy—whether those entities are directly regulated (that is, required to surrender allowances) or not. The entities most burdened by the trading program will be those that are least able to pass associated costs—either the direct cost of surrendering allowances or the higher cost of energy under a system that regulates emissions upstream—through to their customers. These issues of cost “pass-through” are discussed further in Issue Briefs #7 and #8, which examine concerns about competitiveness, and in Issue Brief #11, which addresses cost and allocation issues specific to the electricity sector.

Allowances can be distributed to individual entities on the basis of past or current behavior. Alternatively, allowances may be simply auctioned and the revenue retained (and ultimately re-distributed) by the government. Any combination of the above methods can be employed.

In the case of the national SO<sub>2</sub> trading program established under the acid rain provisions of the Clean Air Act, the vast majority of allowances were given for free to those entities with emissions that were regulated under the cap. This same model was used in the eastern states’ nitrogen oxides (NOx) trading program and in the first phase of the European Union Emissions Trading Scheme (EU ETS). Nonetheless, there is no economic reason why the question of how allowances should be allocated cannot be separated from the question of how compliance obligations should be assigned—that is, there is no reason why allowances cannot or should not be provided to entities other than those directly regulated under an emissions trading program. In fact, where most of the costs of compliance are passed through to entities that are *not* directly regulated (typically in the form of higher energy prices), equity considerations may argue for an allocation focused on compensating downstream energy users.

In that case, recipients of free allowances would sell those allowances to entities that do face a direct compliance obligation. An emissions allowance can be thought of as just another input—like capital or labor—that the regulated entity needs to produce its intended product. Regardless of how allocation occurs, the allowances must eventually find their way into the hands of the regulated entities.

In the simplest case, the government may give allowances free of charge (*gratis*) to regulated or unregulated entities, or sell allowances to the regulated entities. To date, most existing trading programs—including the U.S. SO<sub>2</sub> and NOx programs

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as well as the EU ETS—have allocated most allowances for free to regulated entities. This *gratis* allocation transferred the wealth represented by the permits from the government to regulated entities, thereby affecting the equity of the program. Yet economists regularly point out that selling allowances and using the revenue to cut other taxes (or avoid tax increases) can substantially lower overall program costs. Thus, in the case of the U.S. SO<sub>2</sub> and NOx programs as well as the EU ETS, concerns about compensating regulated industry appear to have trumped efficiency considerations.

Interestingly, the allowance allocation plans that have been announced for Phase 2 of the EU ETS, as well as the allocation approaches that have been proposed for the northeastern states’ Regional Greenhouse Gas Initiative and in several draft bills introduced in the 110<sup>th</sup> Congress, rely on a mix of *gratis* allocation to different entities and allowance sales (auctions). Perhaps even more interesting, some Congressional proposals feature *gratis* allocations to entities such as states and energy-intensive commercial enterprises that are not directly regulated under the proposed policy. This change in thinking with regard to allocation policy might be taken to reflect a greater preference for efficiency. But since these proposals generally do not propose to use allowance-auction revenues to reduce taxes or displace existing distortionary taxes, their break with past allocation precedents is more likely to reflect different equity priorities.

As soon as allowances are seen as representing wealth—perhaps a considerable amount of wealth—it becomes obvious that how this wealth is distributed via the allowance allocation method will alter the relative well-being of individual firms and stakeholder groups in the economy. Allocation can also, however, alter the behavior of the aggregate economy and the pattern of GHG emissions going forward if the allocation is dependent on current or future behavior (in contrast to an allocation based entirely on historic behavior). This is because an allocation based on future actions or behavior inevitably creates incentives for those actions or behaviors. Since those actions or behaviors in turn can affect the efficiency of the cap-and-trade program, it is imperative that the incentive properties of any updating allocation method be well thought through as later discussion of an example from the EU ETS illustrates.

### Using Gratis Allocation to Mitigate the Costs of the Emissions Reduction Program to Individual Entities

As noted above, equity and other distributional objectives can be achieved through the allocation of allowances. An example is provided by draft legislation (S. 1766) introduced in the 110<sup>th</sup> Congress by Senators Bingaman and Specter. This proposal would allocate a portion of the permits for free to both regulated and unregulated entities in the energy and manufacturing sectors, as well as to states. In addition, it would steadily increase the portion of allowances auctioned relative to the portion being distributed gratis (specifically, the portion of allowances auctioned increases from 12 percent of the total allowance pool in 2012 to 26 percent by 2030). Revenues from auctioning allowances would be used to fund technology development, climate-change adaptation, and assistance to low-income households. Other legislative proposals in both the House and Senate follow the Bingaman/Specter approach and use allowance allocation for a variety of purposes besides compensating regulated industry, including to provide credits for early reductions, to promote CO<sub>2</sub> sequestration on agriculture lands, to provide adaptation assistance to communities and ecosystems that are particularly vulnerable to the effects of climate change, to subsidize energy costs for low-income households via a direct allocation to states, and to establish a dedicated source of funding for low-carbon technology R&D and commercialization activities.

While it is feasible to use allocation as the Bingaman/Specter bill proposes (that is, to distribute the cost burden imposed by the cap more equitably), doing so effectively requires good information about which sectors, households, and regions of the country will bear the cost of meeting the emissions cap. Unfortunately, this information is not readily available in a reliable and objective form; moreover, due to the magnitude of the wealth embodied in allowances, there are massive incentives for sectors, households, and regions to claim significant costs in an attempt to capture a larger share of the available allowance pool.

### Gratis Allocation: Grandfathering Based on Emissions

Suppose a decision has been made to allocate allowances for free to a particular sector. How might allowances be allocated within that sector? As has already been noted, gratis allocation to regulated entities has been the norm in emissions trading programs to date, and the simple method applied to distribute allowances to individual firms has usually involved the concept of “grandfathering.” Each regulated entity receives a share of the total allowance pool that is equal to its share of total emissions from all regulated entities in a defined baseline year (equivalently, the emissions of each regulated entity in the baseline year are multiplied by the ratio of the emissions cap to total emissions in the baseline year).

### Gratis Allocation: Grandfathering Based on Output

Grandfathering is a straightforward allocation method, but it relies on past behavior, thereby granting the greatest number of allowances to the historically largest emitters. Grandfathering can also be used in an allocation method that does not reward past emissions but is instead based on past output. That is, each regulated entity within a sector receives a share of the total allowance pool that is equal to its share of total sector-wide output (rather than emissions) in a given baseline year. Thus, the entity with the highest historic output captures the largest share of allowances, not necessarily the entity with the highest emissions.

To date, grandfathering allocations has awarded free allowances only or primarily to regulated entities, but the grandfathering approach can also be applied more broadly to distribute allowances to entities that are not directly regulated. For example, allowances could be awarded to large energy consumers to offset the impacts of higher energy

prices. In such cases, allowances might be allocated on the basis of historical output or labor input or some other metric related to the entity's ability to pass along higher energy costs.

### Gratis Allocation: Output-Based Updating

Any grandfathering approach to allocation is based on past behavior and therefore generally does not take into account changes that occur in a sector over time. A method that does take change into account is output-based updating, which is the dynamic analog to output-based grandfathering. In the updating case, output shares are recalculated over time, and successive allocations are revised to reflect each entity's changing share of sector-wide output.

While updating sounds like an improvement over static allocation, it brings with it new issues. Because regulated entities know their future allowance allocation will be tied to output, and allowances are valuable, this approach creates incentives for firms to increase their share of output so they can increase their share of allowances. Incentives to increase output have two implications. First, as firms compete to increase output and capture a larger share of the allocation, output prices fall (with the allocation acting like a subsidy on output). Second, as prices fall, consumers have a smaller incentive to reduce their consumption of the goods and services produced by the regulated sector. While lower prices

may be good thing for consumers, the fact that conservation is not fully incentivized increases the overall cost of the cap-and-trade program.

### Gratis Allocation: Changing Incentives

There is no limit to the variety of approaches and methodologies that could be used to distribute free allowances to different entities and stakeholder groups. Many forms of allocation have been and will be proposed to achieve some economic and/or political objectives. From the standpoint of economic efficiency and environmental effectiveness, however, what matters most is the effect the allocation method has on the future behavior of entities in the economy. As should be evident from the foregoing discussion, this effect may not be immediately apparent.

Under the EU ETS, for example, a regulated entity loses its allocation if it closes a regulated facility. This seems like a reasonable rule—no emissions, no allocation. But the effect of this rule is to create forward-looking incentives to keep inefficient and perhaps highly emitting facilities operating just so the parent firm can claim allowances. This outcome would likely not be desirable in the power sector, but could be viewed as advantageous for sectors that are subject to external competitive pressures; in this case, keeping facilities from closing and moving abroad would likely be viewed as a good outcome.

### Allocation to New and Retiring Sources

One of the more challenging issues that arises in designing an allocation methodology is how to handle the entry of new sources and the retirement of existing sources. Where will new sources get allowances and what happens to the allowances given to retiring sources that no longer need them? If allowances are auctioned, new entrants and retiring sources pose no special problems—new entrants buy allowances like all existing sources, while retiring sources should be holding no excess allowances.

The problem of accommodating new and retiring sources comes about when some or all allowances are allocated gratis. In this case, the government is transferring wealth to the private sector. If new entrants are not afforded the same wealth transfer as existing sources, they may be disadvantaged. Similarly, retiring sources benefit if they are able to retain their allocations after ceasing operation.

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From the standpoint of economic efficiency and environmental effectiveness, however, what matters most is the effect the allocation method has on the future behavior of entities in the economy.

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## Deciding how to allocate emissions allowances under a CO<sub>2</sub> cap-and-trade program amounts to deciding how to distribute an asset worth, in aggregate, tens (if not hundreds) of billion dollars per year.

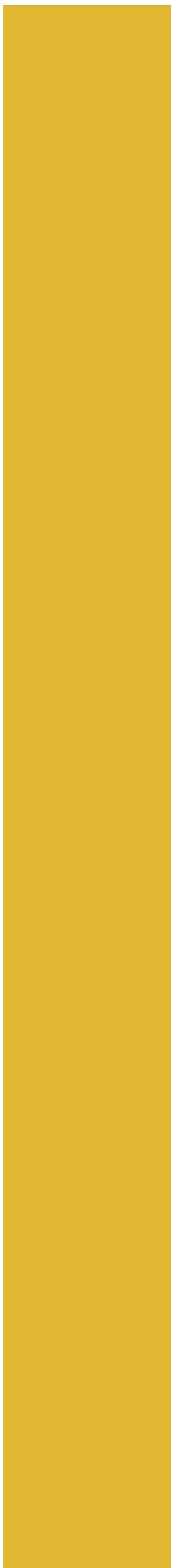
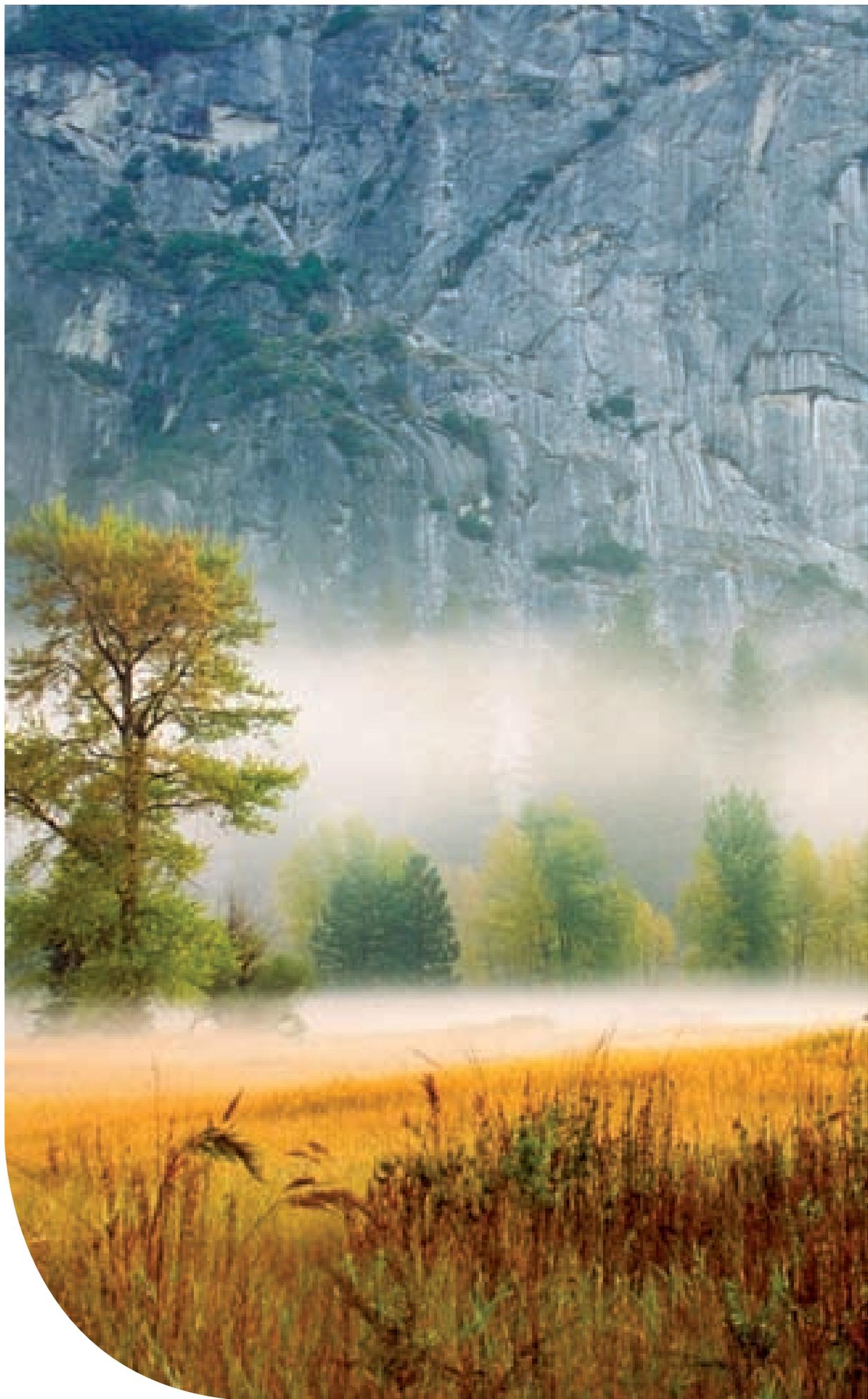
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There is no single view on how to treat this issue. As noted previously, the EU ETS sets aside allowances for future allocation to new entrants and reclaims allowances from retiring sources. In contrast, the current U.S. SO<sub>2</sub> program has a very limited allowance set-aside for new entrants and allows retiring entities to retain their allowances. In some recent climate-policy proposals in the United States, allocations to new entrants are conditioned on the achievement of certain performance standards. For example, new coal-fired power plants might be required to achieve the same emissions level as integrated gasification combined-cycle plants to qualify for allowances from a reserve pool or set-aside for new entrants.

As already noted, the problem with setting allowances aside for new entrants and reclaiming allowances from retiring sources lies in the incentives this creates for future business behavior. Tying allowances for new entrants to the achievement of certain technology benchmarks can favor technology in unintended ways and on grounds other than curbing GHG emissions. Obviously, the concern about creating incentives that distort future behavior in undesirable ways diminishes in importance over time under a policy that gradually shifts to auctioning all or most allowances, as was recently proposed by a coalition of business and environmental groups known as the U.S. Climate Action Partnership.

## Conclusion

Deciding how to allocate emissions allowances under a CO<sub>2</sub> cap-and-trade program amounts to deciding how to distribute an asset worth, in aggregate, tens (if not hundreds) of billion dollars per year. It is a hard distributional question that in some sense begs a legislative answer. Congress has typically been the authority best equipped to adjudicate questions of a fundamentally distributional nature. At the same time, analysis can inform important economic questions. First, the impact of a cap-and-trade program is not as obvious as it might seem: regulated businesses do not necessarily bear the brunt of program costs. More to the point, regulated entities need not be the only entities that receive free allocations. Second, there is growing interest in using auctions to distribute a large share of allowances (and, in some recent proposals, eventually most or nearly all allowances). This change in thinking about allocation has come about for a variety of reasons: one rationale is that using auction revenue to cut other taxes (or to avoid tax increases) can substantially reduce the cost of the climate policy. Finally, it is very important to consider how allocation rules can spur future behavior in possibly unintended ways. Unintended changes in incentives and behavior have the potential to significantly raise the cost of the climate program.





**ISSUE BRIEF 7**

**COMPETITIVENESS IMPACT  
CARBON DIOXIDE PRICING  
ON MANUFACTURING**

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AND WILLIAM A. PIZER

IS



## COMPETITIVENESS IMPACTS OF CARBON DIOXIDE PRICING POLICIES ON MANUFACTURING

Richard D. Morgenstern,  
Joseph E. Aldy,  
Evan M. Herrnstadt,  
Mun Ho, and William A. Pizer

### SUMMARY

In the debate over the design of mandatory federal climate change policy, the potential for adverse impacts on the competitiveness of U.S. industry, on domestic jobs, and on the nation's balance of trade consistently emerges as a key concern. This issue brief explores how production across individual manufacturing industries could be affected by a unilateral policy that establishes a price on carbon dioxide (CO<sub>2</sub>) emissions. (Issue Brief #8 examines possible policy responses to address these impacts.) Our review of existing analyses and new research<sup>1</sup> on the topic of climate policy and U.S. competitiveness yields a number of observations:

- The impact of a CO<sub>2</sub> price on the competitiveness of different industries is fundamentally tied to the energy (and more specifically, carbon) intensity of those industries, and the degree to which firms can pass costs on to the consumers of their products. The answer to the latter question hinges on the extent to which consumers can substitute other, lower-carbon products and/or turn to imports.
- Industry-level studies of competitiveness tend to focus on the energy-price impacts of a specific CO<sub>2</sub> policy. They typically do not consider what level of carbon price would be required to meet a particular emissions-reduction target or how overall program stringency is coupled with

decisions about offsets and/or a safety valve. Studies of competitiveness impacts typically also ignore “general equilibrium” effects, such as the possibility that shifting from coal to natural gas for power generation could drive up natural gas prices and have additional effects on the competitiveness of natural gas users.

- Energy costs in most manufacturing industries (broadly defined at the two-digit classification level) are less than 2 percent of total costs. However, energy costs are more than 3 percent of total costs in a number of energy-intensive manufacturing industries such as refining, nonmetal mineral products, primary metals, and paper and printing. For these more energy-intensive industries, total production costs rise by roughly 1 percent to 2.5 percent for each \$10 increment in the per-ton price associated with CO<sub>2</sub> emissions (with less being known about the impacts of larger CO<sub>2</sub> prices). Also, cost impacts can be considerably greater within more narrowly defined industrial categories.
- Recent case studies in the European Union (EU) found more substantial impacts in some industries when narrower industry classifications were used and process emissions were also considered. Specifically, a \$10-per-ton CO<sub>2</sub> price led to a 6 percent increase in total costs for steel production using basic oxygen furnace (BOF) technology; for cement, production costs increased by 13 percent. With free allowance allocation and some ability to increase prices, however, researchers have

<sup>1</sup> Results of this work are forthcoming in two RFF Discussion Papers, one by J. Aldy and W. Pizer, and another by Morgenstern, Ho, and Shih. This issue brief does not consider competitiveness impacts arising from the regulation of non-CO<sub>2</sub> gases; see Issue Brief #13 for some discussion.

found that adverse impacts on industry can be reduced substantially. Using simple demand models, one study found that output in most industries declined less than 1 percent—and by at most 2 percent in the most strongly affected industries—for a \$10-per-ton CO<sub>2</sub> price with 95 percent free allocation.

- More generally, cost increases can be translated into impacts on production, profitability, and employment using either an explicit model of domestic demand and international trade behavior, or empirical evidence from past cost increases.
- Using an economic model of U.S. industrial production, demand, and international trade, Morgenstern et al. generally find adverse effects of less than 1 percent when estimating the reduction in industrial production due to a \$10-per-ton CO<sub>2</sub> charge. The exceptions are motor vehicle manufacturing (1.0 percent), chemicals and plastics (1.0 percent), and primary metals (1.5 percent). These estimates represent near-term effects—that is, impacts over the first several years after a carbon price is introduced—before producers and users begin adjusting technology and operations to the new CO<sub>2</sub>-policy regime. Longer-term effects could be larger or smaller.
- Using an empirical analysis of historical data on energy prices and industry output across five countries, Aldy and Pizer find somewhat larger impacts. While a \$10-per-ton CO<sub>2</sub> charge is estimated to reduce industrial production by less than 1 percent in most cases—consistent with the results of the Morgenstern et al. study—considerably larger effects are found in some industries, notably non-ferrous metals (3.0 percent), iron and steel (6.0 percent), fabricated metals (1.8 percent), and machinery (3.9 percent).
- Impacts on domestic industries will generally be lower if it is assumed that key trading partners also implement comparable CO<sub>2</sub> prices or that border tax adjustments or other import regulations are used to address the CO<sub>2</sub> content of imported (and exported) goods. Analysis by Aldy and Pizer suggests that such assumptions reduce the estimated impact on domestic production among energy-intensive manufacturing industries by perhaps 50 percent.
- Various current proposals for a mandatory U.S. cap-and-trade program to limit greenhouse gas (GHG) emissions would give free allowances to different industries to help address economic burdens from a CO<sub>2</sub> pricing policy.
- Calculations based on results from Morgenstern et al. suggest that for most industries where energy is more than 1 percent of total costs, giving away free allowances equal to around 15 percent of a firm's emissions from fossil-fuel and electricity use would be sufficient to address adverse impacts on shareholder value. This number varies widely, however, across different industries. As with earlier calculations, narrower industry classifications can produce much higher estimates of the free allocation necessary to address lost shareholder value.

## Introduction

As the United States considers mandatory policies to address climate change, an important consideration is the potential for such policies to cause a significant decline in some domestic industries, along with a corresponding increase in imports and/or production elsewhere in the world. The potential for such impacts gives rise to at least two kinds of concerns: first, the risk of damage to the domestic economy and second, the risk that environmental benefits will be negated or offset to a significant extent if the result of the policy is to shift emissions-intensive production activities to unregulated regions of the world. These impacts are frequently referred to as competitiveness effects, or effects on U.S. competitiveness.

The impact of a CO<sub>2</sub> price on domestic industries is fundamentally tied to the energy (and, more specifically, the carbon) intensity of those industries, the degree to which they can pass costs on to the consumers of their products (often other industries), and the resulting effect on U.S. production. The latter question—that is, the likely impact on U.S. production—hinges on two factors: first, the extent to which domestic products face competition from imports and second, consumers' ability to substitute other, less carbon-intensive alternatives for a given product. The first of these factors relates directly to the environmental risk noted above: because climate change is driven by global emissions of GHGs, the benefits of a domestic policy could be substantially eroded if an increase in U.S. production costs caused the manufacture of emissions-intensive goods to shift to nations that do not adopt GHG policies, or that have substantially weaker policies.

The scale of these potential impacts is unprecedented in the history of environmental regulation, as is the range of industries that would be affected by a mandatory domestic climate policy. Quantifying potential impacts is also complex. By contrast, the debate leading up to the 1990 Clean Air Act Amendments was informed by extensive government-

and industry-sponsored analyses of the likely effects of a cap-and-trade program for sulfur dioxide emissions on the electric power sector. These analyses were greatly simplified by the fact that the policy under consideration targeted a largely regulated industry that faced almost no international competition. A pricing policy for GHG emissions would not only have much more significant direct impacts on coal and other domestic energy industries, it could adversely affect the competitiveness of a number of large energy-intensive, import-sensitive industries. Unfortunately, information concerning industry-level impacts associated with new carbon mitigation policies is quite limited.

This issue brief reviews two recent, detailed analyses of competitiveness effects on European manufacturing industries using case studies of key sectors, and presents some early results from two research projects underway at RFF that explore the potential impacts of a CO<sub>2</sub> price on U.S. manufacturing industries.<sup>2</sup> All of these analyses also consider how permit allocation schemes could affect net industry costs. Throughout the discussion that follows, we assume that the GHG policy is implemented in a single country or bloc of nations (the EU or the United States) and not on a global basis. Global implementation and/or the use of a border tax adjustment or similar policy would reduce the competitiveness effects of a national-level policy, a point to which we return at the end of this issue brief.

Importantly, the results presented here depend, in part, on the breadth of the industry classifications considered and, for some industries, on whether or not process CO<sub>2</sub> emissions are included. The EU studies discussed in this issue brief tend to focus on narrower industrial categories that are more energy-intensive than is typical for the broader industrial classification under which they fall. These studies also include process emissions. In contrast, both U.S. studies focus exclusively on combustion-related emissions and use somewhat broader industrial categories. Each of these features tends to reduce the magnitude of predicted competitiveness impacts. On the other hand, one of the U.S. studies includes emissions associated with intermediate inputs, which would tend to have the opposite effect of increasing the magnitude of predicted impacts. All the analyses reviewed here focus on industry averages. Actual impacts on individual firms—as well as within more narrowly defined sectors—could differ significantly from the industry-wide average. Finally, the emphasis in this issue brief is on summarizing the results of several different analyses; detailed methodological

explanations will be available in the full studies. The question of what policy mechanisms might be available to address adverse competitiveness effects, meanwhile, is taken up in a companion issue brief (Issue Brief #8).

## Recent EU Studies

Two recent studies have estimated the competitiveness impacts of the EU Emissions Trading Scheme (EU-ETS). One study was conducted by McKinsey & Company and Ecofys (hereafter, McKinsey) for the European Commission; the second was conducted by Reinaud for the International Energy Agency (IEA).<sup>3</sup> Both studies adopt a relatively straightforward framework for computing impacts, starting with a calculation of the cost increases that would arise from a particular CO<sub>2</sub> charge. The calculation includes emissions-related cost increases from the consumption of fossil energy and from process emissions, as well as the indirect cost of higher electricity prices.<sup>4</sup> The EU studies also consider the extent to which free permit allocation, based on direct emissions only, could mitigate estimated cost impacts.<sup>5</sup> While both studies focus on representative sub-sectors within particular energy-intensive industries, they also differ in certain respects. The more recent McKinsey study considers a carbon price of \$20 per ton CO<sub>2</sub>, while the IEA scenario considers a price of \$10 per ton CO<sub>2</sub>. Importantly, all of the studies discussed here, including the EU studies, take a specific CO<sub>2</sub> price as a given. That is, none of the studies attempts to address the question of what price would be required to achieve a particular emissions-reduction target, nor do any of the studies examine the cost impacts of other policy design choices, such as whether an offsets program or price-cap mechanism (safety valve) is included.<sup>6</sup> In addition, these studies ignore the possibility that fuel switching from coal to natural gas in the power sector could drive up natural gas prices, creating additional competitiveness concerns for industries that use natural gas.

The McKinsey study considers a 95 percent free allocation coupled with explicit assumptions about how much of any production-cost increase associated with a carbon price will pass through to higher product prices in different

3 McKinsey & Company and Ecofys (2006). EU ETS Review: Report on International Competitiveness; Reinaud, J. (2005) "Industrial Competitiveness Under the European Union Emissions Trading Scheme," International Energy Agency.

4 Both studies assume the power generation industry passes on the full opportunity cost of carbon allowances. To calculate costs associated with electricity consumption, the McKinsey study assumes 0.41 tons of CO<sub>2</sub> emissions per megawatt-hour (MWh); the Reinaud study uses the 2001 average CO<sub>2</sub> intensity of grid-supplied electricity. Neither study considers how facilities might respond to a carbon price by reducing direct emissions and/or electricity consumption, thereby lessening the cost impacts of the carbon policy.

5 While a free allocation clearly benefits shareholders, the question of whether a free allocation based on historic emissions would offset the production-cost increases that are relevant for competitiveness concerns (in terms of changing prices, production, and employment) remains open. Rules that rescind allocations if a plant closes would encourage facilities to use free allowances to offset costs; rules that allow facility owners to keep free allowances when a plant closes would not.

6 The question of how different targets translate to CO<sub>2</sub> prices is discussed in Issue Brief #3.

2 The effect of including other greenhouse gases in any new regulatory scheme is not considered in these analyses; see Issue Brief #14.

manufacturing industries. McKinsey bases these assumptions on the published literature and its own industry expertise. However, this analysis only goes so far as to calculate net cost impacts—it does not report predicted effects on output. In contrast, the Reinaud analysis considers both 90 and 98 percent free allocation, calculates the net effect on prices, and then applies demand elasticities from the literature to estimate changes in output. That is, McKinsey focuses on changes in net costs while Reinaud attempts to trace cost impacts through to effects on output, as the U.S. studies discussed later in this issue brief also do. Key results from the two European studies are displayed in Table 1, where we have interpolated the Reinaud results to match the 95 percent free allocation in the McKinsey study and have scaled both sets of results to match the \$10-per-ton CO<sub>2</sub> price used in the U.S. analyses discussed below.<sup>7</sup>

The results shown in columns 1 and 4 of Table 1 suggest that initial cost impacts, before adjustment for free allowance allocation or cost pass-through, vary widely across industry sub-sectors. This variation reflects differences in energy intensity and, particularly in the case of cement, differences in process emissions. Both the McKinsey and the Reinaud/IEA studies estimate the largest initial cost impacts in BOF steel, aluminum, and cement, with relatively smaller impacts in electric arc furnace (EAF) steel. McKinsey also finds relatively large initial impacts in the petroleum industry (not included in the study done for the IEA), while Reinaud finds relatively large initial impacts in newsprint (not studied by McKinsey).

Not surprisingly, net cost burdens fall significantly if industries are given a free allocation of allowances equivalent to 95 percent of their direct emissions, as shown in columns 2 and 5 of Table 1. The net cost burden after free allocation for BOF steel and cement, for example, falls by roughly 85–90 percent, an amount that reflects the substantial primary fuel consumption and only modest use of electricity that characterizes these industries. In contrast, electricity-intensive industries with significant indirect emissions from electricity use, like EAF steel, see a smaller decline (of roughly 10 percent) in the net cost burden under a 95 percent free allocation based only on direct emissions. This is because the EU ETS allocation scheme does not address cost increases arising from higher electricity prices (where higher electricity prices reflect the indirect emissions associated with power generation). Similarly, aluminum producers do not gain from free permit allocation under the EU ETS rules because of their limited direct emissions, despite the fact that this industry

experiences large cost increases due to its heavy reliance on purchased electricity. Other industries with a mix of direct and indirect emissions—such as certain segments of the pulp and paper industry—fall in between.

The European studies differ most significantly in terms of how far they take the analysis. The McKinsey study develops explicit assumptions about cost pass-through for each industry—that is, how much of a given production-cost increase will show up in higher product prices. These assumptions, which are based on the published literature and on the authors' own expertise, are shown in parentheses in column 3 of Table 1. Estimated price impacts are based on the threshold change in revenue needed to keep a facility open, assuming no change in demand for the product (or facility output) in response to higher prices. Importantly, the analysis also assumes that firms will attempt to pass through all cost increases associated with the climate policy, regardless of free allocation. The Reinaud/IEA study instead applies demand elasticities—that is, it assumes that industrywide prices will rise to reflect the increase in costs but that demand and production will fall somewhat as a result (generally by 2 percent or less).

Assuming cost pass-through of 6 percent, the McKinsey study finds that the net impact on BOF steel, after a 95 percent free allocation, drops to 0.6 percent, as shown in column 3. For cement producers, with an assumed cost pass-through rate that varies from 0 to 15 percent (depending on location), estimated impacts after a 95 percent free allocation range from a net cost of 1.4 percent to a net *gain* of 0.6 percent.<sup>8</sup> For the highly competitive aluminum industry, the McKinsey study assumes zero ability to pass through higher electricity costs. As a result (and because the free allocation is based on direct emissions only), this industry experiences the largest competitive effects, as displayed in Table 1. By contrast, for petroleum refining—where McKinsey assumes a cost pass-through rate of 25–75 percent—the results suggest a net *gain* of 0.9–4.5 percent.

## New RFF Studies

Two new analyses of U.S. manufacturing, one by Morgenstern, Ho, and Shih and the other by Aldy and Pizer, are nearing completion. Morgenstern, Ho, and Shih use a simulation model of the U.S. economy, including trade flows and an international sector, to estimate the domestic, industry-level

<sup>7</sup> Studies were scaled to \$10/tCO<sub>2</sub> by assuming linear cost effects and using an exchange rate of C1 = \$1.39.

<sup>8</sup> The analysis assumes that plants located near the coast cannot pass along higher costs because of competition from imports. By comparison, inland facilities that face less competition are assumed to have some ability to raise prices in response to increased costs.

Table 1

Estimated cost impacts under the EU ETS for various industries (as % of total production costs)

Industry	McKinsey (\$10/tCO <sub>2</sub> )			Reinaud/IEA (\$10/tCO <sub>2</sub> )		
	1	2	3	4	5	6
	Cost increase (%)	Net of free allowances (%)	Net of allowances and cost pass-through* (%)	Cost increase (%)	Net of free allowances (%)	Demand reduction <sup>^</sup> (%)
BOF Steel	6.2	1.0	0.6 (6%)	5.89	0.63	0.79 (-1.56)
EAF Steel	1.0	0.9	0.2 (66%)	1.65	0.63	0.36 (-1.56)
Cement	13.1	1.4	-0.6 to 1.4 (0% to 15%)	14.47	1.77	0.29 (-0.27)
Primary Aluminum	4.1	4.1	4.1 (0%)	2.70**	2.70**	2.09** (-0.86)
Secondary Aluminum	0.2	0.2	0.2 (0%)			
Newsprint				3.62	0.95	1.44 (-1.88)
Chemical Pulp	0.4	0.2	0.0 (50%)			
Paper from Chemical Pulp	0.8	0.4	0.3 to 0.4 (0% to 20%)			
Chemical Pulp/Paper	0.9	0.4	0.2 to 0.4 (0% to 20%)			
Mechanical Pulp/Paper	2.0	1.5	1.1 to 1.5 (0% to 20%)			
Thermo-Mechanical Pulp/Paper	2.7	2.2	1.7 to 2.2 (0% to 20%)			
Recovered Pulp/Paper	1.2	0.7	0.4 to 0.7 (0% to 20%)			
Average Process Petroleum Refining	7.4	0.9	-4.5 to -0.9 (25% to 75%)			

\* Note: Estimated industry-level cost pass-through rates from the McKinsey study are shown in parentheses.

\*\* Denotes figures for aggregate aluminum industry (primary and secondary).

<sup>^</sup> Expected % reduction in demand assuming full pass-through of net costs (including free allocation). Assumed demand elasticities are shown in parentheses.

impacts of pricing CO<sub>2</sub> emissions. Aldy and Pizer conduct an econometric analysis of data on energy prices and industry performance across a number of countries and industries. As noted previously, the industrial categories considered by Morgenstern et al., based on available 2002 data,<sup>9</sup> are broader than those used in the EU studies, while Aldy and Pizer use categories somewhat similar to those of the EU analyses. Both

of the U.S. studies focus exclusively on combustion emissions and ignore process emissions, although one of the U.S. studies (Morgenstern et al.) does include emissions associated with the purchase of domestically produced intermediate inputs. It should be noted that changes in production and energy use since 2002 are not captured by these studies.<sup>10</sup>

<sup>9</sup> The calculations presented here are extrapolated from the Bureau of Economic Analysis *Annual Input-Output Table* for the 1997 benchmark. In addition, we used the Energy Information Administration's *Manufacturing Energy Consumption Survey* from 2002. We anticipate updating the calculations once the 2002 benchmark data become available.

<sup>10</sup> As the climate policy debate has intensified in recent years, some industries may have already begun to adjust production in anticipation of future carbon regulation. For example, in the steel industry there is anecdotal evidence that some of the most carbon-intensive parts of the production process may have already moved off-shore and that more semi-finished steel is imported now than previously.

### Results from the Morgenstern, Ho, and Shih Analysis

The Morgenstern, Ho, and Shih study focuses on plant managers' near-term options for responding to a CO<sub>2</sub> policy that raises the cost of energy (including electricity) as well as that of other intermediate goods. For example, a chemical plant that is suddenly faced with higher energy costs cannot immediately and costlessly convert to more energy-efficient methods. If plant owners leave output prices unchanged, the higher input costs will lower profits. If they instead raise prices to cover higher input costs, sales can be expected to decline. The extent of this decline would depend on the behavior of other chemical plants, other industries, and other sources of product demand. To capture some of these complexities, this analysis considers two different time horizons, immediate and near term.

In the immediate analysis, firms are assumed to have no opportunities at all to respond to higher energy (carbon) prices. That is, firms cannot raise the prices they charge for their outputs, alter the technologies used to produce those outputs, or make other process adjustments, such as substituting cheaper (lower-carbon) alternatives for now more expensive carbon-intensive inputs. Because product or output prices stay the same, the analysis assumes that customers also do not make any immediate adjustments in demand and continue to buy the product under consideration in the same quantities. These assumptions correspond to the assumptions used to estimate "cost increases" in the EU studies (that is, columns 1 and 4 of Table 1), except that the Morgenstern et al. analysis also considers the indirect effects of higher prices for all intermediate goods under a CO<sub>2</sub> pricing policy, not just electricity; and excludes process emissions.

Beyond the immediate time horizon, we would expect that when costs rise across an entire industry, product prices will rise in that industry. This increase in prices would at first increase revenues and thus offset the initial impact of higher costs, but eventually it would also lead to a decline in sales, employment, and profits as customers switch to substitute goods or overseas suppliers whose prices do not reflect a charge for CO<sub>2</sub> emissions.<sup>11</sup> At the same time—that is, within this near-term horizon—industry's ability to adjust the technologies it uses or to substitute cheaper (lower-carbon) inputs in the production process is constrained. Higher product prices mean increased profits per unit sold, but as demand falls, fewer units are sold and revenues and profits may begin to decline.

Over the longer term, firms are likely to substitute some inputs for others—for example, replacing steel with plastic—and generally find ways to save energy and reduce carbon-related costs. The ability to switch to less carbon-intensive inputs and technologies, in turn, ameliorates price and demand effects relative to expected effects in the immediate and near term. The larger economy is also adjusting and customers can be expected to begin altering their purchase behavior in response to new price signals. For example, cement producers may have more options for improving energy efficiency and reducing costs over the long run than they do in the short run. Thus, the long-term impact of a carbon pricing policy on any particular industry reflects a number of competing changes, and may be larger or smaller in net than it is over immediate and near-term horizons. Unfortunately, the results of RFF's longer-term modeling analyses are not yet complete.

To the extent that preliminary model results are available, they indicate that the impact of a carbon charge is most obviously linked to patterns of energy use in particular industries. Table 2 presents estimates of energy costs as a share of total costs. Column 1 displays electricity costs as a share of total costs, while column 2 displays the sum of costs associated with electricity use and direct combustion of fossil fuels. Note that crude oil used as a feedstock in the refining sector is not counted as an energy cost. Similarly, other non-fuel uses of oil and chemical products are also excluded. Even with this feedstock exclusion, however, petroleum refining is still the sector with the highest energy cost (16.4 percent). Other sectors with high energy costs relative to total cost are primary metals (4.7 percent); nonmetallic mineral products, such as cement (3.7 percent); and paper (3.4 percent). At the low end of estimated cost, there are motor vehicles (0.7 percent) and electrical equipment (0.9 percent).

Cost estimates for aggregate industry sectors hide considerable intra-sector variation. For example, estimated energy costs for the chemicals and plastics industry, when viewed at the aggregate level, amount to 2.9 percent of total production costs. However, based on more disaggregated data available for 1997, the range is much wider across specific subcategories within this sector: from 0.6 percent to 34 percent. Based on the earlier data, five of the more narrowly defined industries that fall under the heading of chemicals and plastics have energy cost shares in excess of 10 percent, while three have shares less than 1 percent.<sup>12</sup> Unfortunately,

<sup>11</sup> In response to lower demand, domestic producers will also buy fewer intermediate inputs; however, we do not focus on that effect in this analysis.

<sup>12</sup> The 6-digit data are available from the 1997 benchmark input-output table. In computing the 6-digit combustion shares we assume that the combustion to feedstock ratios across all 6-digit industries is equal to the average ratio for the whole 2-digit industry. It is possible that some of the variation in energy cost share is masking differences in feedstock use.

detailed data on energy expenditures are not yet available for 2002, and there are no data on actual energy use at the level of detail necessary to separate feedstock use from combustion use. Nonetheless, it would be useful to add more detailed data to the Morgenstern et al. analysis in the future to develop a better sense of the range of output effects and net costs, taking into account compensation in the form of allowance allocation.

One major concern associated with pricing CO<sub>2</sub> emissions is that this policy will cause consumers to substitute imports for domestic products. While the potential for increased import substitution is not necessarily linked to current import levels, Table 2 presents information on the current import share of U.S. consumption in column 3 to give an indication of the potential vulnerability of different industries to overseas competition.<sup>13</sup> Apparel has the highest import share, and also has high electricity costs as a share of total costs. Electrical equipment and motor vehicles have relatively high import shares but they are not as energy-intensive. Among the most energy-intensive manufacturing sectors, the primary metals sector has the highest import share at 21 percent, followed by chemicals (20 percent) and nonmetallic mineral products (15 percent).

Over a near-term time horizon, Morgenstern et al. consider the immediate impact of a carbon charge where producers do not adjust prices or technologies—they just pay for the CO<sub>2</sub> content of the energy and intermediate goods they consume. The effect of a \$10-per-ton CO<sub>2</sub> charge on overall production costs is given in the last three columns of Table 2, broken down by effects from the use of direct fuel (column 4), electricity (column 5), and intermediate goods (column 6).<sup>14</sup> Columns 7 and 8 sum these effects to show the total impact due to costs from energy use only, as well as from energy use associated with the consumption of intermediate goods. The largest total cost impacts are in the refining sector (2.3 percent), primary metals (1.5 percent), nonmetallic minerals (1.0 percent), paper and printing (0.9 percent), textiles (0.6 percent), and chemicals and plastics (0.6 percent). Over an immediate time horizon, output prices are regarded as fixed and there is assumed to be no demand response: that is, customers continue to buy the same quantities of goods (output) as long as prices don't change. As a result,

the expected decline in profits simply equals the expected increase in input costs. These effects are generally lower than the results reported in the EU studies, as becomes evident from a comparison to columns 1 and 4 of Table 1. This is due primarily to the fact that the EU studies use narrower classifications to focus on specific industries with high energy use, and, in the case of cement, include process emissions.

Beyond the immediate time horizon, there will be upward pressure on prices to recover the higher costs shown in column 8 of Table 2. The impact of higher prices on sales is estimated by simulating the response for each industry using a model of the U.S. economy.<sup>15</sup> This model allows buyers to choose among the outputs from different industries and to choose between domestic suppliers and importers. Buyers include other firms, households, and exports. Importantly, at this stage of the analysis the industry being scrutinized is itself not allowed to choose different combinations of production inputs. Using this model and assuming that the industry-wide increase in product prices is equal to the increase in costs reported in Table 2, the expected change in output for different industries under a \$10-per-ton charge on CO<sub>2</sub> emissions is shown in column 1 of Table 3.<sup>16</sup>

In all sectors, the decline in sales depends on the elasticity of demand. Primary metals see the largest drop (1.5 percent) followed by chemicals and plastics and motor vehicles (both 1 percent). Fabricated metals and wood and furniture are estimated to experience the smallest demand reductions. Petroleum products likewise experience a relatively small decline (0.4 percent). Over time, however, as evidenced by the oil shocks of the 1970s, impacts on the petroleum sector could increase significantly. The results for this U.S.-based analysis can be compared to the EU estimates in column 6 of Table 1, but it is important to note that the EU estimates include the benefits of a free allocation to producers, while the estimates for U.S. industries in Table 3 do not.

### Results from the Aldy and Pizer Analysis

Aldy and Pizer take an entirely different approach in attempting to quantify the effect of a CO<sub>2</sub> charge on the competitiveness of U.S. industries. They utilize the close relationship between carbon regulation and energy prices to study how policy-induced changes in the cost of fossil energy affect industry-level output, employment, and other commonly used metrics of competitiveness. The analysis is

13 Energy cost share is defined as the value of purchases of electricity and fuel divided by net industry output. The official data from the BEA or BLS is gross industry output which includes transactions between establishments within the same industry. These intra-industry transactions are excluded from our measure of output.

14 An important distinction between this competitive analysis and the EU studies is the consideration of how CO<sub>2</sub> pricing will raise the price of intermediate goods, not just fuel and electricity. For energy-intensive goods, this distinction is relatively minor as the direct effect through energy dominates; for less energy-intensive goods, such as motor vehicles, however, the indirect effect through intermediate goods—such as steel—dominates.

15 Adkins, Liwayway and Richard Garbaccio (2007) "Coordinating Global Trade and Environmental Policy: The Role of Pre-Existing Distortions," mimeo, National Center for Environmental Economics, US EPA; see forthcoming discussion paper for further details.

16 The effect on petroleum refining also assume that refined products—both domestic production and imports—face a similar \$10-per-ton CO<sub>2</sub> charge.

strictly econometric: it relies on historical data to examine the competitiveness impacts of past electricity price changes over the short to medium timeframe, controlling for a range of other relevant factors.<sup>17</sup> Electricity prices are used as a proxy for energy prices because of the lack of consistently available fuel price data in other countries.<sup>18</sup> The analysis focuses on industry behavior in Australia, Canada, New Zealand, the United Kingdom, and the United States over the period 1978–2000. Aldy and Pizer focus on industry responses in these countries because they have similar flexibility in their labor markets; a wider data set of 26 countries is also available.

Their analysis provides statistical estimates of the average effect of electricity prices on output in manufacturing industries, controlling for the subject nation's real GDP, an index of foreign electricity prices, the real exchange rate, any other fixed differences (i.e., differences that are unchanging over time), as well as simple differences in secular trends (that is, different growth rates) across countries.<sup>19</sup> Similar to the analysis by Morgenstern et al., Aldy and Pizer then use their effect estimates to explore how a given CO<sub>2</sub> price would increase energy prices and cause output to decline in particular industries. The key results are displayed in column 2 of Table 3.

Compared to the Morgenstern et al. estimates in column 1, the output effects estimated by Aldy and Pizer are two to six times higher. Comparing the Aldy and Pizer estimates to the EU case study results shown in column 6 of Table 1 (and adjusting for the effects of free allowance allocation to the steel industry in the latter analysis), the output effects estimated by Aldy and Pizer are slightly low for steel and high for aluminum (non-ferrous metals). These differences may arise because the data sources and analysis techniques are different, because the European industries analyzed simply behave differently than their U.S. counterparts, or because the policy experiment is different. Industries in some of the smaller countries in the Aldy and Pizer analysis (Australia, New Zealand, and Canada) may be more import sensitive than industries in the United States, the United Kingdom, or the EU. Also, because Aldy and Pizer use historical variation in national energy (electricity) prices to identify effects on industrial output, they are implicitly considering the impact of many other price changes that may go along with

energy/electricity price changes (this is akin to the effort by Morgenstern et al. to include effects from rising prices for intermediate goods).

In any case, the range of estimated impacts shown in column 6 of Table 1 and in both columns of Table 3 is informative in two respects. First these estimates provide a sense of the absolute magnitude of likely impacts. Second, even if it remains difficult to pin down the absolute magnitude of output effects, these estimates provide information about relative impacts across different industries and can help to identify sectors that are especially vulnerable to adverse competitiveness impacts under a carbon pricing policy.

## Allowance Allocation

While the EU-ETS provides for a near-100 percent free allocation, various domestic policy proposals currently under consideration in the United States are less specific on this issue. One option is to give energy-intensive industries an allocation of free allowances roughly equal to their carbon emissions—where that quantity reflects either direct fuel-related emissions only or all emissions, including indirect emissions arising from electricity use. Alternatively, allocation methodologies could be devised around some notion of compensating firms for lost shareholder value as a result of the climate policy. To get a sense of the difference between these approaches, the results from Morgenstern et al. can be used to quantify the relationship between carbon emissions and the potential for lost shareholder value. If policymakers are concerned about immediate cost impacts under a CO<sub>2</sub> policy, it is instructive to compare the estimates reported in column 8 of Table 2 to the value of CO<sub>2</sub> allowances associated with a 100 percent free allocation (where this value is obtained by simply multiplying each industry's carbon emissions by the \$10-per-ton CO<sub>2</sub> price used in the analysis). If the concern is to address impacts over a somewhat longer time horizon (several years), one could compare the additional impact—positive or negative—associated with rising product prices and declining product demand and compare that to the same allowance value. This calculation is also instructive for understanding more generally the magnitude of the impact a carbon price might have on industry profitability. Comparing effects on profitability to CO<sub>2</sub> allowance value, in turn, can help policymakers develop a sense of how many free allowances might be required to compensate firms in different industries for lost shareholder value.

<sup>17</sup> The Aldy and Pizer research includes two data sets, one U.S. and one international. Here, we report only on the international results that provide industry-level detail.

<sup>18</sup> By the end of the sample period, electricity represented 70 percent of total manufacturing energy costs in the United States and 88 percent of manufacturing industries reported that electricity accounted for the largest share of their energy costs. Further, electricity price changes are highly correlated with underlying fossil-fuel price changes.

<sup>19</sup> Aldy and Pizer consider various specifications with employment, value added, and value of shipments as the predicted variable. Because of the difficulty of isolating output from the value of shipments, these results focus on the specification that uses employment as the predicted variable.

**Table 2** Energy cost shares, import shares, and effect of a \$10/ton carbon charge on costs

	1	2	3	4	5	6	7	8
	Energy share of total costs (%)		Import share of total use (%)	Effect of higher energy prices on unit costs (%)				
	Electricity share	All energy (excl. non-combustion)		Direct fuel combustion	Electricity use	Other intermediate inputs	Energy subtotal	All intermediate inputs
Food	0.91	1.85	8.2	0.13	0.09	0.34	0.22	0.56
Textile	1.90	2.95	27.8	0.17	0.36	0.10	0.53	0.63
Apparel	0.56	0.87	74.2	0.03	0.06	0.21	0.10	0.30
Wood & Furniture	0.93	1.45	22.5	0.17	0.13	0.05	0.30	0.35
Paper & Printing	1.49	3.44	11.9	0.85	0.25	0.00	1.10	1.11
Petroleum	0.79	16.37	11.2	2.38	0.12	0.00	2.49	2.50
Chemical & Plastics	1.46	2.78	26.7	0.34	0.28	0.01	0.62	0.45
Nonmetallic Mineral	1.55	3.71	16.3	0.76	0.30	0.01	1.06	1.07
Primary Metals	2.15	4.73	27.2	0.89	0.84	0.01	1.73	1.58
Fabricated Metals	1.09	1.76	13.6	0.06	0.13	0.34	0.19	0.53
Machinery	0.54	0.89	31.0	0.03	0.07	0.29	0.09	0.39
Computer & Electrical Equipment	0.67	0.89	51.1	0.03	0.09	0.16	0.12	0.28
Motor Vehicles	0.42	0.70	43.3	0.04	0.07	0.31	0.10	0.42
Other Transportation Equipment	0.41	0.77	26.7	0.03	0.06	0.21	0.09	0.30
Misc. Manufacturing	0.53	0.78	39.2	0.02	0.05	0.25	0.07	0.32

**Table 3** Effects on output of a \$10/ton CO<sub>2</sub> charge (%)

	Output effect from Morgenstern et al. input-output estimates	Output effect from Aldy and Pizer time series study*
Food	-0.37	
Textile	-0.78	
Apparel	-0.78	
Wood & Furniture	-0.26	
Paper & Printing	-0.48	
Petroleum	-0.42	
Chemical & Plastics	-0.96	
Nonmetallic Mineral	-0.66	
Primary Metals	-1.54	-5.96 Iron and Steel
Fabricated Metals	-0.27	-3.01 Nonferrous metals
Machinery	-0.66	-1.75
Computer & Electrical Equip	-0.72	-3.92
Motor Vehicles	-1.01	
Other Transportation Equip	-0.73	
Miscellaneous Manufacturing	-0.53	

\* Results are only reported for those industries where the authors have the most confidence in their approach (high energy-intensity without significant sales of co-generated electricity or use of fossil feedstocks). All results are statistically significant.

Table 4 shows what percentage of different industries' emissions would have to be covered by an allocation of free allowances to fully offset estimated losses in shareholder value under a mandatory policy that priced CO<sub>2</sub> at \$10 per ton. Results are shown only for industries where energy costs account for more than 1 percent of total costs. Two estimates are reported in Table 4: one assumes that industries could only claim allowances for their direct CO<sub>2</sub> emissions; the second assumes that a free allocation would also reflect emissions associated with electricity use, in addition to direct emissions. Taking into account only direct emissions—the more common approach used in past allocation designs—the share of emissions needed to compensate firms for losses using free allowances ranges from a low of about 1 percent in the petroleum industry to a high of about 73 percent for chemicals and plastics.<sup>20</sup> On average, for the industries included in Table 4, a free allocation equivalent to approximately 20 percent of direct CO<sub>2</sub> emissions should be sufficient to compensate firms for adverse impacts under a \$10-per-ton policy.

At first glance, some of the results presented in Table 4 seem counterintuitive. As a share of direct emissions, only a relatively small allocation of free allowances would be required to compensate the primary metals industry, for example, even though column 1 of Table 3 indicates that this industry suffers relatively large output losses. This is because the carbon intensity of the industry is also very high: thus, even though the adverse impacts of a carbon price are relatively high, they can be covered by a relatively small share of the free allowances the industry could claim under an allocation based on historic emissions. In contrast, the apparel industry also faces substantial output losses, but because it is less carbon intensive—that is, it has lower emissions per unit of output—this industry requires a larger free allocation, relative to its emissions, to be compensated for adverse impacts on shareholders. Similar cross-industry patterns emerge if direct and indirect emissions are considered as the basis for allocation—in that case, a free allocation corresponding to approximately 15 percent of total emissions (including emissions from electricity and direct fuel use) would be required, on average, to offset industry losses. The implication of these estimates is that giving out free allowances in excess of the emissions share indicated in Table 4—including a 100 percent free allocation—would more than compensate even energy-intensive industries, at least on average, and lead to overall gains in shareholder value.

<sup>20</sup> For example, the EU ETS allocates allowances based on direct CO<sub>2</sub> emissions, which is why EAF steel and aluminum were not significantly advantaged by free allocation in Table 2.

	Share of CO <sub>2</sub> emissions from direct fuel use (%)	Share of CO <sub>2</sub> emissions from direct fuel and electricity use (%)
<b>Food</b>	43.7	25.4
<b>Textile</b>	30.7	9.7
<b>Wood &amp; Furniture</b>	18.7	10.8
<b>Paper &amp; Printing</b>	8.2	6.3
<b>Petroleum</b>	1.2	1.1
<b>Chemical &amp; Plastics</b>	72.8	40.4
<b>Nonmetallic Mineral</b>	20.1	14.5
<b>Primary Metals</b>	17.8	9.2
<b>Fabricated Metals</b>	64.2	20.0

\*Share of allowances is defined as share of each industry's initial emissions levels.

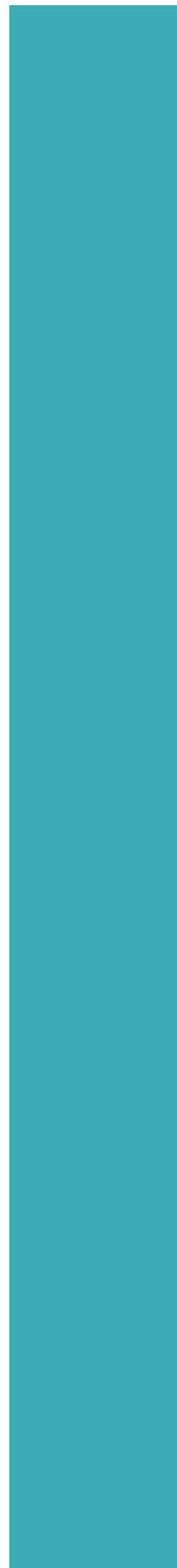
\*\*Energy-intensive industries are defined as industries with energy costs greater than 1 percent of total costs.

## Border Tax Adjustments

Our baseline assumption throughout has been that carbon policies are (or would be) adopted unilaterally by the EU or the United States. The resulting impacts on domestic industries would generally be lower—indeed, probably substantially lower—if key trading partners implement comparable CO<sub>2</sub> control policies or if border tax adjustments are introduced to address the CO<sub>2</sub> content of imported (and exported) goods.<sup>21</sup>

Aldy and Pizer attempt to estimate the potential gains from a border tax adjustment by including a measure of foreign energy prices in their statistical model. Including this measure allows them to ask how an increase in both domestic and foreign energy prices, driven by a CO<sub>2</sub> charge, would affect industry output. While the output effects of foreign prices are harder to measure than the effects of domestic prices, Aldy and Pizer find that impacts on domestic industries might be reduced by as much as half if policy action by the United States to limit CO<sub>2</sub> emissions were coupled either with comparable action by other trading partners or with policies to adjust import prices at the border. Similar questions will be explored as part of further analysis to be undertaken by Morgenstern et al.

<sup>21</sup> Of course, the implementation details of a system of border taxes would matter a great deal—for example, whether the border tax adjustment only covered basic products such as steel, aluminum, and cement rather than also including automobiles, appliances, or other finished goods. These issues are discussed at greater length in Issue Brief #8.





**ISSUE BRIEF 8**

**ADDRESSING COMPETITIVENESS  
CONCERNS IN THE CONTEXT OF A  
MANDATORY POLICY FOR REDUCING  
U.S. GREENHOUSE GAS EMISSIONS**

**RICHARD D. MORGENSTERN**

## ADDRESSING COMPETITIVENESS CONCERNS IN THE CONTEXT OF A MANDATORY POLICY FOR REDUCING U.S. GREENHOUSE GAS EMISSIONS

Richard D. Morgenstern

### SUMMARY

A variety of mandatory policies to reduce U.S. greenhouse gas (GHG) emissions—principally cap-and-trade systems, occasionally carbon taxes, and sometimes standards—are now being seriously debated at the federal level. A frequent concern raised in these debates is the potential for adverse impacts on the competitiveness of U.S. industries, particularly on firms or in sectors that face high energy costs and significant international competition. This issue brief examines the advantages and disadvantages of five strategies or options for addressing competitiveness concerns in the context of federal climate legislation. The first of these options would involve the design of the policy as a whole; all of the remaining options attempt to target industries or sectors that would be particularly vulnerable to adverse impacts under a mandatory program to reduce GHG emissions:

- Weaker overall program targets
- Partial or full exemptions from the carbon policy
- Standards instead of market-based policies for some sectors
- Free allowance allocation under a cap-and-trade system
- Trade-related policies, including some form of border adjustment for energy- or carbon-intensive goods

We arrive at the following observations:

- Cost-effective policies that allow access to inexpensive mitigation opportunities throughout the United States and potentially around the world will generally minimize the economic costs of achieving any given emission target and could be viewed as a first response to competitiveness concerns.
- A weaker overall policy—less stringent emissions caps and/or lower emissions prices—represents the least focused approach available for addressing competitiveness impacts. This approach has the advantage that it does not require policymakers to identify vulnerable sectors or firms and thus avoids the potential for a “gold rush” of industries seeking relief. The disadvantage, obviously, is that less ambitious emission-reduction targets will produce smaller environmental benefits and weaker incentives for technology innovation.
- Simply exempting certain sectors or types of firms provides a direct response to competitiveness concerns and the most relief to potentially affected industries, but it is also the most costly option in terms of reducing the economic efficiency of the policy.
- More traditional (non-market-based) forms of regulation—such as emissions standards or intensity-based regulations—can be

used to avoid direct energy price increases and deliver some emissions reductions. Regulated industries will still face compliance costs, however. Meanwhile, the overall cost to society of achieving a given environmental objective using these forms of regulation will tend to be higher than under a single pricing policy.

- Free allowances can be used to compensate adversely affected industries (even if those industries are not directly regulated under the policy) without necessarily losing the efficiency of a broad, market-based approach. Different forms of free allocation—for example, an allocation based on historic emissions or energy use (“grandfathering”) versus an updating allocation tied to current output—will have very different incentive properties and may respond more or less effectively to concerns about retaining production capacity and jobs in the United States. The consequences of different allocation methodologies and their relative advantages and disadvantages in relation to competitiveness concerns and other policy objectives must therefore be carefully considered.<sup>1</sup>
- Trade-related policies (such as border adjustments for energy- or carbon-intensive goods) can both protect vulnerable domestic firms and industries and create incentives for nations without similar GHG policies to participate in emissions-reduction efforts. However, such policies also risk providing political cover for unwarranted and costly protectionism and may provoke trade disputes with other nations.
- In general, the more targeted policies (that is, all options noted above except an overall weaker policy) will be difficult to police and many industries will have strong incentives to seek special protection by taking advantage of these various mechanisms without necessarily being at significant competitive risk.

## Introduction

Due to the great diversity of GHG sources, addressing global warming will—of necessity—involve many different types of actors, including industries, governments, and individuals. In general, pursuing a cost-effective approach that minimizes the overall cost to society of achieving a particular emissions-reduction target will minimize the burden imposed on businesses and consumers. Broad, market-based strategies

that effectively attach a price to GHG emissions, such as an emissions tax or cap-and-trade program, in particular offer significant cost and efficiency advantages. As a result, it is widely assumed that this type of policy—and most likely emissions trading—will be part of the core policy response to climate concerns in the United States. As part of a broad pricing policy, the use of additional flexibility mechanisms—such as recognizing offset credits from sectors or gases not included under the cap and/or from projects undertaken in other countries—can lower overall program costs while further ameliorating the potential for adverse impacts on particular sectors or the economy as a whole.<sup>2</sup> Close attention to cost and efficiency considerations in the design of an overall policy could thus be viewed as a first step to addressing competitiveness concerns.

At the same time, even a cost-effective strategy for reducing U.S. GHG emissions will likely increase production costs for some domestic producers and will give rise to competitiveness concerns where those producers compete against foreign suppliers operating in countries where emissions do not carry similar costs. These concerns are likely to be most acute in trade-sensitive, energy-intensive sectors (examples might include certain types of manufacturing). The question will likely be asked: why should U.S. firms be disadvantaged relative to overseas competitors to address a *global* problem? The difficulty, moreover, is not just political: if, in response to a mandatory policy, U.S. production simply shifts abroad to unregulated foreign firms, the resulting emissions “leakage” could vitiate some of the environmental benefits sought by taking domestic action.

One option is for the United States to impose trade-related sanctions, both to protect domestic industries and reduce the potential for GHG leakage by prodding other countries to take steps they would not otherwise take to limit emissions. Other options involve modifications to the domestic policy itself. These might include adding particular design features to an economywide cap-and-trade system or, possibly, substituting standards or other regulatory mechanisms for market-based policies in certain sectors. As policymakers consider these options, however, an important caution is in order. As compelling as the argument for protecting vulnerable firms or industries might be, few provisions or program modifications designed to accomplish this can be implemented without some cost to the environment (in the sense that they result in higher emissions) and to the overall economy (in the sense that they will result in more expensive

<sup>1</sup> Issue Brief #6 provides more detail concerning specific issues related to allocation.

<sup>2</sup> See Issue Brief #15 concerning offsets.

abatement options being used to achieve the same emissions result). Nor are trade-related actions costless: they might raise legality concerns under World Trade Organization (WTO) rules and risk provoking countervailing actions by other nations.

This issue brief examines the advantages and disadvantages of five potential strategies for addressing competitiveness concerns in the context of federal climate legislation. Our assumption here, as in other issue briefs, is that such legislation will feature a market-based cap-and-trade or carbon tax system as the primary mechanism for limiting future U.S. GHG emissions. Both domestic-policy modifications and specifically trade-oriented provisions are considered. We also discuss some of the complexities involved in identifying which industries are particularly susceptible to competitiveness concerns while noting that additional attention is given to this issue in a companion brief on measuring competitiveness impacts.

## Alternative Competitiveness Policies

Efforts to address competitiveness concerns in the context of a mandatory domestic climate policy typically involve one or more of the following options:

- Weaker overall program targets
- Partial or full exemptions from the carbon policy
- Standards instead of market-based policies for some sectors
- Free allowance allocation under a cap-and-trade system<sup>3</sup>
- Trade-related policies, including some form of border adjustment for energy- or carbon-intensive goods

### Weaker Overall Program Targets

This option involves adjusting the stringency of the policy as a whole such that it results in a lower economy-wide emissions price (we assume that this would be done without regard to the obligations of specific industries). In the case of a cap-and-trade system, a lower price can be achieved by allowing a greater quantity of emissions under the cap or by including a safety valve or other mechanism designed to limit emission prices to a desired maximum level (the lower the safety-valve price, the weaker the policy and vice versa). Other options for making the policy more flexible (such as allowing a larger role for offset credits) can also help to reduce domestic emissions costs—whether they do so in a way that risks undermining environmental objectives depends on how they are designed and implemented. Under a tax system, lower prices can be

achieved very simply by reducing the amount of the levy. In both cases, the question of program stringency has a temporal dimension: a policy that is weaker in the short run can be made more aggressive at a later point in time.

### Pros

The lower emissions price associated with a less stringent policy will produce smaller economywide costs and price impacts, and should ameliorate the competitiveness concerns of trade-sensitive firms or industries. The principal advantage of this option is that it does not require the government to identify particularly vulnerable firms or industries, thereby avoiding the need to distinguish truly disadvantaged parties from those who simply seek preferential treatment or regulatory relief. Further, this option does not require additional mechanisms or special provisions, nor does it diminish the cost-effectiveness of the underlying policy.

### Cons

The principal disadvantage of a weaker policy is that it also produces weaker results—not only in terms of emissions reductions and technology innovation, but also in terms of the perception that the United States is taking serious action. By its very nature, an overall weakening of the policy does not target cost reductions to the most vulnerable firms or industries. And unless emissions prices and reduction targets are dramatically lowered, competitive issues will remain.

### Discussion

Different climate-related legislative proposals would have widely varying cost and price impacts; in this context, the appropriate overall level of stringency for U.S. policy remains a subject of active debate.<sup>4</sup> To help inform this debate, MIT researchers recently analyzed the costs associated with achieving different emissions reductions targets.<sup>5</sup> The emissions trajectories modeled resulted in total emissions from 50 percent to 80 percent below 1990 levels by 2050, consistent with the range of targets contained in proposals currently pending before Congress. Using their Emission Prediction and Policy Analysis model, the MIT researchers estimated that permit prices in the year 2015 would need to reach \$30–\$50 per ton of carbon-dioxide equivalent (CO<sub>2</sub>-e) to achieve these targets, with the higher end of the price range corresponding to the more ambitious reduction targets modeled. According to the same analysis, permit prices in the year 2050 would be higher by roughly a factor of four to achieve the mid-century targets modeled.

<sup>3</sup> Note that the equivalent of free allowance allocation under a cap-and-trade system can also be achieved under a system that instead taxes emissions. In this case, tax rebates or credits, or some other mechanism that effectively returns a portion of revenues collected under the tax can be used to compensate adversely affected industries.

<sup>4</sup> This is discussed at length in Issue Brief #2 on domestic mitigation targets.

<sup>5</sup> This analysis is discussed at greater length in Issue Brief #3 on mitigation costs.

While a Congressional majority has yet to coalesce around any particular emissions-reduction goal, the trend in the last year or more has been toward more stringent targets. To take just one example, the bi-partisan National Commission on Energy Policy (NCEP) recently strengthened the widely-cited climate-policy recommendations it first put forward in late 2004. While this earlier proposal called for an initial phase (to the early 2020s) during which emissions growth would merely slow, the group in April 2007 recommended a 15 percent reduction below current (2005) emission levels to be achieved by 2030. The updated NCEP recommendations also increase the proposed starting price of the safety valve (from \$7 per ton CO<sub>2</sub>-e in the group's earlier proposal to \$10 per ton in the current proposal), along with the rate of escalation of the safety-valve price (whereas NCEP's 2004 proposal called for the safety valve price to increase at a rate of five percent per year in nominal terms, the current recommendations specify that the same rate of escalation should be implemented in real terms—that is, at a rate of five percent per year above the rate of inflation). One of the more prominent legislative proposals introduced in the 110<sup>th</sup> Congress, by Senators Bingaman and Specter (S. 1766), is modeled on the NCEP proposal but calls for an even higher starting safety-valve price—\$12 per ton.

Interestingly, the inclusion of a safety valve—the term applies to a mechanism that directly limits costs under a cap-and-trade program by making an unlimited number of additional allowances available for sale at a fixed, pre-determined price—will affect the policy differently, depending on the price level adopted. Set at a high price, the safety valve will function primarily as an insurance policy—one intended to limit economic impacts only in cases of unexpectedly high mitigation cost. By contrast, a safety valve price set at a relatively low level will tend to determine both environmental and economic outcomes and is generally equivalent to adopting a weaker emissions-reduction target.<sup>6</sup> If competitiveness concerns are primarily motivated by the potential for adverse consequences at the extremes of potential policy cost—extremes that could be induced by bursts of economic growth, unusual weather or other conditions that lead to a spike in energy use, disruptions in the supply of lower-carbon fuels, or by the failure of new technologies to come online as anticipated—then even a relatively high safety-valve price may be adequate to address these concerns without much effect on the emissions reductions expected from the policy.

<sup>6</sup> Put another way, if the safety valve price is set sufficiently low, the emissions target becomes irrelevant because the marginal cost of abatement can be expected to exceed the safety-valve cost cap long before emissions targets are reached. At that point, program outcomes are more or less entirely driven by the safety valve price.

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An obvious option for addressing competitiveness concerns is simply to exempt certain industries from the broader GHG-reduction policy. The key challenge in implementing this approach is determining which firms or sectors are particularly vulnerable.

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In sum, weakening the overall policy may address the concerns of the most vulnerable industries, though if the objective is primarily to provide insurance against extreme policy impacts, other mechanisms—for example, a safety valve somewhat above expected prices—can be used to protect industry while largely maintaining the integrity of the environmental objective. Other options, considered below, attempt to deal more directly with vulnerable industries and would presumably be implemented as an alternative to weakening the overall policy.

### Partial or Full Exemptions from the Carbon Policy

An obvious option for addressing competitiveness concerns is simply to exempt certain industries from the broader GHG-reduction policy. The key challenge in implementing this approach—or indeed, any of the targeted policies discussed in the remainder of this issue brief—is determining which firms or sectors are particularly vulnerable to cost and competitiveness concerns and should, as a result, qualify for special treatment (in this case, a full or partial exemption). Applying a very high threshold for exemption risks excluding vulnerable producers, while setting the threshold too low opens the door to unlimited lobbying for more favorable treatment.

The mechanics of actually providing exemptions, by contrast, are relatively easy. In a cap-and-trade system where downstream entities—primarily energy users—are regulated, exempt firms would face reduced requirements (or perhaps none at all) to submit allowances to cover their emissions. In the case of a carbon tax, eligible firms would face a reduced levy (or possibly none at all). Exemptions could also be provided to downstream firms or sectors in a system that regulated upstream entities (i.e., energy suppliers). In that case, a procedure would need to be established to credit exempt downstream entities based on their emissions or fuel use. The credit could be payable in allowances (in the case of a cap-and-trade system) or via a tax credit or rebate (in the case of an emissions tax).

### Pros

The principal advantage of exemptions is that they can be used to protect vulnerable firms or industries in a convincing and targeted way, potentially making it politically possible to adopt a more stringent economywide GHG-reduction target.

### Cons

The principal disadvantage of this approach is that it would likely increase the total, economywide cost of achieving a given emissions target because exempting certain firms or sectors would almost certainly leave at least some inexpensive mitigation options untapped. As a result, the program would be both less efficient and more costly overall. This approach may also raise equity concerns: if the same national target is pursued but some industries or firms are exempt from participating, this clearly places a greater burden on the remaining non-exempt industries. Finally, the difficulty of identifying truly vulnerable firms or industries cannot be overemphasized. Politically and technically, it will be extremely challenging to adjudicate requests for exemptions on the basis of vulnerability to competitive harm.

### Discussion

Interestingly, two proposals currently under consideration in Congress already call for significant exemptions but do not limit these exemptions to sectors that would seem most obviously at risk of suffering a business disadvantage under a mandatory domestic climate policy. For example, a bill introduced by Senators Feinstein and Carper (S.317, 110<sup>th</sup>) covers only the electricity sector—almost 40 percent of U.S. emissions—and therefore exempts primary (non-electricity) energy use by households and the industrial sector along with all transportation related emissions. A

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Compared to an allocation based on grandfathering, an updating allocation can have important differences in terms of creating incentives to maintain (or even expand) domestic production.

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bill introduced by Senators Lieberman and McCain (S.280, 110<sup>th</sup>), by contrast, covers all large facilities—defined as facilities in the electric power, industrial, and commercial sectors that emit at least 10,000 metric tons CO<sub>2</sub>-e per year or more—plus transportation fuels at the refinery or importer (this program would cover an estimated 70-75 percent of the total U.S. emissions). Only households, agriculture, and small non-transport emitters are exempt. In both these cases, however, the less than full coverage envisioned in the proposals appears to be motivated more by practical and political considerations—for example, that it might be easier to start by focusing on the electric power sector or on larger sources—than by competitiveness concerns per se.

For a cautionary lesson concerning the political hazards of exemption, one could look to the energy (Btu) tax proposed by the first Clinton administration in 1993. At that time, many firms and industries made claims of business hardship. As a result, the final House legislation included a long list of exemptions added at the request of members or recommended by the administration. Ultimately, of course, the Btu tax was defeated in the Senate and the policy was never implemented—in part because its effectiveness was undercut by the exemptions.

### Performance Standards Instead of Market-based Policies for Some Sectors

Performance standards come in many varieties and may include minimum, average, and tradable standards for

emissions or energy use per unit of output.<sup>7</sup> Unlike broad, market-based CO<sub>2</sub> policies, they do not produce a direct increase in energy costs—therefore, they do not create as much pressure for firms to raise product prices. For this reason, performance standards may seem less likely than market-based policies to raise competitiveness concerns for industries that face international competition and to create incentives for shifting production abroad.

### Pros

Well-crafted performance standards have the potential to encourage efficiency improvements without putting as much upward pressure on domestic production costs. In doing so, they may reduce the potential for domestic production to shift to countries without mandatory GHG-reduction policies (and thus avoid the emissions leakage that would result from such shifts). In general, efficiency and cost considerations argue for corporate average standards rather than facility-level standards. Tradable performance standards—such as were used to effect the phase-down of lead in gasoline in the 1980s or as exemplified by current proposals for a national renewable energy portfolio standard (RPS)—provide even more flexibility and are even more cost-effective.

### Cons

Performance standards are more costly than broad market-based approaches because they do not encourage end users to reduce their consumption of GHG-intensive goods, and do not balance the cost of emissions reductions across different sectors. Relying on standards instead of market-based instruments to achieve emissions reductions will leave behind some low-cost abatement opportunities, thereby raising the overall cost incurred by society to achieve a particular emissions target. From an implementation standpoint, standard setting can be contentious and may require government to estimate technology costs in a particular sector more precisely than would be required to implement a broad-based cap-and-trade program or emissions tax.

### Discussion

The academic literature provides abundant evidence that market-based mechanisms, especially broad-based ones, provide lower-cost emissions reductions than standards do.<sup>8</sup> Some of the most important benefits of market-based instruments are often not realized immediately and become manifest only over a long period of time. Unlike performance standards, market-based instruments provide a continual

incentive to reduce emissions—thus they promote technology innovations that, by their nature, take time to develop and deploy. Market-based instruments also offer maximum flexibility in terms of the means used to achieve reductions including, for example, the shift to new technologies that occurred in the U.S. sulfur dioxide program. In the case of GHGs, where emissions are not concentrated in a single sector, the flexibility afforded by a broad, price-based system would be expected to provide even greater cost and efficiency benefits relative to more traditional regulatory mechanisms.

Notwithstanding these observations, it seems that firms and industries, particularly competitive ones, often prefer standards to market-based policies. They may fear that it will be more difficult to pass along increased energy costs under a market-based CO<sub>2</sub> policy; in addition, they may expect to be in a stronger position to negotiate the form and stringency of a regulatory program that is tailored to specific sectors rather than designed for the economy as a whole.

### Using Free Allowance Allocation to Address Competitiveness Concerns

Allocation refers to the approach used to distribute permits or allowances under an emissions trading program. Here, two decisions are important at the outset. The first concerns how many allowances (or what share of the overall allowance pool) will be given away for free. The second concerns the *methodology* to be used in apportioning free allowances to different industry sectors and—within sectors—to individual firms. In most existing emissions trading programs, the great majority of allowances has been given for free to directly regulated entities, primarily on the basis of historic emissions (an approach often called “grandfathering”). More recent climate-policy proposals, however, (in addition to providing for a larger auction) have proposed to allocate free allowances in a way that recognizes firm-level changes over time, typically based on an emissions, energy use, or output measure. The latter approach is known as updating allocation. Compared to an allocation based on grandfathering, an updating allocation can have important differences in terms of creating incentives to maintain (or even expand) domestic production—thereby reducing the potential for emissions leakage—and in terms of the effect on shareholder value.

### Pros

The principal advantage of using a free allocation of allowances to address competitiveness concerns is that it can compensate firms for losses suffered as a result of the new policy without excluding those firms’ emissions from

<sup>7</sup> See also Issue Brief #10 on technology deployment policies.

<sup>8</sup> For a recent review see Freeman, Jody and Charles D. Kolstad (eds.), *Moving to Markets in Environmental Regulation: Lessons from Twenty Years of Experience*, Oxford University Press, New York, 2007.

the broad-based cap. Thus it avoids the efficiency losses or reduction in environmental benefit associated with other options for responding to industry concerns (such as weakening the overall policy, exempting some industries, or relying on traditional standards-based forms of regulation in some sectors).

In terms of the methodology used to distribute free allowances to individual firms, traditional grandfathering—which leaves the allocation fixed over time regardless of whether a business changes operations or even shuts down—can compensate firms owners for losses in value but does not necessarily discourage firms from retiring or moving their emissions-producing operations overseas to avoid costs associated with the regulatory program going forward.

The alternative of an updating output-based allocation, where allowance shares are continually adjusted to reflect a firm's changing output,<sup>9</sup> effectively subsidizes production. That is, firms stand to gain a larger allocation of free allowances if they expand their operations and a smaller allocation if they move off-shore, downsize, or shut down. While incentives of this type are generally regarded by the economics literature as distorting and hence inefficient—because they induce firms to produce above the level that would otherwise make economic sense<sup>10</sup>—they may be attractive in the context of concern about competitiveness impacts precisely because they tend to encourage domestic production and discourage firms from moving operations (and emissions) overseas. The subsidy benefit generated by an updating allowance methodology accrues to domestic consumers as well as to firms that face competition from foreign suppliers, either (or both) in markets at home and in export markets abroad.

### Cons

The principal case against free allocation is that it misses the opportunity to auction allowances and use the revenue to provide broad, offsetting benefits for the economy as a whole. From the standpoint of maximizing economic efficiency, it would make more sense to auction all allowances and use the proceeds to reduce taxes on income or investment. Compelling arguments can also be made for auctioning allowances and using the revenues to support other public policy objectives, such as funding energy R&D, offsetting the impact of higher energy prices on consumers (and especially

low-income households), and supporting efforts to adapt to the impacts of climate change.

Another concern is that, if too generous, free allocation based on historic emissions (grandfathering) risks conferring windfall gains on some firms, especially in cases where a firm is able to pass most of the costs of regulation through in the form of higher prices for its products. In that case, giving the firm free allowances would amount to a transfer of wealth from consumers—who will face higher prices for the firm's goods—to business owners or shareholders who do not really bear a substantial share of the cost burden associated with the policy.

An updating free allocation that subsidizes domestic production also gives rise to the same concerns noted in connection with other targeted responses that distort behavior relative to what would happen under a broad CO<sub>2</sub> pricing policy. Namely, allocation decisions in practice may fail to target truly trade-sensitive firms or industries and thus end up subsidizing emissions-intensive industries that are not really at risk of shifting their operations overseas, such as electric utilities. In that case, an updating allocation will create efficiency losses and increase the overall cost of the policy to society, while providing only limited benefits in terms of maintaining domestic production, preserving U.S. jobs, and reducing the potential for emissions leakage.

### Discussion

Relative to targeted exemptions or to relying on performance standards instead of market-based approaches, using free allowances to compensate vulnerable industries as part of a broad, cap-and-trade or emissions tax program generally maintains efficiency. Among these three options, an allocation-based approach remains the most cost-effective because it preserves the ability to trade off emission reductions throughout the economy—without excluding some sectors—so that the environmental objective is achieved by exploiting the least expensive abatement opportunities. Tying free allocation to future production—or even to future employment, as proposed in legislation recently introduced by Senators Bingaman and Specter (S. 1766)—provides a way to not only compensate firms for unrecovered costs under the regulatory program but to also provide inducements for maintaining domestic production. The principle disadvantages are (1) that government will forgo revenues from auctioning allowances that could be used for other purposes and (2) that it will be difficult, as with all targeted measures for addressing competitiveness concerns, to identify truly vulnerable sectors. Moreover, free allocation involves

<sup>9</sup> Note that, in theory, an updating allocation could also be based on emissions or energy use. Most discussions of this approach, however, assume that an updating allocation will be based on output so as to avoid providing incentives for emissions or energy use. Indeed, proponents argue that an important advantage of the updating, output-based approach is that it provides incentives to become more efficient (or less carbon intensive) by maximizing output per unit of emissions or energy use.

<sup>10</sup> By the same token, economic theory may favor any allocation based on past behavior over an updating methodology because it avoids creating incentives that change behavior going forward. Allocation issues are discussed in more detail in Issue Brief #6.

difficult and politically contentious decisions about how many allowances should be given away for free and how those allowances should be divvied up, not only across industry sectors but also among individual firms within a sector.

### Trade-related policies

The principal aim of trade-related policies is to level the competitive playing field between domestic and foreign suppliers. In this case, efforts to level the playing field would likely involve using a tariff or some other mechanism to impose roughly equivalent costs on imports into the United States—presumably based on their embedded carbon or energy content—as the climate policy imposes on domestic production. A similar mechanism—presumably involving some type of export subsidy—could be used to level the playing field for U.S.-produced goods that compete in foreign markets against goods produced in countries without mandatory emissions policies, though this option is not discussed as often. A recent proposal by American Electric Power and the International Brotherhood of Electrical Workers (AEP/IBEW) would require importers from countries that do not have emissions-reduction requirements comparable to those of the United States to submit emissions allowances to cover the carbon content of certain products.<sup>11</sup> This mechanism would only engage after a certain amount of time, during which the United States would encourage its trading partners to undertake emissions-reduction efforts; would only apply to bulk, energy-intensive goods; and would account for free allocation to domestic industry by reducing the import obligation.

#### Pros

If they can be successfully defended under WTO rules, border adjustments would protect U.S. firms or industries against adverse competitiveness impacts related to the implementation of a mandatory domestic climate policy. The approach would provide the added benefit of creating real incentives for major trading partners to adopt similar policies or otherwise take steps to reduce GHG emissions. Once authorized in U.S. legislation, even the threat of such adjustments might trigger some favorable policy responses from other nations.

#### Cons

Even if they can be successfully defended under WTO rules, border adjustments have several disadvantages. To the extent they act as barriers to trade (beyond correctly accounting for the cost of emissions), such adjustments are inherently

inefficient and costly to U.S. consumers and industries that depend on imported goods. Moreover, because of the difficulty of accurately measuring embedded energy or carbon content for specific items, implementing such a policy could be both expensive and controversial in practice. More importantly, there is a risk that the system could be abused by firms or industries—or even by other nations if they use it as grounds for instituting their own system of border adjustments—for purely protectionist reasons unrelated to climate policy. These actions, in turn, could work against long sought after free-trade objectives. They could also undermine the trust and good relations necessary to foster international cooperation and agreement on future global efforts to address climate change risks.

#### Discussion

Since any directly trade-related action risks a challenge by U.S. trading partners before the WTO dispute settlement body, the first issue to consider is what kind of policy would be WTO-legal (consequences of illegality are mentioned below). Even though WTO law is vague on this issue, the United States might be able to address the problem of offshore emissions associated with imported products (so-called process emissions) by applying to imports a carbon tax or emissions-permit requirement that is *equivalent* to the requirements imposed on U.S.-produced goods under domestic policy. Arguably, if this equivalent policy does not discriminate against imports versus domestic products, or disadvantage some imports relative to others, it could be seen as an extension of U.S. policy. In that case, it would likely pass WTO scrutiny without reference to the environmental exceptions provided for under Article XX in the General Agreement on Tariffs and Trade.<sup>12</sup>

Further complexities arise in developing administrative procedures for assigning process carbon emissions to specific imported products. On the one hand, the border adjustment policy might be considered more acceptable if it were based on the processes and fuels used in the United States—the so-called U.S. predominant method of production. At the same time, however, it might be necessary to establish procedures that would allow foreign producers to make different claims concerning assumed process emissions based on the submission of technical data. Such determinations would be more defensible—and easier to calculate—if the focus were on basic products, such as steel, aluminum, and cement,

11 This proposal was incorporated in S.1766 by Senators Bingaman and Specter.

12 If an Article XX exception was required, the justification would center on whether the border adjustment is applied on a variable scale that takes account of local conditions in foreign countries, including their own efforts to fight global warming and the level of economic development in developing countries. In either case, it would be easier to defend a border adjustment for carbon taxes or other price-based measures such as a cap-and-trade program rather than for traditional regulation.

rather than on automobiles, appliances, or other finished goods.

The amount of any border adjustment might be diminished to the extent that domestic producers are effectively subsidized by a free allowance allocation. Thus, for example, if 50 percent of available allowances under a domestic cap-and-trade program are allocated for free to affected industries, an importer might have to surrender allowances equal to only half of estimated process emissions associated with the imported product. If a carbon tax were imposed, without exemptions, importers would presumably face an equivalent adjustment at the border and there would be no need to account for offsetting benefits to U.S. producers. A variety of other issues might also complicate the use of border adjustments, including the question of how to treat imports from a country or region with some form of domestic carbon policy versus imports from countries that lack such a policy altogether. Such issues, however, lie beyond the scope of this issue brief.

In the best case, a policy of border adjustments will effectively protect vulnerable domestic firms or industries against adverse competitiveness impacts from a domestic climate policy while simultaneously creating incentives for other nations to reduce their emissions. To improve the prospects for a successful WTO defense, great sensitivity must be shown on a number of issues when designing such a policy, including the need to put major trade partners on notice and provide sufficient time for them to develop viable domestic emissions-reduction policies of their own if they do not already exist. Such sensitivities define many of the parameters suggested, for example, by the AEP/IBEW proposal. Once legislation was in place, U.S. customs would need to establish a substantial infrastructure to assess the carbon footprint of imported products and apply border adjustments accordingly. Interestingly, even if a U.S. policy of carbon-based border adjustments was ultimately found to violate WTO law—by no means a certainty—the only available remedy is for the United States to change the law or suffer retaliation. No damages for past harm are due.

## Identifying Vulnerable Industries

Identifying the specific industries that are most likely to be adversely affected by a mandatory domestic GHG-reduction policy is complex, both in terms of the data and the analytical tools needed to make this assessment. At a minimum, information would be needed on the emissions and energy intensity of firms; their ability to reduce emissions and energy use; their ability to pass through costs to customers, which depends in part on the elasticity of consumer demand for the product in question if prices rise; and, importantly, on the nature and extent of international competition. Often, firms themselves do not have good estimates of these parameters. The capacity of the public sector to obtain such data may be even more limited.

Issue Brief #7 on competitiveness impacts discusses different approaches for identifying industries that warrant concern and measuring their degree of vulnerability. Three different approaches are considered. The first examines the energy and emissions intensity of production in different industries and computes the impact of a CO<sub>2</sub> price on their cost structure. The second, using a model of the U.S. economy that accounts for international trade, considers the effects of a change in cost structure on domestic production. The third method discussed relies instead on historical data to characterize energy use and output across multiple industries and countries and to examine how domestic (and foreign) energy-price changes might impact production. In addition to describing these different methodological approaches, Issue Brief #7 provides estimates for different industries of the likely magnitude of competitiveness impacts under a domestic climate policy.



**ISSUE BRIEF 9**

**CLIMATE TECHNOLOGY  
RESEARCH, DEVELOPMENT, AND  
DEMONSTRATION: FUNDING SOURCES,  
INSTITUTIONS, AND INSTRUMENTS**

**RICHARD G. NEWELL**

## CLIMATE TECHNOLOGY RESEARCH, DEVELOPMENT, AND DEMONSTRATION: FUNDING SOURCES, INSTITUTIONS, AND INSTRUMENTS

Richard G. Newell

### SUMMARY

There is growing consensus among policymakers and stakeholders that an effective federal program to reduce greenhouse gas (GHG) emissions should include policies that hasten the development and commercialization of low- and no-carbon energy technologies, as well as technologies that increase end-use energy efficiency. Alongside policies such as a GHG cap-and-trade system that would directly mandate emissions reductions, policies that would instead target innovation and investment in GHG-reducing technologies have been much discussed. While both types of policies may be motivated by concerns about climate change, technology policies are generally framed in terms of technology-development activities or technology-specific mandates and incentives rather than primarily in terms of emissions.

A wide range of options for promoting climate-friendly technologies is currently being employed or proposed at the federal and state levels. It is useful to roughly categorize these options according to which stage of the technology-innovation process they target: research, development, and demonstration (RD&D) or commercial deployment. After exploring various rationales for technology policy, this issue brief examines the funding sources, institutions, and policy instruments that have a potential role to play in enhancing RD&D efforts to advance climate change mitigation and adaptation technologies. A companion issue brief addresses options for promoting technology deployment, including mandates, financial incentives, and enabling regulations.

A number of important messages emerge:

- An emissions price established through a GHG cap-and-trade or tax system would induce firms to invest and innovate in developing technologies that reduce emissions more effectively and at lower cost.
- Nonetheless, several motivations exist for including additional RD&D policies as complements to a pricing policy in a comprehensive strategy to address climate change. R&D tends to be underprovided in a competitive market because its benefits are often widely distributed and difficult to capture by individual firms. Given the likelihood that the magnitude of GHG reductions needed to address climate concerns will increase significantly over time, private-sector investment in technology innovation is likely to fall short of what may be desirable over the long term, particularly given the fragility of expectations concerning future GHG prices and the uncertain credibility of near-term policy commitments. Ensuring that capable, university-trained researchers will be available to the public and private sectors in the future provides another compelling motivation for public spending on technology R&D, especially given the importance of investing in human capital to maintain long-term economic competitiveness.
- While public funding for research tends to be widely supported, there is less agreement about the justification for public-policy intervention (beyond the emissions

price) as one moves from basic R&D to the demonstration and deployment phases of technological innovation.

- Although particular energy RD&D programs have produced some notable failures and although their performance has varied widely, studies have found that federal energy R&D investments have on the whole yielded substantial direct economic benefits as well as external benefits such as pollution mitigation and knowledge creation. Government-sponsored energy R&D programs are also commonly thought to have improved substantially since the 1970s and early 1980s—both in terms of the way they are managed and in terms of the objectives they target—as their emphasis shifted from energy independence and large-scale demonstration projects to environmental improvement, precommercial research, public-private partnerships, and cost-sharing. Private industry involvement is almost always mentioned as being very important, particularly as new technologies approach the commercialization stage.
- Substantially boosting efforts to develop and deploy low-GHG energy alternatives would require a sustained increase in RD&D funding and increased market demand for associated technologies (where increased demand would likely be due, at least in part, to the concurrent implementation of policies that provide an economic incentive for reducing GHG emissions). Increased funding could come from general revenues through the standard appropriations process, from revenues generated by emission taxes or the sale of emission allowances, or from wires and pipes charges on electricity and other fuels. Alternatively or in addition, increased investment could be induced through more generous R&D tax credits. Because associated revenues may be less likely to be diverted for other budget purposes, allowance sales or wires and pipes charges, or both, are likely to provide the largest and most stable dedicated funding stream.
- Numerous existing institutions are engaged in energy RD&D, including the U.S. Department of Energy (DOE), DOE's national laboratories, the National Science Foundation (NSF), universities, individual firms, private research consortia, and non-profit research institutions. These institutions vary both in terms of their roles in funding versus performing research and in terms of which stage(s) of the innovation process they primarily engage (i.e., basic research, applied research, development, and demonstration). The existing system of institutions involved in energy innovation is best characterized as an interconnected network of entities with different and somewhat overlapping roles—it does not have a highly unified or linear structure.
- A number of objectives are frequently noted in relation to public investments in RD&D. These include effective and efficient management and performance, stable funding, insulation from politics, and public accountability. Some of these aspirations are mutually reinforcing, while others may conflict.
- Regarding the *administration* and *coordination* of federal energy RD&D, greater concern is typically expressed about existing institutional capacity to manage an expanded funding base for *applied* RD&D than about the ability of existing government institutions (such as the DOE Office of Science, the NSF, and the National Institute of Standards and Technology) to effectively administer increased funds for *basic* research. The existing suite of institutions that actually perform RD&D—including universities and other non-profit institutions, the national laboratories, and private firms—seems sufficiently broad to handle an increase in funding, although capacity would need to deepen if considerable expansion of current research efforts was desired.
- The main institutional options for administering an expanded public investment in applied energy RD&D are the existing DOE program offices (i.e., Energy Efficiency and Renewable Energy, Fossil, and Nuclear), a new government agency or agencies (for example, recent proposals have called for an energy version of the Defense Advanced Research Projects Agency or “ARPA-E” and a Climate Technology Financing Board), a new quasi-public corporation (recent proposals refer to a new Energy Technology Corporation or Climate Change Credit Corporation), and/or private research consortia. These options differ in terms of how likely they are to meet the range of policy objectives mentioned above (e.g., efficiency and accountability)—in perception and in practice.
- The primary mechanisms that have historically been used to deliver public support for RD&D—including contracts, grants, and tax credits—will continue to play a central role, perhaps with some incremental modifications. Technology innovation prizes represent a new opportunity for expanding the range of instruments used to provide RD&D incentives; both the private and public sectors are currently experimenting with this approach.

## The Role of RD&D Policy

R&D encompasses activities associated with discovering new knowledge and applying that knowledge to create new and improved products, processes, and services—in this case with the aim of reducing GHG emissions.<sup>1</sup> Demonstration projects, on the other hand, test the feasibility of GHG-reducing technology at a scale that is closer to what would be employed in wider commercial deployment.

When considered alongside policies that impose mandatory GHG-reduction requirements, additional technology policies may not seem necessary or desirable. After all, the point of market-based approaches is to establish a price on GHG emissions. This price in turn attaches a financial value to GHG reductions and—just as people will consume less of something that carries a price than they will of something that is given away for free—should induce households and firms to buy technologies with lower GHG emissions (a more efficient appliance, for example) the next time they are in the market. This market-demand pull should in turn encourage manufacturers to invest in R&D efforts to bring new lower-GHG technologies to market, just as they do for other products and processes.

There are nonetheless several rationales or motivations for considering technology-oriented policies within a portfolio of climate policies that also includes pricing emissions. The economics literature on R&D points to the difficulty firms face in capturing all the benefits from their investments in innovation, which tend to spill over to other technology producers and users. This market reality can lead to underinvestment in innovative efforts—even given intellectual property protection—potentially warranting policies that directly target R&D. In a related manner, the fact that knowledge can be relatively inexpensive to share once it is produced raises the possibility that coordinated public R&D programs can conserve resources by reducing duplicative efforts.

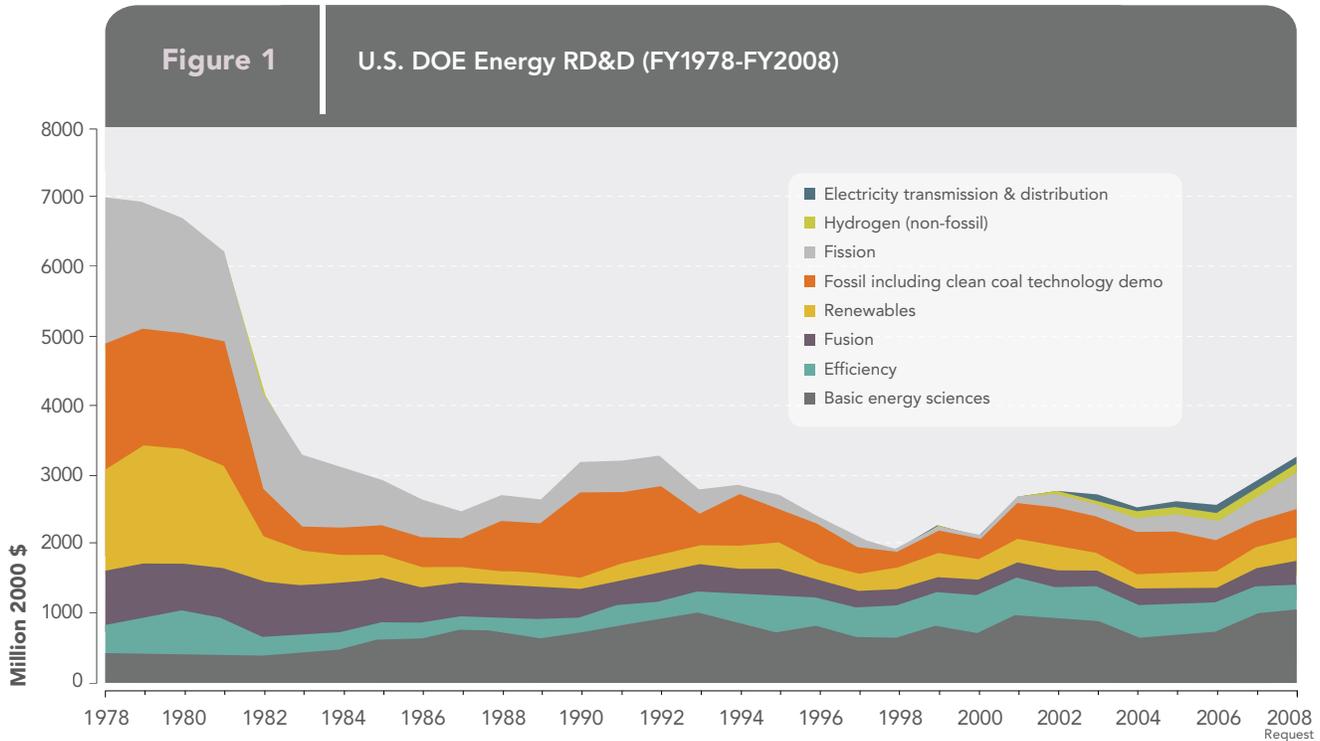
The problem of private-sector under investment in technology innovation may be exacerbated in the climate context where the energy assets involved are often very long-lived and where the incentives for bringing forward new technology rest

heavily on domestic and international policies rather than on natural market forces. Put another way, the development of climate-friendly technologies has little market value absent a sustained, credible government commitment to reducing GHG emissions. Moreover, the mismatch between near-term technology investment and long-term needs is likely to be even greater in a situation where the magnitude of desired GHG reductions can be expected to increase over time. If more stringent emissions constraints will eventually be needed, society will benefit from near-term R&D to lower the cost of achieving those reductions in the future. An emissions price that is relatively low in the near term may be inadequate to induce such innovative efforts absent very credible expectations that the policy will indeed be tightened in the future. If the politically feasible near-term emissions price (and/or the expected long-term emissions price) is lower than the socially optimal level, market inducements for R&D on GHG-reducing technologies will also be insufficient.

Similarly, rationales for public support of technology demonstration projects tend to point to the large expense; high degree of technical, market and regulatory risk; and inability of private firms to capture the rewards from designing and constructing first-of-a-kind facilities. These motivations provide potentially compelling rationales for public policies targeted at the R&D (research, development) and D (demonstration) phases of the technology innovation process. In addition, by virtue of its critical role in the higher education system, public R&D funding will continue to be important in training researchers and engineers with the skills necessary to work in either the public or private sectors to produce GHG-reducing technology innovations. By supporting graduate students and post-doctoral researchers, public funding for university-based research will affect the economy's capacity to generate scientific advances, technology innovations, and productivity improvements in the future. This linkage has made research funding a priority among many who are concerned about the long-term competitiveness of the U.S. economy and has led to a recent increase in political support for expanded spending—particularly on physical sciences and engineering.

In contrast, critics of public funding for RD&D pose the concern that government is ill-positioned to “pick winners” among a broad array of technological possibilities and commercial opportunities. They argue that decisions about how to invest in technology innovation are best left to a private sector motivated through broad incentives such as a price on GHGs. Even granting that a legitimate economic rationale

<sup>1</sup> The National Science Foundation (NSF) defines research as “systematic study directed toward fuller knowledge or understanding,” with basic research being directed toward the “fundamental aspects of phenomena and of observable facts without specific applications toward processes or products in mind.” Applied research, by contrast, is directed toward determining “the means by which a recognized and specific need may be met.” Development is defined by NSF as “systematic application of knowledge or understanding, directed toward the production of useful materials, devices, and systems or methods, including design, development, and improvement of prototypes and new processes to meet specific requirements.” See NSF. 2007. *Federal Research and Development Funding by Budget Function: Fiscal Years 2005-07*. Washington, DC: NSF.



for public involvement exists *in theory*, critics assert that the practical import of most such programs is negligible and likely to be more than offset by the cost and waste associated with pork-barrel spending and unnecessary government intrusion into the market. At a minimum, these critiques point to the importance of designing institutions, instruments, and incentives for delivering publicly supported RD&D in ways that minimize the risk of producing undesirable outcomes.

Despite some well-know failures, however, studies typically find that federal energy R&D investments have, on the whole, yielded substantial direct economic benefits as well as external benefits such as pollution mitigation and knowledge creation (a later section of this issue brief provides more detail on U.S. DOE programs). Nonetheless, and even given increasing concerns over global climate change, investment in energy R&D began to increase again only recently following a dramatic decline in both public- and private-sector spending over the last three decades. In that time period, low fossil-fuel prices and the deregulation of the natural gas and electric utilities industries led to substantial reductions in private-sector R&D expenditures, while efforts to balance the federal budget and a lack of political interest prevented the federal government from offsetting this decline. U.S. DOE expenditures on energy RD&D, including

basic energy sciences, now total slightly more than \$3 billion annually. This is less than half, in inflation-adjusted terms, of the peak level of spending reached in 1978 (see Figure 1). Identifying potential sources of funding for an expanded federal investment in technology RD&D therefore represents an important challenge for policymakers, as discussed in the next section.

Overall, public funding for research tends to receive widespread support based on the significant positive spillovers typically associated with the generation of new knowledge. Agreement over the appropriate role of public policy in technology development tends to weaken, however, as one moves from support for research and development to support for demonstration projects and particularly deployment. For most standard market goods, economists and other experts generally see clear justification for a government role in supporting research, but much weaker rationales for government intervention in the realms of technology commercialization and widespread deployment.

## RD&D Funding Options

A major concern for any RD&D program is funding.<sup>2</sup> Decisions

<sup>2</sup> This section benefited greatly from Nordhaus, R., et al. 2004. Public Sector Funding Mechanisms to

about the funding source(s) to be used for these programs have consequences for the magnitude, availability, and continuity of financial support in the future. They can also have implications for the institutional management of funds as well as the degree and nature of government oversight. This section discusses potential sources of funding for an expanded federal role in climate-related technology RD&D, including funding through general revenue, dedicated revenue (for example, from the sale of emission allowances), or wires and pipes charges. Institutional options for administering and performing publicly supported RD&D are discussed in the next section, while the use of tax credits as a mechanism for funding private-sector R&D efforts is discussed in the final section.

### General Revenue

One option for funding federal RD&D efforts is to rely on general revenues disbursed via Congressional appropriations through the U.S. Treasury. The year-to-year nature of the appropriations process can, however, be detrimental to long-term planning. Agencies can enter into multi-year agreements, but their financial commitments cannot exceed their current fiscal year appropriation. Options do exist that would allow for some long-range planning: for example, the government can use advance appropriations to commit specific amounts of funding for future years. Congress is generally averse to such pledges, however, because they constrain future appropriation options; moreover, promised funds are also easily rescinded. Another option is lump-sum appropriation in which all funding to be provided over the life of a program is made available in the year of enactment. This scheme provides some measure of stability, though any money carried over from year-to-year is still vulnerable to redistribution for other projects.

### Dedicated Revenue, Including Revenue from the Sale of Emission Allowances

By establishing a dedicated revenue source, Congress could help to avert some of the problems associated with relying on general revenues. A dedicated tax on some aspect of energy generation, distribution, or consumption could help fund R&D if resulting revenues were placed in a trust fund, as per the Highway Trust Fund. The federal government can be contractually required to allow the administering agency to draw down the fund. Also, appropriations committees can be restricted from spending at a level below receipts in an attempt to redistribute extra funds for other purposes. This is not the case with all trust funds, however. The Nuclear Waste

Fund, for example, is subject to annual appropriations. Since most climate-policy proposals introduced in Congress have focused on limiting GHG emissions through a cap-and-trade program (rather than by taxing emissions), any associated revenue stream that could potentially be available for RD&D would come from allowance sales. Several current proposals set aside at least a portion of revenues from auctioning allowances or from the direct sale of allowances at a fixed price under an emissions-price ceiling (that is, a safety valve) to support technology RD&D and deployment incentives. Typically, this results in a targeted funding stream on the order of several billion dollars annually, and up to \$50 billion or more in total over multiple years of program implementation (with total amounts limited in some proposals mainly by funding caps). Targeting revenues from allowance sales under a safety-valve mechanism to technology development has the environmentally appealing feature that lesser near-term emissions reductions (due to the safety valve) help to pay for expanded investments in future abatement potential. In fact, one recent legislative proposal uses the term “Technology Accelerator Payment” to refer to safety valve payments. On the other hand, targeting expected revenue streams to any particular purpose in advance runs counter to a longstanding principle of public finance that favors separating revenue sources from spending.

For example, the Bingaman-Specter “Low Carbon Economy Act of 2007” (S. 1766, 110th) would establish an “Energy Technology Deployment Fund” within the Treasury. Revenues from allowance sales would be deposited into this fund to be used for zero- and low-carbon technology deployment. Another example is the Lieberman-McCain “Climate Stewardship and Innovation Act of 2007” (S. 280, 110th), which would establish a new entity called the Climate Change Credit Corporation (CCCC) to receive and disburse GHG allowances and resulting revenues. Some of these revenues would be used to support a new technology deployment program, the Climate Technology Challenge Program. One potential distinction between these and other related proposals is whether allowances and/or funds from the sale of allowances are actually disbursed by a government agency through the Treasury or directly allocated to and disbursed by a quasi-governmental non-profit corporation.

In either case, it is important to note that new funding in both of these legislative proposals is actually directed to technology *deployment*, rather than research. For this reason, the more significant legislation for energy R&D may be the recently enacted America Competes Act (S. 761 and HR.

2272, 110th) which, among other things, authorizes a very substantial increase over the next several years in the budget for physical sciences and engineering research in DOE's Office of Science, the NSF, and the National Institute of Standards and Technology (NIST). In addition, this bill establishes an Advanced Research Projects Agency-Energy (ARPA-E) within DOE (see further discussion later in this issue brief). The degree to which future appropriations will support these authorizations remains to be seen.

### Wires and Pipes Charges

Using dedicated fees on electricity, natural gas, or other forms of energy—sometimes referred to as wires and pipes charges—could help fund RD&D within or outside the normal appropriations process. By levying surcharges on the transmission and distribution of electricity and/or natural gas, or as part of federally regulated rates for transporting oil, coal, or other fuels, Congress could establish a stable source of funding for energy-technology investments. This is closely related to the approach of using electricity wires charges for “public benefit funds” that in turn support energy efficiency programs and related research activities (states that currently have such funds include New York and California). Another example is the Universal Service Fund, which was established by the Telecommunications Act of 1996 and which uses fees on telephone services to promote wider access to telecommunications.

In principal, the proceeds from a wires charge could flow to any number of different institutional entities, including a federal trust fund, state agencies, a quasi-governmental corporation, private research consortia, or to the collecting firm (such as the distribution utility in the case of a fee on electricity services) for approved purposes. One potential problem is that it could be administratively difficult to levy fees in cases where carbon-containing fuels are not subject to existing transportation rate regulation. It may also be desirable to harmonize the relative charge across various fuels (e.g., based on carbon content). These considerations may argue for instead relying on emissions allowances or GHG taxes (as described in the preceding section) as the primary funding source. Wires and pipes charges may nonetheless have certain practical advantages and could be imposed even in the absence of, or in advance of, mandatory GHG regulations. A related alternative is a so-called “check-off” program analogous to those that fund the agricultural commodity boards overseen by the Department of Agriculture (such boards exist for beef, pork, and dairy). Congress could direct the Federal Energy Regulatory Commission to impose a

wires and pipes charge on certain types of fuels *if* the charge is passed by industry referendum. In 2002, for example, the American Gas Association proposed a check-off program for gas research. We discuss a related institutional option—“self-organizing industry boards”—in a later section on private research consortia.

## RD&D Institutional Options

A range of institutional options exists for administering and performing energy RD&D in the public and private sectors. These options include government agencies (e.g., DOE, NSF, the Environmental Protection Agency, and the Department of Defense), private firms and consortia, universities, and other non-profit research institutions. We focus here primarily on the institutions most often considered in policy discussions concerning an expanded role for public funding of energy- or climate-related RD&D.

### U.S. Department of Energy and the National Laboratories

The U.S. government has spent over \$100 billion in real terms on energy R&D over the last three decades, mostly through DOE programs. This direct federal spending represented about a third of total national expenditures on energy R&D; the balance was spent by the private sector. The private-sector share of the total has fallen, however, over the last decade. DOE energy research has gone through several transitions over the last three decades, both in terms of its relative focus on precommercial basic research versus technology demonstration and in terms of the emphasis placed on different technology areas (e.g., nuclear power, fossil fuels, energy efficiency, and renewables). Along the way, the Department's research objectives have also shifted from addressing concerns related primarily to energy security and resource depletion to a greater emphasis on environmental issues.

While the energy independence goal of the Nixon administration's Project Independence quickly proved impractical, government policy with respect to energy R&D stressed the development of alternative liquid fuels well into the 1980s. This emphasis culminated in the creation of the Synthetic Fuels Corporation (SFC) in 1980 which became emblematic of the large, expensive demonstration projects undertaken during this era. The following year, the incoming Reagan administration dramatically changed the direction of national energy policy and federal research goals began to stress long-term, pre-competitive R&D and lower overall budgets. The 1980s were mostly a time of retrenchment for

DOE's research program, although funding levels stabilized in the late 1980s and early 1990s. Congressional appropriations also began to emphasize environmental goals at that time, with large expenditures for the Clean Coal Technology demonstration program.

The shift to a greater emphasis on environmental goals, energy efficiency and renewable energy, public-private partnerships, and cost-sharing continued over the course of the Clinton administration in the 1990s. Federal support for basic energy research has received the most consistent funding since the late 1980s, including in recent years. Nonetheless, interest in large-scale, government-sponsored demonstration projects has continued: a recent example is the FutureGen Initiative, which seeks to demonstrate zero-emissions technologies for producing hydrogen and electricity from coal. Interestingly, the debate around FutureGen has highlighted some of the conflicting viewpoints that exist regarding the proper orientation of federal energy RD&D. On the one hand, some are concerned that the project represents too much public involvement in a large demonstration project; on the other hand, FutureGen has been criticized for being too oriented toward longer-term research and not enough toward near-term commercialization. This is in part related to funding requirements for the project, which demand a lower cost-share for private-sector participants than would otherwise be typical because the project is classified as research.

A number of studies over the last several years have evaluated the performance of federal energy R&D programs.<sup>3</sup> Although these programs have produced some notable failures and although their performance has varied widely, the literature typically finds that federal energy R&D investments have, on the whole, yielded substantial direct economic benefits as well as external benefits such as pollution mitigation and knowledge creation. Government-sponsored energy R&D programs are also commonly thought to have improved substantially since the 1970s and early 1980s, both in terms of the way they are managed and in terms of the objectives they target. On balance, available studies suggest that federal intervention is most appropriate for R&D activities that are unlikely to be adequately funded by private industry. Moreover, these studies tend to find that the optimal federal energy R&D portfolio is balanced, flexible, and incorporates both basic and applied research, with successes offsetting unanticipated failures. Private-industry involvement is almost always mentioned as being very important, particularly as

technology reaches the commercialization stage; greater international cooperation is also desirable. Typically, stronger leadership, targeted spending, rigorous oversight, and clear goals and benchmarks are recommended as measures that can facilitate project success and help to minimize wasteful expenditures.

At present, the federal government sponsors RD&D on GHG-reducing technologies primarily through the approximately \$3 billion in DOE-funded grants and contracts that are awarded annually to national labs, universities, and industry for energy-related research. This research support is administered largely by the DOE Office of Science and the DOE program offices: Energy Efficiency and Renewable Energy (EERE), Fossil Energy (FE), and Nuclear Energy (see DOE organizational chart at <http://www.energy.gov/organization/orgchart.htm>). The NSF and other federal agencies also fund research relevant to energy and climate-mitigation technology, but these efforts tend to be on a smaller scale and focused more on basic science. Federal grants and contracts fund both research centers and individual projects, and are often awarded through a competitive process involving a request for proposals, proposal review, and selection.

Within DOE, the Office of Science focuses on basic research, while the program offices focus almost entirely on applied research and development. In the United States, the DOE Office of Science is the largest single supporter of basic research in the physical sciences, accounting for 40 percent of federal outlays in this area. The Office of Science makes extensive use of peer review and federal advisory committees to develop general directions for research investment, help identify priorities, and determine which scientific proposals to support. Tables 1 and 2 show how much funding DOE directed to specific research areas in FY2006 and how this funding was distributed to different entities engaged in energy R&D.<sup>4</sup> Note that the acronym FFRDC in these tables stands for "federally funded research and development center."

Of the 37 currently active FFRDCs, DOE sponsors 16—more than any other agency.<sup>5</sup> Otherwise known as the national labs, these 16 FFRDCs perform about two-thirds of DOE-funded energy R&D and receive about 95 percent of their funding from the federal government. FFRDCs administered by universities and other non-profit entities receive the majority of funding, with the remainder going to industry-run

3 National Research Council. 2001. *Energy Research at DOE: Was it Worth It?* Washington, DC: National Academies Press. Also see: J. Chow and R.G. Newell. 2004. *A Retrospective Review of Energy R&D*. Washington, DC: Resources for the Future.

4 Based on \$4.5 billion in R&D spending by the DOE program offices and Office of Science (which also supports non-energy related research). Source: National Science Foundation. 2007. *Federal Funds for Research and Development: Fiscal Years 2004–06*. Arlington, VA: NSF.

5 See <http://www.nsf.gov/statistics/nsf06316/> for a master list of all FFRDCs.

Office	Total	Intramural	FFRDCs			Industry	Universities	Nonprofits
			Industry	University	Nonprofit			
<b>Energy Efficiency and Renewable Energy</b>	<b>100%</b>	<b>37%</b>	<b>7%</b>	<b>9%</b>	<b>35%</b>	—	<b>10%</b>	<b>3%</b>
Basic Research	3%	1%	1%	—	1%	—	—	—
Applied Research	41%	16%	4%	4%	12%	—	4%	1%
Development	50%	20%	2%	5%	18%	—	5%	1%
R&D Plant	5%	—	—	—	5%	—	—	—
<b>Fossil Energy</b>	<b>100%</b>	<b>23%</b>	<b>1%</b>	<b>4%</b>	<b>5%</b>	<b>52%</b>	<b>10%</b>	<b>5%</b>
Basic Research	2%	—	—	—	—	—	2%	—
Applied Research	43%	6%	1%	1%	1%	24%	8%	1%
Development	55%	17%	—	3%	4%	28%	—	4%
<b>Nuclear Energy</b>	<b>100%</b>	<b>—</b>	<b>24%</b>	<b>16%</b>	<b>36%</b>	<b>7%</b>	<b>13%</b>	<b>—</b>
Applied Research	99%	—	24%	16%	35%	7%	13%	—
Development	1%	—	—	—	1%	—	—	—
<b>Office of Science</b>	<b>100%</b>	<b>2%</b>	<b>2%</b>	<b>49%</b>	<b>25%</b>	<b>4%</b>	<b>17%</b>	<b>1%</b>
Basic Research	84%	2%	2%	39%	20%	4%	17%	1%
R&D Plant	16%	—	—	10%	5%	—	—	—
<b>TOTAL</b>	<b>100%</b>	<b>9%</b>	<b>4%</b>	<b>37%</b>	<b>25%</b>	<b>9%</b>	<b>15%</b>	<b>2%</b>

Office	Total	Intramural	FFRDCs			Industry	Universities	Nonprofits
			Industry	University	Nonprofit			
<b>Energy Efficiency and Renewable Energy</b>	<b>645</b>	<b>238</b>	<b>43</b>	<b>58</b>	<b>226</b>	—	<b>63</b>	<b>17</b>
Basic Research	22	9	4	2	4	—	2	1
Applied Research	264	103	26	24	76	—	27	7
Development	325	127	12	30	113	—	33	9
R&D Plant	35	—	1	2	32	—	—	—
<b>Fossil Energy</b>	<b>478</b>	<b>110</b>	<b>5</b>	<b>21</b>	<b>22</b>	<b>250</b>	<b>45</b>	<b>24</b>
Basic Research	9	0	—	—	—	—	9	—
Applied Research	204	30	5	5	5	114	37	7
Development	264	80	—	15	17	135	—	17
R&D Plant	1	—	—	—	—	1	—	—
<b>Nuclear Energy</b>	<b>249</b>	<b>3</b>	<b>61</b>	<b>39</b>	<b>89</b>	<b>17</b>	<b>33</b>	<b>7</b>
Applied Research	248	3	61	39	87	17	33	7
Development	2	0	—	—	—	—	—	—
<b>Office of Science</b>	<b>3,183</b>	<b>57</b>	<b>62</b>	<b>1,560</b>	<b>810</b>	<b>130</b>	<b>538</b>	<b>26</b>
Basic Research	2,681	57	52	1,239	645	128	535	25
R&D Plant	502	—	10	321	166	2	3	1
<b>TOTAL</b>	<b>4,555</b>	<b>409</b>	<b>171</b>	<b>1,678</b>	<b>1,147</b>	<b>396</b>	<b>679</b>	<b>75</b>

FFRDCs, industry, universities, and other non-profit research organizations. The main DOE labs focused on energy science and technology are the university-administered Ames, Argonne, Lawrence Berkeley, and Fermi labs; the industry-administered Idaho lab; the non-profit administered National Renewable Energy, Oak Ridge, and Pacific Northwest National labs; and the DOE-administered National Energy Technology Laboratory. All are overseen by the DOE Office of Science, except for the National Renewable Energy Laboratory and the National Energy Technology Laboratory, which are overseen by the Department's EERE and FE program offices respectively.

### U.S. National Science Foundation

The NSF's mission is to support all fields of science and engineering, except medicine. With a current annual budget of just under \$6 billion, the NSF backs about 20 percent of all federally funded basic research performed at American universities and colleges. Unlike DOE, which maintains the network of national labs, the NSF funds all work directly through the researcher's home institution. A major focus of the NSF's current strategic plan is encouraging transformational and multidisciplinary fundamental research. In supporting basic research, the NSF provides funding in nascent areas of R&D where private firms typically do not wish to venture. The NSF also integrates education and training objectives in its funding decisions to help build human capacity to apply technological advances and conduct future research.

Although the NSF does not have a program specifically geared toward energy research, energy- and climate-related projects may be funded across several of its disciplinary categories. Almost 60 percent of FY2002 funding went to engineering, the physical sciences, and environmental sciences. Thus, for example, recent NSF grants have been awarded for research to improve storage technologies for solar energy, to study the use of bacteria to filter hydrogen gas, and to develop new engineering techniques to improve technologies that extract energy from ocean wave currents. Several of the NSF's strategic foci are also directly relevant to GHG mitigation, including advanced manufacturing technology, biotechnology, advanced materials and processing, civil infrastructure systems, and environmental research.

### Advanced Research Projects Agency-Energy (ARPA-E)

The Defense Advanced Research Projects Agency (DARPA) has provided the inspiration for a number of proposals that would create an analogous agency focused on innovative

energy technology research—"ARPA-E." A major motivation is the desire to provide an efficient institutional home for R&D that does not fit well within the existing DOE organizational "stovepipes." The 2005 National Academy of Sciences (NAS) report *Rising Above the Gathering Storm* included the following recommendations concerning a new ARPA-E:<sup>6</sup>

The director of ARPA-E would report to the [DOE] under secretary for science and would be charged with sponsoring specific research and development programs to meet the nation's long-term energy challenges. The new agency would support creative "out-of-the-box" transformational generic energy research that industry by itself cannot or will not support and in which risk may be high but success would provide dramatic benefits for the nation. This would accelerate the process by which knowledge obtained through research is transformed to create jobs and address environmental, energy, and security issues. ARPA-E would be based on the historically successful DARPA model and would be designed as a lean and agile organization with a great deal of independence that can start and stop targeted programs on the basis of performance and do so in a timely manner. The agency would itself perform no research or transitional effort but would fund such work conducted by universities, startups, established firms, and others. Its staff would turn over approximately every four years. Although the agency would be focused on specific energy issues, it is expected that its work (like that of DARPA or NIH) will have important spinoff benefits, including aiding in the education of the next generation of researchers. Funding for ARPA-E would start at \$300 million the first year and increase to \$1 billion per year over five or six years, at which point the program's effectiveness would be evaluated and any appropriate actions taken.

A House bill to create an ARPA-E (H.R. 364) was voted out of the Science Committee in June 2007 and sent to the full House. The House version would have established ARPA-E within DOE and defined its primary objective as follows: "to reduce the amount of energy the United States imports from foreign sources by 20 percent over the next ten years." H.R. 364 goes on to state that ARPA-E should accomplish this objective by "(1) promoting revolutionary changes in the critical technologies that would promote energy independence; (2) turning cutting-edge science and engineering into technologies for energy and environmental

<sup>6</sup> Augustine, N., et al. 2006. *Rising Above the Gathering Storm: Energizing and Employing America for a Brighter Economic Future*. Washington, DC: National Academies Press. Also see: Van Atta, R. 2006. *Energy and Climate Change Research and the DARPA Model*. Testimony before the House Committee on Government Reform, 109<sup>th</sup> Congress, 2nd Sess. Mowery, D. 2006. *Lessons from the history of federal R&D for an Energy ARPA*. Testimony to the House Committee on Science, 109<sup>th</sup> Congress, 2nd Sess.

application; and (3) accelerating innovation in energy and the environment for both traditional and alternative energy sources and in energy efficiency mechanisms to decrease the Nation's reliance on foreign energy sources." Authorized funding levels were similar to the recommendations in the *Gathering Storm* report and would be deposited in an energy independence acceleration fund within the U.S. Treasury to be used for awarding competitive grants and entering into cooperative agreements or contracts with academic institutions, companies, or consortia (including the national labs).

In April 2007, the Senate passed S. 761 (the America Competes Act), which among other things stated that "The Secretary [of Energy] shall establish an Advanced Research Projects Authority-Energy to overcome the long-term and high-risk technological barriers in the development of energy technologies." The legislation further provides for the Authority to have a director and an advisory board, requires the NAS to conduct two reviews of its actions, and authorizes appropriations "as necessary." The activities of the Authority are much less specifically defined than in the House ARPA-E bill (H.R. 364).

The House and Senate passed the America Competes Act in July 2007 (S. 761 and HR 2272, 110th), and in doing so adopted the less detailed ARPA-E language of S. 761. The Act was signed into law by President Bush in August 2007. Upon signing it, however, President Bush indicated he was "disappointed that the legislation includes excessive authorizations and expansion of government...including a new Department of Energy agency to fund late-stage technology development more appropriately left to the private sector...." The President also indicated that he "will request funding in my 2009 Budget for those authorizations that support the focused priorities of the ACI [American Competitiveness Initiative], but will not propose excessive or duplicative funding based on authorizations in this bill." Presumably this means that the current administration will not be seeking appropriations for ARPA-E.

This position had been elaborated in more detail in an April 26, 2007 letter from the Secretary of Energy and Director of the Office of Science and Technology Policy, which stated: "At the same time that we support the conceptual goals of ARPA-E, we continue to have serious concerns about its potential implementation and its impact on ongoing DOE basic research efforts. Specifically, the Administration is strongly opposed to the creation of new bureaucracy at

DOE that would drain resources from priority basic research efforts." The letter goes on to express "serious doubts about the applicability of the national defense model to the energy sector" and a concern that the new agency should "not result in the establishment of an additional layer of bureaucracy or hinder the ongoing support for advanced research now underway in these offices. Similarly, we also urge that this legislation not shift DOE's current balance of efforts along the spectrum of research and development."

In concept, ARPA-E was initially intended to have some of the same flexibilities that DARPA has in hiring staff, contracting, and managing research. Proponents argued that ARPA-E would encourage project managers to pursue risky projects with the potential for more revolutionary discoveries by providing proper isolation from the pressure to deliver short-term results along with intense scrutiny of project failures. This approach was intended to complement the traditional "stovepipe" structure of the DOE program offices, which might otherwise limit the pool of resources available for non traditional areas of R&D. Proponents also tended to argue that the agency would need strong support from the Secretary of Energy and President. It remains to be seen, however, whether an energy version of DARPA would receive the simple oversight and strong backing in Congress that DARPA itself has enjoyed for years. Unlike DARPA, which has natural and closely linked funder, customer, and end-user in the Defense Department, ARPA-E would have no comparable "lead purchaser." Now that it has been established (at least on paper), the question remains what such an agency would accomplish in practice. Even without a mission that is clearly distinct from the broader DOE mission, an ARPA-E with its own director, advisory board, and potentially its own budget, could potentially serve a distinct purpose within DOE.

### Government and Quasi-Government Corporations

A number of recent proposals have sought, through federal legislation, to establish non-profit corporations that would focus on low-carbon energy RD&D. In this section we briefly describe some of these proposals, which have emerged as part of a larger movement over the last several decades toward the establishment of government and quasi-government organizations that have both public- and private-sector characteristics.<sup>7</sup> Supporters of these types of organizations see them as a way to introduce a more entrepreneurial style of management to publicly funded

<sup>7</sup> Kosar, K.R. 2007. *The Quasi-Government: Hybrid Organizations with Both Government and Private Sector Legal Characteristics*. CRS Report for Congress RL30533. Washington, DC: Congressional Research Service. The report discusses several categories of quasi-governmental entities, including: (1) quasi-official agencies, (2) government-sponsored enterprises (GSE), (3) federally funded research and development corporations, (4) agency-related nonprofit organizations, (5) venture capital funds, (6) congressionally chartered nonprofit organizations, and (7) instrumentalities of indeterminate character.

RD&D, with an attendant focus on outputs and results rather than conformance to process. In such organizations, so the argument goes, risk-taking by managers to improve performance would be more accepted and encouraged. Government-established corporations typically also have greater autonomy and flexibility than federal agencies in terms of hiring, salaries, and interactions with the private sector, and in terms of how they operate under budget and regulatory constraints. The ability to act as the recipient of a dedicated revenue stream that is outside the normal appropriations process is also appealing to some. Greater insulation from political influences is frequently mentioned among the advantages of quasi-governmental corporations, although it is not clear how much difference would exist in practice between the pressures experienced by government agencies versus quasi-government corporations.

On the other hand, critics tend to view hybrid public-private organizations as weakening the government's capacity to perform its responsibilities and contributing to an erosion of the protections afforded by due process, governmental checks and balances, and political accountability. They view the attraction of quasi-governmental organizations as reflecting the natural tendency of organizational leaders—whether they operate in the public or private sphere—to maximize autonomy in policy and operations. In government, however, this natural tendency is typically held in check by strong counter forces based on laws and accountability structures. A challenge therefore arises in harnessing the potential power of corporate-based structures to achieve efficient outcomes while also satisfying the need for public accountability.

Federal charters to establish a corporation typically have the following elements: (1) name; (2) purpose; (3) duration of existence; (4) governance structure (e.g., executives, composition of the board); (5) powers of the corporation; and (6) federal oversight powers.<sup>8</sup> These elements each have detailed sub-elements, a discussion of which is beyond the scope of this issue brief. The act that established the Synthetic Fuels Corporation, for example, was about 80 pages long, not including a lengthy explanatory conference report. Other charters are, however, much shorter. Governance structures will affect whether a given corporation is subject to the Administrative Procedures Act, potential auditing by the General Accountability Office, and the Freedom of Information Act; they will also affect the degree to which a corporation is subject to specific provisions of the Government Corporation Control Act regarding budgeting,

financial accounting and auditing, management reporting, security holdings, and debt obligations.

### Energy Technology Corporation

An energy technology corporation (ETC) would be a new, quasi-governmental corporation intended to provide incentives for precommercial research. This idea represents the application of a broader concept—the civilian technology corporation recommended in a 1992 NAS report—applied specifically to the energy sector.<sup>9</sup> The ETC would focus on developing technologies whose size, scope, or expected return falls outside what a private venture capital firm or other private-sector entity might fund. Some have suggested that an ETC would take certain structural elements of the Synthetic Fuel Corporation (SFC), but unlike that entity would encourage innovation through financial incentives and by “buying information” instead of setting production goals.<sup>10</sup> Important guiding principles that have been mentioned in connection with the ETC concept include cost-sharing, industry involvement in project initiation and design, insulation from political concerns, diversification of investments, openness to foreign firms, and program evaluation.

Specifically, proposals to establish an ETC typically call for a single appropriation (to insulate somewhat from political pressure) that would ideally be invested so that the returns could be used to fund loans, loan guarantees, production tax credits, purchase guarantees, and other instruments as appropriate. After a few years, the ETC would be subject to review and potential dissolution. Guided by an appointed board, the ETC would be independent from both the executive and legislative branches and hence would in part avoid the discontinuity and pressure of constituent-driven politics and appropriations. The ETC would also have flexibility in choosing investments and could interact with university consortia, industry, national labs, and other projects. Where cost-sharing is infeasible, the ETC could arrange equity venture agreements with small companies. Exemption from civil service requirements would allow it to offer compensation packages for highly-skilled staff that are competitive with the private sector. The modern ETC would also avoid the cumbersome procurement regulations that hampered the SFC.

Among various problems such a corporation would face, the ETC would be under pressure to show high rates of return,

<sup>8</sup> See: Kosar, Kevin R. 2005. *Congressional or Federal Charters: Overview and Current Issues*. CRS Report for Congress RS22230. Washington, DC: Congressional Research Service.

<sup>9</sup> National Academy of Sciences. 1992. *The Government Role in Civilian Technology: Building a New Alliance*. Chapter 3. Washington, DC: National Academies Press. Also see Deutch, J. 2005. *What Should the Government Do To Encourage Technical Change in the Energy Sector? MIT Joint Program on the Science and Policy of Global Change*. Report No. 120. Cambridge: MIT.

<sup>10</sup> See Deutch (2005).

even though its portfolio would include high-risk investments that otherwise would not be funded given existing market incentives. In fact, a high rate of success might indicate that the ETC is straying toward technologies that are ready for commercialization instead of targeting the earlier, pre-commercial phases of the innovation process. Defining what does or does not constitute “pre-commercial” technology research could be controversial, of course; similarly, it could be difficult in practice to apply other bounds or guidelines to the corporation’s involvement in specific aspects of the technology-innovation process.

### Synthetic Fuels Corporation

The SFC was established in 1980 as an independent, wholly federally-owned corporation to help create a domestic synthetic fuel industry as an alternative to importing crude oil. Under political pressure to backstop international oil prices, the SFC established a production target of 500,000 barrels per day. It had a seven-member board of directors, one of whom was a full-time chairman, and all of whom were appointed by the President and confirmed by the Senate. The SFC had the authority to provide financial assistance through purchase agreements, price guarantees, loan guarantees, loans, and joint ventures for project modules. After predicting oil prices of \$80–\$100 per barrel and a synfuel price of \$60 per barrel, the SFC was crippled when oil prices plummeted to below \$20 per barrel. It was eventually canceled in 1986 after several billion dollars in expenditures. Many experts have criticized the SFC as an example of an inappropriate and failed intrusion of government into large-scale commercial demonstration, an area better left to the private sphere.<sup>11</sup>

### Climate Change Credit Corporation

The Lieberman-McCain “Climate Stewardship and Innovation Act of 2007” (S. 280, 110th) proposes to establish a new entity called the Climate Change Credit Corporation (CCCC). The CCCC would be a nonprofit corporation; it would not issue stock and would not be considered “an agency or establishment of the United States Government.” The CCCC would have a bi-partisan, five-person board of directors, one of whom would be chairman and all of whom would be appointed by the President and confirmed by the Senate. With respect to technology, the main purpose of the CCCC would be to act as the recipient of emissions allowances, which it would sell. The proceeds would then be transferred to a new Climate Technology Challenge Program (CTCP) within DOE. The CTCP in turn would award funding for “development, demonstration, and deployment of

technologies that have the greatest potential for reducing greenhouse gas emissions” using a competitive process. In this structure, the flow of money from a non-governmental corporation to the DOE could present implementation problems. S. 280 would also establish a Climate Technology Financing Board within DOE to represent the federal government’s interest in joint venture partnerships, loans, and loan guarantees with industry. As mentioned above, these purposes relate mainly to technology deployment rather than to RD&D.

### Private Research Consortia

Private industry consortia represent another potential entity for administering and/or performing RD&D activities. Joint investment and collaboration can help internalize spillover benefits and reduce redundant research among firms, thereby increasing overall innovation, reducing costs, or both. There have been several examples of industry consortia since federal antitrust policy toward collaborative R&D was revised in the 1980s. In addition to securing funding, one of the main challenges for private consortia is finding areas for cooperative research that do not run afoul of the normal competitive interests of companies. Another issue for industry consortia engaged in alternative energy research is that a wide variety of fuels, technologies, and approaches are likely to be relevant for achieving GHG reductions. At a minimum this implies that no single consortium could address the full spectrum of energy- and climate-technology RD&D opportunities. This section describes several existing private-sector consortia that could play an expanded role in energy-technology innovation, particularly as coordinators and administrators of increased RD&D funding. Outside the energy sector, perhaps the best-known private consortium is SEMATECH, the Semiconductor Manufacturing Technology Consortium.

### SEMATECH

Until 1996, SEMATECH was funded in equal amounts by industry and DARPA (its budget totaled about \$200 million annually). SEMATECH’s 2007 budget is \$160 million. The original goal of this consortium was to perform pre-commercial mid-term research in a collaborative setting with the ultimate goal of reviving American competitiveness in the semiconductor industry. However, much of the research was done in highly proprietary areas, such as manufacturing processes. Hence, the focus of the consortium shifted toward encouraging R&D by firms that develop semiconductor manufacturing equipment. This allowed for the industry as a whole to benefit somewhat equally from SEMATECH R&D.

<sup>11</sup> See, for example: Cohen, Linda R. and Roger G. Noll. 1991. *The Technology Pork Barrel*. Washington, DC: Brookings.

The consortium has its own central research facility and draws upon constituent firms for technical staff. The direct employment of assignees eases technology transfer back to the member firms.<sup>12</sup>

### Electric Power Research Institute

The Electric Power Research Institute (EPRI) was established as a nonprofit organization in 1973 in response to government pressure following a major blackout that struck the Northeast region in 1965.<sup>13</sup> It was charged with managing a national R&D program for the electric power industry. EPRI was initially funded by a fee levied on member firms based on their size. Member firms that paid fees had access to all R&D results and could serve on various committees within the organization. EPRI is well established in the electric power industry: its members currently generate over 90 percent of U.S. electricity. EPRI acts as a funding clearinghouse through which project leaders select engineers and scientists to perform R&D. Rather than operate a major centralized laboratory, the Institute funds external research.

EPRI has been an effective vehicle for wide-ranging collaborative research, but deregulation in the 1990s caused its revenues to decline to \$285 million in 2006 after peaking at over \$600 million in 1994 (EPRI 2006 Annual Financial Report). The organization has adapted by changing its decision-making and funding structures. In the past, EPRI's Board of Directors and Research Advisory Committee (RAC) reviewed projects along with organizational goals and priorities during an annual joint meeting. Now that many member companies find themselves in direct competition, they have the option to buy into various *a la carte* projects presented by the Board. A small portion of the resulting funds is funneled back to EPRI's Office of Innovation to fund long-term, potentially revolutionary research. About 25 percent of EPRI funds go into deployment projects. Overall, about 90 percent of project funds go directly to technology RD&D, while 10 percent of funds are spent on economic and industry analyses.

### United States Council for Automotive Research

Beginning in the 1980s, U.S. automakers began collaborating on technology initiatives. Facing increased competition from foreign automakers (and taking advantage of new freedom from antitrust laws), Chrysler, Ford, and General Motors developed several research consortia. It became clear that an umbrella organization was needed to coordinate these

efforts and, in 1992, the United States Council for Automotive Research (USCAR) was founded for just that purpose. Over the past decade, consortia overseen by USCAR have addressed diverse automotive technologies, such as new batteries and light materials for fuel-efficient vehicles. In 2003, USCAR joined the U.S. DOE and five major energy corporations to form the FreedomCAR & Fuel Partnership, which was created to focus on the transition to a hydrogen economy. Prior to this, many of the same entities participated in the Partnership for a New Generation of Vehicles, which was aimed at building a car that could travel up to 80 miles on a gallon of gasoline while offering a competitive level of performance, utility, and cost to own. USCAR now oversees more than 30 consortia, teams, and working groups. Most of these consortia use existing research facilities and research funds. Technical experts are generally on loan from the participating automakers or from other involved organizations. USCAR partners with DOE on many projects and uses DOE's network of national laboratories. One concern that has been raised about USCAR, however, is that it gives a limited set of companies preferential access to public resources.

### Gas Technology Institute

The Gas Technology Institute (GTI), formerly known as the Gas Research Institute, is a consortium that involves all three segments of the gas industry: production, pipelines, and distribution. Though it began as a funding hub for outside research, the GTI now maintains 29 research and test facilities. Until recently, it was funded by a surcharge on natural gas transported through interstate pipelines. In 1998, a Federal Energy Regulatory Commission settlement required the GTI to phase out this surcharge and move to voluntary funding by 2004. This development has dramatically reduced the organization's budget: its funding in 2006 totaled approximately \$50 million, compared to budgets in the late 1980s and early 1990s that consistently totaled around \$200 million. GTI's longer-term research is now funded by royalties from the technologies it develops and by voluntary contributions from a subset of "sustaining members"—these contributions total about \$2 million annually. Sustaining members have access to all foundational R&D being done within the long-term research program.

### Self-Organizing Industry Boards

One proposed variation on traditional research consortia (such as EPRI or SEMATECH) is the self-organizing industry board (SOIB).<sup>14</sup> This approach also has some features in common with the "check-off" programs that fund the

12 See: Grindley, P., D.C. Mowery, and B. Silverman. 1994. SEMATECH and Collaborative Research: Lessons in the Design of High-Technology Consortia. *Journal of Policy Analysis and Management* 13(4):723-758.

13 See Appendix G in National Academy of Sciences. 1999. *Decision Making in the U.S. Department of Energy's Environmental Management Office of Science and Technology*. Washington, DC: National Academies Press.

14 Romer, P. and Z. Griliches. 1993. Implementing a National Technology Strategy with Self-Organizing Industry Boards. *Brookings Papers on Economic Activity: Microeconomics* 2:345-399.

agricultural commodity boards overseen by the Department of Agriculture. Under a SOIB-based research system, an industry would lobby the Secretary of Commerce or other responsible agency to find that collective action in support of RD&D would benefit the public. If the hearing is successful, the industry would hold a referendum to levy a tax or fee on the product or service it provides. The fee would be levied industry-wide, regardless of how an individual company voted. Though collection of this fee would be enforced by the government, revenues would not go to the Treasury. Firms within each industry would set up a series of boards dedicated to R&D; for example, a SOIB might support relevant university research or R&D investments by upstream industries. Each firm could contribute the fees collected from its customers to the board of its choice; if a suitable board did not exist, firms could establish one to their liking.

A major advantage of the SOIB approach is that it harnesses the public tax system to share the cost of high-spillover R&D without being paralyzed by the vagaries of Congressional oversight and appropriations. Moreover, it relies on the power of competition to direct funds into projects. Instead of having to respond to political pressure, firms can funnel money to the RD&D areas they feel would be most productive for the industry. The ability of new SOIBs to be created and compete with existing SOIBs helps ensure against research organizations becoming complacent and entrenched.

## RD&D Policy Instruments: Contracts and Grants, Tax Credits, and Prizes

Alongside a system of patents and intellectual property rights, three primary mechanisms exist for encouraging R&D: research contracts and grants, research tax credits for the private sector, and innovation inducement prizes. In addition, important roles exist—within the public and private sectors—for coordination, planning, and road mapping of R&D activities; international cooperation; and general funding for national-level capacity building, including support for university-based science and engineering research and education infrastructure.

### Contracts and Grants

Contracts and grants issued by DOE and NSF for research performed at the national labs or by universities, other non-profit institutions, and private firms represent by far the most important policy mechanism currently used to deliver federal support for energy RD&D. The government also funds demonstration projects to test and learn about the

integration, reliability, and performance of GHG-reducing technologies that may not find adequate private funding otherwise. Demonstration projects (such as the ongoing FutureGen initiative) are typically designed and coordinated in partnership with the private sector at a scale that is closer to what would be employed in wider commercial deployment. The discussion of U.S. DOE programs elsewhere in this issue brief provides further elaboration on the level and allocation of this type of funding.

### Tax Incentives for Private R&D

The Internal Revenue Code provides for two types of R&D tax incentives—tax credits and expensing. Both apply generally, though not solely, to energy- or climate-related R&D and both give firms incentives to expand research beyond what they would otherwise undertake by reducing the after-tax cost of R&D investments. Section 41 of the tax code allows firms to claim tax credits for extra expenditures on energy research and exploration while Section 174 provides for an expensing exception, whereby the taxpayer may treat research and exploration expenditures as current expenses, rather than charging them to a capital account that would be amortized only over a longer period of time.

The tax credit provided under Section 41 amounts to 20 percent of qualified research expenditures beyond a firm's baseline level (based on historical research expenditures or an alternative method). Qualified expenses include in-house salaries and supplies, certain time-sharing costs for computer use, and contract research performed by certain non-profit research organizations; moreover, these expenses must be incurred in the process of discovering new information that the taxpayer could use to develop new products or processes. A 20-percent credit with a separate threshold for payments is available for funds provided to universities for basic research; similarly, payments to certain energy research consortia (such as EPRI) are eligible for a 20-percent credit with no threshold. The U.S. Treasury estimates that the cost of these tax incentives has averaged about \$5 billion each in recent years. Overall, econometric studies have found that they are effective in the sense that private sector research spending has increased roughly one-for-one with each dollar of tax credit extended. R&D tax credits have the advantage of encouraging private efforts to advance technology while leaving specific R&D decisions and judgments about the most productive areas for investment, given both economic and regulatory incentives, to industry. As a result, there is less need for policy intervention in the market and for government to "pick winners." Tax credits have other advantages over

alternative R&D funding mechanisms: they create less of an administrative burden, obviate the need to target individual firms for assistance, and can be made permanent (and therefore not subject to annual appropriations).

Nonetheless, several factors have limited the overall impact of the research and exploration tax credit such that it represents only a small fraction of total federal and private-sector R&D expenditures. First, the credit was originally added to the tax code as a temporary measure—consequently, it has had to be renewed more than ten times, often with modifications. This uncertainty makes long-range research planning based on tax considerations difficult and has led many to call for making the research and exploration credit permanent. It has also proved difficult in practice to distinguish expenses that qualify for the credit from other expenses; moreover, under current rules, eligible expenditures are quite restricted. Even if research is considered qualified, related expenses such as overhead and equipment costs are not covered (although certain equipment costs are eligible for accelerated depreciation). Expenses for basic research conducted in-house and research conducted overseas are excluded altogether. Finally, tax credits are ineffective in situations where a firm has little taxable income. Thus the strength of the incentive they provide will vary with the business cycle.

Distributional considerations may also enter. One disadvantage of tax credits is that firms can claim them for research they would have undertaken even without additional incentives—in that case firms are rewarded at taxpayer expense without providing commensurate public benefit. To address this concern, tax credits are typically offered only for expenses above a defined baseline level, but in practice the true baseline level is impossible to determine. In addition, the fact that the vast share of credits tends to be claimed by large firms may raise equity concerns, although this result is somewhat to be expected given that large firms conduct most of the research.

In the context of climate policy, the main shortcoming of a tax credit approach is the difficulty of targeting R&D efforts that are particularly relevant to GHG mitigation. A recent modification of the existing credit to include contributions to energy research consortia addresses this issue to some extent. In addition, some groups (such as the National Commission on Energy Policy) have recommended that tax credits be increased for technologies aimed at improving end-use efficiency or otherwise reducing GHG emissions. It may be difficult, however, for Congress and the Treasury to develop

workable qualification rules for an augmented R&D tax credit that would focus specifically on efforts relevant for GHG mitigation while excluding other types of R&D. This approach is also vulnerable to a broader concern that attempts to achieve particular policy goals by fine-tuning the tax code can create significant windfall opportunities for interest groups, distort market incentives, and result in bad tax policy.

### Innovation Inducement Prizes

Recently, attention has turned to innovation-inducement prizes or awards as another possible mechanism for delivering R&D incentives. The idea would be to offer financial or other rewards for achieving specific technology objectives that have been specified in advance (in contrast to ex-post awards like the Nobel Prize).<sup>15</sup> Inducement prizes have historically played a role in advancing technology in areas ranging from maritime navigation and canning to mathematics, commercial aviation, and automotive engineering. Recent examples relevant to energy and climate policy include the Hydrogen Prize Act (which passed the House in the 109<sup>th</sup> Congress), a number of energy prizes authorized in the Energy Policy Act of 2005 (these have yet to be funded, however), Congressional interest in prizes to be administered by the NSF, the privately-funded Automotive X-Prize, and the Earth Challenge Prize announced by British financier Richard Branson. The prize approach has also been explicitly endorsed in some proposals as an instrument to be used by ARPA-E.

Inducement prizes are clearly not suited to all research objectives, but they have the potential to play a larger role along with research contracts, grants, and R&D tax credits. In contrast to these other instruments, prizes have the attractive incentive property of targeting and rewarding innovation outputs, rather than inputs: the prize is paid only if the objective is attained. Prizes or awards can help to focus efforts on specific high-priority objectives, without specifying how the goal is to be accomplished; potentially, they can also attract a more diverse range of innovators. A National Academy Committee recently endorsed the idea of establishing a program of innovation inducement prizes at NSF. This effort would be launched as an experimental program in close consultation with the academic and non-profit community, technical societies, and industry.<sup>16</sup>

<sup>15</sup> Newell, R.G. and N. Wilson. 2005. *Technology Prizes for Climate Mitigation*. RFF Discussion Paper 05-33. Washington, DC: RFF.

<sup>16</sup> National Research Council. 2007. *Innovation Inducement Prizes at the National Science Foundation*. Washington, DC: National Academies Press.



**ISSUE BRIEF 10**  
**CLIMATE TECHNOLOGY  
DEPLOYMENT POLICY**

**RICHARD G. NEWELL**

**10**

## CLIMATE TECHNOLOGY DEPLOYMENT POLICY

Richard G. Newell

### SUMMARY

There is a growing consensus among policymakers and stakeholders that an effective federal program to control greenhouse gas (GHG) emissions must have as one element policies to hasten the development and commercialization of low- and no-carbon energy technologies, as well as technologies that improve end-use energy efficiency. Alongside policies designed to directly mandate GHG reductions, such as a GHG cap-and-trade system, policies that instead target the development and adoption of GHG-reducing technologies have been much discussed. While both general types of policies may have GHG reductions as their ultimate aim, technology policies are often framed in terms of technology-development activities or technology-specific mandates and incentives rather than primarily in terms of emissions.

A wide range of climate-related technology policy options are currently being employed or have been proposed at the federal and state levels. It is useful to categorize these options roughly according to which stage of the technology-development process they target: research, development, and demonstration, or widespread commercial deployment. This issue brief focuses on technology deployment, while a companion brief (Issue Brief #9) addresses technology research, development, and demonstration, including options for funding, institutions, and research policy instruments.

After exploring various rationales and motivations for implementing technology-deployment policies as part of a strategy for addressing climate change, this paper examines relevant policy options, including standards (e.g., technology, performance, and efficiency standards), subsidies (e.g., tax credits, tendering, loan guarantees), and limited liability. A number of important messages emerge:

- Pricing GHG emissions through a cap-and-trade or tax system would provide direct, cost-effective, and technology-neutral financial incentives for the deployment of GHG-reducing technology.
- For technology policies to help achieve a given level of emissions reductions at lower overall social cost than an emissions-pricing policy alone, they must be targeted to addressing market problems *other than* emissions reduction per se. Thus technology policies are best viewed as a *complement* to rather than a *substitute* for an emissions pricing policy.
- As complements to a cap-and-trade system, technology policies will tend to lower the allowance price associated with achieving a given aggregate cap level, rather than producing additional emissions reductions below the cap. As complements to a GHG tax, such policies will tend to increase the total amount of emissions reductions achieved by a given tax. Again, because the emissions price may not be a complete measure of cost, whether technology policies lower the overall cost

to society of achieving emissions reductions depends on their being well-designed and targeted to addressing distinct market problems.

- There are several specific market problems to which technology deployment policies could be efficiently directed, if the benefits of practicable policies were found to justify the costs in particular circumstances. These market problems include information problems related to energy-efficiency investment decisions, knowledge spillovers from learning during deployment, asymmetric information between project developers and lenders, network effects in large integrated systems, and incomplete insurance markets for liability associated with specific technologies.
- Although market problems are often cited in justifying deployment policies, such policies in practice often go much further in promoting particular technologies than a response to a legitimate market problem would require. Therefore, while conceptually sound rationales may exist for implementing these policies, economists and others tend to be skeptical that many of them, as actually proposed and implemented, would provide a cost-effective addition to market-based policies. Critics point out that deployment policies intended to last only during the early stages of commercialization and deployment often create vested interests that make the policies difficult to end.
- Others argue that mandating GHG reductions will be more politically feasible if government includes policies tied to the deployment of specific technologies. These policies may attract more support than a pricing policy because they often employ “carrots” (subsidies) rather than “sticks” (fees or mandates), provide a way to promote particular technologies that have strong political constituencies (such as biofuels), make the cost of reducing emissions and adopting new technologies less visible by spreading it to the general taxpayer, and may not have an explicit price attached to them (as do emissions prices).
- Technology standards and subsidies can be viewed as different means to achieve the same ends (for example, increased energy efficiency, greater reliance on renewable energy). Just as there are important differences between an emissions-trading program and an emissions tax, however, standards and subsidies tend to differ in terms of who bears the cost, how their impact evolves over time, and what kinds of outcomes they guarantee (that is, whether they provide certainty about achieving certain deployment objectives versus certainty about achieving certain cost objectives).
- Standards tend to guarantee that specific technologies will be deployed in a certain quantity (or as a minimum share of the market) or that certain performance criteria will be achieved, but leave the cost of achieving the standards uncertain. Technology subsidies, on the other hand, pin the incremental cost spent on technology to the level of the incentive and leave uncertain how much deployment (or what level of performance) will be achieved at that cost. Ceilings (and floors) on credit prices within a tradable standards system can blur these distinctions.
- Regarding distributional consequences, the cost of imposing a standard tends to fall primarily on households and firms in the regulated sector. By contrast, the cost of providing subsidies tends to fall on taxpayers more generally. However, this distinction can also be altered somewhat through self-financing mechanisms such as “feebates” (to promote improved automobile fuel economy, for example, subsidies for efficient vehicles could be funded by fees on inefficient vehicles).
- Different deployment policies also have different dynamic properties. The incentives generated by standards are typically more static in the sense that industry has no reason to exceed the standard, which eventually becomes less binding as technology matures (of course, as technology improves, policymakers may also respond by raising standards). Fixed subsidy levels, on the other hand, may continue to provide incremental deployment incentives, depending on the payment structure.
- As with emission standards, the cost-effectiveness of technology-oriented standards can be increased by incorporating flexibility mechanisms such as credit trading, banking, and borrowing. Likewise, tendering, or reverse auctions, can help facilitate cost competition by making subsidy recipients bid for the minimum subsidy needed to deliver a specified quantity of new technology. This approach can help reduce the cost of technology deployment over time by ensuring that a given expenditure of public resources produces the maximum amount of deployment (or conversely, that a given deployment target is achieved at the lowest possible cost to taxpayers).
- Loan guarantee programs may be conceptually justified if informational asymmetries exist in credit markets for relevant technologies. On the other hand, loan guarantees

create implicit subsidies; as such, their benefits must justify their costs. Because loan guarantees insulate projects, at least in part, from default risk, they can create incentives for developers to take on riskier projects while doing less than they should to guard against preventable risks.

- There may be a rationale for establishing a joint insurance pool or limiting liability for certain technologies like carbon storage if there is insufficient availability of private liability insurance or there are substantial potential difficulties in assigning liability. On the other hand, liability protection provides a form of implicit subsidy by insulating parties from potential damages caused by their technologies. Thus, if designed poorly they may reduce incentives for those parties to take appropriate actions to mitigate risks where possible.
- Finally, a number of other policies may be critical in helping certain GHG-reducing technologies compete effectively to potentially gain a foothold in the marketplace. The successful deployment of new technologies often requires better information and verification methods; infrastructure planning, permitting, compatibility standards, and other supporting regulatory developments; and institutional structures that facilitate technology transfer, such as rule of law, judicial or regulatory transparency, intellectual property protection, and open markets. A balance must be struck, however, between enabling technologies to compete and constructing policies that preferentially support specific technology options or systems.

## The Role of Climate Technology Deployment Policies

When considered alongside policies that directly mandate GHG reductions, additional technology policies may not seem necessary or desirable. After all, the market-based approaches featured in most recent proposals for a mandatory U.S. climate policy would give rise to a price on GHG emissions. This price places a clear financial value on GHG reductions and like other market prices (such as energy prices) should induce households and firms to buy technologies with lower GHG emissions (for example, more energy-efficient products) the next time they are in the market.

Generic public funding for research tends to receive widespread support based on the significant positive

spillovers that are often associated with the generation of new knowledge. Agreement about the appropriate role of public policy in technology development tends to weaken, however, as one moves from policies targeting research and development to policies directed at demonstration projects and particularly deployment. In the case of standard market goods, many experts (and especially economists) believe that while the government's role in supporting research may be clear, the rationale for government intervention quickly weakens when it comes to commercializing and deploying new technology on a large scale.

A similar point of view might carry over to the rationale for government intervention on behalf, specifically, of new technologies to reduce GHG emissions, *if* a sufficient market price has been placed on these emissions through government policy. This perspective would tend to support a complementary set of strategies that couple emissions pricing policies with policies to support research, development, and demonstration (where public investment in demonstration is limited and directed toward learning)—but *not* widespread deployment. There are nonetheless several economic rationales and other motivations for considering measures oriented toward technology deployment within a portfolio of climate policies.

Information problems provide one rationale for policies to promote energy-efficient technologies. This is particularly the case where it has been demonstrated that consumers systematically undervalue energy efficiency or where the incentives for efficiency investments are split between those who pay for a new technology and those who benefit. A good example is the landlord-tenant problem: a landlord has no incentive to pay for efficiency improvements if the tenant pays the energy bills and therefore captures any resulting cost savings. Another potential rationale involves spillover effects and the process of so-called “learning-by-doing”—a term that describes the tendency for production costs to fall as manufacturers gain production experience. An emissions price will encourage producers to make investments in new technology that result in learning-by-doing. But if the benefits of this learning spill over to other producers without full compensation to the early adopters, incentives for early adoption will be diluted and investment in learning-by-doing will fall short of what is optimal for society as a whole at a given emissions price. In cases like this, a compelling rationale may exist, in principle, for public support of deployment efforts early in the transition to commercialization.

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## Any deployment policy must strike a careful balance between enabling technologies to compete and preferentially supporting specific options or systems.

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Network effects provide a motivation for deployment policies aimed at improving coordination and planning—and, where appropriate, developing compatibility standards—in situations that involve interrelated technologies, particularly within large integrated systems (for example, energy production, transmission, and distribution networks). Setting standards in a network context may reduce excess inertia (for example, so-called chicken-and-egg problems with alternative-fueled vehicles), while simultaneously reducing search and coordination costs, but standards can also reduce the diversity of technology options offered and may impede innovation over time. Loan guarantee programs may be conceptually justified if informational asymmetries exist in credit markets for relevant technologies. Finally, incomplete insurance markets may provide a rationale for liability protection or other policies for certain technology options (for example, long-term CO<sub>2</sub> storage).

The argument against technology-oriented policies, even where the market problems described above exist, centers on the concern that government is ill-positioned to “pick winners” among a broad array of technological possibilities and commercial opportunities. Critics argue that decisions about new technology are best left to a private sector motivated through broad incentives such as a price on GHGs. In this view, technology deployment policies represent an unnecessarily restrictive and costly strategy for advancing the larger policy objective, where that objective—in this case, reducing GHG emissions—can be less expensively achieved through flexible market-based policies. Another perspective is that even if it were theoretically possible to address the

market problems noted above through deployment policies, the practical import of attempting to do so would likely be negligible and/or more than offset by the cost and waste associated with pork barrel spending and unnecessary government intrusion into the market. From this perspective, simply pointing to the conceptual plausibility that certain market imperfections exist is insufficient; rather, one would need to closely measure the extent of such problems in specific cases and tailor policy interventions accordingly. This would mean identifying practicable policies that directly address the problems identified—and then implementing those policies in a manner that ensures benefits exceed costs (and ideally that net benefits are maximized).

The remainder of this issue brief discusses several common types of technology deployment policies in more detail. A number of other policies and programs are not covered here, but may be critical in helping to enable certain GHG-reducing technologies to compete effectively, including:

- Information programs (such as product efficiency labeling or energy efficiency audits) and programs to develop measurement and verification methods (for example, for energy-efficiency technologies, carbon storage, etc.)
- Infrastructure planning; permitting; regulatory development; compatibility standards (for example, for fueling systems); and public outreach for specific technology options, systems, and networks (for example, transmission and distribution lines, nuclear waste storage, carbon capture and storage)
- Programs to promote international technology transfer and encourage the development of structures or institutions that enable technology transfer (such as rule of law, judicial or regulatory transparency, intellectual property protection, and open markets)

Before moving on to a detailed discussion of standards, subsidies, and liability protection as means for accelerating the commercialization of new technologies, it is worth emphasizing the general point that any deployment policy (including the additional types of policies noted above) must strike a careful balance between enabling technologies to compete and preferentially supporting specific options or systems.

### Standards

Standards can take several forms and provide varying degrees of flexibility, from uniform technology standards at one

end of the spectrum to fully tradable emissions standards at the other. The cost-effectiveness of these approaches tends to improve as one moves from rigid technology standards toward standards that can be implemented using a market-based trading system. This is because more flexible standards—applied to actual emissions—can be designed to take advantage of all major means of reducing emissions, including substitution toward more efficient equipment and lower-carbon fuel inputs, end-of-pipe emissions control (for example, carbon capture and storage), and changes in end-use demand.<sup>1</sup> The cost-effectiveness of any type of standard—technology-based or otherwise—can typically be increased by incorporating flexibility through credit trading, banking, and borrowing. Cost certainty can be introduced by incorporating price ceilings (and floors) for compliance credits, as in an emissions cap-and-trade system.

### Uniform Technology Standards

The least flexible type of regulation is a uniform technology standard that requires every covered entity to install a particular type of technology. Examples include requirements that all coal-fired power plants install carbon capture and storage technology, that all light bulbs be fluorescent, or that all vehicles be flex-fuel capable. Technology standards of this type each take advantage of only one means of reducing emissions.

In response to this critique, one might attempt to establish a suite of technology standards that cover every aspect of the system in question and thereby attempt to capture all abatement opportunities. But to produce cost-effective results, this approach would require setting each individual technology requirement in a way that equalized incremental emissions abatement costs across the system as a whole. Even if it were practically possible to do this for an individual facility or firm, it would be impossible to set a single set of standards that balanced the various circumstances at each individual firm or facility in a manner that minimized total costs. Uniform technology standards may also stifle innovation over time because once the standard is achieved there is no incentive to go beyond it (other than to reduce the cost of the approved technology). A primary advantage of uniform technology standards, on the other hand, is that verifying the installation and operation of required technologies is relatively easy. This advantage from an enforcement standpoint is unlikely to be important in an advanced industrialized country like the United States, but may be more relevant in certain

developing country contexts.

### Market Share (Portfolio) Standards

Market share or “portfolio” standards provide additional flexibility by applying requirements at an industry-wide level, rather than obliging every firm or facility to meet exactly the same technology standard. An example is a renewable portfolio standard designed to require that a minimum share of all electricity sold in a state comes from qualifying renewable sources. If one firm faces relatively high costs in delivering renewably generated power, it can buy renewable energy credits from a firm that faces lower costs, just as in an emissions cap-and-trade system. Renewable portfolio standards have been adopted by over 20 states and proposed at the federal level. In states that have such standards, different technologies qualify toward meeting the standard; in addition, some states have separate targets for specific types of renewable technology (e.g., solar).

The portfolio standard concept has also been proposed for other types of climate-friendly technologies and even for end-use efficiency. For example, a portfolio standard to promote carbon capture and storage could require that a certain number or share of all new fossil-fueled power plants be fitted with carbon capture and storage technology. Alternatively, a broader clean energy portfolio standard could be designed to include all non-carbon forms of power generation, including nuclear power in addition to renewables and fossil systems with carbon capture and storage. Similarly, some states have begun to experiment with “efficiency portfolio standards” that require utilities to meet a minimum percentage of demand for electricity services through energy efficiency programs (the same idea has also been proposed at the federal level).<sup>2</sup>

The design of such standards will obviously have a large impact on their cost-effectiveness. As a means of reducing GHG emissions, for example, a portfolio standard that includes more low-carbon options will tend to reduce costs relative to a portfolio standard that is focused on a particular type of technology.

### Emissions Performance Standards

Emissions performance standards specify a certain maximum level of emissions per unit of output (for example, pounds of CO<sub>2</sub> per kWh or grams of CO<sub>2</sub> per gallon of motor fuel). Performance standards can also be imposed at the level of an individual source or, if trading is allowed, at the level of an

<sup>1</sup> Applying flexible performance standards to equipment manufacturers, versus to direct emitters, does not have these properties. Flexibility in meeting an equipment efficiency standard may lower compliance costs for equipment manufacturers, but will not, for example, encourage reductions in end-use energy demand.

<sup>2</sup> See further discussion in Issue Brief #11, which provides more detail on issues related to climate-change regulation in the electricity sector.

industry or sector as a whole (in which case the standard will give rise to a tradable emissions credit system). Performance standards reflect a desire to move away from specifying particular technologies or classes of technology, toward a focus on regulating emissions in a technology-neutral fashion. This tendency is evident in the increasingly broad types of portfolio standards described above, with a “clean energy” portfolio standard being the broadest. From the standpoint of reducing emissions it might also make sense to encourage relatively low-emission conventional coal and natural gas systems, as well as more efficient electricity production and end-use technologies, in addition to the technologies typically included in renewable or clean energy portfolio standards.

The desire to encourage a wide variety of abatement options leads logically back to a broad policy approach: tradable emissions performance standards or even an emissions cap-and-trade system. The primary distinction between a tradable emissions performance standard and a cap-and-trade system is that the performance standard is intensity-based. That means the overall quantity of emissions allowed under the system will vary depending on the level of output (in other words, if a GHG performance standard, in pounds per kWh, is applied to electricity production, then final emissions will depend on how many kWh are generated). A drawback of intensity-based standards (relative to a quantity-based cap-and-trade program) is that they create an implicit subsidy to increase output: as firms produce more, they are allowed a greater quantity of emissions. Any additional emissions that result from an increase in production, up to the level of the performance standard, are free to the producer. This means, in effect, that firms have the ability to generate the equivalent of free allowances by increasing their output. As a result, achieving an equivalent emissions target using intensity-based performance standards will tend to result in higher emissions prices and lower output prices relative to achieving the same target using a cap-and-trade system. The overall cost of attaining a given emissions target will also tend to be higher because the performance standard, by keeping output prices relatively low, does not encourage as much end-use energy efficiency and conservation.

On the other hand, the implicit allocation of credits based on output can protect consumers from bearing the cost of emissions allowances passed on to them by firms that might otherwise experience a windfall gain if they receive free allowances under a cap-and-trade program. The implicit allocation of emission credits to regulated entities under a tradable performance standard therefore produces different

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The cost-effectiveness of any type of standard—technology-based or otherwise—can typically be increased by incorporating flexibility through credit trading, banking, and borrowing.

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distributional effects relative to a cap-and-trade system, where the decision about how to allocate allowances can be separated from the decision about which entities get regulated.

Another distinction between these two approaches is that performance standards must be applied at the sector or sub-sector level, where the unit of output is comparable. Unless sector-specific performance standards are linked through inter-sector emissions trading, this can lead to differences in the stringency of the standards applied to different sectors and to unnecessarily costly emissions reductions overall. This need to develop different output metrics and emissions targets for different sectors is in contrast to a cap-and-trade system where the only relevant units are tons of emissions and where the system can apply on an economy-wide scale. Nonetheless, tradable performance standards hold some political appeal because they tend to keep output prices lower than under a cap-and-trade system, because they deal with credit allocation implicitly rather than explicitly, and because they tend to push regulatory decisions toward the sector level where they can be more readily managed by organized interests.

### Energy Efficiency Standards

In contrast to emissions performance standards, energy efficiency standards regulate energy use—rather than emissions generated—per unit of output. In the United States, energy efficiency standards for equipment used in buildings

have historically been applied in the form of minimum efficiencies for individual products (for example, refrigerators, air conditioners), while efficiency standards for automobiles have been applied in the form of fuel-economy standards averaged across manufacturers' fleets (where standards have to be met separately for each automobile company's domestic-car, imported-car, and light-truck fleet).

A number of recent proposals, however, have called for reforming the corporate average fuel economy or CAFE system to make it more flexible while simultaneously making the overall program more stringent. Specifically, recent proposals would allow CAFE compliance credits to be traded across fleets and across manufacturers. Similarly, as has already been noted, there is interest in "energy efficiency portfolio standards" that would target aggregate reductions in electricity use, rather than the efficiency levels of specific products. In the latter case, quantifying and verifying electricity savings (relative to what would have otherwise occurred) is more challenging than measuring renewable energy output, emissions, or the energy-efficiency of individual technologies. This presents a significant hurdle to the implementation of an efficiency portfolio standard that has the same simplicity and credibility as trading programs based on more readily measured metrics or characteristics. Nonetheless, some states have developed methods for measuring demand reductions and are beginning to include energy savings from conservation programs along with renewable energy in their portfolio standards.

As discussed earlier, the primary economic rationale for including energy efficiency standards in a suite of climate technology deployment policies is if there are verifiable market problems that result in sub-optimal purchasing decisions regarding the energy-related operating costs of vehicles and equipment. Such a rationale would continue to exist even with a CO<sub>2</sub> pricing policy, as any market problems that resulted in the undervaluation of future energy savings would also act to diminish the full impact of the emissions price in terms of creating incentives for energy-efficiency improvements. The relevant economic question then becomes how to set the stringency of the energy-efficiency policy so as to maximize its net benefits, taking into account all relevant costs and benefits. Analysts differ in their assessments concerning the extent to which consumers and firms really undervalue energy efficiency when making purchase decisions about energy-using equipment—indeed, this debate has persisted since the 1970s. Efforts to improve methods for measuring and verifying the effectiveness of

energy-efficiency programs also continue and are receiving increased scrutiny as the expectations for these programs grow.

## Subsidies

Mechanisms for subsidizing climate-friendly technologies come in a wide variety of forms, including tax credits, direct payments, tendering or reverse auctions, and loan guarantees. In the context of an emissions trading program, it is also possible to subsidize certain technologies through differentiated allowance allocation.<sup>3</sup> The common feature of these approaches is that they provide a positive financial incentive for purchasing and/or using particular technologies. Subsidies can be designed to reach the same ends as standards, but they operate by providing financial "carrots" rather than a regulatory or financial "sticks." This feature can have distinct political advantages compared to standards and market-based emissions policies, although it is worth noting that standards may hold greater appeal for technology *suppliers* because they provide a more guaranteed market. For example, increased renewable electricity generation can be pursued through either a production tax credit or a renewable portfolio standard (in fact, both are being used in the United States today in the sense that many states have introduced renewable portfolio standards on top of an existing federal production tax credit for renewable energy sources). Increased ethanol production can be induced through an excise tax credit or a renewable motor fuel standard (again, both are currently being used in the United States). Of course, a market-based policy that puts a price on emissions also provides positive financial incentives for the adoption of GHG-reducing technology—and does so in a technology-neutral fashion.

As means to achieving a particular technology end, however, there are several important differences between subsidies and standards. First, subsidies can guarantee a lower and upper limit to the amount of resources spent on technology deployment—either on an incremental basis, by setting the level of subsidy provided per unit of output (e.g., cents per kWh), and/or in aggregate by capping the total subsidy amount made available (total \$). A price guarantee is often mentioned by renewable electricity developers as a positive feature of policies such as "feed-in tariffs," which guarantee a minimum price for renewable electricity delivered to the grid (Germany's system being an example). But subsidies do not guarantee that a particular technology-deployment target will

<sup>3</sup> For example, the bill introduced by Senators Bingaman and Specter in the 110<sup>th</sup> Congress (S. 1766) provides "bonus" allowances for carbon capture and sequestration. In the European Union's Emissions Trading Scheme, different allocation rules for new facilities subsidize different technologies, though not always in a way that produces climate-friendly results.

be met—they may produce results that under- or over-shoot a particular target. Standards, on the other hand, can guarantee a particular level of performance in an individual technology or an aggregate penetration level or market share, but their ultimate cost is not known in advance. Including a price ceiling in the design of a tradable standard can blur this distinction, just as including a “safety valve” mechanism may blur the distinction between an emissions tax and a cap-and-trade system.

Second, subsidies require explicit or implicit (in the case of tax credits) financial outlays from the public treasury. By contrast, the cost of standards is born by producers and consumers within the regulated sector. This may be viewed as positive or negative depending on one’s view of whether the broad beneficiaries of reduced climate risks (taxpayers) should pay for emissions reductions, or rather that the cost burden should fall on a narrower group of sources and consumers who impose those climate risks through their emissions. Alternatively, the difficulty of raising public funds might be seen as an argument in favor of standards. A third related difference is that subsidies drive the prices of outputs like electricity and motor fuel lower, which removes incentives for demand reductions and in fact encourages increased demand for, and supply of, energy services. This is a fundamental distinction and it leads most economists to the view that negative externalities, such as GHG emissions, are best addressed through policies that raise the cost of behaviors that produce those externalities while positive externalities—such as the spillover benefits and knowledge creation associated with research and development—are better addressed through policies that provide positive incentives. As discussed previously, however, variations of this general principle may be justified if technology subsidy policies are in fact designed to act as complements to an emissions policy in order to generate positive knowledge spillovers through learning and cost reduction for new technologies.<sup>4</sup> This implies that subsidy policies should only target technologies for which clear learning opportunities exist and should do so only in a limited fashion early in the deployment process. It should also be the case that subsidies elicit investment and produce learning that would not otherwise be undertaken by the private sector in response to the emissions policy alone. These criteria would likely *not* be met by a number of existing subsidies or mandates, many of which target relatively mature technologies (e.g., wind power, corn-based ethanol) where markets are well-established and significant early learning has already been achieved.

<sup>4</sup> For example, when one company builds and operates a carbon capture and storage facility, it learns ways to implement this technology more cheaply. This knowledge is directly or indirectly shared with (that is, it spills over to) other companies as they build other facilities.

Finally, subsidies often require relatively large outlays of funding (or equivalently, they forego large amounts of revenue that would otherwise be collected by the public treasury) for the amount of incremental technology deployment they induce. This occurs because, under many subsidy designs, the subsidy accrues to parties that would have adopted the technology even absent the subsidy. So-called “free-riding” behavior—which studies have found can be quite high—will dilute the effectiveness of the policy in the sense that it reduces the actual environmental benefit achieved for a given expenditure of public resources. Some subsidy designs, such as tendering (reverse auctions) and loan guarantees, can be structured to better target truly incremental technology investment. Different types of subsidies also differ in terms of how they affect the budget (e.g., tax credits versus direct appropriations), and in terms of who is eligible or in a position to benefit (e.g., private companies who pay taxes versus public cooperatives that do not). The remainder of this section discusses the design and potential role of specific types of subsidy policies, including tax credits, tendering, and loan guarantees.

### Tax Credits and Grants

Tax credits are often given to offset corporate income, personal income, sales, and property taxes as a form of technology subsidy. Tax credits can directly lower the up-front investment cost of new equipment; alternatively tax credits can be used to subsidize actual production using new equipment. Examples include the existing, federal renewable-energy production tax credit and similar, recently enacted tax credits for investments in new nuclear power generation and energy-efficient building equipment. Each type of tax credit has advantages and disadvantages in terms of how effectively it promotes technology deployment and makes use of limited resources. A generic disadvantage of tax credits is that they are ineffective if the relevant party has no taxable income (unless the tax credit is refundable), as may be the case for some start-up companies and certainly is the case for municipal and cooperative utilities that have no tax liability. In addition, the effectiveness of the credit is dependent on the larger tax code under which the credit is being granted.

Investment tax credits can be quite effective in promoting technology deployment because the entire incentive is provided up-front. Grants or direct investment subsidies likewise share this property; moreover, like investment tax credits, which typically cover only a portion of the investment, they can be designed to encourage or require cost-sharing. Grants have the advantage that they can be effective with entities that do not have taxable income; in addition, there

is no lag between the time when the recipient has to put up funds for a project and the time when the subsidy benefit accrues. On the other hand, investment tax credits and grants provide no guarantee that the projects or technologies they subsidize will actually be used in the manner and to the extent needed to justify the investment. In addition, investment tax credits can encourage project developers to focus on inflating cost estimates (so as to maximize tax benefits) rather than on efficient production. Addressing this concern may require costly project monitoring.

Tax credits based on production, rather than investment, help to ensure that public resources go only to technologies that are actually used (an example is the current federal renewable-energy production tax credit, which is based on kWh generated rather than on investment in renewable energy projects). The disadvantage of production incentives is that they may be less effective at overcoming deployment hurdles in cases where up-front capital requirements present a significant challenge for new technologies. Given that there is often a significant lag between the initial financing of a project and actual production, and given that the availability of tax credits in future years may be subject to Congressional appropriations, firms may not be able to capitalize expected tax savings at the time the investment is made. Finally, production tax credits do little to address construction risk—that is, the possibility that a project, especially if it involves unfamiliar or groundbreaking technology, will never be successfully completed and produce useful output.

### Tendering Policies (Reverse Auctions)

Tendering refers to a policy in which project developers submit proposals for new facilities and bid the minimum price they would accept for output. A government agency or authorized agent manages the reverse auction, accepting the lowest bids (hence the term ‘reverse auction’). This approach forces would-be subsidy recipients to compete on the basis of cost. It has the advantage of maximizing the amount of deployment achieved for a given expenditure of public resources (or alternatively, of minimizing taxpayer outlays for a given amount of deployment) and can help reduce the cost of technology deployment over time.

For example, the United Kingdom established the Non-Fossil Fuel Obligation, a sequence of tendering auctions, between 1990 and 1999. During the course of the program the average price paid for electricity from large wind power projects reportedly fell by 75 percent, although other factors clearly contributed to this decline as well. From 1998 to 2001, the

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The economic rationale for technology deployment policies rests on society’s interest in promoting complementary knowledge creation and dissemination—especially where new knowledge is critical to lower the cost of future emissions reductions.

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state of California held three reverse auctions for renewable energy. The Department of Defense, the U.S. Postal Service, and several other states have also used reverse auctions to significantly reduce government costs for certain purchases. Reverse auctions are likely to be most efficient for high-dollar, large-quantity, clearly-defined purchases where there are multiple potential suppliers.

Another concern that has been raised about reverse auctions, and indeed about technology deployment policies more generally, is that they tend to support whatever qualifying technology is currently least expensive, rather than technologies that might have greater potential in terms of the performance improvements and cost reductions that could be achieved through learning-by-doing. From this perspective, it makes sense to target deployment policies intended to promote learning-by-doing to a relatively narrow set of technologies where the potential for knowledge gains and related spillovers is highest. The rationale for narrowly targeting deployment policies may seem at odds with the notion that the broadest possible program coverage—in the context of an emissions pricing policy—will yield the least expensive reductions. In fact, the same arguments for broad coverage would apply to technology deployment policies if their primary purpose was to produce near-term emissions reductions.

As discussed earlier, however, the economic rationale for

technology deployment policies rests on society's interest in promoting complementary knowledge creation and dissemination—especially where new knowledge is critical to lower the cost of future emissions reductions. Thus, technology deployment policies should not be considered a substitute for cost-effective emissions policy and different design considerations should apply. As discussed previously, yet a different rationale applies in the case of deployment policies targeted specifically to energy-efficiency technologies: for the most part these policies, rather than being designed to generate new knowledge, serve a distinct informational purpose in terms of addressing market problems that affect energy operating-cost decisions.

A different concern is that a reverse auction system may favor incumbents who can submit lower bids due to size and experience. While low bids are an otherwise good thing, a competitive market is necessary for truly competitive bidding and it would be important to ensure that the market is indeed not captured by a small number of companies. Another issue that can arise is that many winning projects may go undeveloped, which can be a concern when the subsidy is delivered via investment tax credits that are pre-assigned due to credit caps (as they typically are).

Tendering auctions can be designed to address many of these concerns and could be legislated with the flexibility to adapt over time based on the results of previous auctions and ongoing technological developments. Among other things, a reverse auction can be subject to mandatory quantity levels and bid ceilings that might change subject to lessons learned in the previous round. Mechanisms can be incorporated in the way the auction is structured to prevent speculative bids; examples include requiring bidders to obtain prior planning permission or requiring winners to apply for relevant permits within a short period of time or lose the bid. The costs associated with these requirements may deter false bids, but may also create a trade off in terms of raising additional barriers to entry in the competition.

### Loan Guarantees

In a loan guarantee program, the government takes responsibility for a certain portion of a loan in case the debtor defaults. Such programs may be conceptually justified if informational asymmetries exist in credit markets for relevant technologies. Technologies that are on the cusp of commercial viability—even if they appear very promising—may not be able to get loans at appropriate rates in private credit markets, either because they seem likely to default or

because potential lenders simply lack the information needed to assess default risk. By vouching for these perceived “high-risk” projects, the government can give project developers access to lower-cost capital and thereby facilitate the early deployment of new technologies. Loan guarantees represent an implicit subsidy, however, and as with all other types of subsidies it is important that their benefits justify their costs. Because such guarantees insulate projects, at least in part, from default risk, they may create incentives for developers to take on riskier projects and do less than they should to protect against preventable risks.

Loan guarantee programs have been used extensively in the past for various social purposes, and their role in the energy- and climate-policy arena was recently expanded by the Energy Policy Act of 2005, which established a new loan guarantee program for clean energy technologies. Loan guarantees may be of more use to independent power producers and start-ups, as most investor-owned utilities have strong credit. Similarly, public and co-op utilities probably would not benefit from such guarantees since they generally borrow at rates that are already at or below the Treasury bond rate.

There has been some prior experience with the use of loan guarantees to encourage the commercialization of energy technologies. In the late 1970s, the U.S. Department of Energy (DOE) underwrote loan guarantees of up to 75 percent of debt financing for start-up plants to produce synthetic fuel. Under that program, DOE guaranteed \$1.5 billion of the \$2.2 billion Great Plains Coal Gasification Facility; after completion, the owners defaulted on the loan and abandoned the plant to DOE. The new owner, Dakota Gasification Company, now operates the plant at a net profit and some of the revenues are going to paying off DOE's original investment.

DOE has also provided loan guarantees for up to 90 percent of project debt financing and up to 90 percent of total costs for alcohol-fuel production facilities. In this case, DOE issued three loan guarantees for the construction of ethanol plants. One of the recipients, the New Energy Company, defaulted on its loan and DOE paid out the guarantee. After much refinancing, the company has become a major ethanol producer in the Midwest. Plant developers in two other instances also defaulted, but without a silver lining; one plant was sold for salvage and the other was dismantled and reconfigured. Another DOE loan guarantee program, for geothermal power, underwrote debt up to 75 percent of total project costs. Of eight projects, four defaulted. However, one developer used the DOE guarantee to build a successful

geothermal-powered electric generation plant. After paying off its loan, the project developer used the experience to get private financing for several other facilities in California, eventually expanding to other states and abroad.

As this record suggests, the results of loan guarantee programs for energy technologies have been mixed, with many projects eventually defaulting on their loans and triggering a government payout. However, some recipients have leveraged the experience gained through projects backed by loan guarantees to establish a successful position in the energy sector. In any event, given the historic default rate it seems clear that these were not simply cases of asymmetric information, where private lenders didn't understand the technology or misperceived project risk. These projects really were high-risk, as evidenced by the fact that many of them ultimately defaulted.

In this context, questions have been raised concerning the implementation of “no-cost” loan guarantees for clean energy technologies currently under development at DOE, where the implicit credit subsidy provided by the guarantee is to be paid to DOE by the borrower at the time of the loan. It will be a challenge to determine the appropriate level of this payment if the government truly expects to bear no cost from guaranteeing the loan. Based on past experience, the cost of the credit subsidy may be substantial, which would imply that the borrower's upfront payment to DOE would also need to be substantial. If set too high, however, this payment might negate the appeal of the guarantee. In principle, an accurately set credit subsidy payment sets the loan guarantee at the appropriate level by solving the problem of asymmetric information (i.e., borrowers are in a better position to assess the risk of a specific project than lenders) rather than acting as an implicit subsidy. If the credit subsidy is paid for by appropriations from public funds, however, the loan guarantee becomes another form of subsidy. Even then, loan guarantees may represent an attractive *alternative* to other types of subsidies because they provide a useful screening mechanism for focusing subsidies on marginal projects and thereby mitigate, at least to some extent, the subsidy “free-rider” problem. In other words, this form of subsidy only costs the government money if a project defaults, in which case the project was probably sufficiently risky that it would not have gone forward without the additional incentive provided by loan guarantees.

## Limited Liability

Due to the prevalence of coal in electricity generation, a major focus of recent climate-policy discussions has been overcoming hurdles to the commercialization of carbon capture and storage (CCS) technology. CCS entails capturing carbon released during energy production and sequestering it underground. Since the effects of a large accidental release of sequestered CO<sub>2</sub> would undo the GHG benefits of the technology—and could potentially create additional risks to human health or the environment<sup>5</sup>—the liability involved in early CCS projects could discourage investment in related technologies. By capping either the magnitude of damages or the timeframe over which a CCS project operator is liable for such risks, the government could alleviate a potentially major impediment to commercializing CCS technology. The economic rationale for a government role in establishing a joint insurance pool or limiting liability is strongest if insufficient private liability insurance is available or if there are substantial difficulties in assigning liability. The latter issue is particularly significant given the decadal to century-long timeframes relevant for CO<sub>2</sub> storage and given the potential for sequestered CO<sub>2</sub> to migrate through very large, interconnected underground reservoirs. On the other hand, liability protection provides a form of implicit subsidy by insulating parties from potential damages caused by their actions; as such, it may reduce incentives for those parties to take appropriate steps to mitigate risks where possible.

## Previous Experience with Liability Caps

The federal government has established several liability caps in the past. The Price-Anderson Nuclear Industries Indemnity Act limits the liability of nuclear generation facilities. Reactor licensees are required to purchase the maximum amount of private insurance available (\$300 million). Each licensee must also be prepared to contribute up to \$95.8 million to an industry insurance pool in the case of an accident. Beyond these limits, there is no further private liability. The Montreal Convention limits the liability of airlines for damages incurred by passengers on international flights. The Oil Pollution Act (OPA), which applies to oil spills on water, limits liability based on the type and tonnage of a vessel. The OPA also governs the Oil Spill Liability Trust Fund, which is funded by a 5 cent-per-barrel tax on oil. The fund is capped at \$2.7 billion and may be drawn upon if a responsible party can absolve itself of charges of negligence and legal violations.

<sup>5</sup> A significant accidental release of CO<sub>2</sub> has the potential to acidify soil or water, or even—under circumstances where the gas is trapped in an enclosed space—to suffocate animals and people.

The Terrorism Risk Insurance Act establishes protocols for government assistance in the case of a major terror incident. The Act is triggered in cases where losses exceed \$100 million. First, individual insurers must pay an amount up to 20 percent of their total earned premiums. After that threshold is passed, the federal government covers 85 percent of remaining damages. If damages to an industry are less than \$27.5 billion, however, the assistance must be recouped from individual insurers as a surcharge on all commercial insurance premiums. There is an overall cap of \$100 billion on total annual federal assistance.

### Addressing Liability Issues for Carbon Storage

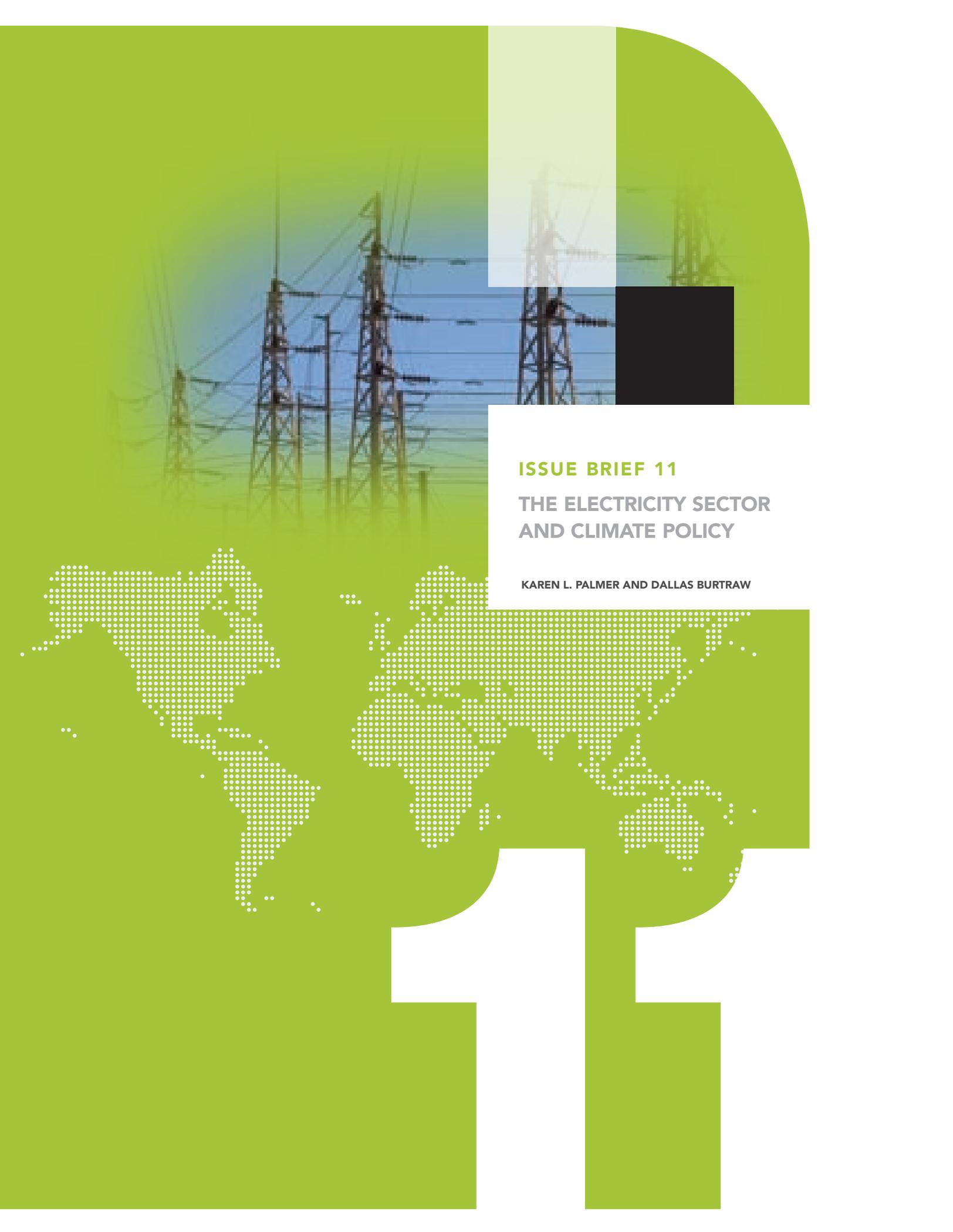
In addressing liability issues related to carbon storage, concerns about the potential climate impacts of CO<sub>2</sub> leakage back to the atmosphere should be treated separately from concerns about the potential for human health and local environmental damages in the event of a large-scale release. In addition, it will be important for liability policies to be clear in terms of which components of the storage system (e.g., transmission, injection, storage) they cover and when they start and over what time periods they apply (e.g., immediately upon project completion, after an initial period once capture and storage are underway, etc.).

In the case of carbon storage, the great diversity of possible sequestration sites makes estimating potential risks and damages difficult. Whereas the other liability funds discussed above were based on at least some actuarial data, little data exist for CCS technology and it is not clear that related practices—such as enhanced oil recovery—are sufficiently similar to provide reliable projections about the likely performance of large-scale CCS projects. Still, a small surcharge on carbon storage or other related activity is one option for supporting a CCS liability fund similar to the Oil Spill Liability Trust Fund. Another option for addressing climate-related liability concerns (as opposed to health and local environmental concerns) is to apply a small discount factor to carbon storage credits (if the potential for leakage is judged to be non-negligible); another is for the government—after some period of time—to assume any regulatory liability should such leakage occur.

The FutureGen initiative, which aims to have a working power plant with CCS operating by 2012, has already generated some activity in terms of liability policy. The final four potential sites for this initiative are in Texas and Illinois, and Texas has agreed to accept full liability for the project should it be located there. Illinois initially balked at offering liability

protection, but has now adopted similar liability protections. It remains to be seen whether other states would accept this responsibility, or whether it will be adopted at a federal level. A potential downside is that federal liability protection could have the effect of associating CCS with nuclear power (which has a similar liability cap) and influencing perceptions about the potential for catastrophic damages. However, experts on carbon storage point out that the risk profile for CCS technology is fundamentally different from that of nuclear technology. Carbon storage appears likely to become safer (less prone to leakage) over time as the CO<sub>2</sub> is dissolved or trapped in surrounding water or porous rock. The risks associated with storing nuclear waste, on the other hand, arguably increase over time in the sense that the potential for leakage may be higher in the future than it is in the present (although the consequences of such leakage also become less severe over time as the waste decays and its radioactivity declines).





**ISSUE BRIEF 11**

**THE ELECTRICITY SECTOR  
AND CLIMATE POLICY**

**KAREN L. PALMER AND DALLAS BURTRAW**

## THE ELECTRICITY SECTOR AND CLIMATE POLICY

Karen L. Palmer and  
Dallas Burtraw

### SUMMARY

The electricity sector is the most prominent target for climate policy because it is the largest single source of carbon dioxide (CO<sub>2</sub>) emissions and of potential CO<sub>2</sub> emissions reductions in the United States. Moreover, because electric power generators are among the largest point sources of important air pollutants such as sulfur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), and mercury, the industry has been extensively regulated in the past. An economy-wide climate policy will achieve emissions reductions at least cost, but advocates of an electricity-focused policy believe it could serve as a bridge to—or component of—a broader policy. State governments have moved ahead of the federal government in adopting various climate-related policies that affect the electricity sector, some of which may complement and some of which may conflict with a future federal policy.

- One of the major challenges of designing a federal cap-and-trade system for greenhouse gas (GHG) emissions is addressing the heterogeneous way such a system would affect electricity producers and consumers across the country. This heterogeneity arises from regional differences in the way electricity is regulated and in the fuels used for electricity generation.
- In states with market-determined prices, free allowance allocation to emitting companies can deliver net gains to companies and provide little relief to customers.
- In states under cost-of-service regulation, free allowance allocation is likely to produce essentially the opposite result: providing benefits to customers with little net financial impact on companies.
- In general, the electricity industry should be able to pass through a large fraction of the cost of emissions reductions by charging consumers higher prices for electricity. At the sector level, only a small share of allowances created by a cap-and-trade policy would need to be distributed for free to incumbent generators to preserve the market value of the industry's portfolio of existing assets—this point being most relevant for market-based generators. At the level of an individual firm, however, the effects of a mandatory climate policy on the market value of existing assets can be more severe.
- Technology standards, performance standards, and programs to increase energy efficiency are thought to be less cost-effective, from a broad economic perspective, than emissions caps (or taxes) as a means of reducing CO<sub>2</sub> emissions. Nonetheless, these other policies may be justified as ways to address a market-failure. If CO<sub>2</sub> emissions are capped, a key effect of these other policies would be to reduce the demand for, and therefore the price of, CO<sub>2</sub> emissions allowances; but they would not produce additional emissions reductions below the cap.

## Introduction

The U.S. electricity generation sector is responsible for roughly 40 percent of all CO<sub>2</sub> emissions in the United States and 9 percent of energy-related CO<sub>2</sub> emissions worldwide. Thus it is a major target of domestic climate policy proposals.<sup>1</sup> Proposals to cap emissions of CO<sub>2</sub> from electricity generators, generally as a part of a larger package to reduce emissions of multiple pollutants, have emerged in each of the past several sessions of Congress. The electricity sector is also covered under numerous economy-wide GHG cap-and-trade proposals introduced in the 110th Congress. While none of the federal legislative proposals has been enacted, several states have proceeded with developing their own regulatory programs. A group of governors of ten Northeast states extending from Maryland to Maine, for example, has signed on to the Regional Greenhouse Gas Initiative (RGGI) with the aim of imposing the world's second mandatory cap on CO<sub>2</sub> emissions (after the European Union's Emission Trading Scheme) beginning in 2009. The RGGI program seeks to reduce electric-sector emissions from participating states by approximately 35 percent below business-as-usual levels by 2020. California has adopted a more stringent target: the state aims to return its economy-wide emissions to 1990 levels by 2020. Moreover, California law specifies that the emissions-reduction target includes all emissions associated with electricity generation to serve California customers, including emissions from facilities located outside the state.<sup>2</sup> A group of western states, including Washington, Oregon, Arizona, New Mexico, Utah, and two Canadian provinces, have since joined California in an effort to develop a regional policy. Many other states have initiatives underway, including New Jersey and Florida, which recently proposed policies that address GHG emissions.

While cap-and-trade policies, either economy-wide or sector-specific, have received the most attention in the domestic climate policy debate, a number of other potential policies have been proposed to reduce CO<sub>2</sub> emissions from the electricity sector. Chief among these alternatives would be a CO<sub>2</sub> emissions tax. A tax would have the advantage of being easier to administer and it would avoid the question of whether and how to allocate allowances to the private sector under a cap-and-trade program. Instead, policymakers would need to decide how to use tax revenues; but this

decision is more explicit and transparent than free allocation of emission allowances. One of the reasons that regulated sources may prefer an emissions-trading program to a tax is that under past cap-and-trade systems, the great majority of emission allowances have been given away for free to companies, usually on the basis of a measure (such as heat input) that relates to past emissions. In the domestic climate policy debate, how to initially distribute emissions allowances remains an open question. Policymakers are struggling to define principles for the allocation of allowances and are seriously entertaining proposals that would auction (rather than give away for free) some or all of these valuable assets. At the same time, policymakers are considering a variety of additional options to address electric-sector GHG emissions, including renewable portfolio standards (RPS) and policies to encourage demand-side energy efficiency and conservation. GHG performance standards for new electricity generators could well emerge as another policy option; this approach would continue 35 years of regulatory precedent. The purpose of this issue brief is to summarize alternative approaches to reducing CO<sub>2</sub> emissions from electricity generation.

## Brief Background on the Electricity Sector

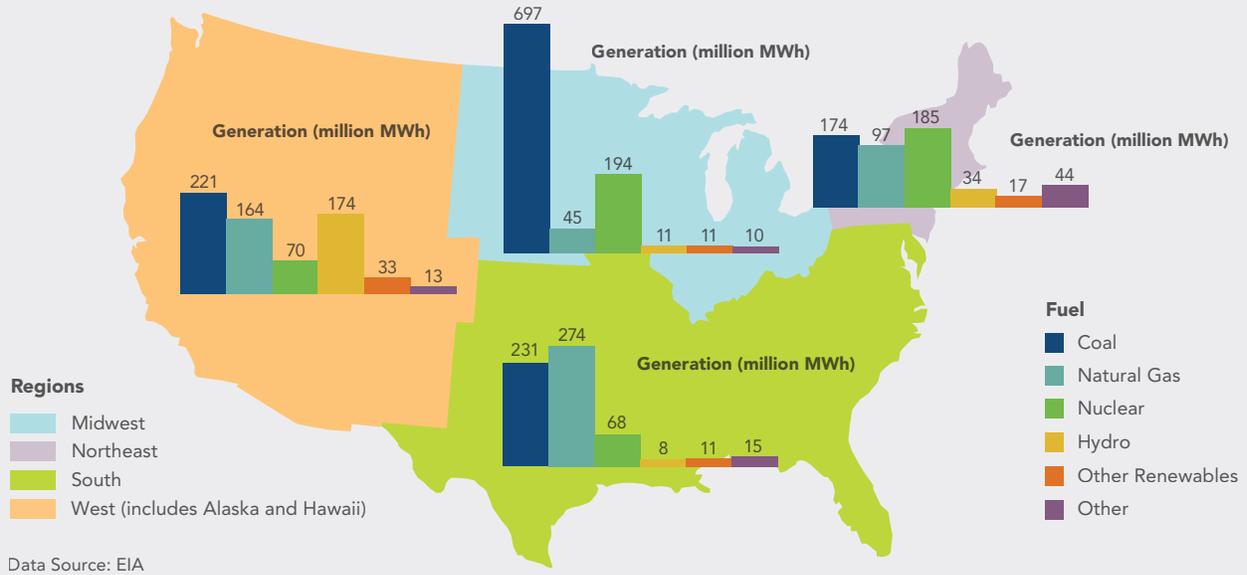
Two features of the electricity industry are important to understand when considering how to regulate CO<sub>2</sub> emissions from this sector. The first concerns the mix of fuels used to generate electricity. Just over half (51 percent) of the electricity generated in the United States is produced using coal, which has an average CO<sub>2</sub> emissions rate of roughly 1 ton per megawatt-hour (MWh). Natural gas, the second most important fossil fuel used to generate electricity, accounted for approximately 16 percent of electricity generation nationally in 2004; average CO<sub>2</sub> emissions per MWh generated using natural gas are roughly half the emissions associated with coal. Nuclear power and renewable energy, including hydropower, are important non-emitting sources of generation; they currently account for about 21 percent and 9 percent of the nation's electricity mix, respectively. Figure 1 shows the mix of fuels used to generate electricity by region.

Table 1 shows changes in technology and fuel use in the electricity sector that could result from carbon regulation. The table shows the generation mix for 2004 and the projected mix for 2030 based on forecasts developed by the Energy Information Administration (EIA) under a business-as-usual scenario with no climate policy. The Electric Power Research Institute (EPRI) has studied the technical potential of advanced

1 Emissions of CO<sub>2</sub> from the electricity sector account for 33 percent of total GHG emissions in the United States.

2 California's in-state generation mix has relatively low emissions. The same is not true of the generation mix associated with power imported to the state. In fact, imported power accounts for roughly 20 percent of California's electricity consumption, but about half of overall CO<sub>2</sub> emissions from electricity use in the state. Legal restrictions under the Commerce Clause of the Constitution and the Federal Power Act constrain the state's ability to limit emissions from out-of-state sources of electricity, but efforts to design policies that would address this issue are underway.

**Figure 1** Electricity Generation by Fuel in 2005



power-generation technologies that could be deployed in response to a climate policy, setting aside cost considerations. EPRI contemplates a dramatic increase in nuclear and natural gas, and a decline in new conventional coal plants, with the new coal generation that does get built shifting toward systems that make use of carbon capture and storage technology. The EIA has analyzed a price-based policy that would impose a cost of \$35 per ton CO<sub>2</sub> (in 2004 dollars) by 2030. EIA's projections for nuclear power are similar to those in the EPRI study, but the EIA results show much smaller growth in natural gas generation. A smaller increase in natural-gas use is made up by additional growth in non-hydro renewables. Compared to EPRI, EIA also finds a much larger decline in coal generation under GHG constraints and a bigger decline in total electricity generation. Perhaps the distinction to note between these two studies is that EIA presents a more conventional view of technology options but offers an economic view of how investment decisions are made. One important issue that neither study is able to account for is the difficulty of siting new facilities. This deployment hurdle is especially daunting for nuclear power and for new transmission capability, which may be necessary to bring renewables to market. In addition, there is no experience

with siting infrastructure for large-scale carbon capture and storage.

The mix of fuels used to generate electricity varies substantially across the country with coal playing a big role in the Midwest, Southeast, and Mountain states and natural gas being more prominent in the Gulf states, New England, and the Pacific states. This variation is important because coal-dependent states would be more affected by CO<sub>2</sub> restrictions than other states. Renewable resources are also concentrated more heavily in some parts of the country than in others, as indicated in Figure 2. This figure shows how much of different kinds of non-hydro renewable generation are projected to come from different regions under an EIA model simulation of a policy that requires renewable generators to supply 15 percent of the electricity sold by large utilities in 2020. Figure 2 suggests that a national policy designed to promote increased use of renewable resources will have differential impacts across regions of the country. Of particular interest is the effect in the Southeast, where EIA finds that biomass generation, both from dedicated biomass plants and from co-firing with biomass at existing coal plants, grows substantially. Some doubt this finding because it is not clear that available



Technology	Generation (billion kWh)		Change in Generation from EIA Reference Case (billion kWh)	
	Data	EIA Reference Case	EPRI Advanced Technology Targets*	EIA Cap-Trade Case (CT-3)**
Nuclear	789	871	506	547
Renewables***	323	504	123	687
Total Coal	1,954	3,205	-310	-1,439
Coal w/ CCS			789	****
Natural Gas	619	822	-352	48
Petroleum	115	101		-74
<b>TOTAL</b>	<b>3,800</b>	<b>5,503</b>	<b>-102</b>	<b>-231</b>

\* Amounts in this column do not sum to the total because of additional data not presented here.  
 \*\* Allowance price in Cap-Trade Case (2004 dollars): \$22.09/ton CO<sub>2</sub> in 2010 and \$35.34 in 2030.  
 \*\*\* Includes hydro.  
 \*\*\*\* Except for plants currently under construction the only coal plants built have CCS technology.

2004 Generation Data: Total Electric Power Industry data from Table EIA-906: "Net Generation by State by Type of Producer by Energy Source." Available at [http://www.eia.doe.gov/cneaf/electricity/epa/epa\\_sprdshts.html](http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html).

EIA Reference Case and Cap-Trade Case: Energy Information Agency, "Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals," (Table ES 2b) March 2006. Available at: [http://tonto.eia.doe.gov/FTPROOT/service/sroiaf\(2006\)01.pdf](http://tonto.eia.doe.gov/FTPROOT/service/sroiaf(2006)01.pdf).

EPRI Advanced Technology Target: S. Specker, "Electricity Technology in a Carbon Constrained Future," (page 15) Electric Power Research Institute, February 2007. Available at: [http://mydocs.epri.com/docs/CorporateDocuments/Newsroom/EPRIUSElectSectorCO2Impacts\\_021507.pdf](http://mydocs.epri.com/docs/CorporateDocuments/Newsroom/EPRIUSElectSectorCO2Impacts_021507.pdf).

biomass resources in the Southeast are as abundant or low-cost as the EIA analysis assumes. Nationally, the EIA modeling results show a ten-fold increase in biomass generation from 2005 levels and a nearly three-fold increase over the levels that would be expected absent the 15 percent renewable energy requirement.

Regional differences in the effects of a federal climate policy are also driven by variations in the structure and regulation of the electricity sector. The traditional industry structure of vertically integrated utilities supplying retail customers with the bulk of their electricity needs at regulated prices is still the dominant model in much of the country, including in the South and in the Mountain and Plains states. States in other parts of the country have opened their electricity sector to more competition in generation, with generally limited entry by competitive retail providers, and have seen divestitures

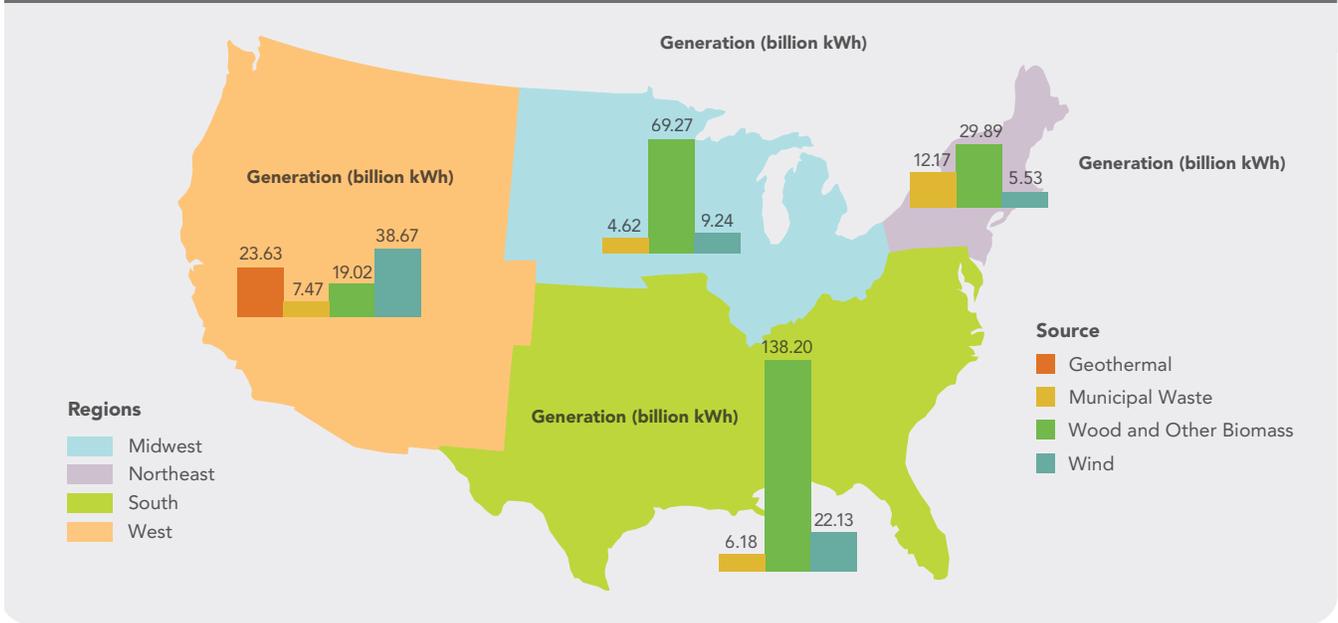
of generation assets to independent power producers. In these regions, the prices paid by electricity consumers reflect the marginal costs of generation as determined in wholesale markets rather than regulated rates set to guarantee cost recovery for service providers. This difference has important implications for how customers experience the costs of climate policies, particularly under different methodologies for allocating emissions allowances in the context of a cap-and-trade policy. We return to this issue in a later section.

### Economy-Wide Versus Electricity-Specific Programs

The question of whether a policy should be economywide or focused on the electricity sector is a complex one. As discussed at length in other issue briefs (notably Issue Briefs #4 and #5) a broad-based policy that includes all GHG sources

**Figure 2**

**Predicted Renewables Generation by Type in 2020 under a 15% Renewable Portfolio Standard**



This map displays an approximate representation of the regional renewable generation results from the “Impacts of a 15-Percent Renewable Portfolio Standard” by the U.S. Energy Information Administration, Report # SR-OIAF/2007-03, June 2007.

and sinks will achieve the most emissions reductions at the lowest overall cost to society. In particular, a singular focus on the electricity sector will tend to direct energy consumers away from electricity and toward the direct use of primary fuels such as natural gas or oil. This would shift emissions to un-covered sources (creating emissions “leakage”) and would undermine the environmental objectives of the program. Sector-specific policies may have their own independent justifications and consequences, but such programs assuredly would not achieve emissions reductions in the most cost-effective manner because the cost of emissions reductions would vary across sectors. If a cap-and-trade approach is used, then applying it broadly—to as many sources and sectors as possible—would create rational price signals for all sorts of investment and consumption decisions throughout the economy.

As an initial step, a sector-specific policy could be consistent with the ideal of a broad-based approach if it creates a bridge to a more comprehensive program. EIA modeling analyses of various cap-and-trade programs suggest that roughly two-

thirds to three-fourths of emissions reductions under a broad-based approach will come from the electricity sector, at least for the first couple decades of a flexible economy-wide CO<sub>2</sub> program. Thus there may be significant overlap between the nearer-term, relatively low-cost emissions reductions elicited by an electric-sector-only policy and an economy-wide policy. Starting with a sector-specific policy may also avoid some of the competitiveness concerns that tend to arise in connection with an economy-wide program, since the electricity sector at a national level is not subject to export substitution in the same way that other energy-intensive sectors (aluminum, for example) may be. That is, focusing on electricity in a domestic policy is unlikely to lead to an exodus of electricity producers. However, even a sector-specific policy is unlikely to comprehensively capture all GHG emissions from electricity generation, depending on how affected sources are defined. Some program designs, for example, might not cover off-grid or self-generation and may inadvertently create incentives for expanded self-generation (especially by large electricity users).

## Regulatory Options in the Electricity Sector

Several options exist for regulating CO<sub>2</sub> emissions in the electricity sector. Some are mutually exclusive while others could be implemented in a complementary fashion. Reductions in electric-sector CO<sub>2</sub> emissions will be brought about by changes in demand and supply. The list of policy options reviewed in this issue brief is organized roughly in order of increasing prescriptiveness at the federal level; in addition, the policy options further down the list may imply a greater role for state agencies:

- Incentive-based GHG policies (cap-and-trade or emissions tax)
- Performance standards
- Technology standards and direct technology support
- Introducing environmental concerns into resource planning
- Policies to promote demand-side efficiency

### Incentive-Based Approaches

Economists view incentive-based regulation—either a cap-and-trade program or emissions taxes—as the most efficient approach to reducing emissions. By imposing a cost on all emissions, both provide strong incentives for continuous innovation to develop lower-carbon technologies for electricity generation. Although there are differences between tradable permit systems and a tax, a cap-and-trade program can be modified to mimic some of the features of a tax and vice versa.<sup>3</sup> In particular, assuming banking is allowed in a trading program, both a trading approach and tax give firms flexibility in terms of the nature and timing of mitigation measures undertaken. For purposes of this discussion we focus on cap and trade, because this approach is featured in most current proposals.

To what extent a carbon pricing policy creates incentives for electricity consumers to reduce consumption depends in part on how electricity prices are determined and on how emissions allowances are distributed initially. Both issues are discussed at length below.

### Performance Standards

Performance standards come in two flavors. We use the term ‘technology standard’ to refer to standards that do not provide any flexibility in the design or operation of a facility. By contrast, the term ‘performance standard’ is increasingly being used to describe a standard that must be met, in aggregate or on average, by a portfolio of facilities,

perhaps with different technologies. In other words, such standards specify a maximum or, when trading is allowed, an average level of emissions that is not technology specific. Recent proposals have called for a clean energy portfolio standard to encourage a mix of new nuclear, renewable, and new fossil generation with carbon capture. Another example that has already been adopted by several states is the renewable portfolio standard (RPS), which requires a certain level of generation using non-hydro renewable energy resources (rather than non-emitting technologies more generally).<sup>4</sup> Portfolio standards typically require that a percentage of electricity generated or sold to customers must be provided using a listed set of technologies. Most proposals for a national-level portfolio standard would give electricity providers flexibility to determine what mix of listed technologies allows them to meet the standard most cost-effectively and would provide the added flexibility of trading. Trading allows utilities that face higher costs for renewable energy to purchase excess renewable- or clean-energy credits from other utilities or merchant generators that face lower costs to help meet their compliance obligation. More than 20 states have adopted RPS policies. Generally these policies make retail utilities responsible for compliance. In contrast to a national policy that would likely allow relatively unrestricted credit trading among utilities, trading under all but a handful of state policies is more constrained in the sense that it is generally limited to sources within a nearby geographic region. Several state programs also have specific targets or requirements for particular types of renewables, such as solar power, under the broader RPS.

Performance standards or portfolio requirements can be used to overcome deployment hurdles for renewable sources of energy.<sup>5</sup> As a technology deployment (rather than emissions reduction) policy, a national RPS would tend, in the short run, to have a fairly small effect on electricity prices in competitive wholesale power markets—at least as long as incumbent facilities continue to operate, which is likely to be quite a long time in the electricity sector. The near-term effect on electricity prices would likely be small because renewable energy credits that subsidize the operating cost of renewable generators are essentially funded by payments from the existing fleet

<sup>4</sup> Both types of proposals have been introduced in the 110<sup>th</sup> Congress. Senate Amendment 1538, for example, would establish a national clean energy portfolio standard, whereas Senate Amendment 1537 and similar legislation in the House of Representatives (H.R. 969) would establish a national renewable portfolio standard.

<sup>5</sup> As noted previously, the application of portfolio standards or other forms of regulation to emissions sources that are also covered under a cap-and-trade program will not produce additional emissions reductions—such policies may affect the means used to achieve the cap or the distribution of emissions reductions across different sources and entities, but overall emissions will always rise to the level of the cap. Additional technology-oriented policies can, however, be expected to reduce the market price of allowances (by effectively creating a separate constraint on emissions that reduces demand for allowances), thus potentially also ameliorating the apparent price impacts of the policy (albeit not its overall cost to society). For further discussion of these issues and of the arguments for and against technology deployment policies more generally, see Issue Brief #10.

<sup>3</sup> See Issue Brief #5.

of fossil generators. Although these payments raise the variable cost of operation for fossil generators, the change in marginal generation cost is offset to some degree by the reduced utilization of high-cost fossil units that are displaced by the introduction of renewables. In the long run, however, the marginal cost of generation will be dominated by new investment and at that point the subsidy for renewables would be more apparent in electricity prices.

Wind would likely be the dominant new technology to enter the market in response to a national renewable energy mandate, particularly if the RPS target is relatively low. Wind energy has low variable costs—once a wind facility is built, the costs of operating that facility are relatively small since it uses a “fuel” that, when available, is essentially free. Thus, although wind is an intermittent resource, the marginal cost of using it to produce a MWh of electricity is likely to be smaller than the market value of the renewable energy credit it would generate under a mandatory RPS. To the extent that the subsidy effect of the credit more than compensates for variable operating costs at renewable energy plants, the immediate impact of the RPS policy on electricity prices would likely be small. Under somewhat higher national RPS targets, of course, other renewable technologies—notably biomass—would be expected to play a more important role. Nevertheless, variable operating costs for biomass generation, though they are typically higher than variable operating costs for wind, would likely still be significantly offset by the value of renewable energy credits. Thus, in competitive wholesale power markets, during specific times of day and in specific regions, an RPS policy may actually lead to a reduction in electricity price in the near term.

In competitive markets, existing fossil-fuel electricity generators (rather than end-use consumers) would be expected to bear the lion's share of the cost of a renewable or clean energy technology requirement in the form of lower profits. Also, by reducing electricity producers' demand for natural gas, an RPS policy actually can reduce the price of natural gas to households and businesses. An RPS policy may help to reduce the cost or improve the performance of future renewable power sources if the industry, through learning-by-doing as more renewables are brought on line, discovers cheaper ways to build and more efficient ways to operate renewable energy technologies.

As already noted, renewable energy policies do not target CO<sub>2</sub> emissions directly; thus they will not produce emissions reductions as cost-effectively as a cap-and-trade approach.

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Even in their most efficient forms—including, for example, program designs that allow for national-level trading—portfolio standards that target particular technologies are a more costly way to achieve emission reductions than approaches that address emissions directly through a cap-and-trade program or an emissions tax. Renewable energy mandates may induce the deployment of targeted generation technologies in an efficient manner, but the targeted technologies may not be the least-cost option for reducing emissions. Instead, the more compelling justification for such policies is likely to be grounded in the argument that they are needed to address market problems that would otherwise hinder the deployment of even cost-effective renewable energy resources. Furthermore, the fuel-use interaction is complex. Research has shown that at a national level, an RPS policy would tend to displace natural gas generation more than coal—thus existing high-emitting plants would probably not be displaced by renewables; instead, new gas plants would not be built.

### Technology Standards and Direct Technology Support

Technology standards prescribe minimum emissions performance requirements for electricity generation technologies. Familiar examples include the new source performance standards that apply to all new generation

facilities under the Clean Air Act. New source performance standards currently exist for SO<sub>2</sub> and NO<sub>x</sub> and generally require the installation of “best” available control technologies on new generators. Although known as performance standards because they are denominated by a performance metric (typically expressed in units of emissions per unit of heat input or, in some cases, emissions per unit of electricity output), in practice there is typically one identified (best) technology that can achieve the standard. In the climate context, an example of a technology standard would be to require that all new coal-fired power plants be equipped with the technology to capture and sequester CO<sub>2</sub>.

Legislation recently adopted in California (Senate Bill 1368) creates a de facto technology standard by prohibiting the state’s utilities from entering into long-term contracts with generators that emit more than 1,100 pounds of CO<sub>2</sub> per MWh of electricity output. Besides renewable or other zero-carbon technologies, the only conventional fossil-fuel technology now available that can meet this standard is a natural gas-fired combined-cycle gas turbine. Coal plants could not meet this standard using current technology; they would need to incorporate carbon capture systems. The technology for carbon capture is still in the development phase, however, and has not yet been deployed on a large-scale, commercial basis. It is unclear what effect the California standard will have in the near term because other western states have had the opportunity to shuffle resources such that power conforming to the standard could be sold into California while higher-emitting generation was dedicated to other parts of the region. However, research at the California Energy Commission indicates that the opportunity for sustained contract shuffling—after accounting for ownership and long-term contracts, along with oversight by California agencies—is limited.<sup>6</sup> In addition, accounts in the trade press suggest that the California standard has already altered the investment climate for new capacity outside the state by introducing the risk that uncontrolled coal facilities may not be able to serve the California market. If such standards become more widespread they will certainly spark more investment in developing the technologies and regulations necessary to make a carbon capture and sequestration commercially viable.

One difference between the performance (or portfolio) standards described above and more rigid technology standards is that the former typically target the characteristics of a mix of generation technologies while the latter target

the characteristics of a specific generation technology. The rationale for technology standards is closely linked to the long expected life of new generating facilities, most of which are likely to operate for a half century or more. However, technology standards also raise the cost of building new facilities relative to the cost of continuing to operate existing facilities, thereby delaying equipment turnover and the efficiency improvements that would result from replacing old technology. Also, rules governing what constitutes “new equipment” when existing facilities are upgraded raise difficult administrative issues. Consequently, although taken for granted as a good idea by most environmental advocates, technology standards are among the regulatory approaches least favored by economists.

Finally, we note that, in practice, development and deployment policies directly targeting specific technologies can be used to fund or otherwise provide direct support for technologies that are expected to be relevant for generating electricity with low net GHG emissions. Such policies are discussed in more detail in Issue Briefs #9 and #10. The key trade-offs in developing technology policies revolve around the difficulty of identifying which technologies should receive direct support and at what stage of development. Other critical questions include how much support should be provided and in what form. Direct technology support has been an important component of U.S. energy policy in the past, and is likely to continue to be so in the future.

### Introducing Environmental Concerns into Resource Planning

Investment in cleaner generating technologies is critical to reducing CO<sub>2</sub> emissions from the electricity sector. States have used several approaches to encourage such investments, in many cases by intervening in the generation planning process to require greater emphasis on renewable energy technologies or demand side management. Another approach that several states relied on in the past was to require that environmental costs be incorporated in integrated resource planning in a quantitative manner. A formal open resource planning process is often part of public utility commission oversight of the investment plans of regulated utilities; as part of that process, both supply-side generation options and demand-side energy-efficiency options may be considered. In the planning context, social costs may be included by giving weight to the environmental performance of various resources. Around the time the 1992 Energy Policy Act was passed, roughly 20 states included environmental costs in some manner in resource planning. In retrospect, many of those

<sup>6</sup> Alvarado, A and Griffin K. (2007). Revised Methodology to Estimate the Generation Resource Mix of California Electricity Imports: Update to the May 2006 Staff Paper. Sacramento, CA: California Energy Commission.

states were the ones that moved to deregulate their electricity markets and sever the link between independently-owned generation and regulated load serving entities, thereby ending states' direct regulatory influence over investment planning. Nonetheless, the integrated resource planning process survives, especially in regions with cost-of-service regulation, although the extent to which environmental costs are explicitly included varies across states.

### Demand-Side Policies

Another way to reduce emissions is to reduce demand for electricity by improving the efficiency of electric appliances and equipment. Separate from the climate debate, numerous policies and measures have been advanced at the federal and state levels to promote energy efficiency; common strategies have included appliance standards, utility demand-side management (DSM) programs, and building codes and standards.

The climate debate has renewed interest in demand-side policies at both the federal and state levels. Policymakers are looking for ways to expand and improve the performance of existing utility conservation and DSM programs and to promote these programs more broadly. Under traditional rate regulation, utility revenues and profits are tied to electricity sales at a set tariff. Because utilities earn more by selling more electricity they have little incentive to work to reduce customer demand. One way to address this incentive problem is known as revenue decoupling; as the term implies, it involves breaking the link between utility revenues and number of kilowatt hours sold. Instead, electricity prices are adjusted in a way that keeps overall revenues whole. Decoupling changes the incentives such that it is in the utility's interest to minimize costs per customer served, including—where cost-effective—by helping that customer reduce end-use demand. To make the utility whole, the kilowatt-hour price of delivered electricity may rise as increased efficiency investments lead to lower sales. From the perspective of an individual customer, a higher price will provide further incentives to reduce consumption; it may also, however, lead to some electricity users cross-subsidizing others, depending on how efficiency expenditures affect different classes of customers. Advocates of revenue decoupling claim that it removes disincentives for utility investment in customer-side efficiency improvements, but that by itself may be insufficient to provide positive incentives for expanded DSM programs. Consequently, some states are going a step further by allowing utility-company shareholders the opportunity to earn a return on capital investments in energy efficiency.

Some states, such as Texas, are experimenting with yet another policy option, known as an efficiency portfolio standard (EPS). Much like an RPS, an EPS requires utilities to use energy efficiency programs to meet a minimum percentage of projected demand for electricity services. Equivalently, utilities must acquire efficiency credits in proportion to generation, where credits are created by investing in energy efficiency programs. A few states, including Connecticut and Hawaii, have combined the RPS and EPS to create a minimum standard for efficiency and renewable generation. Both policies—EPS and RPS—have also been proposed at the federal level.

Implementing efficiency portfolio policies (and evaluating demand-side programs more generally) poses important challenges in terms of measuring and verifying the amount of energy saved by particular measures and investments. Engineering studies typically conclude that there are enormous opportunities to improve end-use efficiency at low cost. According to one study that involved three national laboratories, electricity demand reductions on the order of 24 percent are achievable nationwide.<sup>7</sup> However, a variety of institutional and market barriers stand in the way of capturing these savings. For instance, due to the diffuse nature of many energy-saving opportunities, identifying and implementing efficiency improvements is often an unrecognized or low priority for busy firms and households. Also, efficiency programs frequently have a variety of hidden administrative costs. In many cases, incentives are not aligned with responsibility for investment decisions and control over energy practices within business organizations, institutions, and buildings. Another factor that may diminish the cost-effectiveness of efficiency measures as a means to reduce GHG emissions is that reduced demand for electricity tends to back out investments in new generators, which themselves tend to be more efficient and have lower CO<sub>2</sub> emissions rates per kWh than older generators.

### Allowance Allocation in the Electricity Sector

The presumptive design for federal legislation to curb U.S. GHG emissions at this time is a cap-and-trade program.

<sup>7</sup> Interlaboratory Working Group (2000). Scenarios for a Clean Energy Future. Oak Ridge National Laboratory, Oak Ridge Tennessee; Lawrence Berkeley National Laboratory, Berkeley, California; and National Renewable Energy Laboratory, Golden, Colorado. The study identifies the "achievable energy savings potential," which is a subset of energy efficiency measures that have been identified as cost-effective on an engineering-cost basis and achievable based on past experience and the propensity of the electricity-consuming households and businesses to adopt such measures. Other studies find similar results—that is, estimated savings on the order of a 25 percent reduction in electricity use—for various regions of the country. See Nadel, S., Shipley, A., and Elliott, R.N. (2004). The Technical, Economic and Achievable Potential for Energy Efficiency in the U.S.—A Meta-Analysis of Recent Studies. American Council for an Energy-Efficient Economy, Washington, DC.

Whatever means are adopted to achieve emissions reductions, the lion's share of costs of reducing electric-sector CO<sub>2</sub> emissions will be borne by electricity customers, and a smaller share will fall to firms and their owners. A cap-and-trade program provides an obvious way to cushion these cost impacts by creating a valuable asset—emissions allowances—that can be transferred back to customers and firms. Deciding how, exactly, to distribute allowance value to intended parties via allocation is not straightforward. Furthermore, providing free allowances as a means of compensating particular stakeholders tends to raise the cost of the overall policy dramatically compared to auctioning emissions allowances and using the proceeds in ways that boost overall economic efficiency (e.g. by reducing taxes on income or investment).<sup>8</sup> Thus, some of the most vexing issues associated with designing a cap-and-trade program involve the initial distribution of emissions allowances, including whether allowances should be directly allocated or auctioned.

The question of how to allocate CO<sub>2</sub> emissions allowances within the electricity sector is complicated by important differences in the way states regulate electricity markets. At present, the country is divided into essentially two regulatory models: in some states, markets determine the generation component of electricity price while in other states electricity prices are set by cost-of-service regulation. In price-regulated markets, generators most likely will not be allowed to pass through the cost of GHG emissions under a cap-and-trade program if they have been given free allowances. This is because free allowances have zero original cost and original cost is what regulators add to a firm's total cost to determine electricity rates. Even though utilities will consider the opportunity cost of using free allowances in the operation of generation technology, this opportunity value will not be reflected in retail prices in regulated regions. In competitive regions, however, the opportunity cost of using allowances will be reflected in retail prices—that is, even if generators receive a free allocation initially they will pass allowance costs through to customers to the extent they can. This difference means that if allowances are distributed for free to generators based on a fixed historic measure, the impact of a mandatory CO<sub>2</sub> policy on electricity prices will be much greater in states where markets set electricity prices than in states where regulators set prices based on cost. Depending on the stringency of the climate policy, this difference could result in major disparities in the electricity price increases that occur across different states and regions under a common federal cap-and-trade program for GHG emissions.

<sup>8</sup> These topics are extensively discussed in Issue Brief #6, which deals with allocation more generally.

One way to address this disparity would be to auction emissions allowances to the highest bidder. Regulated generators would then pay a price for each allowance they acquire; this cost would become part of utilities' total cost and thus would be folded into retail rates. In the long run, generators in regulated regions could be expected to recover their emissions costs; in the short run, however, regulators may be reluctant to let electricity prices rise too far—as a result, there is always some possibility that they may disallow some portion of costs, whether those costs are related to environmental policy or to other issues.

Auctions also have the beneficial attribute that they generate revenue that could be used to achieve other policy goals.<sup>9</sup> However, this benefit hinges on the wise handling of revenue from the auction. As noted previously, revenues generated by an auction can be used to compensate consumers for higher energy prices by reducing existing taxes; for reasons discussed in Issue Brief #6, this is the approach favored by most economists because the efficiency-enhancing effect of reducing taxes on investment or income helps to minimize total net costs to society. Other policy goals could include promoting R&D investments to advance renewables and other new technologies and compensating stakeholders that are adversely affected by the policy (such as mining communities) or by a changing climate. Indeed, funds could be directed to reduce the impact of climate change through adaptation. Alternatively, free allowances could be allocated to consumers, either directly or through an intermediary organization, or to states (presumably based on population, generation, or emissions)—in that case, free allowances would have to be converted to cash by selling them to regulated entities. In the northeastern states' RGGI memorandum of understanding, member states agreed to auction a minimum of 25 percent of the allowances created by the RGGI program and use the money to provide consumer benefits and for strategic energy purposes. Modeling has shown that the energy-efficiency investments funded by these allowance sales can reduce demand sufficiently to largely mitigate the electricity price increases that would otherwise occur in wholesale power markets. Many RGGI states have decided to auction fully 100 percent of their share of regional CO<sub>2</sub> emissions allowances under the RGGI cap, and many of these states envision using much of the resulting revenue to promote energy efficiency programs.

Although there are compelling arguments for auctioning all or most allowances under a cap-and-trade program, however,

<sup>9</sup> The advantages of auctions are discussed in both Issue Brief #6, on allocation, and Issue Brief #5 on trading versus taxes.

several prominent proposals currently under consideration at the federal level provide for a substantial free allocation—at least in the early years of program implementation. The case for some free allocation is usually made on two grounds. First, policymakers may wish to shield consumers from price impacts related to the program (at least in areas that are still under cost-of-service regulation); although it is worth noting that this would also tend to diminish the efficiency of the policy by reducing incentives for customer-side demand reductions. The second motivation for a free allocation would be to compensate the shareholders of electricity-generation companies that are adversely affected by the policy. Research has shown, however, that accomplishing this latter objective should require only a portion of the total allowances needed to cover electricity sector CO<sub>2</sub> emissions.<sup>10</sup> Put another way, allocating 100 percent of allowances used by the electricity sector for free to generators would vastly over-compensate electricity suppliers in competitive regions, while benefiting electricity consumers in regulated regions.

In fact, many companies in competitive regions stand to profit from a mandatory climate policy even if 100 percent of allowances are sold at auction. These firms benefit because electricity prices in competitive markets—which are virtually always set by the marginal cost of generation from a fossil-fired facility—will rise to reflect the cost of emissions allowances. Higher prices will apply equally to all electricity sold, regardless of how it was generated. Given that many firms also own non-emitting or low-emitting generators, the revenue gains they experience as a result of higher prices are likely to outweigh whatever allowance costs they incur as a result of the policy. For reasons noted previously, such over-compensation is not expected to occur in traditionally regulated electricity markets. In these markets, regulators typically set electricity rates to recover the original cost of utility expenses. Therefore, to the extent that any new allowance costs are covered by an allocation of free allowances, utility expenses would not increase and electricity prices (and utility revenues) would not be expected to rise.

If policymakers decide to allocate emissions allowances for free based on the desire to compensate firms, they can adopt rules to achieve this goal at a lower cost (in the sense that fewer allowances must be given away to achieve a compensation goal) than simple grandfathering based on historic emissions. For example, free allocation could be based on particular firm-level metrics such as fuel mix or

emission rates that provide some indication of a firm's likely exposure to adverse cost impacts under GHG constraints. The cost of compensating adversely affected firms (along with the potential for conferring additional windfalls on other firms that stand to gain under the policy) might be lowered further if allowances are initially apportioned to states and then states adopt a specific formula for distributing allowances to emissions sources.<sup>11</sup>

Another possible approach to free allocation involves updating an individual firm's share of free allowances based on a metric, such as share of total generation, which changes over time. Under this approach a firm that increases its share of total output can increase the share of free allowances to which it is entitled in the future. This has the desirable property that new entrants eventually receive allowances and retired emitters eventually do not. An updating approach is more feasible in the electricity sector than in other sectors because electricity production is a homogeneous good and easily measured. It also has the political virtue of mitigating the electricity-price increases that would otherwise be associated with a cap-and-trade policy in both regulated and deregulated regions (in contrast to other forms of free allocation that only limit the price increase in regulated regions).<sup>12</sup> Unfortunately, shielding consumers from price increases also weakens incentives for end-use efficiency improvements, thereby raising the overall cost of the policy to the economy (where that cost includes lost profit to generators and losses in consumer well-being). On the other hand, an updating, output-based allocation can amplify the incentive for generators to shift to lower-emitting technologies by driving up the price of emissions allowances (even as it has the opposite effect on electricity prices). Allowance prices can be expected to rise because an updating, output-based free allocation will tend to drive up the quantity of electricity generated (both by creating incentives for increased output and diminishing incentives for customer-side efficiency improvements). Increased output would likely translate to increased demand for allowances and upward pressure on allowance prices.

As mentioned above, the reason relatively few allowances would be required to compensate the electricity industry as a whole is that the vast majority of costs associated with emissions reductions in this sector would be borne by electricity consumers. Free allocation to generators

<sup>11</sup> Ibid.

<sup>12</sup> This is because an output-based updating free allocation effectively creates a production subsidy: firms have an incentive to increase their output to capture a larger share of valuable free allowances in the future. This subsidy effect tends to drive prices lower as firms seek to sell more electricity. For a more thorough explanation of the incentive and price effects of different approaches to allocation, see Issue Brief #6.

<sup>10</sup> Modeling indicates that consumers bear eight times the cost that is born by shareholders under a cap-and-trade policy in the electricity sector. Burtraw, Dallas and Karen Palmer, 2007. Compensation Rules for Climate Policy in the Electricity Sector. Resources for the Future Discussion Paper 07-41. Washington, DC: RFF

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The reason relatively few allowances would be required to compensate the electricity industry as a whole is that the vast majority of costs associated with emissions reductions in this sector would be borne by electricity consumers. Free allocation to generators compensates consumers in regulated regions of the country but benefits generators in competitive regions of the country.

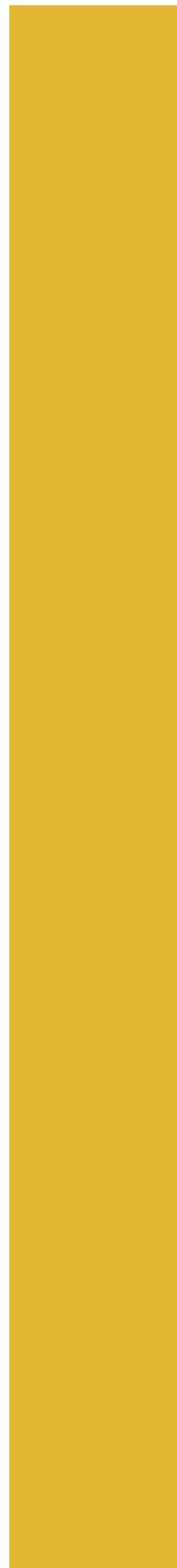
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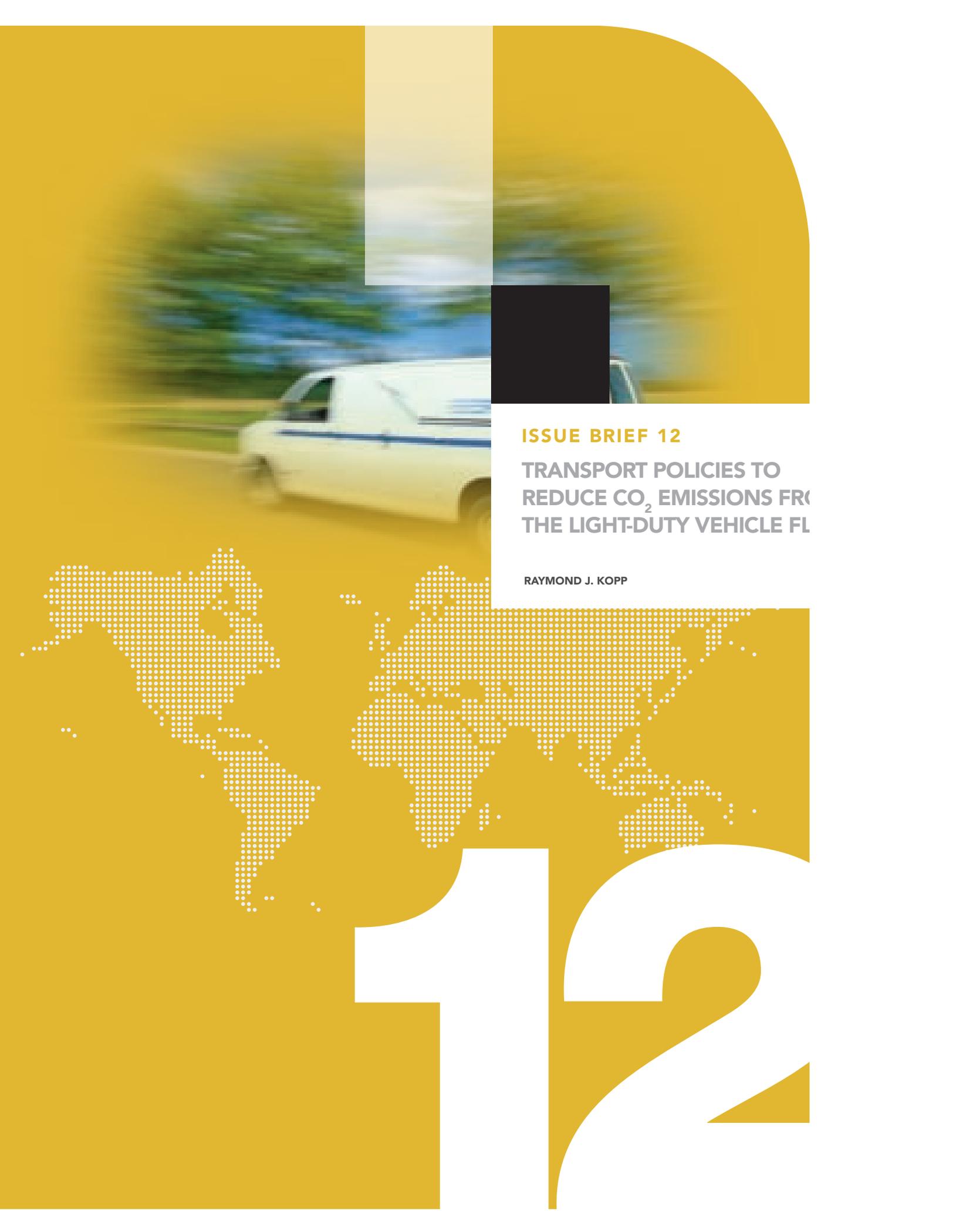
compensates consumers in regulated regions of the country but benefits generators in competitive regions of the country, and hence accentuates regional differences in the incidence of cost under a mandatory climate policy. One proposal for addressing otherwise disparate price impacts across regulated versus competitive markets is to allocate emission allowances (or the value of emission allowances) to load serving entities (LSEs) based on one or more of a variety of measures including electricity consumption, population, or emissions by generators in a state. This approach is sometimes called “allocation to load.” Free allowances allocated to an LSE would reduce the company’s revenue requirements. This would offset the impact of the carbon policy on wholesale electricity prices and thereby mitigate the increase in retail electricity prices. As with an updating free allocation to generators, however, shielding consumers from price increases has the indirect effect of raising the overall cost of the program because it undermines incentives for low-cost end-use demand reductions. Furthermore, allocation to LSEs

invites the question of how allowances should be distributed to these entities—e.g., on the basis of customers served, electricity delivered, or GHG emissions. Different allocation metrics imply a different regional distribution of costs under the program.

If the goal instead is to phase in higher retail prices so that consumers are increasingly exposed to the CO<sub>2</sub> price signal over time, it may be advantageous to assign allowance value to load (using revenues presumably captured through a separate auction of allowances) rather than allowances per se. This is because direct allocation of free allowances can create a sense of entitlement among recipient firms that would not accompany the distribution of equivalent revenues from an allowance auction. More generally, the merits of using allowance value to compensate private interests must be weighed against the other public purposes to which this value could be applied—among them providing broad-based tax relief. Distributing auction revenues rather than allowances per se places compensation goals and other stakeholder claims for a share of the allocation pie on more level footing with these other potential uses.

Beside the possibility of over-compensating some producers in competitive markets, experience with the European Union’s Emission Trading Scheme suggests that free allocation has other problems. For example, free allocation can invite arbitrary provisions such as set-asides for new sources, adjustments for facility retirements, and benchmarking (where eligibility for free allocation might be tied to a requirement that a facility achieves the same emission rate as the most efficient new facility in a given class of technology). A significant body of literature indicates that these types of rules generate incentives that can raise the cost of the overall program and produce unintended consequences. Such provisions will complicate the cap-and-trade program in ways that seriously erode its transparency and efficiency and lead to unanticipated wealth transfers. These problems are generally more significant for updating free allocations than they are for free allocations that are decided on a one-time basis and are not adjusted over time in response to the entry of new facilities or the closure of existing ones.





**ISSUE BRIEF 12**

**TRANSPORT POLICIES TO  
REDUCE CO<sub>2</sub> EMISSIONS FROM  
THE LIGHT-DUTY VEHICLE FLEET**

**RAYMOND J. KOPP**

**12**

## POLICIES TO REDUCE CO<sub>2</sub> EMISSIONS FROM THE LIGHT-DUTY VEHICLE FLEET

Raymond J. Kopp

### SUMMARY

- Transport is the second-largest source of carbon dioxide (CO<sub>2</sub>) emissions and household vehicle use alone accounts for roughly 16 percent of total U.S. emissions. These emissions have been growing roughly 1.5 percent per year.
- Three factors affect CO<sub>2</sub> emissions from light-duty vehicles: vehicle use (typically expressed as vehicle miles traveled or VMT), fuel economy (typically expressed in miles per gallon or mpg), and net greenhouse gas (GHG) emissions associated with the production and consumption of the transportation fuel(s) used. Fuel economy in turn is affected by vehicle characteristics as well as by operating conditions and practices. Growth in VMT has been the principal driver of rising emissions from the light-duty vehicle fleet, since fleet fuel economy and fuel carbon content have remained relatively unchanged over the past decade.
- An emissions tax or cap-and-trade system (or other carbon pricing mechanism) is the only incentive policy that simultaneously address all three of these factors, efficiently allowing trade-offs among them. Policies that target vehicle fuel economy or fuel carbon content, by contrast, do not provide incentives for reducing VMT.
- Concern about whether consumers properly value fuel economy when purchasing vehicles has led to an emphasis on policies that directly address fuel economy rather than increase the price of fuel. Historically, the primary policy tool for influencing transport-sector energy use has been the Corporate Average Fuel Economy (CAFE) program. Although recent reforms to CAFE as it applies to light trucks have likely improved the program's economic efficiency, further changes could potentially yield additional improvements in cost effectiveness. Such changes could include allowing trading across fleets and manufacturers, incorporating a "safety valve" or other cost-containment mechanism, and shifting to a "feebate" system.
- A cap-and-trade mechanism for CO<sub>2</sub> emissions could be designed to focus on vehicle manufacturers. Based on expected lifetime emissions, it would look very similar to a tradable CAFE or feebate program, except that it would tend to raise the price of *all* vehicles to reflect their projected future emissions, not just those with low fuel economy. Such a program could be modified to encourage manufacturers to produce vehicles that utilize lower-carbon transportation fuels, such as biofuels, electricity, or eventually hydrogen.
- Fuel standards have also been proposed to address apparent obstacles to the deployment of low-carbon fuels, such as the interconnectedness of infrastructure, vehicle fuel flexibility, and fuel production and distribution. In their most flexible and hence most cost-effective form, these proposals specify an average life-cycle emissions rate per gallon that must be met

in aggregate (where the life-cycle emissions rate includes emissions from all stages in the production and use of different fuels).

- When assessing the merits of policies designed to alter the carbon intensity of transport fuels and energy sources, one must consider carbon impacts from the entire fuel cycle, taking into account the technologies and energy sources used to produce and distribute new fuels as well as emissions at the point of use. This is especially true for vehicles powered by biofuels, electricity, or hydrogen where upstream factors have a large impact on full fuel-cycle GHG characteristics.
- Although both a carbon tax and an emissions cap-and-trade mechanism address all three drivers of transport-sector GHG emissions, concern about other market failures—along with the view, held by some, that typical CO<sub>2</sub> market prices will not produce the level of emissions reductions needed from this sector—makes it likely that complementary policies to address vehicle fuel economy and fuel carbon content will be adopted, either in addition to or instead of a CO<sub>2</sub> pricing policy for transport-sector GHG emissions. The rationale for such policies does not rest on economic cost or efficiency arguments, but rather brings in a number of other policy judgments and objectives that are often deemed important.
- There is no doubt that an economy-wide carbon price would align all incentives in the right direction and is needed. Additional policies may be useful, however, for the reasons noted above. To the extent that such policies are adopted, economic-efficiency considerations argue for maximizing cost flexibility to the extent possible (for example, by applying either trading or price-based mechanisms). Ideally, policymakers should seek to provide simultaneous incentives for vehicle manufacturers to continually improve fuel economy, for fuel providers to produce fuels with lower life-cycle carbon emissions, and for households to reduce VMT.
- If it proves necessary over time to undertake very deep reductions in transport-sector emissions, fundamentally new technologies, infrastructure, and related institutions could be needed. Policies that may work well in the near term to elicit early emissions reductions at a reasonable cost may not be as effective in a context where much deeper reductions and significant technology breakthroughs are required.

## Transport-Sector Emissions

Electricity generation accounts for one-third of total U.S. GHG emissions, but transportation follows close behind, at 28 percent. The light-duty vehicle fleet (cars and light-duty trucks) accounts for almost two-thirds (62 percent) of CO<sub>2</sub> emissions from transportation. Of these emissions, the vast majority—around 90 percent—comes from household vehicle use; commercial use represents the remainder. Since 1990, CO<sub>2</sub> emissions from the transport sector have increased about 1.5 percent per year, compared to an annual average increase of 1.8 percent for electric power-sector emissions.

The Federal Highway Administration (FHA) reports that the average fuel economy of new passenger cars rose from 17.4 mpg in 1985 to 22.9 mpg by 2005, while the fuel economy of light trucks actually fell from 17.3 to 16.2 mpg.<sup>1</sup> Over the same period, FHA reports that VMT increased by more than 60 percent nationwide, from 1.6 trillion miles per year to almost 2.7 trillion miles. It is precisely this combination of relatively flat fuel economy and sharply higher VMT that has driven recent growth in transport-sector CO<sub>2</sub> emissions.

GHG reductions can be achieved by changing any of the three factors that drive overall emissions from the light-duty vehicle fleet: (1) net emissions associated with the production and use of vehicle fuels, (2) vehicle fuel economy, and (3) total miles driven (VMT).

For example, the carbon content of fuel could be reduced by mixing low-carbon biofuels with petroleum or by running vehicles on electricity or fuel cells that make use of low-carbon energy sources instead of using petroleum-derived fuels.<sup>2</sup> Improving vehicle fuel economy is an obvious way to reduce CO<sub>2</sub> emissions, but this option may indirectly increase VMT if it lowers vehicle operating costs.<sup>3</sup> Finally, any actions that reduce VMT will lower CO<sub>2</sub> emissions as long as fossil fuels continue to supply a significant share of transportation energy needs.

## Relevant Economic Actors

Decisions that affect transport-sector emissions are controlled by three groups of economic actors: households (including vehicle operators or drivers), vehicle manufacturers, and

1 U.S. Department of Transportation (2006). Highway Statistics 2005. Washington, DC, Federal Highway Administration. The Federal Highway Administration lists all 2-axle, 4-wheel vehicles as light trucks. This doesn't match the CAFE new vehicle calculations, which only includes trucks up to 8500 GVWR (gross vehicle weight rating). There is a substantial number of pickups sold above 8500 GVWR so the numbers are not directly comparable.

2 CO<sub>2</sub> emissions are associated with the production of biofuels and may be released during electricity and hydrogen production as well; these must be taken into account when the benefits of these options are calculated.

3 This is known as the "rebound effect": increased fuel economy lowers the per mile cost of driving and therefore could lead to more miles driven.

fuel providers. Drivers and households have different preferences and their vehicle purchase decisions will reflect their willingness to pay for characteristics like power, comfort, appearance, utility, and fuel economy. All else equal, these preferences significantly affect the characteristics of the vehicles that manufacturers offer for sale. Equally important, households and drivers have significant control over VMT and over vehicle operating characteristics.<sup>4</sup>

For their part, vehicle manufacturers respond to consumer preferences, the competitive marketplace, and government requirements in determining the characteristics of the vehicles they produce. Manufacturers can alter the overall fuel economy of their fleets with existing technology, alter the fuel economy of specific models by changing technology, and alter their vehicles' ability to use different fuels. Government mandates aside, manufacturers have sole control over the technology that will be offered for sale in new vehicles.

Fuel producers have the most direct control over the carbon content of the fuel delivered. Their decisions are affected by a number of factors, including fuel prices, vehicle fuel flexibility, fuel quality requirements, and fuel delivery infrastructure.

## Regulatory Options for Reducing Light-Duty Vehicle CO<sub>2</sub> Emissions

This issue brief discusses three categories of policies for reducing CO<sub>2</sub> emissions from the light-duty vehicle fleet. Broad-based policies act to place a price on emissions from vehicles or, equivalently, to price the carbon content of the fuels they use; policies targeted at vehicles seek to reduce CO<sub>2</sub> emissions per vehicle mile traveled; and fuel policies seek to lower the carbon content of fuel directly. While each approach has strengths and weaknesses, the merits of one approach relative to another may change depending on the magnitude of emissions reductions targeted and the timeframe involved. If it proves necessary over time to undertake very deep reductions in transport-sector emissions—reductions that would require fundamentally new technologies, infrastructure, and related institutions<sup>5</sup>—policies that may work well to elicit relatively low-cost reductions in the near term may become less effective.

Many of the policies reviewed here seek to incentivize or mandate new technologies for improving the fuel economy of vehicles and the carbon content of vehicle fuels. When

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It is an open question whether carbon prices at the levels currently under discussion will be sufficient, by themselves, to bring “new” fuel efficiency technology into the marketplace.

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assessing the merits of these policies one must consider the carbon impacts of the entire fuel cycle of the new technologies and fuels. For example, full electric vehicles produce no direct CO<sub>2</sub> emissions, but CO<sub>2</sub> would likely be produced in generating the electricity needed to charge their batteries.<sup>6</sup> Similarly, biofuels can have lower carbon content than hydrocarbon fuels, but accurately assessing their carbon content requires accounting for the entire fuel life-cycle, from the technologies and energy sources used to process biomass feedstocks into transportation fuel back to the energy inputs and emissions outputs associated with cultivating, harvesting, and transporting energy crops in the first place.

### Broad-Based Pricing Policies

Current federal-level discussions of broad-based, economy-wide programs to reduce domestic GHG emissions have focused on a cap-and-trade system using emissions permits or allowances and, to a lesser extent, on carbon taxes. Both policies put a price on emissions and thereby create economic incentives for emissions reductions. As noted in Issue Briefs #4 and #5, either an upstream carbon tax, an economywide upstream CO<sub>2</sub> cap-and-trade system, or a stand-alone fuels tax would have the effect of pricing carbon emissions from transportation fuels.<sup>7</sup>

Because an emissions charge levied on the carbon content of fuel would increase the cost of driving, while imposing

<sup>4</sup> Even holding VMT constant, the manner in which vehicles are driven and maintained, as well as the character of the transportation infrastructure, can affect CO<sub>2</sub> emissions per mile traveled.

<sup>5</sup> An example of a “related institution” would be an agency responsible for transportation planning.

<sup>6</sup> The same is true for hydrogen powered vehicles.

<sup>7</sup> In an upstream system the regulated entity would likely be the petroleum refiner.

proportionally higher costs on less fuel-efficient vehicles,<sup>8</sup> it could alter the vehicle purchasing and operating behavior of households. A higher per mile operating cost would provide incentives for households to reduce VMT, both by traveling less and by using other modes of transport (public transit, bicycling, etc.).<sup>9</sup> It would also create incentives for households to purchase vehicles with better fuel economy and/or the ability to run on less carbon-intensive fuels.<sup>10</sup> Changing consumer demand might in turn alter the mix of vehicles offered by manufacturers; it might or might not alter the fuel-efficiency technologies incorporated in new vehicles, at least in the near-term. Whether a carbon charge would be sufficient to encourage a significant increase in the actual production, distribution, and use of low-carbon fuels depends on the magnitude of the charge.

The effectiveness of a carbon price depends in large part on how responsive consumer behavior is to higher driving costs. Current estimates suggest that a 10 percent increase in fuel prices will cause fuel consumption to fall by 3 to 7 percent over the long run. The decline in fuel consumption would be expected to come from a combination of reduced VMT and long-run changes in average fleet fuel economy.<sup>11</sup> Current analyses indicate that less than half the response would be expected to come from reduced VMT, while just over half would be attributable to improvements in fleet fuel economy.<sup>12</sup>

Although most empirical studies support the notion that household consumption of gasoline is responsive to gasoline prices (which in turn would suggest that a carbon charge would elicit changes in overall VMT and average-fleet fuel economy), it is an open question whether carbon prices at the levels currently under discussion will be sufficient, by themselves, to bring “new” fuel efficiency technology into the marketplace. As one recent study points out, “there is a wide range of existing and emerging technologies for increasing new-vehicle fuel economy for which the discounted, lifetime

fuel savings appear to exceed the upfront installation costs.”<sup>13</sup> One explanation is that households undervalue fuel economy and therefore are not willing to pay the marginally higher purchase cost of more efficient vehicles, leaving manufacturers with no incentive to develop or offer new fuel-saving technologies.<sup>14</sup>

If it turns out that households do value fuel economy, then new technologies will come into the marketplace when the cost of fuel becomes expensive enough. On the other hand, if the undervaluation issue is real, modest carbon charges alone may not create sufficient incentives to drive new technology into the market. Importantly, fuel economy standards, to the extent they correct a market failure separate from climate change—namely, the failure of fuel prices to capture the full energy-security costs of oil consumption—could be a relatively low-cost way to reduce emissions.

### Vehicle-Oriented Policies

This section discusses a variety of policy options that aim to directly alter the GHG-emissions characteristics of vehicles. These options include fuel economy standards, emissions performance standards, tradable performance standards, feebates, vehicle-based CO<sub>2</sub> cap-and-trade systems, and technology mandates.

### Fuel-Economy Standards

Although U.S. gasoline taxes (which currently average 40 cents per gallon) raise the cost of driving and therefore provide some incentive to reduce VMT and improve fleet fuel efficiency, the magnitude of this incentive has actually declined in real terms over the past several decades.<sup>15</sup> Therefore, the primary sector-specific policy that currently exists to promote reduced transportation-related energy consumption is the Corporate Average Fuel Economy (CAFE) program.

The CAFE program was enacted in 1975 to reduce U.S. dependence on foreign oil. It requires each vehicle manufacturer to meet an average fuel-economy standard across new vehicles sold in the United States. Standards are applied separately to each manufacturer’s domestically manufactured cars, its foreign manufactured cars, and its light trucks. From 1975 to 1985, CAFE was responsible for a significant rise in the fuel efficiency of new cars (from less than 15 mpg when the program was launched to approximately 25

8 Conceptually, similar incentives could be achieved via a different mechanism—for example, by applying taxes through vehicle registrations on the basis of carbon emissions per mile (a straightforward function of the vehicle’s average fuel economy) multiplied by miles driven. This would require the vehicle’s computer to be “read” once a year for the mileage data. This approach would not yield precise results because of the difficulty of tracking other factors—such as the type of fuel consumed or driver behavior—that would affect actual emissions.

9 Alternative policies have been proposed for incentivizing VMT reductions by increasing the cost per mile traveled—examples include pay-by-the-mile auto insurance, road taxes, tolls, and congestion fees. Other policies attempt to alter VMT through land-use planning and enhanced (and/or subsidized) public transport.

10 Consumer demand for lower-emissions vehicles would give manufacturers a near-term incentive to offer flexible- and alternative-fuel vehicles capable of using lower-carbon biofuels. Manufacturers would also have greater incentives to make long-term investments in the development of “zero-carbon” all-electric and hydrogen-based vehicles. Since many forms of electricity generation and hydrogen production produce CO<sub>2</sub> emissions, however, regulations on these upstream emissions sources would need to be in place to ensure that the policy produces desired results.

11 Changes in average fleet fuel economy could result from consumers purchasing more fuel-efficient vehicles or from manufacturers incorporating more efficient technologies in the models they offer for sale, or a combination of both.

12 See Parry, I., M. Walls, et al. (2007). “Automobile Externalities and Policies.” *Journal of Economic Literature* 45(3): 373-399.

13 Ibid.

14 The word “undervalue” is meant to describe the possibility that households appreciate the dollar value of the fuel savings that new technologies would provide, but for one reason or another do not properly consider these savings when evaluating the purchase price of a new or used vehicle.

15 See Parry, I., M. Walls, et al. (2007). “Automobile Externalities and Policies.” *Journal of Economic Literature* 45(3): 373-399.

mpg in the mid-1980s).<sup>16</sup> Since 1985, however, the overall fuel economy of the entire light-duty fleet (including light trucks) has been relatively flat or slightly declining. This is largely because the standards remained unchanged (until recently) even as consumer demand shifted toward larger vehicles which tend to have lower fuel economy (e.g., light trucks and sport utility vehicles).

The cost-effectiveness of CAFE as a public policy tool has been much debated,<sup>17</sup> most recently in the context of modifications to the light-duty truck provisions of the program. Beginning in 2011, CAFE standards for light truck will vary according to the “footprint” of the vehicle.<sup>18</sup> This change is intended to discourage manufacturers from relying on the production of smaller vehicles (which tend to have higher fuel economy) as a compliance strategy while creating differentiated standards that will more effectively encourage fuel economy improvements in light-duty trucks. Generally speaking, CAFE or any variant on a fuel-economy standard will serve to force efficiency improvements into the vehicle fleet. Moreover, if properly structured, fuel-economy standards can also provide incentives for manufacturers to produce flexible and alternative-fuel vehicles. However, CAFE by itself does not create direct incentives for consumers to purchase fuel-efficient or alternative-fuel vehicles, nor does it ensure either that low-carbon fuels will be available and used by consumers.

Fuel economy standards like CAFE have been criticized more generally for a lack of cost flexibility. That is, all manufacturers must meet the same standard regardless of the cost of meeting that standard. Proposals for “tradable” CAFE credits would, in theory, add cost flexibility to these policy instruments. However, the benefits of this flexibility would be realized only if a viable trading market for fuel-economy credits developed, and such a market is not guaranteed.<sup>19</sup> A second alternative, recommended in a 2002 study by the National Research Council, would be to include a “safety valve” mechanism in the CAFE program to limit costs. Much like the safety-valve provisions that have been proposed in connection with an economywide GHG cap-and-trade program, the idea would be to make additional compliance credits available at a predetermined price. This would effectively cap the costs manufacturers could incur in complying with program requirements.

The existing CAFE program has other downsides in addition

to the lack of cost flexibility. Standards must be updated over time if efficiency is to be continually improved—something that has proved to be politically difficult, at least in the U.S. context. Moreover, policies of this type provide no incentives to exceed the standard, in contrast to market-based policies like cap-and-trade and CO<sub>2</sub> taxes, which create financial incentives for continual improvement. Finally, and importantly, fuel economy requirements provide no incentive to reduce VMT.<sup>20</sup>

In addition, fuel-economy standards have been criticized for forcing manufacturers to adopt vehicle technologies that consumers do not value and, in doing so, perhaps degrading characteristics that consumers do value. This is worrisome from the manufacturers’ perspective, since it serves to dilute consumers’ enthusiasm for the vehicles offered and could reduce sales.

### Emissions Performance Standards

A vehicle performance standard based on expected CO<sub>2</sub> emissions per mile traveled would directly target vehicle GHG emissions. Like a fuel economy standard, a per-mile performance standard would require manufacturers to produce vehicles with improved fuel economy, but it would also encourage manufacturers to introduce vehicles that run on less carbon intensive fuels (such as biofuels, electricity, or hydrogen).

To be effective, it is critical that performance standards account for GHG emissions from the entire fuel cycle—that is, emissions generated during the production as well as from the use of fuels. This is especially important where vehicles utilize biomass, hydrogen, or electricity “fuels.” In contrast to conventional hydrocarbon fuels, where the great majority of emissions occur at the point of use rather than during upstream production, refining, and distribution processes, full fuel-cycle emissions for many alternative transportation fuels are dominated by upstream emissions. Thus, for example, GHG emissions from an all-electric vehicle are entirely dependent on how the electricity used to charge the vehicle was generated; similarly, different biofuels can have very different full fuel-cycle GHG characteristics depending on the specific biomass feedstocks, conversion technologies, and energy sources used to produce the fuel.

From a GHG-mitigation perspective, a per-mile CO<sub>2</sub> performance standard is more straightforward and perhaps effective than a fuel economy standard, since it goes directly

16 See NRC (2002). *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards*. Washington, DC: National Research Council, National Academy Press.

17 *Ibid.*

18 See Pizer, W. and M. Baker (2005). *Understanding Proposed CAFÉ Reforms for Light Trucks*. Background. Washington, DC, Resources for the Future.

19 Numerous auto manufacturer representatives have stated that such trading is indeed unlikely.

20 The “rebound effect” may increase VMT. See Small, K. and K. V. Dender (2005). *The Effect of Improved Fuel Economy on Vehicle Miles Traveled: Estimating the Rebound Effect Using U.S. State Data, 1966-2001*. University of California Energy Institute.

to the policy objective of interest (reducing emissions) and gives manufacturers incentives to produce not only more efficient vehicles, but vehicles capable of running on lower-carbon fuels. A CO<sub>2</sub> performance standard, however, suffers from many of the same problems as fuel economy standards: it is inflexible with respect to cost, requires continual updating, does not provide incentives to exceed the standard, does not provide incentives to reduce VMT, and risks forcing consumers to pay for technologies they are not interested in purchasing. Flexible-fuel vehicles present an additional difficulty because there is no way to be certain about the extent to which they will actually be operated on the lower-carbon fuel, especially if there is some question about how widely available that fuel alternative will be.

### Tradable Performance Standards

Fuel economy or emissions standards for new vehicles that do not allow trading among vehicle manufacturers are economically less efficient than policies that allow this kind of flexibility. Conceptually, cost-flexible standards encourage manufacturers with cheaper compliance opportunities to exceed the standard and generate credits, and then sell those credits to manufacturers who face higher compliance costs. Without trading, manufacturers who already meet the standard or who can reach it relatively cheaply have no incentive to do anything more, while other manufacturers must expend considerable resources to achieve the same ends.

Adding tradability to performance standards is straightforward. Say new vehicles are subject to a fleet-average emissions performance standard of 0.37 kilograms CO<sub>2</sub> per mile (the equivalent of 27 mpg for a vehicle operating on gasoline). A manufacturer that beats (falls below) the standard by an average of 0.005 kilograms per mile on a million cars collects 5,000 1-kilogram-per-mile credits (0.005 kg per mile per vehicle x 1 million vehicles). These credits can be sold to another manufacturer whose own fleet misses the standard. The same type of trading could be accomplished within CAFE by allowing manufacturers to buy and sell fuel-economy credits for compliance purposes.

It should be noted that simply introducing trading is not guaranteed to improve the economic efficiency of a performance standard. Trading must actually occur when cost differences exist. Given the small number of major vehicle manufacturers, tradable fuel economy or emissions performance credits may or may not lead to a viable trading market.

### Feebates

The term “feebate” usually refers to a symmetric system of fees and rebates (taxes and subsidies) designed to provide consumer incentives for improved technologies. For purposes of this discussion we assume that feebates would apply to the purchase price of new vehicles based on their CO<sub>2</sub> emissions or fuel economy characteristics.<sup>21</sup> This type of policy would have two parts: the “feebate rate” that specifies the level of the fee or rebate at different levels of performance, and the “pivot point” that defines which vehicles will be subject to a fee and which will receive a rebate.<sup>22</sup> The pivot point could be a specific CO<sub>2</sub> per mile performance benchmark (or equivalently, a mile per gallon fuel economy benchmark for gasoline-powered vehicles). Purchasers of vehicles with emissions above this pivot point or benchmark would pay a fee. Logically, vehicles with emissions significantly above the benchmark would be assessed a larger fee than vehicles with emissions only slightly above the benchmark. Similarly, vehicles with emissions below the benchmark would receive a rebate in proportion to their emissions performance relative to the benchmark. Most often, feebate programs are modeled to be revenue neutral—that is, the amount of money collected in fees is enough to pay for the rebates, with the pivot point adjusting over time to maintain revenue neutrality.<sup>23</sup>

A system of feebates would provide incentives for both vehicle purchasers and manufacturers and could induce a fleet-wide shift to lower-emitting vehicles over time. In the near-term consumers would have an incentive to choose relatively more efficient models among existing product offerings. In the longer run, manufacturers would have an incentive to install new efficiency-enhancing technologies so their vehicles could qualify for more favorable treatment under the feebate system. Provided that competitive pressures allow the price of technology improvement to be passed on to the customer, manufacturers would have an incentive to include all forms of low-carbon technology that produce a reduction in fees or an increase in rebates that is larger than their cost. From an emissions-mitigation perspective, this is the most important effect of a feebate policy. In fact, studies by the Department of Energy have concluded that about 90 percent of the impact from feebates would be expected to result from manufacturers electing to incorporate new technology, while only about 10 percent of the impact would be attributable to changes in customer purchase decisions.<sup>24</sup> It is worth

21 While feebates have desirable properties they have not been adopted on a wide scale.

22 See Greene, D., P. Patterson, et al. (2005). “Feebates, Rebates and gas guzzler taxes: a Study of Incentives for Increased Fuel Economy.” *Energy Policy* 33: 757-775.

23 Current “gas guzzler” taxes are a variant on the policy where only a tax is applied and the tax is levied on the basis of fuel economy.

24 See Davis, W., M. Levine, et al. (1995). Effects of Feebates on Vehicle Fuel Economy, Carbon Dioxide Emissions, and Consumer Surplus. *Technical Report Two of Energy Efficiency in the U.S. Economy*. Washington,

noting, however, that this finding assumes manufacturers will not be forced to sacrifice vehicle characteristics that are more highly valued by the customer to make fuel economy improvements. If this is not the case, then the fact that trade-offs exist with other equally or more highly valued vehicle characteristics will tend to diminish the effectiveness of feebates.<sup>25</sup> Finally, unlike a fixed, per-mile CO<sub>2</sub> performance standard, the feebate mechanism creates dynamic incentives for continual improvement. Under this system, it is worthwhile for manufacturers to continue incorporating improvements so long as those improvements are paid for by reduced fees or higher rebates. This would be true even if the vehicle's performance at the outset is already fairly good.

Feebates could be implemented in a variety of ways. Different fee and rebate schedules could apply to different types of vehicles or even to individual manufacturers. This might ameliorate large differences among manufacturers due to differences in their product mix—full-line manufacturers, for example, could have a very different emissions profile than smaller manufacturers that specialize in particular types of vehicles. The disadvantage of this approach, however, is that vehicles with the same fuel economy could face different feebates.

### Cap-and-Trade Program for Vehicle Emissions

Transportation emissions could be included in an economy-wide cap-and-trade permit system; alternatively, a tradable permit system could be constructed for the transport sector alone.<sup>26</sup> Either way, a good many implementation issues would need to be overcome.<sup>27</sup>

One of the most important questions in designing a cap-and-trade system is where to regulate. If the compliance obligation were imposed fully downstream, at the level of the vehicle operator, the logistics of dealing with 200 million regulated entities would be prohibitive. Alternatively, a fully upstream approach could be used to cover the transport sector as part of an economy-wide tradable permit program. In the latter case, the obligation to surrender GHG allowances or permits would be imposed on fuel producers or refiners, and importers based on the carbon content and volume of fuel they handle. Yet another alternative might be to impose the

compliance obligation on vehicle manufacturers based on expected emissions from the vehicles they sell.

Given that a fully downstream system is impractical for regulating transportation emissions, the most often discussed approach for this sector is fully upstream. This means the compliance obligation for most transportation emissions would fall on petroleum refiners. Such a policy would have the same incentives, strengths, and weaknesses as a price or charge on carbon (discussed above).<sup>28</sup> Because reducing CO<sub>2</sub> emissions from the transport sector is likely—at least in the short run—to be more costly than reducing emissions in other sectors of the economy (notably the electricity generation sector), only relatively small reductions, if any, would be expected from the light-duty vehicle fleet—at least at the level of price signal contemplated in most current cap-and-trade proposals. These proposals would produce only a relatively small increase in the price of gasoline—not enough to overcome current price differentials with most lower-carbon alternative fuels or to motivate consumers to significantly alter their driving habits or vehicle purchasing decisions, at least in the short term.<sup>29</sup>

A cap-and-trade or CO<sub>2</sub> tax system that regulated vehicle emissions at the manufacturer level would be similar to a tradable CAFE program or a feebate (discussed above), except that it would effectively tax *all* vehicles (rather than effectively taxing vehicles that emit above the standard or threshold, while subsidizing vehicles that have lower emissions—as both fuel economy standards and a feebate system do). Manufacturers would need to acquire allowances (or pay emissions taxes) equal to some effective lifetime measure of expected emissions from the vehicles they sell—perhaps 100 tons of CO<sub>2</sub> per car at current fleet-average levels of fuel economy. Even with free allowance allocations to manufacturers, much of this allowance cost would be priced into the car and passed along to car buyers.<sup>30</sup> Because the level of the price increase would depend on the vehicle's emissions characteristics, purchasers would have an incentive to choose relatively more efficient models (or models that run on lower-carbon alternative fuels).

DC: US DOE Office of Policy, Greene, D., P. Patterson, et al. (2005). "Feebates, Rebates and gas guzzler taxes: a Study of Incentives for Increased Fuel Economy." *Energy Policy* 33: 757-775.  
 25 See Davis, W., M. Levine, et al. (1995). Effects of Feebates on Vehicle Fuel Economy, Carbon Dioxide Emissions, and Consumer Surplus, U.S. Department of Energy, OPA.  
 26 See Nordhaus, W. and K. Danish (2003). Designing a Mandatory Greenhouse Gas Reduction Program for the U.S., Prepared for the Pew Center on Global Climate Change, Ellerman, D., H. Jacoby, et al. (2006). Bringing Transportation into a Cap-and-Trade Regime. *MIT Joint Program*. Cambridge, MA. Gallagher, K. S., G. Collantes, et al. (2007). Policy Options for Reducing Oil Consumption and Greenhouse-gas Emissions from the U.S. Transportation Sector. Cambridge, MA, Harvard Kennedy School of Government.  
 27 See German, J. (2007). Reducing Vehicle Emissions Through Cap and Trade Schemes". *Driving Climate Change: Cutting Carbon from Transportation*. D. Sperling and J. Cannon, Academic Press.

28 If refiners were responsible for the carbon content of the fuel they sold, they could have an incentive to purchase and blend more biofuels than is currently the case. The strength of this incentive of course depends on the cost of the biofuels vis-à-vis the permit price, the number of vehicles in use that are capable of using biofuels, and the availability of a suitable distribution infrastructure.  
 29 For example, a \$10/ton CO<sub>2</sub> permit price would have a large impact on coal prices, creating a relatively strong incentive for coal-dependent electric utilities to consider shifts in their generation portfolio. In the transport sector, by contrast, the same carbon price would translate into a 10-cent per gallon increase in gasoline prices—a relatively small change especially when compared to the price fluctuations that have affected oil markets in recent years. Given the short-run inelasticity of demand for gasoline, one would not expect a strong response: very likely, refiners would simply pass along the \$10 price of permits and consumers would absorb that cost without significantly changing their behavior.  
 30 Because allowances would have a significant opportunity cost in the CO<sub>2</sub> market—especially in the context of an economy-wide program—manufacturers would be expected to pass along the cost of using allowances, even if they originally receive the allowances for free. For further discussion of cost pass-through issues and of the incentive properties of allocation decisions, see Issue Brief #6.

A manufacturer-based cap-and-trade system for vehicle GHG emissions that was not integrated into an economy-wide carbon market might be less liquid and hence less likely to transmit a clear price signal to vehicle purchasers; in that case, it could be very expensive and inefficient. On the other hand, if a viable permit market did develop—that is, if vehicle manufacturers could freely buy and sell permits—manufacturers would face incentives to continually lower vehicle carbon intensity by either (or both) improving fuel economy and producing more flexible-fuel vehicles. Even then, however, a manufacturer-based approach, especially if it were not part of a broader carbon pricing policy, would likely have the drawback that it fails to create incentives for vehicle operators to actually use lower-carbon fuels or reduce VMT (on the contrary, people might actually drive somewhat more because more efficient vehicles would have lower operating costs<sup>31</sup>).

### Technology Mandates

Technology mandates require manufacturers to produce and sell specific types of vehicles. One of the best-known examples is the California Zero Emissions Vehicle (ZEV) mandate. Other mandates could be fashioned around the production and sale of flexible- and alternative-fuel vehicles.

The purpose of mandates is to force specific technologies, technology characteristics, or performance improvements into the marketplace. This approach has risks and drawbacks, however. It is fair to say, for example, that the California ZEV mandate has not been successful in bringing large numbers of zero-emissions vehicles into the California market. Mandates create no incentives for consumers to purchase new technologies, and therefore consumer acceptance of vehicles produced in response to a mandate is an open issue. A policy that relies on vehicle mandates also risks being ineffective and expensive if the chosen technology and its effect on emissions turn out to fall short of what could be achieved using other technologies that have not been mandated.

### Fuel-Oriented Policies

Fuel-oriented policies constitute another frequently-discussed option for reducing CO<sub>2</sub> emissions from the light-duty vehicle fleet. Regulations that bring about a shift from traditional hydrocarbon-based fuels to new, less carbon-intensive transportation energy sources can lead to lower CO<sub>2</sub> emissions. As has already been noted, however, it will be extremely important for such policies to account for GHG emissions throughout the full fuel cycle, since CO<sub>2</sub> emissions

for many of the likeliest petroleum alternatives are more likely to occur during fuel production rather than at the point of use. In addition, it will be important to consider non-climate environmental and other impacts associated with a shift to lower-carbon fuels—an example would be land-use impacts from a major expansion of the biofuels industry. Such impacts could become important, especially if the expectation is that these new fuels will be deployed in large quantities.

### Fuel standards

Fuel standards would require fuel manufacturers or distributors to produce and sell fuels with lower carbon content. This can be done in different ways and with more or less flexibility. A proposal for a California Low Carbon Fuel Standard (LCFS)<sup>32</sup> is an example—it provides a high degree of flexibility because the standard must be met in aggregate for all transport fuels sold, based on life-cycle emissions.<sup>33</sup> Fuels that beat the standard generate excess permits that can be used to offset emissions from fuels that do not meet the standard.

In a recent analysis of a proposed LCFS for California, Farrell and Sperling argue that permits should be made tradable—that is, it should be possible to buy and sell permits in the market, thereby creating a price differential between fuels with different carbon emissions. In other words, if the standard were tradable in the aggregate, high-carbon fuel could coexist in the market with low-carbon fuel, and relative prices for different fuels would adjust in the market—along with the permit price—to meet the standard.<sup>34</sup> Low-carbon fuels like E85 (a gasoline-ethanol blend with 85 percent ethanol content) would become cheaper—effectively it would be subsidized by conventional gasoline with higher carbon content. The change in relative fuel prices might also encourage consumers to purchase vehicles capable of utilizing low-carbon fuel. While trading would significantly increase flexibility and reduce costs associated with a fuel standard, it is worth noting that there is some risk—simply because the number of fuel providers is small—that a viable market would not develop, even if trading among regulated fuel providers were allowed as it is in the California program.

### Fuel Feebates

Some of the same benefits of a tradable fuel standard could

31 As noted previously, this concern applies more generally to any policy (including CAFE) that only targets vehicle fuel economy without delivering concurrent incentives to reduce VMT.

32 Farrell, A. and D. Sperling (2007). A Low-Carbon Fuel Standard for California: Part 2: Policy Analysis, University of California.

33 In contrast, some fuel standards would require regulated entities to sell specific volumes of particular fuels—for example, the Energy Policy Act of 2005 mandates a specific proportion of biofuel sales.

34 Several alternative policies could alter the relative prices of low- and high-carbon fuels, thereby encouraging the use of low-carbon fuels and the development and deployment of vehicles that can run on them. These policies include explicit government subsidies for the production of low-carbon fuels (e.g., current subsidies for ethanol production), revenue-neutral feebates that would tax high-carbon fuels and subsidize low-carbon fuels, policies to improve the infrastructure for delivering low-carbon fuels, and government-funded R&D to bring down the cost of production.

be achieved by transforming the standard into a feebate, where the pivot point might be grams of carbon emissions per gallon of fuel. The mechanics of such a system would be analogous to those discussed previously for vehicle feebates. Fuels with emissions above some threshold or pivot point would be taxed; those with lower emissions would be subsidized. By changing the relative price of fuels in proportion to their emissions impacts, feebates would generate incentives for fuel providers to introduce lower-carbon fuels and for consumers to purchase those fuels.

### **Fuel-Specific Mandates**

This type of mandate requires fuel providers to produce and sell a minimum quantity of specific fuel alternatives. It can be used to force unconventional fuels such as E-85 into the marketplace. Fuel mandates can be expressed in terms of a required minimum volume of alternative fuels or as a share or percent of overall fuel or energy consumption. The federal Renewable Fuel Standard (RFS) introduced as part of the Energy Policy Act of 2005 is an example: it is expected to require 7.5 billion gallons of renewable fuels in 2012.

### **Conclusion**

As noted at the outset of this issue brief, CO<sub>2</sub> emissions from the transport sector are largely driven by light-duty vehicles. Light-duty vehicle emissions, in turn, are driven by three factors: vehicle fuel economy, the carbon intensity of vehicle fuels, and VMT. To the extent that market failures exist in this sector that cannot be addressed by a single, economywide price on CO<sub>2</sub> emissions, it is unlikely any single policy can effectively target all three of these drivers at once. Thus, some combination of policies to address vehicle characteristics, fuel characteristics, and VMT may be desirable. Moreover, climate policies for the transport sector cannot be considered in a vacuum; in many cases they may not produce desired results without complementary policies to reduce CO<sub>2</sub> emissions from other sectors and to address other energy and social concerns. (For example, efforts to promote all-electric and hybrid-electric vehicles might not produce desired GHG reductions unless policies were also in place to limit emissions from stationary sources such as power plants.)

Only the first regulatory option discussed in this issue brief—a broad-based emissions pricing policy—would simultaneously provide incentives for lower-carbon vehicles, lower-carbon fuels, and reduced VMT. Given that pricing policies like a carbon tax or cap-and-trade program can be implemented on an economywide basis—that is, so that they provide seamless coverage of the transport sector along with other

sectors—the question arises: is there a need for separate transport policies? Many would say yes, based simply on the observation that any politically feasible economywide carbon charge would initially increase gasoline prices by only pennies per gallon and therefore have little or no impact on transport emissions, at least in the short term. Others disagree, arguing that if it is more costly to reduce emissions from light-duty vehicles than from, for example, electric power generators, then it is economically efficient for most emissions reductions to come initially from other sectors while deferring significant transport-sector reductions until some time in the future.

There are, however, additional factors to be considered. The first is the possible existence of a market failure. If consumers undervalue fuel efficiency for some reason, a carbon price signal by itself will not elicit all cost-effective emissions reductions. A second issue concerns the adequacy of incentives for bringing about fundamental technological change. Will a carbon charge alone provide adequate incentives for vehicle manufacturers to begin investing now in the breakthrough technologies that will be needed to achieve significantly deeper emissions reductions later? Finally, a similar threshold issue may exist with respect to the large-scale deployment of lower carbon fuels, especially where those fuels would require substantial investments in a new or enhanced delivery infrastructure. Again, the incentives provided by a carbon pricing policy might not be adequate, by themselves, to overcome the considerable financial and other barriers that might hinder progress in this area.



**ISSUE BRIEF 13**  
**CLIMATE CHANGE  
AND U.S. AGRICULTURE**

JUHA SIIKAMÄKI AND JOSEPH MAHER

13

# CLIMATE CHANGE AND U.S. AGRICULTURE

Juha Siikamäki and  
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## SUMMARY

Despite its relatively small role in generating carbon dioxide (CO<sub>2</sub>), agriculture is frequently discussed in the context of climate change—for several reasons. First, agriculture is one of the key sectors of the economy that may be strongly affected by climate change. Second, while relatively unimportant for CO<sub>2</sub> emissions, the agriculture sector is a major source of other greenhouse gas (GHG) emissions, notably nitrous oxide (N<sub>2</sub>O) and methane (CH<sub>4</sub>). Third, agricultural practices provide opportunities for soil-based carbon sequestration, potentially a relatively cheap mitigation option. Fourth, the recent biofuels boom is transforming U.S. agriculture in ways that have implications not only for GHG emissions and energy production, but also for agriculture and the food sector as a whole. This issue brief brings together each of these aspects of the connection between agriculture and climate change.<sup>1</sup>

## Effects of Climate Change on Agriculture

- Climate change is not expected to materially alter the overall ability of the United States to feed its population and remain a strong agricultural exporter. Generally, climate change is predicted to have overall positive but relatively modest consequences on agricultural production in the United States over the next 30 to 100 years. Longer term consequences are less well understood.

- At the regional level, however, projected effects on agriculture are considerable. Climate change is expected to reduce agricultural output in the South but increase production in northern regions, especially the Great Lakes.
- Predicting changes in precipitation patterns, extreme weather effects, pest populations, plant diseases, and other production risks is inherently difficult. Current assessments do not fully account for potential effects on agriculture from these climate impacts.

## Agriculture as a Source of GHG Emissions

- The agricultural sector is responsible for roughly 8 percent of total U.S. GHG emissions.
- Agriculture is not a major source of CO<sub>2</sub> emissions, but it is the source of almost 30 percent of methane emissions and 80 percent of nitrous oxide emissions. On a CO<sub>2</sub>-equivalent basis, these gases account for nearly 15 percent of all GHG emissions in the United States. Most agricultural nitrous oxide emissions stem from soil management; methane emissions come primarily from animal husbandry (specifically, enteric fermentation in the digestive systems of ruminant animals and manure management).
- While unlikely to be included in a mandatory policy, the agricultural sector is a potential source of low-cost emissions

<sup>1</sup> Broader issues such as overall energy demand, energy security, climate change agreements, and so forth, are outside the scope of this brief.

offsets. Though these offsets provide important GHG mitigation opportunities, incorporating them in a regulatory system presents challenges in terms of measuring, verifying, and assuring the permanence of claimed reductions.

- Cost-effective GHG mitigation opportunities in the agriculture sector include the use of soil management practices to reduce nitrous oxide emissions and increase carbon sequestration.
- Soil-based carbon sequestration, in particular, may represent an important near-term GHG mitigation option, and a means of keeping mitigation costs down until other emissions-reduction technologies develop.

### Biofuels

- Corn-based ethanol production has skyrocketed in recent years, and this trend is likely to continue. Nationwide, nearly 130 ethanol biorefineries with total annual production capacity of 6.7 billion gallons are currently<sup>2</sup> in operation, making the United States the world's largest producer of ethanol.
- The almost 80 new plants currently under construction will approximately double current U.S. ethanol production capacity.
- With more than 13 billion gallons of annual production capacity either already in operation or under construction, domestic ethanol use is poised to far exceed the 7.5 billion gallon annual target established by the federal Renewable Fuels Standard (RFS) adopted in 2005 (the latter policy calls for 5 percent of total U.S. gasoline demand to be met using renewable fuels by 2012). Long-term projections taking into account cost, feedstock supply, and other constraints do not, however, foresee corn-based ethanol production exceeding 15–20 billion gallons annually.
- The current ethanol boom is affecting practically every aspect of U.S. agriculture. In 2007, the nation's farmers planted a record corn crop, increasing corn acreage by 19 percent. Additional land in corn production largely came from shifting acreage out of soybean production. As a result of strong demand, corn prices have not only remained high but are driving up prices for other commodity crops.
- Consumer food prices are not expected to be severely affected by high corn prices resulting from the current ethanol boom. Nevertheless, higher feed costs increase consumer prices for poultry, eggs, and red meats. This will likely cause overall retail food prices to rise somewhat faster than the general rate of inflation through the end of the decade (2008–2010). After these near-term price adjustments, however, consumer food prices are expected to rise more slowly than the general rate of inflation.
- Though corn-based ethanol replaces fossil fuels, its capacity to mitigate GHG emissions is limited. Taking into account the entire product life-cycle, the use of corn-based ethanol is estimated to reduce GHG emissions by roughly 10–20 percent relative to gasoline.<sup>3</sup> Therefore, the foreseeable expansion of corn-based ethanol production can be expected to only marginally reduce total U.S. GHG emissions (by less than 0.5 percent).
- More substantial GHG reductions (up to 80–90 percent relative to gasoline) and significantly larger production volumes could be achieved through the successful commercialization of technologies for producing ethanol from cellulosic biomass. But large-scale expansion of this capability requires technological innovations.<sup>4</sup>

## Effects of Climate Change on Agriculture

Agriculture, especially crop production, is fundamentally linked to climatic conditions, so any changes in climate will necessarily affect agriculture. Several assessments have scrutinized the effects of alternative climate-change scenarios on the U.S. agriculture sector, and although their predictions vary (in some cases widely), there is general agreement that climate change is unlikely to materially alter the ability of the United States to feed its population and remain a strong agricultural exporter.<sup>5</sup>

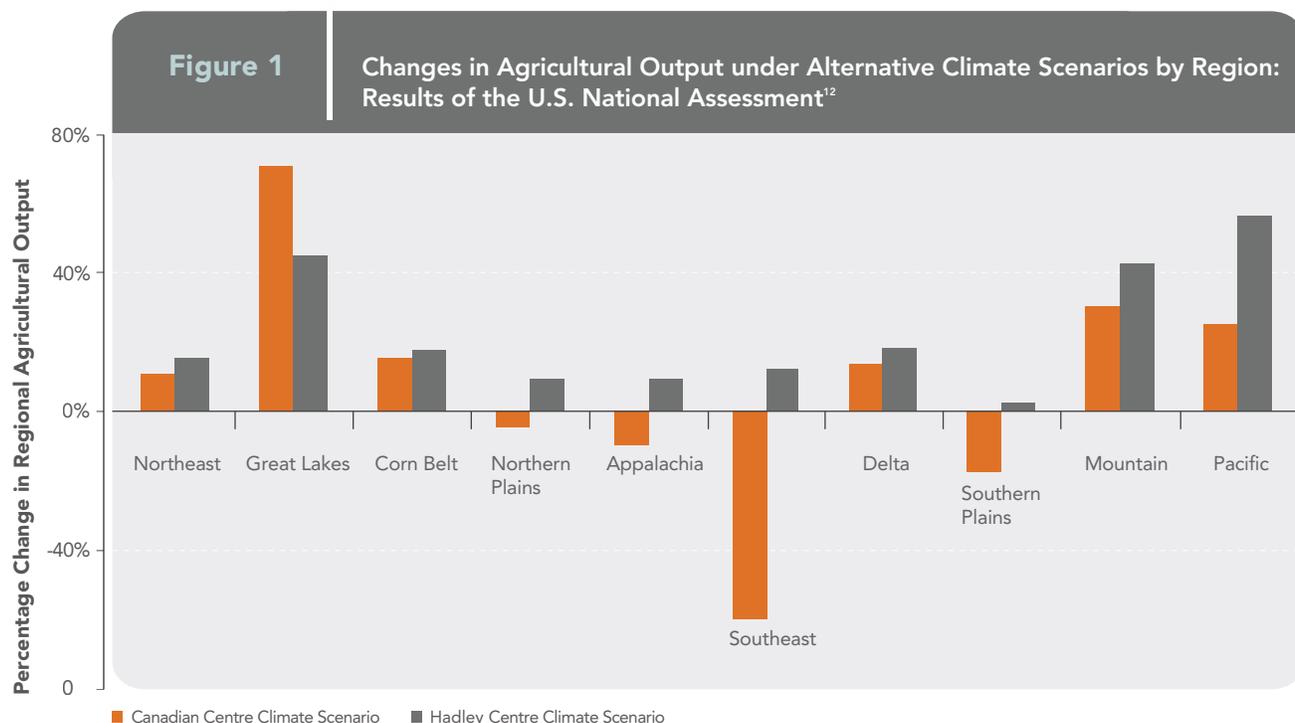
Generally, the predicted economic impacts from climate-related effects on agriculture are positive but moderate in aggregate over about the next 30–100 years. Though projected future growing conditions (temperature,

2 As of August 22, 2007 (Renewable Fuels Association).

3 M. Wang, M. Wu, and H. Huo, "Life-cycle Energy and Greenhouse Gas Emission Impacts of Different Corn Ethanol Plant Types," *Environmental Research Letters* 2(2007):1–13; and K. Sanderson, "A Field in Ferment," *Nature* 444, Business Feature, 673–676, 7 December 2006.

4 M. Wang, M. Wu, and H. Huo, note above.

5 J. Reilly et al., "Agriculture: The Potential Consequences of Climate Variability and Change for the United States," in US Global Change Research Program, *US National Assessment of the Potential Consequences of Climate Variability and Change*, New York: Cambridge University Press, 2001; and R. Adams, R. Hurd, J. Reilly, *A Review of Impacts to U.S. Agricultural Resources*, Arlington, VA: Pew Center on Global Climate Change, 1999.



precipitation) would affect especially crop production and its regional distribution, market adjustments in production, consumption, and trade ensure that even substantial production changes would not become very costly overall. Longer-term agricultural effects of climate change are less well understood.

For example, the U.S. National Assessment<sup>6</sup> examined the effects of alternative climate-change scenarios on agriculture. Depending on the adopted climate model,<sup>7</sup> the results ranged from moderate costs to a few billion dollars of overall benefits in agriculture.<sup>8</sup> Potential agricultural benefits from climate change stem from increasing temperatures and CO<sub>2</sub> levels, which boost crop yields.<sup>9</sup> While increased crop yields generally count as a benefit, the fact that higher yields tend to lower crop prices means that farmers may not be any better off and could in fact suffer losses. Of course, lower crop and food prices are a plus for consumers.<sup>10</sup> Targeted adaptation

efforts would tend to provide positive benefits to agriculture, while increasing pest populations and other production risks associated with climate change would have negative impacts.

Notwithstanding the fact that overall effects are predicted to be moderate, regional impacts can be large. Predicted changes in temperature and precipitation are least favorable to agriculture in the South and Great Plains, where the net effect of climate change is negative (see Figure 1). Predicted losses in agricultural output are especially large in the Southeast.<sup>11</sup> Northern areas, on the other hand—particularly the Great Lakes area—may benefit from more favorable climatic conditions.

Though different assessments project climate-related changes in agricultural production and land prices, these changes are moderate in the context of other trends in agriculture and food markets. For example, agricultural land prices declined roughly 50 percent between 1980 and 1983—a shift that is well beyond the projected effects of climate change. On the consumer side, a recent rise in retail food prices is likely to produce more noticeable impacts than any predicted effect from climate change. Similarly, changes in world markets for

<sup>6</sup> Reilly et al. note above.

<sup>7</sup> Two climate scenarios, the Canadian Climate Centre Model and Hadley Centre Model, were examined in the National Assessment. The Canadian model predicts significant warming in the South such that increases in the average temperature of about 9°F (5°C) are common by the year 2100. The Hadley model predicts more moderate temperature increases (Reilly et al. 2001, note 5 above).

<sup>8</sup> See also C. Field et al. "North America", in *Climate Change 2007: Impacts, Adaptation and Vulnerability, Contribution of Working Group II to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, M.L. Parry, et al. (Eds.), Cambridge University Press, Cambridge, UK, 617-652, 2007.

<sup>9</sup> Higher atmospheric CO<sub>2</sub> concentrations generally enhance the rate of photosynthesis, which in turn improves crop yields.

<sup>10</sup> Reilly et al. 2001, note 5 above.

<sup>11</sup> The U.S. National Assessment defines agricultural output as aggregated crop and livestock production weighted by output prices.

agricultural products, trade and agricultural policies, farming technology, or competing uses for agricultural land are likely to impact this sector more dramatically than climate change over the next several decades.

Predictions about the effects of climate change on agriculture depend critically on underlying assumptions regarding technological change, adaptation to new climatic conditions and regulatory regimes, and alternative land uses. They also depend on international developments with respect to trade, food demand, and production (which in turn are also likely to be affected by climate change). Substantial changes in any of these modeling assumptions will alter and possibly overshadow predicted effects from climate change. For example, new crop varieties are continuously developed and crops today have broader suitable geographical ranges than just a few decades ago. This technological progress will continue and may even intensify in response to climate change. Opportunities to improve crop productivity and adapt to changing conditions are also vastly improved by biotechnology.

Besides temperature changes, the full effect of climate change will depend on other factors such as precipitation (total precipitation and its temporal distribution); extreme weather events (storms, droughts, etc.); changes in pest populations, plant diseases, and weeds; and so forth. These effects are poorly predicted by current climate-change models—different agricultural assessments emphasize inherent difficulties in properly accounting for them—and each may impose important costs on agriculture.

The difficulty of predicting net effects is illustrated by examining water availability—a critically important parameter—in irrigation-dependent areas where climate change is expected to alter both crop yields and water supply. The amount of water available for irrigation will change with both the timing and volume of annual water supply. Currently, much of the precipitation in many irrigation-dependent states occurs during the winter months, whereas demand for irrigation water peaks during the late spring and summer. Two types of water storage—man-made reservoirs and mountain snow pack—smooth this temporal discrepancy in precipitation and water demand. For example, in late April, the water preserved in the snow pack of California's Sierra Nevada mountains currently just about matches what is stored by the state's major reservoirs. According to current projections, rising temperatures may well reduce snow-pack storage capacity by one-third by the middle of the century.

This reduction in natural storage capacity would likely be replaceable, at least in part, by man-made storage, though at considerable cost. Without alternative storage capacity, agricultural producers in California would have to cope with a substantially reduced supply of water for irrigation.<sup>12</sup>

## Agriculture as a Source of GHG Emissions

### Emissions

Currently, the agricultural sector is responsible for about 8 percent of total U.S. GHG emissions (see Figure 2). Within the U.S. economy, emissions from agriculture rank considerably below those from the electric power industry (33 percent of total emissions), the transportation sector (28 percent of total emissions), and the industrial sector (19 percent of total emissions). The contribution from agriculture exceeds, however, the contribution from primary energy consumption in the commercial and residential sectors (6 percent and 5 percent of total emissions, respectively). In absolute terms, agricultural GHG emissions amount to about 595 million metric tons of CO<sub>2</sub>-equivalent per year, whereas total annual U.S. emissions are about 7,260 million metric tons CO<sub>2</sub>-equivalent.<sup>13</sup>

Although agriculture is not a major source of U.S. CO<sub>2</sub> emissions, it is the source of almost 30 percent of methane<sup>14</sup> emissions and 80 percent of nitrous oxide emissions (see Figure 3). Together, these two gases, while not on par with CO<sub>2</sub>, constitute almost 15 percent (on a CO<sub>2</sub>-equivalent basis) of all GHG emissions in the United States.

Nitrous oxide emissions from agricultural soils account for almost two-thirds of overall GHG emissions from agriculture. These emissions originate primarily from the breakdown of manure and nitrogen fertilizers, but are also released from nitrogen-fixing crops (e.g. soybeans, alfalfa, and clover). Nitrous oxide emissions from soil management constitute roughly 5 percent of all U.S. GHG emissions.

Though GHG emissions have increased during the last

12 Changes in the irrigation water supply undoubtedly will have considerable consequences on agriculture. Schlenker et al. examine projected climate-change scenarios for California and predict that declining water availability may reduce the value of farmland by as much as 40 percent (\$1,700 per acre). This effect is due solely to lost irrigation and does not include effects from changing temperature, which the study predicts will further reduce the value of farmland. (Schlenker, W., W. M. Hanemann, and A. Fisher, 2007, *Water Availability, Degree Days, and the Potential Impacts of Climate Change on Irrigated Agriculture in California*, *Climatic Change*, 2007 81:19-38.)

13 U.S. Environmental Protection Agency, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005," April 15, 2007.

14 The decomposition of livestock manure, under anaerobic conditions, produces methane. According to the U.S. Environmental Protection Agency, roughly 540 million CO<sub>2</sub>-equivalent tons of methane were emitted from human-related activities in the United States in 2005 (EPA, note 14 above). Nearly one-third of these emissions originated in the animal husbandry industry, including enteric fermentation and manure management.

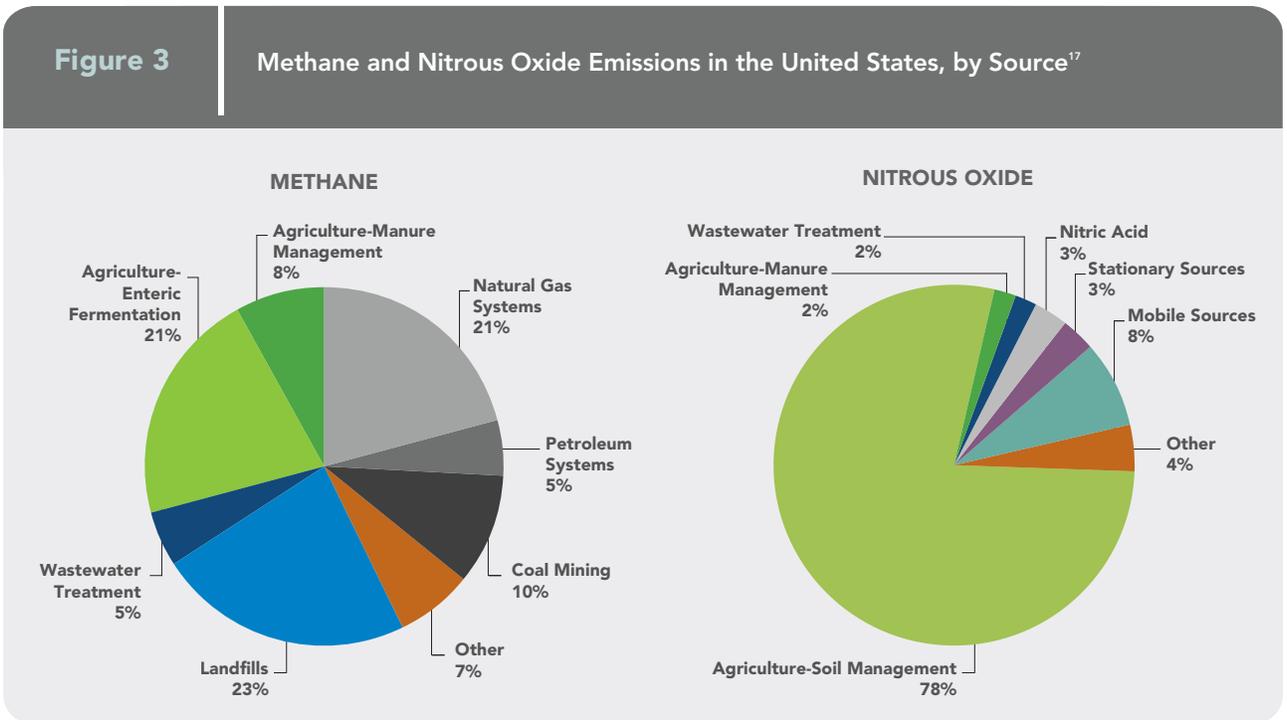
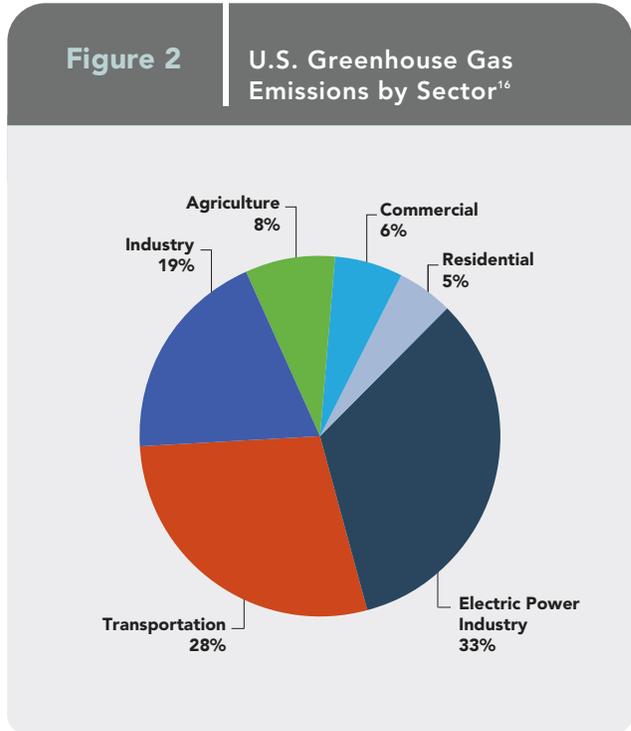
decade, emissions from agriculture have remained nearly constant. Methane from manure management is the main exception to this trend: methane emissions have increased by roughly one-third as livestock production has shifted to larger and larger concentrated animal feeding operations (CAFOs). On the other hand, large production units may facilitate future mitigation efforts by making investments in capital-intensive methane-reduction technologies, such as methane digesters, more cost-effective.

**Potential for GHG mitigation and offsets**

Collectively, the agriculture sector can contribute to GHG mitigation efforts in a number of ways, especially by increasing soil carbon sinks, reducing emissions of nitrous oxide and methane, and providing biomass-based alternatives to fossil-fuel use.<sup>15</sup> Prominent GHG mitigation strategies in agriculture include the following:

1. Improved agricultural land management to increase soil carbon storage.
2. Enhanced livestock and manure management to reduce methane emissions.

<sup>15</sup> See, for example, K. Paustian, J. M. Antle, J. Sheehan, and E. A. Paul, *Agriculture's Role in Greenhouse Gas Mitigation*, Arlington, VA: Pew Center on Climate Change, September 2006.



3. Development of new fertilizer application techniques to reduce nitrous oxide emissions.
4. Increased use of biomass energy crops to replace fossil fuels.

### Improved agricultural land management to increase soil carbon storage

Changes in land use and agricultural practices can increase the amount of carbon stored in soils. Best management practices that increase soil sequestration include adopting conservation tillage, reducing fallow periods, including hay crops in annual rotations, and producing high-residue-yielding crops. Converting lands to conservation set-asides with trees (afforestation) or perennial grasses can produce larger changes in soil sequestration than changes in agricultural practices.<sup>16</sup>

Management practices that increase soil sequestration can be implemented relatively quickly and in many cases at low cost relative to other forms of emissions reductions. The amount of carbon storage that would be economically competitive with other mitigation opportunities, however, is less than the total technical potential for sequestration in agricultural soils. National-level studies suggest that as much as 70 million metric tons of soil-based carbon sequestration per year are available at a cost of \$50 per ton of carbon (\$13 per ton of CO<sub>2</sub>) through best management practices, and another 270 million metric tons of carbon sequestration per year could be achieved by converting agricultural lands to forests.<sup>17</sup>

The profitability of alternative management techniques and the amount of carbon sequestration achievable at a given price vary widely across regions. The potential to increase soil carbon storage on agricultural lands generally ranges from 0.1 to 1 ton per hectare (0.04–0.4 tons per acre) per year due to differences in soil attributes. Most studies suggest that the Midwest and Great Plains regions are well suited for conservation tillage practices, while the Southeast may be better suited for the conversion of agricultural lands to forests.

Agricultural soils do not have an unlimited capacity to store carbon, and for any given management practice a saturation point will be reached over time. Complete carbon saturation is estimated to occur 20–30 years after changes in farm management practices and 70–150 years after afforestation, depending on the tree species used. Also, carbon stored in soils can be quickly released back into the atmosphere once a

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farmer reverts back to traditional tilling practices. Thus, policies that provide offset credits for soil-based carbon sequestration in the context of a domestic CO<sub>2</sub> cap-and-trade program must be cognizant of permanence issues and of the potential for stored carbon to be released. Nevertheless, this option can provide immediate, low-cost GHG-mitigation benefits while more permanent solutions are developed.

### Nitrous Oxide

Primary means of reducing nitrous oxide emissions focus on more efficient and moderate uses of manure and nitrogen fertilizers. This may be achieved by improving the timing and placement of fertilizers, testing soils to determine fertilization requirements, using nitrification additives, and incorporating fertilizers into soils. Technically, these practices could reduce nitrous oxide emissions from agriculture by up to 30–40 percent (reductions available at a competitive cost could be smaller). More efficient fertilizer applications would generate additional water-quality benefits by reducing nutrient runoff.

### Methane

While enteric fermentation in the digestive systems of ruminant animals accounts for most agricultural methane emissions, manure management may offer greater opportunities

<sup>16</sup> In 2005, U.S. agricultural soils were sequestering about 20 MMT of carbon per year with 36% of croplands applying some form of conservation tillage.

<sup>17</sup> K. Paustian et al., note 18 above; and J. Lewandrowski et al., *Economics of Sequestering Carbon in the U.S. Agricultural Sector*, USDA Economic Research Service, 2004.

for mitigation.<sup>18</sup> The main approach for controlling these emissions is to capture the methane and then burn the bio-gas to generate electricity. Other manure management options involve using manure-storage sheds, aeration processes, and lagoon storage systems with methane capture.

Using captured methane to generate electricity can reduce farm outlays for electricity and even provide surplus electricity for sale back to the grid. On-farm electricity generation produces CO<sub>2</sub> emissions but because of the higher global warming potential of methane, net GHG reductions—on a CO<sub>2</sub>-equivalent basis—can approach 90 percent.<sup>19</sup> In addition, the electricity generated from this activity replaces other forms of electricity generation, including generation using equally or more carbon-intensive fossil fuels. In that case, net reductions are achievable even in CO<sub>2</sub> emissions alone.

Over the last few years, interest in methane digesters for use in animal husbandry operations has increased noticeably. Most of the potential for applying this technology is concentrated in major dairy- and livestock-producing regions, such as California, Wisconsin, Iowa, Minnesota, North Carolina, and Texas. For example, California has initiated several programs, including the Dairy Power Production Program, the Self-Generation Incentive Program, and net-metering assembly bills, to encourage manure treatment with methane digesters. The Dairy Power Production and Self-Generation Incentive Programs provide cost-share funding for capital investments in new methane digesters.<sup>20</sup> Assembly Bills 2228 (signed into law in 2002) and 728 (signed into law in 2005) require the state's three largest investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) to offer net metering to dairy farms that install methane digesters. Potential farm-level benefits from methane digestion are especially pronounced for relatively large operations, where the capital cost of installing digesters is least prohibitive, and in warm climates, where methane production potential is greatest.<sup>21</sup>

### Total Mitigation Potential

The agriculture sector offers a wide range of mitigation opportunities. Therefore, the key question is how different

18 Over the past 20 years, methane-suppressing feed additives and more efficient feed rations have become commonplace, but these options have limited the potential to further curb emissions. However, improvements in the quality of grazing plants, nutritional supplements, animal genetics, and pasture management can lead to emissions reductions of up to 20 percent from beef cattle.

19 Burning 1 ton of methane (equivalent to 21 tons of CO<sub>2</sub> if allowed to vent) yields only 2.75 tons of CO<sub>2</sub>. For more information on policy options for methane control in livestock operations, see "Air Emissions of Ammonia and Methane from Livestock Operations: Valuation and Policy Options," Shih, J.-S., D. Burtraw, K. Palmer, and J. Siikamäki. RFF Discussion Paper 06-11 (March 2006) at <http://www.rff.org/documents/RFF-DP-06-11.pdf>.

20 Some federal programs can also provide cost-share funding for methane digesters. Such programs include the Environmental Quality Incentives Program (EQIP), the Conservation Innovation Grants Program (CIG), and the Conservation Security Program (CSP) (NDESC 2005).

21 Shih, J.-S et al., note 22 above.

Activity	\$ per ton CO <sub>2</sub> equivalent				
	\$1	\$5	\$15	\$30	\$50
Afforestation	0	2	137	435	823
Forest Management	25	105	219	314	385
Agricultural Soil Carbon Sequestration	62	123	168	162	131
Fossil Fuel Mitigation in Crop Production	21	32	53	78	96
Agricultural CH <sub>4</sub> and N <sub>2</sub> O Mitigation	9	15	32	67	110
Biofuels Offsets	0	0	57	375	561
<b>All Activities</b>	<b>117</b>	<b>227</b>	<b>666</b>	<b>1,431</b>	<b>2,106</b>

options compare in total mitigation potential and cost. This question is addressed in a recent EPA analysis; Table 1 summarizes the results.<sup>22, 23</sup> Though this issue brief focuses on agriculture, we also present results for forestry-related activities to highlight the relative potential of alternative mitigation options.

The total potential and relative cost of different mitigation activities vary considerably. At a low carbon price (\$1–\$5 per ton of CO<sub>2</sub>), agricultural soil carbon sequestration is the dominant mitigation strategy. Another activity with considerable potential at low carbon prices involves managing forests for carbon sequestration. Afforestation (establishing trees on non-forested lands) and biofuels offsets (substituting biofuels for fossil fuels) offer only moderate mitigation potential at low carbon prices, but emerge as dominant mitigation activities once prices rise above \$30 per ton of CO<sub>2</sub>-equivalent. Measures to reduce fossil-fuel use for crop production and agricultural methane and nitrous oxide emissions provide moderate mitigation capacity at all carbon prices, but their overall emissions-reduction potential is relatively small.

22 "Greenhouse Gas Mitigation Potential in U.S. Forestry and Agriculture", United States Environmental Protection Agency, Office of Atmospheric Programs, Washington, DC, Report EPA 430-R-05-006, November 2005.

23 The results of the EPA-study are by and large consistent with other studies, which have examined the cost of carbon sequestration, including (i) Lewandrowski, J., M. Peters, C. Jones, R. House, M. Sperow, M. Eve, and K. Paustian (2004) "Economics of Sequestering Carbon in the U.S. Agricultural Sector," Washington, DC: U.S. Department of Agriculture, ERS; (ii) Sedjo, R., B. Sohngen, and R. Mendelsohn (2001) "Estimating Carbon Supply Curves for Global Forests and Other Land Uses," Discussion Paper 01-19, Resources for the Future, Washington, DC.; and (iii) Stavins, R. N. (1999) "The Costs of Carbon Sequestration: A Revealed-Preference Approach," *American Economic Review* 89(4): 994-1009.

Overall, agricultural and forestry activities offer substantial GHG mitigation potential. Even at low carbon prices—from \$1 to \$5 per ton CO<sub>2</sub>—these activities can provide annual net emission reductions ranging from 117 to 277 million metric tons CO<sub>2</sub>. The cost-effective potential for emission reductions increases with carbon prices, reaching more than 2,000 million metric tons CO<sub>2</sub>-equivalent emissions per year at a price of \$50 per ton CO<sub>2</sub>. To put these estimates into perspective, current U.S. GHG emissions total about 6,500 million metric tons CO<sub>2</sub>-equivalent per year.

The higher end of the carbon-price range shown in Table 1 is comparable to the range of global carbon prices thought to be necessary—based on current modeling analyses—to stabilize atmospheric CO<sub>2</sub> concentrations later this century. For example, it is estimated that stabilizing CO<sub>2</sub> concentrations in the 550 parts per million range will require carbon prices to reach \$5–\$30 per metric ton CO<sub>2</sub> by 2025, and about \$20–\$90 per metric ton by 2050.<sup>24</sup>

### Challenges

Agricultural emissions are unlikely to be included in binding programs to limit GHG emissions, such as a cap-and-trade program. Extending mandatory emissions-reduction requirements to agriculture would be hampered by several challenges. Agricultural GHG emissions are generally difficult to monitor and verify. Moreover, some types of mitigation—such as carbon sequestration through alternative soil management—may not be permanent.

Despite the likelihood that agriculture would be excluded from a mandatory regulatory program, the sector provides several potentially cost-effective opportunities for CO<sub>2</sub> offsets. Offsets, which are emissions credits generated by sources not covered under a cap-and-trade or other mandatory regulatory program, are attractive for their capacity to expand the pool of available, low-cost emissions-reduction options. However, many of the challenges associated with including agricultural sources in a mandatory regulatory program also apply to the measurement and verification of agricultural offsets. Common performance criteria for crediting offsets require that emissions reductions are real, additional, and permanent.<sup>25</sup> Each category of potential agricultural GHG-mitigation strategies faces difficulties in satisfying these criteria.

For example, the amount of carbon sequestered in agricultural soils is difficult to measure. Each soil type is different in its

capacity to absorb (or release) carbon, and different soils have different saturation points beyond which sequestering additional carbon is not possible or requires radical changes in land use (for example, afforestation). Carbon sequestration also raises questions about permanence; changes in soil management practices can quickly release the sequestered carbon back into the atmosphere. Leakage issues are also potentially difficult: if changing soil management practices to enhance sequestration in one field means that countervailing changes occur in another field, no net sequestration of carbon may result.

Similar challenges arise in the context of non-CO<sub>2</sub> agricultural emissions. For example, nitrous oxide emissions from agricultural soils are affected not only by soil management and fertilization, but also by natural processes—nitrification and denitrification—which can vary depending on the types of soils farmed and crops grown. Measuring changes in these emissions is therefore inherently difficult. Similar issues must be resolved when crediting offsets for methane control in manure management and livestock operations.

### Present programs and proposals related to agricultural offsets

Several emissions-trading markets with distinct policies regarding agricultural offsets currently exist or are in the process of being developed. For example, the European Climate Exchange excludes any offsets from agricultural sinks. The Chicago Climate Exchange, the only voluntary emissions trading market in North America, includes the National Farmer's Union Carbon Credit Program, which allows farmers to aggregate marketable carbon credits for carbon sequestering practices.<sup>26</sup> The Northeast and Mid-Atlantic states' Regional Greenhouse Gas Initiative (RGGI), a first mandatory cap-and-trade program to limit power-sector CO<sub>2</sub> emissions in the United States, includes credits for methane mitigation from manure management practices.<sup>27</sup> The California legislature is developing a statewide cap-and-trade system under Assembly Bill 32 (passed in 2007) but has not yet set up a framework for GHG offsets.

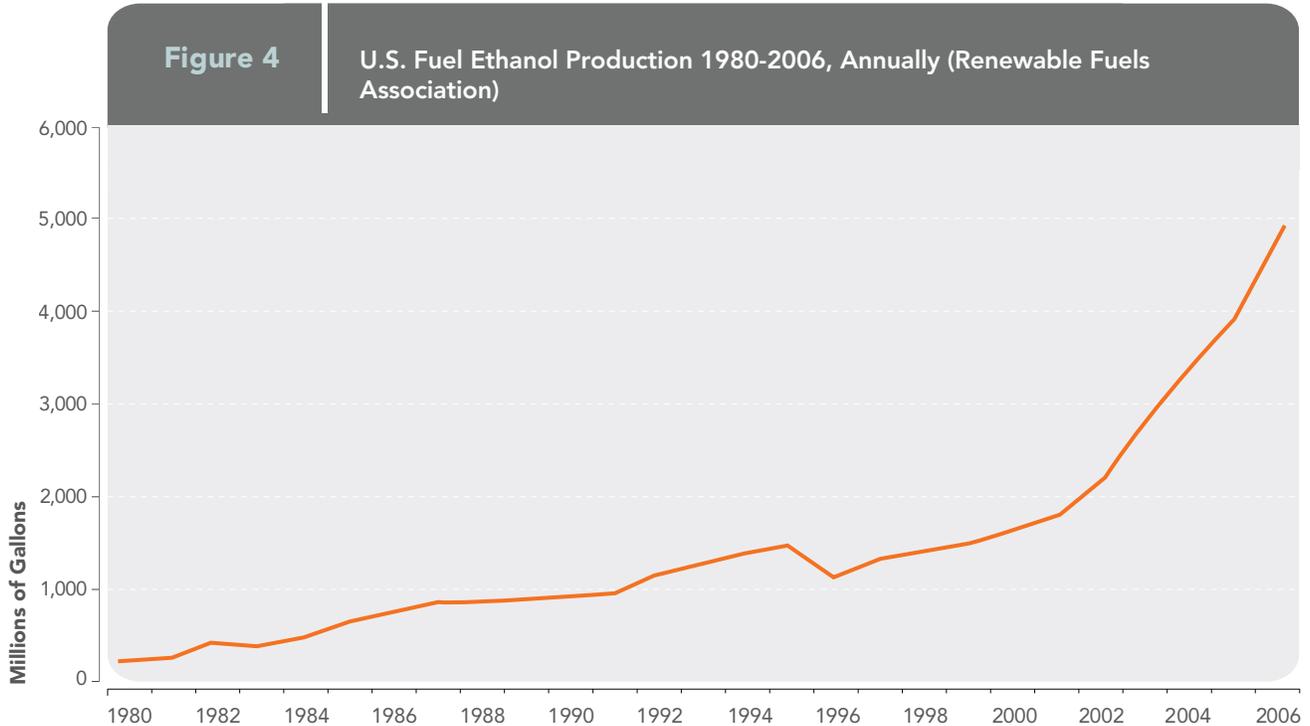
Some proposals for federal climate change legislation have included the agriculture sector. For example, the McCain-Lieberman "Climate Stewardship Act of 2005" and the Waxman "Safe Climate Act of 2006" both propose that emissions trading markets allow farmers to earn credits from

24 Recent studies of the carbon prices required for long-term stabilization of atmospheric CO<sub>2</sub> are summarized in Issue Brief #2 on stabilization scenarios.

25 For more discussion related to offsets, see Issue Brief #15.

26 National Farmer's Union, Carbon Credit Program, 2007 <http://www.nfu.org/issues/environment/carbon-credits/> (accessed July 12, 2007).

27 The Climate Trust, RGGI Eligible Sector 4: Avoided Methane Emissions from Agricultural Manure Management, 2007, [http://climatetrust.org/solicitations\\_RGGI3.php](http://climatetrust.org/solicitations_RGGI3.php) (accessed July 12, 2007).



carbon storage in agricultural soils.<sup>28</sup> However, the amount of offsets permitted in these bills is limited, and no federal legislation has considered credits from agricultural activities that mitigate nitrous oxide or methane emissions.

## Biofuels

U.S. production of ethanol has skyrocketed in recent years—approximately quadrupling since 2000/2001 (Figure 4)—and is poised to double again by the year 2008. According to the Renewable Fuels Association, nearly 130 ethanol biorefineries with total annual production capacity of 6.7 billion gallons nationwide were in operation as of late August 2007.<sup>29</sup> The nearly 80 additional biorefineries currently under construction are expected to approximately double present ethanol production capacity.<sup>30</sup> With the recent expansion of corn-based ethanol production, the United States has become the world's largest producer of ethanol, surpassing Brazil's sugarcane-based ethanol production.<sup>31</sup>

With more than 13 billion gallons of annual production capacity either already in operation or under construction, ethanol consumption in the United States is poised to far exceed the 7.5 billion gallon per year target established by the 2005 Renewable Fuels Standard (which calls for domestic renewable fuels to displace five percent of total U.S. gasoline demand by 2012).

Several factors have contributed to the rapid expansion of ethanol production in the United States. During the last year, relatively high oil prices combined with a 51-cent per gallon tax credit to make ethanol economically attractive; at the same time, demand for ethanol as a substitute for the fuel oxygenate MTBE was growing. More broadly, policymakers view increased use of biofuels as a means of enhancing America's energy security by reducing dependence on fossil fuels. Strongly increased demand for ethanol is almost fully supplied from domestic sources; overseas suppliers are deterred by a 54-cent per gallon tariff on ethanol imports.<sup>32</sup>

Corn prices roughly doubled during the last year, yet demand for corn remains strong.<sup>33</sup> U.S. producers have responded

<sup>28</sup> Evan Branosky, WRI Policy Note 1, World Resources Institute, 1–6, 2006.

<sup>29</sup> <http://www.ethanolrfa.org/industry/locations/>

<sup>30</sup> U.S. production of biodiesel—another principal biofuel and a substitute for diesel—is small relative to ethanol. In 2006, about 250 million gallons of biodiesel were produced in the United States.

<sup>31</sup> In 2006, the United States and Brazil produced more than 70% of world's total ethanol production (13.5 billion gallons). U.S. ethanol is corn based; Brazilian ethanol is derived from sugarcane.

<sup>32</sup> However, ethanol imports from designated Central American and Caribbean countries are duty-free for up to 7% of the U.S. ethanol markets.

<sup>33</sup> See, for example, A. Baker, and S. Zahniser, *Ethanol Reshapes the Corn Market*, *Amber Waves*, Vol. 4,

Corn-based ethanol reduces GHG emissions, but not necessarily by much. Researchers recently estimated that corn ethanol, produced using current technology, reduces GHG emissions on average by 19 percent for every gallon of gasoline displaced.

to these new market conditions surprisingly swiftly; the 2007 corn crop is the largest corn crop planted in more than 60 years.<sup>34</sup> In acreage planted, the 2007 crop—at 92.9 million acres—exceeds the 2006 crop by 19 percent. The increase in corn acreage has been offset by shifting land out of soybean production; soybean acreage declined 15 percent from 2006 to the 2007 total of 64.1 million acres.<sup>35</sup> The recent, dramatic increase in corn acreage has somewhat reduced corn futures prices, though futures prices continue to reflect expectations of strong demand growth going forward. Market adjustments to the rapid expansion of corn-based ethanol production also extend beyond corn itself, trickling through the entire U.S. agricultural and food sectors.

Given current average yields of about 2.8 gallons of ethanol per bushel of corn and 150–160 bushels of corn per acre, every additional billion gallons of ethanol production implies about 2.2–2.4 million acres of additional land devoted to corn. Thus, increasing corn-ethanol production by another 6 billion gallons per year implies an additional land requirement of 13–14 million acres. Farmers' response this year (nearly 15 million

additional acres of corn) seems to roughly uphold the current demand-supply balance. The fact that farmers are planting mostly bioengineered corn (a 12 percent increase from 2006) will also help supply keep pace with demand.

Replacing fossil fuels with corn-based ethanol reduces GHG emissions, but not necessarily by much. After thoroughly examining life-cycle GHG emissions for gasoline and ethanol, researchers at Argonne National Laboratory<sup>36</sup> recently estimated that corn ethanol, produced using current technology, reduces GHG emissions on average by 19 percent for every gallon of gasoline displaced.<sup>37</sup> The study highlights the importance—from the standpoint of GHG emissions—of the process fuel used in ethanol production. Ethanol produced at plants that are fueled by natural gas can achieve GHG reductions of 28–39 percent compared to gasoline. Switching from natural gas to coal as the process fuel, however, may completely eradicate the GHG reduction benefits of ethanol. Although most current ethanol plants run on natural gas, this finding is important because high natural gas prices are encouraging developers to opt for a coal-fueled ethanol production process at new plants. Other well-known, but perhaps less inclusive assessments have suggested yet lower GHG reductions from corn-based ethanol—around 7–12 percent relative to gasoline.<sup>38</sup>

Despite their slight differences, the results from available assessments all suggest that increasing corn-based ethanol usage to 12–14 billion gallons annually (enough to displace nearly 10 percent of U.S. gasoline demand) would reduce present GHG emissions only minimally—by merely a fraction of a percent. Until it becomes technologically and economically feasible to produce cellulosic ethanol, which has the potential to cut GHG emissions by 80–90 percent relative to gasoline, the current ethanol boom seems unlikely to provide significant climate benefits.<sup>39</sup>

Specific provisions in the new U.S. Department of Agriculture (USDA) 2007 Farm Bill proposal would support further expansion of the domestic biofuels industry, including a total of \$1.6 billion directed toward renewable energy and

Issue 2, 2006 (updated May 2007), <http://www.ers.usda.gov/AmberWaves/May07SpecialIssue/Features/Ethanol.htm>.

34 National Agricultural Statistics Service, "U.S. Farmers Plant Largest Corn Crop in 63 Years," News Release, June 29, 2007, Washington, DC: U.S. Department of Agriculture.

35 Soybeans and corn are often planted in rotation. Recent increases in corn acreage often involves farmers shifting from corn-soybean rotation to corn-corn-soybean rotation.

36 M. Wang et al., note 3 above.

37 Cellulosic ethanol would offer more significant GHG emission reductions (up to 80–90 percent, similar to GHG reductions from the sugarcane-based ethanol in Brazil), but cellulosic ethanol production is currently not economically feasible.

38 A. E. Farrell, R. J. Plevin, B. T. Turner, A. D. Jones, M. O'Hare, and D. M. Kammen, "Ethanol Can Contribute to Energy and Environmental Goals," *Science* 311 (27 January 2006): 506–508; and J. Hill, E. Nelson, D. Tilman, S. Polasky, and D. Tiffany, "Environmental, Economic, and Energetic Costs and Benefits of Biodiesel and Ethanol Biofuels," *Proceedings of the National Academy of Sciences* 103, no. 30 (July 25, 2006): 11206–11210.

39 Studies by M. Wang et al. (note 3 above) and Farrell et al. (note 41 above) also address the long-standing dispute about whether the fossil-energy balance of corn ethanol is positive—that is, whether the use of corn ethanol results in a net reduction of fossil-fuel use, taking into account upstream fossil-fuel inputs to grow, harvest, and process corn into ethanol. For example, Wang et al. find that all current and potential future ethanol production processes achieve a positive fossil-energy balance. The energy balance of gasoline, on the other hand, is negative. Farrell et al. reaches similar conclusions.

cellulosic ethanol projects. Other measures in the 2007 Farm Bill proposal include \$500 million for bioenergy and biofuel research, \$500 million to support rural renewable energy systems, and \$210 million to support loan guarantees for cellulosic ethanol projects.

From farmers' perspective, the effects of the ethanol boom are somewhat mixed. Crop producers benefit: high prices and increased demand for corn strengthen other crop prices and agricultural land values. Livestock producers, however, face increased feed prices. Distiller grains, a byproduct of ethanol production, can be used as feed for beef cattle, but poultry and pork production are especially affected by rising corn costs. Nevertheless, USDA expects overall farm incomes to remain strong, in large part due to corn-based ethanol. Higher commodity prices also reduce budget expenses for price-dependent Farm Bill programs and allow agricultural producers to rely on the market for a greater share of their income.

Consumer prices are not expected to be severely affected by the expansion of corn-based ethanol production. Higher feed costs are projected to increase consumer prices for poultry, eggs, and red meats; hence, overall production of these agricultural products may decline slightly. Overall, USDA projects that retail food prices will rise between 2008 and 2010 at a rate moderately faster than the general inflation rate. After these near-term price adjustments, however, consumer food prices are expected to rise more slowly than the general rate of inflation.<sup>40, 41</sup>

Notwithstanding the current boom, growth in the corn-ethanol industry is expected to slow down and then level off. Though annual ethanol production may soon exceed USDA's 10-year baseline projection of 12 billion gallons, long-term corn-ethanol production is not expected to rise beyond 15–20 billion gallons annually. At that level, land requirements for corn cultivation would approach 100 million acres, of which nearly half would be needed to supply corn for the ethanol industry.<sup>42</sup>

An important issue is how the ethanol and agricultural commodity markets will respond to production shortfalls due to weather, pests, and other factors. Ethanol production, which is on track to account for more than 30 percent of U.S. corn consumption in the near future, is less responsive

to the price of corn than other major markets (e.g. for feed uses and exports). As a result, overall demand for corn is likely to become less responsive to prices and larger price changes are likely to follow market adjustments in case of production shortfalls. These effects are magnified by a decline in corn stocks, which have diminished due to strong demand and currently provide only a limited buffer for potential supply shocks. Therefore, the agricultural sector is likely to experience higher overall prices and increased market volatility.<sup>43</sup>

Cellulosic ethanol, though not yet economically competitive, could substantially expand the potential of biofuels. For example, the "billion-ton" study by USDOE and USDA concluded that U.S. agricultural and forestry lands have the resource potential to produce more than one billion tons of biomass per year by the mid-21st century, assuming historically strong productivity improvements continue.<sup>44</sup> This represents potentially adequate feedstock to support 110 billions of gallons of cellulosic-ethanol production per year. Currently, the technical potential of agricultural biomass is about 194 million dry tons per year (enough to support 15 billion gallons of ethanol output). However, significant technological advances are needed to convert this technical potential to economically attractive production.

Finally, continued expansion of the biofuels industry and strong crop prices are bound to have a range of land-use consequences. For example, strong demand for corn has already raised concerns that environmentally sensitive lands in the Conservation Reserve Program (CRP)<sup>45</sup> will be returned to crop production. This, in turn, could have potentially adverse implications for soil conservation, carbon sequestration, and other environmental aspects of agriculture. Future expansion of cellulosic ethanol production may generate similar externalities, and may extend to forested areas.<sup>46</sup> On the other hand, crops such as alfalfa or switch grass, which require less intensive farming practices than corn and other cash crops, may provide feedstock for cellulosic ethanol production while also generating environmental benefits from, for example, reduced soil erosion.

43 Westcott, et al. note 44 above.

44 USDOE and USDA, "Biomass as a Feedstock for Bioenergy and Bioproducts Industry: The Technical Feasibility of a Billion-Ton Supply," U.S. Department of Energy and U.S. Department of Agriculture. Washington DC, April 2005.

45 The Conservation Reserve Program financially encourages farmers to convert highly erodible cropland or other environmentally sensitive land to vegetative cover, such as native grasses, trees, filterstrips, or riparian buffers. Farmers receive an annual rental payment for the term of the multi-year contract. CRP goals include reducing soil erosion, improving water quality, establishing wildlife habitat, and enhancing forest and wetland resources.

46 Sugar-based ethanol production in Brazil already has triggered concerns about increased deforestation. However, the productivity (gallons per acre) of Brazilian sugar-based ethanol production is high, and the acreage required for ethanol is lower than in the United States. Also, Amazonian rainforests, where deforestation is a major concern, are not fit for growing sugarcane. Therefore, ethanol-based deforestation, if any, would primarily be due to secondary effects such as overall increases in crop, feed, and land prices.

40 USDA Economic Research Service, *Agricultural Baseline Projections: U.S. Crops, 2007–2016*, Washington, DC: USDA, 2007.

41 Westcott, P. R. *Ethanol Expansion in the United States: How Will the Agricultural Sector Adjust?* USDA Economic Research Service, Washington, DC: USDA, 2007.

42 USDA Economic Research Service and The Office of Chief Economist, *An Analysis of the Effects of an Expansion in Biofuel Demand on U.S. Agriculture*. Washington DC: USDA May 2007.



**ISSUE BRIEF 14**

**MANDATORY REGULATION OF  
NONTRADITIONAL GREENHOUSE GASES:  
POLICY OPTIONS FOR INDUSTRIAL  
PROCESS EMISSIONS AND NON-CO<sub>2</sub> GASES**

**DANIEL S. HALL**

## MANDATORY REGULATION OF NON-TRADITIONAL GREENHOUSE GASES: POLICY OPTIONS FOR INDUSTRIAL PROCESS EMISSIONS AND NON-CO<sub>2</sub> GASES

Daniel S. Hall

### SUMMARY

Traditional economic theory suggests that the most efficient and least-cost approach for regulating greenhouse gas (GHG) emissions will be as broad as possible—covering as many emissions from as many sources as possible under a single pricing policy designed to elicit the cheapest abatement options. Applying this concept is relatively straightforward for the dominant GHG, carbon dioxide (CO<sub>2</sub>). CO<sub>2</sub> emissions from the use of fossil fuels account for around 80 percent of U.S. GHG emissions<sup>1</sup> and are well-suited to regulation through either an emissions tax or cap-and-trade program.<sup>2</sup> A wide variety of other emissions sources and gases account for the other approximately 20 percent of U.S. GHG emissions.<sup>3</sup> Some of the cheapest mitigation options are likely to involve these “non-traditional” GHGs,<sup>4</sup> making it desirable to include them in a regulatory program. Given the diversity of activities and sources that give rise to these emissions, however, creative policy approaches may be needed to effectively tap associated abatement opportunities.

This issue brief surveys options for regulating

those non-traditional GHG emissions that lend themselves most readily to a mandatory approach, including methane emissions from coal mines, nitrous oxide and process CO<sub>2</sub> emissions from large stationary sources, and emissions of high global-warming potential (GWP) fluorinated gases. Together this group of emissions and sources accounted for about 5.5 percent of the overall U.S. GHG inventory in 2005. As discussed in more detail in Issue Brief #1, many other non-traditional GHG emissions originate from fugitive sources that would be difficult to include in a mandatory program. These emissions are likely best addressed through a project-based program to recognize offset activities as part of a broader tax or cap-and-trade program.<sup>5</sup>

Among the gases covered in this issue brief as potential candidates for inclusion in a mandatory program, some could be integrated relatively easily in a cap-and-trade (or tax) program; others could be included, but special considerations or provisions may need to apply; and others still may need to be addressed through sector-specific policies or through efficiency or technology standards.

- The fluorinated gases could be included in a mandatory program by regulating production sources rather than actual emissions, which are widely dispersed and difficult to measure. The number of entities

1 All emissions data in this issue brief are from 2005 and are taken from a report issued by the U.S. Environmental Protection Agency. U.S. EPA, 2007. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005*, EPA 430-R-07-002, EPA: Washington, DC. Available at <http://epa.gov/climatechange/emissions/usinventoryreport.html> Accessed August 21, 2007. Fossil fuel combustion accounted for 79 percent of U.S. GHG emissions in 2005; the non-energy use of fossil fuels—as lubricants or feedstocks, for example—accounted for another 2 percent.

2 See Issue Brief #5 on taxes, trading schemes, and standards for further discussion of these regulatory approaches.

3 See Issue Brief #1 on U.S. GHG emissions for a detailed breakdown of these emissions.

4 For example, an EIA analysis from March 2006 that considered a range of cap-and-trade proposals found that with modest near-term GHG permit prices (\$8 to \$24 (2004 dollars) per metric ton of CO<sub>2</sub>e in 2020), reductions in other GHGs (i.e., those besides energy-related CO<sub>2</sub>) would account for 25–55 percent of total emissions reductions in 2020, despite composing only about 6 percent of regulated emissions in the reference scenario. (EIA, 2006. *Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals*, SR/OAIF/2006-01, EIA: Washington, DC.)

5 Offset programs are discussed in Issue Brief #15. Such programs could be used to recognize GHG reductions that involve fugitive emissions, such as methane and nitrous oxide emissions from agricultural activities (over 7 percent of U.S. emissions) and from landfill and wastewater treatment (over 2 percent). (See Issue Brief #13 for further information on specific GHG-reduction opportunities in the agricultural sector.) Some non-traditional GHG emissions may be difficult to regulate under any policy, such as methane emitted during the transmission, storage, and distribution of natural gas (around 1 percent of U.S. GHG emissions) or nitrous oxide from mobile combustion (around 0.5 percent of U.S. GHG emissions).

engaged in producing or importing these gases, however, is comparatively small. Fluorinated gases could be included in an economy-wide tax or cap-and-trade program; alternatively, they could be addressed in a separate, stand-alone cap-and-trade (or price-based) program.

- Industrial process emissions from large stationary point sources—where measurement is straightforward—can generally be included in broad tax or cap-and-trade programs. This category of emissions includes process-related CO<sub>2</sub> emissions from industrial sources and nitrous oxide (N<sub>2</sub>O) emissions from stationary combustion and nitric and adipic acid production.
- Methane (CH<sub>4</sub>) emissions from underground coal mines could generally be included in broad tax or cap-and-trade programs, as methane is typically vented from underground mines at a limited number of defined points. By contrast, methane emissions from surface coal mines, which occur as the coal is exposed, and from abandoned mines are fugitive in nature and probably could not be included in a mandatory price-based program. These emissions would likely be best addressed through offset programs.

Remaining sections of this issue brief describe major sources of emissions in each of these categories and outline potential policy options for addressing them.

## Fluorinated Gas Emissions

The fluorinated gases—also frequently called the high global-warming potential (GWP)<sup>6</sup> gases—include three of the six traditional major GHGs: hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF<sub>6</sub>).<sup>7</sup> They currently account for around 2.2 percent of total U.S. GHG emissions. Their share of total U.S. emissions has grown over the last several years, a trend that is projected to continue in the near future.<sup>8</sup> The vast majority of fluorinated-gas emissions originate from widely dispersed end-use activities—frequently

as fugitive emissions or leaks—rather than from large point sources. This implies that regulating the original production sources for these chemicals—a relatively small number of entities—is likely to be the only practical approach to including them in a mandatory policy.<sup>9</sup>

Among the fluorinated gases, HFCs are most commonly used as refrigerants—in mobile and stationary air conditioning or commercial refrigeration systems, for example. They are also used as fire suppressants and as blowing agents in foam production. The majority of emissions come from leaks in air conditioning and refrigeration units. PFCs are used in semiconductor production; they are also associated with aluminum production. SF<sub>6</sub> serves as an insulator and interrupter in equipment that transmits and distributes electricity, and it is also used in magnesium production. Most SF<sub>6</sub> emissions are fugitive releases, such as leaks from gas-insulated electrical substations through equipment seals or releases during servicing or disposal activities. As noted previously, the major proposals for addressing these fluorinated-gas emissions involve regulating production, either by including production sources in an economywide pricing policy, by establishing a separate cap-and-trade system for these emissions, or by utilizing a deposit-refund approach. Each of these options is discussed at greater length below.

### Include fluorinated-gas production sources and imports in an economywide cap-and-trade (or tax) program

Many cap-and-trade proposals currently under discussion would include the high GWP gases from all production and import sources (including gases embedded in imported goods).<sup>10</sup> Producers and importers would be required to submit allowances (on a CO<sub>2</sub>-equivalent basis) for HFCs, PFCs, and SF<sub>6</sub>. To provide incentives for recovering and recycling or destroying these gases, entities would be awarded allowances (or offset credits) for capturing and destroying existing stocks of these chemicals. This approach would have several benefits: it would make higher GWP products relatively more expensive<sup>11</sup> than alternatives with lower GWPs, driving the

6 Global warming potentials (GWPs) are factors that are used to calculate CO<sub>2</sub> equivalent units so as to facilitate comparisons between various GHGs based on the warming impact (radiative forcing) different gases have once in the atmosphere. The GWP of a gas depends on the strength of its warming effect and its lifetime in the atmosphere. HFCs and PFCs all have potent warming effects and many have long lifetimes, resulting in GWPs that range from more than 100 times that of CO<sub>2</sub>, to more than 10,000 times greater over a 100-year period (with the most commonly used gases having GWPs ranging from 1,300 to 4,000). (IPCC/TEAP, 2005. *IPCC/TEAP Special Report: Safeguarding the Ozone Layer and the Climate System: Issues Related to Hydrofluorocarbons and Perfluorocarbons, Summary for Policymakers*, Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.) SF<sub>6</sub> is the most potent GHG covered by the Kyoto Protocol, with a 100-year GWP of 23,900.

7 These are the six gases listed in the Kyoto Protocol.

8 Both recent emissions growth and future growth projections are driven primarily by the substitution of these gases into a variety of applications, rather than from increased demand for refrigeration and other end-use activities. Specifically, HFCs and PFCs are being used to replace ozone-depleting substances, such as CFCs, HCFCs, and halons, as these are phased out under the Montreal Protocol. For further information on projected emissions see U.S. EPA, 2006. *Global Anthropogenic Non-CO<sub>2</sub> Greenhouse Gas Emissions: 1990-2020*. USEPA: Washington, DC. Available at <http://www.epa.gov/nonco2/econ-inv/international.html> Accessed September 18, 2007.

9 The one notable exception involves emissions of HFC-23 from production point sources during the manufacture of HCFC-22; this source accounts for about 10 percent of fluorinated gas emissions in the U.S. These emissions would presumably be included in the regulatory program “at the smokestack” in the manner of traditional air pollutants.

10 Because emissions of high GWP gases are associated with their use (instead of production) it is vital to include all import sources, including the high GWP gases embedded in imported goods. Failure to include imports would create a large potential source of emissions leakage. For examples of current proposals see the Lieberman-McCain “Climate Stewardship and Innovation Act of 2007” (S. 280) or the Bingaman-Specter “Low Carbon Economy Act of 2007” (S. 1766). The Bingaman-Specter legislation explicitly includes the high GWP gases in imported products (e.g., window air conditioning units).

11 A simple calculation helps to provide a rough sense of the scale of the price incentive created by the inclusion of high GWP gases in a cap-and-trade program. Suppose the price for a metric ton of CO<sub>2</sub> emissions is \$10. (This would translate into approximately 10 cents per gallon of gasoline.) One of the most commonly used refrigerants, HFC-134a—which has a relatively low GWP (for a fluorinated gas) of 1300—would therefore have an extra price of \$13,000 per metric ton, or just under \$6 per pound. Assuming that a vehicle air-conditioning unit holds around 2 pounds of refrigerant, there would be around \$12 of value in completely capturing the evacuated refrigerant when the system was recharged. Incentives would be proportionally larger for higher GWP gases and higher CO<sub>2</sub> prices.

near-term adoption of more climate-friendly substitutes in applications where fluorinated gases are currently used. Industry would also face incentives to innovate in developing new chemicals that could perform the same functions with less warming impact. A price signal would also reward owners of more efficient equipment, such as air conditioners, and would encourage the adoption of increasingly efficient units. As already noted, incentives would also exist for the collection and recycling or destruction of existing stocks.<sup>12</sup> Both this approach and the next—creating a separate cap-and-trade system for only high GWP gases—have been suggested by a major producer of refrigerants as possible approaches for regulating this category of emissions.<sup>13</sup>

Because the fluorinated gases have such high GWPs, a potential downside to including them in an economywide approach is that relatively modest prices for CO<sub>2</sub> emissions could produce big changes in the cost of these chemicals.<sup>11</sup> In response, users might shift to alternative materials that generate other health or environmental risks (for example, the use of ammonia as a refrigerant).<sup>14</sup> There is also concern that a particularly sudden increase in prices might unnecessarily burden both producers and end users. A more gradual change in price would give producers time to create lower-GWP alternatives and give consumers time to acquire new equipment that uses lower-GWP alternatives, uses existing gases more efficiently, or is less prone to leakage.<sup>15</sup> Under a cap-and-trade system, allowance allocation could be used to ameliorate potential price shocks by awarding free allowances to the producers of fluorinated gases using an updating output-based approach, although this would tend to reduce overall program efficiency.<sup>16</sup>

12 This approach would also provide regulators with a potential avenue for addressing existing stocks of hydrochlorofluorocarbons (HCFCs), which currently exist in a kind of regulatory limbo between the Montreal and Kyoto Protocols. HCFCs are now being used as replacements for chlorofluorocarbons (CFCs) and other halons under the Montreal Protocol because they have less impact on stratospheric ozone. They are still ozone-depleting substances, however, and their production is being phased out under the Montreal Protocol. They are also—like other fluorinated gases—potent greenhouse gases, but because they were already regulated under the Montreal Protocol they were not included in the Kyoto Protocol. The former agreement, however, regulates the production of ozone depleting substances, whereas the Kyoto Protocol is focused on emissions of GHGs. This means that HCFCs produced legally under the Montreal Protocol are otherwise unregulated. While there is little HCFC production in the United States that results in emissions—the bulk of U.S. production is for chemical feedstocks to make materials such as Teflon(RT)—the United States does import HCFCs in ready-to-use equipment such as window air conditioning units. Further, there are existing stocks of HCFCs in older equipment. All major Congressional proposals for comprehensive mandatory climate legislation to this point have focused on the six Kyoto Protocol gases; none have included other gases (whether HCFCs or others). By allowing existing stocks of HCFCs to qualify for project-based credits—while leaving the Montreal Protocol to address HCFC production—regulators could provide incentives for collecting and destroying HCFC stocks, to the benefit of both the ozone layer and the climate.

13 Testimony of Mack McFarland, Committee on Oversight and Government Reform, U.S. House of Representatives, May 23, 2007.

14 Note that an economy-wide policy would capture all potential trade-offs in terms of climate benefit. For example, switching to refrigerants with lower GWPs would be beneficial, on the one hand, but could also reduce the efficiency of refrigerant-using equipment, such as air conditioners. The result could be an increase in energy use and CO<sub>2</sub> emissions that would offset some of the benefits from switching refrigerants. A broad cap-and-trade or tax policy with a single emissions price will efficiently balance these emissions trade-offs. Other non-climate externalities that might be associated with switching to lower-GWP products, however, will not be captured by a climate policy (economy-wide or otherwise); correcting these externalities requires other, appropriately targeted health, safety, or environmental regulations, or other policies.

15 The situation is analogous to having an initially modest CO<sub>2</sub> price that rises through time in order to avoid prematurely retiring existing capital while providing incentives for investment in less emitting technologies when it is replaced.

16 Updating, output-based allocations can reduce product prices because they reward producers with valuable emissions allowances for each additional unit of output. Producers thus face incentives to boost output, which lowers product prices. Updating, output-based allocations entail efficiency costs because, by

### Create a separate cap-and-trade program

Another possible approach would be to create a separate, stand-alone cap-and-trade program explicitly for the high GWP gases. This would work in a nearly identical fashion to the first approach, but it would offer the option of applying a different price to fluorinated-gas emissions (and thereby addressing the cost concerns noted above).<sup>17</sup> The chief disadvantage of this approach is that it produces a less efficient (and hence more costly) policy overall. Two programs with separate prices imply that society is paying more to achieve reductions in one sector than in another sector, even when those reductions achieve the same environmental benefit. Other disadvantages are more political: once one sector receives a special carve-out, others may line up for theirs. If separate treatment of the fluorinated gases begins to undermine a unified, economywide approach, policy costs and efficiency losses would rise further. In addition, the potential for disruptive levels of price volatility rises under smaller, separate trading programs. Finally, all of these disadvantages also extend into the future: a lower near-term price for fluorinated-gas emissions—one designed to avoid hardship—would also lower the effective incentives for innovation to develop alternative chemicals. To help address some of these disadvantages while still attending to short-term price concerns, one might design a separate program for fluorinated gases such that it gradually converges to, and eventually links with, an economywide policy. In summary, the overall economic cost and political difficulties of a separate cap must be weighed against society's interest in tailoring regulation and managing price increases in this sector.

### Use a deposit-refund approach

A third regulatory option would be to institute a deposit-refund program in which an up-front fee is charged for the production (or initial purchase) of fluorinated gases that is refunded when the gases are later captured and destroyed. This would be similar to a separate cap-and-trade program for only the high GWP gases, except that it fixes the price rather than the quantity of emissions allowed—indeed, it would be effectively identical to an emissions tax on these gases. By setting the fee and rebate amount, policymakers could make a direct decision about the level of cost that would be imposed on users of these gases. As with a separate cap-and-trade program, however, this approach would still have

lowering output prices, they diminish incentives for end-use demand reductions. Potentially this allocation approach could be adopted initially to manage short-term price impacts and then be phased out over time in favor of allocation methodologies that do not entail similar efficiency losses. Policymakers will have to decide how to balance the trade-off between reducing sudden price impacts on fluorinated gases and sacrificing some program efficiency. See Issue Brief #6 for further discussion of these and other issues related to allowance allocation.

17 A similar cap-and-trade system is currently in place for manufacturers of ozone-depleting substances under Title VI of the Clean Air Act. See <http://www.epa.gov/Ozone/title6/phaseout/index.html> Accessed September 19, 2007.

the disadvantage that it forecloses the opportunity to make cost trade-offs with reductions in other sectors—with resulting efficiency losses for the overall policy and higher costs for society as a whole.

## Nitrous Oxide and Process-related CO<sub>2</sub> Emissions From Large Stationary Sources

Several industrial processes emit non-traditional GHGs—particularly nitrous oxide and CO<sub>2</sub> process emissions—at large stationary sources. Process-related CO<sub>2</sub> emissions from industrial sources are separate from (and occur in addition to) the CO<sub>2</sub> emissions associated with fossil-fuel use. For example, cement production begins by heating limestone—calcium carbonate (CaCO<sub>3</sub>)—to produce lime and CO<sub>2</sub> (the lime goes on to form the primary ingredient in cement). Iron is produced by reducing iron ore in a blast furnace with metallurgical coke, a process that emits CO<sub>2</sub>. Other CO<sub>2</sub>-emitting industrial processes include ammonia production, lime production (for uses besides cement), and the production of various metals, including aluminum, zinc, and lead.<sup>18</sup> Industrial process-CO<sub>2</sub> emissions represent about 2 percent of total U.S. GHG emissions, with iron and steel production and cement manufacture accounting for the majority of these emissions.

Nitrous oxide (N<sub>2</sub>O) emissions from stationary sources in the United States come primarily from the production of nitric and adipic acids and from combustion sources.<sup>19</sup> Nitric acid production plants use either non-selective catalytic reduction or selective-catalytic reduction to control emissions of nitrogen oxides (NO<sub>x</sub>), a criteria air pollutant regulated under the Clean Air Act. In addition to controlling NO<sub>x</sub> emissions, non-selective catalytic reduction units are also effective at controlling nitrous oxide emissions but are used in only about 20 percent of plants because of their high energy costs.<sup>20</sup> The other significant stationary sources of nitrous oxide are adipic acid production facilities and large combustion point sources, primarily electric power generation units. Nitrous oxide emissions from adipic acid production can be controlled using conventional pollution control technology.<sup>21</sup> Emissions from stationary combustion are influenced by air-

fuel mixtures, combustion temperatures, and the pollution control equipment employed. Altogether stationary sources of nitrous oxide emissions account for about 0.5 percent of total U.S. GHG emissions. Two primary options for regulating these emissions include covering them under a broad pricing program or mandating a particular control technology or performance standard. Each is discussed below.

### Include industrial N<sub>2</sub>O and process CO<sub>2</sub> emissions in an economywide cap-and-trade (or tax) program

Including nitrous oxide and process-CO<sub>2</sub> emissions from industrial sources in a cap-and-trade program should be straightforward given the relative ease of measuring emissions “at the smokestack.” This approach would allow producers to weigh the relative costs of emissions allowances against the costs of installing and operating new control technology or improving process efficiency to reduce emissions. The price signal generated by inclusion in a cap-and-trade system would also provide incentives for research into improved control devices—such as catalysts for N<sub>2</sub>O—and alternative production processes that are less emissions-intensive.<sup>22</sup> Many of these stationary-source emissions are covered in current GHG regulatory proposals. For example, almost all legislative proposals to date have covered the electric power sector (which includes stationary combustion sources of N<sub>2</sub>O) and most economywide approaches include emissions from nitric and adipic acid production.

### Use control technology mandates or efficiency and performance standards

In the case of many stationary sources—nitric and adipic acid production, for example—known technologies exist for controlling GHG emissions. Thus another regulatory option for these sources would be to simply mandate the use of certain control technologies. However, this approach would likely involve large capital expenses for some industries—for example, almost all nitric acid plants built since the late 1970s have been designed to operate with selective catalytic-reduction units because of lower operating costs and these plants would be forced to redesign their processes to operate with new emissions controls. Further, a technology mandate would not provide the same incentives for research and development to continue improving emissions performance. Some firms have called for performance or efficiency standards to be used to control process-CO<sub>2</sub> emissions rather than including these emissions in a cap-and-trade program, arguing this approach would provide a greater level of cost

18 U.S. EPA, 2007. Chapter 4, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2005*, EPA 430-R-07-002, EPA: Washington, DC.

19 The overwhelming source of U.S. anthropogenic N<sub>2</sub>O emissions—more than three-fourths of the total—is agricultural soil management. The stationary sources discussed here account for about 8 percent of U.S. N<sub>2</sub>O emissions.

20 U.S. Climate Change Technology Program, 2005. *Technology Options for the Near and Long Term*, Section 4.4.1. Available at <http://www.climatechange.gov/library/2005/tech-options/index.htm> Accessed August 21, 2007.

21 U.S. EPA, 2007. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2005*, Section 4.16, EPA 430-R-07-002, EPA: Washington, DC.

22 For example, one technology under development is a cokeless iron-making process. U.S. Climate Change Technology Program, 2005. *Technology Options for the Near and Long Term*, Section 1.4.3. Available at <http://www.climatechange.gov/library/2005/tech-options/index.htm> Accessed August 30, 2007.

certainty for affected firms.<sup>23</sup> While an appropriately designed efficiency or emissions performance standard might be more flexible and efficient than mandating the use of particular control technologies, it remains less efficient than inclusion in a broader market-based policy and still has drawbacks in terms of creating incentives for continuous improvement.

## Methane Emissions From Coal Mines

Methane (CH<sub>4</sub>) emissions from coal mines account for about 0.8 percent of U.S. GHG emissions. As coal is mined, methane trapped in coal seams or in surrounding strata is released. The majority of coal-mine methane emissions (over 60 percent) comes from underground mines, where greater geologic pressure creates and traps larger volumes of this gas. Methane emissions from surface mines are much smaller; they cannot be captured and escape as fugitive emissions into the atmosphere. Small amounts of fugitive emissions are also released from abandoned mines and during post-mining activities including coal processing, storage, and transport.

Methane in underground mines poses a hazard to mine workers, and so has to be extracted or ventilated for safety reasons. Methane is typically liberated from underground coal seams in one of three ways: pre-mine drainage wells, gob wells, or mine-ventilation air systems.<sup>24</sup> Pre-mine drainage wells are drilled months or years prior to mining and extract a highly-concentrated gas (typically over 95 percent methane) that can be sold for commercial distribution to natural gas pipelines or used onsite for heat or power. Most methane from pre-mine drainage wells is thus not emitted to atmosphere. Gob wells exhaust methane released in the fractured rubble zone, called the “gob” area, that forms as the coal seam is mined and the surrounding strata collapse. Because methane concentrations in the gob area are still relatively high (30–90 percent), it is sometimes used onsite or enriched for sale to pipelines, but is also frequently vented to the atmosphere. Finally, mine-ventilation air systems ensure that methane concentrations in the mine are at safe levels. The concentration of methane in ventilated air is too low—below 1 percent—to allow for economic recovery and use in most cases. Therefore, the gas is usually vented.<sup>25</sup> Options for taking advantage of GHG-abatement opportunities

associated with coal-mine methane emissions include directly including these emissions, where possible, under a broader cap-and-trade program; covering these emissions through an offsets program; and a combination of both. Each is discussed below.

### **Include coal-mine methane in an economywide cap-and-trade (or tax) program**

Some proposals have called for coal-mine methane emissions to be directly included in a broader GHG cap-and-trade program. This would be relatively straightforward for emissions from underground mines, as these are captured by active degasification or ventilation systems that can be monitored with relative ease.<sup>26</sup> Inclusion in a broader pricing policy would create incentives for mine owners to recover and use captured methane, reinforcing an existing trend that has seen the amount of methane recovered and used by mines more than double since 1990 (as a result, total methane emissions from underground mines have declined over the last two decades).<sup>27</sup> This approach would be hard to apply, however, to the remaining 40 percent of coal-mine methane emissions from surface mines, abandoned mines, and post-mining activities, where monitoring emissions is far more difficult.

### **Include coal mine methane in an offset program**

Given the difficulties of regulating coal-mine methane directly, it may be easier to include these emissions in a broader policy *indirectly*, via an offsets program. Mine operators (or other project developers) could conduct activities to reduce emissions that would let them earn emissions credits on a project basis. These activities would be voluntary and would occur in response to the financial incentives generated by the allowance market (under a cap-and-trade system) or by the potential for tax rebates (under an emissions tax system).

### **Adopt a hybrid approach**

A third alternative is to adopt a hybrid approach, in which emissions from underground mines are directly included in the cap (meaning that mine owners would need to submit allowances for these emissions), while emissions from surface or abandoned mines, or from fugitive sources, would be addressed through an offsets program. Although technically feasible, adopting different modes of regulation for portions of the mining industry seems likely to be politically contentious.

23 For example, the cement industry in California is urging regulators to employ “Japan-style” energy efficiency requirements rather than including cement producers in a state-wide cap-and-trade program created to implement Assembly Bill 32. G. Hyatt, 2007. “Cement Makers Back Energy Efficient Rule Over Carbon Cap-And-Trade”, *Carbon Control News*, Vol. 1, No. 25, July 2, 2007.

24 Further information on methane from underground coal mines can be obtained from the U.S. EPA Coalbed Methane Outreach Program (<http://www.epa.gov/cmop/index.html>). Specific information on the types of wells used to extract methane came from U.S. EPA, 2005. *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003* EPA 430-K-04-003. EPA: Washington, DC.

25 U.S. Climate Change Technology Program, 2005. *Technology Options for the Near and Long Term*, Section 4.1.4. Available at <http://www.climatechange.gov/library/2005/tech-options/index.htm> Accessed August 21, 2007.

26 In some cases emissions are already monitored; for example, the Mine Safety and Health Administration maintains a database of methane emissions from ventilation air.

27 U.S. EPA, 2007. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2005*, Section 4.16, EPA 430-R-07-002, EPA: Washington, DC.



**ISSUE BRIEF 15**

**OFFSETS: INCENTIVIZING  
REDUCTIONS WHILE  
MANAGING UNCERTAINTY  
AND ENSURING INTEGRITY**

DANIEL S. HALL

## OFFSETS: INCENTIVIZING REDUCTIONS WHILE MANAGING UNCERTAINTY AND ENSURING INTEGRITY

Daniel S. Hall

### Summary

Most market-based regulatory proposals to limit greenhouse gas (GHG) emissions include provisions that allow market participants to seek reductions outside the regulated system. These reductions are typically referred to as offsets. Offsets are attractive because they can expand the available pool of low-cost reduction options, particularly in the near future. Many potential offset projects, however, present challenges because the emissions reductions they generate are difficult to measure or carry risks of impermanence. How can an offset program be designed to incentivize reductions while also ensuring their integrity?

- This memo briefly describes what offsets are, which sectors they are in, and how they have been used in other regulatory programs. We then discuss policy design features and options for addressing risks and uncertainties associated with low-quality offsets. In broad terms, the results of this exploration suggest that an offset program can be used to generate incentives for reductions that would be difficult to motivate or mandate in other ways, but creative approaches will be needed to manage offsets with uncertain environmental benefits.
- Offsets should be real, additional (beyond what would have happened anyway), permanent, and verifiable. These are the commonly accepted criteria for determining the quality and eligibility of offset projects.
- Offsets can be used to achieve emissions reductions in some sectors and for some activities that are difficult to regulate directly. Examples include biological sequestration of carbon; destruction of fugitive methane emissions from sources such as landfills or coal mines; or changes in agricultural soil management practices to reduce nitrous oxide emissions. Offsets can also enhance the dissemination of advanced technologies for reducing carbon dioxide (CO<sub>2</sub>) emissions, particularly in developing countries.
- There is a fundamental tension between generating a large supply of low-cost offsets and ensuring they are high quality. Broadly speaking, two approaches can be used to mitigate—but not eliminate—this tension. The first is to simplify registration and crediting procedures for offset projects that generate emissions reductions which can be verified with a high degree of confidence. The second, complementary approach is to design offset programs that limit the consequences of potentially over-crediting projects in cases where the environmental benefits are less certain. Policymakers will have to decide how to balance trade-offs between minimizing transaction costs and ensuring the environmental integrity of offsets.
- Mechanisms that can minimize the administrative complexity and cost of offset programs include two-step registration procedures that determine project eligibility before developers commence projects, positive lists of pre-approved

offset project types, and tiered systems that use defined crediting levels for different types of projects.

- Policies to address projects with uncertain environmental benefits include credit limits and set-asides that specify a maximum aggregate level of offsetting reductions that can be used for compliance. These effectively place an upper bound on the risk from uncertain or difficult-to-verify projects. Non-uniform crediting can be used to discount certain project types, presumably on a risk basis. Rental credits can be used to limit exposure to offsets from projects that may not produce permanent emissions reductions.
- Policy choices for offset programs must be evaluated holistically. In designing such programs, policymakers should decide first what the overarching goal of the offset program is: generating the maximum number of offsets, minimizing transaction costs for project developers, ensuring environmental benefits, or some combination of these objectives. Designing an offset program will entail making choices about which suite of policy tools will function together to accomplish the goal.

## What Are Offsets?

Offsets do what their name implies: they allow emissions reductions outside of a regulated system to 'off-set' emissions-reduction requirements inside the system.<sup>1</sup> The use of offsetting reductions is not required by law; rather, regulations set rules for which emissions-reduction activities can qualify as offsets. Private agents are motivated to pursue these offsets by their value as an alternative compliance option within the regulated system. Under a cap-and-trade program with offsets, for example, regulated entities could have four compliance options: (1) reducing emissions, (2) buying emissions allowances, (3) purchasing offset credits from unregulated entities that have reduced emissions, or (4) undertaking emissions-reduction projects that qualify as offsets within unregulated portions of their own operations.<sup>2</sup>

Although most commonly associated with cap-and-trade proposals, offsets can also be used under a mandatory

<sup>1</sup> In addition to regulatory offsets, there are voluntary or "retail" offsets. These are typically marketed to individual consumers and public awareness of their existence has been increasing. (Witness the New Oxford American Dictionary's selection of the term "Carbon Neutral" as the 2006 Word of the Year.) The voluntary market has grown significantly in the last three years, but remains a small part of the overall market. According to a World Bank report on the carbon market (K. Capoor and P. Ambrosi, 2007. *State and Trends of the Carbon Market 2007*, World Bank: Washington, DC.), compliance offsets—those used to meet regulatory requirements—accounted for more than 98 percent of the transactions in offset markets in both 2005 and 2006. This paper focuses on compliance offsets.

<sup>2</sup> This last option would be particularly pertinent for multinational companies whose operations were regulated in some countries but not in others.

## Offsets come with a fundamental tension: how can the quality of offsets be assured at a low cost?

emission tax as a way to offset the tax. Offset credits would reduce the tax liability of sources (as well as tax revenues to the government).

Offsets can be a valuable addition to regulatory programs because they expand the available pool of emissions reductions, presumably to include more low-cost options in sectors of the economy that are not regulated or across a wider geographical area. In other words, incorporating offsets can reduce the cost of meeting a given emissions target, make a more stringent target achievable at the same cost, or some combination of both (that is, reduce costs *and* allow for a more stringent target). By increasing the supply of available allowances, offsets can also increase the liquidity and flexibility of allowance markets, and reduce price volatility.

Offsets come with a fundamental tension, however: How can the quality of offsets be assured at a low cost? Performance criteria commonly applied to offsets require that emissions reductions are real, additional, and permanent. That is, offsets should be credited only to activities that actually reduce emissions, are additional to what would have happened anyway,<sup>3</sup> and do not merely shift emissions to another time or place. Ensuring that this is the case requires measurement, monitoring, and verification procedures. Ideally, such procedures would verify high-quality offsets while remaining transparent, streamlined, and administratively simple. In reality, there are trade-offs between ensuring environmental integrity and minimizing transaction costs.

<sup>3</sup> Additionality can be a challenging concept to define and establish, particularly since it is hard to know what would have happened in a "business-as-usual" world where there was not an incentive to generate offsets. The Clean Development Mechanism (CDM) of the Kyoto Protocol, an offset program discussed at length in the text box in this issue brief, has established a methodology for demonstrating additionality. It requires projects to show that some barrier to emissions reductions exists, that the project would not occur without CDM investment, and that the activity is not already a common practice. Source: CDM – Executive Board, "Combined tool to identify the baseline scenario and demonstrate additionality" Version 02.1. Available at [http://cdm.unfccc.int/methodologies/Tools/EB28\\_repan14\\_Combined\\_tool\\_rev\\_2.1.pdf](http://cdm.unfccc.int/methodologies/Tools/EB28_repan14_Combined_tool_rev_2.1.pdf) Accessed September 10, 2007.

## Where Will Offsets Come From?

This section explores potential types of offset projects. What are some key sectors for offsets? What types of offset projects might be undertaken? What implementation challenges might they face? What regulatory concerns do they raise?

Offset opportunities are frequently concentrated in sectors or among activities that may be difficult to regulate directly, such as reducing fugitive emissions or lowering emissions associated with land-use practices. In some cases these emissions cannot be easily or reliably measured—as with soil carbon emissions (or sequestration)—and so are not good candidates for inclusion in a mandatory regulatory system such as a cap-and-trade program or carbon tax. In other cases, it may be difficult to determine, and hence regulate, emissions *ex ante*, but once an offset project is performed—for example, the capture and destruction of methane from landfills—determining the emissions reduction is straightforward.

One distinction among offsets projects is whether they are domestic or international in nature. To avoid double counting, domestic offsets would be limited to activities that are not already included in a mandatory program. For example, eligible domestic offset projects might address small-source emissions (if these are unregulated), biological sequestration, agricultural emissions, or other fugitive emissions; they typically would not include emissions at large point sources likely to fall under a mandatory program.<sup>4</sup> International offsets in countries without binding emissions caps, on the other hand, could involve a much wider range of projects including, in addition to the types of domestic offset projects noted above, projects that reduce energy- or industrial-sector emissions in developing countries through the transfer of advanced technologies. International offsets may face additional implementation and financing hurdles, however, depending on the strength of market institutions and legal frameworks in host countries.

Some of the projects and activities commonly considered for inclusion in a domestic offsets program are briefly reviewed below. The list is not intended to be exhaustive—rather it is based on projects that have been recognized so far under the Clean Development Mechanism (CDM) of the Kyoto Protocol and on the general disposition of U.S. GHG

emissions, particularly fugitive emissions.<sup>5</sup> For each category of emissions, we discuss a few representative project types and identify potential problems in demonstrating that reductions are real, additional, and/or permanent. The information is also summarized in Table 1.

### Biological Sequestration of Carbon

Biological sequestration projects focus on two distinct types of carbon reservoirs: forests and soils. Both contain large quantities of carbon with annual fluxes—changes in stored carbon—that significantly influence net CO<sub>2</sub> emissions to the atmosphere. Forestation projects involve either protecting existing forest that is threatened, or creating and sustaining new forests. These projects can raise significant permanence concerns; namely, how long will a stand of trees be preserved? Leakage problems can also be problematic, since protecting one stand of trees may just lead to another stand elsewhere being exploited. Soil carbon sequestration involves changing land-use or land-management practices (for example, in agriculture) such that additional carbon is sequestered in the soil. Net sequestration from soil carbon projects is often difficult to measure and these projects also raise concerns about permanence.

### Non-CO<sub>2</sub> Agricultural Emissions

A few key activities generate most fugitive non-CO<sub>2</sub> GHG emissions in the agriculture sector (further discussion of sources and emission-reduction opportunities in this sector can be found in Issue Brief #13). The first category of activities involves methane (CH<sub>4</sub>) emissions, primarily from large concentrations of animal waste (for example, manure) and ruminant animals, such as cows, whose digestive processes produce methane. Potential offset projects to address this category of emissions include capturing the methane from animal waste and either flaring it or using it to generate power or heat; options for reducing digestive emissions from ruminant animals are more limited but could involve changes in feed and grazing practices or the use of nutritional supplements. A second important category of agricultural emissions involves the release of nitrous oxide (N<sub>2</sub>O) from soils. Nitrous oxide emissions can be reduced using soil management practices such as changing the application method and amount of fertilizer used, the types of crops grown, and irrigation practices. Quantifying these emissions and documenting reductions, however, is difficult.

<sup>4</sup> Eligibility could also be influenced by other regulations; for example, an offset program might generally allow soil sequestration projects to receive offset credits, but exclude sequestration projects on land enrolled in the Conservation Reserve Program. Since these areas are already being compensated for environmental benefits associated GHG reductions might not be considered sufficiently “additional.”

<sup>5</sup> For more information on U.S. GHG emissions see Issue Brief #1.

### Other Fugitive Emissions

Fugitive emissions are not released from a concentrated source, like a smokestack or tailpipe, but often involve leaks or evaporative processes. Potential offset projects include capturing fugitive methane emissions from landfills or coal mines, detecting and repairing leaks in natural gas pipelines, and reducing emissions of sulfur hexafluoride (SF<sub>6</sub>) from electrical transformers.<sup>6</sup> In some cases it can be difficult to demonstrate that emissions reductions are in addition to the reductions that would have happened anyway, since there are private incentives to reduce many types of fugitive emissions.

### Energy Systems

Domestic energy systems would likely be included in any domestic regulation,<sup>7</sup> but energy-system offsets could still be created through projects in other countries that lack binding emissions constraints. Examples include renewable energy projects, such as installing wind or hydroelectric generators, in other countries; generating power using methane emissions from waste treatment facilities overseas, thus both eliminating methane emissions and displacing some power generation; and energy-efficiency or fuel-switching projects that reduce CO<sub>2</sub> emissions outside the United States. Verifying benefits from these types of projects is usually relatively straightforward, although in some cases additionality could be a concern.

### Industrial Gases

Although domestic industrial emissions, including emissions of non-CO<sub>2</sub> gases, would likely be included in any domestic regulation, offsets could be created by reducing emissions from industrial sources overseas. These types of offset projects have represented the majority of CDM projects undertaken so far. Examples include destroying hydrofluorocarbon (HFC) emissions associated with refrigerant production, reducing nitrous oxide emissions from the production of adipic or nitric acid, or reducing non-energy CO<sub>2</sub> emissions from industrial processes such as cement manufacture. These projects have proved popular under the CDM because there are abundant opportunities for low-cost reductions. Concern is growing, however, that some of these projects may be creating

<sup>6</sup> Fugitive emissions of synthetic gases, like SF<sub>6</sub>, could potentially be regulated directly under a mandatory domestic GHG program, either by including industrial gas production sources in the cap (or tax), or by using a deposit-refund system in which permits are required for producing a gas and credited back when the gas is destroyed. See Issue Brief #14 on non-CO<sub>2</sub> gases for further discussion of regulatory options for industrial gases.

<sup>7</sup> Domestic energy systems would not qualify for offsets when covered by mandatory regulation because projects that reduced emissions (for example, energy efficiency projects) would reduce regulatory obligations in the program (whether the obligation is to submit allowances under a cap-and-trade program or to pay a tax on GHG emissions). In other words, the regulation itself would create direct incentives for reductions at covered sources. Under some mandatory programs—upstream cap-and-trade or carbon taxes on fossil-fuel production, for example—provisions would be needed to credit activities that trap and sequester post-combustion emissions, such as carbon capture and storage (CCS) projects. However, these provisions should be thought of as a refund (of allowances or taxes) rather than an offset. They are analogous to the emitter never bearing any regulatory obligation in the first place (as would likely be the case for an emitter that employed CCS under a downstream cap-and-trade program or carbon tax).

Category	Representative Projects	Concerns
Biosequestration	Forest/soil sequestration	Additionality, permanence, MM&V*
Agricultural projects	Manure methane capture, soil management practices (N <sub>2</sub> O)	MM&V
Fugitive gases	Landfill methane, coal-mine methane	Additionality
Energy systems (international)	Renewable energy, energy efficiency, fuel switching	Additionality
Industrial gases (international)	HFC-23, N <sub>2</sub> O, industrial CO <sub>2</sub>	Perverse incentives? (See discussion of CDM at end.)

\*MM&V: measurement, monitoring, and verification

perverse incentives to continue or even expand activities that create other environmental problems.

## Primary Challenges in Designing an Offset Program

This section explores the design features and options that policymakers should consider when creating offset programs. Two sets of issues must be decided. The first concerns the broad design of the offset system, including defining the overall universe of potential projects. Ideally the approach used to determine eligibility for offset projects would minimize administrative complexity and uncertainty for offset developers. The second set of issues involves striking a balance between encouraging as much inexpensive, offset-based emissions mitigation as possible and protecting the integrity of the overall regulatory program in terms of its ability to meet defined environmental objectives. This challenge, not unrelated to the first, largely comes down to deciding how to deal with lower quality offsets.

### Options for Determining Project Eligibility

Rather than deciding project eligibility on a case-by-case basis, which can be time consuming and impose high transaction costs, alternative mechanisms can facilitate quicker and cheaper review and measurement of offsets.

#### Positive list

A “positive list” identifies activities that are eligible to create

offsets; it can also define a fixed crediting level for these activities. This approach has been adopted in the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade program for limiting electric-sector GHG emissions being developed by several northeastern U.S. states. A positive list can ease administrative burdens and reduce uncertainty for project managers, particularly when dealing with common and well-understood project types.

### **Two-step process**

For projects that require individual review, a two-step process may be appropriate in which offset developers submit a proposal and receive a determination of eligibility prior to beginning work. The second step occurs upon project completion when offsets are verified and credits issued. The CDM currently uses a two-step process—however, the fact that the first step can take a year or longer may discourage participation and investment in offset projects under this program.<sup>8</sup>

### **Tiered offset systems**

Tiered systems are similar to positive lists in that they create standard eligibility and crediting rules. Various offset activities are grouped in specific tiers. “Top-tier” projects—those that are well-understood and easily verified—would have the simplest approval, verification, and crediting procedures. Tiered systems can increase the transparency of the offset approval process.

### **International offsets**

While almost all proposals for offset programs allow domestic offsets, they may also incorporate international offsets. International offsets can expand the pool of available projects, but they may be more difficult to evaluate and administer. They may also enjoy less political support, as there would likely be greater political enthusiasm for generating reductions at home rather than abroad.

### **Offsets from other programs**

As other national and international institutions create offset programs, there is the possibility that the United States could make these offsets fungible with its own. For example, certified emissions reductions (CERs) generated under the CDM program could be eligible for use as a domestic compliance option within a U.S.-based program, as has been proposed for RGGI.

### **Options for Dealing with Low-quality Offsets**

Some types of offsets are well understood and easy to measure and verify. For example, measuring the capture and destruction of landfill methane or industrial gases is relatively straightforward. Inevitably, however, offset programs will have to handle activities that present measurement and verification challenges. There may be uncertainties in quantifying reductions (e.g., for soil carbon sequestration). There may be concerns about permanence or leakage (e.g., in the case of reforestation projects). It may be difficult to demonstrate additionality for some types of projects (e.g., showing that a project to capture methane for use or sale would not happen absent offset credits).

The challenge for an offset program is to balance the need to achieve real reductions against the desire to encourage widespread use of cost-effective mitigation options among otherwise unreachable sectors or activities. If the latter were not an objective, an offset program could simply apply strict eligibility rules—high standards for verifying additionality, permanence, and lack of leakage would ensure that (virtually) all offsetting reductions were real.<sup>9</sup> This approach would ensure high-quality offsets, but has disadvantages: large administrative costs and substantial burdens for offset-project developers could discourage investment. If an offset program is going to produce a reasonable supply of high-quality, low-cost reductions from unregulated sources it will need to incorporate creative and suitable approaches to crediting projects with uncertain environmental value.

### **Set-asides**

An option that may be attractive for incentivizing particularly “high-risk” projects in the context of an emissions trading program is to carve out a portion of allowances under the overall cap and set it aside for these activities. For example, one Congressional proposal calls for 5 percent of the total allowance pool to be set aside for agricultural soil sequestration projects.<sup>10</sup> Set-asides can incentivize particular projects while guaranteeing the integrity of the cap in a cap-and-trade system. If five percent of allowances are credited to agricultural sequestration activities under a set-aside, capped and uncapped emissions will be five percent lower than they would otherwise be if these activities generate real reductions. If they do not generate real reductions, total emissions will still stay within the cap.

<sup>8</sup> Natsource LLC, 2007. *Realizing the Benefits of Greenhouse Gas Offsets: Design Options to Stimulate Project Development and Ensure Environmental Integrity*, National Commission on Energy Policy: Washington, DC.

<sup>9</sup> The CDM has essentially taken this approach. Despite high administrative costs, the program looks poised to produce a substantial volume of offsets over the compliance period of the Kyoto Protocol. (See further discussion in CDM text box.)

<sup>10</sup> Bingaman-Specter “Low Carbon Economy Act of 2007”, S. 1766, 110<sup>th</sup> Congress, section 201(a)(1) and section 205.

### Credit limits

Another regulatory option for handling low-quality offsets is to limit the absolute number of credits available for certain types of activities. For example, another Congressional proposal limits the use of offset credits to a maximum of 30 percent of a covered entity's total compliance obligation.<sup>11</sup> The difference between this approach and a set-aside is that crediting projects that do not produce real emissions reductions will result in total emissions above the cap level. Essentially identical results can be achieved, however, by adjusting the cap level to account for this possibility. To illustrate this, consider two hypothetical cap-and-trade proposals. The first establishes a cap level of 100 tons and a set-aside of 10 allowances from the 100 allowances available under the cap (each allowance represents 1 ton of emissions). The second program establishes a cap level of 90 tons and limits offset credits to 10 tons. Assuming the same types of projects are eligible under both proposals, thus introducing exactly the same risks (of permanence, leakage, etc.), and assuming the set-aside and offset limits are exhausted in each case, the two proposals have identical consequences. If emissions reductions from credited projects are real and permanent, overall emissions will total 90 tons under both proposals. If, on the other hand, credits are claimed for projects that turn out to have no real environmental benefit, actual emissions will total 100 tons in both cases.<sup>12</sup> The lesson for policymakers is that the choice of which approach to use is less important than the size of the set-aside or credit limit in the context of the overall cap and the rules used to verify quality (with all the same trade-offs noted above).

Credit limits (and set-asides) do raise a critical issue, however, in terms of their potential to distort investment incentives for offset projects. With either limits or set-asides, the question arises: how will offset credits be distributed when there are more applicants than available credits? Credits could be awarded on a first come, first serve basis or prorated to individual projects such that the total awarded does not exceed the limit or set-aside amount (in that case, project developers would be credited for something less than the emissions reductions they achieve). In either case, uncertainty about how—or whether—their project will be credited could discourage developers from investing in offset activities.

### Non-uniform crediting

While credit limits and set-asides are essentially quantity-based instruments for handling risky offset projects, non-

uniform crediting is analogous to a price-based approach. The idea is that offset projects receive either more or less than one-to-one crediting: uncertain or risky offset projects receive offset credits at a discounted rate, while other projects receive full or even extra credits. For example, soil carbon sequestration projects might receive credits worth 80 percent of the current best estimate of sequestration.<sup>13</sup> The proposed Lieberman-McCain legislation uses discounted crediting for sequestration projects based on the uncertainty in estimating net emissions benefits: if the range of estimates for a class of projects is broad, the offsets awarded for such projects are near the bottom (low) end of the range.<sup>14</sup> A discounting approach helps address areas where benefits are likely but uncertainties (in measurement, permanence, etc.) remain large. By allowing projects that involve nascent or difficult emissions-reduction opportunities to receive some credit, this approach could promote some near-term investment in developing new abatement options while holding out hope that increased experience and improvements in measurement capabilities would allow crediting levels to be adjusted closer to projects' true value at some point in the future.

As noted previously, non-uniform crediting can also allow greater than one-to-one crediting. If there are certain offset activities that regulators particularly wish to encourage or reward, then awarding additional credit (beyond the best estimate of actual project reductions) will provide even stronger incentives. The Bingaman-Specter legislation uses this approach to encourage investment in carbon capture and sequestration (CCS): eligible geologic sequestration projects receive allowances at a greater than one-to-one rate from 2012 to 2029 (starting at 3.5 times the amount sequestered from 2012 to 2017).<sup>15</sup> Policymakers must recognize, however, that bonus credits represent an additional subsidy and will thus encourage a level of investment in eligible activities that is likely to be inefficient unless it can be justified on some other (non-climate) grounds.

### Rental credit

Offset projects characterized by high risks of impermanence (for example, biological sequestration) could also be dealt with through credits that are "rented" rather than transacted once and for all. The Lieberman-McCain proposal uses a version of this approach: any sequestration projects that are

11 Lieberman-McCain "Climate Stewardship and Innovation Act of 2007", S. 280, 110<sup>th</sup> Congress, section 144(a).

12 If no offset activities are performed and hence no offset credits are claimed, emissions will total 90 tons.

13 This is effectively the approach used for soil sequestration projects within the offset program of the Chicago Climate Exchange (CCX). (The CCX is a North American-based GHG emission trading system that companies can join voluntarily by committing to reduce their emissions. The CCX manages its own offset program.) Each year 20 percent of CCX-eligible offsets that are generated through soil sequestration are placed into a reserve pool to hedge against future reversals in carbon storage. Source: Chicago Climate Exchange, "Soil Carbon Management Offsets" Available at [http://www.chicagoclimatex.com/docs/offsets/CCX\\_Soil\\_Carbon\\_Offsets.pdf](http://www.chicagoclimatex.com/docs/offsets/CCX_Soil_Carbon_Offsets.pdf) Accessed September 7, 2007.

14 "Climate Stewardship and Innovation Act of 2007", S. 280, 110<sup>th</sup> Congress, section 144(c)(3)(B).

15 Bingaman-Specter "Low Carbon Economy Act of 2007", S. 1766, 110<sup>th</sup> Congress, section 207(a)(3).

submitted for credit must be reevaluated every five years and if the net benefits claimed previously have declined (for example, a forest fire destroys a strand of trees that had been claimed), then covered entities must submit new allowances or credits to cover the shortfall.<sup>16</sup> An important political question in designing a credit rental proposal is deciding which party will be liable if previously rented offsets disappear or diminish in value: the covered entity that surrendered the offset credit to meet its compliance obligation or the unregulated entity that generated the offset in the first place. In either case, the idea of rental credits is attractive from an economic perspective because—assuming offset providers and buyers have good information about the likely permanence of emissions reductions from particular projects—they could account for these risks in managing their use of offsets. Problems could arise, however, if private actors expect the government to be the insurer of last resort: for example, if there were an expectation that in the wake of a forest fire which wiped out a large number of offsets the government would merely forgive resulting emissions. Such expectations would encourage overinvestment in high-risk projects, which could then have the perverse effect of increasing political pressure on the government to be the insurer of last resort in the case of a catastrophic event.

## Conclusion

The design options discussed above reflect lessons learned from early offset programs, particularly the CDM. Many of these design options can be used in conjunction with each other. Indeed, policymakers must make decisions about most of the issues reviewed here, even if only implicitly. Finally, it is helpful to evaluate the various choices and options as a package, and to consider the overall implications of a given set of design choices.

For example, policymakers may choose to create an offset program that is outside the cap, consists only of domestic offsets, uses a tiered system with a positive list to determine project eligibility and crediting levels, and utilizes risk-based discounting to credit different project tiers. Such a program would be set up to minimize administrative burden. It would hedge environmental risk through a market mechanism, like discounting, rather than through regulation by offset quotas or caps. On the other hand, policymakers may prefer a tiered system that uses either set-asides or credit limits for certain tiers of activities, and utilizes rental credits with strict liability rules for other tiers. Such a system would be set up

to maximize environmental integrity by reducing the risk that awarding credit to low-quality offsets results in emissions above the cap. Or, again, policymakers may opt for a very open system that allows unlimited offset credits from all sectors, recognizes international offsets, and uses uniform crediting, even from riskier projects. This system would be designed to minimize the overall costs of compliance, albeit at some risk to the environmental integrity of the program. All these design choices will have a substantial impact on the degree to which offsets can, on the one hand, expand the pool of low-cost mitigation options while on the other hand potentially compromising, or at least introducing uncertainty about, the overall environmental benefit achieved by the regulatory program.

## The Clean Development Mechanism

Created under the Kyoto Protocol, the CDM represents the largest offset program in the world.<sup>17</sup> Under the CDM, credits are awarded for specific project activities in developing countries that reduce GHG emissions.<sup>18</sup> Developed countries with binding emissions targets under Kyoto can then purchase these credits to count towards their own compliance. The use of CDM credits to meet domestic regulatory obligations has also been proposed in countries that have not accepted emissions-reduction targets under Kyoto.<sup>19</sup>

The CDM process has stringent requirements. It requires project design documents to be independently evaluated (a process called validation), approved by a host country, and then reviewed and registered by the CDM Executive Board. There are high standards for demonstrating that reductions are additional and permanent. Once a project is registered and activities are underway, all emissions reductions must be measured and verified by an independent party before any offset credits, called Certified Emissions Reductions (CERs), are issued.

Each CER represents one metric ton of reduced carbon dioxide-equivalent (CO<sub>2</sub>e) emissions. CERs can be purchased

<sup>17</sup> A smaller offset program has also emerged under the Chicago Climate Exchange (CCX), a private North American-based GHG emissions trading system that companies can join voluntarily by committing to reduce their emissions. The CCX manages its own offset program. As of August 2007 the CCX had issued offset credits to 34 projects—25 in the United States, 9 overseas—totaling almost 15 million metric tons CO<sub>2</sub>e of reduced emissions. More than half of the emission reductions were from soil carbon sequestration projects. (Chicago Climate Exchange, “CCX Registry Offsets Report, Offsets and Early Actions Credits Issued as of 08/28/2007.” Available at <http://www.chicagoclimatex.com/offsets/projectReport.jsf> Accessed August 28, 2007.) The CCX offset program has been criticized for having insufficient standards for ensuring that reductions—particularly from soil projects—are real and additional. Further, the CCX itself has faced criticisms for being too industry-friendly and lacking public transparency. (Goodall, J., 2006. “Capital Pollution Solution?”, *The New York Times Magazine*, June 30, 2006.)

<sup>18</sup> The Kyoto Protocol also created a separate category of offset activities called Joint Implementation projects, which are projects conducted within Annex 1 (developed world) countries. To date there has been much less activity in JI than in CDM.

<sup>19</sup> For example, the Northeast and mid-Atlantic states have proposed to recognize CDM credits under their Regional Greenhouse Gas Initiative (RGGI) for limiting power-sector carbon emissions if the price of RGGI allowances rises above some defined threshold.

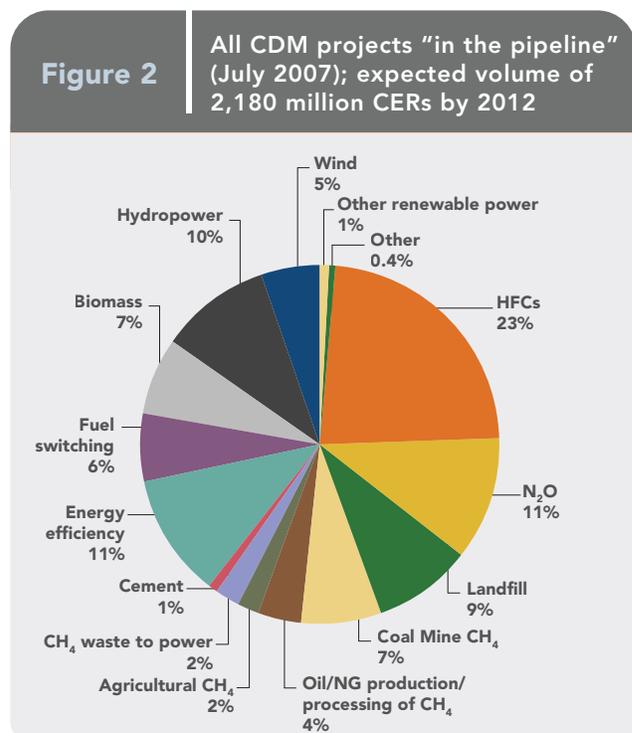
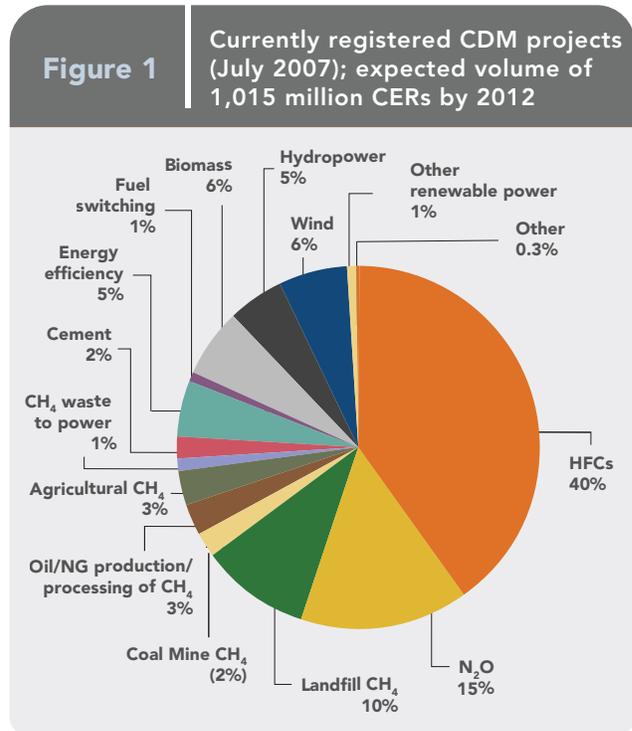
<sup>16</sup> “Climate Stewardship and Innovation Act of 2007”, S. 280, 110<sup>th</sup> Congress, section 144(c)(1).

by countries to meet Kyoto obligations; they can also be purchased by firms—for example, as a means to comply with the European Union’s Emission Trading System (EU ETS) (which in turn is being used by EU countries to help meet their Kyoto obligations).

As of July 2007, more than 700 CDM projects had been registered and another 1,500 applicants had submitted project design documents for validation. Altogether these projects in the CDM pipeline represent cumulative emissions reductions totaling approximately 2.2 billion metric tons CO<sub>2</sub>-e through 2012.<sup>20</sup> For comparison, the projected compliance shortfall among Kyoto participants (including the EU, Japan, and New Zealand, but excluding Canada) from 2008 to 2012 is 2.0 billion metric tons CO<sub>2</sub>-e.<sup>21</sup> To date, few CERs have been issued, as most CDM projects are still relatively recent.

Figures 1 and 2 show the distribution of CERs from various project types, first for the 700 currently registered projects and then for all 2,200 proposed projects, including those now in the CDM pipeline.<sup>22</sup> As is evident from the figures, projects involving non-CO<sub>2</sub> GHG emissions account for the majority of emissions reductions. The single largest share of reductions comes from projects that reduce HFC-23 emissions from HCFC-22 production. These projects accounted for an even larger portion of early CDM entrants, as they represented some of the lowest-cost emissions-reduction options available internationally, but their share has fallen as the opportunities for HFC-23 control have been nearly exhausted.<sup>23</sup> Projects to generate nitrous oxide (N<sub>2</sub>O) reductions have mostly involved controlling emissions from adipic acid production. By contrast, methane (CH<sub>4</sub>) reduction projects have been implemented in a variety of sectors, including coal mines, oil and natural gas production and processing, and various waste management industries, including landfills, wastewater, and animal wastes.

Projects that focus on energy systems, whether they involve energy efficiency, fuel switching (typically to natural gas), or renewable generation, account for a small but growing



20 The actual yield of delivered CERs will almost certainly be less. The World Bank report mentioned previously (Kapoor and Ambrosi 2007. *State and Trends of the Carbon Market 2007*, World Bank: Washington, DC.) estimates a likely CDM yield over the Kyoto compliance period (2008–2012) of 1.5 billion tCO<sub>2</sub>-e. The current issuance success rate among the few projects that have already been issued CERs is about 85 percent (UNEP *Riseo CDM/JI Pipeline Analysis and Database*, July 2007), which extrapolates to a little less than 1.9 billion tCO<sub>2</sub>-e.

21 Kapoor and Ambrosi 2007. *State and Trends of the Carbon Market 2007*, World Bank: Washington, DC. Canada is projected to have a large Kyoto compliance shortfall (perhaps 1.3 billion tCO<sub>2</sub>-e). Whether this will translate to increased demand for CDM credits is uncertain, however, because the Canadian government has published a report stating that the country will fail to meet its emissions reduction target under the Protocol. (Point Carbon, “Canadian government submits Kyoto compliance plan, without compliance”, *Carbon Market North America*, August 29, 2007.)

22 UNEP *Riseo CDM/JI Pipeline Analysis and Database*, July 2007. Available at <http://cdmpipeline.org/>. Accessed August 2, 2007.

23 Wara, Michael. 2006. *Measuring the Clean Development Mechanism’s Performance and Potential*, Program on Energy and Sustainable Development Working Paper #56, Stanford: Palo Alto, CA, and Wara, M., 2007. “Is the global carbon market working?”, *Nature*, 445 (7128): 595-596. Compare the pipeline analyses from these papers (April 2006 and January 2007) with the July 2007 analysis in this paper and with the calculations of the total potential volume of HFC-23 reductions in Wara 2006.

portion of CDM reductions. They represent less than one-quarter of reductions from the 700 currently registered projects but are the fastest-growing category of activity for CDM projects. If all projects in the CDM pipeline are credited with currently projected reductions, energy projects in developing countries will account for more than 40 percent of all CERs generated by 2012.

Prices for CERs are driven by demand, particularly from Europe and the EU ETS, and so are linked to the price of allowances in the EU ETS. Prices in July 2007 for CERs delivered during the Kyoto compliance period (2008–2012) were \$12–\$18 per metric ton CO<sub>2</sub>-e when purchase agreements were arranged directly between buyers and project developers. Prices for credits purchased in a secondary market have tended to be around 70 percent of the EU allowance price; thus CERs in the secondary market were selling for about \$20 per metric ton CO<sub>2</sub>-e in July 2007.<sup>24</sup>

### Criticism of the CDM

The CDM process has drawn criticism for having an administratively complex and time-consuming approval and verification process.<sup>25</sup> Multiple approvals must be obtained and even after registration the quantity of credits to be generated is not certain until reductions are verified. The program's stringent eligibility standards are designed to ensure the integrity of emissions-reduction projects but they have the disadvantage of increasing transaction costs for project developers and reducing the universe of projects that can be profitably undertaken.

The CDM program includes some features designed to mitigate these burdens. For example, there is a list of acceptable methodologies with published guidelines for quantifying emissions for common types of projects, which can help reduce the length of the approval process for many applicants. Further, the existence of the registration process allows project developers to confirm that credits will be generated prior to undertaking projects (even if the exact quantity remains uncertain). Despite these features, however, bureaucratic delays and bottlenecks in the project review and emissions verification steps have led to a growing lag between project application and registration, and then between registration and the issuance of credits.<sup>26</sup>

The CDM program has also drawn criticism on grounds that

payments for some projects that target certain non-CO<sub>2</sub> gases, particularly HFCs, essentially function as subsidies and thus create incentives to sustain—or even expand—activities that exacerbate other environmental problems. There is particular concern that the program creates perverse incentives for firms in developing countries to continue producing HCFC-22, an ozone depleting substance, so that they can receive CDM credits for destroying HFC-23, a by-product of the HCFC-22 production process.<sup>27</sup> Accordingly, some argue that non-CO<sub>2</sub> gases would be better dealt with by side agreements than in conjunction with CO<sub>2</sub>.<sup>28</sup> Critics of the CDM further argue that many of the projects being credited, or those likely to be credited, under the program—particularly where they involve industrial gases like HFCs—are neither promoting technology transfer to less developed countries nor supporting sustainable development for the poor<sup>29</sup>—one of the primary goals of the CDM program as originally conceived under the Kyoto Protocol.<sup>30</sup> Others counter that the value of a multi-gas strategy is that it finds the lowest-cost reductions, wherever they occur, and that an offset market at least ensures that reductions in certain industrial-gas emissions are taking place. One potential strategy for addressing concerns about these gases would be to adjust the crediting rate for projects so that the incentive to reduce emissions is balanced against the perverse incentive to expand opportunities for reducing emissions in the future.<sup>31</sup> In addition, a credible long-term decision about which new emission sources will (or will not) be eligible for offsets would help to eliminate incentives for strategically expanding production.

The CDM is significant for creating the first large-scale market for offset credits in the context of greenhouse gas regulation. It has demonstrated that a market-based system of offset credits can be used to link international emissions reductions, particularly in developing countries, to compliance obligations under a domestic or regional cap. The criticisms that have been leveled at certain aspects of the CDM may offer lessons for policymakers and regulators as countries consider setting up their own offset programs.

27 The concern arises because, given current prices for CDM credits and low abatement costs for HFC-23, the profits from destroying HFC-23 byproduct and selling the CDM credits are greater than the value of the HCFC-22 production itself. Similar concerns have been raised regarding the relative costs of N<sub>2</sub>O destruction from adipic acid production. (Wara, Michael, 2006. *Measuring the Clean Development Mechanism's Performance and Potential*, Program on Energy and Sustainable Development Working Paper #56, Stanford: Palo Alto, CA.) HCFC-22 is used both as a chemical feedstock for synthetic polymers—a process which sequesters the gas without emissions—and in a variety of end-use applications, including as a refrigerant, that result in fugitive emissions. The production of HCFC-22 for non-feedstock purposes is already being phased out by developed countries under the Montreal Protocol, but production in developing countries is allowed to continue without restriction until 2016, at which point a production freeze will go into effect until 2040. After 2040, all production of HCFC-22 worldwide is supposed to cease under the Montreal Protocol (Bradsher, K., 2007. "Push to Fix Ozone Layer and Slow Global Warming", *New York Times*, March 15, 2007.)

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