ECONOMIC AND DISTRIBUTIONAL IMPACTS FROM CARBON FEE AND DIVIDEND POLICIES

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ABSTRACT

The U.S. energy and climate policies currently in discussion have the potential to deliver a sizable reduction in carbon emissions. While many studies have modeled how similar polices might affect the economy, relatively few have assessed household implications. Furthermore, none of those have been under the current post-recession, post-shale gas boom economy. This dissertation examines the effects of a range of carbon fee and dividend policies in the current economic climate. The research evaluates individual economic sectors, as well as households at different income levels, and in different regions and states. The carbon fees range from \$15-\$35/tCO_2, each escalating at 2-8% annually. The U.S. Government's energy-economic model (the National Energy Modeling System—NEMS) was used to identify impacts to each part of the economy. To determine the outcome for households, two external consumer expenditure surveys were incorporated. The results show that this range of policies could reduce carbon emissions between 5-24% over ten years, while reducing GDP by 0.4-1.6%. Most of the avoided emissions (85%) would result from decarbonizing the electricity sector. The carbon fees would raise \$850 billion to \$2.2 trillion, which should be recycled back into the economy through efficiency incentives and household rebates (dividends). Returning 50% of the revenues on a per capita basis would progressively offset increases in direct energy costs for 84% of all U.S. households.

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Chapter 1

U.S. FEDERAL ENERGY AND CLIMATE POLICY AND ANALYSIS

1.1 INTRODUCTION

Levels of accumulated carbon dioxide (CO_2) and other greenhouse gases (GHG) in the Earth's atmosphere, and the additional emissions added daily, are destabilizing established climate patterns and threatening the ecosystems on which all living beings depend. A significant reduction in carbon emissions is essential to avoid further climate destabilization and the resulting increase in severe weather events and coastal destruction. Anthropomorphic climate change and disruption, if left unchecked, will increase the spread of diseases, lead to the failure of agriculture and water supply systems globally, force human migrations, and instigate political upheavals and international conflicts (Allison et al., 2009; IPCC, 2013).[1]

There is no financial incentive for self-limiting emissions if the entity that produces the emissions does not have to include them in its costs of production. Thus GHG emissions are a good example of an externality: the condition that exists when the activity of one entity affects another's welfare outside the market framework (Pindyck and Rubinfeld, 2009). The lack of incentive is further amplified when one considers that impacts from GHGs and climate disruption are global; yet the rules governing emissions are constrained by geopolitical boundaries. If carbon and other GHG emissions are to be reduced, policies must be put in place that provide the incentives to limit or control emissions, encourage energy efficiency, and reward conservation.

Placing a price on carbon would provide strong incentive for reducing emissions through several mechanisms. It would signal consumers to reduce energy consumption by making lower carbon (i.e., more efficient) goods and services more

[1] For a compilation of current scientific evidence, see the referenced IPCC AR5 report and the Copenhagen report. The intent of this research is not to argue if and how emissions from human activity are changing the climate, but to evaluate a set of policies designed to reduce those emissions and minimize their impacts.

competitive. It would provide information to producers about which energy supplies emit more carbon (e.g. coal-fired electricity), and encourage switching to lower carbon inputs (e.g., electricity from wind and solar). It would also signal markets and provide financial incentives to inventors and innovators to develop and market low-carbon products and services to replace the current generation of more carbon-intensive technologies (Nordhaus, 2009). All of these mechanisms depend on policymakers enacting a coherent policy that includes a price on emissions.

The implications of a carbon policy on U.S. energy supply and demand (the first two mechanisms above) are the subject of this document. The last mechanism, signaling inventors and innovators, does not refer to the exploitation of new climate change adaption opportunities (e.g., Funk, 2014), but rather to the product and service opportunities made economically viable when the externalities of emissions are properly taken into account. Direct guidance for this latter group of innovators is the subject of several books (e.g., Koomey, 2012), and is not addressed here directly. However, this dissertation will provide the context for these innovators by showing which sectors of the economy will be the most affected by pricing carbon and which sectors are inflexible (due to existing technology or fuel choices) and would readily benefit from technology innovations.

An understanding of the potential impacts of a proposed carbon policy should be a part of any policymaker's consideration. Unfortunately the tools available to policymakers do not combine U.S. macroeconomic forecasts of such policies with household and other distributional impacts. For example, in 2009, the U.S. considered cap-and-trade policies (e.g., Waxman and Markey, 2009), which would place a limit on the emissions and set a price on the permits for trading additional emissions. Official analysis of the Waxman–Markey bill was performed by the U.S. Department of Energy's Energy Information Administration (EIA) using EIA's primary energy-economic model: the National Energy Modeling System (NEMS)(EIA, 2009a). NEMS is the tool typically used by members of Congress to evaluate major energy related legislative proposals, and it is designed to assess U.S. macroeconomic impacts from such policies. However, pricing or limiting carbon and other GHG emissions will increase the cost of manufacturing goods, delivering goods and services, and providing energy products (e.g., electricity), all of which could have a significant impact on individual households depending on both geographic region and income distribution. Yet, the NEMS doesn't forecast household expenditure information, and therefore cannot properly assess the distributional aspects of any bill.

Today, carbon fee and dividend policies, rather than cap-and-trade, are the focus of the discussion, which would charge a tax on emissions and return a portion of the revenues directly to households (e.g., Boxer and Sanders, 2013). An energy-related tax by itself is regressive. While lower income households spend less money altogether on energy than do wealthy households, they spend a larger portion of their household income on energy. Therefore, lower income households spend a disproportionate amount of their income on energy-related goods and services (Hsu, 2011).

Properly designed, a carbon tax coupled with a dividend could protect lower income households, as well as lessen the shock to energy-intense or trade-exposed industries. Thus, pricing carbon is not used to raise revenues, but is a *fee* charged for harm inflicted on others and would be returned to consumers.[2] How much could be available for the dividend (and at what cost to the economy) and the impacts of the fee and dividend on households requires forecasting not only the macroeconomic impacts of the fee, but household distributional effects.

This study combines the dominant and widely used U.S. energy-economic model (NEMS), with detailed consumer expenditure surveys to show the integrated impacts of carbon fees and dividends on U.S. macroeconomics and households in different regions with different income distributions. Section 1.2 includes a brief discussion of carbon taxes and cap-and-trade for context, and a summary of current and recently-proposed carbon policies. Section 1.3 is a review of analyses on U.S. energy-economic impacts and household distributional impacts from carbon policies, and a brief discussion about how combining the two types of studies is imperative to

[2] A policy which charges a fee for emissions, and returns a portion of the revenues to consumers is referred to as a 'fee and dividend' policy.

properly evaluate such policies. Finally, Section 1.4 introduces the general framework for the rest of this dissertation.

1.2 PRICING CARBON

Common approaches for controlling or limiting emissions include emission tax, cap-and-trade, and command and control regulation. Command and control (CAC), with respect to environmental or energy policy, refers to the direct regulation of an industry or activity by requiring certain technical controls or standards. Such a regulation might command a certain performance level (e.g., appliance standards) or control which technologies are used (e.g., exhaust stack emissions scrubber). The CAC regulatory process is often considered inefficient since it requires source-specific regulation and potentially intensive and costly oversight (Carlson et al., 2000; CBO, 2008; Chan et al., 2012). Furthermore, the size, in terms of total number and diversity of pollution sources, of national and global carbon emissions is much larger than that of typical CAC activities (e.g., control of mercury emissions from coal-fired electricity generators). Consequently, carbon tax and cap-and-trade schemes are usually the preferred approach when discussing carbon emission reductions.[3]

1.2.1 Emission taxes and cap-and-trade

The purpose of this section is not to argue for one policy instrument over the other, but to provide the reader with sufficient context. Carbon tax and cap-and-trade policies employ different methods for achieving a reduction in emissions: a tax sets the price per unit of emissions, while the cap sets the quantity of allowable emissions. However, the two approaches will theoretically achieve the same price and quantity, if one makes many simplifying assumptions including that the markets are efficient, there are no other regulations impacting supply and demand, there are no liquidity constraints for producers and consumers, policymakers have perfect information regarding the

[3] Although, given the difficulty of passing cap-and-trade or fee-and-dividend bills, the U.S. is moving forward with a command and control approach for reducing CO_2 from power plants and possibly refineries as well. For more information, please see EPA Carbon Pollution Standards (EPA, 2013).

marginal abatement costs, the timescale of adjustment for sectors is instantaneous, and many more. To illustrate this in a simple one-consumer–one-producer market, consider a $Supply$ of emitting products and a $Demand$ for those products as shown in Figure 1.1. Without a policy accounting for the externality of emissions, the economic equilibrium, point A, is achieved at a price P_0 for quantity Q_0 emissions.

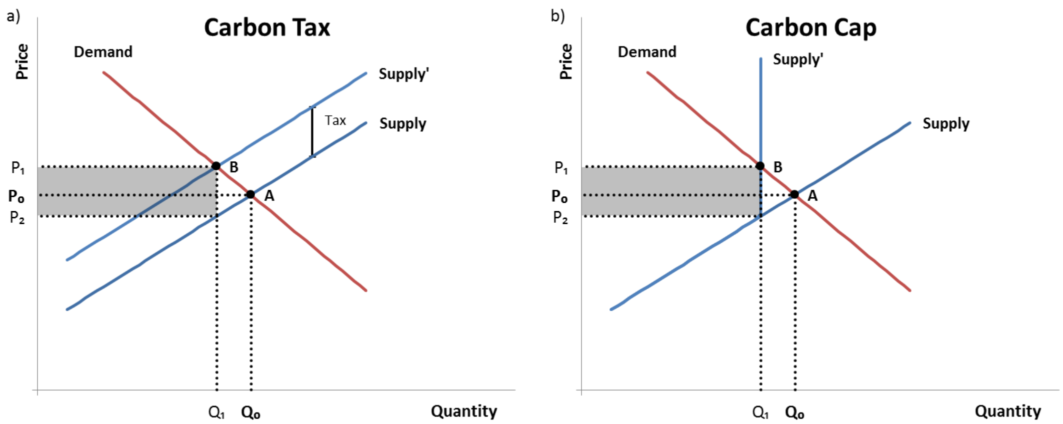

Figure 1.1 Theoretically, carbon tax and carbon cap policies can achieve similar price and quantity

Adding a carbon tax will increase the cost of producing the $Supply$, so the curve shifts vertically by the value of the tax to the $Supply'$ line, as shown in Figure 1.1a. An increase in price reduces demand and the new equilibrium, point B, is now at price P_1 for quantity Q_1. This lower supply quantity is produced (before the tax) at P_2, and the difference between P_1 and P_2 is equal to the tax. The shaded rectangle bounded between prices P_1 and P_2 and by quantity Q_1 represents the total revenue, or potential profit (π), raised from the policy. Here, the price per unit of emissions is known but the quantity of emissions output is not certain and depends on how responsive consumers and producers are and what lower carbon technologies or production processes are available.

Under a carbon cap scenario (See Figure 1.1b), the total quantity of emissions is limited (or capped) at Q_1. Since there is no explicit tax attached to each unit of emissions, the emitting products are produced as described by the original $Supply$ curve until the cap is reached. Once the cap is reached, the new supply curve ($Supply'$) becomes vertical at the capped quantity no matter how high the price. The new equilibrium is point B and the consumer is again faced with price P_1 under the policy. Here, the quantity is known in advance but the price is less certain, and depends on consumer and producer responsiveness. From the consumers' point of view, the two policies are effectively equivalent with respect to prices and quantities.

In this overly-simplified, theoretical example, cap-and-trade and a carbon tax can achieve the same emissions quantity at the same price. In a world of perfect competition, which method is more appropriate depends largely on the relative slopes of the $Demand$ (marginal benefit) and the $Supply$ (marginal cost) curves. When the marginal benefit curve is steeper, quantity regulation (carbon cap) will be more effective, and when the marginal cost curve is steeper, price regulation (carbon tax) will be more efficient (Adar and Griffin, 1976; Higgins, 2013; Weitzman, 1974; Williams, 2002).

Predicting which policy instrument is 'best' requires extensive empirical knowledge of the market structure. However, regulators do not have sufficient information about individual firms' marginal abatement costs (MAC), thus the value chosen for a carbon price or a cap must be made under uncertainty. Yet, errors in the estimation of the MAC have different welfare consequences depending on the slope (Weitzman, 1974). Theoretical prediction is often unreliable due to insufficient information, institutional constraints, technology spillovers, and fiscal interactions (CBO, 2008; Goulder and Parry, 2008). There is ample debate about which policy is preferred, with prominent economists on both sides of the argument, summarized by Goulder and Schein (2013); others argue for a hybrid approach (e.g., Higgins, 2013).

Still, the performance of the two approaches depends on the specifics of design, which some argue is as important as the choice between the two instruments (Goulder and Schein, 2013; Weisbach, 2009). The elements of design revolve around the allocation of the revenues, π, since this represents the difference between the price the consumer pays at B and the costs to the supplier for producing at Q_1. Under a carbon cap, the revenues (if the government gives the permits to emitting to firms) are profit for the producer since a permit to produce one unit of output allows the owner to collect a rent equal to the difference between the selling price (P_1) and the cost of production (P_2). The government might also auction permits off to the highest bidder, and the price will be bid so that the price is equal to the MAC at the cap. Under a carbon tax, the government could collect the revenues and use them for some purpose or it could give them back out in the form of tax cuts or tax credits to a chosen set of individuals, including the emitters themselves (making this look more like cap-and-trade). Ultimately, this profit is collected by whoever is initially allocated the property right (i.e., the permit or allowance to emit).

So, in reality, this can get complicated quickly and the differences between policies can be blurred by the design of the policy. In practice, federal cap-and trade usually has free allocation to emitters (e.g., Waxman and Markey, 2009; WCI, 2014) while real carbon tax proposals involve a rebate to households and/or reductions in personal and corporate income tax receipts or rates (e.g., Boxer and Sanders, 2013; Waxman et al., 2013). Certainly both mechanisms have been recommended or implemented recently in the U.S. and elsewhere.

Which policy and design is better or more appropriate in today's political landscape is not the intent of this section, but to provide some context for the carbon fee and dividend policies discussed throughout the remainder of this dissertation. The current U.S. policy discussion surrounds carbon fee and dividend policies, so this study seeks to provide policymakers with a summary of impacts from such a policy.

1.2.2 Carbon polices worldwide

Globally, there are in effect or planned, ten national and regional cap-and-trade markets and nearly twenty carbon tax policies. Each has its own level of complexity, scope, progress, and success.[4] Perhaps the most familiar is the European Union (EU) Emissions Trading Scheme (ETS). The EU ETS is the largest multi-country, multi-sector GHG cap-and-trade system in the world. The EU ETS was meant to encourage alternatives, but a recession, creation of too many exemptions, disbursement of too

[4] Several papers provide comparisons of design policy details (e.g., Baranzini et al., 2000; Sumner et al., 2011), and many organizations maintain lists and brief descriptions of various policies (e.g., CTC, 2013; EESI, 2012; The Climate Group, 2013).

many permits, price volatility, and gaming by participants (including national governments) has largely undermined the effectiveness of this complex and opaque system (EC, 2014; Ellerman and Joskow, 2008; Feng et al., 2011).

In 2013, China began a series of pilot cap-and-trade ETS which will eventually include seven cities and provincial markets. The scale of this comprehensive carbon market will be second only to the EU ETS (Point Carbon, 2013). This is China's attempt to switch from energy intensity targets to a market-based limit; however, China's powerful polluters have vetoed the carbon cap. To get around this, the Government has set a target for carbon emissions per unit of GDP, so the exact amount will depend on their production of goods and services and will be adjusted at the end of the trading year. Furthermore, there are more permits allocating emissions than there are current emissions in these Chinese markets (Chen and Reklev, 2013; Point Carbon, 2013), which is one of the main criticisms of the EU ETS.

Carbon taxes, an alternative to cap-and-trade, are in place in nearly 20 countries. Sweden, for example, implemented a carbon tax in 1991, following its adoption of the Kyoto protocol, and has since reduced greenhouse gas emissions by 20% beyond what is attributed to other policies (e.g. energy efficiency standards). Despite Sweden's hefty carbon tax of about $140 (USD) per metric ton, Sweden's economy has grown by more than 100% over the same period (Ministry of the Environment, 2008), and the country recently ranked fourth in the world on economic competitiveness (Schwab, 2013).

Carbon taxes are not always successful at reducing overall emissions. For example, Norway also implemented a carbon tax in 1991, yet the country's emissions have since increased. The tax spurred innovation, which lowered energy and carbon intensity, driven in part by carbon sequestration (UNFCCC, 2006), but not as much as it helped increase GDP and, subsequently, total emissions. The tax also led to soaring energy prices, which encouraged a boom in offshore production, and that activity further increased emissions. Finally, several large industries won exemptions from the tax and carried on unchanged, adding to the increase in emissions (Abboud, 2008).

The Canadian Government has implemented a sector-by-sector regulatory approach to reduce GHG emissions, with each province defining and governing its own regulatory process. Government-sponsored programs and measures include federal CAC policies such as electricity performance standards for coal-fired generation, renewable fuel content regulations, and light-duty vehicle GHG regulations (Environment Canada, 2013). Meanwhile, Provincial measures include a cap-and-trade program in Quebec, an electricity sector emissions cap in Nova Scotia, a specified emitters regulation in Alberta, a coal-fired electricity phase-out in Ontario, and a carbon tax in British Columbia (Environment Canada, 2013; Sawyer and Gass, 2014). Despite mild success in reducing emissions under a growing economy (Environment Canada, 2013), critics say Canada's refusal to regulate emissions at the federal level until U.S. legislation is in place is just the latest excuse, and the lack of a comprehensive and effective national policy has forced each province to implement their own policies. This leads to slow progress, inefficiency, and emissions leaks between provinces and the U.S. (Holmes et al., 2012).

The lack of a comprehensive policy, as in Canada, and the complexity, opacity, and potential for gaming under a cap-and-trade system, as experienced under the EU ETS, suggest a carbon fee might have a better chance at success, but such a policy should take a relatively hard stand on exemptions or face Norway's failure. Furthermore, whatever the policy, it should be regulated at least at the federal level to provide adequate direction to consumers and producers and to minimize the easiest form of leakage, which would occur via interstate electricity markets.

1.2.3 Recent U.S. carbon policies

In 2009[5], The U.S. House of Representatives narrowly passed the American Clean Energy and Security Act (H.R. 2454 of the 111th Congress), but was defeated in the

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[5] U.S. carbon policies do not begin in 2009. For example, in 1970, the Clean Air Act (CAA) was established to regulate air emissions from stationary and mobile sources. In 1975, the Corporate Average Fuel Economy (CAFE) standards intended to improve the average fuel economy of cars and light trucks would also indirectly reduce emissions. In 2006, the U.S. Supreme Court decision in Massachusetts v. EPA added carbon dioxide (and other GHGs) as pollutants for regulatory purposes under the CAA.

Senate. Designed by Reps. Henry Waxman (D-CA) and Ed Markey (D-MA), the Waxman–Markey bill (Waxman and Markey, 2009), or ACES, was a comprehensive, national climate and energy legislation that would have established an economy-wide, GHG cap-and-trade system. It included complementary measures to help address climate change while building a clean energy economy. ACES is the closest the U.S. has come to enacting a comprehensive federal climate policy. Shortly afterward, the similar Kerry–Lieberman American Power Act (EPA, 2010) also failed to pass the Senate.

As in Canada, the lack of federal carbon legislation has led to several U.S. regions striking out on their own. A coalition of nine New England and Mid-Atlantic states entered into the Regional Greenhouse Gas Initiative (RGGI) beginning in 2009. This is the first mandatory CO_2 cap-and-trade program in the U.S., and is designed to limit emissions from electric power plants. Emissions in the region have declined by more than 35% since trading began, but these reductions are primarily attributed to lower natural gas prices (which prompted a migration away from coal irrelevant of the policy) and to lower electricity demand (EIA, 2014). In light of lower natural gas prices, a lower cap has been set for 2014 to keep the RGGI a viable emissions policy (EIA, 2014; RGGI, 2014). The lower demand is a result of efficiency measures paid for by auction proceeds leading to a $25 annual savings to the average residential bill (Hibbard, 2012). Although some of the demand reduction is also likely due to and the recession (Navarro, 2012) and to moderate weather patterns (Afsah et al., 2012).

In 2013, California also launched a cap-and-trade program. Unlike RGGI which focuses on the electricity generation sector, California's policy represents the first active multi-sector cap-and-trade program in North America. This economy-wide policy builds on lessons from the RGGI and the EU ETS, and will provide critical experience in how a cap-and-trade system can function in the U.S. The policy intends to reduce greenhouse gas emissions from regulated entities by more than 16% by 2020, and is a central component of the state's broader strategy under Assembly Bill 32 (AB32) to reduce total GHG emissions to 1990 levels by 2020 (C2ES, 2013a; CARB, 2013).

There are other multi-state programs in progress as well, including the Transportation and Climate Initiative encompassing a dozen Northeast and Mid-Atlantic jurisdictions, and the Midwest Greenhouse Gas Reduction Accord (C2ES, 2013b).

On a continental scale, California, along with the other members of the Pacific Coast Collaborative –Oregon, Washington, and British Columbia, signed the non-binding Pacific Coast Action Plan on Climate and Energy which is an agreement to promote policies and regulations to reduce GHG emissions and promote a low-carbon economy (PCC, 2013). California is also a member of the Western Climate Initiative (WCI), along with British Columbia and Quebec, which evaluates emission-trading programs to mitigate the impacts of climate change at a sub-national level. In 2014, California and Quebec linked their cap-and-trade programs and WCI manages the compliance and tracking system (WCI, 2014).

All of these U.S., regionally-implemented, or proposed policies depend on a cap-and-trade system, and all market-based schemes require some clairvoyance on future prices, demand, and market response. Price volatility, excess permits, unforeseen lower fuel prices, gaming by market participants, and other failures can largely undermined the effectiveness of this complex and opaque policy mechanism. On the other hand, a carbon tax can lend predictability to energy prices and would be much less complex and costly to implement and manage than cap-and-trade, since an allowance tracking system and market surveillance would not be required (Goulder and Schein, 2013; Gupta et al., 2007).

However, an energy-related tax by itself is regressive. Pricing carbon would yield substantial government revenues, but careful recycling of these revenues would be necessary if policymakers want to offset the regressive nature of a comprehensive national emissions policy. One method for making such a tax progressive is to return the policy revenues back to households or otherwise subsidize lower income households. For example, Grainger and Kolstad (2009) found that a carbon tax of \$15/tCO_2 could raise as much as \$79 billion a year. If Congress provided an income tax break of \$119, \$112, \$105, and \$76 to individuals in the four lowest income quintiles, respectively, the result would be a balanced burden of about 1% of net annual income for each group, and still leave nearly $50 billion in government revenues.

In 2013, Senators Barbara Boxer (D-CA) and Bernie Sanders (I-VT) proposed, but failed to pass, a bill centered on a carbon fee and dividend framework. The Boxer–Sanders Climate Protection Act (Boxer and Sanders, 2013) proposed a $20 fee per metric ton of CO_2 (tCO_2) beginning in 2014, escalating by 5.6% annually for ten years. The carbon fee would be administered upstream—at the first point of sale of fossil fuels—and would have included border tax adjustments to protect domestic industry and encourage other countries to enact their own carbon policies. The bill would have returned 60% of the revenues monthly as direct dividends. Consistent with Senate PAYGO[6] rules, 25% of the bill's revenues were dedicated to deficit reduction (CBO, 2009a). The remaining revenues were dedicated to funding clean energy proposals and low-income weatherization.

1.3 U.S. ENERGY-CLIMATE POLICY ANALYSIS

Efforts to establish comprehensive national climate policy through Congressional legislation face many obstacles. One of the most prominent is that federal lawmakers need to balance the benefits of a proposed bill against the costs to their home state constituents. Due to energy market complexities, however, understanding the regional or national economic impacts of major national policies is no simple matter. As a result, policymakers and analysts rely on detailed energy models to evaluate the consequences of policy reforms. Estimating economic and environmental impacts using energy models has become necessary when promoting such policies.

[6] The Statutory Pay-As-You-Go Act of 2010 requires new spending or tax changes must be enacted on a "pay-as-you-go" (PAYGO) basis. The cumulative effects of such legislation must not increase projected deficits. Under the PAYGO rules, new proposals must either be budget neutral or offset with savings derived from existing funds, with the intent of strengthening budget discipline. A description of this and other U.S. Government budget concepts can be found at the following website: http://www.whitehouse.gov/sites/default/files/omb/budget/fy2013/assets/concepts.pdf

Unfortunately, today's policymakers lack the necessary modeling tools to comprehensively analyze the details of climate policies currently under debate.

Policymakers need to know the impacts of a proposed bill before voting to enact it. Certainly, they will want to know how effective the policy will be at reducing emissions and at what cost to the overall U.S. economy. However, a discussion about carbon prices will inevitably also turn to questions about state-level and income distributional impacts, neither of which are common outputs of most energy-economic models. The limited effort devoted to estimating regional or state level impacts is a limitation of the previous efforts. Furthermore, most carbon policy studies are pre-recession and pre-shale gas which has shifted supply, demand, and prices in the last few years. As a result, the efforts the energy modeling community put into analyzing the previous round of climate policy discussions have become less relevant in the current debate.

Official evaluations of U.S. energy policy proposals rely on results from NEMS, a prominent energy-economic model created and maintained by the U.S. Energy Information Administration (EIA). Results from this model also serve as the inputs to the Annual Energy Outlook (AEO) which projects energy consumption and related trends, based on existing policies, through the next 20-25 years (EIA, 2012a). Unfortunately, EIA has not yet updated its methodologies to include state-level and distributional income impacts so important to the current national policy debate.

1.3.1 Energy Policy-making in the U.S. is based on NEMS results

NEMS is arguably the most influential energy model in the U.S. EIA uses NEMS to generate the federal government's annual long-term forecast of national energy consumption and to evaluate prospective federal energy policies (EIA, 2009b). NEMS is considered such an important tool that other models are calibrated to its forecasts, in both government and academic practice. Consequently, it has a significant influence over expert opinions of plausible energy futures. If requested by Congress, EIA will evaluate the impacts of a proposed energy and climate policy. Some examples include the analysis of the Kyoto Protocol GHG emissions limits (EIA, 1998), the Lieberman–

Warner Climate Security Act (EIA, 2008a), the Low Carbon Economy Act (EIA, 2008b), the Waxman–Markey (EIA, 2009a), the American Power act (EIA, 2010a), and Carbon Limits and Energy for America's Renewal (CLEAR) Act (EIA, 2010b).

Because of the model's prevalence, many academic publications use NEMS to evaluate how technological or policy changes might impact the U.S. energy-economy. Building off prior work from the national laboratories, the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) commissioned a follow-up report to the EIA Kyoto Protocol study from a group of national laboratory scientists (Brown et al., 2001). Other examples include a prospective analysis of the impact of a federal renewable portfolio standard on U.S. energy markets (Kydes, 2007), the impacts from the 1990 Clean Air Act Amendments (Luong et al., 1998), an analysis of polices to reduce oil consumption and greenhouse gas emissions from the U.S. transportation sector (Morrow et al., 2010), the impact of climate and energy policies on the U.S. forest products industry (Brown and Baek, 2010), the effects of climate policy on freshwater withdrawals for thermoelectric power generation (Chandel et al., 2011), and household impacts of the Boxer–Sanders Climate Protection Act (Wilkerson et al., 2014a). Consulting groups, such as McKinsey & Company (Choi Granade et al., 2009; Creyts et al., 2007) and Rhodium Group (Houser and Mohan, 2014) also use NEMS to analyze the U.S. energy-economy.

NEMS offers a massively detailed representation of the U.S. energy-economic structure which allows for a plausible simulation of energy demand within different sectors. However, several aspects of the model create difficulties when the model is used to evaluate prospective carbon tax policies. While NEMS has some ability to estimate the geographic impacts of climate policy, these calculations are made at a high level with very little regional or sectoral evaluation. Currently, model results are aggregated at the level of nine U.S. Census Divisions.

Furthermore, understanding how costs relate to income levels is a key step to designing the appropriate level of compensation, such as in Boxer–Sanders which proposed to rebate a portion of the total revenue to consumers. Yet NEMS does not analyze the impacts of prospective policies across different household income levels nor track any household distributional or individual consumer details. Furthermore, income and tax related forecasts for consumers and firms are provided only in aggregate, including total disposable income, total personal taxes, total corporate income, and total corporate taxes. Thus, any NEMS-based analysis can only evaluate U.S. consumers as a whole. Until the model incorporates more disaggregated household income, tax, expenditure, and consumption calculations, developing an estimate of the distributional impact of any policy requires combining the NEMS energy forecast with external energy expenditure data.

1.3.2 Previous U.S. carbon policy impact studies

Many organizations have assessed the impacts to the U.S. economy from energy and climate polices (some with NEMS). Each study has strengths and weaknesses, but none is sufficiently comprehensive to assess integrated impacts to both the macroeconomic variables and household income distributions. This section will show where the current body of work falls short, and where the current study fits in.

1.3.2.1 Official U.S. policy analyses

Despite not assessing households or income distributions, a NEMS-based analysis of a U.S. carbon policy is still very useful since NEMS is the most detailed model of the U.S. energy-economy. The EIA analysis of the Waxman–Markey bill (EIA, 2009a) found that, depending on the assumed cost of low-carbon technology adoption and financing options, the proposed cap-and-trade system would reduce cumulative emissions by 21-33% by 2030. Most of these reductions would come from offsets since they are a relatively low-cost compliance option. Otherwise, the vast majority of structural changes would come from CO_2 reductions in electricity-sector achieved primarily from by reducing coal-fired electricity generation. A cap-and-trade scheme defines the emission limit, so the price is a function of the market response. EIA found that this policy would produce an equivalent price for the ‘Basic Case’ (main scenario) of \$32/tCO_2 in 2020 and \$65/tCO_2 in 2030 (in 2007 dollars), with the full suite of scenarios ranging from \$20 to \$47/tCO_2 in 2020 and \$93 to \$191/tCO_2 in 2030, depending on the amount of international emissions trading allowed to occur.

Internalizing the cost of carbon emissions increases the cost of using energy, which reduces economic output and purchasing power, and lowers aggregate demand for goods and services. The projected cost to GDP from Waxman–Markey was found to be 0.3% reduction in the Basic policy case relative to the Reference scenario and ranged from 0.2% to 0.9% by 2030 for all scenarios. Additionally, most of the scenarios evaluated by EIA projected a 3-4% increase in residential electricity prices above the Reference scenario by 2020 to about 9.5 cents/kWh. However, by 2030, EIA projected almost 20% increase over the Reference scenario electricity price to about 12 cents/kWh, reflecting both higher allowance prices and the phase-out of the free allocation of allowances.[7] In total, EIA projected the additional cost to the average American household annual energy bill would be $134 in 2020 and $339 in 2030 (in 2007 dollars) for the Basic policy case.

However, the bill proposed to allocate credits or funds to protect energy-intensive industries from the adverse impacts of the policy. Although these free allocations of emissions permits would be phased out, the intent is to afford energy-intensive industries an adjustment period, lessening the impact to the industry and the overall economy. The bill would keep electricity price impacts to households relatively low by indirectly compensating consumers through allowances to local electricity distribution companies and utilities for ratepayer benefit.

When U.S. policymakers propose an energy or climate bill such as Waxman–Markey, they formally request that EIA estimate the economic impacts resulting from the legislation.[8] EIA, if requested, will also evaluate Boxer–Sanders, as they have done for Waxman–Markey and others. These are useful studies since EIA has extensive experience in modifying NEMS to incorporate new policies and in interpreting NEMS results. However, their analyses are still limited to U.S. macroeconomic impacts. With respect to households, the model can only compute

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[7] Note that these prices are for average (all sectors) electricity prices, but Residential electricity prices are typically much higher than the U.S. average electricity price. For example, in 2013, the average electricity cost 9.5 cents/kWh, but the Residential price was 11.5 cents/kWh (EIA, 2013a)
[8] An example of such a request can be found in Appendix A of EIA's analysis to the Waxman–Markey legislation (EIA, 2009a)

aggregate results (i.e., the average American household), and cannot compute anything relative to distributional and regional household impacts. This has led others speculate on household impacts by building on static results from NEMS (or other models) or building their own distributional interfaces.

The Congressional Budget Office (CBO) completed a separate analysis on the Waxman-Markey bill and found roughly similar macroeconomic impacts as EIA, of about $165 net cost to the average American household in 2010, or roughly 0.2% of average after-tax income.[9] CBO went further to couple the economic forecasts with several national income and expenditure summaries[10] to show the impact to average households in each income quintile bracket. They estimated that the gross costs to households would range from $425 on the average household in the lowest quintile income bracket (lowest 20% of households by income) to $1,380 on the average household in the highest income quintile. However, added to this compliance and resource cost are the benefits of direct rebates and transfers and indirect allocation of allowances. Combined, the CBO estimated that households in the lowest income quintile would actually receive a total net benefit of about $40, while households in the highest income quintile would see a net cost of $245 per year (CBO, 2009b; Elmendorf, 2009). Thus, any comprehensive U.S. energy policy analysis should include extending beyond just the average cost to households, to include policy benefits and distributional aspects.

1.3.2.2 Other household impact studies

The CBO is not the first organization to combine energy-economic forecasts with national summary or expenditure data. Metcalf (2008a) used the Bureau of Labor

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[9] This result was the average impact projected from a suite of peer-reviewed models including NEMS, MIT's Emissions Prediction and Policy Analysis (EPPA) model, U.S. EPA's Applied Dynamic Analysis of the Global Economy (ADAGE), Second Generation Model (SGM) and MiniCAM models developed by the Joint Global Change Research Institute, the Model for Evaluating the Regional and Global Effects of GHG Reduction Policies (MERGE) developed by Stanford University and EPRI, and the Multi-region National-North American Electricity and Environment (MRN-NEEM) model developed and used by CRA International.

[10] CBO obtained income data from the Internal Revenue Service, household characteristics from the Current Population Survey reported by the Bureau of the Census, and data on household expenditures from the Consumer Expenditure (CEX) Survey by the Bureau of Labor Statistics (Elmendorf, 2009)

Statistics (BLS) 2005 Consumer Expenditure (CEX) survey data to assess distributional impacts of a $15/tCO$_2$ carbon fee combined with an earned income tax credit (EITC). Metcalf used macroeconomic results from the MIT Emissions Prediction and Policy Analysis (EPPA) computable general equilibrium (CGE) model, which is the energy-economic portion of the larger Integrated Global System Modeling (IGSM) framework (Paltsev et al., 2005).

Metcalf assumed the entire tax would pass directly to households, which would increase electricity prices by over 14%, natural gas to industrial users by about 9%, and gasoline prices[11] by over 7%. Metcalf also pointed out that a $15/tCO$_2$ tax would increase the price of coal-fired electricity generation by 24 percent (1.78 cents per kilowatt hour) based on the average retail price of electricity in 2003. Coupling these (and other energy-related impacts) to the CEX, the lowest income decile (lowest 10% of households by income) would see a $276 annual cost and the highest decile household would see $1,224 cost.

After Metcalf used the revenues to fund the EITC, the lowest three deciles would still see a small net cost, which would equate to less than 1% of after-tax income. The highest decile would also see slight net cost though it would be insignificant relative to income. However, the middle deciles (4-9) would see a net benefit ranging from 0-0.3% of household income. Metcalf also evaluated average households by the nine Census Divisions and found all would see slight differences, but all within the range of net benefit of 0.2% of after-tax income and net cost of 0.6% of income.

More recently, this approach has been used to compare earlier cap-and-trade and cap-and-dividend legislation. Using the CEX data, Blonz et al., (2011) compared the impact to income quintiles and age groups from several proposed policies. They found that, with all appropriate household allowances, Waxman–Markey is progressive through the lowest four income quintiles, with a net benefit of 0.2% to the lowest quintile and net cost ranging from 0.3% to 0.4% to the next three quintiles.

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[11] Based on U.S. average 2003 gasoline prices

They also found that Waxman–Markey would provide a consistent net benefit to average households in all four Census Regions ranging between 0.66% and 0.86% of income.

Still others have taken the CEX-based analysis further to estimate not only the direct energy costs and incentives, but the indirect costs to households as well. Indirect impacts include the increased cost of non-energy goods and services resulting from increased energy cost. Hassett et al., (2009) considered a $15/t$CO_2$ tax with the primary goal of assessing how regressive a carbon tax is under different metrics (without including rebates and allowances to mitigate it). They determined that using the common income-based metric, both the direct and indirect costs would be regressive. The direct impact from a carbon tax in 2003 would range from 2.12% of after-tax income for the lowest decile households only 0.36% in the highest decile households. The indirect impacts ranged from 1.60% to 0.45%, respectively. Using consumption as a proxy for income, they found the indirect costs for all deciles to be around 0.5% of income, while the direct costs to would range from 0.98% to 0.37% from the lowest to highest deciles, respectively. When using a lifetime-consumption metric, the direct cost regressive range narrows somewhat.

In a similar study, Mathur and Morris (2014) considered direct and indirect costs when the tax revenues from a $15/t$CO_2$ tax in 2010 are used to offset personal income or corporate taxes. They found that the tax swaps lower the overall burden on the poorest two deciles, but exacerbate the regressivity in the higher end. That is, the benefit to the highest income households is greater than their share of the burden. The direct range for a 50/50 split rebate between labor and capital would leave a direct impact of 2.13% direct and 0.91% indirect income burden on the lowest decile to 0.87% benefit for both direct and indirect impacts to the highest decile.

1.3.2.3 Where these studies fall short

The above studies, and many others, all attempt to address a particular aspect of the impacts of carbon policies in the U.S. However, each is only a piece of the puzzle. For example, studies evaluating the indirect costs to households consider the impacts of a tax during a single calendar year, prompting Mathur and Morris to stress that their results do not account for dynamic effects, such as a reduction in emissions, escalating tax rates, macroeconomic feedbacks, efficiency gains, or even consumer responses to increased energy prices.

CGE models generally incorporate interactions and market linkages in the economy and can do a good job at capturing the economy-wide impacts of climate policy, but rely on simplified representations of supply and demand sectors and household income and consumption patterns. Furthermore, CGE-based IAMs, such as EPPA, are designed to capture economy wide, long-run impacts and are not designed to capture annual market responses. So while they solve the energy economic impacts rather quickly, most CGE models of the U.S. economy miss some of the details needed for a comprehensive impact study. NEMS, on the other hand, is arguably the best representation of the U.S. energy economic system, but alone, it cannot assess household distributional impacts.

Some analysts have coupled results from NEMS with consumption survey data, but this data is often very coarse, limiting the study to U.S.-wide income brackets or the nine Census Divisions. Furthermore, the current literature generally deals with market data and projections reflecting pre-recession and pre-shale gas values and expectations. However, the U.S. economic baselines have changed from these recent events, so updated studies are needed.

1.4 EVALUATING CARBON FEE AND DIVIDEND POLICIES

EIA may eventually evaluate a policy similar to Boxer–Sanders, but this still will not address household or other distributional impacts, since these are not treated in the models EIA typically uses. Furthermore, the analysis would be about a specific policy and not about the impacts more broadly. A carbon fee and dividend policy is emerging as preferred over cap-and-trade at the national level, and policymakers need to know what the potential costs and benefits of such a policy would look like in the current post-recession, post shale-gas energy economic environment.

This dissertation demonstrates new methods that harness the existing strengths of the federal government's forecasting and policy analysis tool, NEMS, linked with multiple robust external expenditure data sources. This approach permits analysts to estimate the impact of climate policies across income levels and geography. The carbon fee and dividend polices evaluated here map out the economic impacts from a range of carbon fees and dividends. These detailed forecast model results are integrated with household expenditure data to evaluate the distributional benefits of different rebate amounts to households in different income brackets and regions including several individual states. The results provide a reliable basis on which individual policymakers could evaluate the impacts of legislative proposals on their constituencies.

This approach requires several steps. First, the economic impacts of carbon prices on energy-related emissions, demand, and prices are evaluated using NEMS. Next, these results are correlated to published expenditure data to estimate the direct impacts to income brackets, regions, and some states. This study extends the usefulness of this approach used by others by incorporating both CEX data and the Residential Energy Consumption Survey (RECS) data from the EIA. Then, a rebate of a portion of the revenues is applied uniformly (per capita) to households to determine the net benefit of such dividend policies. Finally, sensitivities to rebate amount and different carbon fee revenue recycling methods will show how to minimize economic and fiscal impacts to the economy and to taxpayers.

This study addresses three critical pieces for evaluating carbon fee policies:

1) U.S. economic and fiscal impacts: How do carbon fees affect macroeconomic and sectoral economic drivers and what are the fiscal impacts?
2) Household impacts: How do tax-rebate policies directly impact households in different income brackets and regions?
3) Revenue Recycling Methods: How do different recycling methods affect these results?

Each of these questions will be addressed in turn in the following chapters. First, Chapter 2 provides additional context for the analysis. It begins with a high-level description of NEMS and what is required to run carbon policy scenarios in the model. Next is a description of the carbon price scenarios and the rebate scenarios used in the study. The reminder of the chapter discusses the general methods and approach including an introduction to several decomposition techniques used in the subsequent chapters.

Chapter 3 addresses the first question above by showing total carbon emission reductions achieved by the carbon fees, the revenues they raise, and the impacts to the economy and demand sectors. The U.S. economy as a whole, the demand sectors, and the electricity supply sector are decomposed to isolate the economic drivers of emissions in each sector. This will show how each sector in the model is affected by such policies, and identify the industries that are most exposed to carbon prices.

Chapter 4 addresses the second question by first showing, for an average American household, the annual financial impact from carbon price and consumption forecasts, and the benefits of several rebate scenarios to the same household. Next, impacts to household income brackets and Census Divisions are assessed in the same manner. This analysis is further extended to assess the impacts to households in the 16 most-populous states.

Chapter 5 presents the results from NEMS of several different direct revenue recycling methods. It synthesizes the knowledge gained from the previous chapters on how the model behaves under carbon prices, and how those prices, combined with rebates, affect American households. It further demonstrates how the NEMS framework is not yet adequate to evaluate realistic revenue recycling methods.

Finally, Chapter 6 highlights the key results, includes a summary of all results, and a discussion of policy implications.

Chapter 2

MODEL, METHODS, AND APPROACH

2.1 INTRODUCTION

This chapter provides an introduction to the model and methods enlisted for this study. Completing this research requires several activities. In particular, one needs to configure and run an energy economic model of the U.S. economy to evaluate the integrated impacts from a range of carbon policies. Also, tools need to be recruited and developed that allow for systematic comparisons between scenarios. These and other methods are introduced here, but will be covered in further detail when relevant in subsequent chapters.

Section 2.2 describes the carbon fee and dividend policies for this study. Next, Section 2.3 provides an introduction to the energy economic model, the National Energy Modeling System (NEMS), including a description of how to set up and run scenarios and the pertinent model variables.

The balance of the chapter describes the techniques used to measure the impacts from these policies. Section 2.4 introduces several economic decomposition methods used to evaluate key economic drivers. Identifying the key drivers will identify which sectors of the U.S. economy are most affected by the carbon policies. Section 2.5 describes how the NEMS economic results can be coupled to household consumer expenditure data to assess the household impacts.

Finally, Section 2.6 provides a brief summary. The NEMS setup, policy scenarios, and analysis techniques described here serve as the backdrop for the ensuing chapters.

2.2 POLICY SCENARIOS

There are two sets of scenarios described here: carbon prices and rebate percentages. Carbon prices are set in NEMS and the results are static when evaluating household impacts.

2.2.1 Carbon price scenarios

A suite of carbon fees at different annual escalation rates allows for an exploration of the carbon policy space. The Boxer–Sanders Climate Protection Act of 2013 proposed a price of $20/t$CO_2$, beginning in 2014 and escalating at 5.6% annually (Boxer and Sanders, 2013). An analysis of that policy shows that both the magnitude and escalation are reasonable, given current economic conditions and projected impacts (Wilkerson et al., 2014a). The scenarios chosen here bound both the starting fee and the escalation rate of that bill.

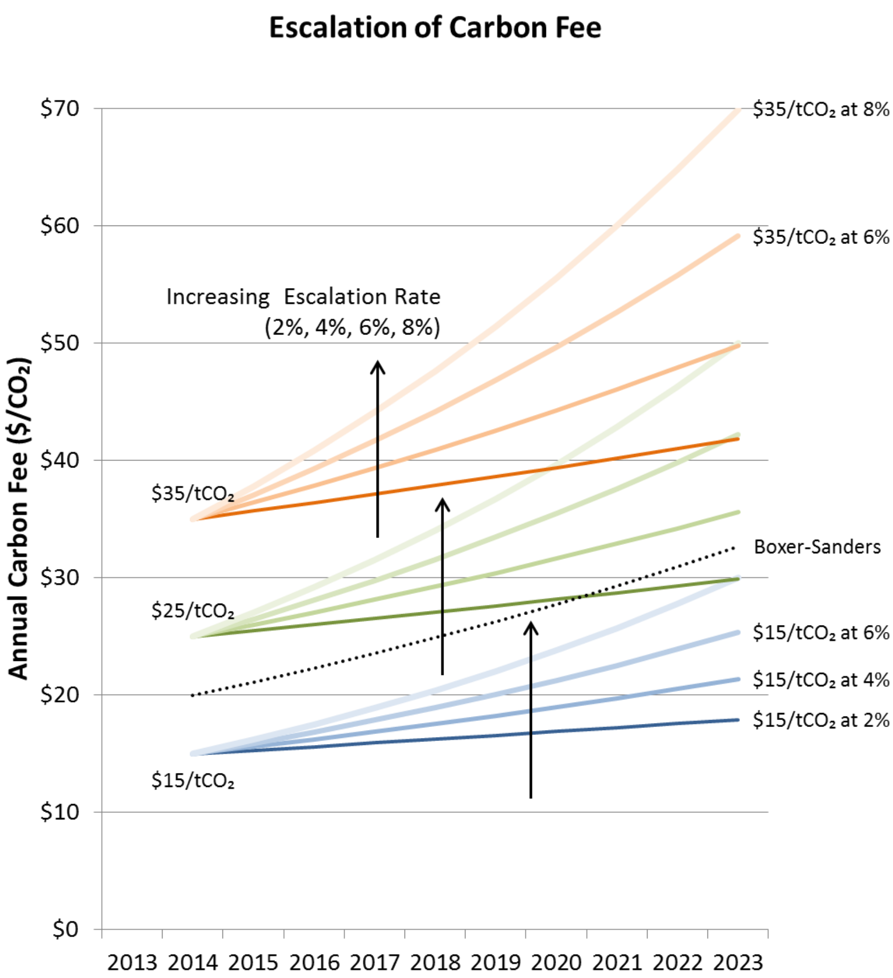

Figure 2.1 Carbon fee scenarios of $15, $25, and $35/t$CO_2$, each escalating at 2, 4, 6, & 8% annually (nominal). The Boxer–Sanders Climate Protection Act of 2013 ($20/t$CO_2$ at 5.6%) is shown for comparison.

The scenarios for this study begin in 2014 at \$15, \$25, and \$35/tCO_2, and each escalates at 2%, 4%, 6%, and 8% annually for ten years (see Figure 2.1). These initial fees and escalation rates were chosen to match those from a recent policy discussion drafted by the U.S. House of Representatives Committee on Energy and Commerce (Waxman et al., 2013). The purpose of these scenarios is to map out the economic and fiscal impacts to the economy and to households over a range of policies. When appropriate or useful, a comparison to the Boxer–Sanders Climate Protection Act scenario result is included.

NEMS is designed to provide a forecast for the next 20-25 years, and the models' current time horizon is 2040. However, this study only focuses on the first ten years for several reasons. First, the end-use appliance detail in NEMS is provided in large part by outside consulting groups (e.g., Navigant) who typically only provide appliance efficiency and penetration projections for the next ten years. As a result, the richness of the bottom-up detail in NEMS is reduced beyond this point and the quality of the forecast diminished. Second, policymakers are focused on the ten-year time horizon because that is the relevant time-frame in which the U.S. budget is evaluated. Third, Chapter 3 will show that most of the models' response to a carbon price of any size occurs within the first few years. For these reasons, this analysis is limited to the first ten years of the policy forecasts.

2.2.2 Revenue rebate scenarios

Boxer–Sanders proposed to return 60% of the annual revenues back to individual households in the form of a per capita rebate. Wilkerson, et al., (2014a) showed that under the carbon pricing scenario of that Bill, a 60% rebate is sufficient to offset the increase in direct energy costs to nearly every household market segment, including the average household in all four Census Regions (Northeast, Midwest, South, West), the first four of five income quintile brackets, and households earning up to \$120,000 per year. Consequently, the focus for this study is on revenue rebates of 40%, 50%, and 60%.

2.3 Energy-economic model: NEMS

NEMS is a technology-rich energy-economic equilibrium model that is a hybrid of "top-down" and "bottom-up" approaches: the model includes economy-wide general equilibrium effects, but uses a detailed engineering-economic approach to generate energy demand from individual technologies and detailed economic sub-sectors (EIA, 2009b; Gabriel et al., 2001). The model includes thousands of input parameters drawn from EIA energy-use surveys, consultants' reports, and model developers' expert opinions. (For a review of the history of NEMS and its predecessors, please see Appendix A.2)

NEMS is developed by the EIA and paid for by U.S. taxpayers. As a result, the model is free to users outside EIA once the user explains the research intent and promises no further distribution of the code. However, that is where the ease and simplicity stops. To engage and run NEMS involves more than a dozen additional software packages and programing environments, several of which are costly, and requires a very diverse skillset to install, configure, and integrate. The list includes compilers, programming environments, an operating system emulator, multiple optimization packages and the necessary solver links. Even the models' macroeconomic activity module (MAM), which determines international and intra-sector feedbacks, has been developed by commercial groups external to EIA. (For a description and summary of the required software and environments, please see Appendix A.3)

2.3.1 Running NEMS

When a NEMS run is initiated, it computes each year in sequence through the entire time horizon, ending in the year 2040 by default. Each run takes nearly four hours on a relatively fast desktop computer. At the end of that cycle, NEMS evaluates the convergence criteria and determines if the run has sufficiently converged to a solution. If it has not, the model uses the current solution as the input to the next cycle and starts over. (Please see Appendix A.4 for a description of model convergence criteria).

The analysis described in the following chapters is based on an independent copy of the NEMS, 2013 Early Release Version. To ensure the model was installed and engaged properly, including its third-party software entourage, the local solution to the Reference case was confirmed to accurately reproduce the EIA's Reference scenario projections (See Appendix A.5), published in the 2013 edition of the Annual Energy Outlook (AEO2013)(EIA, 2013a). Thus, the local Stanford University installation provides a reliable means of assessing what EIA's official copy of NEMS would project for the same scenarios modeled here. Nevertheless, this analysis is independent and should not be confused with official government policy analysis. As a result, outputs from the scenarios described throughout this document are designated as coming from NEMS-Stanford.

2.3.2 Carbon fees and revenue recycling in NEMS

Applying a carbon fee within the NEMS framework is relatively straightforward. Carbon prices are set in the emissions policy data file *epmdata.txt*, which is read when the code is initiated. This input requires an explicit annual carbon price in $/kg of carbon. For a detailed description of this file and the emissions policy submodule, the reader is directed to the NEMS Integrating Module documentation (EIA, 2010c).

NEMS has several default options for how its macroeconomic calculations treat the use of carbon fee revenues. These are set with the *mactax* flag in the *scedes* (scenario description) text file, which is a collection of set points, flags, and input file names to be used during the NEMS run. The *mactax* flag is subsequently used in conjunction with the *mcevcode.txt* text file, which serves as an interface between the core model code and the MAM (EIA, 2013b). To add some confusion, the variable *mactax* becomes the variable *taxmode* in the MAM, so is identified in the *mcevcode.txt* file as such. The value of *mactax,* effectively *taxmode,* can be set from 0-5. A value of 0 turns carbon pricing off, while settings 1-5 turn carbon pricing on with some binary control over how revenues are recycled through the economy: *maxtax* 1 and 2 return revenues to consumers and business (respectively) in a revenue neutral manner;

mactax 3 is deficit reduction; while *mactax* 4 and 5 return revenues to consumers and business (respectively) in a deficit neutral manner.

Revenue neutral refers to legislative bills or proposals that have no net cost, such that revenues raised must offset provisions that lose revenues. Deficit neutral refers to legislative bills or proposals that pay for themselves over some budget period, which is one year in NEMS. A carbon fee in NEMS assumes minimal administrative costs, so revenue neutral and deficit neutral produce almost identical rebate amounts. Both return revenues back into the economy so the model can account for associated tax relief, rebound, and spillovers. Deficit reduction, however, effectively takes that money out of the economy. The model doesn't have any constraints associated with the magnitude of the federal deficit, so paying down this debt is of no consequence to any other decision in the model.

Indeed, all of these default revenue recycling options are problematic in the model for different reasons. For example, returning revenues to *consumers* is effectively a personal tax rebate, but income and tax related information in NEMS is computed in-aggregate by the MAM. Neither NEMS nor the MAM have income classes for targeted redistribution of carbon tax receipts. While there may be other ways of returning tax revenues to households, the reduction in federal personal tax receipts is the only method EIA uses with confidence.[12] So, the redistribution of revenues to *consumers* reduces total aggregate personal tax receipts.

However, income tax is a very progressive tax, so most of the total tax receipts collected are from the wealthiest Americans. Households in the highest income quintile (wealthiest 20% of American households) contribute nearly 70% of all U.S. income taxes, and the top two quintiles (wealthiest 40%) pay more than 85% of all income taxes. By contrast, the lowest quintile contributes less than 0.5% to aggregate U.S. income tax receipts (CBO, 2013). Returning revenues to *consumers* effectively reduces taxes on the wealthiest Americans and has little to no impact on the poorest. Thus, the application of the tax rebate in this manner in NEMS is very regressive.

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[12] Thanks to Russell Tarver at EIA for describing the NEMS revenue recycling process and limitations

Also, returning revenues to the wealthiest households fails to capture the fiscal multiplier effect of giving money to lower income residents. The multiplier is a measure of the effectiveness of government spending. Lower income households, with a multiplier greater than 1, tend to spend more of their dividends and rebates quickly and locally. Higher income households tend to save more and spend less of a rebate, thus a multiplier less than 1. A rebate given to a lower income household will compound or multiply further once spent, since money spent locally also tends to be re-spent quickly and locally. Additionally, greater household spending (and re-spending) encourages firms to hire more employees, which further increases household income and spending (Elmendorf and Furman, 2008; Johnson et al., 2004).

Rebating money to the rich will not necessarily stimulate increased purchasing since the per capita rebate is a much smaller increase in net wealth. Yet, providing the same amount of money to a low-income household will likely spur additional spending on goods and services. Rebating to aggregate income tax payers in the model does allows for a coarse representation of a re-spending effect, and is at least better than nothing. However, a per capita rebate would likely have a greater re-spending effect because fiscal multipliers for low income transfers are generally believed to be higher.

Like returning revenues to *consumers*, returning revenues to *businesses* is effectively a corporate tax rebate, but corporate income and taxes in NEMS are also computed in-aggregate. Corporate tax receipts relative to wealth distribution are even more skewed than in households. The wealthiest 0.1% of all corporations pay almost 85% of all U.S. corporate taxes. The wealthiest 5% pay over 95% of all taxes (TPC, 2011). So, reducing aggregate corporate tax receipts in the model effectively gives a tax break to the wealthiest corporations in America –oil companies, banks, pharmaceuticals, and high-tech companies.

None of the default options allow for a mixture of deficit reduction, residential rebates, and other policy expenditures. Methods for modifying revenue recycling beyond the default options are the subject of Chapter 5; however, that chapter will be far more insightful after understanding the general impacts of carbon fees on the economy (Chapter 3) and to households (Chapter 4). Consequently, for the next few chapters, the default settings for revenue recycling are used to define the analysis framework and evaluate the baseline assumptions in NEMS.

As the current study addresses household impacts, the results described in the next few chapters use *mactax* = 4. Thus, recycling all revenue back to households (minus any revenue required to keep from increasing the deficit) for the purposes of the model's internal macroeconomic calculations. Also, EIA uses *mactacx* = 4 for NEMS sensitivity side cases[13] as described in Appendix D of the AEO2013 (EIA, 2013a). Furthermore, different default revenue options in NEMS do not materially affect GDP, net greenhouse gas emissions, or residential energy prices (see Appendix A.7).

2.3.3 NEMS foresight and convergence issues

The model has some difficulty converging through 2040 under the higher carbon prices escalating at the higher rates (for reasons described in Appendix A.4), especially in the later years. Since this study is concerned with only the first ten years of the policies, a logical solution would be to run the model for only 10-15 years instead of the default 25 years. This imposes a problem that was not immediately solvable. When otherwise identical policy scenarios are run with a last year (variable *LASTYR*) of 2026[14] and 2040, they produce different results. This is a consequence of foresight parameters in the electricity market module (EMM) in NEMS. Even setting the foresight variables appropriately does resolve the issue. The recommendation from EIA is to always run through 2040, since that is the configuration under which the foresight algorithms were developed. (Please see Appendix A.6 for more details on NEMS foresight parameters and issues).

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[13] EIA runs many side cases including a GHG sensitivity study. These side cases do not reflect any policy, but are provided to show how NEMS will behave under different carbon prices. The CO_2 prices for their cases are \$10, \$20, and \$30/tCO_2, so they are not directly comparable to the prices in the current study. However, results from this study correlate well with EIA's side case results. Analysis of the impacts in the current study goes well beyond the results provided by EIA for their side cases.

[14] The policies begin in 2014 and the analysis is through 2023 (first ten years). NEMS convergence is based on the worst three years which are typically the last three years of the run (See Appendix A.4). Thus, running for an additional three years (through 2026) improves the solution for desired time frame.

Lower carbon fees at slower escalation rates typically converged in four to seven cycles through the model horizon of 2040. However, the \$25/tCO_2 escalating at 8% scenario and the \$35/tCO_2 escalating at 6% and 8% scenarios took far more cycles and, ultimately, none of these three scenarios converged through 2040. However, all scenarios converged through the period of interest for this study. (Again, please see Appendix A.4 for a description of model convergence criteria).

2.4 MEASURING U.S. ECONOMIC IMPACTS

When engaging with any policymaker on a discussion about modeling a price on carbon emissions, the first question that arises is about how effective the policy will be in reducing carbon emissions. The next question regards concern for the cost to the economy. NEMS tracks energy and non-energy related CO_2 emissions so the answer to the first question is relatively straightforward from the model results. However, understanding the answer to the second question requires a brief introduction to economic indicators and decomposition methods. Decomposing the key indicators will help diagnose which segments of the market are impacted most by a given policy. This, in-turn, can lead to more in-depth sectoral analysis.

This analysis will illustrate how the policy drives structural changes and technology efficiency. One useful starting point is the IPAT identity (Equation 2.1), which defines the product of population (P), affluence (A), and a wild card technology metric (T) as the impact (I) of that technology. IPAT was suggested as a useful measure of economic growth and impacts in the early 1970's (Commoner, 1971; Ehrlich and Holdren, 1971; Holdren and Ehrlich, 1974).

$$IPAT\text{:}\ \ Impact\ = Population\ x\ \ Affluence\ x\ \ Technology \qquad \mathbf{2.1}$$

Identifying relationships between key economic drivers captured by IPAT is useful; however, it is often considered only a logical starting point to more in-depth analysis (Daily and Ehrlich, 1992; Dietz and Rosa, 1994; Roca, 2002). Consequently, several extensions have been developed to address specific issues based on the basic IPAT framework. Some examples are a behavior extension, I=PBAT (Schulze, 2002), a stochastic interpretation of IPAT (York et al., 2003), and the urbanization for regional carbon management (Scholz, 2006). A useful emissions-related extension of IPAT was popularized by and named after Yoichi Kaya (Kaya, 1990) and is used to compare, among others, the Intergovernmental Panel on Climate Change (IPCC) emissions scenarios (Kriegler et al., 2012; Nakicenovic et al., 2000). The Kaya identity was expanded in fundamental ways by Hummel and Weyant (2006) and will be addressed in the next section.

2.4.1 Kaya identity

The Kaya identity (Equation 2.2) extends IPAT to estimate carbon emissions of the economy. Emissions of CO_2 are equivalent to the product of population (P), affluence or economic welfare (GDP/P), primary energy intensity (PE/GDP), and carbon intensity (CO_2/PE). The first three terms represent the IPAT identity, where the technology wildcard T is represented by primary energy intensity.

$$CO_2 = P * \frac{GDP}{P} * \frac{PE}{GDP} * \frac{CO_2}{PE} \qquad \mathbf{2.2}$$

Primary energy can be decoupled from final energy (FE) to reveal the energy intensity of economic activity (FE/GDP) and energy supply losses (PE/FE). The first term isolates the final energy required to meet the end-user demand for energy services (e.g., water heating, lighting, cooking, etc.). The latter term identifies supply chain losses including energy conversion loses (e.g., combustion efficiency of electricity generators) and transmission and distribution (T&D) infrastructure loses. How these change under different scenarios will determine where structural changes and efficiency improvements occur in the economy. The combination of these two terms replaces the primary energy intensity term (PE/GDP) in Equation 2.2.

Increasing the cost of energy with a carbon fee will impact both behavioral and technology changes, both of which are embodied in the changes in energy demand or intensity. Behavioral impacts would emerge as a *reduced demand for a given energy service*, such as by lowering the household thermostat set point during the winter months. On the other hand, technological efficiency improvements would show up as a *reduction in energy required for a given energy service*, such as installing more efficient lighting in a commercial office building.[15] Unfortunately, the level of disaggregation within each sector in NEMS makes the source of the change difficult to discern. Nonetheless, evaluating the change in energy intensity will encompass both.

Carbon intensity can also be decoupled to account for carbon capture and sequestration (CCS). The total carbon intensity of primary energy (TCO_2/PE) combined with the quantity of CCS will identify the fraction of CO_2 disposed to the atmosphere (CO_2/TCO_2). Combined with the PE and FE expansion, these terms form the expanded Kaya identity (Equation 2.3), which can be helpful in understanding and communicating structural and efficiency impacts of different scenarios (Hummel and Weyant, 2006). NEMS does not forecast measureable CCS until after 2025, so all of the CO_2 emitted from the transformation of carbon-based fuels is assumed to be disposed to the atmosphere. Hence, the final term in the expanded Kaya identity for scenarios described later in this study is equal to 1.

$$CO_2 = P * \frac{GDP}{P} * \left[\frac{FE}{GDP} * \frac{PE}{FE}\right] * \left[\frac{TCO_2}{PE} * \frac{CO_2}{TCO_2}\right] \qquad \textbf{2.3}$$

Using percent changes of these parameters one can determine the fraction of avoided carbon attributable to efficiency changes or result from switching to lower carbon intensity fuels. The percent of primary energy savings and the percent carbon savings from the baseline determine the amount of carbon savings from fuel switching. Demand side efficiency is determined by the final energy savings and supply side is determined by the difference between supply and demand savings (see Equations 2.4–2.6). The sum of these three terms represents 100 percent of the carbon savings.

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[15] Efficiency improvements are often considered demand side improvements, although they can also occur on the supply side. Equation 2.3 distinguishes between demand side energy efficiency and that occurring on the supply side, with the additional complexity that the supply side efficiency term also includes the effects of shifting to (for example) electricity from end-use fuels. See Hummel and Weyant (2006) for more details.

$$\%CO_2\ from\ fuel\ switching = 1 - \frac{\%PE\ savings}{\%CO_2\ savings} \quad \textbf{2.4}$$

$$\%CO_2\ from\ \text{demand}\ side\ efficiency = \frac{\%FE\ savings}{\%CO_2\ savings} \quad \textbf{2.5}$$

$$\%CO_2\ from\ supply\ side\ efficiency = \frac{\%PE\ savings - \%FE\ savings}{\%CO_2\ savings} \quad \textbf{2.6}$$

2.4.2 Integrated assessment model diagnostic indicators

Integrated Assessment Models (IAMs) are becoming more widely used for energy and climate policy analysis. IAMs combine energy-economics with knowledge from the natural and social sciences in a quantitative framework. This framework represents the energy economics of each region (although with far less detail than models such as NEMS), integrated with a simple climate feedback model. The intent of such a model is to inform technology and economic policy decisions in light of climate impacts.

However, different IAMs can report significantly different results based entirely on model assumptions and constraints (Wilkerson et al., 2014b). To help diagnose differences between models and scenarios, a recent IAM inter-model diagnostics study identified the criteria that diagnostic indicators should meet and offered four simple extensions of the Kaya framework that can further characterize the model response to a given policy (Kriegler et al., 2014). These indicators describe the size of the emissions reduction from the policy, the reliance on carbon intensity vs. energy intensity to reduce emissions, the scale of the energy system transformation, and the mitigation costs as a function of carbon price. While these indicators were developed to help diagnose differences between IAMs (which NEMS is not), the methods extend the usefulness of the Kaya framework, so the first three are utilized in this study.

The first indicator assesses the percent carbon reduction from the base case in a given year (t), and is identified as the Relative Abatement Index (RAI). The RAI is also the residual of CO_2 between the reference and policy cases. In global IAM studies,

$$\mathrm{RAI} = \frac{\mathrm{CO}_2^{\mathrm{base}}(t) - CO_2^{policy}(t)}{\mathrm{CO}_2^{\mathrm{base}}(t)} = Res(CO_2) \qquad \textbf{2.7}$$

In the extended Kaya framework in Equation 2.3, the first two indicators involve population and GDP. Within NEMS (as well as in most IAMs), population is exogenous and will not change between scenarios. GDP is endogenous in NEMS, but Chapter 3 will show that there is less than a few percent difference in GDP between the most aggressive scenario and the Reference scenario. So, while population and GDP are both good indicators of economic activity, they will not contribute much to the understanding of impacts between scenarios. This implies that nearly all the differences between policies will depend on changes in energy intensity and carbon intensity, and a relationship between them may prove useful in understanding the impacts. The Carbon over Energy Intensity indicator (CoEI) in Equation 2.8 is the ratio of residuals of carbon intensity ($CI = CO_2/PE$) and energy intensity ($EI = \mathrm{PE/GDP}$), where the two residual terms here take the CO_2 residual form in Equation 2.7. This indicator will show if a changing economy leverages more energy intensity improvements or carbon intensity improvements when confronted with the particular policy scenario.

$$\mathrm{CoEI} = \frac{Res(CI)}{Res(EI)} = \left(\frac{\mathrm{CI}^{\mathrm{base}}(t) - CI^{policy}(t)}{\mathrm{CI}^{\mathrm{base}}(t)}\right)\left(\frac{\mathrm{EI}^{\mathrm{base}}(t)}{\mathrm{EI}^{\mathrm{base}}(t) - EI^{policy}(t)}\right) \qquad \textbf{2.8}$$

A change in carbon intensity is a result of switching to primary fuels with lower carbon content and this structural change is an added burden to the energy infrastructure. One way to quantify this is to consider how much the infrastructure changes as a result of a policy. The Transformation indicator (TI) is a measure of the aggregate structural change in the energy sector (Equation 2.9). This is effectively a measure of the ‘distance’ of each primary energy resource from a reference base year, where the reference frame is the fractional share of total energy (S). So for a given year (t), the TI relative to base year 2013 is the summation of the distance of each fuel type (i) from the 2013 fractional value.

$$\mathrm{TI(t)} = \sum_i |S_i(t) - S_i(2013)| \quad \mathbf{2.9}$$

The fourth indicator defined in the IAM diagnostic study, regarding mitigation costs, is not as useful here since the current study is an assessment of U.S. energy-economic impacts from carbon fees, and not global mitigation responses.

2.4.3 Activity-Structure-Intensity-Fuel (ASIF) Framework

ASIF is an activity-based decomposition framework originally developed to examine changes in emissions from the transportation sector (Schipper and Marie-Lilliu, 1999; Schipper et al., 2000). It assesses the GHG emissions (G) from a particular sector as a function of demand or activity (A), structure or modal share (S_i) for each mode i, modal energy intensity (I_i), and fuel carbon intensity (F_{ij}) for each mode i and fuel type j (Equation 2.10). Many variants of ASIF exist (e.g., Millard-Ball and Schipper, 2011; Schäfer et al., 2009), but essentially all are extensions suggested by the original Schipper, et al. publications.

$$G = \sum_{i,j} A S_i I_i F_{ij} \quad \mathbf{2.10}$$

ASIF is useful because it can identify the drivers for any sector or subsector. While most of the Kaya-related parameters and indicators described above are relatively straightforward and could readily be enlisted to evaluate model results of individual demand sectors, those terms by themselves may miss significant shifts in supply or demand. For example, if consumers still travel as far, but use more public transportation, there may be a significant shift in the type of activity in the transportation sector that is hard to decipher from an over-arching assessment of energy intensity and carbon intensity.

Furthermore, a direct correlation does not necessarily exist for every Kaya term in each demand sector, such as affluence, which is somewhat problematic when evaluating demand sectors with a Kaya-like framework directly. For the U.S. as a whole, GDP/P is perhaps the most commonly used measure of aggregate wealth. Yet not all demand sectors offer good 'wealth' surrogates. For example, in the transportation sector one might use vehicle miles traveled (VMT). Economic growth has certainly driven increased travel as greater prosperity leads to increased car ownership (Paulley et al., 2006), and people are willing to commute further for higher incomes (Kahneman et al., 2006). Recent studies, however, shoes that VMT over the last decade is no longer growing as it used to in the U.S. (Sivak, 2014). Also, an increase in VMT does not always signal an increase in wealth; in fact it can reflect the complete opposite. Sometimes, lower income earners are forced to live far from their workplace due to cost of living disparity, which is often a result of housing market booms or local industry structural changes (Cervero, 1996). Consequently, the direct Kaya analogy may not be appropriate for disaggregating Transportation or any demand sector. However, even if VMT is not an exact measure of wealth, it is a good measure of the activity in the transportation sector that drives energy consumption.

Applying the ASIF framework requires identifying the concepts that capture the essence of the activity, and the structure should closely relate to that activity. Keeping this in mind, the ASIF framework can guide the disaggregation of each of the four demand sectors in NEMS: Transportation, Residential, Commercial, and Industrial, as well as the supply side Electricity sector.

Applying this, or any decomposition framework, is only as good as the available data or model result. ASIF may prove very insightful when evaluating past economic performance with ample historical data. But for forecasting, even a model as detailed as NEMS does not include the level of detail or the desired variables needed to fully analyze the sectors under the complete ASIF process. Yet the analysis is still very useful in evaluating many of the key economic drivers in each sector.

2.4.3.1 Transportation demand Sector

Transportation activity in the original ASIF framework is passenger-miles-traveled. NEMS does not consistently track or forecast passenger-related travel information, but total VMT provides a good surrogate. The transportation sector is, at its core, about moving mass over some distance; however, not all mass being moved is governed by the same incentives. Freight is driven almost purely by economics, while travel is also driven by consumer preferences and whims. Consequently, the two activities must be assessed separately. Travel activity is represented by VMT, whereas Freight activity reported by NEMS is measured in ton-miles traveled (TMT).

The mode shares are represented by the fraction of different vehicle categories, such as light duty vehicles (LDV), heavy trucks, air, bus, and rail. Evaluating shifts in these modes is one of the advantages of ASIF over Kaya. A consumer opting to drive less and take public transportation more, under a particular energy policy, is a mode shift that can be captured by this Framework. Similarly, a dramatic increase in demand for next-day Amazon.com deliveries will be evident in an increase in more air freight activity and less truck and rail activity. The modes are the same for both activities, although the mode shares will be different.

The transportation decomposition in Equation 2.11 is completed with energy intensity, fuel mix (or fuel shares), and carbon intensity. These represent the activity, mode (j), and fuel type (k). Note that this sectoral energy intensity evaluation is based on final or delivered energy.

$$Travel\ CO_2 = \sum_{jk} VMT * \frac{VMT_j}{VMT} * \frac{FE_j}{VMT_j} * \frac{FE_{jk}}{FE_j} * \frac{CO_{2_{jk}}}{FE_{jk}}$$

2.11

$$Freight\ CO_2 = \sum_{jk} TMT * \frac{TMT_j}{TMT} * \frac{FE_j}{TMT_j} * \frac{FE_{jk}}{FE_j} * \frac{CO_{2_{jk}}}{FE_{jk}}$$

The transportation demand sector of NEMS is very detailed, tracking different mode shares, corporate average fuel efficiency (CAFE) of fleet and non-fleet vehicles, new vehicle sales and prices, and many other parameters. Unfortunately, the model does not provide consistent information between modes to properly apply a sector-wide ASIF analysis. This is especially problematic for the freight side of the sector. For example, NEMS provides TMT for shipping, air, and rail, but only for domestic freight. For international freight, the reported freight activity is in the dollar value of shipments; yet international air and shipping account for most of the fuel in these two modes. Also, activity for medium and heavy commercial trucks and fleet LDVs is reported in VMT, not TMT.

On the travel side of the sector, activity of the rail and air modes are reported as passenger miles traveled, while the road modes are reported with VMT. While one could assume that all of the road VMT is based on having a single passenger, the output of NEMS does not support this sector-wide assumption.

Chapter 3 will show that this sector experiences very little impact from even the most aggressive carbon fees modeled here, especially in terms of impacts to carbon intensity. Consequently, this study does not attempt a comprehensive ASIF decomposition of the transportation sector but will instead revert to a simple assessment of the impacts to a portion of the sector activity and mode shares independently.

2.4.3.2 Residential buildings demand sector

Framing the residential sector under ASIF is not as trivial as one might think. Average household size is a good measure of wealth, in the Kaya decomposition sense, but it is not quite the same as activity. When moving from the suburbs to an urban area, one will likely move into a smaller residence. But this change does not necessarily represent a loss in wealth or change in energy-related activity in the sector, since the move was not necessarily prompted by energy reasons. Total number of households (HH) alone better captures the activity. The hypothetical move into the city might also take the resident from a single-family residence (SFR) to a multi-family residence (MFR). Along with mobile homes[16] (MH), these HH types define the modes, or structure, of the sector in Equation 2.12. The size of the HH may not represent

[16] Mobile homes represent traditional mobile homes and manufactured homes in the NEMS framework.

activity, but when combined with energy per square-foot, it does reflect HH energy intensity. Carbon intensity can be split into different fuel types including electricity, natural gas, petroleum-derived products, and wood/other. The 'fuel' term in the ASIF framework is a combination of the fractional share of energy from each fuel k in each mode i (FE_{jk}/FE_j) and the carbon intensity of each of those fuels in each mode ($CO_{2_{jk}}/FE_{jk}$).

$$Residential\ CO_2 = \sum\nolimits_{jk} HH * \frac{HH_j}{HH} * \left[\frac{sqft_j}{HH_j} * \frac{FE_j}{sqft_j}\right] * \left[\frac{FE_{jk}}{FE_j} * \frac{CO_{2_{jk}}}{FE_{jk}}\right] \tag{2.12}$$

Unfortunately, while NEMS does provide an endogenous forecast for the number of HH in each of the three modes, it does not provide any information relative to energy consumption or energy intensity in each mode. So for this analysis, the entire residential market is considered as a single mode (see Equation 2.13). The resulting framework is left with activity, energy intensity, fuel mix, and carbon intensity. So the resulting analysis will not include changes as a result of sector structural shifts.

$$Residential\ CO_2 = HH * \frac{sqft}{HH} * \sum\nolimits_k \frac{FE_k}{sqft} * \frac{CO_{2_k}}{FE_k} \tag{2.13}$$

2.4.3.3 Commercial Buildings demand Sector

The commercial sector is, in some respects, the most logical with respect to the ASIF framework. Activity in the sector can be represented by total square footage of commercial floorspace, which can go up or down depending on the market. However, it is important to note that a decreasing square footage may simply represent an increase in efficient use of the area. So, a decrease in activity does not necessarily represent a retracting sector.

The eleven different commercial building types identified in NEMS, which are listed in Table 2.1, define the sector structure. Some of the building types in this sector represent substitutes (e.g., small and large office); however, in general, significant changes in structure can represent structural changes in the types of businesses in the U.S.

Table 2.1 Commercial Building types in NEMS

Commercial Buildings		
Assembly	Health Care	Mercantile/Service
Education	Lodging	Warehouse
Food Sales	Office - Large	Other
Food Service	Office - Small	

NEMS produces a forecast for square-footage changes and total energy consumption for each of these building types, so energy intensity for each mode j is a direct relationship of energy per area (see Equation 2.14). NEMS does not directly provide building-specific carbon or fuel type in its standard output tables. However, EIA has provided the necessary supplemental tool[17] (***DB_Commercial.xlsm***) for extracting fuel type for each building from the NEMS restart files. This extra analysis support provides carbon-related information at the sector level and at the building level. This enables the completion of the ASIF framework with the fuel shares k and the carbon intensity of each fuel.

$$Commercial\ CO_2 = \sum_{jk} sqft\ * \frac{sqft_j}{sqft} * \frac{FE_j}{sqft_j} * \left[\frac{FE_{jk}}{FE_j} * \frac{CO_{2_{jk}}}{FE_{jk}}\right] \qquad \textbf{2.14}$$

2.4.3.4 <u>Industrial demand Sector</u>

The Industrial Sector is fundamentally about creating and processing, and the resulting products and services contribute to the U.S. GDP. Industrial sector GDP is a good representation of sector activity, although it will fluctuate with commodity prices and forecasts and can move widely without much change in apparent activity. NEMS identifies the industrial sector modes based on the subsectors or industries (such as

[17] Commercial Sector spread sheet tool, guidance, and sector insight provided by Erin Boedecker and Kevin Jarzomski of EIA

Iron and Steel, Cement and Lime, and Bulk Chemical) in the North American Industry Classification System (NAICS) code.[18]

The structure term is the ratio of the industry GDP (GDP_j) to the GDP of the whole industrial sector. Energy intensity is the final energy for a given industry per dollar of GDP for the same industry, which indicates the amount of energy to produce a unit of output. An energy mix term will show the fractional share of the energy in the sector for each fuel type k. Finally, carbon intensity is the CO_2 emission coefficient of particular fuel k, and will show changes related to switching to lower carbon-intensive fuels. Thus, Equation 2.15 defines the decomposition, which matches other ASIF-based industrial sector decompositions (e.g., González and Martínez, 2012).

$$Industrial\ CO_2 = \sum_{jk} GDP * \frac{GDP_j}{GDP} * \frac{FE_j}{GDP_j} * \left[\frac{FE_{ij}}{FE_j} * \frac{CO_{2_{jk}}}{PE_{jk}}\right] \qquad \textbf{2.15}$$

However, NEMS does not project sector or industry-specific GDP, so another representation for activity and mode shares is needed. Industrial sector GDP is the value added (output less intermediate consumption of goods and services) within the U.S. industrial sector. It is a measure of the economic production that takes place within the sector minus all capital consumption costs, such as those associated with depreciation of capital assets (buildings, machinery, and equipment). For a historical perspective, the U.S. Bureau Economic Analysis (BEA) provides prior data on gross output and value added by industry; however NEMS does not break out labor, capital, or profits by industry to create a revenue stream per industry.[19]

NEMS does track the Value of Shipments (VS), which is gross output minus inventories. VS is a measure of output that reflects a level of domestic production, and is represented consistently across industries in the model. It includes all shipments–

[18] NAICS is used by business and government to classify business establishments according to type of economic activity. U.S. Census Bureau main NAICS website: http://www.census.gov/eos/www/naics/index.html.
[19] Thanks to Kay Smith and Kelly Perl of EIA for providing an understanding of the MAM and IDM use of value of shipments.

intermediate as well as final goods– and it includes the cost of energy, unlike GDP by industry. VS is consistent with the economic expenditures generated in IHS Global Insight's model of the U.S. economy (which is part of the MAM). The industrial module translates macroeconomic estimates from the MAM into demand by industry. One can replace the GDP variables from Equation 2.15 with VS to arrive at Equation 2.16.

$$Industrial\ CO_2 = \sum_{jk} VS * \frac{VS_j}{VS} * \frac{FE_j}{VS_j} * \left[\frac{FE_{jk}}{FE_j} * \frac{CO_{2_k}}{FE_{jk}}\right] \qquad \textbf{2.16}$$

2.4.3.5 Electricity supply sector

The primary goal of a carbon fee is to reduce carbon emissions, and Equations 2.4–2.6 above will identify what fraction of the avoided carbon emissions come from fuel-switching verses efficiency across the entire U.S. energy supply system. Chapter 3 will show that most of the structural changes in the energy system from these policies come from switching from coal to mostly natural gas, and this energy transformation takes place almost entirely within the electricity supply sector.

Activity in the electricity supply sector is represented by total electricity generation (G). The structure for this sector is the fraction of supply generated by each generating technology (G_j), such as combined-cycle, conventional coal, and combustion turbines. The energy intensity is in terms of the primary energy consumed to produce the electricity by each technology (E_j/G_j). These terms are all shown in Equation 2.17.

$$Electricity\ CO_2 = \sum_{jk} G * \frac{G_j}{G} * \frac{E_j}{G_j} * \frac{CO_{2_j}}{E_j} \qquad \textbf{2.17}$$

One could include a fuel mix term for the fraction of the each primary fuel type k within each technology j (E_{jk}/E_j) and the subsequent CO_2 intensity ($CO_{2_{jk}}/E_{jk}$) of each of those fuel types within each technology. However, many of the generating technologies are represented by a single fuel type, such as conventional coal or advanced nuclear, so this extra detail is mostly redundant with respect to the sector structure. Consequently, this analysis considers the total carbon emissions intensity for each generating technology CO_{2j}/E_j.

The standard NEMS output includes installed capacity and generation by technology, but not emissions by technology. However, at the end of each NEMS cycle, the electricity market module writes out a database of information (***emmdb.mdb***) which can be used to extract emissions by technology.[20]

2.4.4 Log-mean Divisia index (LMDI) decomposition approach

Once the Kaya and ASIF frameworks are populated with data, a numerical decomposition method can be employed to quantify the impacts from each parameter. There are many methods and derivatives to choose from, and which is appropriate depends on the theoretical foundation, adaptability to the problem, ease of use, and ease of understanding and result (Ang, 2004). Many studies have assessed or compared methods appropriate for evaluating national and global energy and carbon impacts (e.g., Ang and Liu, 2001, 2007a; Ang, 2005, 2004; Liu and Ang, 2003; Szép, 2013; Zhao et al., 2010). Most converge on the log-mean Divisia index (LMDI) as the most appropriate method for many reasons: path dependency, ability to handle zero values, consistency in aggregation, and ease of use and interpretation. This Divisia index approach has also been adopted by the US Department of Energy to construct an aggregate energy efficiency index for the United States (Wade, 2002)

Divisia-based index decomposition analysis methods, derived from the Divisia index (Divisia, 1925; Hulten, 1973), were first proposed for use in this field by Boyd, et al., (1987). The LMDI[21] method is a weighted sum of logarithmic growth rates, where the weights are the component shares of total value. The method disaggregates

[20] Thanks to Laura Martin from EIA for providing the information necessary to access this data.
[21] LMDI here is Log-mean Divisia index method I (LMDI I). LMDI method II (LMDI II) has a slightly more complex weighting method then LMDI I (Ang et al., 2003) and does not provide additional value in this study.

the economy into sectors then weights sectoral energy intensity by their output shares. This can attribute changes occurring in an economy to a change in energy intensity (intensity effect), a shift in structure or modes (structural effect), or simply a change in activity (activity affect) (Liu and Ang, 2003).

The LMDI method can be applied as a multiplicative or an additive decomposition, where the multiplicative effectively determines index annual growth rates and the additive determines relative impact values. Choosing one or the other is a user preference and depends on the intended audience of the study results. Fortunately, LMDI is one of the few methods that have an explicit correlation between the two decomposition approaches, so one only needs to derive one or the other. Of particular interest for this study is evaluating the impacts of economic drivers on annual emissions, so what follows are the additive decomposition equations. Please see Appendix 0 for a summary of this derivation. For explicit derivations and proofs of both the additive and multiplicative LMDI I approaches, one can review Ang (2005) or Ang et al., (2009).

To illustrate this decomposition, consider a simple three-term expansion of the industrial sector, in which activity, structure, and intensity are provided for each subsector. The total energy consumption (E) is the sum-product the three terms:

$$E = \sum_i E_i = \sum_i A \frac{A_i}{A} \frac{E_i}{A_i} = \sum_i A S_i I_i \qquad \textbf{2.18}$$

Where A (=$\sum_i A_i$) is the total activity in the sector, S_i (=A_i/A) is the structural share of each subsector, and I_i (=E_i/A_i) is the energy intensity of each subsector. The change in total energy consumption between time *0* and *t* is then defined as:

$$\Delta E_{tot} = E^t - E^0 = \Delta E_{act} + \Delta E_{str} + \Delta E_{int} \qquad \textbf{2.19}$$

where the subscripts act, str, and int denote the effects associated with the overall activity level, structure, and sectoral energy intensity, respectively. This formula could be employed to determine changes between years of the same scenario, or to compute changes between a policy scenario and the Reference scenario. To compute the LMDI, each of the right hand side (RHS) terms in Equation 2.19 will take the logarithmic form in Equation 2.20.

$$\Delta E_{act} = \sum_i \frac{E_i^t - E_i^0}{\ln(E_i^t) - \ln\left(E_i^0\right)} \ln\left(\frac{A^t}{A^0}\right)$$
$$\Delta E_{str} = \sum_i \frac{E_i^t - E_i^0}{\ln(E_i^t) - \ln\left(E_i^0\right)} \ln\left(\frac{S_i^t}{S_i^0}\right) \qquad \textbf{2.20}$$
$$\Delta E_{int} = \sum_i \frac{E_i^t - E_i^0}{\ln(E_i^t) - \ln\left(E_i^0\right)} \ln\left(\frac{I_i^t}{I_i^0}\right)$$

One must ensure proper bookkeeping of each nested subscripted value. This becomes more tedious when computing a five-factor LMDI decomposition, where one must keep track of subsector i industry values and multiple fuel types j within each subsector. A full expansion of the industrial sector to evaluate contributions to industrial emissions[22] would include the fuel-type energy mix fraction M_{ij} (=E_{ij}/E_i) and carbon intensity F_{ij} (=C_{ij}/E_{ij}):

$$C = \sum_{jk} C_{ij} = \sum_{jk} A \frac{A_i}{A} \frac{E_i}{A_i} \frac{E_{ij}}{E_i} \frac{C_{ij}}{E_{ij}} = \sum_{jk} AS_i I_i M_{ij} F_{ij} \qquad \textbf{2.21}$$

The decomposition framework would expand Equation 2.19 to include the additional two terms, where additional subscripts mix and emf denote the effects associated with the sectoral energy mix and emission factor (or carbon intensity), respectively.

$$\Delta C_{tot} = C^t - C^0 = \Delta C_{act} + \Delta C_{str} + \Delta C_{int} + \Delta C_{mix} + \Delta C_{emf} \qquad \textbf{2.22}$$

Similarly, Equation 2.20 would be extended to include the additional RHS terms to provide Equation 2.23.

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[22] In all these LMDI decomposition equations, one can use carbon emission (e.g., ΔC_{tot}) or CO_2 emissions (e.g., $\Delta CO_{2_{tot}}$), as long as it is used consistently on both sides of the equation.

$$\Delta C_{act} = \sum_i \frac{C_i^t - C_i^0}{\ln(C_i^t) - \ln(C_i^0)} \ln\left(\frac{A^t}{A^0}\right)$$

$$\Delta C_{str} = \sum_i \frac{C_i^t - C_i^0}{\ln(C_i^t) - \ln(C_i^0)} \ln\left(\frac{S_i^t}{S_i^0}\right)$$

$$\Delta C_{int} = \sum_i \frac{C_i^t - C_i^0}{\ln(C_i^t) - \ln(C_i^0)} \ln\left(\frac{I_i^t}{I_i^0}\right) \qquad \textbf{2.23}$$

$$\Delta C_{mix} = \sum_i \frac{C_i^t - C_i^0}{\ln(C_i^t) - \ln(C_i^0)} \ln\left(\frac{M_{ij}^t}{M_{ij}^0}\right)$$

$$\Delta C_{emf} = \sum_i \frac{C_i^t - C_i^0}{\ln(C_i^t) - \ln(C_i^0)} \ln\left(\frac{F_{ij}^t}{F_{ij}^0}\right)$$

Occasionally, the data will have a value of zero which may require some attention when applying the LMDI framework. This issue will arise when values in a given subsector go to, or from, zero over the period being analyzed. For example, in the electricity supply sector, specific technologies make up entire subsectors and some of these technologies are either introduced or retired between one LMDI period and the next. In this case, the LMDI logarithmic formulation will cause an error. One proposed method is to use a small value (SV) strategy. Ang and Liu (2007b) have shown that this is a good approach, as long as the occurrences of this condition represent a small fraction of the dataset and that the SV substitute used is very small. The SV used in this study is 1×10^{-100}, which is more than an order of magnitude smaller than necessary for the very few occurrences found in this study.

With this LMDI primer as the backdrop, each of the terms in the Kaya and ASIF formulations in the previous sections can be quantified for its relative impact. This will not be completed for every identity, but only when relevant to the discussion.

2.5 MEASURING HOUSEHOLD IMPACTS AND SOCIAL WELFARE

2.5.1 Pragmatic approach

The previous section described methods for assessing the macroeconomic and sectoral impacts from carbon fees, and these fees will impact consumers directly through increased energy costs. A comparison of results from a carbon policy case and the Reference scenario will show the direct cost of the policy on all residential consumers. For the Reference case, the total residential sector expenditure in a given year for a particular fuel is simply the product of the price per unit of fuel and the total number of fuel units consumed (i.e., Price * Quantity). When the carbon fee is applied, the price of the fuel increases which drives down demand.

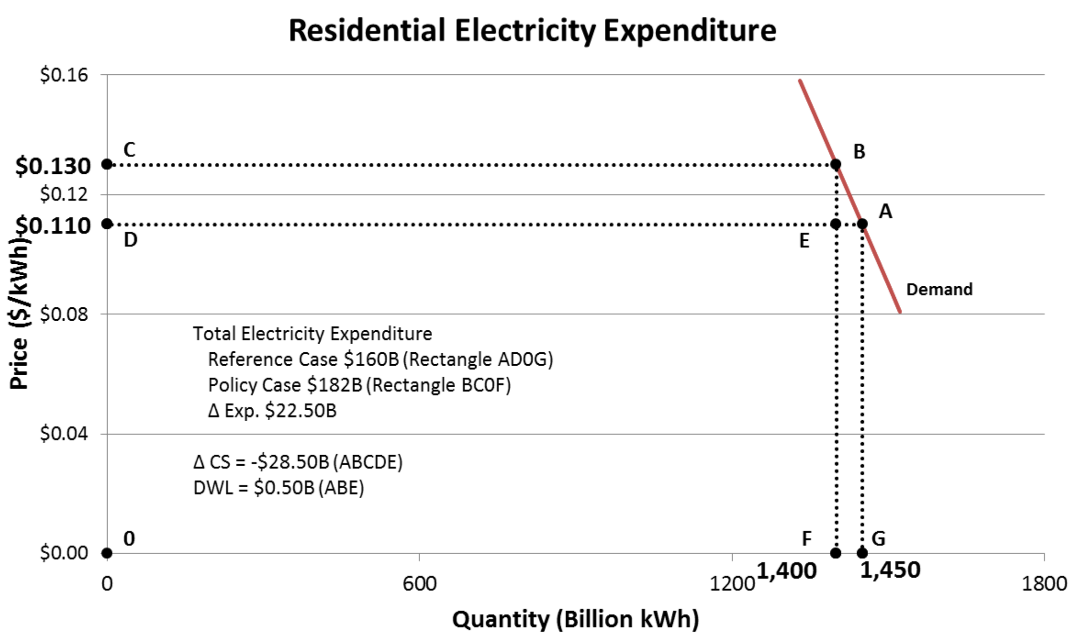

Figure 2.2 Change in residential electricity demand from an increase in the price of electricity. Point A is the reference case price and total quantity of electricity consumed in the residential sector; point B is the demand for electricity under the new higher energy price.

Figure 2.2 illustrates this using a realistic change in residential electricity demand when the price of electricity is increased from $0.11 to $0.13 per kWh. Initial demand is point A in the figure, and point B represents the demand at the new price after the policy is in place. NEMS provides very little information about the path between point A and B, so a linear demand function, $p(q)$, is assumed.

The total residential sector expenditure on electricity is the product of the price per unit of fuel and the total aggregate[23] quantity of fuel consumed that year. Graphically, total expenditure is the area of the rectangle bounded by the price, quantity, and the origin. For the reference scenario, this is the area of rectangle AD0G. For the policy scenario this is the area of rectangle BC0F. The difference in expenditure represents the change in direct costs to residential consumers (in aggregate), as shown in Equation 2.24.

$$\underbrace{Price\ x\ Quantity}_{Policy} - \underbrace{Price\ x\ Quantity}_{Reference} = \underbrace{Cost\ of\ policy}_{Direct\ Costs} \qquad \textbf{2.24}$$

Figure 2.2 also indicates the change in consumer surplus (CS) and the dead weight loss (DWL) from the policy. The CS for a given equilibrium point is the total value consumers are willing to pay for each incremental unit starting at the first unit. Graphically, the CS is the area bounded from below by the actual price paid for all units and above by the demand curve. Another way to state this is the integral of the demand from 0 to Q, less the actual expenditure.

$$\int_0^Q (p(q)dq - P * Q \qquad \textbf{2.25}$$

With an assumed linear demand, the CS for a given scenario is the upper triangle bounded between the price for that scenario and the demand line. Comparing the CS between the reference and policy scenarios, the loss in CS (ΔCS) is the trapezoidal area bounded by ABCDE. Most of the ΔCS comes from higher cost for the remaining Q that consumers still buy under the policy (rectangle bounded by BCDE). This is also equal to the tax revenue from the new (lower) consumption of this particular fuel. However, the remaining triangle (ABE) is the DWL. The DWL is

[23] Remember that NEMS considers consumers in-aggregate, so quantity provided in the model output is total quantity of each fuel consumed by everyone for a given year.

value consumers lose by no longer being able to buy fuel at the original price, and also represents consumers who are potentially priced out of the market (depending on the good). The DWL also represents a value that will not be transferred to the government as fee revenue. Note that the DWL is less than 2% of the ΔCS for this policy scenario example.

With only two points representing the market, there are only a few simple metrics obtainable from NEMS results: a numerical comparison of total direct costs and the ΔCS. The realistic and representative electricity price example in Figure 2.2 shows that the ΔCS is usually a small fraction over the direct costs. In addition, the loss in consumer welfare is less tangible to policymakers. Thus, the focus will be on a simple metric of a change in direct energy related costs to the residential sector. Furthermore, this is a commonly used (e.g., Blonz et al., 2011; Hassett et al., 2009; Metcalf, 2008b) and arguably highly policy relevant metric to which policy makers can relate. How to translate it to individual household costs will be described in more detail as it becomes relevant in Chapter 4.

2.5.2 Limitations to this approach

Calculating policy costs in this manner has some limitations. According to classical demand theory, if consumer preferences are known it is possible to provide a monetary measure of the welfare impact from a variation in the prices of the goods. This leads to the ideas of Compensated Variation (CV) and Equivalent Variation (EV). The CV represents how much additional income would return the consumer to the original utility after the policy, while the EV represents how much consumer's income would need to change to induce the same welfare loss of the policy (Mas-Colell et al., 1995). Both CV and EV measure the pure income effect of a change in the price of one good relative to other goods, so they are two different answers to the question of how much change in income is necessary to offset a change in price so that a consumer's utility remains constant. In addition, the poorest people may have the least willingness to pay, so not accounting for CV and EV might be more relevant in income distributional calculations.

However, neither consumers' preferences nor their utility are known. The ΔCS reflects both the substitution and income effects (without necessarily holding utility constant). Consequently, economists often consider the ΔCS as an approximation to the unobservable CV and EV, especially when the economic impacts are relatively small (Hicks, 1956; Hotelling, 1938; Willig, 1976). Yet, ΔCS for the average American has already been shown to be on the same order as the change in the direct cost of the policy, which is a more tangible metric for policy makers to utilize.

An additional limitation is that this calculation ignores externalities and treats the CS in the reference case as an economically efficient outcome. CS is more complicated when there are externalities present. One can still treat it as an accounting tool for analyzing changes to gross consumer welfare, but cannot use it as a measure of net welfare impacts without an explicit treatment of the externalities. Some of the area identified as CS under equilibrium conditions is not properly considered CS if the marginal social costs (MSC) are included. Similarly, the label DWL is not accurate because there is a gross loss to both consumer and producer surplus (PS). When those losses result from pricing an externality, such as through a carbon fee, the avoided harms are larger than the gross DWL calculation. So this simple formulation makes no sense when fixing a negative externality, since there is no "dead weight" component to this loss. The loss is more than offset by the gross social gains from making consumers pay the full price of their actions (Mansfield and Yohe, 2004).

Figure 2.3 shows the change in demand when the externality of emissions impacts is internalized. As above, the CS prior to taxing emissions is the area bounded by the initial price ($P1$) and the demand curve; this is the sum of areas a, b, c, and d. If one can compute a marginal private cost (MPC), then areas f, g, and h define the PS. Including damages from the emissions (the marginal environmental cost or MEC—not shown) with the MPC, results in the marginal social cost (MSC). This increases the price per unit consumption, which in turn reduces demand. The MEC for consumption of $Q1$ units is the area between the MSC and the MPC (areas, c, d, e, f, g, and h). At the new equilibrium price ($P2$) the CS is area a, and the PS is area h. The revenue raised by the emissions fee is areas b, c, and g. The DWL from the fee is areas d and f;

however, the avoided damages are areas d, f, and e, the sum of which is greater than the DWL.

If all the data were available to calculate the supply curves and externalities (not just the two-point demand curve available from the NEMS output), then a proper analysis of the changes in CS and PS would be as illustrated in Figure 2.3. However, this is not possible with the NEMS outputs. Producer cost curves cannot be constructed based on energy or CO_2. Furthermore, there is a large uncertainty around the social cost of carbon emissions (SCC), with estimates ranging from single digits to nearly \$100/tCO_2 depending on the chosen discount rate (Greenstone et al., 2011; Nordhaus and Sztorc, 2013). Currently, the center estimate is around \$21-\$35/tCO_2 (Nordhaus, 2014), which is in the range of the carbon prices in the current study.

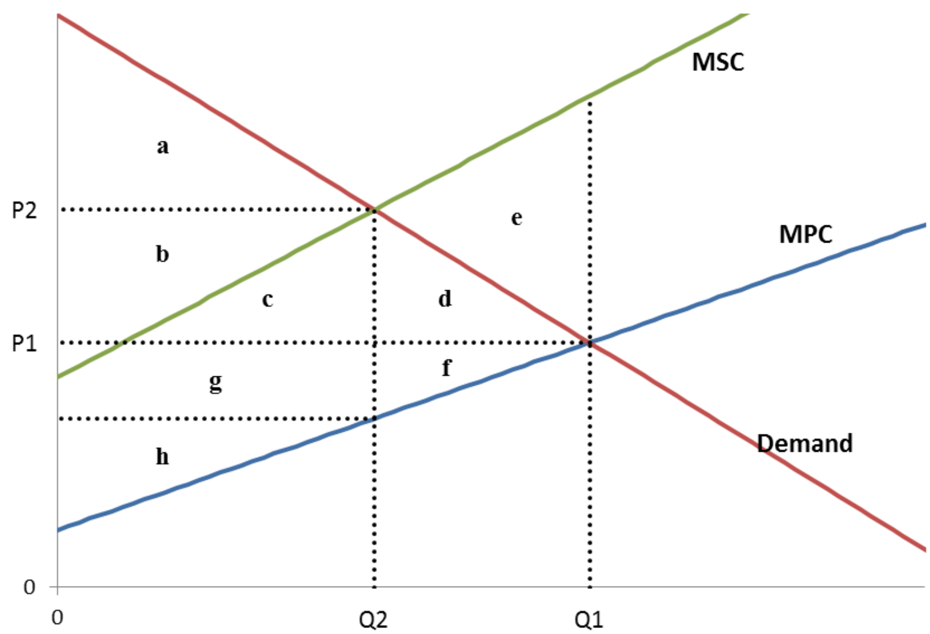

Figure 2.3 Example of internalizing the externality. The marginal social cost (MSC) is the sum of the marginal private cost (MPC) and the marginal environmental cost.

So, the more pleasing welfare and environmental metrics are very hard to measure and communicate because the data is either not there at all or not observable. The simple method described by Figure 2.2 might have some limitations and is not the best way to resolve the questions about the costs to households, particularly due to externalities. However this method is a commonly used metric for similar studies (thus will proved a point of comparison), is a policy relevant metric to which policy makers can relate, and will serve as a traceable account[24] for further calculations.

2.6 Methods and Approach Summary

To affect sound policymaking, a complete analysis of carbon fees on the U.S. infrastructure requires several steps defined in this chapter. It necessitates that one run a general equilibrium model of the U.S. energy economic system, and that model should be NEMS due to its position as the officially accepted U.S. forecasting and modeling tool. An analysis of the energy economic impacts should go beyond national macroeconomic impacts to include the impacts to demand sectors and any supply sectors exposed to the policy (e.g., electricity supply sector). Ultimately, researchers should be compelled to assess the impacts to households, since that is how consumers perceive and how policymakers argue the benefits and costs of such policies.

Chapter 3 will report on and summarize the results from the carbon price policies in NEMS, then show applications of the decomposition techniques described above to evaluate the macroeconomic and sectoral impacts to the U.S. Economy. Chapter 4 will assess the financial cost to households from the increased energy cost resulting from the carbon fees, and apply different rebate percentages to determine how sensitive the net household impacts are to different policies. In Chapter 5, both of these pieces are combined by modifying NEMS to integrate the rebate and recycle the remaining revenue to the extent possible in NEMS.

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[24] Defined by Moss and Schneider (2000) in guidance to IPCC authors, “traceable account” means to clearly state how results are constructed and the reasons for adopting a particular strategy and why others were not adopted. The IPCC guidance was focused on probability distributions, but the guidance applies to any scientific communication.

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Chapter 3

ENVIRONMENTAL, FISCAL, AND ECONOMIC IMPACTS OF CARBON FEES

3.1 INTRODUCTION

At the heart of any climate and energy policy debate lie three key questions: How effective is the policy at accomplishing its purpose? How much will it impact the economy? How will it affect the policymakers' constituents? The first two questions address the macroeconomic and sectoral impacts from carbon fees, which are the topic of this chapter. The third question will be addressed in Chapter 4.

This chapter begins in Section 3.2 with a discussion of the macroeconomic impacts to the U.S. in terms of carbon emissions, GDP, and revenues resulting from carbon price policy scenarios. It will show that the carbon policies modeled here can significantly reduce carbon emissions with only minor impacts to the U.S. economy. Section 3.3 will explore carbon fee effects further by decomposing the Kaya identity to determine how much each economic driver is responsible for changes in emissions in the Reference scenario, and how the policy scenarios differ.

Section 3.4 begins with a decomposition of the electricity sector since this supply sector will bear the brunt of the carbon fee response. It will show that the electricity sector response is initially to shut down coal-fired generators and dispatch more of the existing natural gas-fired generators. This Section continues with a decomposition of economic and emission drivers in each of the four demand sectors in NEMS: Transportation, Residential, Commercial, and Industrial. This will show that, since the primary response to a carbon fee is to decarbonize the electricity sector, the Transportation sector will see almost no impact. Most of the impacts to the other demand sectors will come from changes in the fuel mix related to electricity supply.

Section 3.5 will summarize the impacts described throughout the chapter.

3.2 MACROECONOMIC IMPACT

3.2.1 Carbon dioxide emissions

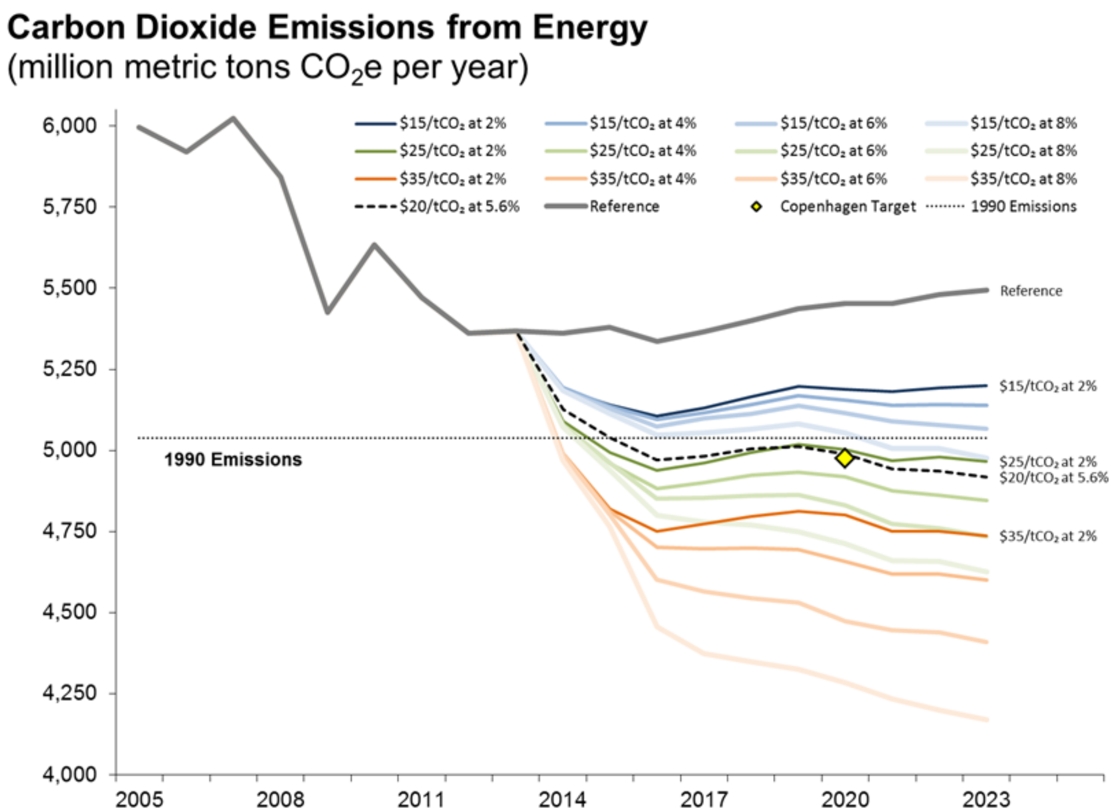

Figure 3.1 Energy-related carbon emissions. Shows carbon fee and escalation rate sensitivity and Boxer–Sanders results, all compared to the reference scenario, 1990 emissions level, and Copenhagen Accord 2020 target.

Lower natural gas prices, some energy efficiency, and several economic crises have combined to reduce CO_2 emissions levels for the U.S. over most of the last decade (Burtraw and Woerman, 2012). Despite this recent decline, EIA projects a small, but steady, increase in energy-related carbon emissions over the next decade as the economy slowly recovers (EIA, 2013a). By contrast, a carbon fee applied in 2014, at any carbon price, will further reduce energy-related emissions. This reduction will occur most rapidly during the first few years of implementation (see Figure 3.1). Furthermore, all but the most lenient scenarios will continue to push emissions trends downward throughout the next decade. By pricing carbon, all of these policies will extend the reduction in emissions observed since 2007, making that the peak year for national emissions of CO_2 from energy use. With the exception of the \$15/tCO_2 scenarios, these carbon policies will achieve 1990 CO_2 emission levels within the first few years of implementation.

The primary purpose of placing a price on carbon is to reduce carbon emissions, and the carbon fees modeled here will lower U.S. energy-related CO_2 emissions by a range of 293–1324 million metric tonnes (MMt[25]) of CO_2 (5.3%–24.1%) through 2023 relative to the baseline scenario (see Table 3.1). Not surprisingly, higher initial fees or faster annual escalation rates will accelerate the reduction in CO_2.

Table 3.1 CO_2 Emissions and percent reductions from baseline

	Baseline Emissions (MM tCO_2)			
	2005	2013	2020	2023
Reference	5,997	5,369	5,452	5,494

	Scenario 2023 Emissions (MM tCO_2)				Percent Reduction in 2023 from reference 2023			
	Rate: 2%	4%	6%	8%	Rate: 2%	4%	6%	8%
\$15/tCO_2	5,201	5,139	5,066	4,977	5.3%	6.5%	7.8%	9.4%
\$25/tCO_2	4,966	4,847	4,735	4,625	9.6%	11.8%	13.8%	15.8%
\$35/tCO_2	4,738	4,601	4,410	4,170	13.8%	16.3%	19.7%	24.1%

	Scenario 2020 Emissions (MM tCO_2)				Percent Reduction in 2020 from 2005 Level			
	Rate: 2%	4%	6%	8%	Rate: 2%	4%	6%	8%
\$15/tCO_2	5,189	5,156	5,115	5,054	13.5%	14.0%	14.7%	15.7%
\$25/tCO_2	5,003	4,919	4,830	4,713	16.6%	18.0%	19.5%	21.4%
\$35/tCO_2	4,801	4,659	4,474	4,285	19.9%	22.3%	25.4%	28.6%

Under the Copenhagen Accord, the U.S. has committed to reducing its economy-wide greenhouse gas emissions to "in the range of 17% below" 2005 levels by 2020 (UNFCCC, 2010). To show how these carbon fees would contribute toward this commitment, Table 3.1 also provides a summary of the results in 2020. None of the \$15/tCO_2 scenarios will achieve the Copenhagen 2020 target, although the \$15/tCO_2 at 8% escalation scenario will approach this level by 2023. However, all of

[25] For clarification, the MM in MMt stands for 'thousand, thousand.' So MMt is a thousand, thousand tons or a millions tons (metric).

the other scenarios, including the Boxer–Sanders Climate Protection Act ($20/t$CO_2$ at 5.6%), are in the range of 17% reduction or significantly better.[26]

Another way to look at the carbon reductions is through the relative abatement index (RAI), defined in Equation 2.7, which is the fraction of carbon emissions reduction from the same year of the Reference scenario. Figure 3.2 shows the RAI for all scenarios. The RAI is a good indicator of long lasting environmental impacts.

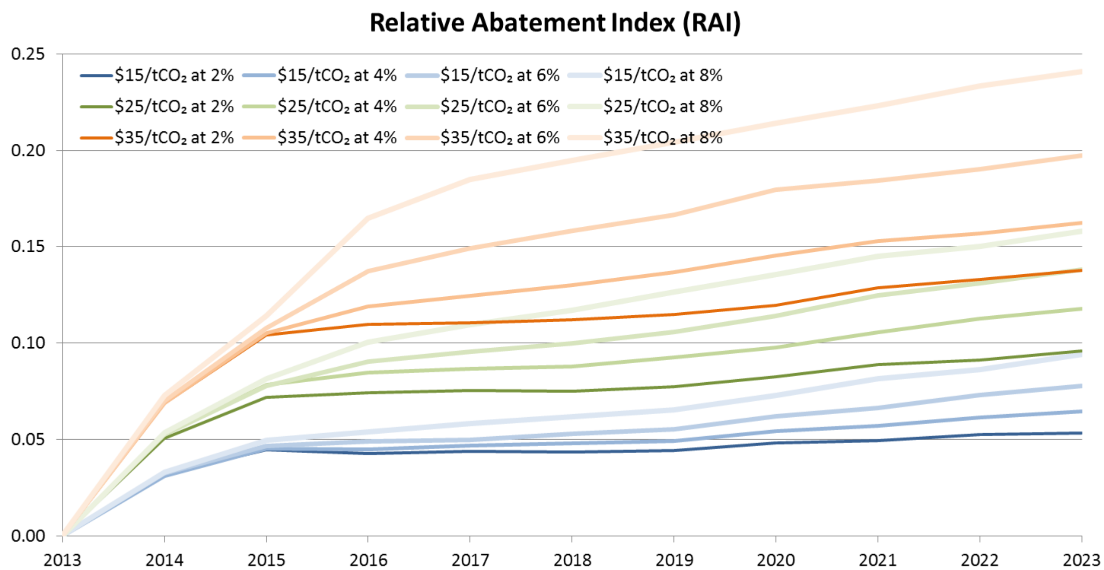

Figure 3.2 Relative Abatement Index (RAI). This is effectively the fraction (or percentage) of emissions reduced.

The magnitude of the initial price dictates the amount of initial carbon reduction, as seen in Figure 3.2 by the $15, $25, and $35/t$CO_2$ results grouped accordingly for the first few years. In the third year of the policy, 2016, the individual scenarios begin to distinguish themselves and fan out. This three-year delay is, in part, an artifact of the efficiency technology and fuel switching drivers in NEMS that

[26] The U.S. commitment under the Copenhagen Accord covers all emissions of six greenhouse gases (methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride). However, NEMS projects only CO2 emissions from energy use, which is a subset of the national emissions profile, accounting for approximately 79% of gross and 91% of net greenhouse gas emissions in the United Sates (EIA, 2012b). When we compare the projected greenhouse gas emissions to the U.S. commitment under the Copenhagen Accord, we make the assumption that the percentage reduction required by the overall commitment applies proportionally to CO2 emissions from energy use (i.e., that a 17% reduction of total greenhouse gas emissions implies a 17% reduction in CO2 emissions from energy). CO2 emissions data and projections from 2010 forward come from NEMS; data from 2009 and earlier come from published EIA data (EIA, 2012c).

consider both an instantaneous price increase and a sustained three-year increase as discussed in Wilkerson, et al., (2013). In the third year of elevated energy prices, the model allows consumers to commit to more substantial retrofits since the price signal is not a short-lived spike. This makes some sense when one considers replacing an appliance prior to the end of its useful life: the early retrofit would not occur until elevated prices have proven to be sustained. NEMS introduces some heterogeneity in fuel and appliance mix by allowing consumers to choose a more efficient same-fuel technology (e.g. new refrigerator), or switch fuels (e.g., switching from an electric stove to a gas stove) when energy prices increase from a carbon fee on, for example, coal-fired electricity.

3.2.2 Policy revenues

Carbon pollution fees[27] would raise between \$849 billion and \$2.2 trillion in revenues over the next decade, depending on the aggressiveness of the scenario (see Table 3.2). Carbon emissions generally decline in all policy scenarios due to escalating fees, and these escalating fees result in an annual increase in net revenues for even the most lenient scenario. As an example, the scenario of \$25/tCO_2 escalating annually at 2% would raise \$127.23 billion in 2014, and a slightly higher \$127.32 billion in 2015. Under a combination of reduced emissions and a 2% escalation rate, the revenues would slowly ramp up to \$148 billion (nominal) in 2023, growing at a compound annual growth rate (CAGR) of about 1.7%.

Table 3.2 also includes the total aggregate (undiscounted) revenue for the first ten years of each scenario and the net present value (NPV) of that revenue stream assuming a 4% social discount rate (DR). Both numbers are reported here because different consumers of these model results expect one or the other. For example, when dealing with policymakers in preparation for an analysis of the Boxer–Sanders Climate Protection Act (Wilkerson et al., 2014a), the author was asked to aggregate

[27] The scenarios described here do not include any carbon equivalency fee provisions aimed at imposing the carbon pollution fee on embodied carbon in imported goods. Nor are rebates of the fee on exported fossil fuels modeled. Thus, this analysis is limited to a purely domestic perspective on fiscal impacts of carbon fee legislation.

the fiscal impacts to the government in nominal terms, since that is how Congress debates spending in any given year. However, NPV of the cash stream is also included since microeconomic readers will argue that the time horizon is more than a few years, and money in the future is valued less than the same amount of money today. Consequently, both results are included here as a practical matter.

Table 3.2 Annual and total revenues from policy scenarios

	Annual Revenue (Billion nominal 2011 USD)												
Policy Scenario	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	CAGR[1]	Total[2]	NPV[3]
\$15/tCO_2 at 2%	\$77.81	\$78.63	\$79.70	\$81.68	\$83.86	\$86.08	\$87.65	\$89.29	\$91.25	\$93.23	2.0%	\$849.19	\$684.10
\$15/tCO_2 at 4%	\$77.90	\$80.14	\$82.67	\$86.33	\$90.20	\$94.35	\$97.85	\$101.46	\$105.55	\$109.72	3.9%	\$926.17	\$741.77
\$15/tCO_2 at 6%	\$77.80	\$81.54	\$85.51	\$91.09	\$96.83	\$103.13	\$108.83	\$114.79	\$121.41	\$128.39	5.7%	\$1,009.32	\$803.78
\$15/tCO_2 at 8%	\$77.77	\$82.83	\$88.32	\$95.51	\$103.39	\$112.01	\$120.29	\$128.71	\$138.98	\$149.23	7.5%	\$1,097.05	\$868.94
\$25/tCO_2 at 2%	\$127.23	\$127.32	\$128.49	\$131.62	\$135.16	\$138.50	\$140.85	\$142.65	\$145.87	\$148.38	1.7%	\$1,366.07	\$1,101.33
\$25/tCO_2 at 4%	\$126.98	\$128.95	\$132.03	\$137.85	\$144.03	\$150.05	\$155.59	\$160.43	\$166.32	\$172.47	3.5%	\$1,474.71	\$1,182.33
\$25/tCO_2 at 6%	\$126.98	\$131.46	\$136.31	\$144.55	\$153.44	\$162.67	\$171.30	\$179.42	\$189.71	\$199.98	5.2%	\$1,595.82	\$1,272.72
\$25/tCO_2 at 8%	\$126.83	\$133.40	\$139.95	\$150.53	\$162.21	\$174.50	\$186.98	\$199.68	\$215.52	\$231.15	6.9%	\$1,720.75	\$1,365.19
\$35/tCO_2 at 2%	\$174.73	\$172.04	\$172.98	\$177.33	\$181.68	\$186.00	\$189.22	\$191.02	\$194.83	\$198.17	1.4%	\$1,838.00	\$1,482.89
\$35/tCO_2 at 4%	\$174.68	\$175.25	\$177.96	\$184.96	\$192.38	\$199.91	\$206.34	\$212.72	\$221.31	\$229.19	3.1%	\$1,974.70	\$1,584.97
\$35/tCO_2 at 6%	\$174.50	\$178.11	\$180.96	\$190.32	\$200.83	\$212.26	\$222.13	\$234.02	\$247.58	\$260.78	4.6%	\$2,101.50	\$1,678.77
\$35/tCO_2 at 8%	\$173.94	\$180.17	\$181.94	\$192.87	\$207.11	\$222.51	\$237.97	\$254.04	\$272.15	\$291.76	5.9%	\$2,214.45	\$1,761.29

Notes [1] Compound annual growth rate
[2] Total revenues in billion nominal 2011\$
[3] Nominal net present value (NPV) of revenue stream assuming a discount rate of 4.0%

The appropriate DR for computing the NPV for a carbon fee is somewhat arbitrary. Certainly, the government has various interest rates for specific activities.[28] However, the government does not typically think about a stream of cash from a value-added tax (like a carbon fee) in terms of a long-term DR since it is not choosing between competing investments with scarce capital in the same way microeconomic actors often do. For low risk, short time horizons, one could use a risk-free rate for the DR, such as the Federal 3-month Treasury Bill which guarantees a certain percent return in three months on an investment made today. Since this study spans ten years, a short term interest rate is not quite appropriate. On the other hand, one might infer a value of 8% to 12% for a long term, or risky investment; however, that implies inherent risk of a long-term return; again, not representative of the revenue stream from a value-added tax. Using the Federal funds rate, which is typically on the order

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[28] A select list can of various U.S. Federal Reserve Interest and discount rates can be found at: http://www.federalreserve.gov/releases/h15/data.htm

of 4%, is perhaps a more appropriate discounting method. So the Fed Rate[29] of 4% is used and as the *social* DR.

Assigning a *private* DR for consumers is even more subjective and personal, and ultimately depends on ones' initial wealth and general prosperity, as well as the time horizon and the risk of an investment. It is also likely to vary between households according to income, education, and other socioeconomic variables. Choosing a DR assumes how a household should look at a stream of expected future payments, not necessarily how they actually do. So in Chapter 4, when economic value to individual households is considered, the same DR of 4% will be used so revenue streams and rebates can be evaluated together.

3.2.3 Gross Domestic Product (GDP)

All of the carbon pollution fees would have modest impacts on U.S. GDP (see Figure 3.3a). At the end of the ten-year period, the baseline GDP in 2023 is $20.5 trillion. The scenarios range from $20.4 and $20.2 trillion, or between 0.4% and 1.6% change from the Reference scenario (see Figure 3.3b). This loss in GDP represents a delay in wealth, since the economy will need to churn away for a short period of time to achieve the same level of GDP achieved in the Reference case. However, this delay ranges from 50 days (1.7 months) for the most lenient scenario to 246 days (8.2 months). Thus, while the emission reductions produced by these carbon scenarios are significant, adjustments in the energy sector and the economy as a whole appear to be relatively inexpensive in aggregate.

Chained GDP is computed with the model's estimate of the price index of inflation. The reference scenario index grows steadily at an average of 1.68% annually to about 1.22 in 2023, as shown in Figure 3.4, where the index of 2011 = 1.00. The

[29] The Fed Rate in the current post-financial-crisis world is currently practically zero due to the Fed's intervention in the monetary markets. However, Quantitative Easing is expected to roll back in the very near future, and the NEMS Reference scenario forecasts this rate to be back to 'on the order' of 4% by 2015. While the actually number fluctuates from year to year, a fixed value is used here for convenience.

policy scenarios slightly increase this inflation rate from between 1.75% to 1.91% annually, with the most aggressive scenario growing to an index of 1.25 in 2023.

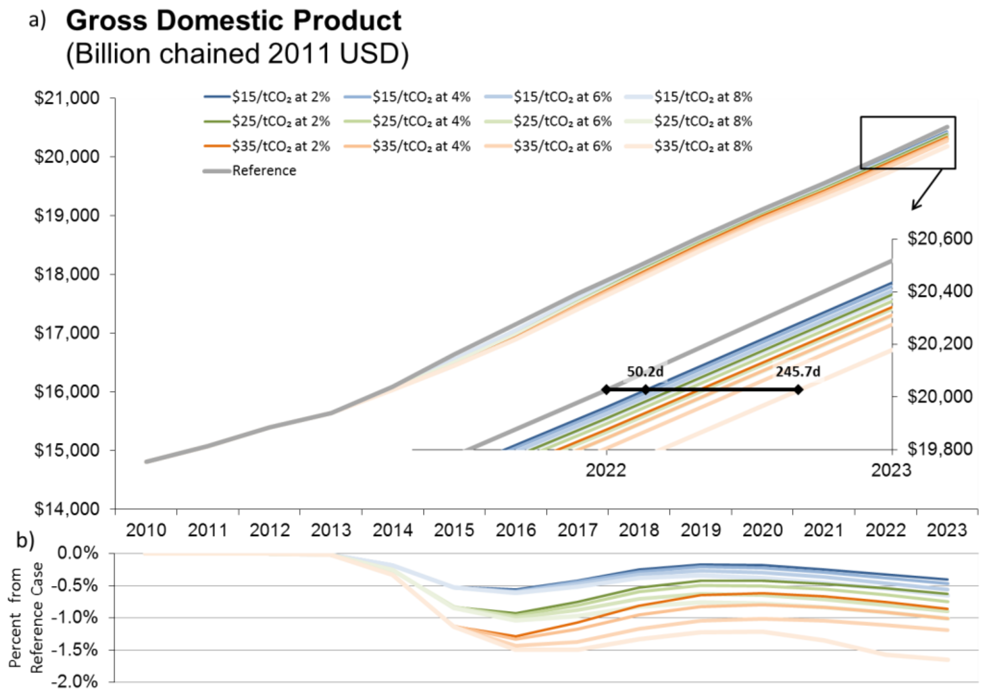

Figure 3.3 GDP impacts from carbon fee scenarios; a) billion chained 2011$ with an inset that shows year ten of the scenarios and equivalent delay in wealth, b) percent change from reference scenario

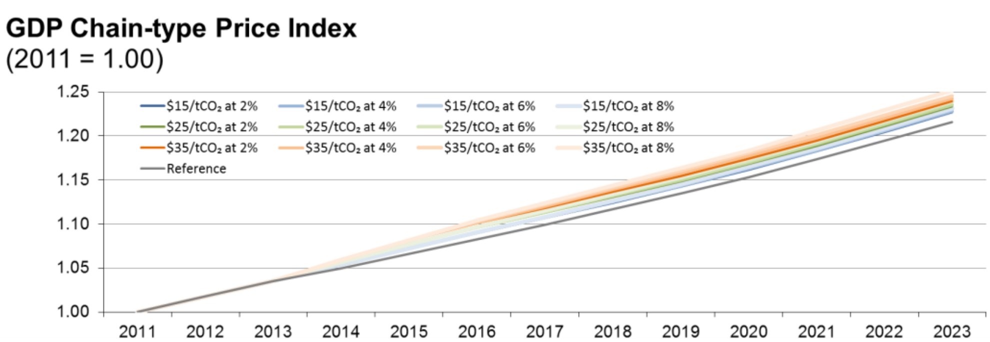

Figure 3.4 GDP price index

Figure 3.5 shows the annual growth rates for each scenario including the Reference Case. In the few years prior to policy implementation, GDP growth is on the order of 2% per year on the heels of financial crises, and the annual growth from 2013-2014 reflects EIA’s expectation of a dramatic economic recovery. The carbon scenarios all initially slow economic growth slightly, although all significantly outperform the few years prior to 2013. After the initial energy sector adjustments that result from the carbon fees, annual growth of all scenarios will exceed the Reference scenario growth rate.

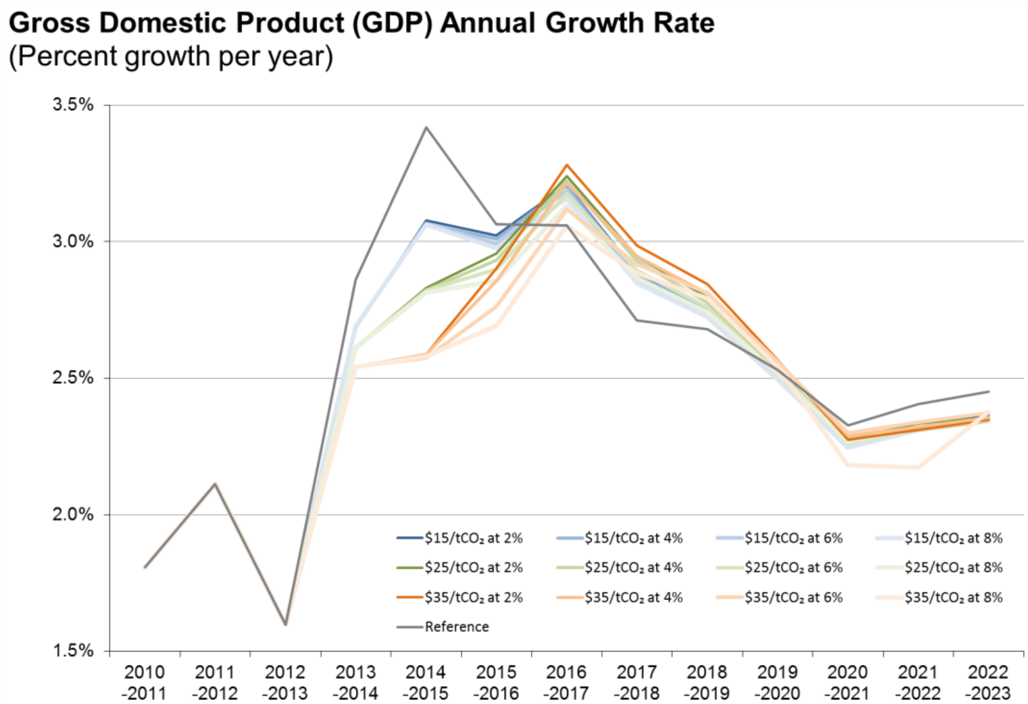

Figure 3.5 Annual GDP growth rates

These projected impacts to GDP are very likely overstated. First, impacts of policies aimed at reducing energy related carbon emissions that could potentially be funded by the revenues have not been included. By reinvesting money raised by the carbon pollution fee into activities that reduce emissions and compensate exposed industries, these programs would reduce overall costs of compliance.

Second, the model does not account for improvements in U.S. public health and related reductions in healthcare expenditures associated with reduced air pollution brought about by the program. These benefits are significant. Prominent economists recently concluded that air pollution damages from some industries, such as coal-fired power plants, are greater than the amount those industries contribute to GDP (Muller et al., 2011). This finding is particularly important, since these policies will induce coal plants to shut down early, for which the costs to GDP are included yet corresponding human health benefits are not.

Third, the structure of the macroeconomic model in NEMS does not account for any impacts of deficit reduction on future U.S. debt servicing costs.

Finally, the projected impacts to GDP are limited by the core assumptions in NEMS. Notably, the model does not fully account for the possibility of induced innovation, which many analysts believe would be spurred by a price on carbon. Environmental economists have shown that induced innovation in the context of climate policy has the potential to significantly lower compliance costs and increase social welfare, which would minimize impact to GDP (Goulder and Mathai, 2000).

3.3 MACROECONOMIC DECOMPOSITION

Using the Kaya framework defined in Chapter 2, one can evaluate the impact to economic drivers, including the GDP discussed above. Figure 3.6 shows a comparison of Kaya parameters from the reference scenario and a sample scenario ($25/t$CO_2$ at 2%). Population is exogenous[30] to NEMS so the baseline assumptions remain constant through all scenarios, and the previous section demonstrates that GDP impacts are small. Consequently, the largest changes show up in energy intensity (FE/$GDP-chained), which reflects demand side reductions; energy supply losses (PE/FE), which represents supply side efficiency improvements; and carbon intensity (CO_2/PE), reflecting a significant change in the carbon content of primary energy use (i.e., fuel switching).

Most of these parameters behave rather linearly, even under aggressive policy scenarios, implying an assumed constancy in the model that does not reflect real-world economics. Population is exogenous, but shown in the figure for completeness. GDP shifts slightly, but still grows at a steady pace, and GDP/P (affluence) does not change

[30] Population is exogenous to NEMS and grows steadily at about 0.95% annually from 318.38 million in 2013 to 350.07 million in 2023. Since the rebate portion of these policy scenarios is intended to largely offset impacts to individual households, there is no real economic or financial driver that would significantly alter population. Consequently, the reference scenario population is not modified for any of these scenarios.

much in any scenario since GDP growth is resilient under these policies. Energy consumption decreases (somewhat muted by the slight decrease in GDP), so energy intensity decreases steadily. However, it does so only a little faster once the policy is implemented. Energy supply losses improve early then remain relatively constant, and the most aggressive scenario shows less than 5% improvement in distribution efficiency. The most notable macroeconomic impact is from a significant reduction in carbon intensity, which declines quickly over the first few years, then more slowly. All of the scenarios exhibit a similar behavior, and Figure 3.7 shows a comparison of all scenarios in 2023 (relative to 2013).

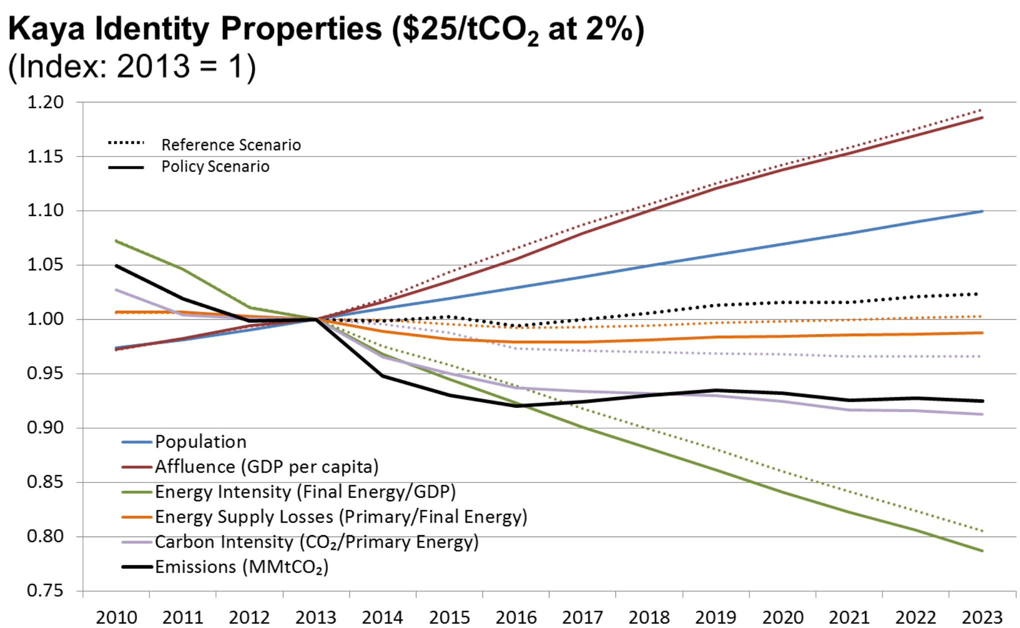

Figure 3.6 Kaya identity parameters comparing Reference scenario (dotted lines) and $25/tCO$_2$ at 2% (solid lines)

One can also quantify the contributions to annual carbon emissions from each of the Kaya parameters using the LMDI decomposition technique described in Section 2.4.4. For a simple application of the LMDI approach, assume there is only one sector: the U.S. economy. In the Reference scenario, emissions will expand with a growth in population and GDP (affluence), but general improvement in the energy efficiency of end-use technologies will reduce energy intensity and carbon intensity. The net result is a relatively neutral, but slightly increasing total emissions year over year (see Figure 3.8a).

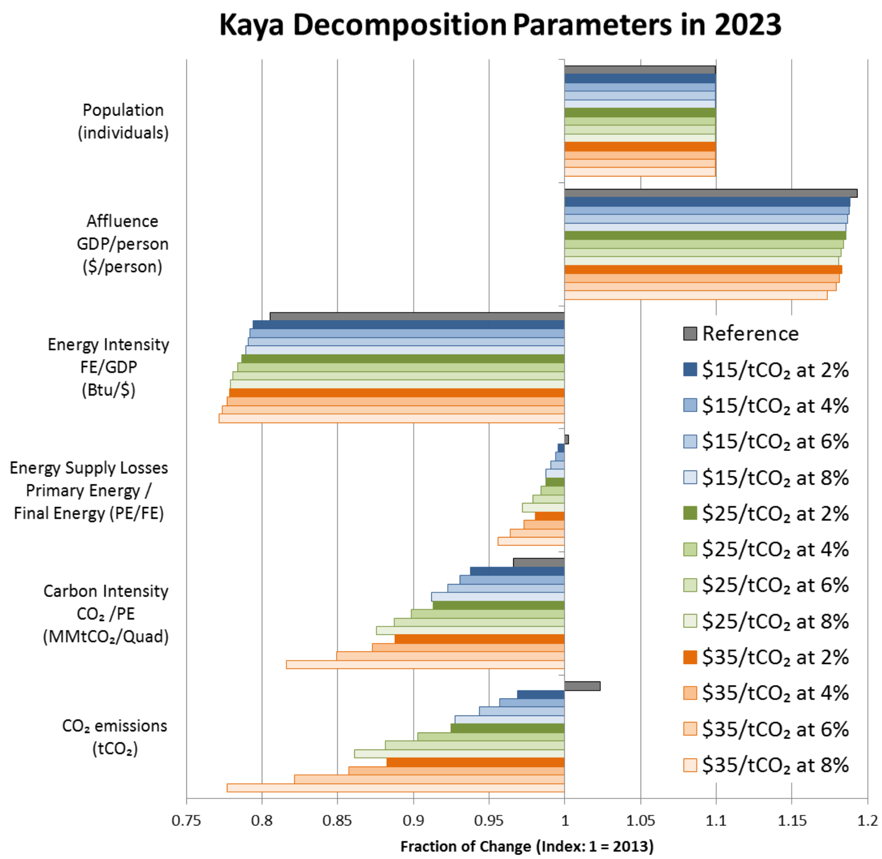

Figure 3.7 Kaya parameters for all scenarios in 2023. Fractional change from 2013 to 2023

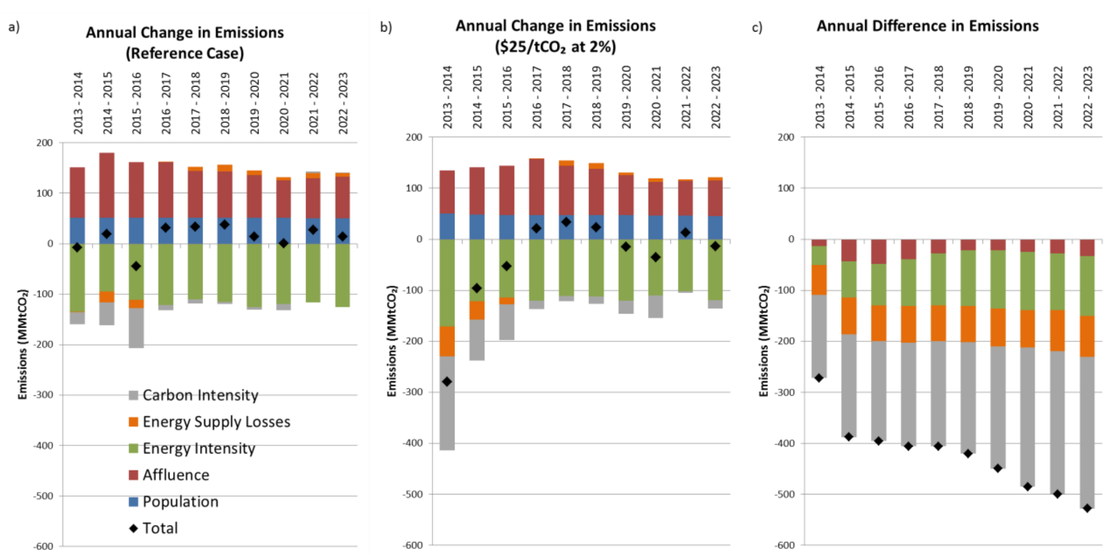

Figure 3.8 Effect from each Kaya parameter on annual change in carbon emissions. a) Reference case, b) policy scenario ($25/tCO$_2$ at 2%), c) difference between Reference and policy case each year.

Quantifying the effects of a carbon policy reinforces that most changes will occur within the first few years (see Figure 3.8b). The policy impact to each term becomes clear when comparing the differences between the Reference and the policy scenario (see Figure 3.8c). Although population is exogenous, per capita emissions differs slightly between the reference and policy scenario. The mild slowdown in GDP growth helps reduce emissions a little, but most of the emissions reductions come from efficiency improvements and carbon intensity changes. While all three panels in in Figure 3.8 are annual differences between the scenarios, Figure 3.8c is effectively also an accumulated difference between the two scenarios. Changes occurring in the first year between the two are still in effect in subsequent years. So the values on this panel represent the cumulative amount of avoided carbon for this policy scenario.

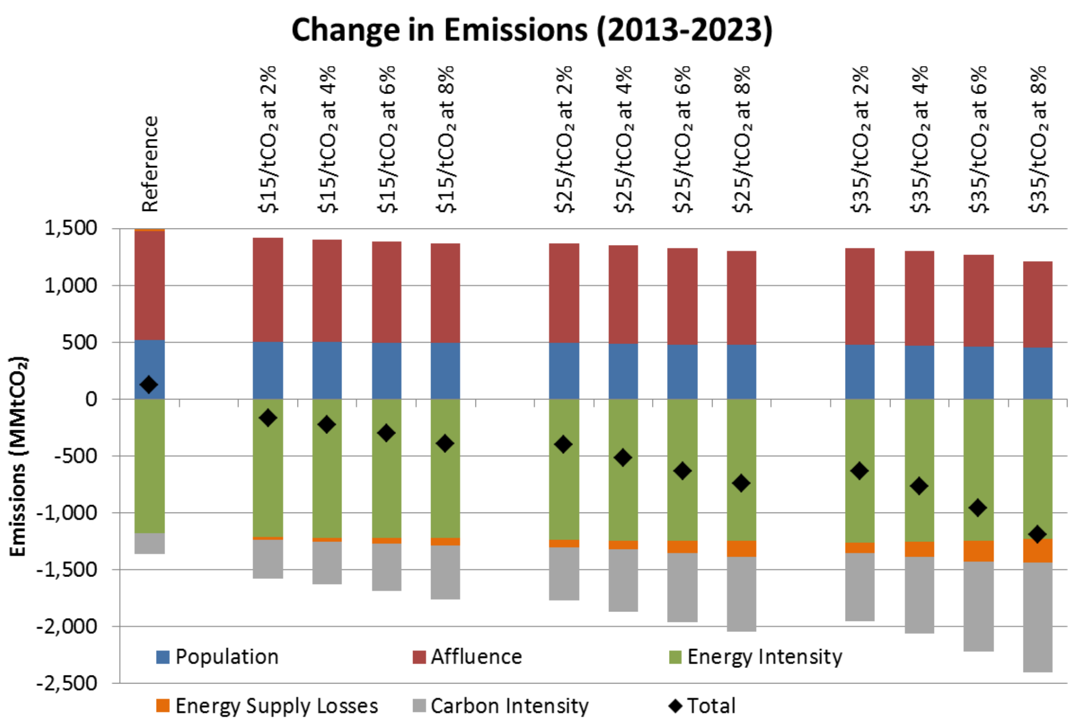

Figure 3.9 Effect from Kaya parameters on annual change in carbon emissions

The accumulation of the annual change from each effect over the whole decade (2013 to 2023) is shown for all scenarios in Figure 3.9. The reference scenario shows a slight increase in total emissions over the next decade from a combination of increases in population and GDP, and decreases in energy and carbon intensities. In general, all the scenarios mirror this, and the more aggressive the scenario, the greater the carbon intensity effect. (Please see Appendix 0 for a table showing the numerical results to Figure 3.9, and annual charts for each scenario similar to Figure 3.8b).

3.3.1 Avoided carbon

The previous sections showed the scale of emissions avoided by implementing a carbon fee and that those avoided emissions come mostly from energy and carbon intensity improvements. What is perhaps more important is how those carbon savings are achieved. Did energy efficiency become an affordable resource? Were consumers priced out of the market and forced to reduce demand? Was the electricity supply industry forced to strand high-carbon assets by quickly switching fuels?

Equations 2.4–2.6 show how much each of these activities contribute to the total emission reductions. Figure 3.10 shows the results for one policy case (\$25/tCO_2 at 2%), and illustrates that more than half of the avoided CO_2 will come from switching to lower carbon fuels. About a quarter of the reduction will come from demand side efficiency, and the remaining from supply side efficiency. These results also show that efficiency contributes more in the latter years of the policy, but demand-side efficiency savings never displace fuel switching as the primary means for reducing carbon emissions. Wilkerson, et al. (2013) showed that the NEMS building sectors are very stiff relative to energy efficiency, even when offered access to free capital to cover the higher cost for more efficient appliances. So if one believes more efficiency can be gained from the residential and commercial appliance sectors, then the demand side energy efficiency band would be larger and the total carbon emissions for these policy cases would be even lower.

Figure 3.11 shows a similar net performance from all of the policies by 2023. The amount of fuel switching vs. efficiency generally depends on the initial price and escalation rate. High carbon fees that escalate rapidly force supply side to switch fuels promptly to reduce operating costs, as evidenced by the difference in the fuel switching and supply-side efficiency between the \$15 and \$35/tCO_2 scenarios. The \$25/tCO_2 scenarios begin to exhibit that same characteristic, but then, surprisingly, supply-side efficiency takes over. This shift indicates that \$25/tCO_2 is the approximate threshold for changes in the supply side structure.

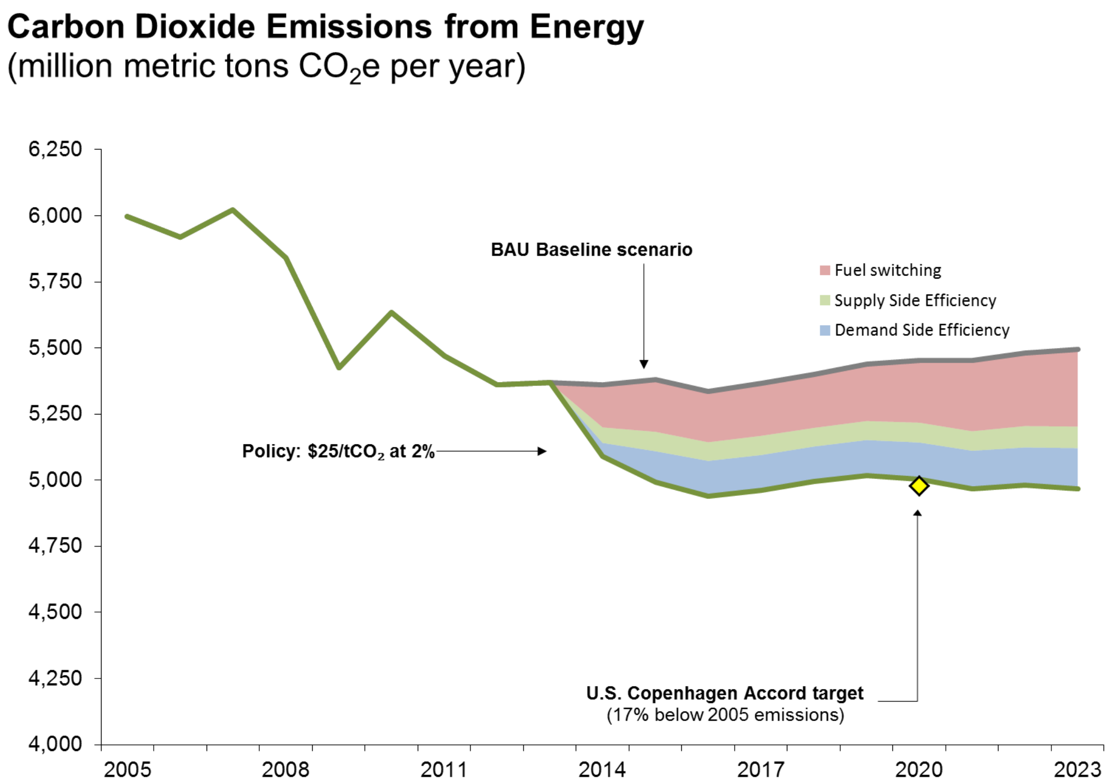

Figure 3.10 Carbon savings from efficiency and fuel switching for example policy: \$25/tCO_2 with 2% escalation per year

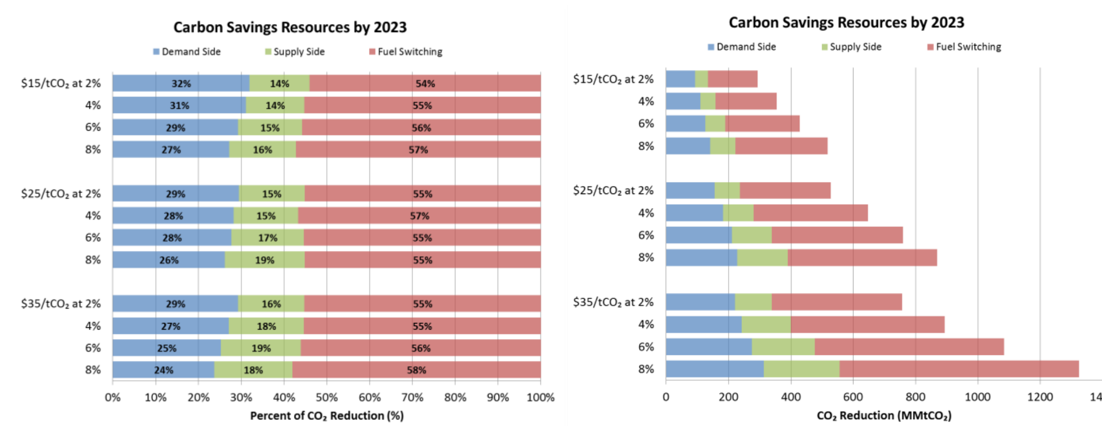

Figure 3.11 How carbon is avoided by 2023 for all scenarios. Percent of savings on the left, total savings on the right.

On the other hand, when faced with low annual escalation rates, consumers have time to upgrade building shells and appliances, for example, which will reduce the burden on the energy supply system. This result is demonstrated by comparing two policy cases that have similar carbon fees in 2023: $15/t$CO_2$ at 8% and $25/t$CO_2$ at 2%. Although these two policies have about the same final carbon price in 2023 (see Figure 2.1), more energy efficiency (less fuel switching) takes place under the lower escalation rate than the higher escalation rate.

3.3.2 Energy and carbon intensities

Figure 3.12 compares carbon and energy intensities directly to illustrate the temporal aspects of the policy response. Note there are three dimensions to this figure. The two axes indicate the change in energy and carbon intensities relative to the base year, 2013. In this plot, both are equal to a unit of intensity (1.0) in 2013; however, their reference values are 6.2 MBTU/$GDP (chained) and 55.8 MMtCO_2/Quad BTU respectively. The asterisks along the Reference scenario indicate the energy and carbon intensity values in each year starting in 2010 in the upper-right corner of the plot. So, in 2010, the U.S. consumed more energy per GDP and emitted more carbon from that energy than it did in 2013 since both values are greater than 1.

The Reference scenario trajectory indicates significant reduction in energy intensity has already planned for an 18% reduction in savings over the next decade (0.82 of 2013 value). Yet the Reference scenario only projects a 3% reduction in carbon intensity over the same period (0.97 of 2013 value). Furthermore, while the energy intensity reduction occurs in relatively steady increments each year, the carbon intensity changes mostly occur in the first few years as existing economic incentives expire in the model, such as measures from the American Recovery and Reinvestment Act of 2009, Energy Improvement and Extension Act of 2008, and the Energy Independence and Security Act of 2007 (EIA, 2009c). Keep in mind that the Reference case has an increase in net emission (see Figure 3.10) due to population and GDP growth, even though both carbon and energy intensities decrease.

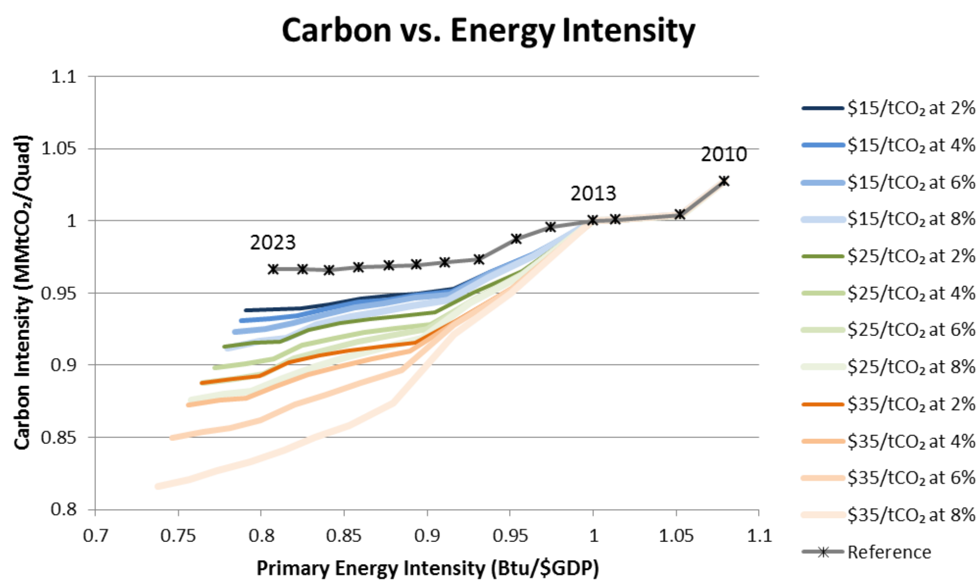

Figure 3.12 Carbon intensity vs. energy intensity

The initial economic reaction to the carbon fee is to switch to lower carbon fuels to promptly reduce carbon intensity. Figure 3.12 reiterates that most of the avoided carbon is accounted for in the first few years, as evident by the quick decline in carbon intensity in every scenario from 2013 to 2016 relative to the Reference case. It also shows that, like absolute carbon emissions reduction, there is a wide range in the amount of carbon intensity reduction between the scenarios, ranging from 0.82 to 0.94 of the 2013 value by 2023. The figure also shows that most of the energy intensity reductions are already embedded in the reference case. The most aggressive scenario only extends the energy intensity reduction an additional 9% from the Reference scenario, to 73% of the 2013 value by 2023. So while this represents a significant improvement in energy intensity, most of it is already included in the baseline scenario.

Figure 3.12 presents this relationship between energy and carbon intensities as they evolve along policy-driven trajectories. One can also look at the relative relationship of carbon and energy intensity changes by evaluating the ratio of the residuals (or the ratio of the percent change), which is the carbon intensity over energy intensity (CoEI) indicator defined in Equation 2.8. Separately, the residuals of carbon intensity and energy intensity would look very similar to the logarithmic-like profiles for RAI above in Figure 3.2. So the CoEI in Figure 3.13 shows which is leveraged more in a given year to meet the economics driven by the carbon prices. The general shape of the CoEI curves for all scenarios are similar. In the first few years, carbon intensity is reduced nearly twice as fast as energy intensity, but the gap quickly narrows as more energy efficiency is adopted over the next few years. As both approach diminishing returns at the end of the first decade, carbon intensity improvements continue to dominate the savings. For higher initial carbon fees, even more emphasis is placed on changing carbon intensity rather than energy intensity.

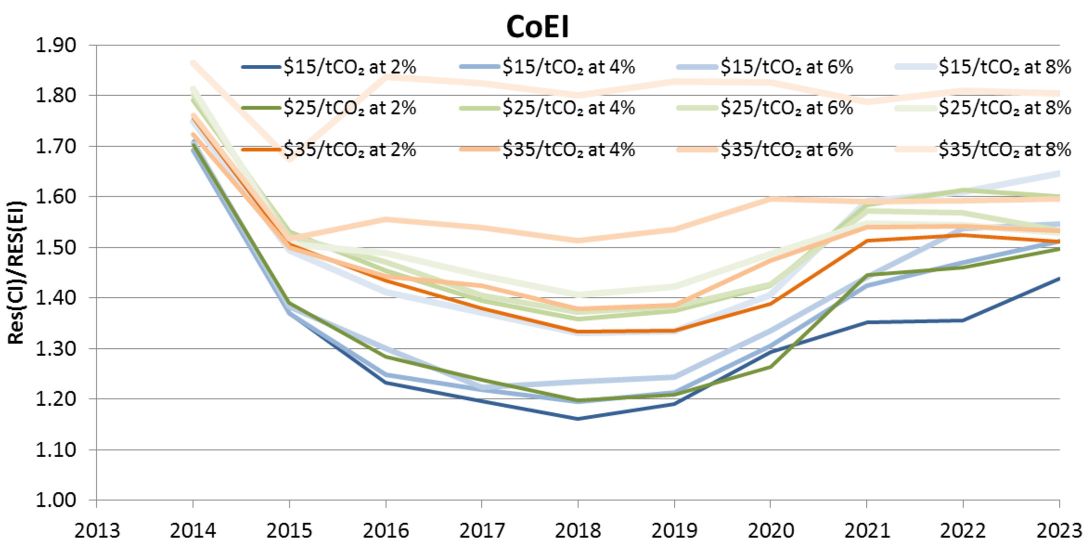

Figure 3.13 Residuals of Carbon over Energy intensity (CoEI)

Keep in mind that there is an important difference between the carbon vs. energy intensity plot (Figure 3.12) and the CoEI plot (Figure 3.13). The carbon vs. energy intensity plot shows the trajectory of the two values and their change relative to the 2013 Reference case value. The CoEI plot evaluates only the changes in the two variables. So CoEI in Figure 3.13 represents the policy case differences from the Reference case trajectory in Figure 3.12. Thus, while the carbon vs. energy intensity plot shows that energy intensity improvements will far surpass carbon intensity improvements relative to 2013, the carbon policies will have a much greater impact on carbon intensity improvements than on energy intensity.

The CoEI can be difficult to interpret. For example, A CoEI indicator factor of 1.5 means that carbon intensity is reduced one and a half times faster than energy intensity is reduced during the same year, but it says nothing about the magnitude of the reduction of either. Furthermore, since most of the carbon reduced by these policies is done so in the first few years of implementation, the importance of CoEI as an indicator is less effective thereafter. So it is best to use these all of these tools and metrics together to evaluate the impacts.

3.3.3 Fuel mix

The evidence shows that most of the carbon reductions are achieved by reducing carbon intensity, which is a result of switching to fuels with lower carbon content. This activity is dominated by swapping coal for natural gas, with the rest from renewables (see Figure 3.14). Without any measureable electrification of the transportation sector, this dramatic reduction is borne almost entirely by the electricity sector. With the decrease in natural gas prices over the past several years, many coal facilities are already on a knife edge of profitability. As operating costs of these plants increase with the addition of a carbon fee, they quickly become too costly to sustain.

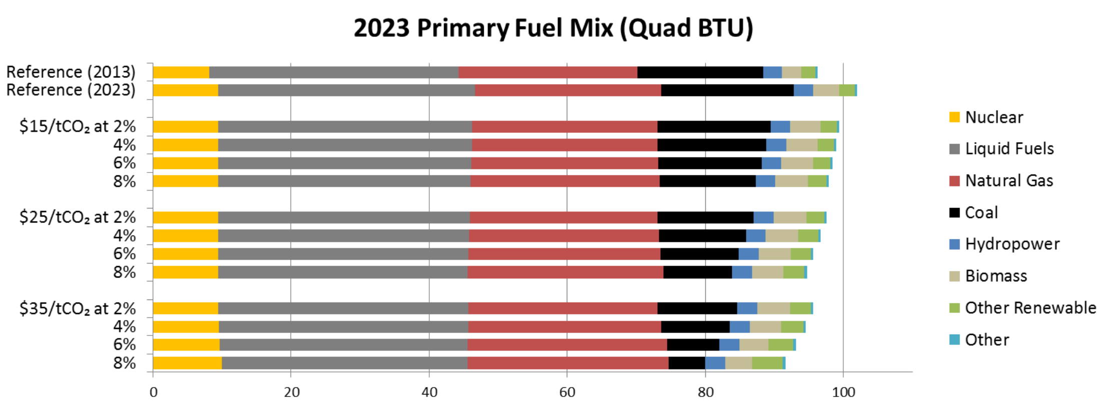

Figure 3.14 Primary fuel mix in 2023

Another way to evaluate the overall change in the primary energy structure is to quantify how much adaption is required to meet the new fuel mix. Figure 3.15 shows the Transformation Index, which is a measure of how ‘far’ the annual energy structure is from the base year (2013). The larger the value, the greater the structural change that has occurred in the energy sector since the reference year. The Reference scenario is already expecting to see some change, but nearly all of that takes place in the first few years and mirrors the carbon intensity reductions shown above in Figure 3.12. Not surprisingly, most of the structural changes from the policy scenarios also occur in the first few years of the policy implementation.

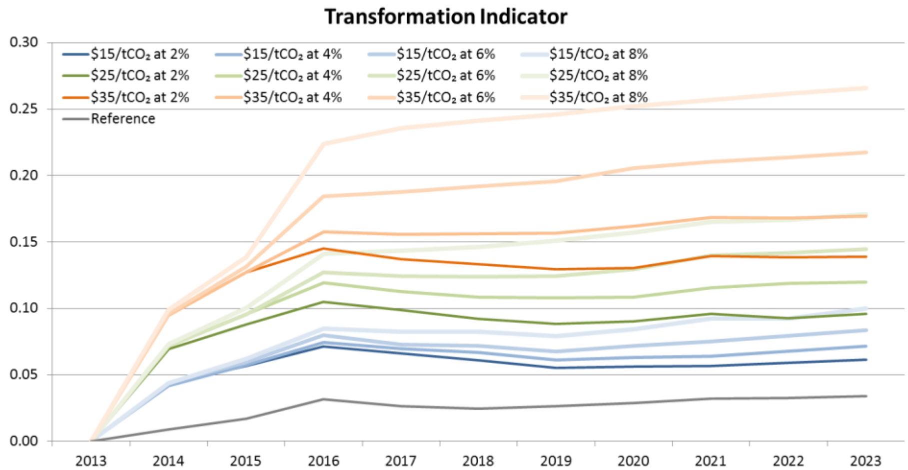

Figure 3.15 Transformation Indicator

3.4 SECTORAL IMPACTS

The individual sectors in NEMS can also be disaggregated to identify how each is impacted by these carbon policies. But first, it is instructive to put the sectors in perspective relative to associated energy and carbon emissions. Primary energy consumption in the U.S. is in the range of 100 Quad BTUs, and the dotted lines in Figure 3.16 represent the forecast of demand by sector for the Reference scenario. In decreasing order of total consumption, the sectors are Industrial, Transportation, Residential buildings, and Commercial buildings. The solid lines in the figure represent the energy consumption response from one policy case ($25/t$CO_2$ at 2%).

In the Reference case, overall total energy consumption in the U.S. will grow slowly from just over 96 Quads in 2013 to 102 Quads in 2023, and most of that expansion will come from the Industrial sector. Under the policy, total consumption will almost reach 98 Quads in 2023, which is slightly lower than total historical consumption in 2010. The largest portion of the change in consumption will come from the Industrial sector, followed closely by the Commercial and Residential sectors. However, the Transportation sector will see almost no change from this, or really any policy. All of the policies behave similarly for a given sector, and Figure 3.17a summarizes sectoral energy consumption in 2023 from all scenarios.

Figure 3.17b highlights energy-related carbon emission by sector in 2023. The policy will have a trivial effect on the Transportation sector, which will see only between 1% and 3% reduction in emissions across the policy spectrum. The Industrial sector will see a slight increase in emissions under the most lenient policy to a 17% reduction under the aggressive policy. However, the building sectors will both see significant reduction in emissions from these policies. The Residential sector savings range from 11% to 42% savings, and the Commercial sector from 8% to 43%.

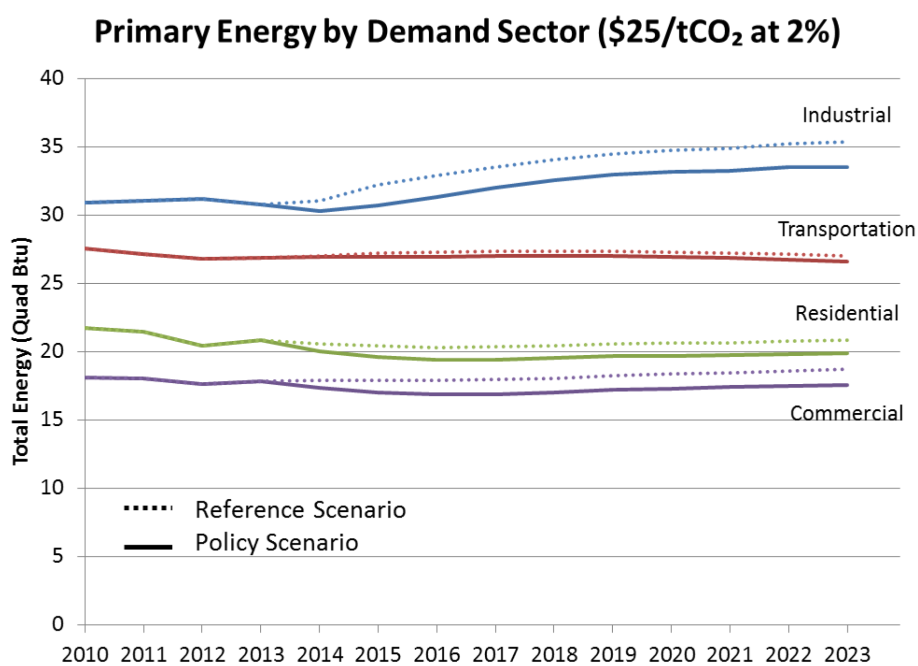

Figure 3.16 Primary energy consumption by demand sector

Figure 3.18 shows the evolution of emissions over the next decade in the Reference case from each demand sector resulting from the use of four main fuel categories: petroleum-based products, natural gas, coal, and electricity. Even in the reference scenario, Transportation and the buildings sectors are expected to reduce or maintain emission levels. By contrast, the industrial sector is expected to expand and will increase emissions accordingly. Although the Transportation sector accounts for only about a quarter of all primary energy consumed in the U.S., it was responsible for a third (33%) of all U.S. emissions in 2013. The fuel mix of this sector is dramatically different than that of the others, with petroleum (e.g., gasoline, diesel) as the dominant fuel accounting for nearly all of the sector emissions.

Emissions from the Industrial sector represent almost 28% of total U.S. CO_2 emissions, while the Residential and Commercial buildings sectors emitted about 21% and 18%, respectively in 2013. All three of these sectors are fueled by electricity and natural gas predominantly, with some direct coal use and measureable petroleum use in the Industrial sector. In the Industrial sector, almost 40% of the associated emissions came from the use of electricity in 2013 and about 30% from natural gas. The Industrial sector uses almost the same amount of total electricity as the buildings sectors, although electricity contributes a much smaller portion of its emissions. For the building sectors, electricity-related emissions account for about three quarters of the emissions with natural gas making up most of the remaining quarter.

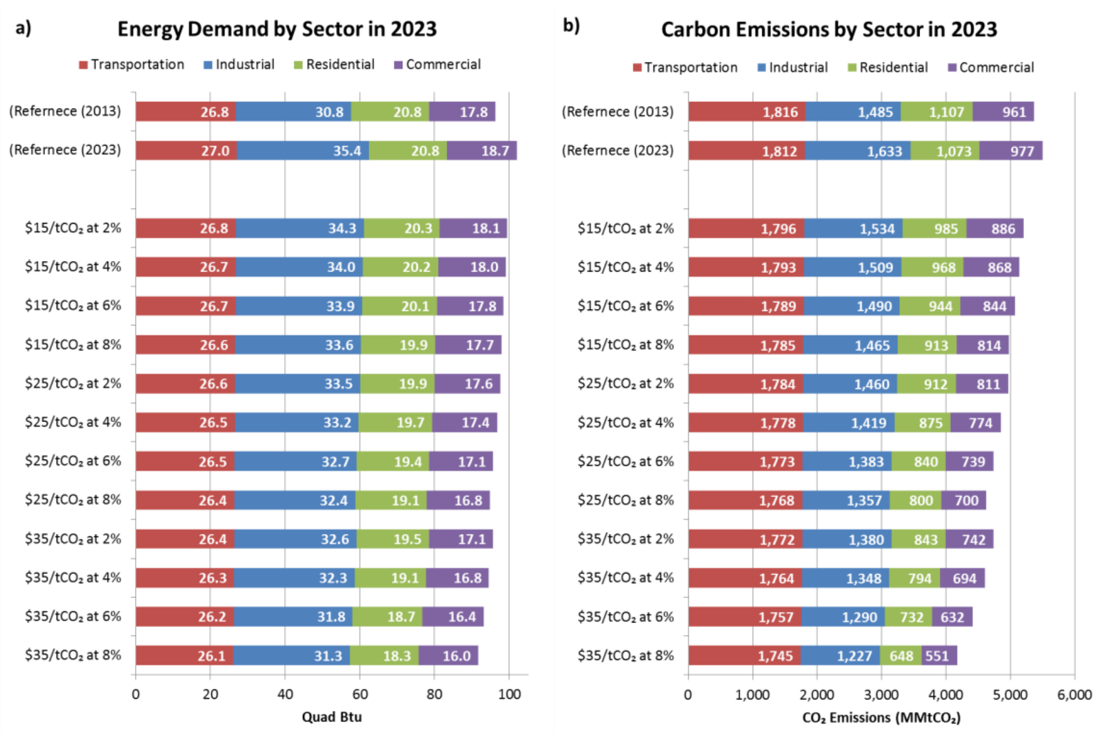

Figure 3.17 Policy impacts to a) energy consumption and b) related emissions in 2023 by sector

The avoided emissions from the $25/t$CO_2$ at 2% are perhaps more enlightening. Figure 3.19 shows that nearly all of the avoided emissions are split roughly evenly among the Industrial, Residential, and Commercial sectors, and almost none of the savings come from the Transportation sector. This is not too surprising since Figure 3.14 shows that nearly all of the changes in U.S. energy supply come from switching away from coal. So any change in emissions in the transportation sector is driven by change in demand, rather than fuel switching.

For all three non-Transportation sectors, nearly all emissions reduction comes from decarbonizing electricity, followed distantly by a reduction in natural gas usage. Since the carbon content of natural gas is not changing, any associated emissions reduction here represents a change in demand (either technology upgrades or behavior changes). This reasoning also applies to the petroleum-related savings in the Transportation sector. Conversely, electricity-related emission reductions come mostly from switching to lower carbon fuels for electricity generation. This accounts for about 40% of primary energy consumption in the U.S., but will account for about 85% of the avoided emissions. (Please see Appendix B.4 for avoided emissions by sector and fuel type for all scenarios).

An additional result of avoided emissions is a shift in sector contribution to carbon fee revenues. The tax affects all sectors based on their respective emissions. So in 2014, the first year of the policy, Transportation sector contributes about 34% of all revenues, Industrial about 28%, Residential about 20% and Commercial the remaining 18%. Transportation sector sees little change from the policies so continues to emit about the same amount irrelevant of the policy. However, the more aggressive the policy, the more avoided emissions are achieved from the other three sectors– especially the building sectors. For the most aggressive case, the transportation sector will be responsible for about 42% of total revenues, while the Residential and Commercial building sectors will only contribute 16% and 13%, respectively. The Industrial sector will contribute a relatively constant 29% of emissions under all scenarios.

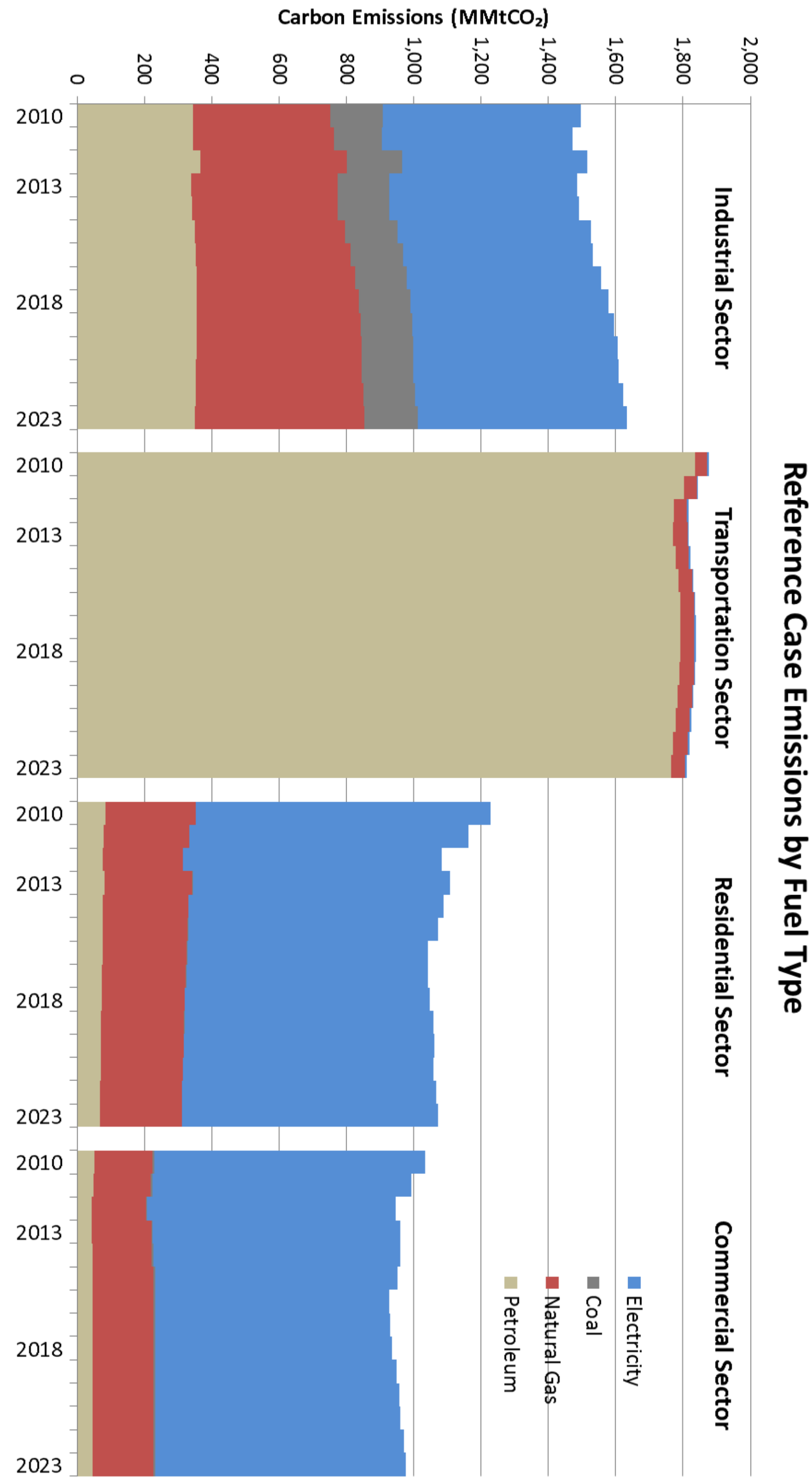

Figure 3.18 Reference Case emissions by sector and fuel type

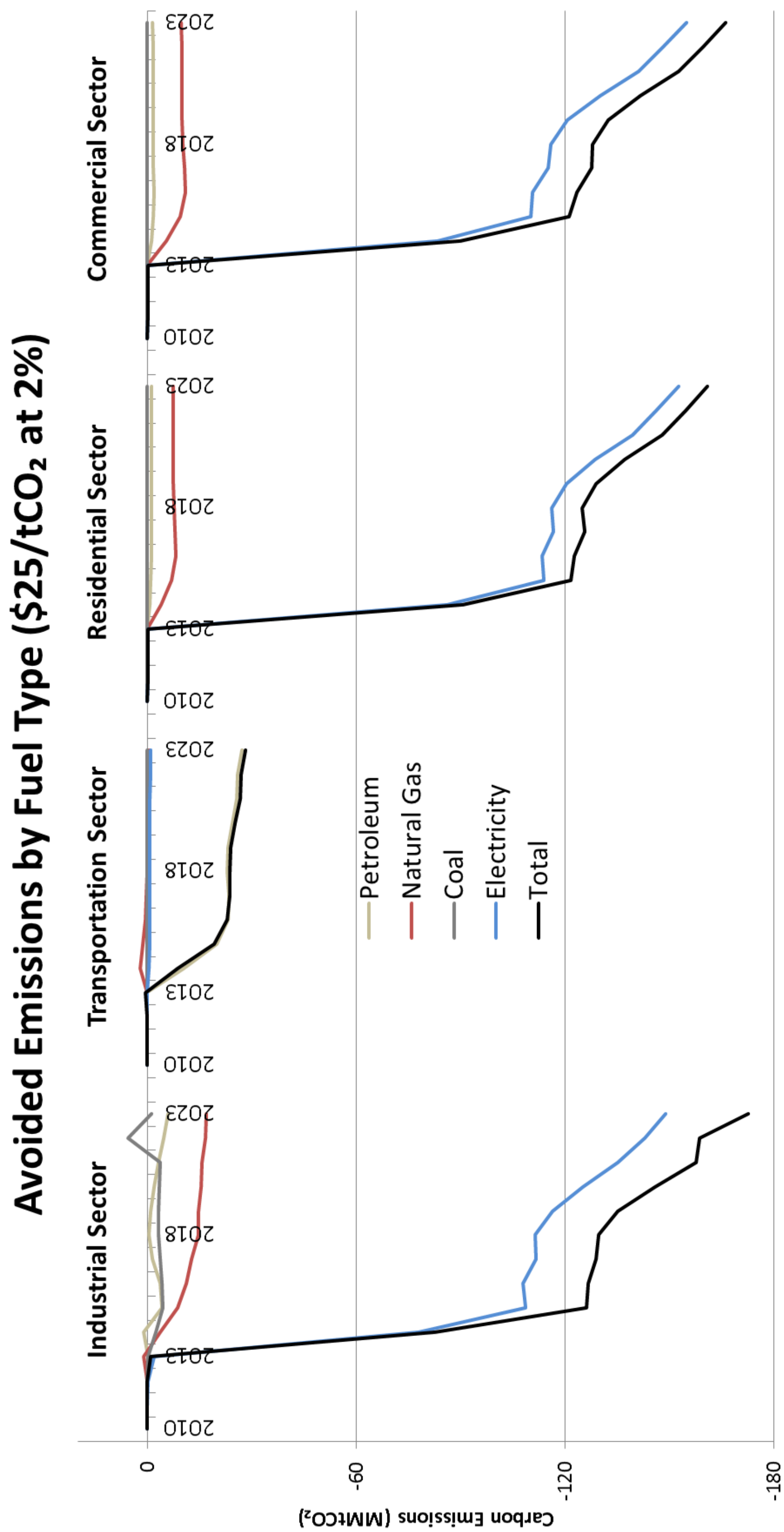

Figure 3.19 Avoided Emissions by sector and fuel type

3.4.1 Electricity supply sector

3.4.1.1 Fuels for electricity generation

Fuel categories for electricity generation include coal, natural gas, nuclear, renewable resources, and petroleum. Renewables include conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power. An 'other' category includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

In the Reference scenario, total generation is expected to rise steadily from 4,045 billion kWh in 2013 to 4,506 billion kWh in 2023 (see Figure 3.20). Only a slight change is expected in the fraction of electricity supplied from each fuel type through 2023. Coal's share of total generation will decrease slightly from 40% to less than 38%. Natural gas and nuclear will hold steady at about 27% and 20% respectively. Renewables will grow from 13% to almost 15%. Petroleum and 'other' will both decrease slightly but combined account for less than 1% of the total in 2013.

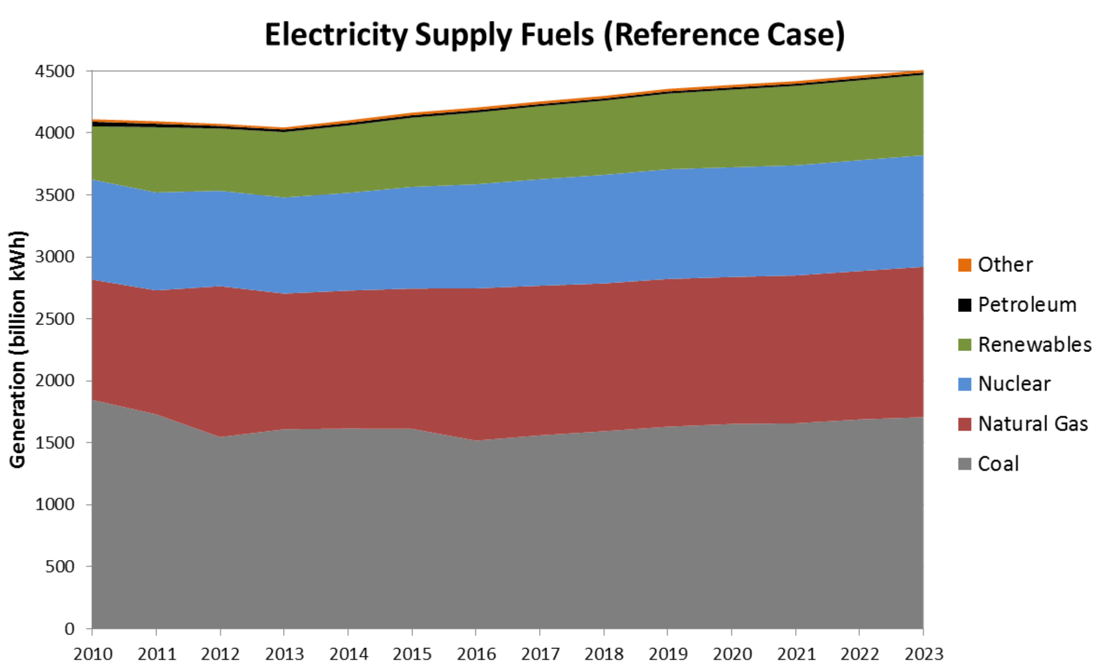

Figure 3.20 Electricity supply by fuel type (reference scenario)

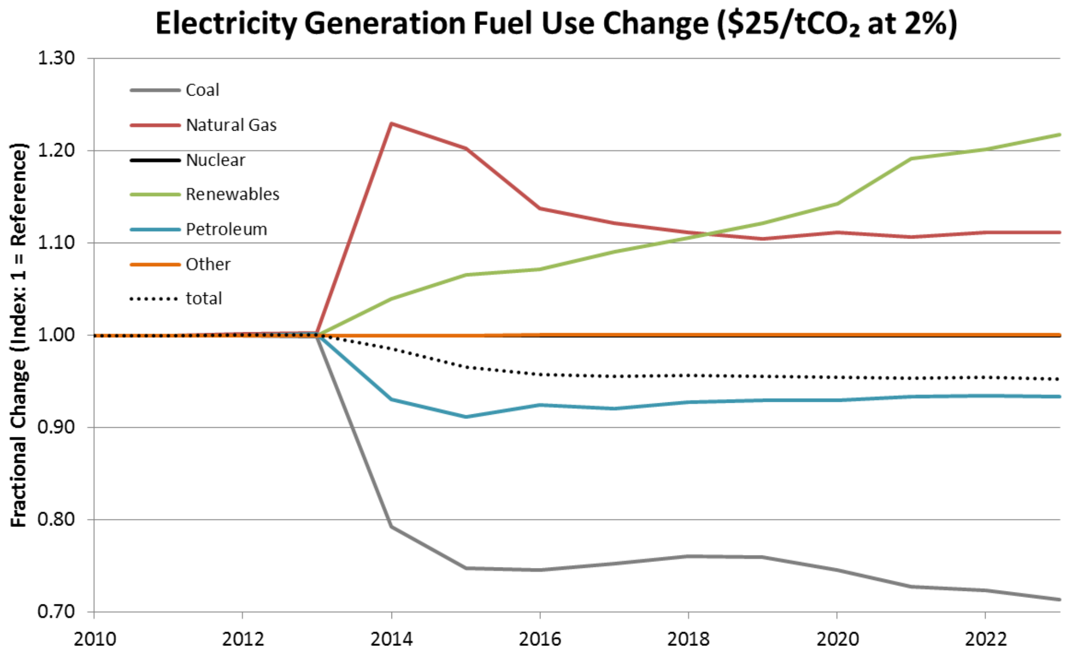

Figure 3.21 Electricity supply fuels change from reference scenario

Figure 3.21 shows how the electricity sector will respond under a carbon policy ($25/tCO$_2$ at 2%). Coal generation is quickly reduced to about 75% of what it is in the Reference scenario. Most of the loss in coal-fired generation is initially replaced by dispatching natural gas, which rises with coal's decline, to 20% more than projected in the Reference case. This rapid natural gas increase subsides to only 10% over the Reference scenario as natural gas prices continue to rise and more renewables are included. Thus, coal is swapped for natural gas in the short run, but renewables steadily grow by more than 20% through the end of the decade. Petroleum, already a very small piece of total electricity generation, also decreases. Nuclear baseload generation remains constant, in terms of total energy generated, as does the 'other' category. Despite these dramatic fuel-switching activities, total electricity generation is reduced by only about 5%, and most of that occurs within the first few years.

3.4.1.2 Installed capacity

The immediate and dramatic response to even this modest carbon policy suggests the electricity sector is simply re-dispatching existing natural gas plants instead of coal plants. To evaluate this, one can look at the NEMS forecasts for installed capacity by generation technology. Figure 3.22 shows the projected capacity available to meet peak demand for the Reference scenario, which will hover around 1000 GW for the next decade. By 2023, almost half of this will be met with conventional coal plants (26%) and conventional combined cycle (CC) plants (21%). The remainder is supplied by about 13% conventional combustion turbines (CT), 15% renewables, 10% nuclear, and conventional steam turbines (ST) will continue to account for about 8%. In the Reference scenario, advanced technologies make up only 3% of the total by 2023. As above, the renewables category includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind. The 'other' category includes pumped storage, fuel cells, and distributed generation (primarily peak-load capacity fueled by natural gas).

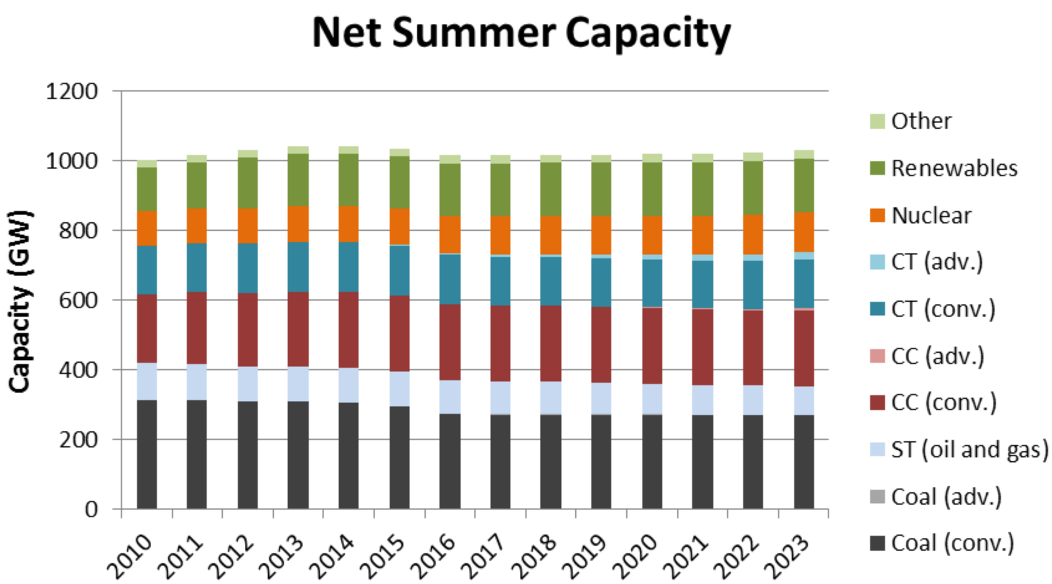

Figure 3.22 Electricity supply capacity by technology (reference scenario). This represents the steady hourly output that generating equipment is expected to supply to system load

Figure 3.22 includes all existing power plants as well as any additions and retirements. These additions (planned and unplanned combined) and retirements[31] are isolated in Figure 3.23. The Reference scenario will add about 80 MW total by 2023. In the first few years, this this includes conventional coal, CCs and CTs. Renewables

[31] New additions and retirements occur after Dec 31, 2010, since that is the base year for NEMS electricity generation data

will grow steadily throughout the rest of the decade, while the latter half of the decade will see substantial addition of advanced CTs and eventually some advanced CCs. Under the policy, the expansion of advanced CTs is swapped for earlier adoption of CCs, and the amount of renewables is doubled.

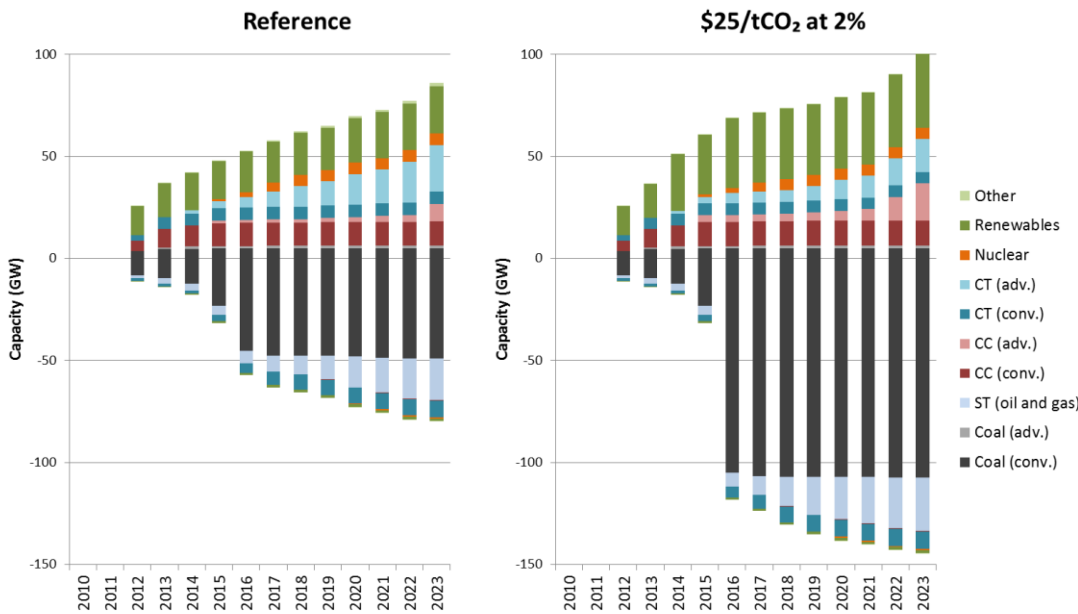

Figure 3.23 Electricity supply planned and unplanned capacity additions and retirements by technology.

In the Reference scenario, conventional coal dominates the retirement side, but is accompanied by the retirement of STs and some conventional CTs. Under the policy, all of the retirements remain roughly similar to the Reference scenario except for coal, which will more than double the amount of retired capacity. Most of this coal-fired generation is retired in 2016. NEMS requires sustained three-year elevated energy prices before agents in the model can make major structural changes. So, in 2016, utilities can finally retire much of the coal-fired generation that has remained too expensive to operate for the past three years.

These additions and retirements alter the fuel mix of electricity generation, and Figure 3.24 compares the reference scenario to the sample policy case. Under the policy, total generation (or demand) initially decreases. When the policy begins in 2014, there is an initial reduction in coal-fired generation that is mostly matched with additional generation from gas-fired conventional CCs. The increase in advanced technologies is not very large in aggregate. Altogether, retired coal-fired generation is replaced by nature gas and, to a lesser extent, renewables.

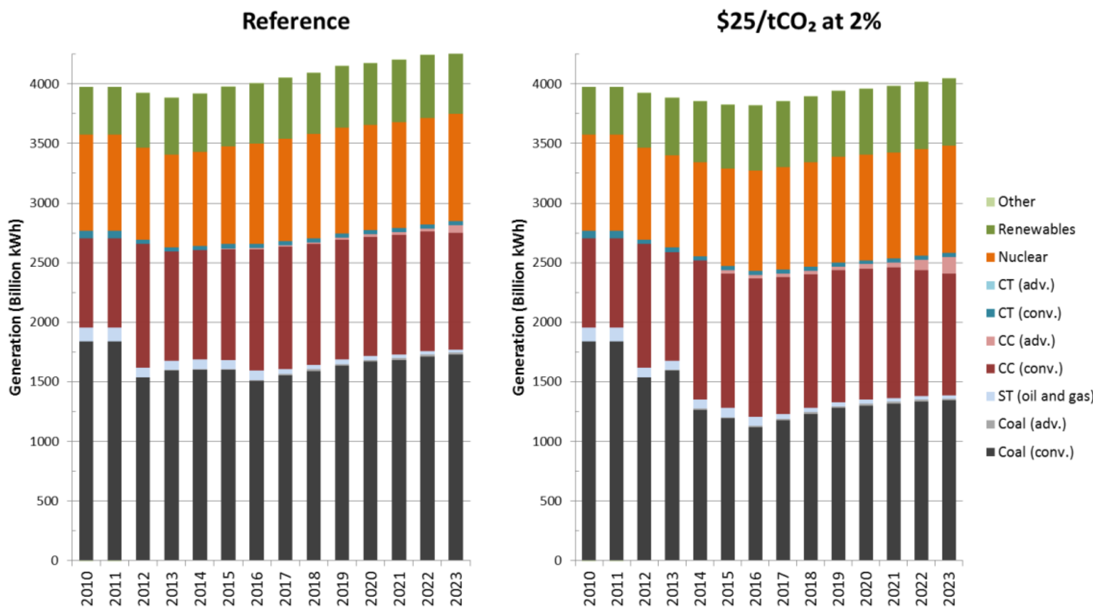

Figure 3.24 Electricity generation under the Reference scenario and sample policy scenario ($25/t$CO_2$ at 2%)

The dramatic retirement of coal-fired resources in 2016 (Figure 3.23), is not mirrored by a dramatic change in fuel shares in the generation mix (Figure 3.24). Upon the adoption of the policy in 2014, utilities almost immediately chose to dispatch more of their existing natural gas resources since some are now cheaper than some coal-fired resources. This is reasonable since CCs and CTs are typically constructed to meet intermediate or peak power demands, and are not anywhere near full capacity factor (CF). Thus, the near-instantaneous switch from coal to natural gas is a reasonable result.

$$CF = \frac{GWh\ generated\ per\ year}{8760h\ per\ year * GW\ installed\ capacity} \qquad \textbf{3.1}$$

To demonstrate this switch, one can look at the CF of each technology between the Reference scenario and a policy case. CF is a measure of how much capacity of a given technology or resource is used to generate electricity (see Equation 3.1). A CF = 1 means the resource is generating at full capacity for the entire year. When the policy begins in 2014, there is an almost exact match in the response in the reduction of coal CF to the increase in that of CCs, as illustrated in Figure 3.25. The CF of Coal returns to the Reference case trajectory after 2016 when many coal plants are retired. Advanced coal becomes more affordable a few years earlier, which helps to lower the CF of the more expensive CCs in the latter half of the decade. The U.S. average capacity factor (across all technologies) is about 0.45 and holds relatively constant under all policies.

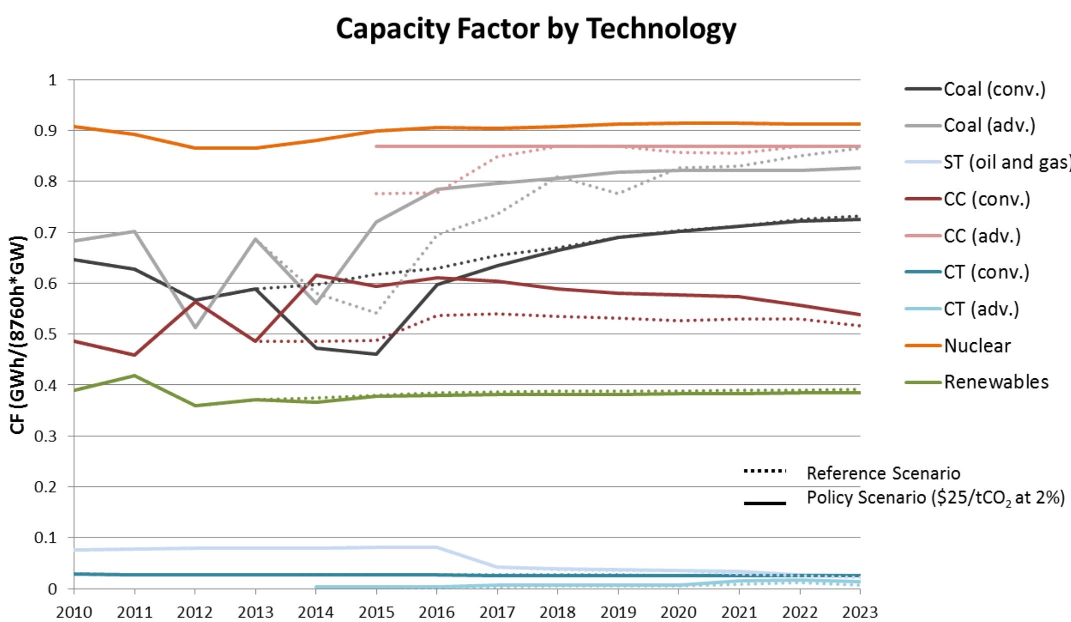

Figure 3.25 Capacity factor of each technology

3.4.1.3 Electricity sector decomposition

Finally, one can decompose the electricity sector by technology to quantify the impacts to carbon emission from each economic driver (ASIF indicator). A list of emissions by technology is not part of the standard NEMS output, but it can be found in the electricity market module output database (***emmdb.mdb***).[32] This database file is written at the end of each NEMS cycle and provides emissions for over 30 different technology types. Please see Appendix B.5 for details on this file and correlations to the shorter list of technology types used in this study.

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[32] Thanks for Laura Martin of EIA for describing the *emmdb.mdb* file and its contents.

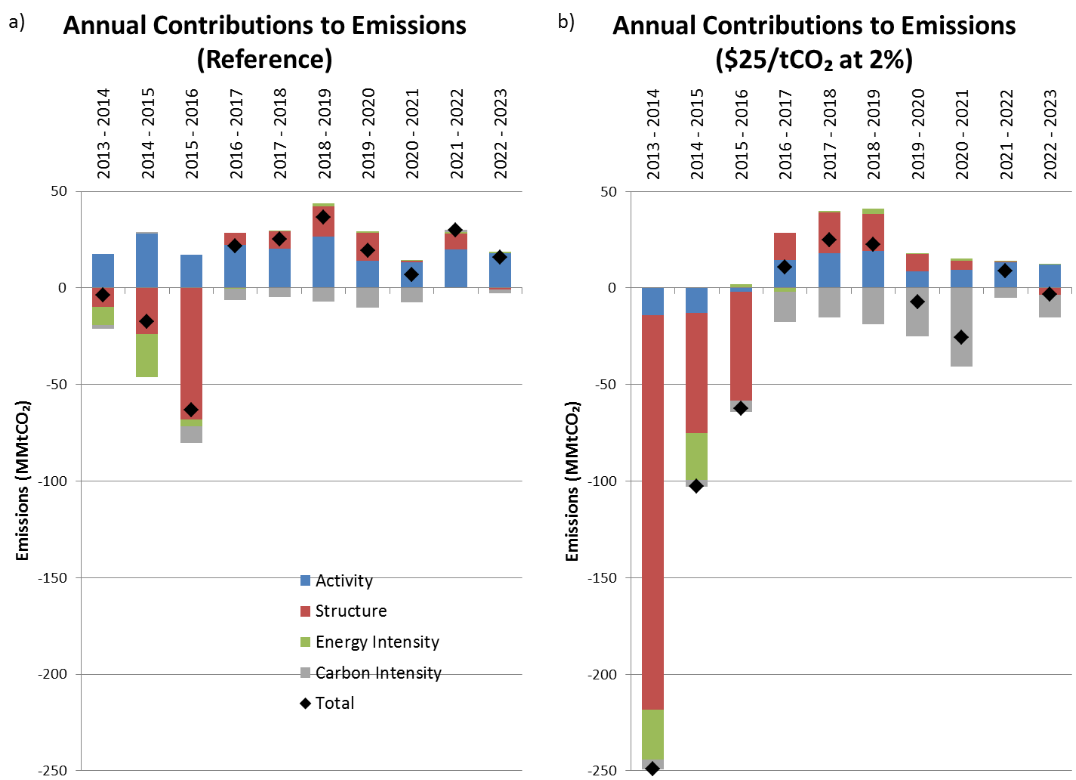

Figure 3.26 ASIF indicators for electricity generation under the a) Reference scenario and b) policy scenario ($25/tCO$_2$ at 2%)

Figure 3.26a shows the annual difference in emissions in the Reference scenario, and that most of the change in the electricity sector will arise in the next few years. The sector will generate more energy per installed capacity (energy intensity), increasing emissions, which is offset somewhat by a reduction of installed capacity (activity). The greatest driver of emissions reduction in the first few years is the change in mode shares (structure), swapping STs for CTs for example.

Under the policy scenario (see Figure 3.26b), there is a dramatic reduction in carbon emissions on the first few years. In the first year, energy generation is more efficient with increased dispatch of CCs and CTs, and although these are more expensive to operate (in the absence of a carbon fee), the sector benefits from generating with lower-carbon fuels. However, in the third year, overall energy intensity (GWh generated / GW installed capacity) is dramatically increased when the model allows the sector to retire all power plants that are increasingly too expensive to operate. This increase is largely offset by changes in structure and activity that are generally more efficient. Keep in mind, that although there is substantial fuel switching going on, many of the generating technologies are represented by a single fuel type, such as conventional coal or advanced nuclear. So, including a fuel mix indicator would be mostly redundant with respect to the sector structure. Thus, there is not a fuel mix term in this LMDI decomposition. (Please see Section 2.4.3.5 for additional explanation).

While the primary reason for the reduction in emissions in the sector is the switch from coal, carbon intensity does not show up explicitly in this ASIF decomposition. Structure, in this analysis, is represented by technology. So, while coal is one of the technologies, the energy intensity of coal is not changing much. Slight improvements from carbon intensity do arise in technologies such as CTs, which could use oil or gas, both of which have different emissions factors.

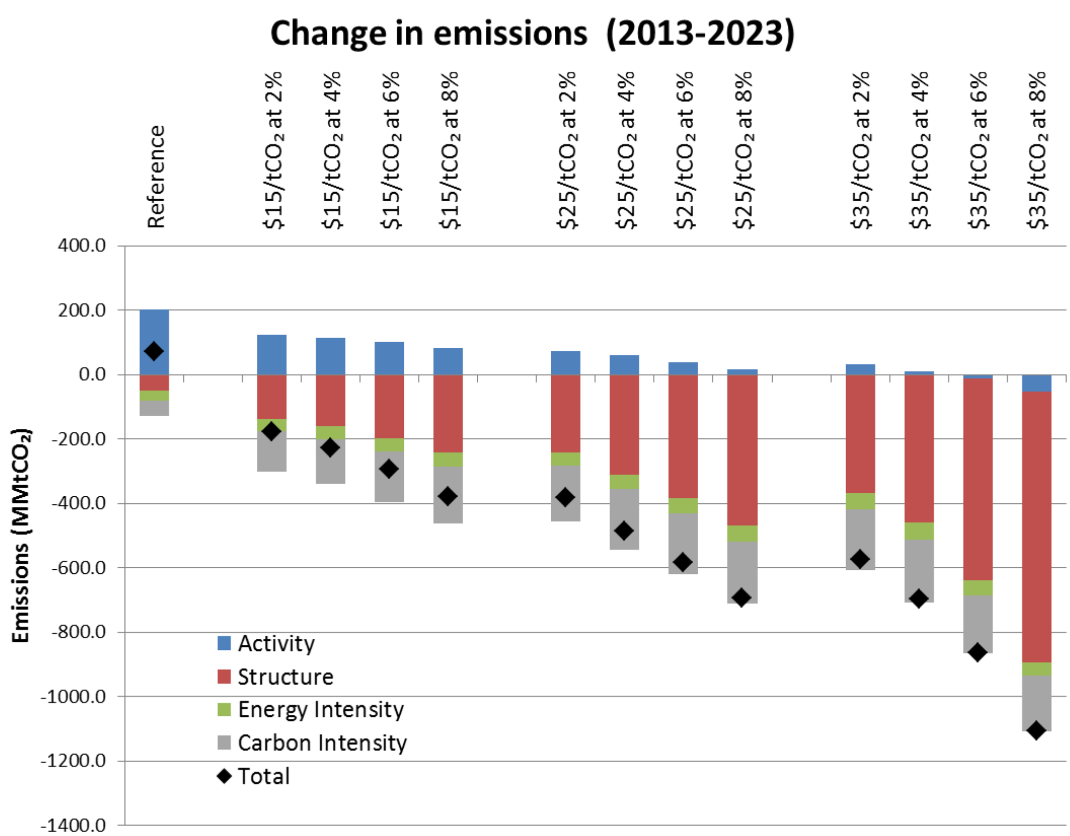

Figure 3.27 ASIF indicators for electricity generation from 2013-2023 under all scenarios

The significant structure adjustment in 2016 has a profound impact on the total change in emissions over the entire decade for all scenarios (see Figure 3.27). Total consumption does not change much in any scenario relative to the Reference, so each experiences only a small activity affect. The result of the net swing experienced in energy intensity in the first few years of the policy remains relatively constant between the scenarios as well, so all scenarios experience roughly the same intensity effect in aggregate (except for the most aggressive policies). The fuel switching that occurs in this ASIF decomposition takes place through technology, which is captured in the structure effect, so the direct carbon intensity effect within technologies remains relatively constant. So the only significant driver in the difference between scenarios is in this structural effect. (Please see Appendix B.6 for decomposition numerical results to all scenarios).

3.4.2 Transportation demand sector

A proper decomposition of this sector should evaluate transportation freight modes separately from travel modes, since the two are governed by differing incentives. Freight is driven almost purely by economics, while travel is also driven by consumer preferences and whims. Travel activity is represented by vehicle miles traveled (VMT), whereas Freight activity reported by NEMS is measured in ton-miles traveled (TMT). The mode shares in both subsectors are represented by the fraction of different vehicle categories, such as light duty vehicles (LDV), heavy trucks, air, bus, and rail.

The NEMS transportation demand sector is very detailed, tracking energy use of different mode shares, corporate average fuel efficiency (CAFE) of fleet and non-fleet vehicles, new vehicle sales and prices, and many other parameters. Unfortunately, the model does not provide consistent information between modes to properly apply a subsector-wide analysis of freight or travel. This is especially problematic for the freight side of the sector. For example, NEMS provides TMT for ship, air, and rail, but only for domestic freight. For international freight, the reported activity is in the dollar value of shipments, yet international activity may account for most of the fuel for the air and ship modes. Similarly, activity for medium and heavy commercial trucks and fleet LDVs is reported in VMT, not TMT.

On the travel side of the sector, activity of the rail and air modes are reported as passenger miles traveled, while the road modes are reported with VMT. One could assume that the all of the road VMT is based on having a single passenger, but the output of NEMS does not support this assumption.

Section 3.4.1 illustrated that most of the economy-wide emissions reduction comes from decarbonizing the electricity supply sector. Furthermore, most of the fuels used in the transportation sector have relatively constant emissions factors (e.g., natural gas, gasoline). Consequently, none of the policy scenarios will have much of an impact on emissions from the transportation sector. This point was illustrated in the avoided emissions by sector plot in Figure 3.19 above.

For all these reasons, this study does not attempt an ASIF decomposition of the transportation sector, which is ironic since the framework was originally developed for historic analyses of this sector.[33] Instead, this section will look at several of the drivers of activity independently.

3.4.2.1 General sector response

A thorough treatment of forecasts in the transportation sector is not possible with NEMS output data.[34] Not only is the output inconsistent between modes, but the data has been aggregated between travel and freight modes which are governed by different mechanisms. EIA has summarized sector-wide energy and emissions, indicating which aggregate modes experience impacts from carbon fees. The majority of the fuels used in this sector have fixed carbon content, so a carbon fee will have little impact on the carbon intensity of the sector overall. Indeed, Figure 3.28 illustrates that nearly all

[33] This illustrates the constant struggle analysts have in utilizing model forecast results for a structured analysis. Inconsistent and sparseness of model outputs impede efforts to correlate model forecasts with historical studies.
[34] Thanks to John Maples of EIA for helping to explain details about the NEMS transportation module and confirming that the model provides only the limited output described in this section.

major transportation modes, as well as the sector as a whole, show negligible change in carbon intensity when a policy is applied.

The two notable exceptions are impacts to the passenger rail and bus modes. Passenger rail carbon intensity reduction is strictly a result of decarbonizing the electricity sector, which impacts the electric portion of commuter rail services. Despite this decrease in carbon intensity, total passenger rail energy consumption increases by about 1% in relative to the reference scenario implying an increase in passenger rail activity (See Figure 3.29). Due to inconsistent output data, it is not possible to tie this increase to a decrease in other modes. The increase is about 1% total growth by 2023, and this mode contributes less than 1% of total sector emissions and consumes an even smaller part of the energy in the sector. Passenger rail and bus modes are a relatively small portion of the sector and, combined, they reduce transportation carbon intensity by less than 0.05%.

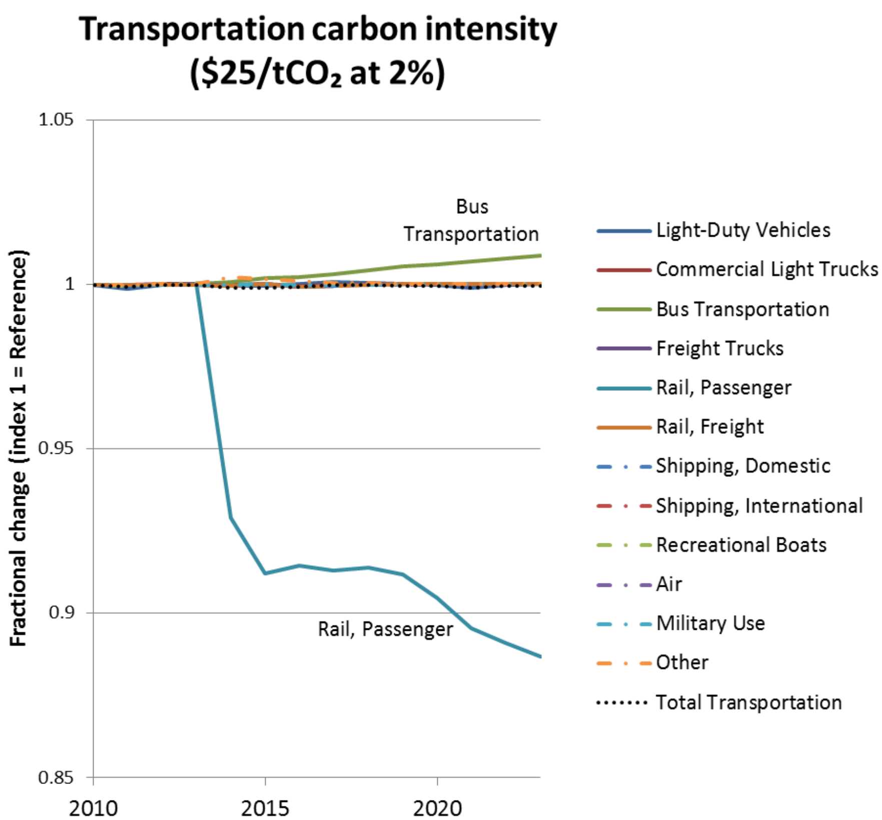

Figure 3.28 Carbon intensity changes in the transportation sector

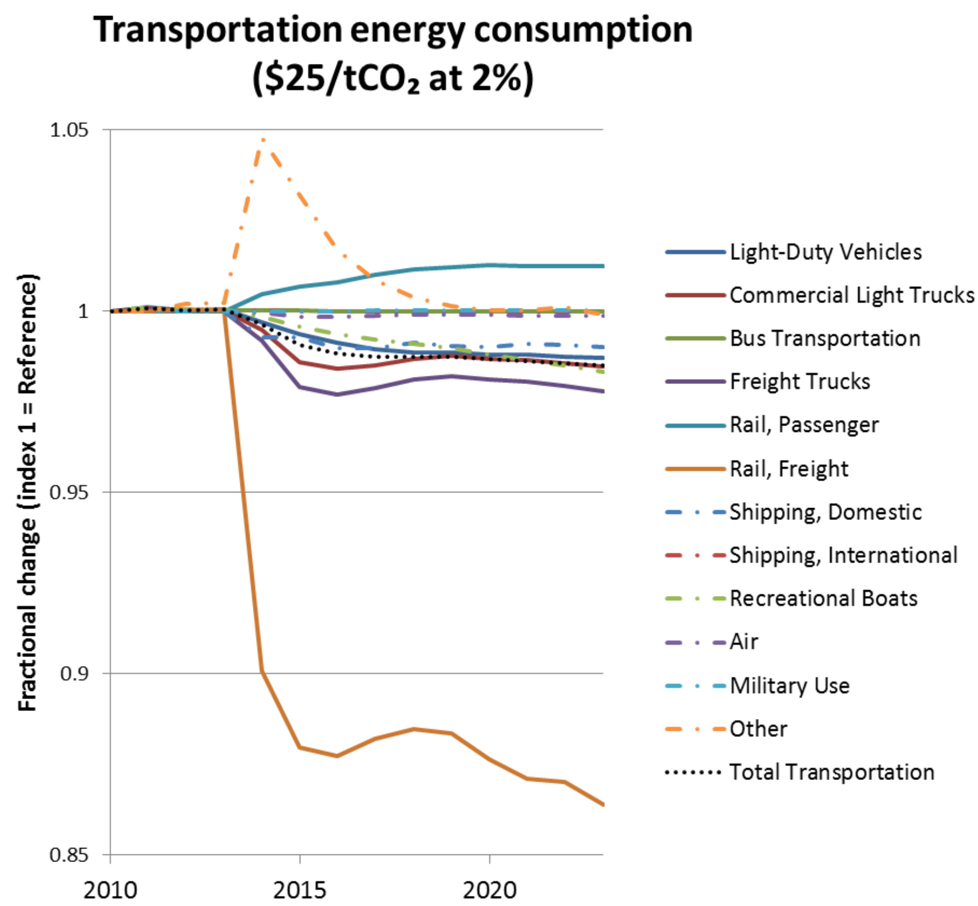

Figure 3.29 Energy consumption changes in the transportation sector

While the rest of the transportation modes will not experience any significant change in carbon intensity, some modes will see measurable changes in energy consumption. Figure 3.29 shows the most significant reduction in energy consumption will come from the rail freight mode, which will reduce consumption by 10% in the first year of the policy. Since this mode will not undertake any carbon efficiency activities, the reduction in energy demand is a direct reflection of change in activity. Other modes that will see lower demand include freight trucks, commercial light trucks, light-duty vehicles, recreational boats, and domestic shipping. However, all of these will see less than 2% reduction in demand. Several modes will see almost no change in demand: air travel, international shipping, military, and bus travel.

In contrast, the 'Other' category will see a significant increase in demand under the carbon fee, which then tapers off over the decade. This category is almost entirely pipeline fuel, but also includes general lubricant consumption. 'Pipeline fuel', which represented 2.7% of total transportation energy demand in 2013, is the natural gas consumed by pipeline operators to fuel pumps and compressors. It accounts for roughly 94% of the installed pumping horsepower required to transport natural gas (Davis et al., 2013). The dramatic increase in the natural gas pumping demand is a result of the increase in natural gas requirements in the electricity supply sector. Recall that the electricity supply sector's initial response to a carbon fee is to dispatch more natural gas plants. This sudden demand from the electricity sector for natural gas tapers off over the decade as other generation resources are brought on line.

3.4.2.2 Rail and other non-road freight transportation modes

Rail freight transportation mode is the most impacted by a carbon fee, in terms of energy demand. Since this mode is in a category by itself, one can complete a decomposition to see the relative impacts. Activity in this mode is billion ton-miles, energy intensity is BTU/ton-mile, and carbon intensity is tCO_2/ BTU. Applying a very simple one-mode ASIF framework, it is clear that emissions changes in this mode are almost entirely a result from changes in activity (see Figure 3.30a).

In the absence of the policy, rail freight is expected to expand, adding 50 billion ton-miles annually in most of the next few years, then tapering off to roughly 30 billion ton miles at the end of the decade. Energy and emissions, and therefore energy and carbon intensity, have a direct correlation with activity, so changes in activity are the sole driver of changes in emissions in this mode.

Under the policy, activity is reduced by almost 100 billion ton-miles in the first year, then it slowly returns to a growth pattern similar to the Reference scenario. This lower total level of activity is about 245 billion ton-miles less than the Reference scenario in 2023. Again, changes in activity are the sole driver of changes in emission in this mode, even under a carbon fee. One can do the same analysis for other non-road modes of transport (including air freight, air travel, and domestic shipping), and find the same general result. The response to a carbon fee is the same in each of these modes, where the activity is the primary driver of emissions, and energy and emissions have a direct correlation. So, the change in energy consumption shown is a surrogate for change in activity.

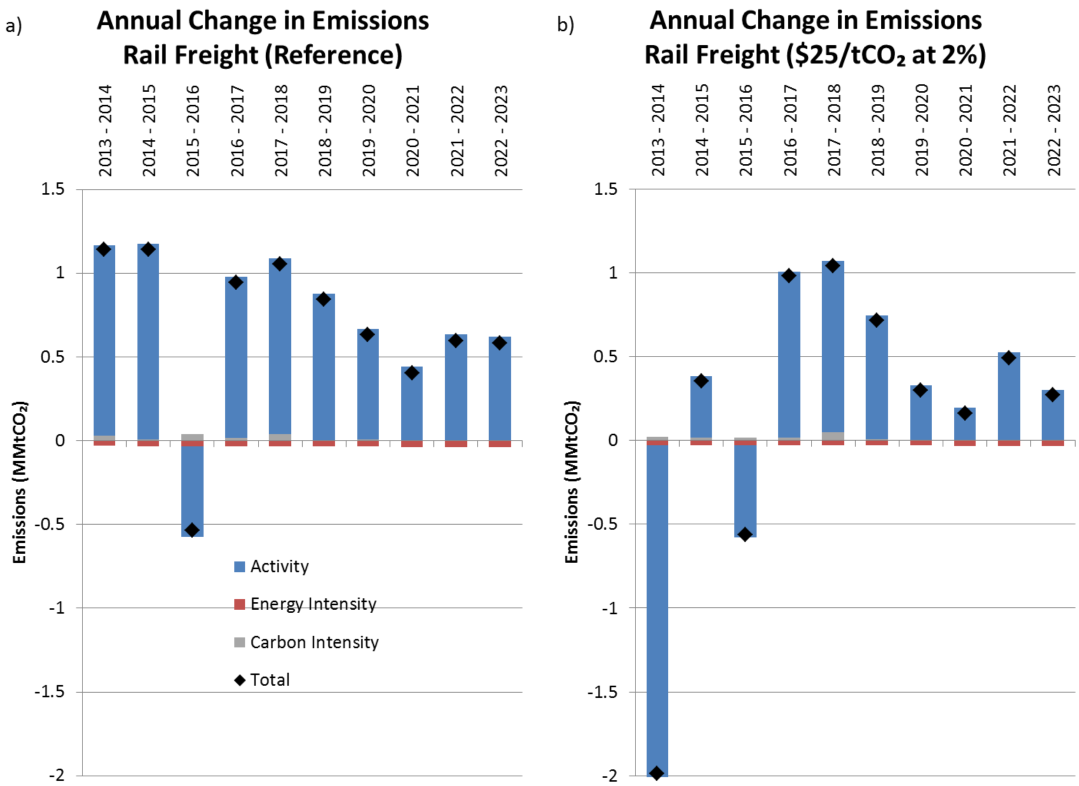

Figure 3.30 Annual carbon fee effects on rail freight transportation mode

3.4.2.3 <u>On-road travel and freight transportation modes</u>

NEMS aggregates the activity for on-road travel and freight, so it is impossible to isolate them. The model does provide very detailed energy consumption for all sub-modes, so one can still look at the combined transportation modes. For example, LDVs include cars, small trucks, and motorcycles, and NEMS projects the amount of energy each of these LDV types will consume. Figure 3.31a shows that in the Reference scenario, all three of these light duty modes will continue to reduce energy consumption over the next decade. The net total demand for these three modes will decrease steadily from about 15.1 Quad BTUs in 2013 to 13.9 Quad BTUs in 2023.

Under the policy, all modes see an initial decrease when the policy begins, but then energy demand of motorcycles and automobiles will begin to offset some of the demand for Light trucks (see Figure 3.31b). Motorcycles and automobiles will experience almost the same change in demand, so the curves are almost on top of each other in Figure 3.31b. The total energy demand under this policy scenario ($25/t$CO_2$ at 2%) will be 13.7 Quad BTUs, only slightly lower than the reference scenario.

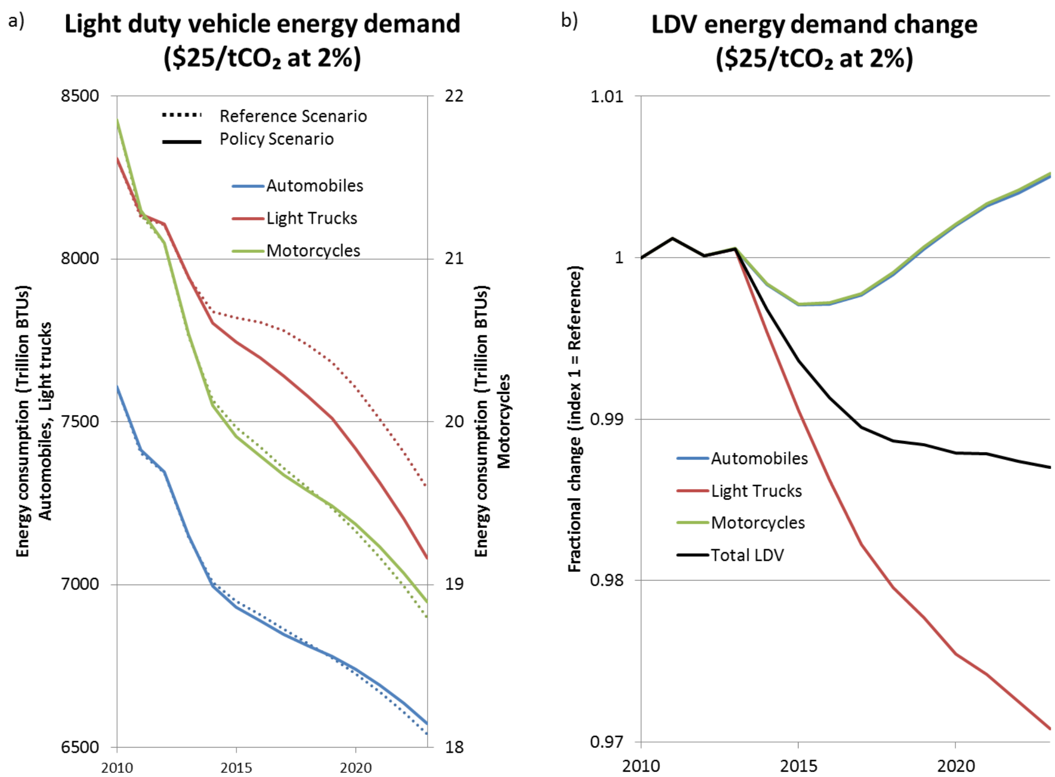

Figure 3.31 LDV energy consumption and policy impacts on consumption

While NEMS forecasts each of the LDV types separately with respect to energy consumption, the output aggregates automobiles, motorcycles, and light trucks (under 8500 pounds) into one LDV category for both activity and emissions. Likewise, NEMS forecasts medium commercial trucks (10,000 -26,000 pounds) and heavy commercial trucks (above 26,000 pounds) separately in terms of energy, but combines the two into one category for activity and emissions. However, light commercial trucks (8500 – 10,000 pounds) are identified independently for emissions and activity. Combined, these three aggregated categories represent all road vehicles, except buses, and accounted for 77.8% of total sector energy consumption and 77.4%

of total sector carbon emissions in 2013. While these are not generally substitutes, one can look at an ASIF breakdown of this subset of the Transportation sector.

Figure 3.32 shows very little difference between the Reference case and the policy case. The effect of the policy is nearly identical on both carbon intensity and energy intensity. As with other modes in this sector, the carbon content of the fuels is relatively constant, so there is no measureable difference in carbon intensity effects. Under the Reference scenario, there are significant energy intensity gains underway. This is primary due to the annual retirement of LDVs. LDVs accounted for almost 90% of the activity in this sector so improvements in LDVs will define the sector as a whole. However, there is little room for additional improvement under the policy case, since the annual energy intensity effect is nearly identical between the two scenarios.

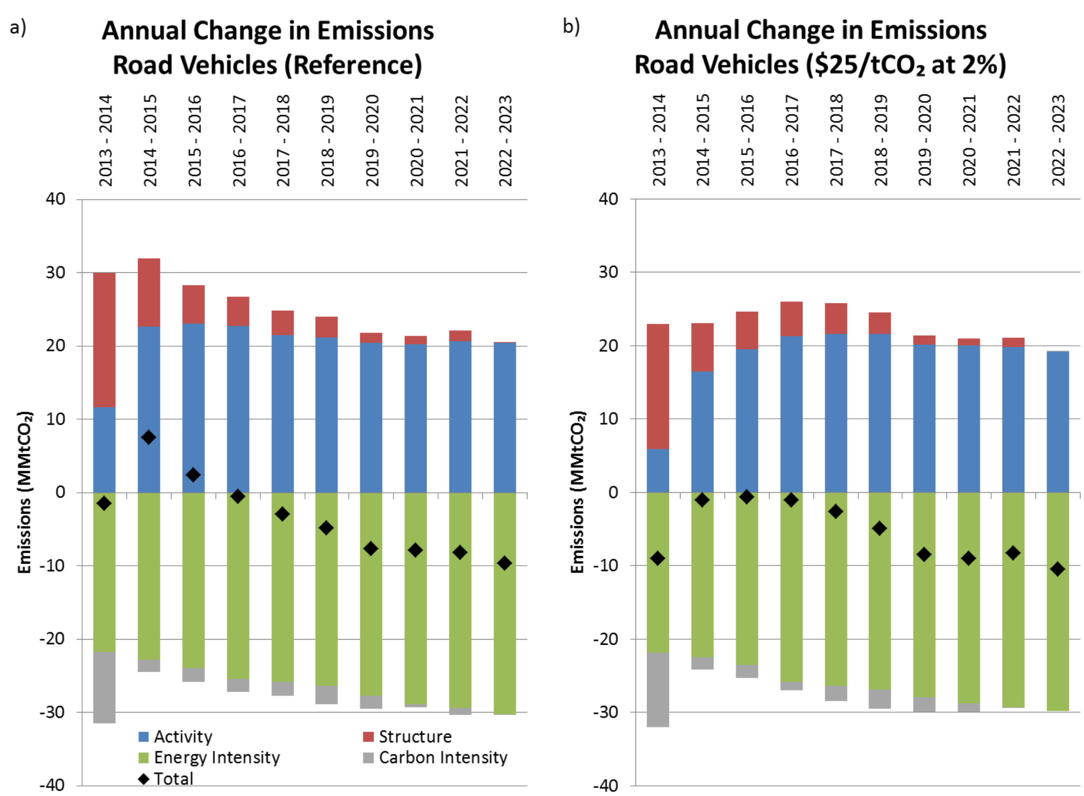

Figure 3.32 Annual carbon fee effects on LDV, light commercial trucks, heavy trucks

The notable difference between the two scenarios comes from structure effects and activity affects. In the Reference case, light truck activity remains relatively constant, but heavy vehicle activity increases faster than LDV activity. This causes a shift in mode share percent, which shows up as structure effect in Figure 3.32a. Under the policy case (see Figure 3.32b), the LDV aggregate category slows down a little while the two truck categories remain almost unchanged, causing an increase in structure effect between the two scenarios. This difference does not represent mode shifting since one would not likely trade in a motorcycle for a heavy commercial truck. Rather, it is simply that the LDV community is less tolerant of the increase in energy prices and reduces activity more than the other modes. In fact, all modes see about a 2% reduction in activity by 2023. This net reduction in activity across all modes is apparent in the difference in the activity affect between the two scenarios, and this is the primary driver in the change in emissions for the sector.

Most of the emissions savings across the U.S. come primarily from decarbonizing the electricity supply sector, which has very little impact on the transportation sector. Furthermore, the carbon content of fuels used in transportation is relatively fixed, so the only improvements in carbon intensity occur wherever transportation is electrified, such as in commuter light-rail systems. The model projects almost no measureable electrification of general transportation as a result of any of these carbon policies.

Due to the data output structure of NEMS, it is impossible to properly assess consumer choices under carbon fee policies. Activity of travel and freight should be considered separately since they are motivated by different mechanisms. Unfortunately, NEMS does not provide consistent data within freight or travel subsectors, so one cannot determine shifts between modes. For example, it is currently impossible to quantify any mode shifts from private LDVs to public transportation as prices escalate. Furthermore, the model does not output activity or emissions at the same level of detail provided for energy consumption, making even a mode-specific assessment impossible for most modes. Nonetheless, this partial evaluation of the sector shows that a reduction in activity is the dominant factor leading to emissions reduction in the transportation sector.

3.4.3 Residential buildings demand sector

3.4.3.1 Sector activity and structure

The representative activity in the Residential demand sector is the total number of households (HH), and the structure (modes) is represented by the types of homes: single family residences (SFR), multi-family residences (MFR), and manufactured and mobile homes (MH). NEMS includes an endogenous forecast for growth in all three modes, but does not predict (or export) mode-specific energy consumption. Consequently, for this analysis, the residential market is considered as having a single mode consisting of all HH. This is unfortunate since one of the primary interests of this study to assess household impacts.

One can still look at mode share changes in the forecasts, despite not knowing the differences in energy intensity between different modes. Figure 3.33 shows annual growth of all three modes for the Reference case, the sum of which is the total annual activity in the sector. In 2013, the total number of HH was almost 119 million residences, which is forecast to grow at a steady 1.0% annually to more than 131 million HH in 2023. The fractional share for each mode in the Reference case remains relatively steady, with SFRs making up 71-72% of the total, MFRs accounting for 23-24%, and MH making up the remaining 5% of total HH.

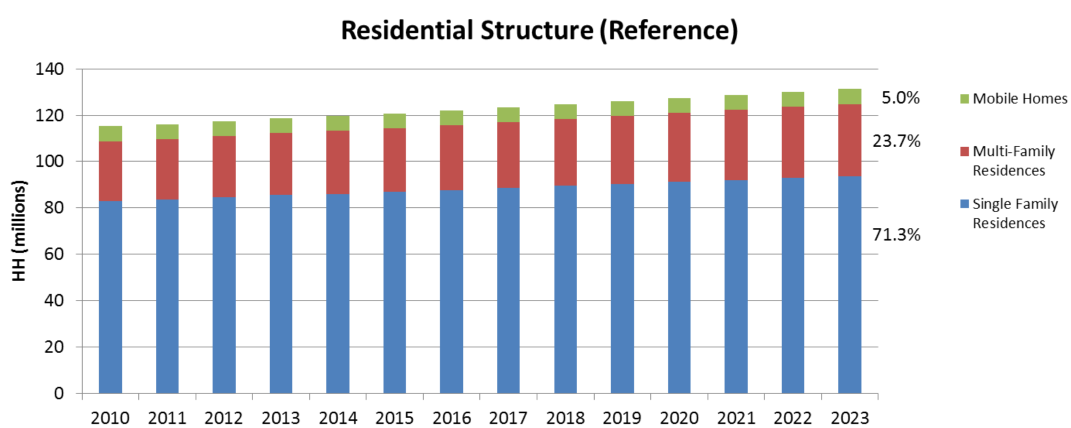

Figure 3.33 Reference case activity and building types in the Residential sector

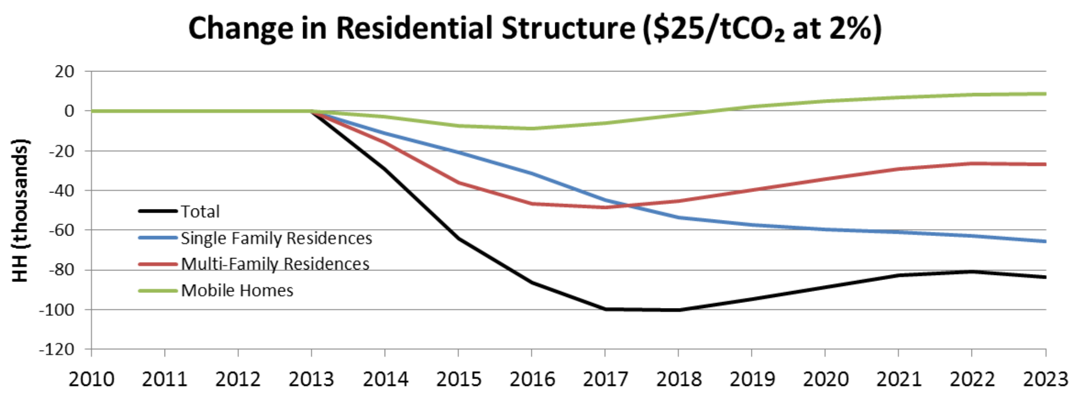

Figure 3.34 Building type shift from policy scenario ($25/tCO_2$ at 2%)

A carbon price policy creates a compounding effect: The increase cost in energy will effectively lower the total disposable consumer income while raising the cost of all other goods due increased transportation and manufacturing costs. This directly affects consumer expenditures related to house purchases and construction. However, the policies modeled here are not so onerous as to significantly shift HH activity. For example, the mode shifts in the $25/tCO_2$ at 2% policy scenario are on the order of tens of thousands of homes. Total activity change is a reduction of approximately 83,000 HHs by 2023, or about 0.06%. Figure 3.34 shows the evolution of the mode shift. In the first few years under the policy, housing construction declines, but that tapers off and shifts slightly away from SFRs to MFRs and MHs.

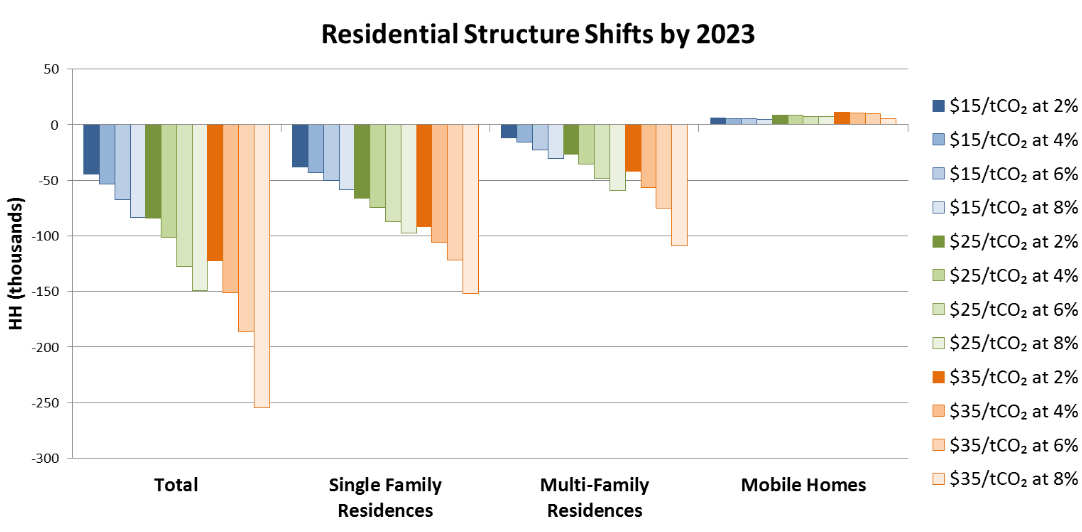

Figure 3.35 Mode shifts in all scenarios in 2023

All of the policy scenarios show similar progressions; in each, the magnitude of change reflects the aggressiveness of the policy. Figure 3.35 shows the total change in each indicator by 2023 for all scenarios. The most aggressive scenario ($35t$CO_2$ at 8%) would reduce total activity by about 250,000 HH in 2023, a decrease of 0.19% from the Reference case.

3.4.3.2 Sector decomposition

NEMS does not provide and energy consumption forecasts relative to each HH type, so the following analysis reverts to total HHs as the only mode in the Residential sector. Applying the remaining pieces of the ASIF framework, as described in Section 2.4.3, one can look at changes in energy intensity, carbon intensity, and sector CO_2 emissions (see Figure 3.36). The total number of HHs only changes by a fraction of a percent, so the policy and Reference case lines for activity are practically one. Energy intensity is reduced by a small amount. However, as also shown in Figure 3.19, most of the saved carbon emissions from this sector are obtained by reducing carbon intensity, which stems primarily from a change in the electricity fuel mix.

One can also look at the final energy fuel mix for this sector to understand where consumers are making choices. NEMS tracks four basic energy resources for each sector: electricity, natural gas, petroleum-derived liquids, and coal/wood/other. Figure 3.37 shows the evolution of the energy intensity of these four fuels between the Reference scenario and the $25t$CO_2$ at 2% scenario. A price on carbon will drive down the energy intensity, relative to the Reference scenario, of all fuels except wood/coal. Wood use increases as a heating fuel type (although nearly insignificant with respect to percentage of the sector), altering the total emissions averaged over total HH. The result is an increased average HH energy intensity for heating. One particularly interesting data point is the rebound from 2012 to 2013, highlighting EIA’s expectation of a housing market recovery.

Using the LMDI decomposition, one can determine the contribution to Residential sector emissions from changes in the ASIF parameters (see Figure 3.38). The NEMS output does not include energy intensity for each mode (i.e., HH types) so the decomposition assumes a single-mode sector. The effect from total activity change can still be quantified. As shown above, the addition of a carbon fee has very little impact on total change in activity. The total number of HH is reduced from the Reference scenario; however total number of HH still increases. The growth in the total number of HH raises total emissions year over year in both the Reference and policy scenario. Energy intensity changes are already a significant part of the Reference scenario, but adding a carbon fee helps reduce carbon emissions in the first few years.

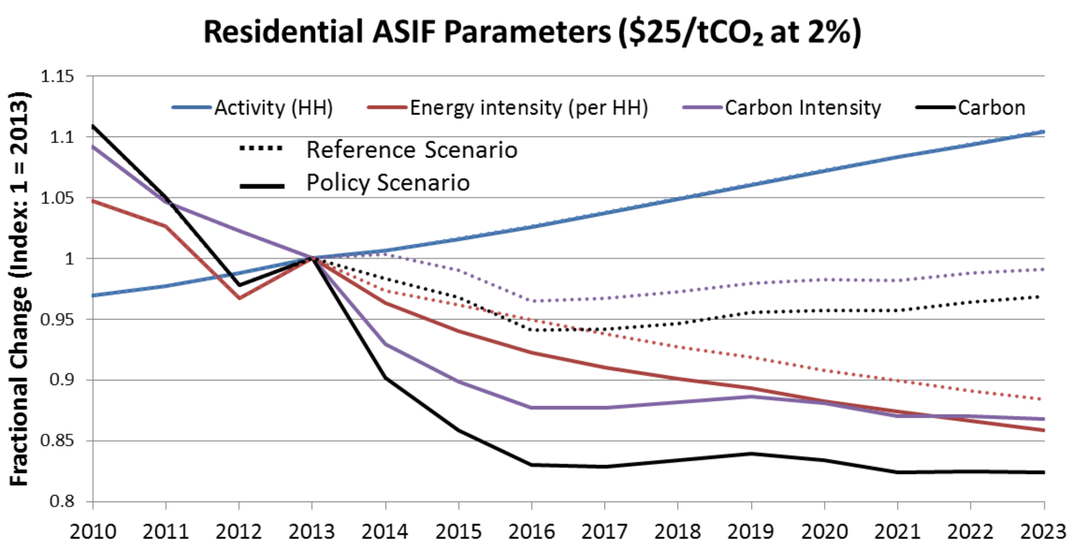

Figure 3.36 Residential sector ASIF parameters for sample scenario

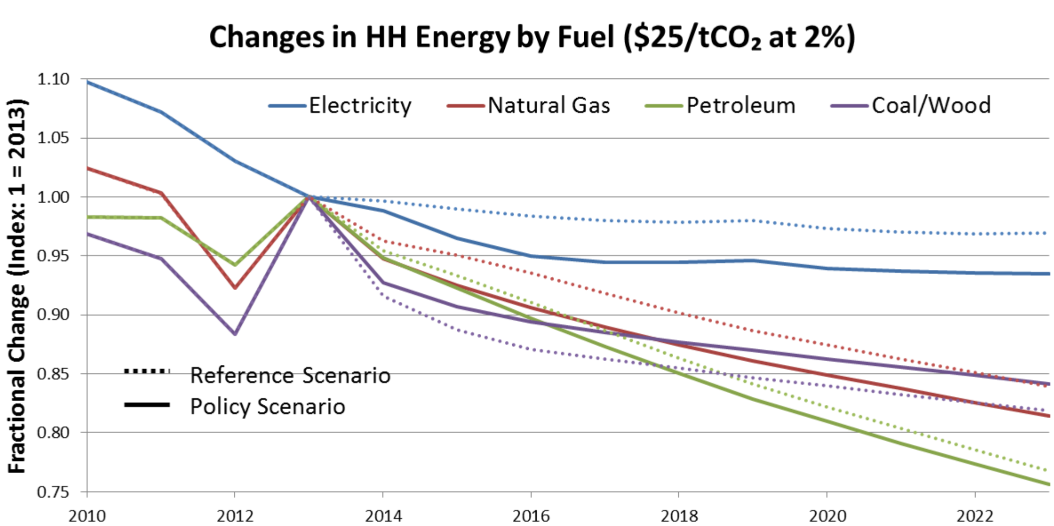

Figure 3.37 Changes in Residential sector energy intensities for each energy resource

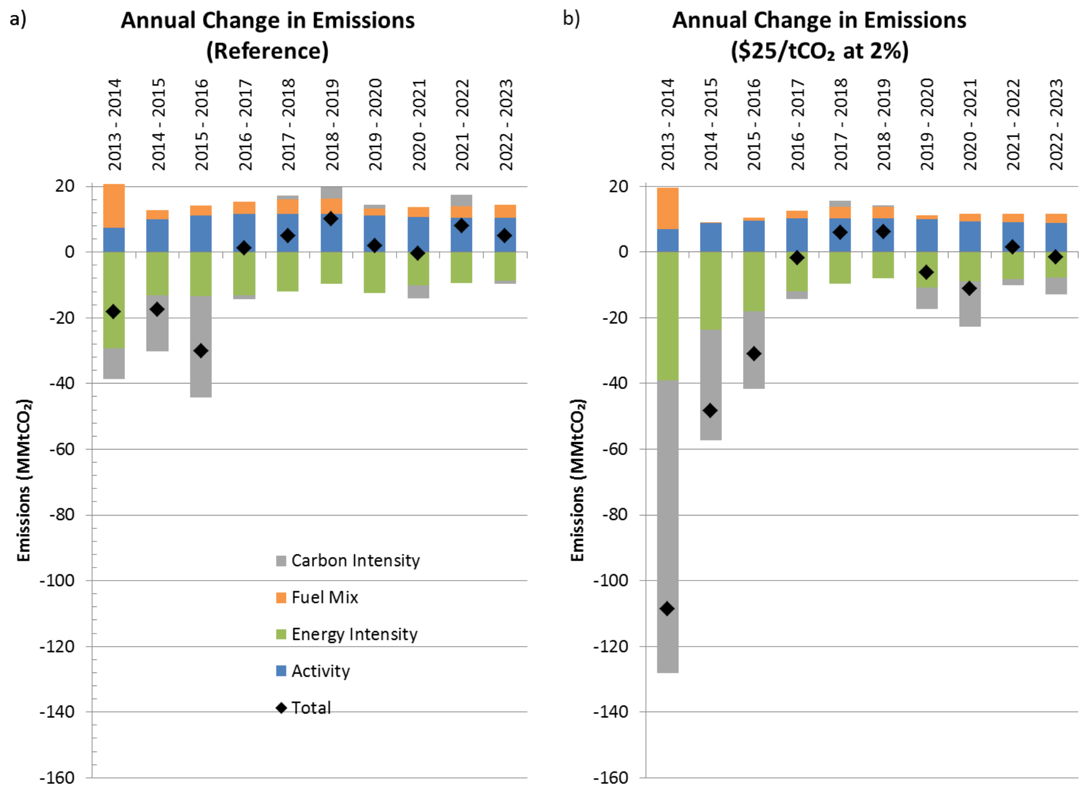

Figure 3.38 Effect from each ASIF parameter on annual change in carbon emissions. a) Reference case, b) policy scenario ($25/tCO_2$ at 2%)

The fuel mix effect shows the change in demand for different fuels. Residential consumers in the model are not likely to switch fuels directly, such as converting from an electric stove to a natural gas stove, until prices are significantly elevated for at least three years. So, most of the impact from fuel mix comes from a change in energy demand as a whole. The significant impact from 2013-2014 in both scenarios is from a reduction in natural gas demand, which reduces the natural gas share of the sector fuel consumption. In the policy scenario, the majority of the carbon savings come from electricity generation changes. Again, it is clear that policy-induced changes occur in the first few years. The total emissions from the Residential sector are 12% lower than the Reference case in 2016 and 15% lower in 2023.

Figure 3.39 shows the ten-year impact for all scenarios. The activity effect is approximately the same in the Reference scenario and in most of the policy scenarios. In general, activity is relatively insensitive to the policies, except in the most aggressive scenarios. The Reference scenario already has significant energy intensity, which is only improved slightly under the policy cases. The fuel mix effect shows there is little direct fuel switching involved. But since one of the fuels in the mix is electricity, the major driver of carbon savings between scenarios comes from changes in carbon intensity, a direct result of decarbonizing electricity. (Please see Appendix B.7 for numerical results for each scenario.)

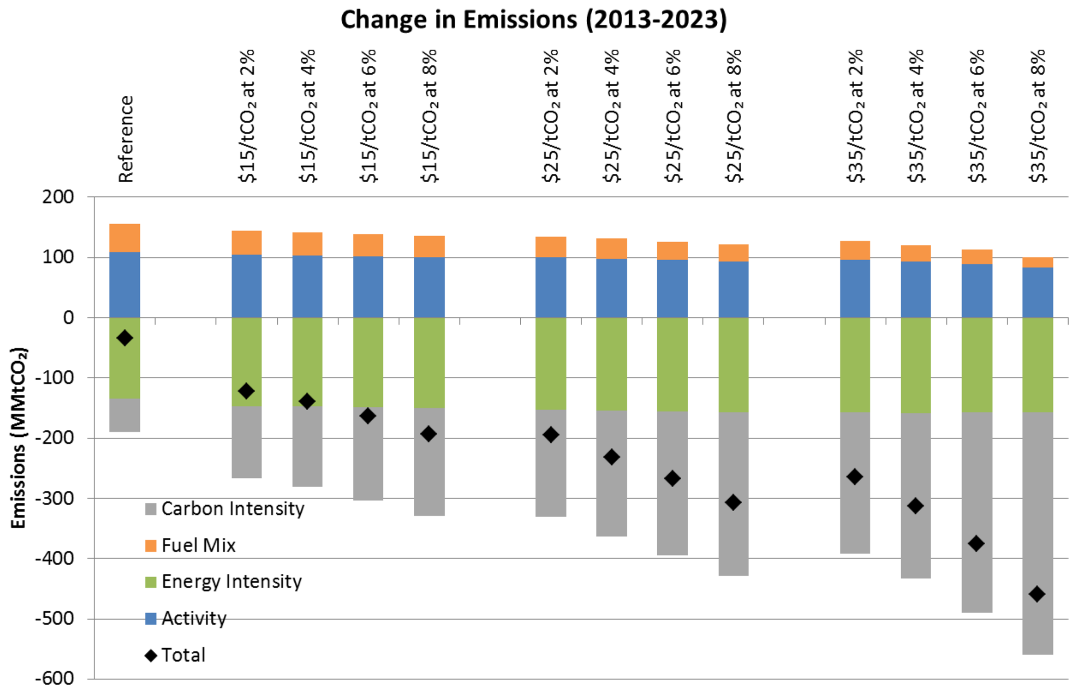

Figure 3.39 Residential sector effect from each ASIF parameter from 2013-2023 under all scenarios

3.4.4 Commercial buildings demand sector

3.4.4.1 Sector activity and modes

The representative activity in the Commercial demand sector is total area of commercial floor space. Total activity in this sector was 82.9 billion square feet (sqft) in 2013, which is forecast to grow at a steady 1% annually to 92.1 billion sqft in 2023. This increase reflects roughly 2% of new additions each year, minus demolitions. The overall effect of a carbon fee on this activity is evident in Figure 3.40. In the first few years of the policy, the reduction in square area from the Reference case is driven by a reduction in new construction. As the policy progresses, planned new construction tapers off after the first few years, and then the sector experiences a rapid increase in demolition (less surviving floorspace) of less efficient buildings. This demolition is roughly matched (with a slight lag) with new commercial floorspace in the mid-term. Combined, the sector returns to within about 20 million sqft of floorspace relative to the reference case, which is less than 0.02% change from the reference scenario.

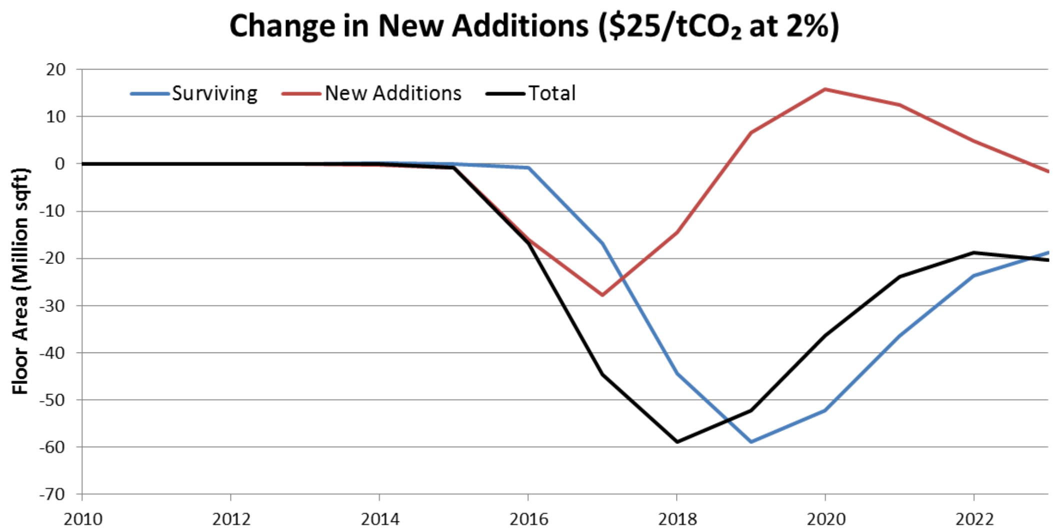

Figure 3.40 Commercial sector activity changes relative to the Reference scenario

The modes of the commercial sector are the different building types. Figure 3.41 shows that all 11 building types in the Reference scenario expect to grow steadily over the next decade. This is not a particularly interesting plot, but it shows that the fractional share of each mode in the Reference case is projected to maintain a roughly constant share of the sector over the next decade. The three largest modes are Mercantile/Service, accounting for about 21% annually, and Warehouse and Education, each accounting for about 14%. Assembly and Mercantile/Service growth rates are slowing gradually throughout the decade, as are Education and Food Sales, but to a lesser extent. Modes that are slowly expanding relative to the whole are Other buildings (in particular), Healthcare, Lodging, and Warehouse. That leaves Small Offices, Large Offices, and Food Service, which are all growing at the same average rate as the total. However, over the decade, all modes are expected to retain their 2013 share of the sector (within a few percent).

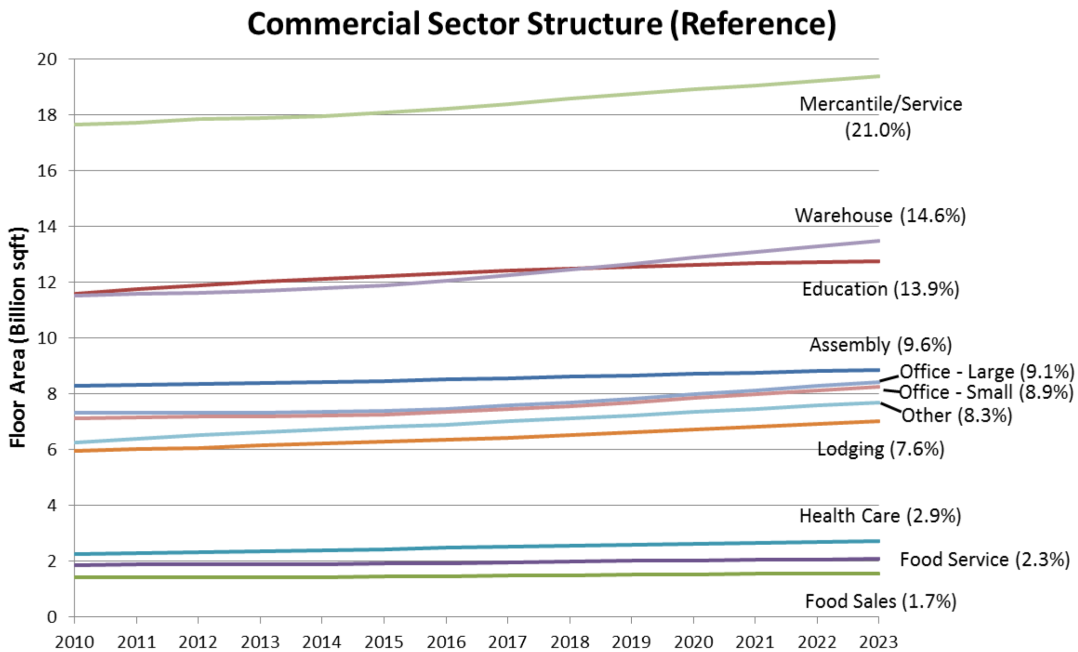

Figure 3.41 Commercial sector building types in the Reference scenario

Under a carbon fee, the general response in the sector as a whole is a reduction in new additions, and nearly all of the modes show a similar pattern as the total sector floorspace curve (see Figure 3.42). The mode with the greatest affected floorspace is also the largest mode, Mercantile/Service, which has a reduction of almost 13 million sqft by 2023. The next two are Offices-Large and Offices-Small and each recovers all but about 2.5 million sqft. The mode affected least is Healthcare, which is only reduced by 100 thousand sqft from the base scenario by 2023. This is roughly the size of a single large hospital. The Warehouse mode, about 14% of total sector floorspace, is an exception. As prices increase due to a carbon fee, consumers purchase fewer goods and services. The result is a short-term increase in storage facilities, likely from excess unpurchased inventory, while offices and merchant/service facilities decrease in size.

Although the Mercantile/Service mode will experience the largest total reduction in square footage by 2023 relative to the Reference scenario, both Food Sales and Food Service have a larger proportional impact (0.09%). A carbon fee will directly affect consumer disposable income, which will in turn limit how much discretionary spending occurs.[35] The fee will also increase the cost of delivering goods, including food, to stores and restaurants. Faced with higher prices and lower disposable income, consumers quickly respond by reducing unnecessary spending, such as eating out less and buying fewer or less expensive groceries (Quelch and Jocz, 2009). The least affected modes are Education and Healthcare, which see less than 0.01% decrease from the reference case.

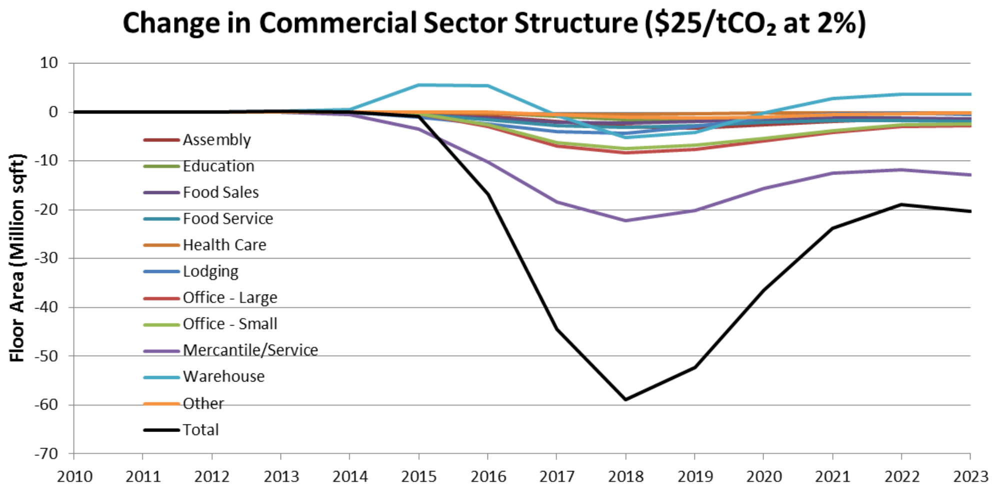

Figure 3.42 Commercial sector building type changes relative to the Reference scenario

3.4.4.2 Energy and carbon intensities

In 2013, total activity was nearly 83 billion sqft, energy intensity about 104 MBTU/sqft, and carbon intensity was 112 $MMtCO_2$/Quad BTU. The product of these values results in total sector carbon emissions of 961 $MMtCO_2$ in 2013. Activity is forecast to grow steadily over the next decade, yet energy intensity and carbon intensity will be lower in 2023 than in 2013 (See Figure 3.43). The resulting carbon emissions will drop accordingly over the next few years, but then accelerate as activity picks up at the end of the decade.

Figure 3.44 compares the Reference data with the policy case. As shown above, the policy does not affect total activity very much, but it does lead to a

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[35] Even if a rebate of the revenues makes up for a households' portion of the carbon fees, the rebates will most likely be returned at the end of the year with tax returns, so the consumer will not make the direct spending correlation.

measureable reduction in energy intensity. However, the policy's real impact is a carbon intensity change in the sector's fuels. The combined reduction in energy and carbon intensities drives future carbon emissions down as well. By contrast, the reference case shows rising emissions in the latter half of the decade.

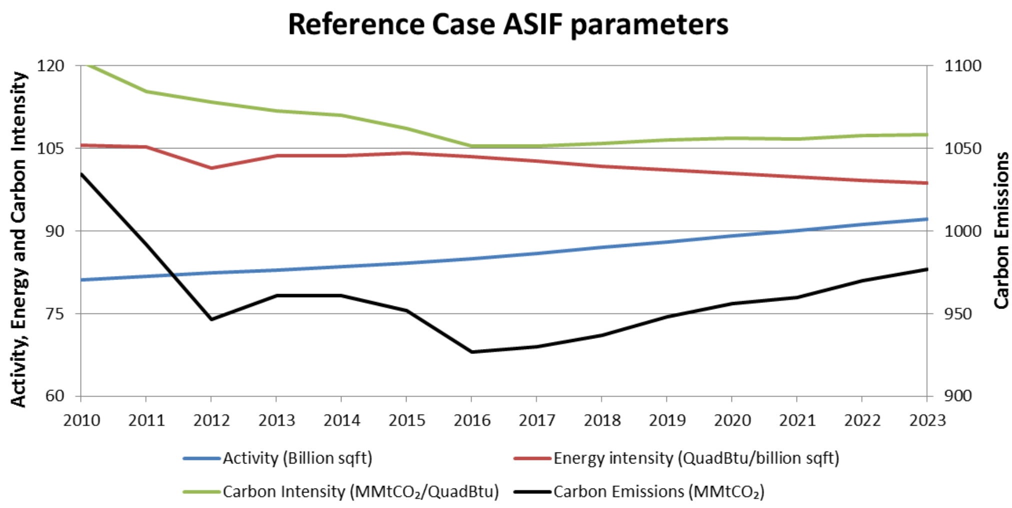

Figure 3.43 Commercial sector reference case ASIF parameters (note: the scales do not go to zero)

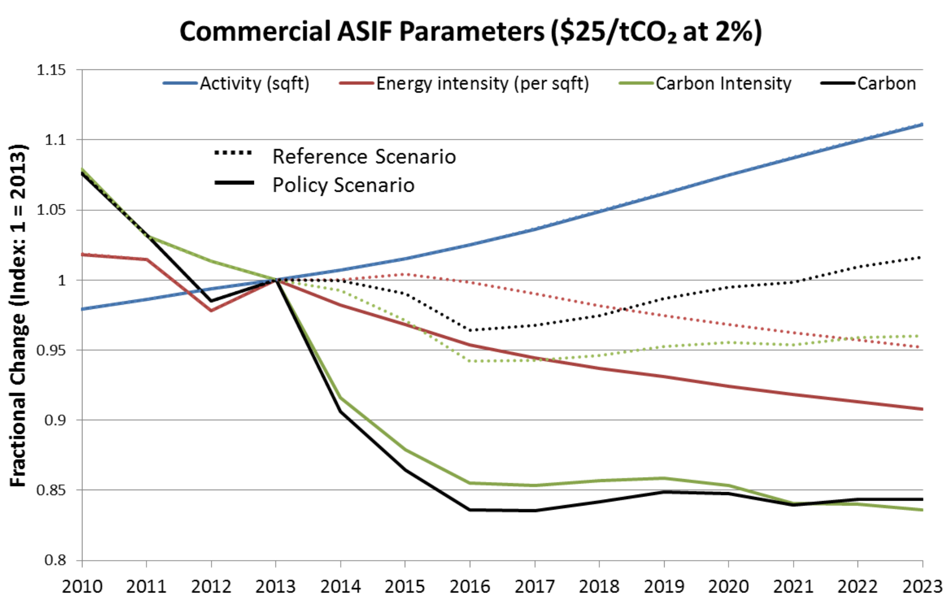

Figure 3.44 Commercial sector ASIF parameters impacts for sample scenario

All policies exhibit similar profiles, and the resulting percent change in 2023 from the Reference scenario is shown in Figure 3.45. Even in the most aggressive scenarios, activity is affected by less than 0.1%. So, while the carbon policy does affect choices among the modes, it is not a significant driver of the differences between scenarios. Energy and carbon intensities behave similarly across the scenarios. In each, carbon intensity is reduced on the order of three times more than energy intensity.

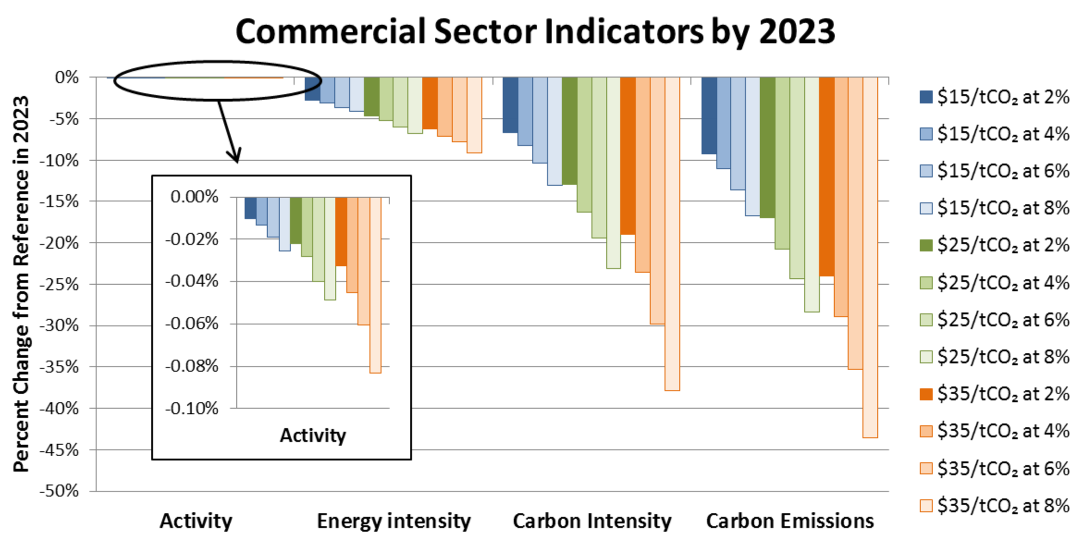

Figure 3.45 Commercial sector ASIF parameters for all policies

Since nearly all of the impacts from the policy are in carbon and energy intensities, Figure 3.46 shows a direct comparison of the two. The axes are roughly square in the figure, so the scale of the carbon intensity reduction to energy intensity reduction is visually proportional. In the Reference case, energy intensity increases slightly in the first few years after 2013, then reverses and continues uniformly for the rest of the decade. By contrast, none of the policy cases exhibit the initial increase, but decline uniformly throughout the time horizon. Meanwhile, reduction in carbon intensity is concentrated in the first few years in the Reference case, an impact that is amplified in the Policy scenarios.

The energy intensity reported above is based on all energy consumed within the sector. Ancillary services, such as street lighting, municipal water, and other municipal services, account for between 16.5% and 18% of the total annual energy in the sector. The standard NEMS output includes a forecast of energy consumption within each building type, but ancillary services are provided independently, because they are difficult to attribute to a single building type. So when looking at building-specific energy data, ancillary services are not included. However, when applying the ASIF decomposition, these services are treated as an additional building 'type'.

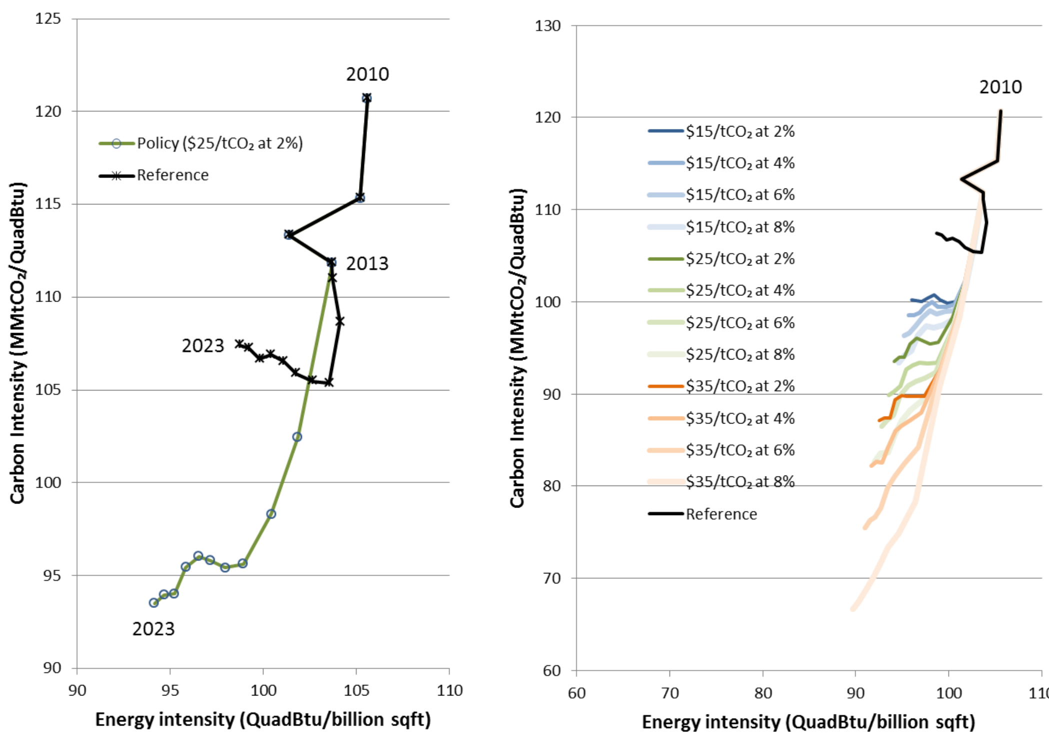

Figure 3.46 Commercial sector Energy intensity and Carbon intensity

Food Service and Food Sales are the most energy-intense modes, since they consume energy all day and night with ovens, stoves, lighting, and refrigeration. Similarly, Healthcare runs every day, around the clock, to provide health/life support systems and climate/humidity controls. Warehouses, on the other hand, are not surprisingly the least energy-intense since they are generally large, open structures with little supporting equipment and few climate controls. The Assembly mode has the second lowest energy intensity. This mode includes conference centers, which may draw ample energy through the day, balanced with less frequently-used assembly buildings such as churches. Each mode is expected to reduce energy intensity on the order of 4% to 8% over the next decade, prior to any carbon policy. The exception is large offices, which will hold relatively constant.

Under the policy, each mode will quickly reduce its energy intensity but only by about 3% to 5% from the Reference scenario. This limited response is due in part to how the Commercial module estimates consumer behavior. The model structure is a constrained lifecycle cost minimization based on risk-adjusted time preference premiums, or discount rates. The least-cost approach employed here drives consumers with high discount rates to make financial decisions based mostly on upfront capital cost and less on long-term operating costs. Wilkerson et al. (2013) noted that about three quarters of the commercial sector floorspace in NEMS is governed by agents with discount rates between 50% to 1,000%. These high rates indicate a very strong preference toward minimizing capital costs not operating costs. As a result, most of the sector will not upgrade or retrofit energy technologies when faced with these carbon polices. Only the other, smaller fraction of the sector, driven more by long-term costs, will adopt energy efficient technologies, and this happens in the first few years. For details about mode-specific energy and carbon intensities, please see Appendix B.8.

3.4.4.3 Sector decomposition

While the standard NEMS output includes a forecast for floor area and energy per building type, it does not include emissions by building type. However, the NEMS sector framework is essentially an appliance stock and building shell model, so this data is certainly calculated during the run to enable NEMS to aggregate total emissions for the sector. To retrieve this data from the model, EIA provided an MS Excel workbook, ***DB_commercial.xlsm***[36], which allows one to import a restart file[37]

[36] Thanks to Kevin Jarzomski and Erin Boedecker at EIA for providing this tool and explaining its contents and how to use it.
[37] A 'restart' file is a common numerical computational output at the end of a cycle. The purpose is to record a snapshot of all pertinent variables such that one could begin with this restart file as an input if the code crashes. Thus, it provides a better initial condition for the new run. It is often a binary file and may not conform to any standard format; hence it is often only readable by the code that wrote it.

from a completed NEMS run and extract the emissions data (See Appendix B.9 for details on this process).

Using the full ASIF framework in Equation 2.14 requires activity, fractional mode shares, energy intensity of each mode, fractional fuel shares, and carbon intensity of each fuel within each mode. A change in each of these parameters impacts the sector's emissions. Figure 3.47a shows the contributions to change in emissions for the Reference scenario. As with other sectors, emission in the commercial sector will decline through 2016 as existing polices run their course, and that is mostly attributed to improvements in carbon intensity. Beyond the first few years, however, emissions from the sector will be relatively steady from a balance of increased activity and reduced energy intensity.

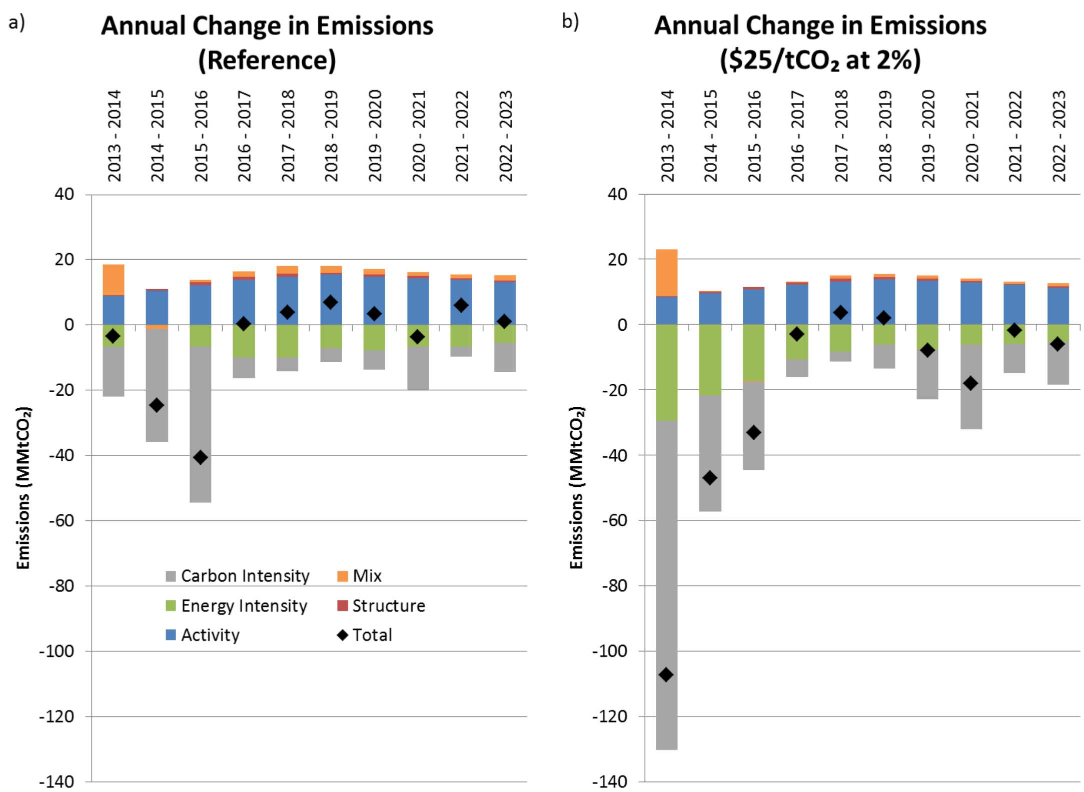

Figure 3.47 Commercial sector annual emissions attributions from a) Reference scenario and b) a policy scenario

Under the policy scenario in Figure 3.47b, the primary contributor to overall emissions reduction is from prompt fuel switching embodied in the carbon intensity of electricity, followed distantly by a change in energy intensity. Since there is very little change in floorspace in any building type or across the sector, the annual activity increase contributes roughly the same amount to emissions as in the Reference scenario. The total annual emissions reduction of the policy scenario over the Reference Scenario is 13.3% by 2016 and 17.0% by 2023.

Figure 3.48 shows the ten-year impact for all scenarios. As with the Residential sector, the activity effect is approximately the same in the Reference scenario and in most of the policy scenarios. In general, activity and mode shares (structure) are relatively insensitive to these carbon price policies, except in the most aggressive scenarios. The Reference scenario already has significant energy intensity, which the policy cases only improve slightly. The fuel mix effect shows there is little direct fuel switching involved. However the major driver of carbon savings between scenarios comes from changes in carbon intensity, which is a direct result of decarbonizing electricity. (Please see Appendix 0 for other scenario results.)

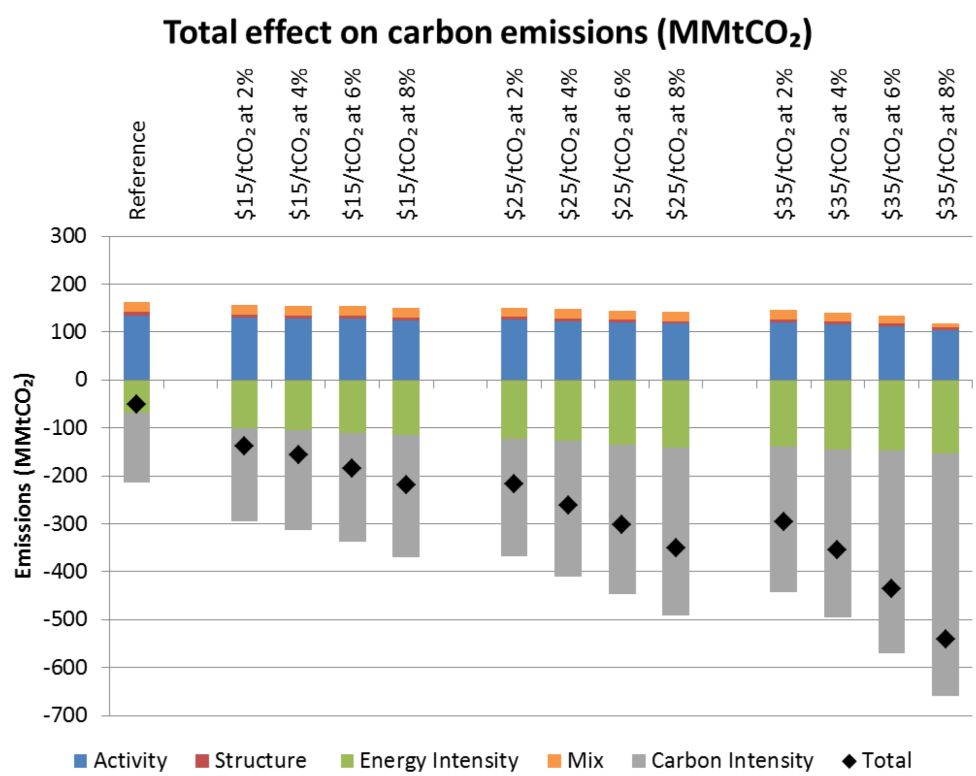

Figure 3.48 Commercial sector effect from each ASIF parameter from 2013-2023 under all scenarios

3.4.5 Industrial demand sector

3.4.5.1 Sector as a whole

The activity in the Industrial sector is represented by Value of Shipments (VS), which is a measure of output, minus inventory and fuel costs. The NEMS Macroeconomic Activity Module (MAM) provides the activity for the industrial sector based on NEMS forecast of the prices and availability of energy. In 2013, the total industrial sector VS was $7,086 billion (in 2011$). The sector consumed 23.8 Quad BTU, leading to total sector energy intensity of 3.36 BTU/$VS. This consumption emitted 1,484 $MMtCO_2$, or 62.4 $MMtCO_2$/Quad. Figure 3.49 shows how the reference scenario values evolve and the impact to each from a carbon policy scenario.

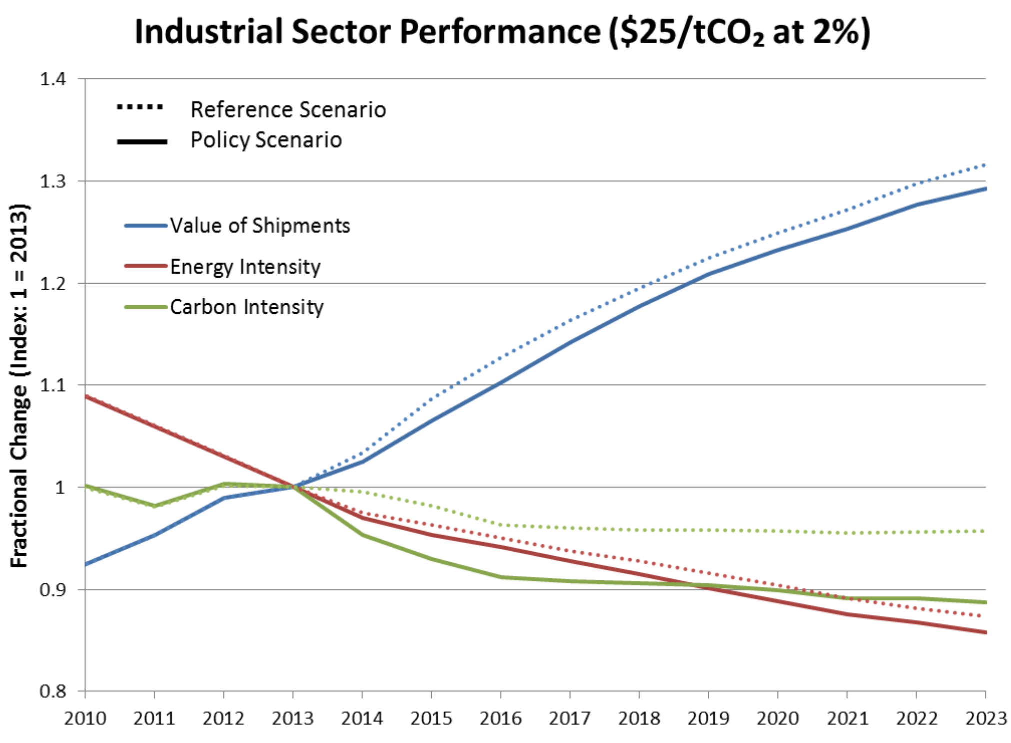

Figure 3.49 Industrial sector Reference and sample scenario impacts

The VS for the entire sector is expected to grow steadily over the next decade, and the policy will only slightly impact that trajectory. Similarly, energy intensity is declining on the whole, which the policy only slightly improves. The larger change comes from a reduction in carbon intensity, which will occur mostly in the first few years of the policy. In general, all of the scenarios behave similarly, and the total change in 2023 for all scenarios is shown in Figure 3.50.

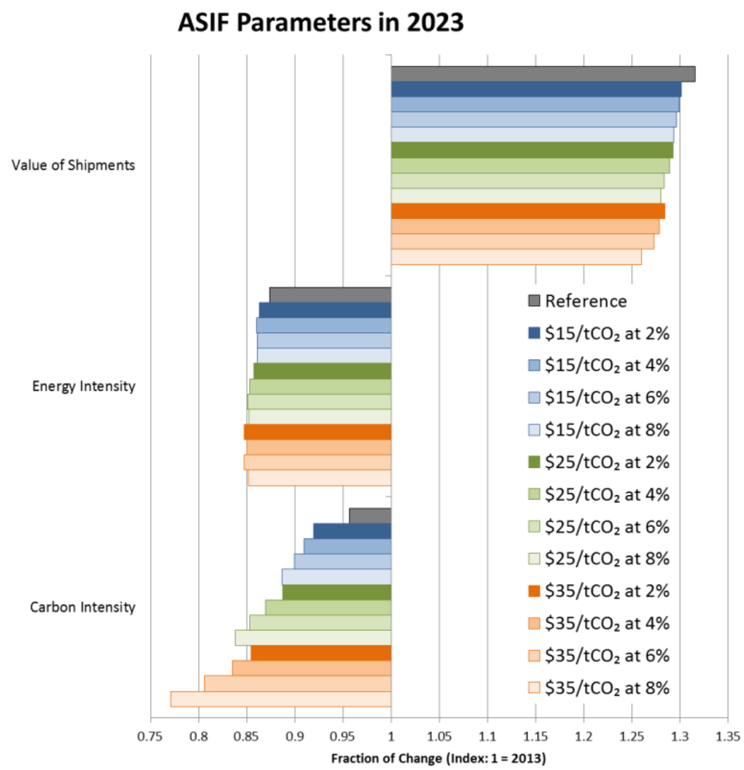

Figure 3.50 Industrial sector scenario impacts in 2023

3.4.5.2 Sector activity and modes

The structure, or modes, of the activity are represented by the individual industries. Rising and falling energy and other commodity prices affect each industry differently. Industry-specific activity is provided to NEMS by the MAM based on NEMS forecasts of energy prices and quantities. The industry-level aggregate values are shown in Table 3.3, but some are provided by the MAM with further disaggregation. The first three subsectors in the table represent the non-manufacturing segment of the industrial sector, while the rest are the manufacturing portion.

In the Reference scenario, the total Industrial sector activity will grow steadily from $7,086 billion in 2013 to $9,323 billion in 2023. The four largest industries in 2013 are Construction, Chemical Manufacturing, Transportation Equipment, and Food

Products. All four of these segments are growing, but the first three are also capturing a larger share of the sector by 2023.

Table 3.3 Industrial Sector Reference scenario activity from MAM

Industrial Sector and Subsector Activity	2010	2013	2023	2010-2023 (Floating Scale)	2010-2023 (Fixed Scale)
Total Sector Activity (Billion 2011$)	**6553.2**	**7085.5**	**9323.4**		
Subsector Mode Shares Industrial Value of Shipments					
Agriculture/Forestry/Fishing/Hunting	5.0%	4.5%	4.0%		
Mining	6.9%	7.3%	6.1%		
Construction	15.2%	14.7%	16.9%		
Food Products	9.5%	9.2%	8.7%		
Beverages and Tobacco Products	1.6%	1.4%	1.1%		
Textile Mills and Products	0.8%	0.8%	0.5%		
Apparel	0.2%	0.3%	0.2%		
Wood Products	1.3%	1.4%	1.3%		
Furniture and Related Products	0.9%	0.9%	0.8%		
Paper Products	2.4%	2.2%	2.1%		
Printing	1.3%	1.1%	0.8%		
Chemical Manufacturing	10.4%	9.7%	10.3%		
Petroleum and Coal Products	7.8%	7.5%	5.7%		
Plastics and Rubber Products	2.7%	2.8%	2.6%		
Leather and Leather Products	0.1%	0.1%	0.0%		
Stone, Clay, and Glass Products	1.3%	1.3%	1.3%		
Primary Metals Industry	3.2%	3.4%	3.5%		
Fabricated Metal Products	4.3%	4.4%	4.0%		
Machinery	4.8%	5.0%	5.7%		
Computers and Electronics	6.7%	6.2%	7.3%		
Transportation Equipment	9.7%	12.1%	12.4%		
Electrical Equipment	1.7%	1.6%	1.8%		
Miscellaneous Manufacturing	2.2%	2.3%	2.9%		
Total	100.0%	100.0%	100.0%		

The table also includes two columns of spark lines. Both lines represent the same data for each industry from 2010-2023 to show the general trend in the activity of each. The only difference is in the axes. In the first spark line column, the axes are floating independently to illustrate the general behavior within each mode, but the second line forces all spark lines in the table to have the same y- axis values, bounded by the smallest (Leather and Leather Products) and largest (Construction) values. Combined, the two spark lines show the general trend in a given industry (floating), and the relevance of that change to the entire set of industries (fixed). For example, the Petroleum and Coal Products mode is dominated almost entirely by the refining industry. Refinery activity fluctuates over the duration, illustrating that refinery costs and production are driven by commodity prices that also fluctuate. Overall, the impact to the sector from this fluctuating activity is relatively small. The minimum and maximum data points are also identified on each spark line (red and black respectively) to further help illustrate the general trends in each mode.

Once NEMS receives the activity forecast from the MAM, the industries are categorized as energy intense, non-energy intense, and non-manufacturing. Since NEMS is an energy-economic model of the U.S. and not an industrial manufacturing and production model, EIA reorganizes this industry list to include only those that characterize the bulk of the energy consumed by the sector. These industries, shown in Table 3.4, represent over 85% of sector activity. The remaining portion is aggregated into a 'Balance of Manufacturing' category.

This list requires some description. As before, the first three rows in Table 3.4 are the non-manufacturing parts of the industrial sector, and the remaining make up the manufacturing parts. The three non-manufacturing segments are included in their entirety here, as are the Food, Wood, Paper, Plastics, Fabricated Metal Products, Machinery, Computers, Transportation Equipment, and Electrical Equipment industries. However the six remaining industries are only pieces of their respective industries. The Refining Industry is 95% of the Petroleum and Coal Products subsector in 2013. The Bulk Chemicals Industry (organic, inorganic, and agricultural chemicals as well as resins, synthetic rubber, and fibers) is only 48% of the Chemical Manufacturing subsector. The Glass and the Cement and Lime Industries account for 23% and 8% (respectively) of the Stone, Clay, and Glass Products subsector. The Iron and Steel and the Aluminum Industries account for 56% and 16% of the Primary Metals Industry subsector, respectively. These industry segments, along with the Paper and the Food Products industries, are identified as energy intense by EIA (marked in bold in Table 3.4), but only account for about 26% of total sector activity in 2013.

The Balance of Sector includes the remaining industries or segments not directly identified in the table, as well as many entire industries including all Textiles, Apparel, Leather, Beverage and Tobacco (which is separate from the Food Industry), and Printing. This Balance of Sector is steadily growing in aggregate, and the fixed-axis spark line shows that these activities are helping drive growth in the sector activity relative to the itemized industries. While most of the itemized activities are maintaining a steady percentage of the sector, or even declining, the Balance of Sector share is growing.

Table 3.4 Industrial Sector Reference scenario activity

Industrial Sector and Subsector Activity	2010	2013	2023	2010-2023 (Floating Scale)	2010-2023 (Fixed Scale)
Total Sector Activity (Billion 2011$)	**6553.2**	**7085.5**	**9323.4**		
Industrial Subsector Mode Shares (Value of Shipments)					
Agriculture	5.0%	4.5%	4.0%		
Mining	6.9%	7.3%	6.1%		
Construction	15.2%	14.7%	16.9%		
Refining Industry[1]	7.5%	7.1%	5.4%		
Food Industry[1]	9.5%	9.2%	8.7%		
Wood Products	1.3%	1.4%	1.3%		
Paper Industry[1]	2.4%	2.2%	2.1%		
Bulk Chemical Industry[1]	5.2%	4.6%	4.4%		
Plastics	2.7%	2.8%	2.6%		
Glass Industry[1]	0.3%	0.3%	0.3%		
Cement and Lime Industry[1]	0.1%	0.1%	0.1%		
Iron and Steel Industries[1]	1.7%	1.9%	2.1%		
Aluminum Industry[1]	0.5%	0.5%	0.6%		
Fabricated Metal Products	4.3%	4.4%	4.0%		
Machinery	4.8%	5.0%	5.7%		
Computers	6.7%	6.2%	7.3%		
Transportation Equipment	9.7%	12.1%	12.4%		
Electrical Equipment	1.7%	1.6%	1.8%		
Balance of Manufacturing	14.5%	14.1%	14.4%		
Total	100.0%	100.0%	100.0%		

[1] Energy Intense Industries (as identified by EIA)

3.4.5.3 Sector energy and carbon

Each industry included in Table 3.4 exhibits a different level of activity, energy consumption, and carbon emission. Table 3.5 shows that energy consumption in the sector will grow from almost 24 Quad BTU in 2013 to more than 27 Quad BTU in

2023. The Bulk Chemical industry accounts for nearly a quarter of the energy use overall, despite only accounting for 4.4% of the sector activity. Refining and the Balance of Manufacturing make up another quarter of sector energy consumption. In general, total energy consumption is increasing in every segment.

Table 3.5 Industrial Sector Reference energy consumption

Energy Consumption	2010	2013	2023	2010-2023 (Floating Scale)	2010-2023 (Fixed Scale)
Total Sector Consumption (QuadBTU)	**23.98**	**23.79**	**27.34**		
Industrial Subsector Energy Consumption					
Agriculture	3.7%	3.6%	3.3%		
Mining	8.1%	8.9%	8.5%		
Construction	7.1%	7.4%	8.3%		
Refining Industry[1]	15.0%	15.1%	13.3%		
Food Industry[1]	4.8%	4.9%	4.8%		
Wood Products	1.2%	1.4%	1.5%		
Paper Industry[1]	8.3%	7.9%	8.2%		
Bulk Chemical Industry[1]	24.6%	23.7%	24.0%		
Plastics	1.2%	1.3%	1.2%		
Glass Industry[1]	1.1%	1.1%	1.2%		
Cement and Lime Industry[1]	1.0%	1.2%	1.4%		
Iron and Steel Industries[1]	5.3%	5.8%	6.0%		
Aluminum Industry[1]	1.5%	1.7%	1.8%		
Fabricated Metal Products	1.4%	1.6%	1.5%		
Machinery	0.8%	0.9%	0.9%		
Computers	1.0%	1.0%	1.1%		
Transportation Equipment	1.7%	2.2%	2.2%		
Electrical Equipment	0.3%	0.3%	0.3%		
Balance of Manufacturing	11.9%	10.0%	10.5%		
Total	100.0%	100.0%	100.0%		

[1] Energy Intense Industries (as identified by EIA)

The industries that EIA identifies as energy intense consume more than 60% of the energy in the sector, despite representing only 26% of the activity. This disparity between energy and activity is very apparent in the energy intensities (BTU/$VS) shown in Table 3.6. The Sector average energy intensity in 2013 is 3,360 BTU/$VS, which declines steadily to 2,930 BTU/$VS by 2023 in the Reference scenario. The Cement and Lime industry contributes about 0.1% of the Sector activity, uses about 1% of Industrial sector energy, but operates at more than ten times the sector energy intensity average, and is far above other segments in the sector. The Bulk Chemical

Industry consumes almost a quarter of the energy used by the sector, and the energy intensity is five times the sector average. Close behind are Paper, Glass, Iron and Steel, and Aluminum, all more than three times the sector average. While energy use will generally increase, with the exception of the Mining and Refining segments, energy intensity will steadily decline in all segments over the next decade in the Reference Case.

Table 3.6 Industrial Sector Reference energy intensity (kBTU/$VS)

Energy Intensity	2010	2013	2023	2010-2023 (Floating Scale)	2010-2023 (Fixed Scale)
Sector Energy Intensity (kBTU/$VS)	**3.62**	**3.32**	**2.90**		
Indexed Industrial Subsector Energy Intensity (Index 1 = Whole Industrial Sector Intensity)					
Agriculture	0.75	0.80	0.92		
Mining	1.16	1.21	1.39		
Construction	0.47	0.50	0.58		
Refining Industry[1]	2.02	2.13	2.44		
Food Industry[1]	0.50	0.54	0.62		
Wood Products	0.95	1.02	1.17		
Paper Industry[1]	3.43	3.65	4.18		
Bulk Chemical Industry[1]	4.76	5.17	5.91		
Plastics	0.45	0.48	0.55		
Glass Industry[1]	3.20	3.51	4.02		
Cement and Lime Industry[1]	10.76	11.85	13.57		
Iron and Steel Industries[1]	3.03	3.06	3.50		
Aluminum Industry[1]	2.77	3.09	3.54		
Fabricated Metal Products	0.34	0.36	0.41		
Machinery	0.16	0.17	0.20		
Computers	0.15	0.16	0.19		
Transportation Equipment	0.17	0.18	0.21		
Electrical Equipment	0.15	0.17	0.19		
Balance of Manufacturing	0.82	0.71	0.81		

[1] Energy Intense Industries (as identified by EIA)

As with energy consumption, the energy intense segments emit 60% of the sector emissions. Table 3.7 shows that total carbon emissions in 2013 are 1,485 $MMtCO_2$, which will grow to 1,633 $MMtCO_2$ by 2023. Refining and Bulk Chemical Industries produce about 17% and 16 % (respectively) of the emissions in 2013, so together these two segments account for a third of all Industrial sector emissions. The Iron and Steel Industry emits a distant 8.5%, followed by the Food Industry at 6.6%.

Next are Construction, Agriculture, and Paper, each about 4.5%. The Balance of Manufacturing alone is responsible for about an eighth of sector emissions. With the exception of the Paper and Plastics industries, all segments are expected to increase CO_2 emissions over the next decade in the Reference scenario.

Table 3.7 Industrial Sector Reference carbon emissions ($MMtCO_2$)

Carbon Emissions	2010	2013	2023	2010-2023 (Floating Scale)	2010-2023 (Fixed Scale)
Total Sector Emissions ($MMtCO_2$)	**1496.1**	**1484.7**	**1632.7**		
Industrial Subsector Carbon Emissions					
Agriculture	4.8%	4.6%	4.2%		
Mining	3.7%	3.7%	3.5%		
Construction	4.7%	4.8%	5.6%		
Refining Industry[1]	17.5%	17.2%	15.3%		
Food Industry[1]	6.7%	6.6%	6.5%		
Wood Products	1.1%	1.2%	1.3%		
Paper Industry[1]	5.2%	4.5%	4.3%		
Bulk Chemical Industry[1]	17.3%	15.9%	15.9%		
Plastics	2.6%	2.6%	2.4%		
Glass Industry[1]	1.3%	1.3%	1.4%		
Cement and Lime Industry[1]	1.7%	2.1%	2.4%		
Iron and Steel Industries[1]	7.9%	8.5%	9.2%		
Aluminum Industry[1]	3.0%	3.4%	3.6%		
Fabricated Metal Products	2.5%	2.6%	2.4%		
Machinery	1.6%	1.7%	1.8%		
Computers	2.1%	1.9%	2.1%		
Transportation Equipment	3.1%	3.9%	3.9%		
Electrical Equipment	0.5%	0.5%	0.6%		
Balance of Manufacturing	12.5%	12.8%	13.7%		
Total	100.0%	100.0%	100.0%		

[1] Energy Intense Industries (as identified by EIA)

For carbon intensity, the sector on average emits 62.4 $MMtCO_2$/Quad BTU in 2013, which will decline to 59.7 $MMtCO_2$/Quad BTU by 2023. Unlike energy intensity, Table 3.8 shows that most of the segments are within a factor of two of the sector average; however, quite a few industries operate at twice the sector average. The highest is the Aluminum Industry, followed very closely by Plastics, Electrical Equipment, Machinery, and Computer industries, which all operate at between 1.9 and 2.0 times the sector average for carbon intensity. Next are Cement and Lime, and Fabricated Metals, both about 1.7 times the sector average. However, most of these emit very little total carbon. Most of the sector is expected to reduce carbon intensity over the next decade in this Reference case.

One can also show the carbon and energy intensities along with industry size, in terms of value of shipments (VS). In Figure 3.51, the y-axis is carbon intensity, the x-axis is the percentage of industry total VS, and the size of the bubble represents energy intensity. The Construction industry is almost 15% of total Industrial sector VS, while Cement and Lime Industry contributes about 0.1%. This chart highlights that the most energy intense industries are relatively small in terms of total VS.

Table 3.8 Industrial Sector Reference carbon intensity ($MMtCO_2$/Quad BTU)

Carbon Intensity	2010	2013	2023	2010-2023 (Floating Scale)	2010-2023 (Fixed Scale)
Sector Carbon Intensity ($MMtCO_2$/Quad)	**62.39**	**62.41**	**59.71**		
Indexed Industrial Subsector Carbon Intensity (Index 1 = Whole Industrial Sector Intensity)					
Agriculture	1.29	1.26	1.28		
Mining	0.46	0.41	0.41		
Construction	0.66	0.65	0.67		
Refining Industry[1]	1.16	1.14	1.15		
Food Industry[1]	1.39	1.34	1.35		
Wood Products	0.96	0.90	0.86		
Paper Industry[1]	0.62	0.57	0.52		
Bulk Chemical Industry[1]	0.70	0.67	0.66		
Plastics	2.12	1.99	2.02		
Glass Industry[1]	1.21	1.18	1.20		
Cement and Lime Industry[1]	1.68	1.70	1.73		
Iron and Steel Industries[1]	1.49	1.46	1.53		
Aluminum Industry[1]	2.06	2.02	1.96		
Fabricated Metal Products	1.75	1.65	1.67		
Machinery	2.06	1.94	1.97		
Computers	2.04	1.91	1.87		
Transportation Equipment	1.88	1.78	1.81		
Electrical Equipment	2.10	1.97	2.01		
Balance of Manufacturing	1.05	1.29	1.31		

[1] Energy Intense Industries (as identified by EIA)

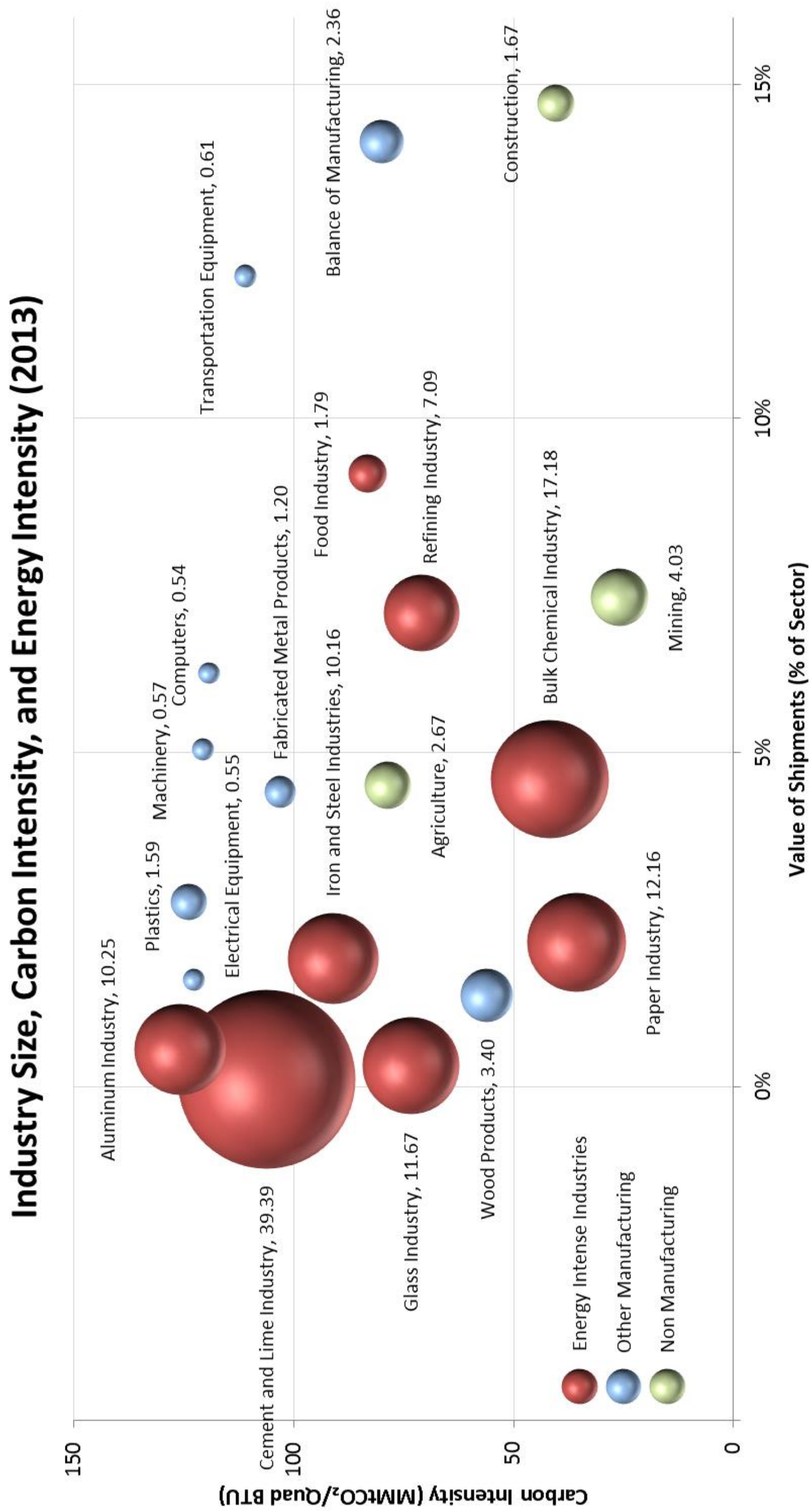

Figure 3.51 Industrial sector carbon and energy intensities for sample scenario and Reference case

3.4.5.4 Policy impacts

The individual industries in this sector vary disparately with respect to VS, energy consumption, and carbon emissions. So applying a carbon fee will affect each segment differently. Figure 3.52 shows the evolution of carbon and energy intensities for the \$25/tCO_2 at 2% scenario relative to the Reference scenario. In the figure, the solid lines represent the policy case and the black dotted lines represent the Reference scenario. Each policy trajectory includes three markers: the asterisk marks the beginning of the data in 2010, the closed circle is at 2013 (the base year before the policy), and the open circle is 2023. Note that the Cement and Lime industry inset occurs far to the right since the industry's energy intensity is more than twice that of next largest, Bulk Chemicals.

The general trend under the policy is that industries characterized with high energy intensity (such as Cement and Lime and Bulk Chemicals) already have significant reductions over time in energy intensity in the Reference Scenario. Similarly, those industries characterize with high carbon intensity (such as Plastics, Electrical Equipment, and Computers) expect significant carbon intensity reductions in the Reference scenario. Those characterized with both high energy and carbon intensities (such as Aluminum and Iron and Steel) are expected to reduce both. The result of the policy is to extend these trends in energy and carbon intensity reduction, with varying degrees of impact.

Again, the disparate range for each of the terms is an important factor. Seven of the eight industries labeled as energy intense by EIA are readily identifiable on the chart as the most energy intense industries, but they span the full spectrum of carbon intensity. Food is the eighth industry for carbon intensity, but its energy intensity is lower than the sector average. Nevertheless, Food represents about 5% of total sector energy consumption. The only industries not identified as energy intense by EIA but which consume more energy than Food are Construction and Mining, and both are already very efficient in terms of energy and carbon intensities.

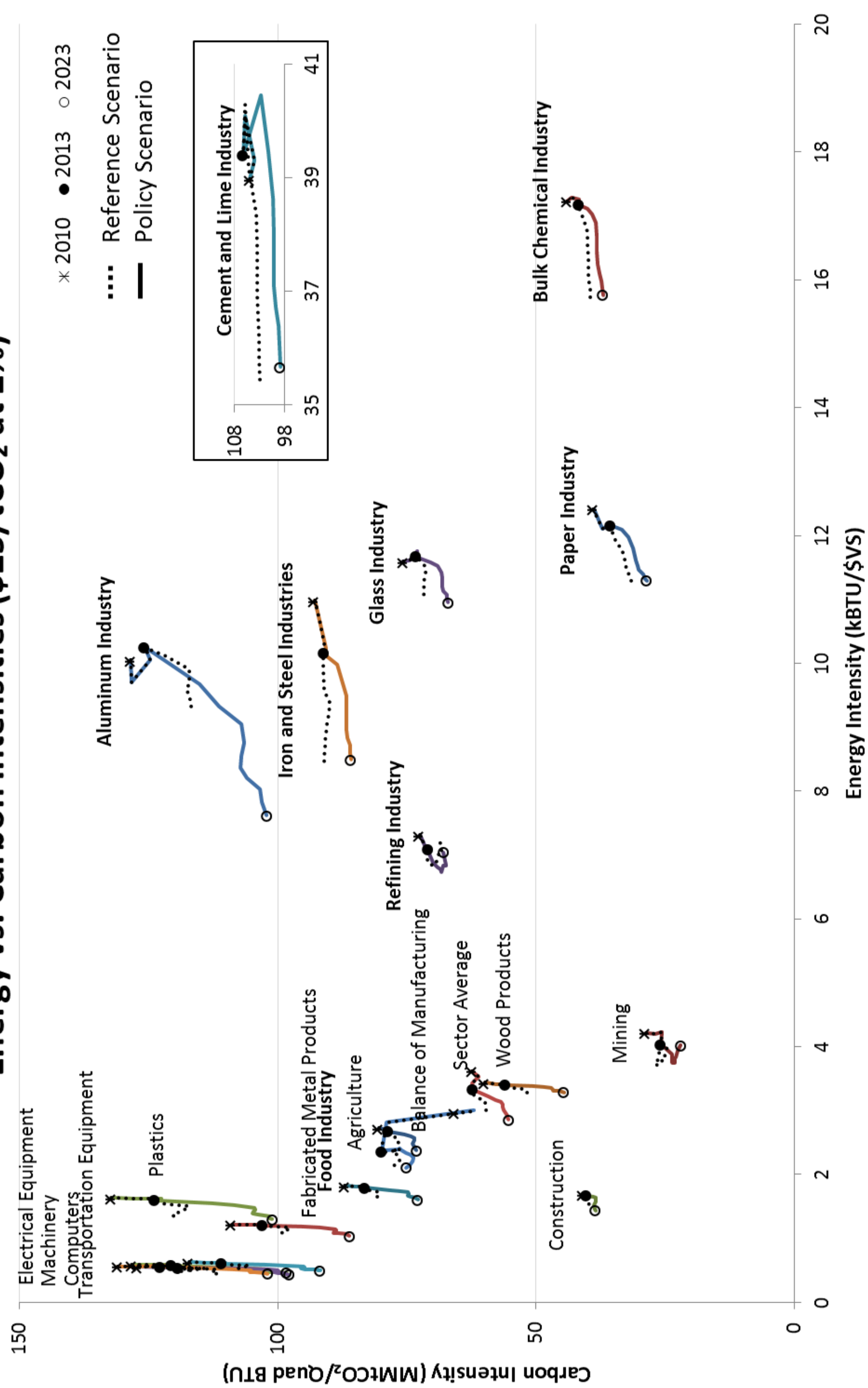

Figure 3.52 Industrial sector carbon and energy intensities for sample scenario and Reference case

3.4.5.5 Sector decomposition

The ASIF decomposition requires total activity (VS) and the mode shares of that activity, represented by the individual industry VS. It also requires energy intensity of each industry as well as the carbon intensity and share of each fuel in each industry. NEMS provides projections for several fuels within each industry, including natural gas, coal, renewables, purchased electricity, and several petroleum products. While the two buildings demand sectors use predominantly electricity, and the Transportation sector uses different petroleum products, the Industrial sector fuel mix varies widely by industry.

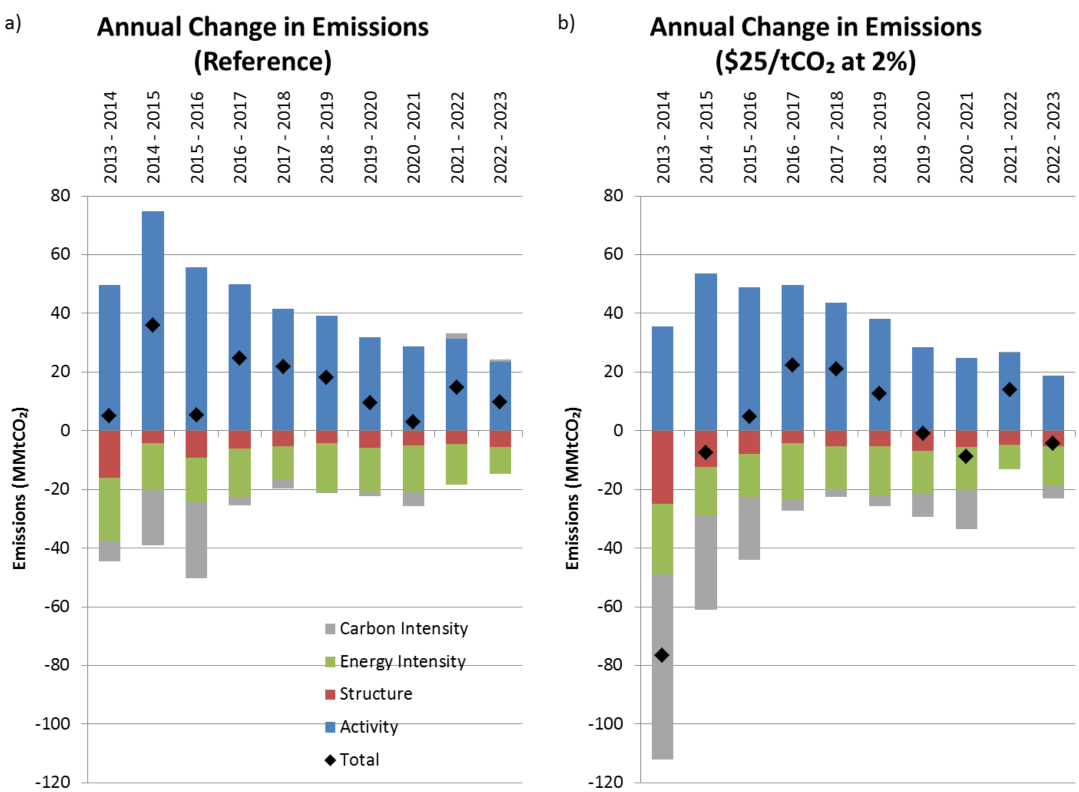

Figure 3.53 Industrial sector annual emissions attributions from a) Reference and b) policy scenarios

The model unfortunately does not provide an output of emissions by fuel type. While some fuels have a fixed emissions factor, as with natural gas combustion, others such as ‘renewables’, combined heat and power (CHP), and purchased electricity, are quite ambiguous. Nonetheless, one can eliminate the fuel mix term from the ASIF framework in Equation 2.16 and evaluate aggregate changes in carbon intensity from each sector as a lumped parameter. This will still highlight any change in carbon intensity, but will not distinguish between efficiency vs. fuel switching.

Figure 3.53a shows the annual impact on emissions from a change in the ASIF parameters for the Reference scenario. In general, emissions are expected to rise over the next decade, primarily due to an increase in projected activity. This corresponds well with the anticipated expanding GDP growth rate as the economy rapidly shakes off the recent financial crises. As with the other demand sectors, the Industrial sector will continue to improve carbon efficiency over the next few years under the Reference Case, but this progression will cease once existing policies expire. Under the carbon policy (see Figure 3.53b), the Industrial sector will respond by slightly reducing overall activity and improving carbon intensity even further than the Reference Case. However, beyond the impact of the first few years, the year-over-year decomposition looks very similar to the Reference Case.

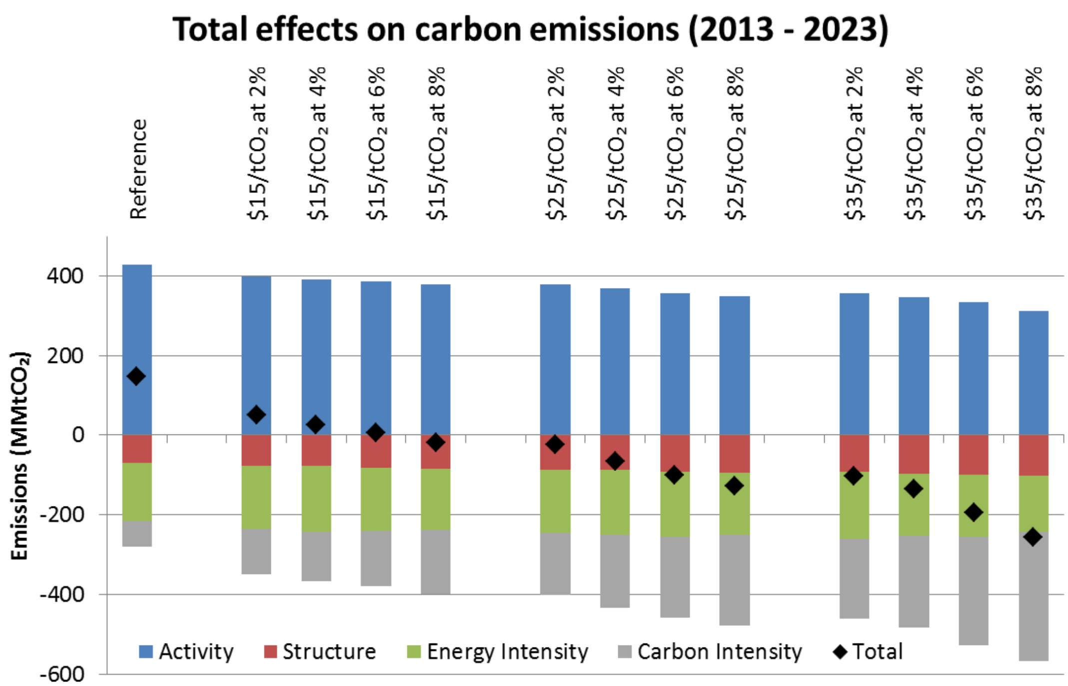

Figure 3.54 Industrial sector effects from all scenarios

Figure 3.54 shows the ten-year impact for all scenarios. Activity (VS) will drive growth in emissions in the Reference scenario, but this effect is reduced somewhat in all policy scenarios. The rise in emissions is countered with energy and carbon intensity effects. In general mode share (structure) is relatively insensitive to the carbon price policies since most of the exposed industries are relatively small in terms of total share of activity. (Please see Appendix 0 for annual results from all scenarios.)

3.4.5.6 Industry-specific decomposition

One can also evaluate the activity, energy intensity, and carbon intensity of each individual industry to determine which are most affected by the policy. Table 3.9 shows each industry and the Reference scenario effects from changes in activity, energy intensity, and carbon intensity. The first two data columns show the base year share of VS from each industry and the industry's carbon emissions. The next three columns show the impacts to emissions over the next decade from the Reference forecast. The sum of these three for each industry, plus the 2013 emissions, results in the 2023 emissions. The percent contribution to VS in 2023 is also included. The eight energy-intense industries are highlighted for convenience.

Table 3.9 Industry-specific decomposition results for Reference scenario

			Reference				
	2013		2013 - 2023			2023	
Industry	Mode Share[1] (% of sector)	Total Emissions ($MMtCO_2$)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions ($MMtCO_2$)	Mode Share[1] (% of sector)
Agriculture	4.5%	67.9	10.4	-7.9	-1.9	68.6	4.0%
Mining	7.3%	54.7	5.1	0.4	-3.6	56.7	6.1%
Construction	14.7%	71.0	33.2	-12.2	-0.9	91.0	16.9%
Refining Industry[2]	7.1%	254.9	-1.5	5.6	-8.4	250.6	5.4%
Food Industry[2]	9.2%	98.1	22.5	-10.7	-3.5	106.3	8.7%
Wood Products	1.4%	18.6	5.3	-0.7	-1.7	21.4	1.3%
Paper Industry[2]	2.2%	67.0	17.6	-5.3	-9.2	70.1	2.1%
Bulk Chemical Industry[2]	4.6%	236.3	60.1	-22.8	-14.7	259.0	4.4%
Plastics	2.8%	39.1	7.8	-7.4	-1.1	38.4	2.6%
Glass Industry[2]	0.3%	18.8	6.3	-1.2	-0.5	23.3	0.3%
Cement and Lime Industry[2]	0.1%	31.0	12.8	-3.7	-1.1	39.0	0.1%
Iron and Steel Industries[2]	1.9%	126.9	48.5	-25.2	-0.2	149.8	2.1%
Aluminum Industry[2]	0.5%	50.8	17.9	-5.8	-4.1	58.7	0.6%
Fabricated Metal Products	4.4%	39.2	7.4	-5.2	-1.4	39.9	4.0%
Machinery	5.0%	25.0	10.7	-5.2	-0.7	29.8	5.7%
Computers	6.2%	28.7	13.7	-6.4	-2.0	33.9	7.3%
Transportation Equipment	12.1%	58.5	17.9	-10.8	-1.7	63.9	12.4%
Electrical Equipment	1.6%	7.8	3.2	-1.6	-0.2	9.2	1.8%
Balance of Manufacturing	14.1%	190.8	60.1	-21.8	-5.8	223.2	14.4%
Total	100.0%	1484.7	358.7	-148.0	-62.7	1632.7	100.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table 3.10 Industry-specific decomposition results for policy scenario

Industry	2013 Mode Share[1] (% of sector)	2013 Total Emissions ($MMtCO_2$)	Policy Scenario ($25/$tCO_2$ at 2%) 2013 - 2023 Activity effect	Energy Intensity effect	Carbon Intensity effect	2023 Total Emissions ($MMtCO_2$)	2023 Mode Share[1] (% of sector)	Percent difference from Reference 2013 - 2023 Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions ($MMtCO_2$)	Mode Share
Agriculture	4.5%	67.9	9.7	-7.9	-4.8	64.9	4.1%	-6.6%	-0.3%	-158.9%	-5.4%	1.7%
Mining	7.3%	54.7	4.5	-0.2	-8.5	50.6	6.3%	-12.0%	-138.1%	-136.8%	-10.8%	3.8%
Construction	14.7%	71.0	32.9	-12.2	-3.6	88.1	17.2%	-0.7%	0.2%	-303.8%	-3.2%	2.2%
Refining Industry[2]	7.1%	255.1	-5.4	-1.6	-10.7	237.4	5.5%	-258.4%	-129.0%	-28.2%	-5.3%	1.9%
Food Industry[2]	9.2%	97.8	20.6	-10.7	-12.9	94.9	8.8%	-8.2%	0.3%	-263.6%	-10.8%	0.8%
Wood Products	1.4%	18.5	4.5	-0.6	-4.2	18.3	1.4%	-14.4%	14.4%	-139.7%	-14.5%	0.6%
Paper Industry[2]	2.1%	66.8	14.7	-4.8	-14.3	62.5	2.1%	-16.2%	9.1%	-55.5%	-10.9%	-0.4%
Bulk Chemical Industry[2]	4.6%	235.9	47.7	-20.3	-28.3	235.1	4.4%	-20.6%	11.0%	-93.0%	-9.2%	-1.5%
Plastics	2.8%	39.0	4.5	-7.0	-6.9	29.6	2.4%	-41.8%	4.7%	-526.0%	-23.0%	-4.9%
Glass Industry[2]	0.3%	18.7	5.1	-1.3	-1.8	20.8	0.3%	-18.4%	-3.6%	-282.5%	-10.8%	-2.3%
Cement and Lime Industry[2]	0.1%	30.9	11.2	-3.3	-2.4	36.4	0.1%	-12.4%	9.9%	-123.2%	-6.6%	-1.4%
Iron and Steel Industries[2]	1.9%	126.7	36.0	-23.2	-7.8	131.8	2.0%	-25.6%	8.1%	-3288.8%	-12.1%	-4.6%
Aluminum Industry[2]	0.5%	50.7	7.8	-12.9	-9.0	36.6	0.5%	-56.5%	-120.9%	-118.4%	-37.7%	-13.1%
Fabricated Metal Products	4.4%	39.1	6.4	-5.5	-6.5	33.5	4.1%	-13.9%	-3.9%	-372.9%	-16.1%	1.2%
Machinery	5.0%	25.0	8.7	-5.5	-4.9	23.3	5.6%	-18.5%	-6.4%	-563.3%	-21.9%	-0.9%
Computers	6.2%	28.7	12.2	-6.5	-5.7	28.6	7.3%	-10.8%	-1.6%	-181.5%	-15.6%	-0.3%
Transportation Equipment	12.1%	58.4	15.0	-11.0	-10.5	51.9	12.2%	-16.2%	-1.4%	-519.7%	-18.7%	-1.2%
Electrical Equipment	1.6%	7.8	2.8	-1.6	-1.4	7.5	1.8%	-13.4%	-2.1%	-589.4%	-18.3%	0.6%
Balance of Manufacturing	14.1%	191.1	52.9	-23.0	-12.5	208.5	14.1%	-11.9%	-5.7%	-114.2%	-6.6%	-2.1%
Total	100.0%	1483.8	292.0	-159.0	-156.6	1460.1	100.0%	-18.6%	-7.4%	-149.8%	-10.6%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

The results from the policy case are shown in Table 3.10. The policy case results include the emissions impacts from changes in activity, energy intensity and carbon intensity, and the end result in 2023 for emissions and mode share. The table goes further to compare the percent change in each indicator from the Reference scenario results, and the sign indicates direction, rather than increase or decrease. For example, emissions from Refining activity is reduced by 1.5% between 2013 and 2023 in the Reference scenario, and by 5.4% under the policy scenario. Table 3.10 shows this 250% change in emissions reduction that is due to changes in activity.

Under the policy scenario, activity in each industry is reduced, decreasing related emissions impacts further than the References Scenario. Besides the Refining industry, Aluminum industry experiences more than a 50% additional reduction and Plastics more than 40%. More notable changes come from energy and carbon intensity effects. Reduction of emissions from the energy intensity effect is improved by more than 100% in three industries, Mining, Refining, and Aluminum, with only slight improvements in the other industries. However, emissions reductions from carbon intensity effects further reduces emissions in nearly all industries by more than 100% over the Reference scenario, and some by over 500%. Most notably, the Iron and Steel Industry experiences a further reduction in emissions by over 2000% due to carbon intensity effects. (See Appendix B.13 for results from all scenarios.)

3.5 Summary of Policy Macroeconomic Impacts

Lower natural gas prices, some energy efficiency, and several economic crises have combined to reduce CO_2 emissions levels for the U.S. over most of the last decade. Despite this recent decline, EIA projects a small, but steady, increase in energy-related carbon emissions over the next decade as the economy slowly recovers.

The primary reason for pricing carbon is to reduce carbon emissions, and the policies modeled here can do that with a minimal impact to the macro U.S. economy. Far from a one-to-one impact, these policies will reduce emissions over the next decade between 5% and 24% from the Reference forecast scenario, while only affecting U.S. GDP by 0.4% to 1.6%. In doing so, they will raise revenues ranging from $0.8 trillion to $2.2 trillion in aggregate from 2014 to 2023.

Almost all of the avoided carbon from these polices will come from switching away from higher carbon fuels and most of that will occur in the first few years of the policy. About 85% of avoided emissions will come as a result of changes in electricity generation technologies as the electricity supply sector dispatches natural gas plants instead of coal-fired plants in the short term, and adds more renewables throughout the next decade.

The Transportation sector was responsible for a third (33%) of U.S. CO_2 emission in 2013. However, since most of the avoided carbon will come from the electricity sector, the Transportation sector will see very little response from these policies. The dominant fuels in this sector are petroleum-based. So, with little opportunity for reducing carbon or energy intensity of vehicles, any avoided carbon from this sector will come from a reduction in demand or activity.

However, electricity is a dominant energy source for the other three demand sectors, Industrial, Residential buildings, and Commercial buildings, and each sector will account for roughly a third of the total avoided carbon. The two buildings sectors can expect to see only a slight reduction in activity and only marginal improvements in energy efficiency, so most of the avoided carbon will come from the benefit of a cleaner electricity supply.

Carbon emissions from the Industrial sector accounted for almost 28% of total U.S. 2013 CO_2 emissions, while the Residential and Commercial buildings sectors emitted about 21% and 18%, respectively in 2013. All three of these sectors are predominantly fueled by electricity and natural gas, with some direct coal use and measureable petroleum use in the Industrial sector. In the Industrial sector, almost 40% of the associated emissions came from the use of electricity in 2013 and about 30% from natural gas. The Industrial sector uses almost the same amount of total electricity as the buildings sectors, although electricity contributes a much smaller portion of its emissions. For the building sectors, electricity-related emissions account for about three quarters of the sector emissions with natural gas making up most of the remaining quarter.

The Industrial sector is different than the other demand sectors. While the structure of the other three sectors is fairly homogenous, the modes of the Industrial sector are represented by individual industries, each with a uniquely different impact from an energy policy. Energy intense industries, such as Iron and Steel, and Aluminum will incur significant changes in activity, and those plus a few others will see changes in energy intensity. However, almost every industry will reduce exposure to carbon fees by reducing carbon intensity; indeed, nearly all will see a decrease in carbon intensity that is more than twice that of the Reference scenario.

An additional result of avoided emissions is a shift in sector contribution to carbon fee revenues. The tax affects all sectors based on their respective emissions. So in 2014, the first year of the policy, Transportation sector contributes about 34% of all revenues, Industrial about 28%, Residential about 20% and Commercial the remaining 18%. Transportation sector sees little change from the policies so continues to emit about the same amount irrelevant of the policy. However, the more aggressive the, the more avoided emissions are achieved from the other three sectors –especially the building sectors. For the most aggressive case, the transportation sector will be responsible for about 42% of total revenues, while the Residential and Commercial building sectors will only contribute 16% and 13%, respectively. The Industrial sector will contribute about 29% of the revenues irrelevant of the policy.

This analysis does not addressed impact by region. Different regions in the U.S. have different energy consumption drivers, carbon intensity, price of electricity, affluence, or even economic make-up. An example of this disparity is that most industry occurs in the south, so policies will have a different impact here than they do on the U.S. as a whole. Some regional differences will be discussed in the next chapter, but for the most part are left to future researchers to explore.

Chapter 4

HOUSEHOLD IMPACTS FROM CARBON FEES AND REVENUE REBATES

4.1 INTRODUCTION

Chapter 3 illustrated U.S. macroeconomic and sectoral impacts from carbon fees, and showed that modest policies could significantly reduce CO_2 emissions with minimal cost to the economy. One remaining concern of most policymakers is how these policies will impact their constituents. Answering that is the subject of this chapter.

A carbon fee, in practice, should be applied as far upstream in the energy supply chain as possible, such as the mouth of the coal mine or point of production. This approach helps to minimize the program management and oversight costs required to enforce the policy. However, no matter where in the supply stream the fee is applied, one should expect the additional cost to be passed down to end-users and consumers of energy. This will directly affect consumer and household energy-related expenditures, both in what they can afford and how they respond to higher prices. To understand the direct impacts of a carbon fee on U.S. households, one must know how much households currently spend annually on different types of energy. Properly defining a rebate program to minimize the direct impacts to households requires also knowing how those expenditures will change as a result of future energy supply market prices.

Understanding the way costs relate to income is a key step to designing the appropriate level of compensation, such as policy proposals that rebate a portion of the total revenue to consumers (e.g., Boxer and Sanders, 2013). NEMS offers a massively detailed representation of the U.S. energy-economic structure, which allows for a plausible simulation of U.S. energy demand for different fuel types within different sectors. However, NEMS does not directly analyze the impacts across different household income levels. Also, while NEMS has some ability to estimate the geographic impacts of climate policy, these calculations are made at a high level with very little regional evaluation. Currently, model results are aggregated to the level of the nine U.S. Census Divisions. So, by itself, NEMS cannot properly describe impacts to specific American households.

Until the model includes detailed household expenditure and consumption calculations over a more refined geographical and distributional structure, NEMS energy forecasts must be combined with external energy expenditure data to assess the real household impacts of any policy. Current household expenditure by income levels can be obtained from a number of published government surveys. This study utilizes both the Consumer Expenditure (CEX) data and the Residential Energy Consumption Survey (RECS) data. This expenditure data can be projected against the NEMS energy market consumption forecast of the residential sector to forecast household impacts.

This chapter illustrates how to couple and integrate these rich consumer datasets with NEMS forecasts. Section 4.2 provides a detailed explanation of the data, shows why both data sets are required, and defines the method for how they can be coupled to the NEMS forecast results. Section 4.3 describes the impacts to energy prices from the carbon policies. In particular, this section describes changes in prices to Residential customers for electricity, natural gas, and gasoline.

Evaluating the impacts to households begins with assessing the cost of each policy on the average American household. Section 4.4 first shows total energy sector expenditures by fuel type for the average American household, then summarizes the change in total energy expenditures for each fuel type from the NEMS Residential sector for all U.S. households in aggregate. Combined, these two pieces will define the net cost of the policies on a per-household basis for the average American household. Adding a per capita rebate will show the net benefit is positive.

The next two sections highlight regional impacts and income distribution impacts. Section 4.5 looks at the impacts to average households in each of the four Census Regions, the nine Census Divisions, and the 16 most-populous states. Section 4.6 evaluates the impacts by seven income brackets for the average American household in each bracket, and the Census Regions and Divisions. These two sections show a 50% rebate is sufficient to provide a net positive benefit to nearly all households across the U.S. by both income and geographic region.

The methods described here offer a significant improvement over previous studies in some respects and an incremental improvement in others. So, the chapter concludes with Section 4.7 which summarizes the findings and discusses what data and model outputs would further the analysis.

4.2 DATA AND METHODS

Energy-related household expenses cover activities such as water heating, space cooling, cooking, and lighting. But an effective evaluation of carbon fee impacts should also include external energy-related expenditures such as gasoline and personal air travel. Changes to household energy expenditures (inside and outside the home) are dependent on the market equilibrium between future prices and future demand, and both price and demand can be obtained from the NEMS policy scenario forecasts. NEMS forecasts broad energy supply, demand, and prices given assumptions about the state of the economy, international markets, and energy policies. So, although NEMS tracks total number of households and income (driven by exogenous parameters), it makes no attempt to assess distributional impacts.

Furthermore, some household energy expenses (e.g., air travel) are not correlated to households or even the Residential demand sector within NEMS. As a result, a detailed hybrid model like NEMS is best used to consider the broader market trends, not to accurately project income-based household energy demand and costs at a future point in time. To understand how to use published datasets that itemize household energy expenditure, one should first understand what is available from NEMS.

One can leverage a number of published government surveys to obtain current household expenditure based on income levels. This expenditure data, once plied from the datasets, must be projected against the NEMS future energy market consumption in the Residential sector. In general, the aggregate residential consumption and price forecasts generated by NEMS under the policy cases are used to assess changes in aggregate expenditure from the Reference scenario. These impacts to households (in aggregate) correspond to what economists have called the "direct component" of total impacts (Hassett et al., 2009; Mathur and Morris, 2014). To determine the per-household impact, the energy-related expenditures from the CEX and RECS are mapped to their corresponding outputs from the NEMS residential sector. Then one can project the changes to expenditures using model outputs, which ensures that the projected household impacts are driven by the same price and quantity projections determined in the NEMS framework.[38] Finally, one can rebate a portion of the revenues to households. This Section will walk through each step of the process.

4.2.1 NEMS Framework

Chapter 3 showed the NEMS general equilibrium solutions under the Reference scenario and a suite of carbon policies. Beyond the macroeconomic and sectoral impacts addressed above, NEMS also solves for the price and aggregate quantity consumed for each fuel in each sector. While prices and quantities are changing in each demand sector (and fuel prices are indeed different between demand sectors), this chapter focuses on the impact of the cost of carbon fees on households. Consequently, only the Residential demand sector price and quantity forecasts from NEMS are used to compute the impacts to households.

NEMS provides energy price and quantities for all major fuels used in the Residential sector, which can be combined to obtain the total amount of expenditure in the sector for a given forecast year. A carbon fee increases the cost of buying energy products and services, which alters consumption (either with technology or through behavior). NEMS forecasts this response, which is embodied in the difference between the Reference scenario and each policy scenario. Section 2.5 described the fundamental process for combining the NEMS outputs to quantify the impact from the policies. The resulting equation, Equation 2.24, is repeated here for convenience,

[38] The effect of population growth is ignored (which biases estimated household energy consumption upwards) in order to compensate for the inability to estimate the change in income distributions in the projections (an omission that biases estimated household energy consumption downwards).

where the 'Cost of policy' refers to the aggregate direct costs of the policy to the whole Residential sector in millions of dollars ($USD).

$$\underbrace{Price\ x\ Quantity}_{Policy} - \underbrace{Price\ x\ Quantity}_{Reference} = \underbrace{Cost\ of\ policy}_{Direct\ Costs} \qquad \textbf{2.24}$$

One can rewrite Equation 2.24 to more explicitly represent a single fuel type, and arrive at Equation 4.1. The total direct impact of a policy on the Residential sector for a given fuel is the difference in total expenses per year between the policy scenario and the reference scenario.

$$P_i^y\ Q_i^y\big|_{policy} - P_i^y Q_i^y\big|_{reference} = C_i^y \qquad \textbf{4.1}$$

Where:
P_i = Residential energy price for fuel i in $/MMBTU
Q_i = Residential energy consumption for fuel i in Quad BTU
C_i = Total cost of the policy relative to the Reference scenario for fuel i in $billion
i = Fuel type (e.g., electricity, natural gas, gasoline)
y = Forecast year

One could simply divide the total expenditures in NEMS by the number of households to get the average expense with and without the policy. However, NEMS lacks vital information about certain household-related expenses, in particular transportation costs. Furthermore, NEMS is not designed to accurately represent the average household, but rather the broader market and economy. For both of these reasons, one must obtain accurate external data about actual energy-related expenditure to properly assess the impacts to the average American household in different regions and by different incomes.

Representative household expenditures can be obtained from published surveys, which are snapshots of actual historical behavior. Assume, for the moment, that average household expenditures for each fuel type in 2011 have already been obtained. Then the cost per household for a particular fuel type can be escalated by the normalized increase in expenditures from NEMS:

$$\left(\frac{E_i^{2011}}{(PQ)_i^{2011}}\right) * C_i^y = e_i^y \qquad \textbf{4.2}$$

Where:

E_i^{2011} = Historic (2011) household expenditure or fuel type i in $ /year

e_i = Residential energy expenditure for fuel i in $/year

The parenthetical term in Equation 4.2 is the ratio of measured (or surveyed) household expenditure on a given fuel (E_i^{2011}) in $/year to NEMS historic total sector consumption ($(PQ)_i^{2011}$) in $billions. The result is a per-household scale factor, which represents the fraction of total expenditure for each average household. This ratio, multiplied by the total policy cost for that fuel (C_i^y) defines the per-household policy cost. Thus, one can evaluate the scaling of costs for any fuel based on future prices and quantities. Finally, the total energy-related cost per average household in a given year from the policy can be obtained with the summation of all fuel costs:

$$\sum_i e_i^y = e^y \qquad \textbf{4.3}$$

Using this rudimentary framework, one can link NEMS forecasts with any external household energy expenditures data. Further development and application of the framework will depend on the detail and resolution of the chosen household expenditure datasets.

4.2.2 Household expenditure data

NEMS provides the change in future fuel prices and quantities under each policy scenario, but information relative to representative household expenditures is still needed. No single survey dataset can provide all of the necessary information to properly evaluate carbon price impacts to households at the desired resolution. As a result, this study leverages two different surveys: CEX and RECS. The CEX is a wide-angle snapshot of historical household expenditures and, as a result of its breadth, lacks the desired geographical resolution and depth on energy-specific expenditures.

RECS, on the other hand, dramatically improves on the geographical resolution–even isolating some individual states, and provides significant depth on energy consumption related to residential buildings. However, RECS lacks data related to household energy expenditures that occur outside the home, such as personal vehicles and air travel. Consequently, these datasets are complementary and both are necessary to comprehensively assess the impacts of a carbon policy on household energy expenditures.

4.2.2.1 Consumer Expenditure (CEX) Survey

The Bureau of Labor Statistics' (BLS) CEX is perhaps the most comprehensive survey on consumer expenditures, providing cross-sectional data on all household expenditures, income, and other characteristics. The CEX is produced annually, but the published result is from the prior year. This study uses the 2012 version describing 2011 household expenditures (BLS, 2013a).

The CEX is the only Federal survey to provide information on the complete range of consumers' expenditures and incomes. The annual report provides detailed expense summaries on various activities including type of foods, rent and mortgage, utilities, furnishings, apparel, healthcare, transportation, entertainment, and others. The survey data are used by policymakers, businesses and academic researchers, and by other Federal agencies. However, its primary use is to regularly revise the Consumer Price Index (CPI) market basket of goods and services and their relative importance (BLS, 2013b).

The use of this survey to evaluate distributional impacts is not unprecedented. The 2003 CEX was used to determine a revenue-neutral GHG tax-rebate policy (Metcalf, 2008b). More recently, this approach was used to compare earlier cap-and-trade or cap-and-dividend legislation (Blonz et al., 2011). However, coupling the CEX with NEMS forecasts is new. The benefit of coupling these tools was demonstrated with an analysis of the Boxer–Sanders Climate Protection Act of 2013 (Wara et al., 2014; Wilkerson et al., 2014a) and further used to assess a range of carbon price scenarios (Cullenward et al., 2014).

4.2.2.1.1 The CEX data

The CEX includes hundreds of household expenditure line items, but only five energy-related line items or fuel types: natural gas, electricity, fuel oil and other fuels, gasoline and motor oil, and public and other transportation. Table 4.1 summarizes the number of households (or consumer units) and the five fuel type expenditures for several market segments. In 2011, the average American household spent $5,171 on energy-related activities, which was 10.4% of the total average household expenses. Households in a higher income, or wealth, bracket spent more money on energy but a smaller percentage of the total. Of the $5,171 spent on energy-related activities, the average household spent about 51% on gasoline, 28% on electricity, 10% on public and other transit –including airline travel, 8% on natural gas, and the remaining 3% on fuel oils and other fuels. Figure 4.1 illustrates the average American household and the income quintile distribution of energy expenditure in 2011.

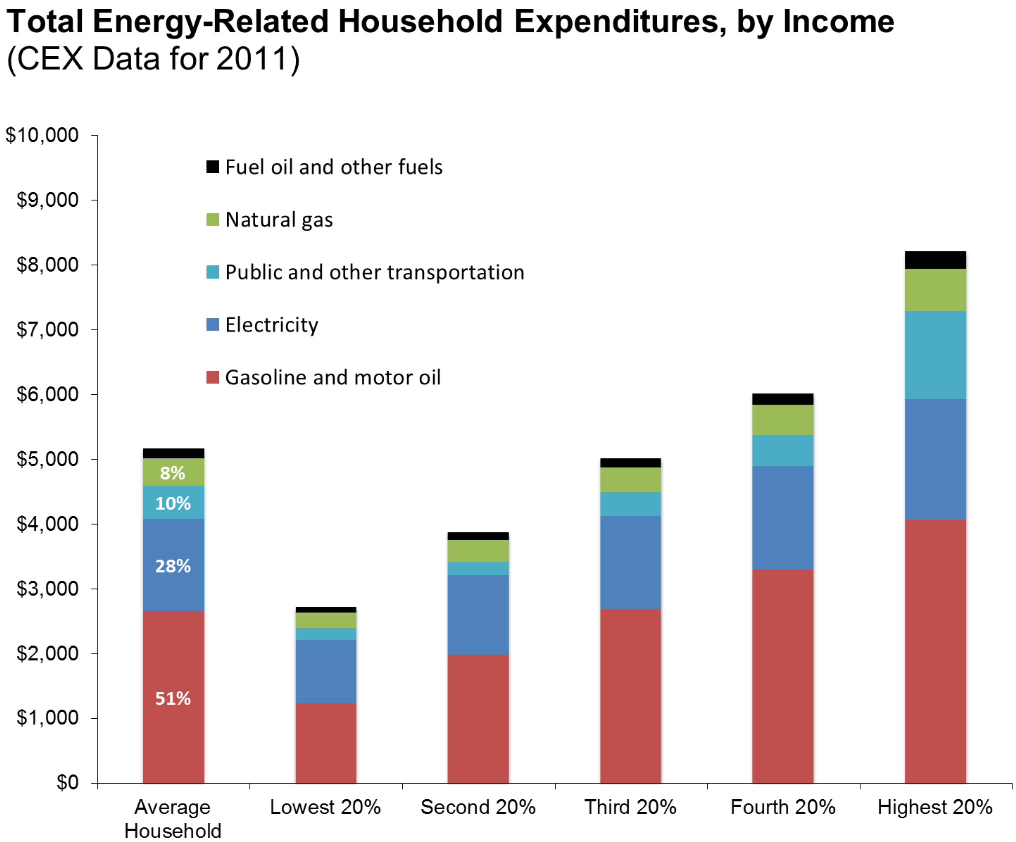

Figure 4.1 Average American household and income quintile energy expenditure

Table 4.1 CEX income distributions and energy expenditures for income quintiles, Regions, and household incomes

Market Segment	Households		Expenditure			Energy Expenditure by Fuel Type: $/HH, % of energy expenditures, indexed to avgerage consumer														
			Total	Energy		Natural Gas			Electricity			Fuel oil & Other Fuel			Gasoline & Motor Oil			Public Transportation		
	thous.	% of total	$/HH	$/HH	% of Total	$/HH	% of energy	Index¹	$/HH	% of energy	Index¹	$/HH	% of energy	Index¹	$/HH	% of energy	Index¹	$/HH	% of energy	Index¹
Average Household																				
Avg. Consumer Unit	122,287	100%	$49,705	$5,171	10.4%	$420	8.1%	1.00	$1,423	27.5%	1.00	$157	3.0%	1.00	$2,655	51.3%	1.00	$516	10.0%	1.00
By Income Quintiles																				
Lowest 20 % (Q1)	24,435	20%	$22,001	$2,722	12.4%	$243	8.9%	0.58	$985	36.2%	0.69	$85	3.1%	0.54	$1,227	45.1%	0.46	$182	6.7%	0.35
Second 20 % (Q2)	24,429	20%	$32,092	$3,876	12.1%	$338	8.7%	0.80	$1,234	31.8%	0.87	$119	3.1%	0.76	$1,981	51.1%	0.75	$204	5.3%	0.40
Third 20 % (Q3)	24,473	20%	$42,403	$5,016	11.8%	$386	7.7%	0.92	$1,429	28.5%	1.00	$140	2.8%	0.89	$2,694	53.7%	1.01	$367	7.3%	0.71
Fourth 20 % (Q4)	24,520	20%	$57,460	$6,015	10.5%	$472	7.8%	1.12	$1,603	26.7%	1.13	$170	2.8%	1.08	$3,295	54.8%	1.24	$475	7.9%	0.92
Highest 20 % (Q5)	24,430	20%	$94,551	$8,217	8.7%	$659	8.0%	1.57	$1,863	22.7%	1.31	$270	3.3%	1.72	$4,073	49.6%	1.53	$1,352	16.5%	2.62
By Region																				
Northeast (NE)	22,538	18.4%	$54,547	$5,661	10.4%	$596	10.5%	1.42	$1,338	23.6%	0.94	$487	8.6%	3.10	$2,510	44.3%	0.95	$730	12.9%	1.41
Midwest (MW)	27,107	22.2%	$47,192	$5,031	10.7%	$600	11.9%	1.43	$1,225	24.3%	0.86	$121	2.4%	0.77	$2,632	52.3%	0.99	$453	9.0%	0.88
South (S)	44,901	36.7%	$45,699	$5,204	11.4%	$243	4.7%	0.58	$1,763	33.9%	1.24	$70	1.3%	0.45	$2,794	53.7%	1.05	$334	6.4%	0.65
West (W)	27,741	22.7%	$54,745	$4,853	8.9%	$387	8.0%	0.92	$1,135	23.4%	0.80	$64	1.3%	0.41	$2,569	52.9%	0.97	$698	14.4%	1.35
By Household Income																				
Less than $5k (HH1)	4,978	4.1%	$22,960	$2,578	11.2%	$241	9.3%	0.57	$909	35.3%	0.64	$49	1.9%	0.31	$1,148	44.5%	0.43	$231	9.0%	0.45
$5k to <$10k (HH2)	5,449	4.5%	$20,884	$2,470	11.8%	$201	8.1%	0.48	$900	36.4%	0.63	$100	4.0%	0.64	$1,112	45.0%	0.42	$157	6.4%	0.30
$10k to <$15k (HH3)	8,170	6.7%	$19,959	$2,667	13.4%	$229	8.6%	0.55	$1,006	37.7%	0.71	$87	3.3%	0.55	$1,172	43.9%	0.44	$173	6.5%	0.34
$15k to <$20k (HH4)	7,745	6.3%	$24,806	$3,220	13.0%	$316	9.8%	0.75	$1,127	35.0%	0.79	$113	3.5%	0.72	$1,487	46.2%	0.56	$177	5.5%	0.34
$20k to <$30k (HH5)	14,460	11.8%	$30,398	$3,830	12.6%	$324	8.5%	0.77	$1,215	31.7%	0.85	$132	3.4%	0.84	$1,971	51.5%	0.74	$188	4.9%	0.36
$30k to <$40k (HH6)	13,328	10.9%	$36,769	$4,299	11.7%	$371	8.6%	0.88	$1,302	30.3%	0.91	$97	2.3%	0.62	$2,247	52.3%	0.85	$282	6.6%	0.55
$40k to <$50k (HH7)	11,347	9.3%	$40,306	$4,977	12.3%	$380	7.6%	0.90	$1,433	28.8%	1.01	$142	2.9%	0.90	$2,679	53.8%	1.01	$343	6.9%	0.66
$50k to <$70k (HH8)	17,376	14.2%	$50,034	$5,471	10.9%	$427	7.8%	1.02	$1,516	27.7%	1.07	$158	2.9%	1.01	$2,961	54.1%	1.12	$409	7.5%	0.79
$70k to <$80k (HH9)	7,385	6.0%	$57,977	$6,003	10.4%	$462	7.7%	1.10	$1,600	26.7%	1.12	$169	2.8%	1.08	$3,345	55.7%	1.26	$427	7.1%	0.83
$80k to <$100k (HH10)	10,456	8.6%	$65,390	$6,643	10.2%	$522	7.9%	1.24	$1,662	25.0%	1.17	$187	2.8%	1.19	$3,612	54.4%	1.36	$660	9.9%	1.28
$100k to <$120k (HH11)	7,045	5.8%	$76,496	$7,298	9.5%	$603	8.3%	1.44	$1,710	23.4%	1.20	$228	3.1%	1.45	$3,921	53.7%	1.48	$836	11.5%	1.62
$120k to <$150k (HH12)	6,107	5.0%	$87,239	$8,048	9.2%	$598	7.4%	1.42	$1,760	21.9%	1.24	$267	3.3%	1.70	$4,150	51.6%	1.56	$1,273	15.8%	2.47
$150k and more (HH13)	8,440	6.9%	$123,056	$9,551	7.8%	$779	8.2%	1.85	$2,147	22.5%	1.51	$331	3.5%	2.11	$4,267	44.7%	1.61	$2,027	21.2%	3.93

Notes: ¹ Indexed to Avg. Conusmer Unit

Table 4.1 shows three market segments: by income quintiles, by Census Region, and by household income brackets. This is only a small sample of what data are available. CEX also provides segments by reference person's age, education, occupation, and race; as well as by household size, number of wage earners, family composition and others.

Beyond the dollars spent and the percent of total energy budget per household, Table 4.1 also includes an index (or multiplier). This index shows how much a particular market segment spent compared to the average American household for a particular fuel type. For example, the lowest quintile bracket (Q1) spent $243 on natural gas. This expense for Q1 was 0.58 (58%) of what the average American household spent on natural gas (i.e. $243/$420).

4.2.2.1.2 Correlating CEX data to NEMS

The five fuel types, $i = [1:5]$, are the historical costs per household (e_i^{2011}) that interface with the NEMS price and demand forecasts in Equation 4.2. These need to be matched to corresponding price and quantity outputs from NEMS. Natural gas and electricity have direct price and quantity correlations within the NEMS Residential Sector, and matching 'fuel oil and other fuels' is simply a consumption-weighted average of propane, kerosene, and distillate fuel oil prices and quantities. 'Gasoline and motor oil' is matched to retail gasoline prices and consumption for light-duty vehicles. 'Public and other transportation' is matched to retail gasoline prices and population-weighted shares of national consumption for light duty vehicles. This last expenditure includes taxis, buses, trains, and air travel; because there is no equivalent category in NEMS, it is assumed that gasoline price and quantity changes would reasonably approximate the expected consumer response to a carbon fee policy.

To evaluate the cost of a carbon policy to the average U.S. household, one can simply insert the Average Consumer Unit fuel expenditures from the table into the total cost equation (4.2) to get Equation 4.4.

$$\sum_{i=1}^{5} e_i^y = e^y \qquad \textbf{4.4}$$

NEMS results are provided for the whole U.S. and for each of the nine Census Divisions. However, CEX is aggregated to the four Census Regions. When merging the CEX Region data to NEMS, one must first aggregate the nine Census Divisions from NEMS into the appropriate Census Region (see Table 4.2). For example, the Northeast Census Region (NE) is comprised of two Census Divisions: New England (01) and Mid Atlantic (02). The regional quantity (Q_r) is the sum of the divisional quantities (Q_d), and the regional price is weighted by the price and quantities from each division.

$$Q_{r,i}^{y} = \sum\nolimits_{d} Q_{d,i}^{y} \qquad\qquad P_{r,i}^{y} = \frac{\sum_{d}(P_{d,i}^{y} Q_{d,i}^{y})}{Q_{ri}^{y}} \tag{4.5}$$

Once the regional NEMS prices and quantities have been aggregated from the division level, Equation 4.1 becomes Equation 4.6, where r is the region of interest (e.g., NE). Combined, Equations 4.5 and 4.6 can be used to correlate any collection of child category to a parent category.

$$P_{r,i}^{y} Q_{r,i}^{y}\big|_{policy} - P_{r,i}^{y} Q_{r,i}^{y}\big|_{reference} = C_{r,i}^{y} \tag{4.6}$$

Table 4.2 Correlation between Census Regions and Census Divisions

Census Regions	Census Division	States Included
Northeast (NE)	New England (01)	ME, NH, VT, MA, RI, CT
	Middle Atlantic (02)	NY, PA, NJ
Midwest (MW)	East North Central (03)	WI, MI, IL, IN, OH
	West North Central (04)	MO, ND, SD, NE, KS, MN, IA
South (S)	South Atlantic (05)	DE, MD, DC, VA, WV, NC, SC, GA, FL
	East South Central (06)	KY, TN, MS, AL
	West South Central (07)	OK, TX, AR, LA
West (W)	Mountain (08)	ID, MT, WY, NV, UT, CO, AZ, NM
	Pacific (09)	AK, WA, OR, CA, HI

This ***direct method*** works well for the national and regional analyses since NEMS provides results equal to or at a higher resolution than that of the CEX data. However, NEMS does not track household income brackets, so an additional step is required when attempting to answer questions about distributional impacts. An example of this step can be framed around the income quintile market segment itemized in Table 4.1.

The quintile wealth brackets compare household expenditures within the same region (the U.S. in this case), so they are based on U.S. average values and one cannot distinguish regional or other differences among expenditures directly. So, while each quintile group spent a different amount on different fuel types, they are all subjected to the same average U.S. fuel prices in NEMS for this analysis. Consequently, the ratio between the expenditures of each income bracket relative to the average household represents a difference in amount spent on fuel in NEMS (See Equation 4.7). So, by scaling the quantity of each fuel type in Equation 4.6 by the appropriate index value from the table, one can estimate the quantity of fuel consumed in NEMS by each income category.

$$\frac{E_{s,i}^{2011}}{E_{i}^{2011}} = \delta_{s,i} \qquad \textbf{4.7}$$

The fuel type values in Table 4.1 represent the average expenditures within each quintile, and the values still represent the expenditures inserted into Equation 4.2; however, they are scaled by the index values. This ***index method*** provides the fraction of total expenditures from each segment. For example, households in the lowest quintile (Q1) have an index value of 0.58 for natural gas expenditure ($\delta_{Q1,natural\_gas} = 0.58$). Multiplying the total expenditures in NEMS by the CEX index values for a particular segment (δ_s), Equation 4.2 becomes:

$$\delta_{s,i} * \left(\frac{E_{i}^{2011}}{(PQ)_{i}^{2011}}\right) * C_{i}^{y} = e_{s,i}^{y} \qquad \textbf{4.8}$$

Equation 4.8 can now be used as the complete framework for any region, segment, and fuel type. In the context of the derivation, the region was the entire U.S. If the data in NEMS is of equal or higher resolution than the CEX data, then the index value (δ_s) is 1.

While this indexed method provides a good approximation of the impacts to different market segments within a region, the direct method is always preferred when possible since it more appropriately uses future prices and quantities for the segment of interest. The principal difference between these methods lies in the inherent assumptions about future prices and quantities. The index method fixes the total expenditure ratios between segments. However, in reality prices and quantities in different segments can change based on many inputs such as local policies, economies, and structural shifts.

On the other hand, the index method is very appropriate for income-based market segments since each household income bracket is indexed to regional energy consumption. There are no direct policies targeting a reduction in energy consumption in, say, the highest quintile income households. So this method will work well.

4.2.2.1.3 Limitations to using the CEX

An analysis of household impacts using the CEX has already been shown in the literature (see Section 1.3.2.2).[39] However, the broad perspective of the CEX limits the ability focus on residential energy consumption. Perhaps more importantly, the very coarse Census Region summaries are not sufficient to adequately evaluate household impacts from a carbon price policy. For example, The West (W) Census Region includes Wyoming (WY) and California (CA), yet the energy infrastructures of these states are at opposite ends of the per capita emissions spectrum (EIA, 2013c). Aggregating them together masks both the potential benefits of a carbon fee to states like CA, which have already reduced the carbon intensity of the energy supply system, and the potential costs to states like WY which have not.

While a state-level analysis is most desirable, accurate NEMS results are not yet available at this level. However, evaluating geographical regions smaller than the Census Region would improve policymakers' understanding of policy impacts to their constituents. Table 4.2 shows that within their Census Region, CA and WY are in different Census Divisions, so the ability to evaluate policy impacts at the Division

[39] Although, previous studies have not coupled CEX with detailed NEMS results.

level would be an improvement over the four Census Regions. The RECS allows this evaluation and more.

4.2.2.2 Residential Energy Consumption Survey (RECS)

The US Department of Energy's Energy Information Administration (EIA) publishes the RECS about every four years, with the latest published in early 2013 showing 2009 residential energy use data. The span between publications is unfortunate, but the report covers significant detail and coverage of all energy consumption within U.S. residential buildings. The RECS consists of two surveys: The Household Survey, which collects data on energy-related characteristics on the housing unit, usage patterns, and household demographics of a representative sample of housing units; and the Energy Supplier Survey, which collects data on how much electricity, natural gas, propane/LPG, fuel oil, and kerosene were consumed in the sampled housing unit during the reference year. It also collects data on actual dollar amounts spent on these energy sources (EIA, 2013d).

For the latest RECS, EIA tripled the number of households surveyed, which enabled the isolation of energy consumption within several individual states. Beyond results at the standard national, Census Region, and Census Division levels, RECS now includes 16 individual states, up from four states in the 2005 report. These are the 16 most populous states and represent 63% of the population. RECS is an integral part of several EIA data products and reports such as the Annual Energy Review (AER).

4.2.2.2.1 The RECS data

In many respects, the RECS data are very similar to the CEX data. However, the focus of RECS is to assess energy-related consumption and expenditures in residential buildings. It does this with less resolution on incomes brackets: thirteen household income brackets in CEX, and seven income levels in RECS (see Table 4.3). Similarly, instead of the five income quintiles found in the CEX, RECS identifies three income categories relative to the poverty line.

One noticeable gap in the RECS data, when compared to the CEX data, is the lack of transportation fuels. Since RECS is only concerned about building energy consumption, the surveyors do not ask any questions pertaining to personal vehicle expenses or other energy-related travel expenses. One could obtain household-related gasoline consumption data from EIA, but unfortunately, the latest comprehensive report was published in 2005, summarizing data from a 2001 survey (EIA, 2005). Even if it were not out of date, this report would only provide information about personal vehicles, not public transportation expenses and airline travel. As a result, recent expenditure data for these two transportation categories must come from the CEX. Since public transportation and airline travel account for over half of the average American household energy-related expenditures, the total shown from RECS for the average American household is about half of that reported in CEX.

Data on the other three fuel categories (electricity, natural gas, and other fuels) are available from the RECS, but require some manipulation to provide the format presented in Table 4.3. The published RECS data tables present fuel expenditures in terms of average expense per household using that fuel, and total expenditures for all households. For electricity, there is effectively 100% penetration in U.S. residential buildings, so the reported number is the same as the population weighted average. However, not all households have natural gas or the other fuels. For these, the average expense to the average American household is the total expenditure (for all homes) weighted by the number of households. All other fuels are aggregated, since together they represent less than 5% of average household energy expenditures.

The RECS shows similar expenditures as the CEX for each of the three overlapping fuel types. The purpose of the RECS is to accurately measure residential energy consumption, so it is likely that RECS consumption numbers are more accurate than energy-related data from the CEX. The market segments shown in Table 4.3 are only a sample of what RECS publishes. Other categories include a comparison between rural and urban households, size of the metropolitan area, climate region, housing type (e.g., single family), ownership, age and square footage of home, and others. The RECS also publishes energy consumption by end-use appliance for most of these market segments.

Table 4.3 RECS income distributions and energy expenditures for income relative to poverty, Regions, and household incomes

Market Segment	Households		Total Energy Expend.	Energy Expenditure by fuel type $/HH, % of energy expenditures, indexed to avgerage consumer								
				Natural Gas			Electricity			Fuel oil & Other Fuel		
	thous.	% of total	$/HH	$/HH	% of energy	Index[1]	$/HH	% of energy	Index[1]	$/HH	% of energy	Index[1]
Average Household												
Avg. Consumer Unit	113,600	100%	$2,024	$490	24.2%	1.00	$1,340	66.2%	1.00	$194	9.6%	1.00
Income Relative to Poverty Line												
Below 100 Percent	16,900	15%	$1,668	$400	24.0%	0.82	$1,140	68.3%	0.85	$128	7.7%	0.66
100 to 150 Percent	11,300	10%	$1,711	$421	24.6%	0.86	$1,149	67.1%	0.86	$142	8.3%	0.73
Above 150 Percent	85,500	75%	$2,134	$516	24.2%	1.05	$1,404	65.8%	1.05	$213	10.0%	1.10
By Region												
Northeast (NE)	20,800	18.3%	$2,591	$748	28.8%	1.53	$1,300	50.2%	0.97	$544	21.0%	2.81
Midwest (MW)	25,900	22.8%	$1,982	$698	35.2%	1.42	$1,114	56.2%	0.83	$170	8.6%	0.88
South (S)	42,100	37.1%	$2,037	$292	14.3%	0.60	$1,641	80.6%	1.22	$104	5.1%	0.53
West (W)	24,800	21.8%	$1,571	$392	25.0%	0.80	$1,102	70.1%	0.82	$77	4.9%	0.40
By Household Income												
Less than $20k (HH1)	23,700	20.9%	$1,573	$385	24.5%	0.79	$1,042	66.3%	0.78	$145	9.2%	0.75
$20k to <$40k (HH2)	27,500	24.2%	$1,736	$423	24.3%	0.86	$1,153	66.4%	0.86	$160	9.2%	0.83
$40k to <$60k (HH3)	21,200	18.7%	$1,975	$464	23.5%	0.95	$1,337	67.7%	1.00	$174	8.8%	0.90
$60k to <$80k (HH4)	14,200	12.5%	$2,104	$489	23.2%	1.00	$1,398	66.5%	1.04	$215	10.2%	1.11
$80k to <$100k (HH5)	9,300	8.2%	$2,338	$568	24.3%	1.16	$1,558	66.7%	1.16	$211	9.0%	1.09
$100k to <$120k (HH6)	5,700	5.0%	$2,579	$691	26.8%	1.41	$1,653	64.1%	1.23	$235	9.1%	1.21
$120k and more (HH7)	12,000	10.6%	$3,065	$745	24.3%	1.52	$1,982	64.7%	1.48	$338	11.0%	1.75

Notes: [1] Indexed to Avg. Conusmer Unit

4.2.2.2.2 Correlating RECS data to NEMS

Mathematically, to couple RECS data to NEMS outputs, one would follow the same process described for the CEX. The real benefit to using the RECS data is realized with the more refined geographic aggregations. All of the market segments in RECS are available at the Census Region level. For example, RECS provides results for average expenditure by household income level for each region. To be fair, so does the CEX; however, this is as far as the CEX goes. The RECS also provides average household expenditures for each of the Census Divisions, smaller sub-Divisions, and 16 individual states as shown in Table 4.4.

Table 4.4 RECS geographical coverage. Each line in the 'States included' column indicates the level of resolution available for average household energy expenses.

Region	Division	Sub-Division	States Included
Northeast (NE)	New England (01)		MA
			CT, ME, NH, RI, VT
	Middle Atlantic (02)		NY
			PA
			NJ
Midwest (MW)	East North Central (03)		IL
			MI
			WI
			IN, OH
	West North Central (04)		MO
			IA, MN, ND, SD
			KS, NE
South (S)	South Atlantic (05)		VA
			GA
			FL
			DC, DE, MD, WV
			NC, SC
	East South Central (06)		TN
			AL, KY, MS
	West South Central (07)		TX
			AR, LA, OK
West (W)	Mountain (08)	Mountain North	CO
			ID, MT, UT,WY
		Mountain South	AZ
			NM, NV
	Pacific (09)		CA
			AK, HI, OR, WA

When the NEMS results are as resolved as the RECS data, the ***direct method*** is used to account for changes in NEMS forecast results more effectively (e.g., Census Regions). As with the CEX, when the RECS data have a higher resolution than the NEMS results (such as market segments relating to a specific state) the ***index method*** is used to scale the quantity of each fuel type by the appropriate index value from Table 4.3. Since the geographical resolution data provide by RECS is more resolved than the Census Divisions (NEMS regional limit), the quantity of each fuel type is scaled by the appropriate index value from the table to estimate the quantity of fuel consumed in NEMS by each geographical sub-region.

4.2.2.2.3 Limitations to the RECS

The improved geographical resolution of RECS over the CEX is very exciting because it allows for an estimation of household impacts with the Census Divisions and even some individual states. However there are still some limitations. First, RECS does not include data about household transportation energy expenditures. The CEX data show that transportation costs accounts for about half of the energy expenses of the average American household. So without this data, one cannot use RECS by itself.

Second, although the RECS data is very detailed with respect to energy expenses in the residential sector, the latest publish dataset is already four years old. Furthermore, the survey results were collected prior to the latest economic crisis. Of course, the NEMS residential sub-module data and structure is based on an even older version of RECS (2005). Nonetheless, using this data will require some normalization between pre-and post-economic crisis to apply to forward projections of household economic impacts.

4.2.2.3 Merging RECS and CEX

Neither CEX nor RECS can independently answer all of the pertinent questions about household impacts from carbon fee-rebate policy scenarios. Combined, however, the two datasets are complementary and allow one to dig deeper than any previous study. Ultimately, the goal is a state-level analysis of the impacts. While neither data set provides this, the RECS offers a higher resolution than the CEX and is perhaps more accurate with respect to energy consumption within the home. So RECS is used for the first three fuel types: natural gas, electricity, and other fuels. Since RECS does not identify either of the transportation fuel expense categories, both transportation expense categories come from CEX.

Combining the two datasets poses three minor issues: the data are from different years, the data describe expenditures from opposite sides of an economic crisis, and the market segment categories do not always match. To bring the RECS data to the same monetary vintage as the CEX transportation data, the RECS 2009 results are inflated to 2011 using values from the U.S. Bureau of Economic Analysis (NBER, 2013). However, to account for the economic crisis, growth between the CEX 2009 and the CEX 2011 for each fuel expense is used scale the three non-transportation RECS 2009 categories. See Appendix 0 for the conversion derivation.

Solving the third minor issue, regarding mismatched categories between RECS and CEX, depends on whether the mismatch is between regions or income distribution levels. The CEX transportation categories are available at the Census Region level, and these values are assigned to all RECS Divisions and sub-divisions within that Region. This will diffuse any sub-Regional impacts, but will at least capture an estimate of Census Region impacts from a carbon fee on transportation-related activities. When the income market segments do not correlate directly, then less detailed RECS categories are retained and the CEX data are re-aggregated from the public-use microdata[40] (PUMD). The PUMD (from either survey) should not be aggregated to a resolution finer than that published in the official report, but the BLS has provided ample documentation for re-aggregating to the same or more coarse resolutions (BLS, 2012a, 2012b, 2012c; Swanson, 2012). A description of the process with some examples can be found in Appendix C.3.

Once harmonized and combined, the energy expenditures from CEX and RECS can be projected against their corresponding outputs from NEMS to find the total costs from any carbon policy.

4.2.3 Rebate method

Compared to incorporating the expenditure data, applying a rebate to consumers is relatively straightforward. Under Boxer–Sander, 25% of tax revenues from non-income resources must be allocated to deficit reduction to be consistent with Senate PAYGO[41] rules (CBO, 2009a). The remaining 75% could be returned to consumers in

[40] Thanks to Adam Reichenberger and Mark Vendemia at BLS for helping to explain the data, its limitations and how to re-aggregate.
[41] Please see Footnote 6 on page 12 for a definition and description of PAYGO.

the form of a rebate or recycled into the economy through incentive programs. The Senate rules regarding this deficit reduction component address relatively minor value added tax additions. However, if a fully integrated climate and energy policy were to be enacted, then the 25% earmark could be negotiable. Nonetheless, it has already been demonstrated that a rebate on the order of 50-60% is adequate to keep most households in most market segments whole (Wilkerson et al., 2014a).

This study assesses the impacts of a rebate of 40%, 50%, and 60% of the revenues. All revenue not allocated to a rebate and deficit reduction could be allocated to policy expenditures and incentives. A conservative assumption is that this has zero effect on the economy. If policy programs mitigate the impacts of a carbon fee (especially in non-household sectors), or if these programs decrease energy consumption in any sector, then the actual national GDP impact should be smaller than projected in Chapter 3. Similarly, if deficit reduction has beneficial impacts on the cost of debt service[42] or on the interest rate on government debt, then the actual GDP impacts should, again, be smaller than projected.

The rebate is distributed uniformly per capita, but the following analysis is on a per-household basis. So, regions or market segments with higher number of people per household, on average, will receive a larger rebate. Total U.S. population is obtained from the NEMS forecasts. Although this is an exogenous field in the model, NEMS uses population as one of many variables to determine the energy market equilibrium and the resulting prices and quantities. So, this population is in balance with the forecast of energy prices and quantities. Population in NEMS grows at about 0.95% annually from 318.38 million in 2013 to 350.07 in 2023.

Putting it all together, the annual rebate payment to a given household (Rev_{hh}^{y}) is the total revenue for a given year (Rev_{T}^{y}) from Table 3.2, multiplied by the rebate percentage (r%), then divided by the population for that year (pop^{y}) and scaled by the number of people per household (pph):

[42] Debt service is the cash required for a particular time period (usually one year) to cover the repayment of interest and principal on a debt

$$\frac{(r\%)\left(\mathrm{Rev}_T^y\right)}{\mathrm{pop}^y}\mathrm{pph} = \mathrm{Rev}_{hh}^y \quad \textbf{4.9}$$

4.3 ENERGY PRICES AND QUANTITIES

This section covers the forecast energy prices consumers will face under the policies for three major end-use energy resources: electricity, natural gas, and gasoline. NEMS solves for the energy-economic market equilibrium prices and quantities for every fuel type in each demand sector, and one can expect all end-use fossil fuel prices to increase under a carbon price policy.

4.3.1 Electricity

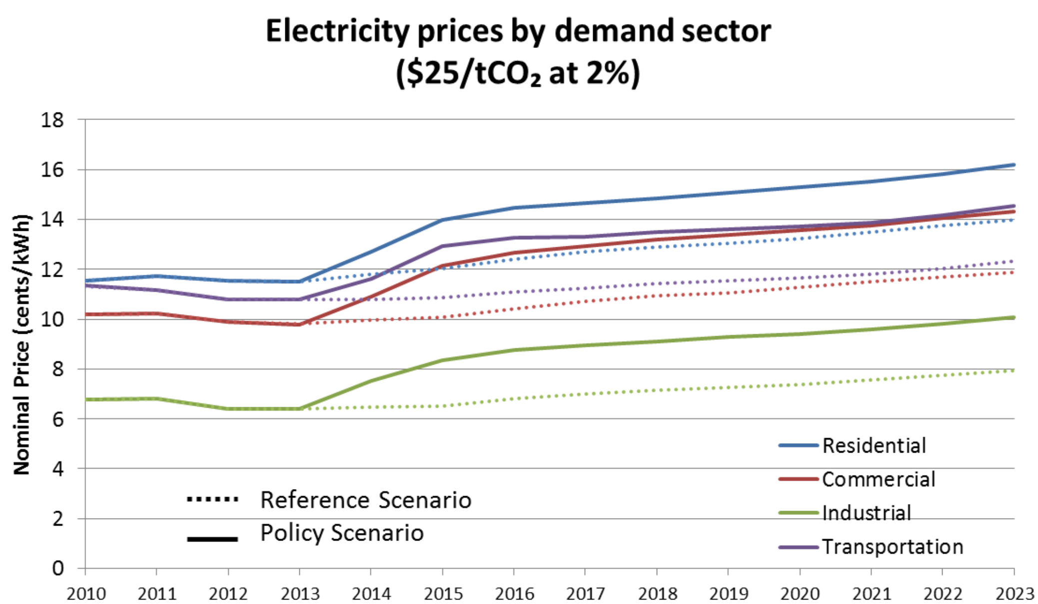

Figure 4.2 Electricity prices per sector under $\$25/tCO_2$ at 2% policy

The U.S. average electricity price in 2013 was 9.5 cents per kWh; however, each demand sector sees different prices. In general, the Residential sector is exposed to the highest price due to more costly transmission and distribution infrastructure. These customers faced 11.5 cents per kWh in 2013. Transportation and Commercial sectors were not too far behind that at 10.8 and 9.8 cents per kWh respectively. The industrial sector pays the least amount for electricity, 6.4 cents per kWh on average, since a significant portion of demand is produced on-site at cost.

Figure 4.2 illustrates electricity prices of the Reference scenario and a policy scenario. Under the Reference scenario, all sectors will experience a steady increase in electricity prices. The Residential and Commercial building sectors can expect an increase of 22% and 21%, respectively, the Industrial sector will see a 24% increase, and the Transportation sector will see only a 16% increase.

By 2023, the price impact of the policy, relative to the Reference scenario, will range from an additional 16% increase in the Residential sector to 27% in the Industrial sector. The annual price forecasts for both scenarios for each demand sector are shown in

Table 4.5. The effect of the carbon fee on prices is immediate. Most of the increase in price occurs within the first few years, after which the price trajectory of each demand sector stops diverging and roughly parallels the Reference case through the rest of the decade. This correlates well with the electricity transformation described in Section 3.4.1.

Table 4.5 Electricity prices

Electricity Prices (Nominal cents/kWh)

Sector	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total % from 2013
Reference Scenario												
Residential	11.5	11.8	12.0	12.4	12.7	12.9	13.0	13.2	13.5	13.7	14.0	21.7%
Commercial	9.8	10.0	10.1	10.4	10.7	10.9	11.1	11.3	11.5	11.7	11.9	21.1%
Industrial	6.4	6.5	6.5	6.8	7.0	7.2	7.3	7.4	7.6	7.7	7.9	23.7%
Transportation	10.8	10.8	10.9	11.1	11.3	11.4	11.5	11.7	11.8	12.0	12.3	14.0%
All Sectors Average	9.5	9.7	9.8	10.1	10.4	10.5	10.7	10.8	11.1	11.3	11.5	20.7%
Policy Scenario ($25/tCO$_2$ at 2%)												
Residential	11.5	12.7	14.0	14.5	14.7	14.9	15.1	15.3	15.5	15.8	16.2	40.9%
Commercial	9.8	10.9	12.1	12.7	12.9	13.2	13.4	13.6	13.8	14.0	14.3	46.2%
Industrial	6.4	7.5	8.4	8.8	9.0	9.1	9.3	9.4	9.6	9.8	10.1	57.4%
Transportation	10.8	11.6	12.9	13.3	13.3	13.5	13.6	13.7	13.9	14.2	14.5	34.5%
All Sectors Average	9.5	10.7	11.8	12.2	12.5	12.6	12.8	13.0	13.2	13.5	13.8	45.2%
Percent Difference												
Residential	0.0%	7.4%	16.2%	16.5%	15.6%	15.1%	15.6%	15.4%	15.1%	15.3%	15.7%	
Commercial	0.0%	9.3%	20.3%	21.5%	20.9%	20.8%	21.1%	20.5%	19.8%	20.1%	20.7%	
Industrial	0.0%	16.3%	28.6%	29.0%	27.8%	27.1%	27.8%	27.4%	26.8%	26.9%	27.2%	
Transportation	0.0%	7.5%	19.2%	19.6%	18.3%	17.9%	18.0%	17.8%	17.6%	17.9%	18.0%	
All Sectors Average	0.0%	10.0%	20.4%	21.1%	20.2%	19.9%	20.4%	20.0%	19.6%	19.8%	20.3%	

Table 4.6 Policy impacts on sector electricity prices for all scenarios in 2023

	Electricity prices (nominal cents/kWh)				
	Residential	Commercial	Industrial	Transportation	All Sectors Average
Reference (2013)	11.5	9.8	6.4	10.8	9.5
Reference (2023)	14.0	11.9	7.9	12.3	11.5
Percent change	21.7%	21.1%	23.7%	14.0%	20.7%
Scenario cents/kWh (2023)					
$15/t$CO_2$ at 2%	15.3	13.3	9.2	13.5	12.8
$15/t$CO_2$ at 4%	15.4	13.5	9.4	13.7	13.0
$15/t$CO_2$ at 6%	15.7	13.8	9.6	14.0	13.3
$15/t$CO_2$ at 8%	16.0	14.1	9.9	14.4	13.6
$25/t$CO_2$ at 2%	16.2	14.3	10.1	14.5	13.8
$25/t$CO_2$ at 4%	16.5	14.6	10.4	14.8	14.1
$25/t$CO_2$ at 6%	17.0	15.2	10.9	15.2	14.6
$25/t$CO_2$ at 8%	17.4	15.6	11.3	15.7	15.1
$35/t$CO_2$ at 2%	17.0	15.2	10.9	15.3	14.7
$35/t$CO_2$ at 4%	17.5	15.8	11.4	15.9	15.2
$35/t$CO_2$ at 6%	18.0	16.3	11.9	16.1	15.7
$35/t$CO_2$ at 8%	19.8	18.3	14.9	17.4	17.9
Scenario percent from Reference in 2023					
$15/t$CO_2$ at 2%	9.1%	11.8%	15.7%	9.8%	11.7%
$15/t$CO_2$ at 4%	10.5%	13.5%	18.3%	11.5%	13.5%
$15/t$CO_2$ at 6%	12.3%	16.1%	21.5%	13.7%	15.9%
$15/t$CO_2$ at 8%	14.5%	19.0%	25.6%	16.7%	18.8%
$25/t$CO_2$ at 2%	15.7%	20.7%	27.2%	18.0%	20.3%
$25/t$CO_2$ at 4%	17.9%	23.4%	31.2%	20.1%	23.1%
$25/t$CO_2$ at 6%	21.5%	27.9%	37.3%	23.6%	27.6%
$25/t$CO_2$ at 8%	24.5%	31.7%	43.1%	27.6%	31.6%
$35/t$CO_2$ at 2%	21.7%	28.1%	37.6%	24.4%	27.9%
$35/t$CO_2$ at 4%	25.4%	32.9%	44.0%	28.8%	32.6%
$35/t$CO_2$ at 6%	28.6%	37.1%	49.8%	31.0%	36.8%
$35/t$CO_2$ at 8%	41.3%	54.1%	88.4%	41.7%	56.3%

The annual price trajectories are similar across all policy scenarios, and Table 4.6 lists the 2023 electricity prices for each scenario by sector. Residential electricity prices could see a range of 9% - 40% increase over the Reference scenario depending on the policy scenario. While the Residential sector will experience the smallest percentage increase in prices from these scenarios, it will still remain the most expensive sector for delivered electricity due primarily to the broad transmission and distribution (T&D) network required.

Not all electricity is created equal with respect to energy and carbon intensity, so a price per unit of embodied primary energy is more useful for the subsequent Household analysis. NEMS aggregates this value in terms of $/MMBTU. The trends, of course, are very similar to those in Table 4.5, but vary slightly as the fuel mix of electricity generation changes (Please see Appendix C.4 for an example of annual costs in chained $/MMBTU). NEMS not only forecasts this aggregate price for each demand sector, but also within each of the nine Census Divisions. Table 4.7 shows the Residential electricity prices for the Reference and policy scenarios in terms of 2011$/MMBTU. The table is organized by Census Regions as well.

Table 4.7 Policy impacts on Residential electricity prices by Census Division

Residential Electricity Prices (2011 chained $/MMBtu)

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total % from 2013
Reference Scenario													
	National	32.5	33.0	33.1	33.6	33.9	33.9	33.7	33.6	33.7	33.7	33.7	3.6%
NE	New England	51.3	50.8	50.1	49.8	49.6	48.7	48.2	48.4	48.7	47.8	49.1	-4.3%
	Middle Atlantic	43.6	44.2	44.0	44.4	44.2	44.3	43.9	43.7	43.3	43.4	43.4	-0.5%
MW	East North Central	32.4	32.6	33.0	33.8	34.8	34.9	34.8	34.7	34.8	35.0	35.2	8.6%
	West North Central	28.3	29.0	29.3	30.1	30.5	30.4	30.2	30.1	30.0	30.0	30.0	5.9%
S	South Atlantic	31.6	32.3	32.6	33.2	33.4	33.5	33.3	33.2	33.0	32.9	32.8	3.8%
	East South Central	25.6	26.0	26.0	26.6	26.7	26.6	26.4	26.3	26.1	26.0	25.8	0.7%
	West South Central	27.9	28.7	28.8	29.5	29.9	30.0	30.1	30.5	31.3	32.3	32.1	15.3%
W	Mountain	29.7	30.2	30.2	30.6	31.0	31.1	30.9	30.7	30.5	30.8	31.2	5.1%
	Pacific	35.9	36.0	35.9	36.1	36.0	35.8	35.4	35.7	35.8	35.2	34.6	-3.4%
Policy Scenario ($25/t$CO_2$ at 2%)													
	National	32.5	35.2	38.0	38.7	38.7	38.5	38.4	38.3	38.3	38.3	38.5	18.2%
NE	New England	51.3	52.9	53.9	53.1	52.4	51.1	51.5	51.8	51.6	51.2	51.7	0.8%
	Middle Atlantic	43.6	45.5	49.5	50.2	49.4	49.5	49.1	48.8	48.4	48.5	48.6	11.5%
MW	East North Central	32.4	35.3	38.8	40.2	40.5	40.5	40.4	40.3	40.2	40.4	40.7	25.5%
	West North Central	28.3	31.4	34.6	35.4	35.9	35.7	35.7	35.7	35.5	35.5	35.5	25.4%
S	South Atlantic	31.6	34.7	37.4	38.1	38.0	37.9	37.7	37.6	37.4	37.3	37.3	17.8%
	East South Central	25.6	29.5	30.7	31.2	31.2	31.0	30.7	30.6	30.5	30.3	30.2	18.1%
	West South Central	27.9	29.9	34.3	35.1	35.4	35.5	36.0	36.5	37.4	38.1	38.6	38.4%
W	Mountain	29.7	32.8	34.9	35.2	35.4	35.5	35.5	35.3	35.3	35.4	35.8	20.3%
	Pacific	35.9	37.9	39.1	39.2	39.0	38.5	38.0	37.6	37.2	36.9	36.7	2.5%
Percent Difference													
	National	0.0%	6.7%	15.0%	15.1%	14.1%	13.7%	14.2%	13.9%	13.6%	13.7%	14.1%	
NE	New England	0.0%	4.0%	7.5%	6.7%	5.6%	4.9%	6.8%	7.0%	5.9%	7.1%	5.3%	
	Middle Atlantic	0.0%	2.9%	12.6%	13.2%	11.8%	11.7%	11.8%	11.7%	12.0%	11.8%	12.1%	
MW	East North Central	0.0%	8.2%	17.8%	18.8%	16.6%	16.0%	16.3%	16.2%	15.5%	15.5%	15.6%	
	West North Central	0.0%	8.1%	18.3%	17.9%	17.4%	17.6%	18.2%	18.6%	18.4%	18.5%	18.4%	
S	South Atlantic	0.0%	7.5%	14.6%	14.8%	13.9%	13.3%	13.4%	13.2%	13.1%	13.4%	13.5%	
	East South Central	0.0%	13.8%	18.2%	17.6%	16.6%	16.2%	16.2%	16.4%	16.5%	16.9%	17.3%	
	West South Central	0.0%	4.1%	19.0%	18.9%	18.4%	18.3%	19.6%	19.7%	19.3%	17.8%	20.0%	
W	Mountain	0.0%	8.7%	15.6%	15.0%	14.5%	14.3%	14.7%	15.1%	15.7%	15.2%	14.5%	
	Pacific	0.0%	5.3%	9.0%	8.7%	8.3%	7.4%	7.5%	5.2%	3.7%	5.0%	6.1%	

Table 4.8 Electric power sector fuel mix from New England and Mid Atlantic Divisions

Electric Power Sector : New England

$25/tCO$_2$ at 2%	Trillion Btu			Share of sector			% Change from 2013	
	Reference		Policy	Reference		Policy	Reference	Policy
Resource	2013	2023	2023	2013	2023	2023	2013 - 2023	2013 - 2023
Liquid Fuels	3.9	1.1	1.0	0.4%	0.1%	0.1%	-72%	-75%
Natural Gas	469.1	456.5	417.0	44.3%	42.7%	41.2%	-3%	-11%
Steam Coal	52.4	30.8	8.8	5.0%	2.9%	0.9%	-41%	-83%
Nuclear	377.9	404.9	404.9	35.7%	37.9%	40.0%	7%	7%
Renewable	116.1	144.6	143.4	11.0%	13.5%	14.2%	25%	24%
Electricity Imports	39.0	30.9	36.5	3.7%	2.9%	3.6%	-21%	-6%
Total	1058.4	1068.8	1011.6	100%	100%	100%	1%	-4%

Electric Power Sector : Middle Atlantic

$25/tCO$_2$ at 2%	Trillion Btu			Share of sector			% Change from 2013	
	Reference		Policy	Reference		Policy	Reference	Policy
Resource	2013	2023	2023	2013	2023	2023	2013 - 2023	2013 - 2023
Liquid Fuels	18.4	7.1	6.0	0.5%	0.2%	0.2%	-61%	-67%
Natural Gas	876.5	822.9	872.7	21.6%	19.9%	22.4%	-6%	0%
Steam Coal	1174.5	1139.4	789.1	28.9%	27.6%	20.3%	-3%	-33%
Nuclear	1577.0	1661.4	1661.4	38.9%	40.2%	42.7%	5%	5%
Renewable	378.7	476.4	533.1	9.3%	11.5%	13.7%	26%	41%
Electricity Imports	33.0	26.1	30.9	0.8%	0.6%	0.8%	-21%	-6%
Total	4058.0	4133.4	3893.2	100%	100%	100%	2%	-4%

Each division will experience different responses to the policy. For example, the two North East (NE) regions, New England and Mid Atlantic, paid the most for electricity in 2013. Yet the carbon policy will increase New England prices by only 5% over the Reference scenario in 2023, and by 12% in the Mid Atlantic. This disparity results from the primary energy fuels used to generate electricity in each division. Table 4.8 shows the electric power sector fuel mix for these two divisions. In 2013, coal accounted for only 5% of New England's electricity supply, but almost 30% in the Mid Atlantic. Furthermore, the Mid Atlantic consumes almost four times more electricity than New England, further amplifying the relative cost of decarbonizing the grid. These dramatically differences play a significant part in the net impacts to consumers in these different geographical regions. (Please see Appendix C.5 for electric power sector break down for all nine Census Divisions.)

Table 4.8 shows that under the policy, total electricity demand in both divisions dropped by 4% by 2023 as compared with the slight rise in demand in the

Reference scenario. The carbon fee will also increase prices, thereby reducing demand, for other energy sources. Table 4.9 shows that in all divisions, total energy demand will drop between 2013 and 2023, relative to the Reference case. In some divisions, this drop is represented by slowing demand (e.g., Mountain, West South Central), in others, demand reversal (e.g., Mid Atlantic, Pacific), and still others, a further reduction in demand (e.g., New England, East North Central).

Table 4.9 Policy impacts on Residential electricity demand by Census Division

Residential Electricity demand (Quad Btu)

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total % from 2013
Reference Scenario													
	National	4.64	4.65	4.66	4.68	4.72	4.77	4.82	4.84	4.88	4.92	4.97	7.1%
NE	New England	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	-0.7%
NE	Middle Atlantic	0.43	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	2.1%
MW	East North Central	0.62	0.61	0.61	0.61	0.60	0.60	0.60	0.60	0.60	0.60	0.60	-4.1%
MW	West North Central	0.34	0.34	0.34	0.34	0.34	0.34	0.35	0.35	0.35	0.35	0.36	4.8%
S	South Atlantic	1.17	1.18	1.18	1.19	1.21	1.22	1.24	1.25	1.27	1.29	1.30	11.8%
S	East South Central	0.40	0.40	0.40	0.41	0.41	0.41	0.42	0.42	0.43	0.43	0.44	10.1%
S	West South Central	0.69	0.71	0.72	0.72	0.73	0.74	0.76	0.76	0.77	0.77	0.78	12.7%
W	Mountain	0.32	0.33	0.33	0.33	0.34	0.35	0.35	0.36	0.37	0.37	0.38	18.8%
W	Pacific	0.50	0.49	0.49	0.49	0.49	0.50	0.50	0.50	0.50	0.50	0.51	0.8%
Policy Scenario (\$25/tCO$_2$ at 2%)													
	National	4.64	4.61	4.55	4.52	4.55	4.60	4.66	4.67	4.71	4.75	4.79	3.3%
NE	New England	0.16	0.16	0.15	0.15	0.15	0.16	0.16	0.16	0.15	0.16	0.16	-2.2%
NE	Middle Atlantic	0.43	0.44	0.43	0.42	0.42	0.43	0.43	0.43	0.43	0.43	0.43	-0.8%
MW	East North Central	0.62	0.61	0.59	0.58	0.58	0.58	0.58	0.58	0.58	0.58	0.58	-7.4%
MW	West North Central	0.34	0.33	0.33	0.32	0.33	0.33	0.33	0.33	0.34	0.34	0.34	0.0%
S	South Atlantic	1.17	1.17	1.15	1.15	1.16	1.18	1.20	1.21	1.23	1.24	1.26	7.9%
S	East South Central	0.40	0.39	0.39	0.39	0.39	0.40	0.40	0.41	0.41	0.41	0.42	5.2%
S	West South Central	0.69	0.71	0.70	0.69	0.70	0.71	0.72	0.72	0.73	0.74	0.74	7.0%
W	Mountain	0.32	0.32	0.32	0.32	0.33	0.33	0.34	0.35	0.35	0.36	0.36	14.4%
W	Pacific	0.50	0.49	0.48	0.48	0.48	0.49	0.49	0.49	0.49	0.50	0.50	-0.5%
Percent Difference													
	National	0.0%	-0.9%	-2.5%	-3.5%	-3.7%	-3.5%	-3.5%	-3.5%	-3.5%	-3.5%	-3.6%	
NE	New England	0.0%	-0.5%	-1.2%	-1.5%	-1.5%	-1.3%	-1.4%	-1.5%	-1.5%	-1.6%	-1.5%	
NE	Middle Atlantic	0.0%	-0.4%	-1.7%	-2.6%	-2.8%	-2.7%	-2.7%	-2.7%	-2.8%	-2.8%	-2.9%	
MW	East North Central	0.0%	-0.9%	-2.6%	-3.6%	-3.7%	-3.5%	-3.4%	-3.4%	-3.4%	-3.4%	-3.4%	
MW	West North Central	0.0%	-1.0%	-3.0%	-4.1%	-4.3%	-4.3%	-4.3%	-4.4%	-4.4%	-4.5%	-4.5%	
S	South Atlantic	0.0%	-1.0%	-2.6%	-3.5%	-3.7%	-3.5%	-3.4%	-3.4%	-3.4%	-3.4%	-3.5%	
S	East South Central	0.0%	-1.8%	-3.6%	-4.5%	-4.5%	-4.3%	-4.2%	-4.2%	-4.2%	-4.3%	-4.5%	
S	West South Central	0.0%	-0.6%	-3.0%	-4.5%	-4.9%	-4.8%	-4.9%	-5.0%	-5.0%	-4.9%	-5.1%	
W	Mountain	0.0%	-1.1%	-2.6%	-3.5%	-3.6%	-3.5%	-3.5%	-3.6%	-3.7%	-3.8%	-3.7%	
W	Pacific	0.0%	-0.6%	-1.5%	-2.0%	-2.0%	-1.9%	-1.8%	-1.6%	-1.2%	-1.2%	-1.4%	

4.3.2 Natural Gas

As with electricity, a carbon fee will increase the cost of natural gas, and Figure 4.3 illustrates natural gas prices of the Reference scenario and a policy scenario. Under the Reference scenario, all sectors will experience a steady increase in electricity prices. The Residential and Commercial building sectors can expect an increase of about 39%, the Industrial sector will see a 63% increase, and the Transportation sector will see only a 30% increase.

By 2023, the impact of the policy on prices over the Reference scenario will range from an additional 13% increase in the Transportation sector to 37% in the Industrial sector. The annual price forecasts for both scenarios for each demand sector are shown in Table 4.10. As with electricity, most of the price increase occurs within the first few years, after which the price trajectory of each demand sector roughly parallels the Reference case through the rest of the decade.

The annual price trajectories are similar across all policy scenarios, and Table 4.11 lists the 2023 natural gas prices for each scenario by sector. Residential electricity prices could see a range of a 20-50% increase over the Reference scenario, from the most lenient policy scenario to the most aggressive.

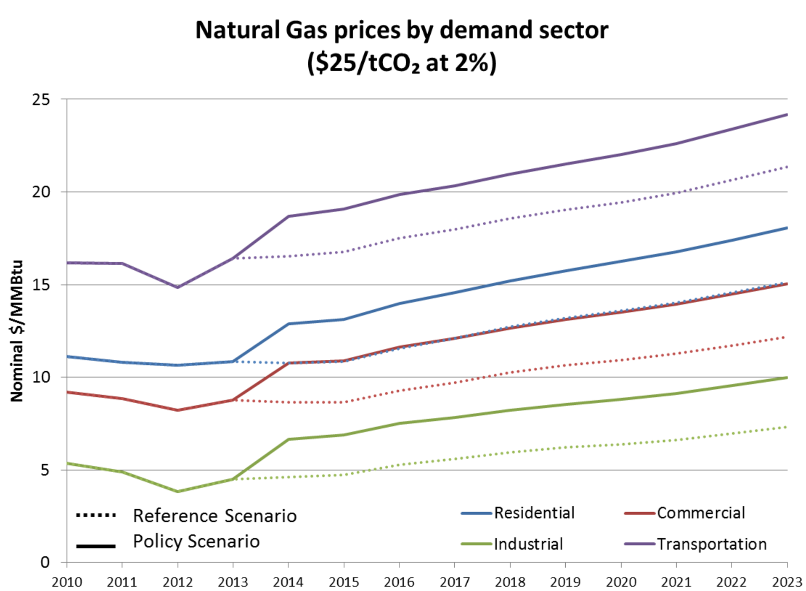

Figure 4.3 Natural gas prices per sector under $25/tCO_2$ at 2% policy

Table 4.10 Policy impacts on natural gas prices by sector

Sector	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total % from 2013
	Natural Gas Prices (nominal $/MMBtu)											
Reference Scenario												
Residential	10.8	10.8	10.8	11.6	12.1	12.7	13.2	13.6	14.0	14.6	15.1	39.4%
Commercial	8.8	8.6	8.6	9.3	9.7	10.3	10.6	10.9	11.3	11.7	12.2	39.0%
Industrial	4.5	4.6	4.7	5.3	5.6	6.0	6.2	6.4	6.6	7.0	7.3	63.0%
Transportation	16.4	16.5	16.8	17.5	18.0	18.6	19.0	19.4	20.0	20.6	21.3	30.1%
All Sectors Average	6.2	6.2	6.3	6.8	7.2	7.6	7.9	8.2	8.5	8.8	9.2	48.5%
Policy Scenario ($25/tCO$_2$ at 2%)												
Residential	10.8	12.9	13.1	14.0	14.6	15.2	15.7	16.2	16.8	17.4	18.1	66.4%
Commercial	8.8	10.7	10.9	11.6	12.1	12.7	13.1	13.5	13.9	14.5	15.0	71.5%
Industrial	4.5	6.7	6.9	7.5	7.8	8.2	8.5	8.8	9.1	9.5	10.0	122.6%
Transportation	16.4	18.7	19.1	19.9	20.3	21.0	21.5	22.0	22.6	23.4	24.2	47.4%
All Sectors Average	6.2	8.2	8.4	9.0	9.4	9.9	10.2	10.6	10.9	11.4	11.9	91.1%
Percent Difference												
Residential	0.0%	19.6%	21.2%	20.9%	20.3%	19.4%	19.2%	19.6%	19.5%	19.5%	19.4%	
Commercial	0.0%	24.3%	26.1%	25.4%	24.6%	23.5%	23.3%	23.7%	23.6%	23.6%	23.4%	
Industrial	0.0%	45.0%	45.7%	42.0%	39.9%	38.1%	37.7%	38.2%	37.8%	37.3%	36.6%	
Transportation	0.0%	13.3%	13.7%	13.5%	13.1%	12.8%	12.9%	13.2%	13.2%	13.3%	13.3%	
All Sectors Average	0.0%	31.7%	33.1%	32.0%	30.7%	29.3%	29.1%	29.5%	29.3%	29.1%	28.7%	

Table 4.11 Policy impacts on sector natural gas prices for all scenarios in 2023

	Residential	Commercial	Industrial	Transportation	All Sectors Average
	Natural Gas prices (nominal $/MMBtu)				
Reference (2013)	10.8	8.8	4.5	16.4	6.2
Reference (2023)	15.1	12.2	7.3	21.3	9.2
Percent change	39.4%	39.0%	63.0%	30.1%	48.5%
Scenario nominal $/MMBtu (2023)					
$15/tCO$_2$ at 2%	16.8	13.8	8.8	23.0	10.7
$15/tCO$_2$ at 4%	17.0	14.0	9.0	23.2	10.9
$15/tCO$_2$ at 6%	17.4	14.4	9.4	23.5	11.3
$15/tCO$_2$ at 8%	17.8	14.8	9.7	23.9	11.6
$25/tCO$_2$ at 2%	18.1	15.0	10.0	24.2	11.9
$25/tCO$_2$ at 4%	18.6	15.5	10.5	24.7	12.3
$25/tCO$_2$ at 6%	19.2	16.1	11.0	25.2	12.9
$25/tCO$_2$ at 8%	19.8	16.7	11.6	25.8	13.4
$35/tCO$_2$ at 2%	19.3	16.3	11.2	25.4	13.0
$35/tCO$_2$ at 4%	20.0	16.9	11.8	26.1	13.6
$35/tCO$_2$ at 6%	20.6	17.5	12.3	26.6	14.1
$35/tCO$_2$ at 8%	21.3	18.2	12.9	27.4	14.8
Scenario percent from Reference in 2023					
$15/tCO$_2$ at 2%	20.0%	16.1%	11.2%	86.5%	-6.5%
$15/tCO$_2$ at 4%	21.7%	18.0%	13.9%	88.4%	-4.8%
$15/tCO$_2$ at 6%	24.3%	21.0%	18.2%	91.3%	-1.9%
$15/tCO$_2$ at 8%	27.1%	24.3%	22.9%	94.3%	1.2%
$25/tCO$_2$ at 2%	29.1%	26.6%	26.1%	96.4%	3.5%
$25/tCO$_2$ at 4%	32.9%	30.9%	32.3%	100.6%	7.5%
$25/tCO$_2$ at 6%	37.0%	35.7%	39.1%	105.1%	12.0%
$25/tCO$_2$ at 8%	41.6%	41.0%	46.7%	109.8%	17.0%
$35/tCO$_2$ at 2%	38.1%	37.0%	40.9%	106.1%	13.5%
$35/tCO$_2$ at 4%	43.0%	42.6%	48.8%	111.7%	18.6%
$35/tCO$_2$ at 6%	47.3%	47.5%	55.7%	116.2%	23.2%
$35/tCO$_2$ at 8%	52.5%	53.3%	63.4%	122.4%	28.8%

NEMS also forecasts natural gas prices by sector and Census Division. Residential natural gas prices ranged from $9/MMBTU to over $13/MMBTU in 2013 (See Table 4.12). In the Reference scenario, all regions are expected to face increased natural gas prices. In general, the Census Divisions that currently have lower prices will experience larger price increases. By the end of the decade, the range of natural gas prices across all divisions will be much narrower. Under the policy all divisions will see a relatively uniform additional increase of between 15 and 29% over the Reference scenario.

Table 4.12 Policy impacts on Residential natural gas prices by Census Division

		Residential Natural Gas Prices (2011 chained $/MMBtu)											
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total % from 2013
Reference Scenario													
	National	10.5	10.3	10.2	10.7	11.0	11.4	11.6	11.8	12.0	12.2	12.4	18.7%
NE	New England	13.3	13.1	12.9	13.4	13.7	14.1	14.3	14.5	14.6	14.8	15.0	12.6%
NE	Middle Atlantic	12.1	11.9	11.8	12.2	12.5	12.8	13.0	13.1	13.2	13.4	13.6	12.6%
MW	East North Central	9.1	8.8	8.5	9.1	9.4	9.8	10.0	10.1	10.3	10.5	10.7	17.3%
MW	West North Central	9.4	9.1	8.8	9.3	9.7	10.2	10.4	10.6	10.7	10.9	11.1	18.9%
S	South Atlantic	12.9	12.5	12.3	12.8	13.1	13.4	13.6	13.7	13.9	14.2	14.4	12.2%
S	East South Central	11.2	11.1	10.9	11.4	11.8	12.1	12.3	12.4	12.6	12.9	13.2	17.8%
S	West South Central	10.0	9.8	9.6	10.1	10.3	10.6	10.7	10.8	10.9	11.2	11.4	14.3%
W	Mountain	9.4	9.3	9.1	9.7	10.1	10.5	10.8	10.9	11.2	11.5	11.8	25.4%
W	Pacific	9.9	9.7	10.4	11.0	11.5	12.0	12.4	12.5	12.8	13.0	13.2	34.0%
Policy Scenario ($25/t$CO_2$ at 2%)													
	National	10.5	12.2	12.2	12.8	13.1	13.5	13.7	13.9	14.1	14.4	14.6	39.6%
NE	New England	13.3	15.0	14.9	15.5	15.8	16.2	16.5	16.7	16.8	17.1	17.3	29.6%
NE	Middle Atlantic	12.1	13.9	13.8	14.3	14.5	14.9	15.1	15.3	15.4	15.7	15.9	31.5%
MW	East North Central	9.1	10.7	10.6	11.1	11.5	11.8	12.1	12.2	12.4	12.7	12.9	41.5%
MW	West North Central	9.4	10.9	10.8	11.4	11.8	12.2	12.4	12.6	12.9	13.1	13.3	42.1%
S	South Atlantic	12.9	14.5	14.3	14.9	15.2	15.5	15.7	15.9	16.1	16.4	16.7	30.0%
S	East South Central	11.2	13.0	13.0	13.6	13.9	14.2	14.4	14.6	14.8	15.2	15.5	38.3%
S	West South Central	10.0	11.8	11.6	12.2	12.4	12.7	12.9	13.0	13.1	13.4	13.7	36.8%
W	Mountain	9.4	11.2	11.1	11.7	12.1	12.5	12.8	13.0	13.3	13.6	13.9	47.4%
W	Pacific	9.9	11.6	12.4	13.0	13.4	13.9	14.2	14.5	14.8	15.0	15.2	54.2%
Percent Difference													
	National	0.0%	18.8%	20.0%	19.5%	18.8%	18.0%	17.7%	18.0%	17.9%	17.9%	17.7%	
NE	New England	0.0%	14.7%	15.4%	15.6%	15.2%	14.8%	14.7%	14.9%	15.1%	15.3%	15.2%	
NE	Middle Atlantic	0.0%	16.6%	17.0%	17.1%	16.7%	16.5%	16.4%	16.7%	16.8%	16.9%	16.8%	
MW	East North Central	0.0%	21.8%	24.1%	23.2%	22.2%	20.9%	20.7%	21.0%	21.0%	20.9%	20.7%	
MW	West North Central	0.0%	20.3%	22.9%	22.2%	21.3%	19.7%	19.3%	19.8%	19.7%	19.7%	19.5%	
S	South Atlantic	0.0%	15.8%	16.9%	16.7%	16.3%	15.9%	16.0%	16.0%	15.9%	16.0%	15.8%	
S	East South Central	0.0%	17.8%	19.2%	18.8%	18.1%	17.6%	17.8%	17.7%	17.7%	17.6%	17.4%	
S	West South Central	0.0%	19.9%	21.5%	21.0%	20.3%	19.7%	20.0%	20.0%	20.0%	19.8%	19.7%	
W	Mountain	0.0%	20.1%	21.7%	20.5%	19.8%	18.8%	18.2%	19.0%	18.5%	17.9%	17.5%	
W	Pacific	0.0%	19.2%	19.0%	17.8%	17.1%	16.0%	15.2%	15.8%	15.4%	15.2%	15.1%	

Table 4.13 Policy impacts on Residential natural gas demand by Census Division

		Residential Natural Gas Demand (Quad Btu)											
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total % from 2013
Reference Scenario													
	National	4.93	4.78	4.76	4.73	4.70	4.66	4.64	4.62	4.61	4.59	4.57	-7.3%
NE	New England	0.21	0.21	0.21	0.21	0.20	0.20	0.20	0.20	0.20	0.20	0.20	-6.2%
NE	Middle Atlantic	0.90	0.86	0.86	0.85	0.84	0.84	0.83	0.83	0.82	0.82	0.81	-9.1%
MW	East North Central	1.33	1.29	1.28	1.26	1.24	1.22	1.21	1.19	1.18	1.17	1.15	-13.2%
MW	West North Central	0.43	0.42	0.42	0.42	0.41	0.41	0.40	0.40	0.40	0.39	0.39	-9.7%
S	South Atlantic	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.46	0.46	0.46	0.46	1.5%
S	East South Central	0.18	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.15	0.15	0.15	-15.5%
S	West South Central	0.34	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	-2.4%
W	Mountain	0.39	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	-2.7%
W	Pacific	0.69	0.68	0.68	0.67	0.67	0.67	0.67	0.68	0.68	0.68	0.68	-1.0%
Policy Scenario (\$25/tCO$_2$ at 2%)													
	National	4.93	4.70	4.63	4.58	4.55	4.52	4.50	4.48	4.47	4.45	4.43	-10.1%
NE	New England	0.21	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.19	-8.4%
NE	Middle Atlantic	0.90	0.85	0.84	0.83	0.82	0.81	0.81	0.81	0.80	0.80	0.79	-11.7%
MW	East North Central	1.33	1.26	1.24	1.21	1.20	1.18	1.16	1.15	1.14	1.12	1.11	-16.3%
MW	West North Central	0.43	0.41	0.41	0.40	0.40	0.39	0.39	0.39	0.38	0.38	0.38	-12.7%
S	South Atlantic	0.45	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.45	0.45	-1.5%
S	East South Central	0.18	0.17	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.15	0.14	-18.4%
S	West South Central	0.34	0.33	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.33	-5.3%
W	Mountain	0.39	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	-5.5%
W	Pacific	0.69	0.67	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.67	-3.4%
Percent Difference													
	National	0.0%	-1.6%	-2.7%	-3.2%	-3.2%	-3.1%	-3.0%	-3.0%	-3.0%	-3.0%	-3.0%	
NE	New England	0.0%	-1.1%	-1.9%	-2.3%	-2.3%	-2.3%	-2.3%	-2.3%	-2.3%	-2.4%	-2.4%	
NE	Middle Atlantic	0.0%	-1.4%	-2.3%	-2.8%	-2.8%	-2.7%	-2.7%	-2.7%	-2.8%	-2.8%	-2.8%	
MW	East North Central	0.0%	-1.9%	-3.3%	-3.9%	-3.8%	-3.7%	-3.6%	-3.6%	-3.6%	-3.6%	-3.6%	
MW	West North Central	0.0%	-1.7%	-3.1%	-3.7%	-3.7%	-3.5%	-3.3%	-3.3%	-3.3%	-3.3%	-3.3%	
S	South Atlantic	0.0%	-1.4%	-2.4%	-2.8%	-2.8%	-2.8%	-2.8%	-2.8%	-2.9%	-2.9%	-2.9%	
S	East South Central	0.0%	-1.6%	-2.9%	-3.4%	-3.4%	-3.4%	-3.4%	-3.4%	-3.5%	-3.5%	-3.5%	
S	West South Central	0.0%	-1.5%	-2.7%	-3.2%	-3.1%	-3.0%	-3.0%	-3.0%	-3.0%	-3.0%	-3.0%	
W	Mountain	0.0%	-1.6%	-2.8%	-3.3%	-3.2%	-3.1%	-3.0%	-3.0%	-3.0%	-2.9%	-2.8%	
W	Pacific	0.0%	-1.4%	-2.4%	-2.7%	-2.7%	-2.6%	-2.4%	-2.4%	-2.4%	-2.5%	-2.5%	

Table 4.13 shows that, despite large natural gas price increases, total energy demand will only be reduced by a few percent in each division over the Reference scenario. Unlike electricity, the carbon content of natural gas is fixed. Residential consumers using natural gas directly must change either behavior or upgrade to a more efficiency technology to lessen the carbon fee impact.

4.3.3 Gasoline

Table 4.14 shows how gasoline prices will change in the Reference scenario and a policy scenario. Under the Reference scenario, gasoline prices will rise steadily from

$3.24/gallon (U.S. average) to $3.45/gallon. This modest, single-digit percentage increase will be similar in all Census Divisions. The policy scenario will increase prices by an additional 6%-8% over the Reference scenario by 2023.

In the Reference scenario, demand is expected to drop across the board, with the greatest decrease coming from the Midwest and Northeast regions. As with natural gas (See Table 4.15), the policy is expected to reduce demand by less than 1.5% in every division.

Table 4.14 Policy impacts on gasoline prices by Census Division

		Gasoline Prices (2011 chained $/gallon)											
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total % from 2013
Reference Scenario													
	National	3.24	3.17	3.12	3.12	3.15	3.19	3.26	3.32	3.38	3.43	3.45	6.7%
NE	New England	3.30	3.28	3.23	3.22	3.25	3.29	3.35	3.42	3.48	3.52	3.55	7.3%
	Middle Atlantic	3.28	3.23	3.19	3.18	3.20	3.25	3.30	3.38	3.43	3.48	3.51	7.0%
MW	East North Central	3.21	3.14	3.08	3.09	3.12	3.16	3.22	3.28	3.34	3.38	3.39	5.6%
	West North Central	3.14	3.08	3.04	3.03	3.05	3.10	3.16	3.23	3.28	3.33	3.36	7.0%
S	South Atlantic	3.20	3.13	3.09	3.08	3.11	3.15	3.22	3.28	3.34	3.39	3.42	7.0%
	East South Central	3.20	3.07	3.03	3.02	3.04	3.09	3.15	3.22	3.27	3.32	3.35	4.7%
	West South Central	3.16	3.07	3.02	3.01	3.04	3.08	3.14	3.20	3.26	3.30	3.33	5.2%
W	Mountain	3.25	3.18	3.15	3.14	3.18	3.23	3.29	3.35	3.41	3.46	3.48	7.1%
	Pacific	3.38	3.33	3.28	3.30	3.33	3.40	3.47	3.55	3.60	3.65	3.68	8.7%
Policy Scenario ($25/t$CO_2$ at 2%)													
	National	3.24	3.37	3.31	3.32	3.37	3.42	3.47	3.56	3.60	3.66	3.69	14.2%
NE	New England	3.30	3.48	3.42	3.42	3.47	3.51	3.57	3.66	3.69	3.75	3.79	14.6%
	Middle Atlantic	3.28	3.43	3.38	3.38	3.42	3.47	3.52	3.61	3.65	3.71	3.75	14.3%
MW	East North Central	3.21	3.34	3.28	3.28	3.33	3.38	3.44	3.53	3.57	3.62	3.66	13.8%
	West North Central	3.14	3.28	3.23	3.23	3.28	3.33	3.39	3.47	3.52	3.57	3.60	14.7%
S	South Atlantic	3.20	3.33	3.28	3.28	3.33	3.38	3.44	3.52	3.57	3.63	3.66	14.5%
	East South Central	3.20	3.27	3.22	3.22	3.26	3.31	3.37	3.46	3.50	3.56	3.59	12.3%
	West South Central	3.16	3.27	3.21	3.21	3.26	3.30	3.36	3.44	3.48	3.54	3.57	12.9%
W	Mountain	3.25	3.38	3.33	3.33	3.39	3.44	3.50	3.58	3.63	3.69	3.72	14.3%
	Pacific	3.38	3.53	3.47	3.49	3.56	3.62	3.68	3.77	3.82	3.87	3.91	15.5%
Percent Difference													
	National	0.0%	6.3%	6.2%	6.3%	7.0%	7.0%	6.7%	7.1%	6.6%	6.8%	7.0%	
NE	New England	0.0%	6.1%	5.9%	6.2%	6.8%	6.8%	6.6%	6.9%	6.3%	6.6%	6.8%	
	Middle Atlantic	0.0%	6.2%	6.0%	6.3%	6.9%	6.9%	6.7%	7.0%	6.5%	6.7%	6.9%	
MW	East North Central	0.0%	6.5%	6.5%	6.3%	6.8%	6.9%	6.7%	7.5%	7.0%	7.3%	7.8%	
	West North Central	0.0%	6.6%	6.3%	6.6%	7.4%	7.5%	7.2%	7.7%	7.0%	7.1%	7.2%	
S	South Atlantic	0.0%	6.4%	6.2%	6.5%	7.1%	7.2%	6.9%	7.3%	6.7%	6.8%	7.1%	
	East South Central	0.0%	6.5%	6.3%	6.6%	7.3%	7.3%	7.1%	7.4%	6.8%	7.0%	7.2%	
	West South Central	0.0%	6.5%	6.3%	6.6%	7.3%	7.3%	7.1%	7.4%	6.7%	7.1%	7.3%	
W	Mountain	0.0%	6.4%	5.9%	6.0%	6.7%	6.6%	6.4%	6.9%	6.4%	6.7%	6.8%	
	Pacific	0.0%	5.9%	5.9%	5.9%	6.8%	6.4%	6.2%	6.3%	5.9%	6.1%	6.3%	

Table 4.15 Policy impacts on gasoline demand by Census Division

		Gasoine demand (Quad Btu)											
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total % from 2013
Reference Scenario													
	National	15.86	15.50	15.39	15.30	15.21	15.11	14.99	14.88	14.69	14.48	14.29	-9.9%
NE	New England	0.74	0.72	0.72	0.71	0.70	0.69	0.68	0.67	0.66	0.65	0.64	-14.1%
	Middle Atlantic	1.74	1.70	1.68	1.66	1.64	1.61	1.59	1.56	1.53	1.50	1.47	-15.7%
MW	East North Central	2.30	2.19	2.15	2.11	2.08	2.06	2.03	2.02	1.97	1.92	1.88	-18.4%
	West North Central	1.18	1.13	1.12	1.11	1.10	1.09	1.07	1.07	1.05	1.02	1.00	-15.1%
S	South Atlantic	3.30	3.26	3.26	3.26	3.26	3.25	3.24	3.22	3.20	3.18	3.15	-4.4%
	East South Central	1.12	1.09	1.08	1.07	1.06	1.05	1.04	1.03	1.01	1.00	0.98	-12.0%
	West South Central	2.08	2.05	2.05	2.04	2.04	2.03	2.02	2.01	2.00	1.98	1.96	-5.8%
W	Mountain	1.08	1.08	1.08	1.08	1.08	1.09	1.09	1.08	1.08	1.07	1.07	-1.5%
	Pacific	2.31	2.28	2.27	2.26	2.25	2.24	2.22	2.20	2.18	2.16	2.14	-7.4%
Policy Scenario ($25/t$CO_2$ at 2%)													
	National	15.86	15.44	15.28	15.17	15.06	14.94	14.81	14.69	14.49	14.29	14.09	-11.1%
NE	New England	0.74	0.72	0.71	0.70	0.69	0.68	0.67	0.66	0.65	0.64	0.63	-15.4%
	Middle Atlantic	1.74	1.69	1.66	1.64	1.62	1.59	1.57	1.54	1.51	1.48	1.45	-16.9%
MW	East North Central	2.30	2.19	2.14	2.10	2.09	2.06	2.02	2.01	1.95	1.91	1.87	-18.8%
	West North Central	1.18	1.13	1.11	1.10	1.09	1.07	1.06	1.06	1.03	1.00	0.99	-16.3%
S	South Atlantic	3.30	3.25	3.23	3.22	3.22	3.21	3.20	3.18	3.16	3.13	3.11	-5.8%
	East South Central	1.12	1.09	1.07	1.06	1.05	1.04	1.03	1.02	1.00	0.98	0.97	-13.3%
	West South Central	2.08	2.05	2.03	2.02	2.02	2.01	2.00	1.98	1.97	1.95	1.93	-7.2%
W	Mountain	1.08	1.07	1.07	1.07	1.07	1.07	1.07	1.07	1.06	1.06	1.05	-3.0%
	Pacific	2.31	2.27	2.25	2.24	2.22	2.21	2.19	2.17	2.15	2.13	2.11	-8.8%
Percent Difference													
	National	0.0%	-0.4%	-0.7%	-0.9%	-1.0%	-1.1%	-1.2%	-1.3%	-1.4%	-1.3%	-1.4%	
NE	New England	0.0%	-0.4%	-0.8%	-1.0%	-1.2%	-1.3%	-1.3%	-1.4%	-1.4%	-1.5%	-1.5%	
	Middle Atlantic	0.0%	-0.4%	-0.8%	-1.0%	-1.2%	-1.3%	-1.3%	-1.4%	-1.4%	-1.5%	-1.5%	
MW	East North Central	0.0%	-0.3%	-0.6%	-0.2%	0.3%	-0.1%	-0.5%	-0.6%	-1.3%	-0.6%	-0.5%	
	West North Central	0.0%	0.1%	-0.5%	-0.8%	-0.9%	-1.2%	-1.2%	-1.3%	-2.0%	-1.4%	-1.4%	
S	South Atlantic	0.0%	-0.4%	-0.8%	-1.0%	-1.2%	-1.3%	-1.3%	-1.4%	-1.4%	-1.5%	-1.5%	
	East South Central	0.0%	-0.4%	-0.8%	-1.0%	-1.2%	-1.3%	-1.3%	-1.4%	-1.4%	-1.5%	-1.5%	
	West South Central	0.0%	-0.4%	-0.8%	-1.0%	-1.2%	-1.3%	-1.3%	-1.4%	-1.4%	-1.5%	-1.5%	
W	Mountain	0.0%	-0.4%	-0.8%	-1.0%	-1.2%	-1.3%	-1.3%	-1.4%	-1.4%	-1.5%	-1.5%	
	Pacific	0.0%	-0.4%	-0.8%	-1.0%	-1.2%	-1.3%	-1.3%	-1.4%	-1.4%	-1.5%	-1.5%	

4.4 AVERAGE AMERICAN HOUSEHOLD IMPACTS

Once the expenditure data has been re-aggregated, one can assess the household costs from carbon policy scenarios, as well as the benefits of different rebate scenarios, across market segments. Evaluating the impacts to the average American household will fully illustrate the process defined above.

4.4.1 Policy costs

First, the net difference in total Residential sector expenditures between the Reference and each policy scenario is determined from the NEMS results. Table 4.16 shows the total energy expenditures for the baseline and the \$25/tCO_2 at 2% policy scenario for each of the five categories. The expenditures in the table represent the terms defined in Equation 4.1, where the first section of the table is the product of price and quantity for each fuel in each year for the baseline scenario; the second section is the product of price and quantity for the policy scenario; and the third section provides the difference, or right-hand-side of the equation. This last section represents the total direct cost of the policy by fuel type per year.

Table 4.16 Total Residential energy expenditures for the Reference and policy scenario

	Total Expenditures (All units in billion 2011 chained USD)									
Fuel Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Baseline Scenario										
Electricity	$153.61	$154.23	$157.39	$159.83	$161.37	$162.40	$162.86	$164.20	$165.81	$167.42
Natural Gas	$48.97	$48.34	$50.51	$51.75	$53.20	$54.02	$54.45	$55.14	$55.99	$56.81
Fuel Oil	$26.85	$26.13	$26.01	$26.21	$26.21	$26.24	$26.30	$26.30	$26.30	$26.30
Gasoline	$395.06	$386.53	$383.95	$385.03	$388.35	$392.83	$398.03	$399.75	$399.52	$397.02
Other Transportation	$395.06	$386.53	$383.95	$385.03	$388.35	$392.83	$398.03	$399.75	$399.52	$397.02
Policy Scenario (\$25/tCO_2 at 2%)										
Electricity	$162.45	$172.91	$174.81	$175.76	$177.06	$178.91	$179.07	$180.07	$181.92	$184.18
Natural Gas	$57.25	$56.43	$58.40	$59.52	$60.82	$61.68	$62.34	$63.06	$63.98	$64.84
Fuel Oil	$28.63	$28.04	$27.93	$28.03	$28.08	$28.07	$28.05	$28.02	$28.01	$27.97
Gasoline	$418.52	$407.26	$404.73	$407.96	$410.89	$414.35	$421.05	$420.07	$421.01	$419.12
Other Transportation	$418.52	$407.26	$404.73	$407.96	$410.89	$414.35	$421.05	$420.07	$421.01	$419.12
Difference (Policy - Baseline)										
Electricity	$8.85	$18.68	$17.42	$15.92	$15.69	$16.51	$16.21	$15.87	$16.11	$16.76
Natural Gas	$8.28	$8.10	$7.90	$7.77	$7.63	$7.65	$7.89	$7.92	$8.00	$8.03
Fuel Oil	$1.78	$1.91	$1.92	$1.81	$1.87	$1.83	$1.75	$1.72	$1.71	$1.67
Gasoline	$23.46	$20.73	$20.78	$22.93	$22.54	$21.52	$23.02	$20.33	$21.49	$22.10
Other Transportation	$23.46	$20.73	$20.78	$22.93	$22.54	$21.52	$23.02	$20.33	$21.49	$22.10

The next step is to determine the known expenditure per household. This requires the surveyed, historic, per-household expenditure data and the NEMS historic total expenditure for each fuel. The survey results for house-related energy are obtained from RECS, and these are shown in the first column of Table 4.17. Since these data are from 2009, they need to be inflated to 2011, but they also need to be scaled to reflect the change in demand between 2009 and 2011, that is described in Section 4.2.2.3. The scale factors are in the second column of the table and the result of the scaling is included the 'Final 2011 HH Expenditure' column. Below those three line items are the two travel-related expenditures obtained directly from CEX.

Table 4.17 Household (HH) expenditures and total expenditure

	RECS 2009 HH Expend. ($/HH)	RECS 2009 Scale RECS 2009 to 2011[1]	CEX 2011 HH Expend.	Final 2011 HH Expenditures[2] ($/HH)	Final 2011 HH Expenditures[2] (%)	NEMS 2011 Total Expenditure[3] (billion $)
Electricity	$1,340.49	0.8696		$1,215.64	23.7%	$166.79
Natural Gas	$490.05	1.0334		$528.15	10.3%	$52.18
Fuel Oil	$193.75	1.1135		$224.99	4.4%	$29.34
Gasoline			$2,655.00	$2,655.00	51.7%	$449.34
Other Transportation			$516.00	$516.00	10.0%	$449.34
Totals				$5,139.78		$1,146.98

Notes

[1] Scale RECS 2009 data to estimate 2011 expenditure, based on the change in expenditure betw een CEX 2009 and 2011. Also need BEA inflator from 2009 to 2011 (=1.0428927679)

[2] Electricity, Natural gas, and Fuel Oil are RECS 2009, then scaled by column 2; gasoline and Other Transportation are from CES 2011

[3] Price x quantity in 2011 for each fuel from NEMS. Units are billion 2011 chained USD

Combined, the average American HH spent $5,140 on energy, which represents 10% of total household expenditures as reported by CEX. Slightly more than half of this expenditure was on gasoline. The average American household energy expenditures are illustrated in Figure 4.4.

The NEMS historic total expenditure is in the last column of Table 4.17. This looks very much like the results in Table 4.16, but these values are from 2011. The ratio of final per-household expenditure and the NEMS 2011 total expenditure defines the fraction of total energy consumed by a single household. The values in Table 4.17 are constant for all scenarios (for the average American household) since all the values in this table are historical. However, the results in Table 4.16 will change for each carbon price policy scenario.

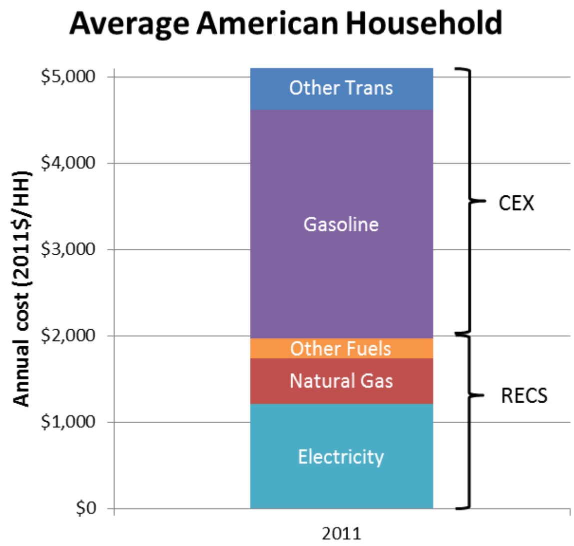

Figure 4.4 Energy-related expenditures, average American household (2011)

One can now insert the terms from Table 4.16 and Table 4.17 into Equation 4.2 to solve for the total change in per-household expenditures each year for each fuel type. The cost increase per fuel from the $25/t$CO_2$ at 2% policy is shown in Table 4.18. The carbon fee will cost the average American household $327 in the first year and roughly $360 per year on average through 2023. The total for the first ten years of the policy is $3,613 (NPV of $2,945), mostly from expenditure increases on gasoline and electricity.

Table 4.18 Total change in expenditures per household ($25/t$CO_2$ at 2%).

Change in Household Fuel Expenditures for $25/t$CO_2$ at 2% policy scenario (2011 chained USD)

Fuel Type	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	**Totals**	**NPV[1]**
Electricity	$64.48	$136.13	$126.94	$116.04	$114.36	$120.34	$118.15	$115.69	$117.45	$122.17	**$1,151.74**	**$928.36**
Natural Gas	$83.80	$81.96	$79.93	$78.68	$77.18	$77.48	$79.87	$80.17	$80.97	$81.25	**$801.30**	**$650.40**
Fuel Oil	$13.66	$14.65	$14.76	$13.91	$14.35	$14.03	$13.42	$13.19	$13.07	$12.80	**$137.85**	**$112.25**
Gasoline	$138.59	$122.46	$122.81	$135.48	$133.18	$127.15	$136.02	$120.11	$126.98	$130.58	**$1,293.36**	**$1,049.98**
Other Transportation	$26.94	$23.80	$23.87	$26.33	$25.88	$24.71	$26.43	$23.34	$24.68	$25.38	**$251.36**	**$204.06**
Total	**$327.48**	**$378.99**	**$368.31**	**$370.44**	**$364.96**	**$363.71**	**$373.89**	**$352.50**	**$363.15**	**$372.18**	**$3,635.61**	**$2,945.05**

Notes

[1] NPV based on a 4% discount rate

All of the policies show similar responses across fuel types, with price levels varying due to carbon price and escalation rates. Furthermore, these results are based on the NEMS outputs, so they do not change based on the rebate portion of the policy. Table 4.19 shows the total change in household expenditures per year for the average American household under all policy scenarios.

Table 4.19 Total change in household expenditure costs for average American household

Scenario	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Totals	NPV[1]
Change in Total Household Expenditures For All Policies (2011 chained USD)												
$15/tCO_2$ at 2%	$197.45	$229.07	$213.27	$226.13	$218.86	$218.57	$242.02	$211.18	$218.07	$222.95	**$2,197.58**	**$1,779.22**
$15/tCO_2$ at 4%	$196.30	$234.00	$224.76	$237.82	$237.98	$242.47	$269.85	$241.23	$250.70	$259.42	**$2,394.53**	**$1,928.14**
$15/tCO_2$ at 6%	$188.80	$234.47	$233.67	$246.74	$250.94	$260.70	$294.29	$272.86	$290.38	$301.74	**$2,574.60**	**$2,060.14**
$15/tCO_2$ at 8%	$187.98	$240.10	$244.52	$263.30	$274.78	$291.85	$329.49	$311.50	$335.40	$355.61	**$2,834.52**	**$2,255.56**
$25/tCO_2$ at 2%	$327.48	$378.99	$368.31	$370.44	$364.96	$363.71	$373.89	$352.50	$363.15	$372.18	**$3,635.61**	**$2,945.05**
$25/tCO_2$ at 4%	$327.56	$387.69	$384.65	$390.92	$395.59	$400.84	$424.46	$400.33	$419.48	$433.67	**$3,965.19**	**$3,194.21**
$25/tCO_2$ at 6%	$327.38	$393.38	$404.22	$423.83	$439.36	$452.38	$482.66	$466.35	$488.74	$512.79	**$4,391.10**	**$3,516.13**
$25/tCO_2$ at 8%	$327.82	$400.59	$431.09	$464.03	$485.90	$503.49	$538.35	$526.84	$563.68	$593.27	**$4,835.06**	**$3,853.64**
$35/tCO_2$ at 2%	$450.13	$533.02	$521.25	$508.91	$507.26	$499.90	$507.35	$492.04	$502.06	$509.93	**$5,031.83**	**$4,078.33**
$35/tCO_2$ at 4%	$442.45	$535.08	$546.35	$547.66	$562.58	$574.60	$568.90	$560.65	$584.38	$596.58	**$5,519.23**	**$4,446.09**
$35/tCO_2$ at 6%	$441.88	$544.01	$598.97	$628.35	$634.57	$648.35	$660.43	$651.27	$653.72	$673.66	**$6,135.20**	**$4,923.56**
$35/tCO_2$ at 8%	$442.31	$549.80	$649.45	$687.11	$706.74	$719.03	$735.69	$820.62	$820.37	$839.49	**$6,970.61**	**$5,549.66**

Notes

[1] NPV based on a 4% discount rate

4.4.2 Rebate and net benefits

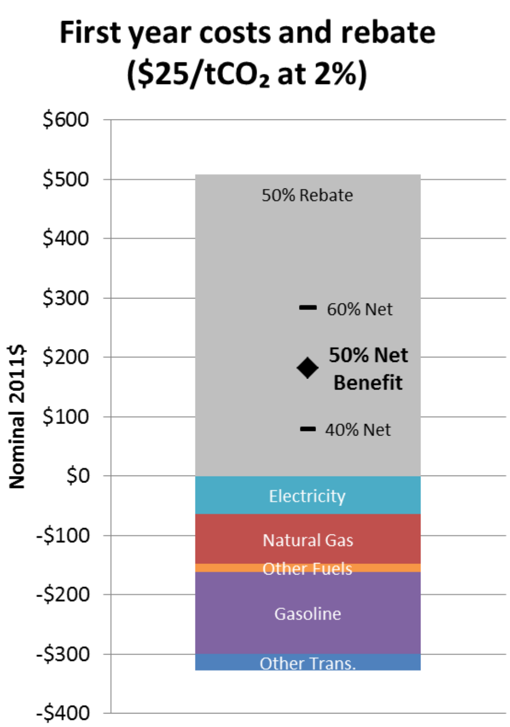

Figure 4.5 Costs and Benefit to the average American household in 2014

The rebates are a direct function of the revenues raised by the carbon fee, and those annual revenues for each policy are listed in Table 3.2. As an example, assume the rebate will be 50% of the revenues; that is, 50% of the revenues raised will be returned directly to households on a per capita basis. The revenue for the first year under the $25/tCO_2$ at 2% scenario is $127.23 billion, and 50% of that ($63.62 billion) is set aside for the rebate. Population in the U.S. is projected to be 321.48 million people, so the per capita rebate would be $197.89.

The average American household had 2.57 occupants according to RECS, which remains a constant for this analysis. Using Equation 4.9 and the 50% rebate example above, the rebate to the average American household in 2014 would be $508.93. Figure 4.5 combines this first-year rebate with the total additional cost for each fuel (from the first column of Table 4.18). The net benefit for the first year of this policy is $181.45. So the average American household would remain positive under this policy and rebate scenario. Furthermore, Figure 4.5 shows that even under a 40% rebate, the average household will still be better off with the policy than under the Reference scenario.

Of course, each subsequent year has a different revenue amount based on emissions, as well as a growing population, so the per capita rebate amount will change each year. Table 4.20 lists the 50% rebate to each household for each year under each policy. Generally, the rebate increases over time under each policy, with the exception of a few policies with slightly less total revenue in 2015 than in 2014.

Combining the costs from Table 4.19 and the revenues from Table 4.20 provides the annual net benefit shown in Table 4.21. These net benefits show that the average American household will be better off in every year, in every policy scenario, with a 50% rebate of the revenues. The policies range from about $1000 to $2000 in aggregate benefit to the average household over the first ten years.

The annual net benefit ranges between $100 and $200 per household for most of the scenario years, with a few exceptions. The cost to consumers rises in the first few years as electric utilities quickly decarbonize the grid. Revenues, and therefore the rebate, will not keep pace during this timeframe. However, once beyond the initial reaction, energy prices stabilize and generally grow in parallel to the Reference scenario. At this point, carbon fee revenues are adequate to meet the costs under the 50% rebate scenario.

Table 4.20 Annual 50% rebate to average American household for all scenarios

Total Household Rebate Under a 50% Rebate Policy (2011 chained USD)

Scenario	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	**Totals**	**NPV[1]**
$15/tCO₂ at 2%	$311.25	$311.51	$312.70	$317.42	$322.80	$328.22	$331.05	$334.10	$ 338.28	$ 342.47	**$3,249.80**	**$2,626.05**
$15/tCO₂ at 4%	$311.61	$317.48	$324.35	$335.48	$347.22	$359.73	$369.59	$379.66	$ 391.30	$ 403.03	**$3,539.44**	**$2,843.42**
$15/tCO₂ at 6%	$311.19	$323.04	$335.51	$353.97	$372.72	$393.21	$411.05	$429.53	$ 450.10	$ 471.62	**$3,851.93**	**$3,076.90**
$15/tCO₂ at 8%	$311.06	$328.15	$346.55	$371.18	$397.96	$427.08	$454.36	$481.60	$ 515.23	$ 548.15	**$4,181.33**	**$3,321.96**
$25/tCO₂ at 2%	$508.93	$504.37	$504.12	$511.50	$520.24	$528.09	$531.98	$533.78	$ 540.78	$ 545.03	**$5,228.84**	**$4,228.48**
$25/tCO₂ at 4%	$507.93	$510.83	$518.01	$535.69	$554.41	$572.14	$587.68	$600.31	$ 616.58	$ 633.53	**$5,637.12**	**$4,533.39**
$25/tCO₂ at 6%	$507.91	$520.80	$534.84	$561.73	$590.63	$620.23	$647.02	$671.34	$ 703.29	$ 734.57	**$6,092.36**	**$4,873.76**
$25/tCO₂ at 8%	$507.30	$528.49	$549.10	$584.99	$624.39	$665.35	$706.22	$747.18	$ 798.98	$ 849.07	**$6,561.07**	**$5,221.22**
$35/tCO₂ at 2%	$698.91	$681.53	$678.71	$689.14	$699.33	$709.19	$714.71	$714.77	$ 722.27	$ 727.92	**$7,036.49**	**$5,694.49**
$35/tCO₂ at 4%	$698.72	$694.26	$698.22	$718.77	$740.51	$762.23	$779.35	$795.97	$ 820.45	$ 841.89	**$7,550.38**	**$6,078.94**
$35/tCO₂ at 6%	$698.00	$705.58	$710.02	$739.61	$773.05	$809.32	$839.01	$875.66	$ 917.84	$ 957.94	**$8,026.02**	**$6,431.35**
$35/tCO₂ at 8%	$695.76	$713.76	$713.87	$749.50	$797.20	$848.39	$898.82	$950.57	$1,008.92	$1,071.71	**$8,448.49**	**$6,740.41**

Notes

[1] NPV based on a 4.0% discount rate

Table 4.21 Annual net benefits from a 50% rebate

Total Net Household Benefits Under a 50% Rebate Policy (2011 chained USD)

Scenario	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	**Totals**	**NPV[1]**
$15/tCO₂ at 2%	$113.80	$ 82.44	$ 99.43	$ 91.28	$103.94	$109.65	$ 89.03	$122.91	$ 120.21	$ 119.52	**$1,052.22**	**$846.83**
$15/tCO₂ at 4%	$115.31	$ 83.48	$ 99.58	$ 97.67	$109.24	$117.26	$ 99.74	$138.43	$ 140.60	$ 143.60	**$1,144.91**	**$915.27**
$15/tCO₂ at 6%	$122.39	$ 88.57	$101.83	$107.23	$121.78	$132.51	$116.76	$156.67	$ 159.72	$ 169.88	**$1,277.33**	**$1,016.76**
$15/tCO₂ at 8%	$123.08	$ 88.05	$102.03	$107.88	$123.18	$135.23	$124.86	$170.11	$ 179.84	$ 192.54	**$1,346.81**	**$1,066.41**
$25/tCO₂ at 2%	$181.46	$125.38	$135.82	$141.07	$155.28	$164.37	$158.09	$181.28	$ 177.64	$ 172.85	**$1,593.23**	**$1,283.43**
$25/tCO₂ at 4%	$180.37	$123.14	$133.36	$144.77	$158.81	$171.30	$163.23	$199.98	$ 197.10	$ 199.86	**$1,671.94**	**$1,339.18**
$25/tCO₂ at 6%	$180.53	$127.42	$130.61	$137.89	$151.27	$167.85	$164.36	$204.98	$ 214.55	$ 221.78	**$1,701.26**	**$1,357.62**
$25/tCO₂ at 8%	$179.49	$127.90	$118.00	$120.96	$138.49	$161.86	$167.88	$220.34	$ 235.29	$ 255.80	**$1,726.01**	**$1,367.58**
$35/tCO₂ at 2%	$248.79	$148.52	$157.47	$180.23	$192.08	$209.29	$207.36	$222.72	$ 220.22	$ 218.00	**$2,004.66**	**$1,616.16**
$35/tCO₂ at 4%	$256.27	$159.18	$151.88	$171.11	$177.93	$187.64	$210.45	$235.33	$ 236.06	$ 245.30	**$2,031.14**	**$1,632.85**
$35/tCO₂ at 6%	$256.12	$161.56	$111.05	$111.26	$138.48	$160.97	$178.58	$224.39	$ 264.12	$ 284.28	**$1,890.82**	**$1,507.80**
$35/tCO₂ at 8%	$253.45	$163.96	$ 64.41	$ 62.40	$ 90.45	$129.36	$163.13	$129.95	$ 188.56	$ 232.22	**$1,477.89**	**$1,190.75**

Notes

[1] NPV based on a 4.0% discount rate

The magnitude of the dip in net benefits in the first few years correlates to the magnitude of the initial carbon fee. A carbon fee has opposing effects: emissions will decline in response to the fee incurring a cost to consumers, but the remaining emissions will raise revenues that fund the rebate. The NPV of the first ten years of the policy captures this temporal effect (See Figure 4.6). Under the \$15/tCO_2 scenarios, increasing the escalation rate slightly increases the net benefit. This suggests that the escalating fee may not be efficient at reducing emissions, since the growing fees do not continue to consistently drive emissions down. The revenues for the \$35/tCO_2 scenarios, on the other hand, do not keep pace with costs as the carbon fee escalation rate increases. In this case, the average annual net benefit from the rebate declines with increasing escalation rate. This suggests that the hefty fee is effective at reducing emissions, but doing so is at a disproportionate cost as the rate increases. For the moderate \$25/tCO_2 scenarios, the revenues barely keep pace with costs, as the net difference remains relatively constant with increasing escalation rate.

Figure 4.6 also shows the net benefit for 40% and 60% rebate scenarios. The average household will maintain a net positive NPV with a 40% rebate under all policies except the most aggressive. These costs and benefits for the average American household are summarized in Table 4.22. As a point of reference, if one believes the indirect costs are as high as the direct costs shown here, then a rebate of between about 65% would be required to compensate the Average American household under every scenario.

(Please see Appendix 0 for an explanation and derivation of the scaling factors between RECS 2009 to 2011.)

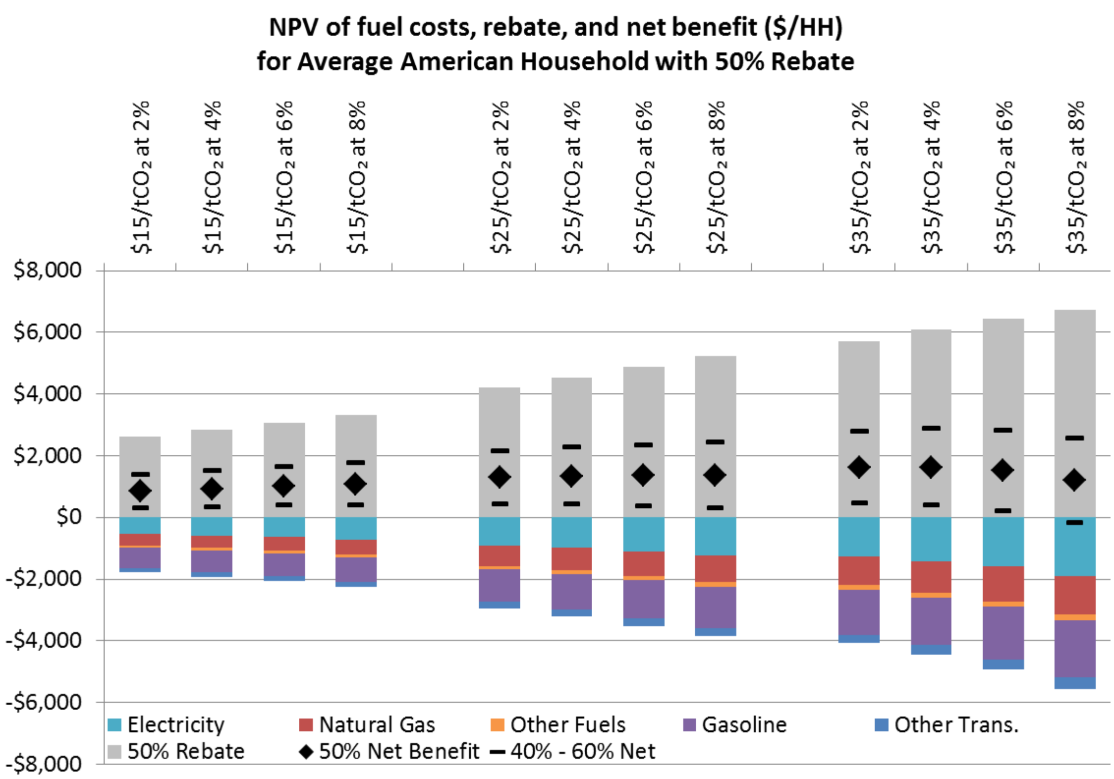

Figure 4.6 NPV Costs, rebates and net benefits to the average American household under 50% Rebate.

Table 4.22 Average American household summary

	Policy impacts to the Average American Household								
	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	Total Costs	50% Rebate	2014 Net Benefit	NPV
Historical Energy Expenditure (2011)									
CEX[1]	$420.00	$1,423.00	$157.00	$2,655.00	$516.00	$5,171.00			
RECS[2]	$426.13	$1,385.27	$193.75			$2,005.16			
Average American Household									
$\$15/\mathrm{tCO_2}$ at 2%	$38.55	$50.20	$8.16	$84.18	$16.36	$197.45	$311.25	$113.80	
$\$15/\mathrm{tCO_2}$ at 4%	$38.88	$49.04	$8.08	$83.98	$16.32	$196.30	$311.61	$115.31	
$\$15/\mathrm{tCO_2}$ at 6%	$38.89	$49.99	$8.23	$76.76	$14.92	$188.80	$311.19	$122.39	
$\$15/\mathrm{tCO_2}$ at 8%	$39.65	$48.57	$8.16	$76.69	$14.90	$187.98	$311.06	$123.08	
$\$25/\mathrm{tCO_2}$ at 2%	$64.48	$83.80	$13.66	$138.59	$26.94	$327.48	$508.93	$181.46	
$\$25/\mathrm{tCO_2}$ at 4%	$65.12	$83.24	$13.64	$138.62	$26.94	$327.56	$507.93	$180.37	
$\$25/\mathrm{tCO_2}$ at 6%	$65.19	$83.21	$13.61	$138.47	$26.91	$327.38	$507.91	$180.53	
$\$25/\mathrm{tCO_2}$ at 8%	$65.54	$83.70	$13.64	$138.09	$26.84	$327.82	$507.30	$179.49	
$\$35/\mathrm{tCO_2}$ at 2%	$89.17	$116.54	$18.95	$188.77	$36.69	$450.13	$698.91	$248.79	
$\$35/\mathrm{tCO_2}$ at 4%	$88.96	$116.56	$18.94	$182.51	$35.47	$442.45	$698.72	$256.27	
$\$35/\mathrm{tCO_2}$ at 6%	$89.23	$116.28	$19.06	$181.94	$35.36	$441.88	$698.00	$256.12	
$\$35/\mathrm{tCO_2}$ at 8%	$90.60	$115.07	$18.98	$182.24	$35.42	$442.31	$695.76	$253.45	
NPV[3] of Costs and Rebate (2014-2023)									
$\$15/\mathrm{tCO_2}$ at 2%	$533.51	$371.35	$67.44	$675.62	$131.31	$1,779.22	$2,626.05	$846.83	
$\$15/\mathrm{tCO_2}$ at 4%	$588.41	$397.71	$72.66	$727.90	$141.47	$1,928.14	$2,843.42	$915.27	
$\$15/\mathrm{tCO_2}$ at 6%	$635.52	$441.26	$79.48	$756.80	$147.08	$2,060.14	$3,076.90	$1,016.76	
$\$15/\mathrm{tCO_2}$ at 8%	$715.49	$480.49	$86.25	$814.95	$158.38	$2,255.56	$3,321.96	$1,066.41	
$\$25/\mathrm{tCO_2}$ at 2%	$928.36	$650.40	$112.25	$1,049.98	$204.06	$2,945.05	$4,228.48	$1,283.43	
$\$25/\mathrm{tCO_2}$ at 4%	$992.45	$711.73	$121.54	$1,145.80	$222.69	$3,194.21	$4,533.39	$1,339.18	
$\$25/\mathrm{tCO_2}$ at 6%	$1,115.37	$788.12	$132.38	$1,239.39	$240.88	$3,516.13	$4,873.76	$1,357.62	
$\$25/\mathrm{tCO_2}$ at 8%	$1,221.32	$882.46	$145.07	$1,343.66	$261.14	$3,853.64	$5,221.22	$1,367.58	
$\$35/\mathrm{tCO_2}$ at 2%	$1,267.35	$927.58	$154.93	$1,447.21	$281.26	$4,078.33	$5,694.49	$1,616.16	
$\$35/\mathrm{tCO_2}$ at 4%	$1,410.30	$1,023.63	$168.27	$1,543.85	$300.05	$4,446.09	$6,078.94	$1,632.85	
$\$35/\mathrm{tCO_2}$ at 6%	$1,595.12	$1,120.76	$184.16	$1,694.24	$329.28	$4,923.56	$6,431.35	$1,507.80	
$\$35/\mathrm{tCO_2}$ at 8%	$1,908.19	$1,232.98	$199.25	$1,849.74	$359.50	$5,549.66	$6,740.41	$1,190.75	

Notes:

[1]CEX 2011 includes all five categories

[2]RECS 2009 only in-house expenditures, corrected for inflation and changes in expenditures from CEX 2009 and CEX 2011

[3]NPV based on discount rate of 4.0%

4.5 REGIONAL HOUSEHOLD IMPACTS

4.5.1 Introduction to Regions, Divisions, and States

The real benefit to using the RECS data over the CEX data is for the geographic resolution. The CEX only breaks out the four main Census Regions of Northeast (NE), Midwest (MW), South (S), and West (W). However, the RECS data are aggregated to the nine Census Divisions, as well as a few sub-Divisions and even individual states which are highlighted in Figure 4.7. In the figure, colors represent the four Regions and each Region is divided into two or three Divisions. The dark-shaded states represent the 16 most populous states which are reported individually within the RECS. These 16 states account for almost two thirds (63%) of the U.S. population.

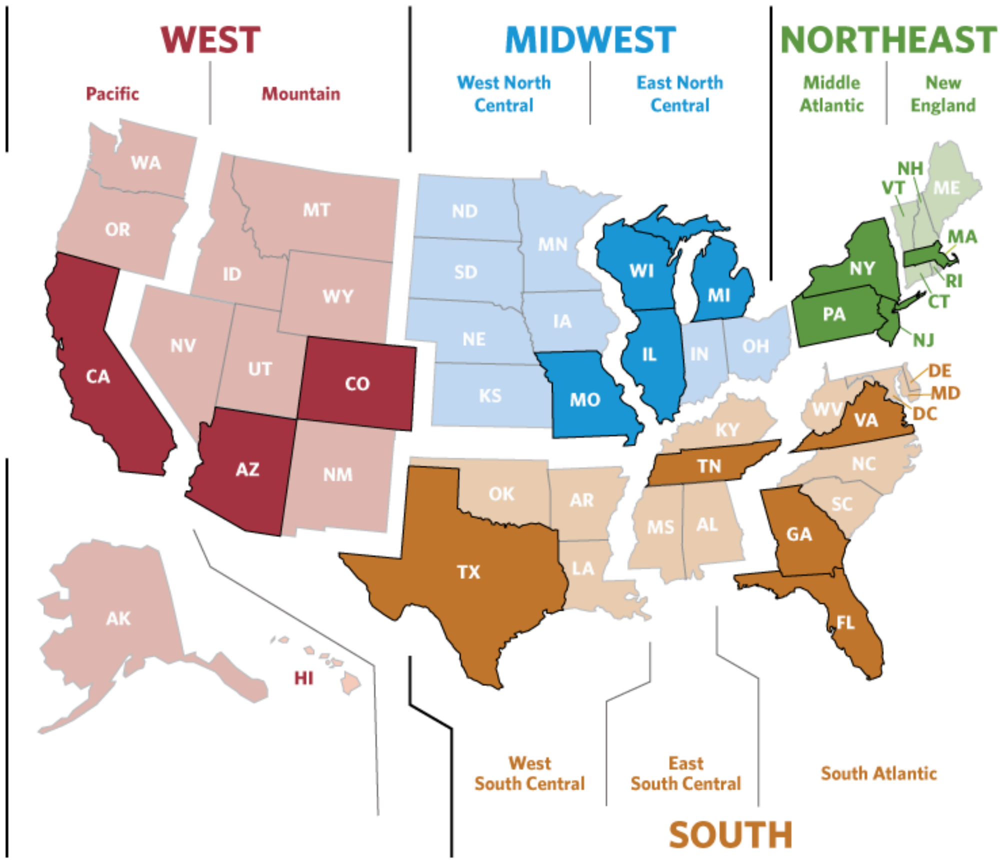

Figure 4.7 Census Regions, Divisions, and Individual States for which RECS provides aggregated data. Darker shaded states are reported individually in RECS. (EIA, 2013d)

This segmentation is particularly useful when several populous states are in the same Division. An extreme example is the Middle Atlantic Division in the NE Region, which includes only three states: New York (NY), Pennsylvania (PA), and New Jersey (NJ). All three are heavily populated and are reported individually in RECS. When most of the states within a Division are not heavily populated, the non-populous states are aggregated together. As an example, the West region is divided into the Pacific and Mountain Divisions. The Pacific Division includes the five Pacific and coastal states of California (CA), Oregon (OR), Washington (WA), Hawaii (HI), and Alaska (AK). Here, CA is reported separately in terms of energy expenditures, and the remaining four states are reported in aggregate. (Table 4.4 for an itemization)

Divisions within the NE, MW, and S Regions have relatively continuous external drivers of energy consumption, such as climate. The states within each Division do not face exactly the same weather, but there is a continuum from one state to the next. For example, states in the two Divisions of the NE Region have similar climate as the other states in the same Division. The average households within the New England Division are exposed to similar weather and are at roughly similar latitudes, both of which affect heating and lighting demand. These states also have similar renewable energy generation availability since they are all states participating in the Regional Greenhouse Gas Initiative (RGGI, 2014). So, differences between households in this Division from carbon fees and rebates are largely a reflection of fuel mix, which is driven by local policies and choices, and occupancy rate differences.

The W Region is very different. Both of its Divisions (Pacific and Mountain) span the full latitudinal extent of the contiguous U.S., and are exposed to a range of solar radiation and hours of daylight, all key drivers of energy consumption. The Pacific Division includes AK at significantly higher latitude than the rest of the Division, and the tropical island state of HI, which arguably has different weather than any other state. Furthermore, both Divisions in the West include deserts, massive mountain ranges, vast plains, and extensive forests, sometimes all occurring within a single state, and all of which will impact energy demand and renewable energy choices. Defining the ‘average’ household in either Division presents a challenge.

Fortunately, RECS further divides the Mountain Division into South and North subdivisions. Although not illustrated in Figure 4.7, the Mountain South sub-Division includes the southernmost states in the Division: Nevada (NV), Arizona (AZ), and New Mexico (NM), with the rest falling into the North sub-Division. While this does collect similar states together, a large amount of variability remains within each sub-Division. Nonetheless, this is still a better resolution than simply using the four-Region CEX data.

Table 4.23 Region, Division, Sub Division, and State energy expenditures from RECS

Market Segment	Households		Total Energy Expend.	Energy Expenditure by fuel type¹ $/HH, % of energy expenditures, indexed to average consumer — Electricity				Natural Gas				Fuel oil & Other Fuel			
	million	% of total	$/HH	$/HH	% of energy²	Index U.S.³	Index Div.⁴	$/HH	% of energy²	Index U.S.³	Index Div.⁴	$/HH	% of energy²	Index U.S.³	Index Div.⁴
Average Household															
Avg. Consumer Unit	113.6	100%	$2,024	$1,340	66.2%	1.00		$490	24.2%	1.00		$194	9.6%	1.00	
By Region, Division, Sub-Division, and States															
Total Northeast Region	**20.8**	**18.3%**	**$2,591**	**$1,300**	**50.2%**	**0.97**		**$748**	**28.8%**	**1.53**		**$544**	**21.0%**	**2.81**	
New England Division	5.5	4.8%	$2,744	$1,293	47.1%	0.96	1.00	$591	21.5%	1.21	1.00	$860	31.3%	4.44	1.00
MA	2.5	2.2%	$2,452	$1,120	45.7%	0.84	0.87	$768	31.3%	1.57	1.30	$564	23.0%	2.91	0.66
CT, ME, NH, RI, VT	3.0	2.6%	$2,983	$1,437	48.2%	1.07	1.11	$443	14.9%	0.90	0.75	$1,107	37.1%	5.71	1.29
Middle Atlantic Division	15.3	13.5%	$2,537	$1,303	51.4%	0.97	1.00	$805	31.7%	1.64	1.00	$430	17.0%	2.22	1.00
NY	7.2	6.3%	$2,442	$1,160	47.5%	0.87	0.89	$806	33.0%	1.64	1.00	$476	19.5%	2.46	1.11
PA	4.9	4.3%	$2,361	$1,349	57.1%	1.01	1.04	$492	20.8%	1.00	0.61	$520	22.0%	2.69	1.21
NJ	3.2	2.8%	$3,022	$1,556	51.5%	1.16	1.19	$961	31.8%	1.96	1.19	$159	5.3%	0.82	0.37
Total Midwest Region	**25.9**	**22.8%**	**$1,982**	**$1,114**	**56.2%**	**0.83**		**$698**	**35.2%**	**1.42**		**$170**	**8.6%**	**0.88**	
East North Central Division	17.9	15.8%	$2,015	$1,116	55.4%	0.83	1.00	$758	37.6%	1.55	1.00	$141	7.0%	0.73	1.00
IL	4.8	4.2%	$2,050	$1,179	57.5%	0.88	1.06	$804	39.2%	1.64	1.06	$65	3.2%	0.33	0.46
MI	3.8	3.3%	$2,161	$1,016	47.0%	0.76	0.91	$934	43.2%	1.91	1.23	$184	8.5%	0.95	1.31
WI	2.3	2.0%	$1,904	$1,061	55.7%	0.79	0.95	$648	34.0%	1.32	0.86	$191	10.0%	0.99	1.36
IN, OH	7.0	6.2%	$1,949	$1,146	58.8%	0.85	1.03	$666	34.2%	1.36	0.88	$121	6.2%	0.63	0.86
West North Central Division	8.1	7.1%	$1,886	$1,095	58.0%	0.82	1.00	$558	29.6%	1.14	1.00	$233	12.4%	1.20	1.00
MO	2.3	2.0%	$1,926	$1,191	61.9%	0.89	1.09	$557	28.9%	1.14	1.00	$174	9.0%	0.90	0.75
IA, MN, ND,SD	3.9	3.4%	$1,951	$1,087	55.7%	0.81	0.99	$508	26.0%	1.04	0.91	$359	18.4%	1.85	1.54
KS, NE	1.8	1.6%	$1,800	$1,050	58.3%	0.78	0.96	$706	39.2%	1.44	1.26	$0	0.0%	0.00	0.00
Total South Region	**42.1**	**37.1%**	**$2,037**	**$1,641**	**80.6%**	**1.22**		**$292**	**14.3%**	**0.60**		**$104**	**5.1%**	**0.53**	
South Atlantic Division	22.2	19.5%	$2,059	$1,672	81.2%	1.25	1.00	$268	13.0%	0.55	1.00	$120	5.8%	0.62	1.00
VA	3.0	2.6%	$2,140	$1,570	73.4%	1.17	0.94	$393	18.4%	0.80	1.47	$123	5.8%	0.64	1.03
GA	3.5	3.1%	$2,049	$1,554	75.9%	1.16	0.93	$457	22.3%	0.93	1.71	$34	1.7%	0.18	0.29
FL	7.0	6.2%	$2,017	$1,897	94.1%	1.42	1.13	$57	2.8%	0.12	0.21	$61	3.0%	0.32	0.51
DC, DE, MD, WV	3.4	3.0%	$2,326	$1,676	72.1%	1.25	1.00	$426	18.3%	0.87	1.59	$221	9.5%	1.14	1.84
NC, SC	5.4	4.8%	$1,870	$1,480	79.1%	1.10	0.89	$244	13.1%	0.50	0.91	$131	7.0%	0.68	1.10
East South Central Division	7.1	6.3%	$1,949	$1,524	78.2%	1.14	1.00	$290	14.9%	0.59	1.00	$134	6.9%	0.69	1.00
TN	2.4	2.1%	$1,808	$1,442	79.7%	1.08	0.95	$279	15.4%	0.57	0.96	$0	0.0%	0.00	0.00
AL, KY, MS	4.6	4.0%	$2,065	$1,598	77.4%	1.19	1.05	$302	14.6%	0.62	1.04	$163	7.9%	0.84	1.22
West South Central Division	12.8	11.3%	$2,047	$1,653	80.8%	1.23	1.00	$336	16.4%	0.69	1.00	$58	2.8%	0.30	1.00
TX	8.5	7.5%	$2,167	$1,807	83.4%	1.35	1.09	$328	15.1%	0.67	0.98	$31	1.4%	0.16	0.53
AR, LA, OK	4.2	3.7%	$1,852	$1,381	74.6%	1.03	0.84	$360	19.4%	0.73	1.07	$112	6.0%	0.58	1.94
Total West Region	**24.8**	**21.8%**	**$1,571**	**$1,102**	**70.1%**	**0.82**		**$392**	**25.0%**	**0.80**		**$77**	**4.9%**	**0.40**	
Mountain Division	7.9	7.0%	$1,749	$1,182	67.6%	0.88	1.00	$447	25.5%	0.91	1.00	$116	6.7%	0.60	1.00
Mountain North Sub-Div.	3.9	3.4%	$1,610	$915	56.8%	0.68	0.77	$546	33.9%	1.11	1.22	$149	9.2%	0.77	1.28
CO	1.9	1.7%	$1,558	$779	50.0%	0.58	0.66	$579	37.2%	1.18	1.30	$200	12.8%	1.03	1.72
ID, MT, UT, WY	2.0	1.8%	$1,660	$1,045	63.0%	0.78	0.88	$515	31.0%	1.05	1.15	$0	0.0%	0.00	0.00
Mountain South Sub-Div.	4.0	3.5%	$1,885	$1,440	76.4%	1.07	1.22	$350	18.6%	0.71	0.78	$85	4.5%	0.44	0.73
AZ	2.3	2.0%	$1,939	$1,604	82.7%	1.20	1.36	$274	14.1%	0.56	0.61	$61	3.1%	0.31	0.52
NM, NV	1.7	1.5%	$1,812	$1,218	67.2%	0.91	1.03	$453	25.0%	0.92	1.01	$0	0.0%	0.00	0.00
Pacific Division	16.9	14.9%	$1,488	$1,064	71.5%	0.79	1.00	$367	24.7%	0.75	1.00	$57	3.9%	0.30	1.00
CA	12.2	10.7%	$1,423	$1,013	71.2%	0.76	0.95	$359	25.2%	0.73	0.98	$48	3.4%	0.25	0.84
AK, HI, OR, WA	4.7	4.1%	$1,655	$1,196	72.2%	0.89	1.12	$387	23.4%	0.79	1.06	$72	4.4%	0.37	1.26

Notes:

¹ Directly from RECS 2009 (before accounting for inflation or scaling demand from 2009 to 2011 from CEX 2009 and CEX 2011)

² Percent of in-House energy expenditure, ignores travel expenses fro CEX which are about half of all energy expenditure

³ Indexed to Avg. Consumer Unit

⁴ Indexed to parent Census Division

The nine Census Divisions in RECS correlate directly with the NEMS regional expenditure outputs, so one can use the *direct method* for linking RECS to NEMS. However, to get the future energy expenditures for smaller sub-Divisions and states, the *index method* is used. Since the finest resolution available in the NEMS result is the Census Division level,[43] state energy consumption is indexed to the parent Division energy expenditures, which are identified in Table 4.23. The table includes the index value relative to the average American household and to the average respective Division household, which allows one to see how much households spend relative to the rest of the U.S. and to their neighbors.

The annual costs and benefits to average households in each of these geographical areas are determined in a similar manner as for the average American household. First, the annual costs to each segment under the carbon price policy are computed, and then the rebate is applied based on the number of households and occupants in each segment.

4.5.2 Census Divisions impacts

Both the RECS data and NEMS outputs are available at the Division level, but the two CEX transportation categories are at the Region level. Gasoline accounts for about half of all household energy-related expenditures, and the average household in each Region spends within 5% of the national average (see Table 4.1). Thus, using the Region data from the CEX as a surrogate for the Division-level analysis for this fuel type is reasonable. The other category from the CEX, public transportation, has a much wider spread in expenditures; however, it is only about 10% of total energy expenditure, and an even smaller fraction of the carbon fee impacts. Furthermore, only the highest income households are likely to incur significant costs from this category under a carbon fee. So, using the Region-level data as a surrogate for the Division expenditure will have little impact on this analysis if Divisions or states vary dramatically within the same Region.

Figure 4.8 compares the first-year impacts of the average American household and average Division-level households from the costs and benefits of a \$25/tCO_2 at 2% scenario with a 50% rebate. The figure also includes the net benefits from a 40%

[43] Appendix 0 defines necessary factors for scaling RECS 2009 demand to 2011 (apart from just inflation); however, the CEX 2009 and CEX 2011 data used to determine this are only at the four Census Region level, so the scale factor for a region is used for all sub-Regional disaggregation.

and 60% rebate for reference. The separation between Divisions in the figure reflects the Census Regions. The two Divisions in the first group make up the NE Region; the next two are the MW, the group of three Divisions is the S, and the last two are the W Region. The results represent the same carbon price scenario, so the per capita rebate to every individual is the same across the country. The difference in value among the rebate bars reflects the number of residents in the average Division household.

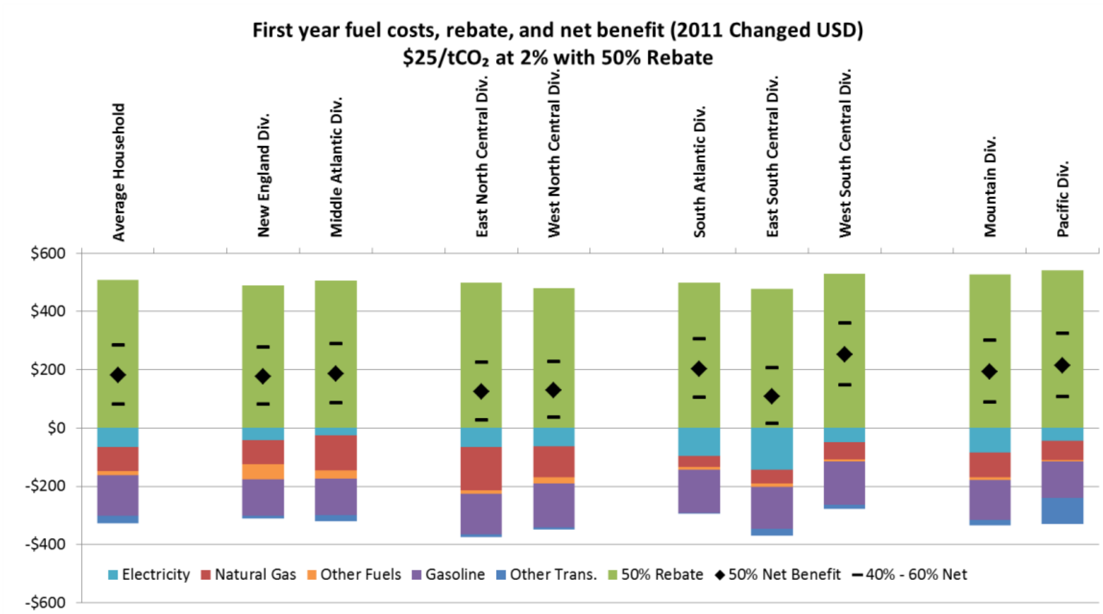

Figure 4.8 First year impacts to average household by Division ($25/tCO$_2$ at 2% and a 50% Rebate)

The impact differences between Divisions within the same Region highlights the importance of assessing the impacts at the most resolved level possible. For example, the S has three Divisions with very different net results. The East South Central Division, for example, will experience a much higher added cost for electricity than its neighboring Divisions, but the West South Central Division will pay more for natural gas than the other two. These differences are only amplified by the occupancy differences between them.

In the West Region, households in the Pacific Division will receive only a slightly larger rebate than the Mountain Division. Their total policy costs are also similar, but the distribution of costs is very different between them. On average, a household in the Mountain Division incurs a much higher cost for electricity and slightly higher cost for natural gas than an average household in the Pacific Division. The Pacific Division, on the other hand, will see a much larger increase from travel. The combination leads to a higher positive net benefit from the rebate for the Pacific Division. Numerical results for Divisions and Regions are included in Table 4.24 at the end of the next section on state-level impacts.

4.5.3 State-level impacts

The next step is to extend the *index method* to estimate the impacts to individual states or small collections of states as identified in RECS. To help keep the impacts to individual states in perspective with their neighbors, Figure 4.9 collects the first year impacts by Census Region, Division, sub-Division (in the case of the Mountain Division), then state. These results are listed in Table 4.24 at the end of the section.

A quick glance at Figure 4.9 reveals a few interesting points. First, the average household in all states (or collections of states) will receive a net positive benefit from a 50% rebate scenario under a $25/t$CO_2$ at 2% policy, and nearly all will benefit under a 40% rebate scenario. Second, net benefits to individual state(s) within the Northeast and Midwest Regions are relatively consistent within their respective Regions and Divisions, while the South is a little less regionally consistent, and the West varies widely even within the same Division. This is a reflection of the climatological disparity between states, fuel mix choices, and occupancy rates. For example, Mountain North sub-Division will see significantly higher costs associated with natural gas usage, whereas Mountain South will see far more from electricity usage. Meanwhile, air travel is a dominant factor in costs to households in the Pacific Division, presumably due to the isolated states of Alaska and Hawaii.

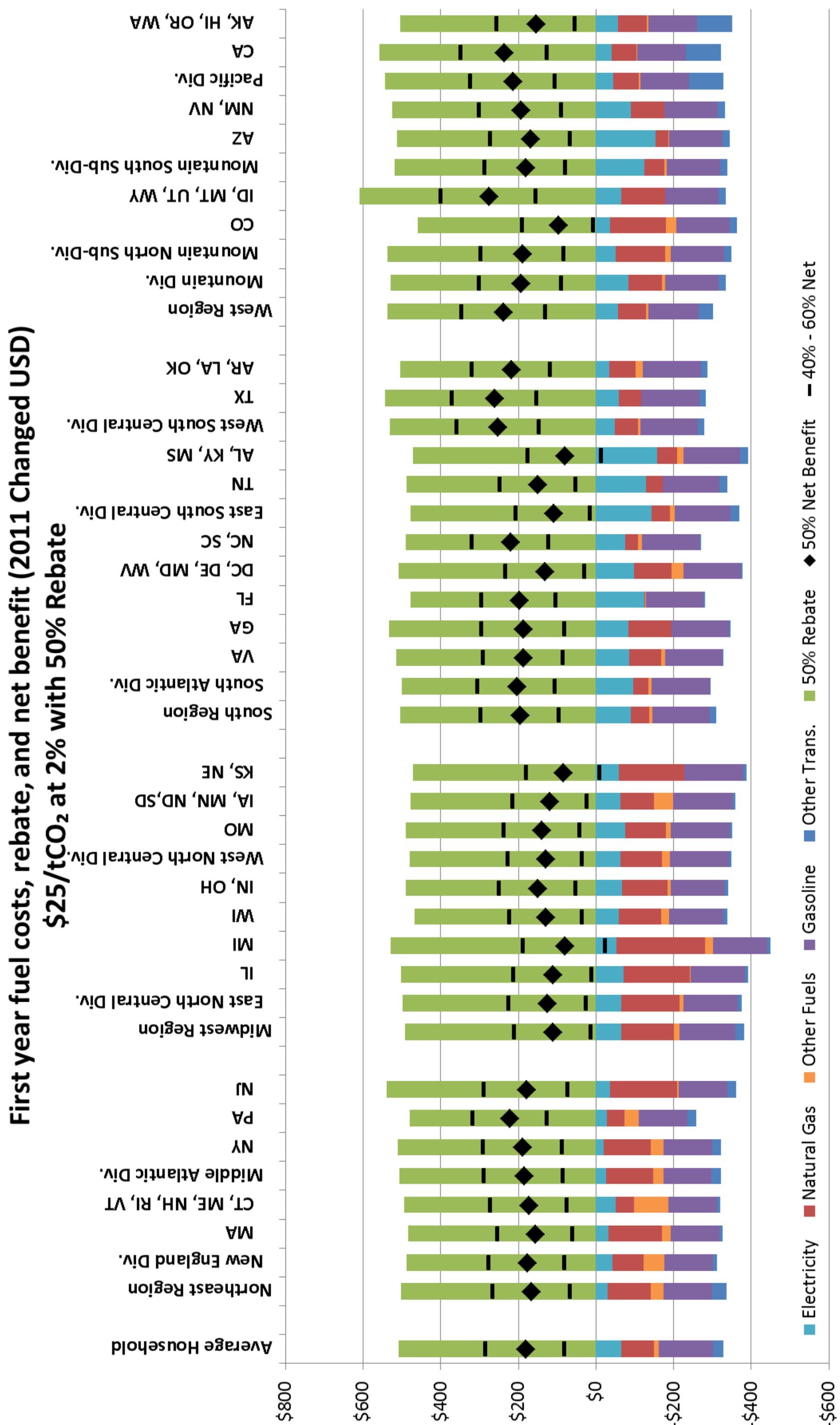

Figure 4.9 State-level impacts to the average household in each state(s) for $\$25/tCO_2$ at 2% with a 50% Rebate.

The rebates in the West Region are perhaps more interesting. The greatest average number of people per household (pph) is 3.08, according to RECS, found in the aggregate collection of Idaho (ID), Montana (MT), Utah (UT), Wyoming (WY), while the smallest is 2.33 in Colorado (CO). These two groups represent the entire Mountain North sub-Division, but due to this disparity, the Division-level result is merely an average and not representative of the state(s) within it. While the average household in CO will just break even from a 40% rebate policy, an average household in the Mountain North sub-Division is balanced out with the other states and will face costs and benefits in aggregate that reflect the national average.

The result for the aggregate of ID, MT, UT, and WY is particular interesting, since it includes three states with some of the highest per capita carbon emissions (WY, MT, UT) as well as one of the lowest (ID) (EIA, 2013c). This circumstance emphasizes the importance of assessing carbon and energy policy at the smallest geographic level the data will support.

Each geographic region in the figure is subject to different mixes of fuels and associated costs, so each will be impacted differently. In the NE Region, the New England Division is split into Massachusetts (MA) and an aggregate of the remaining states. Policy costs in MA will arise more from changes in electricity pricing, while the rest of New England, with its unique dependence on fuel oil, will pay more for 'other fuels'. Despite this fuel mix difference, an average household in both regions will bear about the same total increase in fuel costs and receive about the same household rebate.

The Middle Atlantic Division has been broken out entirely into three individual states, NY, PA, and NJ. Of these three states, households in NJ will see the largest total costs from the policy, mostly from natural gas use. Part of this additional cost is likely due to the higher number of occupants (energy consumers), but on the flipside, NJ will also receive higher rebates per household because of this high occupancy. The opposite is true in PA, which has a lower occupancy rate and will, therefore, see a lower total cost and receive a lower rebate. However, the net benefit to PA is still larger than NY or NJ.

Average Households in Midwest Region states will all see similar net impacts, but these net impacts are, on average, the lowest in the country. Most states in this Region with barely breaking even with a 40% rebate. Two state(s), Michigan (MI) and the aggregate of Kansas (KS) and Nebraska (NE), will not break even under a 40% rebate. Both will see the significant increases in costs from natural gas use in particular, with MI experiencing the largest natural gas cost of any state. However, with more occupants than any other in the Region, the significant rebate will help keep the net benefit positive at a 50% rebate. For KS and NE, however, the combination of higher fuel costs and smaller rebate will leave these two states with the smallest net rebate in the Region under this policy scenario.

The South Region is also relatively homogenous with a few exceptions. In the South Atlantic Division, the Capital Area aggregate (District of Columba (DC), Delaware (DE), Maryland (MD), and West Virginia (WV)) and the Carolinas (North Carolina (NC) and South Carolina (SC)) have dramatically different net results than the rest of their South Atlantic parent Division. Although households in the Capital Area will not see as much of an increase in electricity as households in Florida (FL), they will instead see additional costs for natural gas and other fuels, reducing their net benefit. Households in the Carolinas, on the other hand, will see less increase in electricity costs than those in the Capital Area, but with very little increase in natural gas costs, their net benefit is the highest in the Division.

The other two Divisions in the South Region are quite different from the South Atlantic Division, but relatively consistent within their respective Divisions. The East South Central Division separates Tennessee (TN) from the three remaining states, which is useful given the states' relatively smaller increase in electricity expenditure from the policy. However, these three states (Alabama—AL, Kentucky—KY, and Mississippi—MS) will see the highest increase in electricity prices in the Region, leading to low net benefit to the entire Division. The West South Central Division separates Texas (TX) from the three remaining states of Arkansas (AR), Louisiana (LA), and Oklahoma (OK), which will see some of the lowest costs and the highest household rebates in the Region.

Table 4.24 Region, Division, Sub Division, and State net benefits

Costs and Benefits to the average household
($25/tCO$_2$ at 2% with 50% rebate)

Market Segment	Households			First Year Costs (2014)						First Year Rebate		
	million	% of total	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-$64.48	-$83.80	-$13.66	-$138.59	-$26.94	**-$327.48**	$508.93	**$181.46**	$1,283.43
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-$29.51	-$111.03	-$33.56	-$124.95	-$37.47	**-$336.52**	$501.98	**$165.46**	$2,077.83
New England Division	5.5	4.8%	2.47	-$41.71	-$81.76	-$53.44	-$124.78	-$9.80	**-$311.50**	$488.83	**$177.34**	$2,391.56
MA	2.5	2.2%	2.44	-$31.31	-$138.11	-$22.98	-$124.78	-$9.80	**-$326.99**	$483.60	**$156.62**	$2,227.72
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-$51.52	-$46.02	-$88.49	-$124.78	-$9.80	**-$320.62**	$493.72	**$173.11**	$2,358.35
Middle Atlantic Division	15.3	13.5%	2.56	-$25.19	-$121.61	-$26.40	-$125.01	-$22.90	**-$321.11**	$506.47	**$185.37**	$2,144.81
NY	7.2	6.3%	2.58	-$19.97	-$121.90	-$32.39	-$125.01	-$22.90	**-$322.17**	$510.05	**$187.88**	$2,273.83
PA	4.9	4.3%	2.43	-$27.02	-$45.44	-$38.65	-$125.01	-$22.90	**-$259.02**	$480.04	**$221.01**	$2,326.32
NJ	3.2	2.8%	2.73	-$35.96	-$173.47	-$3.63	-$125.01	-$22.90	**-$360.96**	$539.62	**$178.66**	$1,957.45
Total Midwest Region	25.9	22.8%	2.49	-$64.09	-$136.94	-$14.18	-$143.86	-$23.29	**-$382.36**	$493.11	**$110.75**	$1,551.62
East North Central Division	17.9	15.8%	2.52	-$64.20	-$150.22	-$11.39	-$139.31	-$9.35	**-$374.47**	$499.05	**$124.58**	$1,659.75
IL	4.8	4.2%	2.54	-$71.72	-$169.29	-$2.40	-$139.31	-$9.35	**-$392.05**	$502.51	**$110.45**	$1,524.81
MI	3.8	3.3%	2.68	-$53.22	-$228.46	-$19.50	-$139.31	-$9.35	**-$449.84**	$530.01	**$80.17**	$1,458.56
WI	2.3	2.0%	2.36	-$58.05	-$109.86	-$21.03	-$139.31	-$9.35	**-$337.60**	$466.51	**$128.91**	$1,640.82
IN, OH	7.0	6.2%	2.48	-$67.71	-$116.01	-$8.47	-$139.31	-$9.35	**-$340.85**	$490.45	**$149.60**	$1,809.40
West North Central Division	8.1	7.1%	2.42	-$63.06	-$105.85	-$20.71	-$153.09	-$6.58	**-$349.28**	$479.54	**$130.26**	$1,684.52
MO	2.3	2.0%	2.48	-$74.63	-$105.28	-$11.50	-$153.09	-$6.58	**-$351.08**	$490.07	**$138.98**	$1,698.37
IA, MN, ND,SD	3.9	3.4%	2.41	-$62.15	-$87.62	-$49.01	-$153.09	-$6.58	**-$358.45**	$476.85	**$118.40**	$1,568.18
KS, NE	1.8	1.6%	2.38	-$57.97	-$169.22	$0.00	-$153.09	-$6.58	**-$386.86**	$471.24	**$84.38**	$1,360.97
Total South Region	42.1	37.1%	2.55	-$90.53	-$45.85	-$8.38	-$147.86	-$17.60	**-$310.22**	$505.39	**$195.18**	$2,003.88
South Atlantic Division	22.2	19.5%	2.52	-$96.42	-$38.07	-$9.46	-$148.20	-$3.41	**-$295.55**	$499.46	**$203.91**	$2,194.31
VA	3.0	2.6%	2.60	-$85.05	-$82.27	-$10.03	-$148.20	-$3.41	**-$328.95**	$515.47	**$186.52**	$2,138.38
GA	3.5	3.1%	2.69	-$83.36	-$111.12	-$0.77	-$148.20	-$3.41	**-$346.86**	$533.30	**$186.44**	$2,183.77
FL	7.0	6.2%	2.42	-$124.19	-$1.74	-$2.49	-$148.20	-$3.41	**-$280.02**	$478.16	**$198.14**	$1,979.79
DC, DE, MD, WV	3.4	3.0%	2.57	-$96.98	-$96.71	-$32.07	-$148.20	-$3.41	**-$377.37**	$508.02	**$130.65**	$1,610.28
NC, SC	5.4	4.8%	2.48	-$75.54	-$31.77	-$11.40	-$148.20	-$3.41	**-$270.31**	$490.29	**$219.98**	$2,402.54
East South Central Division	7.1	6.3%	2.41	-$143.25	-$47.60	-$10.96	-$144.99	-$22.13	**-$368.92**	$477.73	**$108.80**	$1,821.53
TN	2.4	2.1%	2.47	-$128.20	-$44.06	$0.00	-$144.99	-$22.13	**-$339.38**	$488.94	**$149.56**	$2,185.99
AL, KY, MS	4.6	4.0%	2.39	-$157.48	-$51.62	-$16.27	-$144.99	-$22.13	**-$392.49**	$472.36	**$79.86**	$1,568.59
West South Central Division	12.8	11.3%	2.68	-$49.18	-$59.74	-$4.93	-$148.90	-$15.93	**-$278.67**	$530.56	**$251.88**	$1,942.01
TX	8.5	7.5%	2.74	-$58.76	-$57.03	-$1.38	-$148.90	-$15.93	**-$282.00**	$543.13	**$261.13**	$1,821.09
AR, LA, OK	4.2	3.7%	2.55	-$34.32	-$68.42	-$18.47	-$148.90	-$15.93	**-$286.04**	$504.50	**$218.46**	$1,952.37
Total West Region	24.8	21.8%	2.72	-$57.41	-$71.79	-$5.42	-$128.94	-$36.87	**-$300.43**	$537.77	**$237.34**	$2,905.93
Mountain Division	7.9	7.0%	2.67	-$83.78	-$85.08	-$9.49	-$137.70	-$18.27	**-$334.32**	$528.11	**$193.80**	$2,299.49
Mountain North Sub-Div.	3.9	3.4%	2.72	-$50.22	-$127.11	-$15.47	-$137.70	-$18.27	**-$348.77**	$537.32	**$188.55**	$2,421.17
CO	1.9	1.7%	2.33	-$36.37	-$142.83	-$27.98	-$137.70	-$18.27	**-$363.15**	$460.16	**$97.01**	$1,586.17
ID, MT, UT, WY	2.0	1.8%	3.08	-$65.45	-$113.02	$0.00	-$137.70	-$18.27	**-$334.44**	$610.32	**$275.88**	$3,211.38
Mountain South Sub-Div.	4.0	3.5%	2.62	-$124.28	-$52.20	-$5.05	-$137.70	-$18.27	**-$337.51**	$518.57	**$181.06**	$2,001.36
AZ	2.3	2.0%	2.59	-$154.27	-$31.97	-$2.59	-$137.70	-$18.27	**-$344.81**	$512.79	**$167.98**	$1,753.30
NM, NV	1.7	1.5%	2.66	-$88.87	-$87.42	$0.00	-$137.70	-$18.27	**-$332.26**	$525.96	**$193.70**	$2,282.06
Pacific Division	16.9	14.9%	2.74	-$44.76	-$65.70	-$3.58	-$125.02	-$90.02	**-$329.09**	$542.83	**$213.74**	$2,860.32
CA	12.2	10.7%	2.82	-$40.59	-$62.92	-$2.54	-$125.02	-$90.02	**-$321.10**	$557.23	**$236.13**	$3,071.10
AK, HI, OR, WA	4.7	4.1%	2.55	-$56.55	-$73.20	-$5.68	-$125.02	-$90.02	**-$350.47**	$505.01	**$154.53**	$2,302.77

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

(Please see Appendix C.6 for similar results from other scenarios)

4.6 HOUSEHOLD INCOME BRACKET IMPACTS

4.6.1 Average American household

The average American household, as well as the average household in each Division and state, can be compensated for the anticipated fuel cost increases under all of these carbon fee scenarios by returning half of the revenues directly to consumers. However, most Americans do not live in this average household. Assessing the impacts across different income brackets will better represent the impacts to American households. For this, RECS is still used for the in-house energy expenditures and CEX for the transportation expenditures. Both surveys provide energy expenditures by household income brackets, but the thirteen CEX household income bracket data are re-aggregated to match the seven brackets in RECS. After re-aggregating according to Appendix C.3, one can use the *index method* to show the costs, rebates, and net impacts to average American households in each income bracket.

Figure 4.10 illustrates the first year costs, rebate, and benefits across income brackets under the \$25/tCO_2 at 2% carbon policy. The first bar in the figure is the average American household with a total cost of \$327 and a rebate of \$508 in 2014. The income brackets in RECS are in \$20,000 after-tax increments; all households earning over \$120,000 are lumped together into the last bracket. The figure shows that a 50% rebate is sufficient to offset the costs for households earning below \$100,000 annually, and a 40% rebate is sufficient for households earning under \$80,000. Also, the first three income brackets, which earn less than \$60,000 per year, will receive a net benefit greater than the average American household, and \$60,000-\$80,000 income households are on par with the U.S. average.

Figure 4.10 also shows the cumulative percentage of population. The lowest income bracket includes 21% of all households in the U.S., and the second largest includes an additional 24%. Nearly two thirds (64%) of all households make less than \$60,000 and all will do better than the American household average. A 50% rebate is sufficient to offset the direct costs of this policy to the first 84% of all households, and a 60% rebate will include the through 89% of all households. So only the 11% of households in the highest income bracket will face a loss under a 60% rebate. To fully offset the added costs to this largest income bracket would require an 83% rebate.

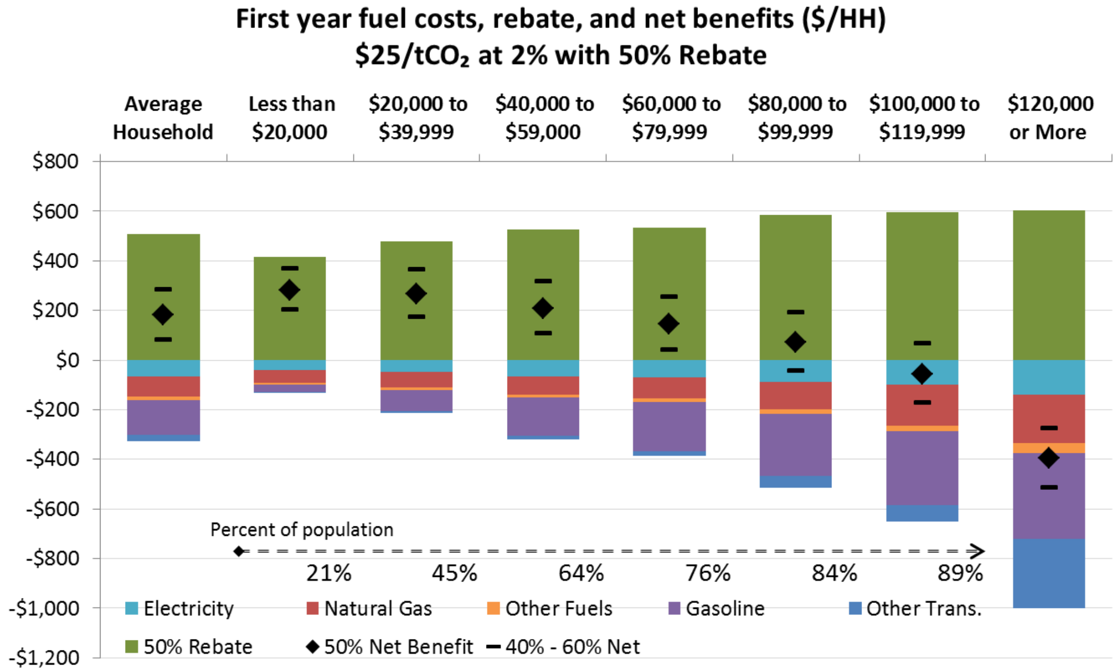

Figure 4.10 Impacts to average American households by income bracket

One important caveat here is that while a 50% rebate will progressively protect 84% of all American households, this represents less than 30% of the aggregate wealth. As described in Section 2.3.2, households in the highest income quintile (wealthiest 20% of American households) contribute nearly 70% of all U.S. income taxes. So while these carbon fee and dividend policies can protect 84% of all households (on average), the remaining 16% of the wealthiest households representing the majority of money spent on energy and U.S. tax receipts will see a net cost.

All of the household income brackets in Figure 4.10 will receive the same per capita rebate, so the difference in the value of the rebate bar is strictly a reflection of the number of pph. On average, there are 2.57 pph, but lower income households trend closer to about 2 pph. Upper income households have closer to 3 pph and will receive a proportionately larger household rebate. Furthermore, as household income rises, so does in consumption of gasoline and other transportation costs from the carbon policy. The increase in other transportation is conspicuously much larger in the highest income bracket, since higher income households tend to drive and fly more often (Aamaas et al., 2013) and will incur a larger penalty for this activity.

Table 4.25 lists the numbers behind Figure 4.10 and includes the first year net impact as a percentage of income for each income bracket. For the first six income brackets, this is based on the average income within the bracket. So, for the second lowest bracket, households earning $30,000 would receive 0.88% additional income from the fee-rebate policy, with a range of 0.66% to 1.3% additional income for this category, depending on household income. For the highest income bracket, a 50% rebate is not sufficient to offset the cost of the policy so these households will face a 0.3% net income loss based on households earning the category minimum of $120,000 (earning more than this will incur a smaller percentage loss with respect to income). Table 4.25 also lists the NPV of the first ten years under this policy for each income bracket. Table 4.26 summarizes each scenario, with respect to the net benefit of the first year and the NPV of the first ten years of each policy. In general, the policies seem pretty well balanced across income distributions. As either the initial carbon fee or the escalation rate increase, the net benefit and NPV remain relatively constant. So the percentage of income (although not shown in the table) would also remain relatively constant across the policies for each income bracket.

Table 4.25 First year net benefits for income brackets

		Household Income Brackets[1] ($25/t$CO_2$ at 2% with 50% Rebate)						
	Average Household	Less than $20,000	$20,000 to $39,999	$40,000 to $59,000	$60,000 to $79,999	$80,000 to $99,999	$100,000 to $119,999	$120,000 or More
Percent of HH	100.0%	20.9%	24.2%	18.7%	12.5%	8.2%	5.0%	10.6%
Electricity	-$64.48	-$38.98	-$47.68	-$64.13	-$70.12	-$87.11	-$98.01	-$140.92
Natural Gas	-$83.80	-$51.79	-$62.30	-$75.02	-$83.35	-$112.48	-$166.73	-$193.68
Other Fuels	-$13.66	-$7.67	-$9.36	-$11.03	-$16.90	-$16.17	-$20.12	-$41.67
Gasoline	-$138.59	-$30.44	-$88.02	-$153.32	-$198.29	-$251.35	-$300.10	-$344.40
Other Trans.	-$26.94	-$3.41	-$5.87	-$14.39	-$17.36	-$47.87	-$65.71	-$279.31
Net cost	-$327.48	-$132.28	-$213.23	-$317.89	-$386.02	-$514.98	-$650.66	-$999.97
50% Rebate	$508.93	$415.07	$478.47	$527.00	$532.94	$586.16	$594.60	$603.53
50% Net Benefit	$181.46	$282.79	$265.23	$209.11	$146.92	$71.18	-$56.06	-$396.45
Percent of Income[2]	0.29%	2.83%	0.88%	0.42%	0.21%	0.08%	-0.05%	-0.33%
NPV (2014-2023)[3]	$1,283.43	$2,166.11	$2,017.11	$1,511.87	$998.89	$343.24	-$701.40	-$3,585.10

Notes: [1]First year after tax values in 2011 chained USD

[2]Based on average income in each category, except for the highest bracket where the minimum income is used. U.S. income average from CEX

[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

Table 4.26 First year net benefits for income brackets

	Household Income Brackets[1] ($25/tCO$_2$ at 2% with 50% Rebate)							
	Average Household	Less than $20,000	$20,000 to $39,999	$40,000 to $59,000	$60,000 to $79,999	$80,000 to $99,999	$100,000 to $119,999	$120,000 or More
Percent of HH	100.0%	20.9%	24.2%	18.7%	12.5%	8.2%	5.0%	10.6%
50% Net Benefit of first year of the policy								
$15/tCO$_2$ at 2%	$113.80	$174.38	$164.17	$130.57	$93.00	$47.62	-$29.03	-$234.89
$15/tCO$_2$ at 4%	$115.31	$175.29	$165.32	$131.96	$94.59	$49.67	-$26.16	-$231.36
$15/tCO$_2$ at 6%	$122.39	$176.02	$168.99	$139.26	$104.22	$63.29	-$9.74	-$202.08
$15/tCO$_2$ at 8%	$123.08	$176.40	$169.46	$139.79	$104.88	$64.27	-$7.92	-$200.06
$25/tCO$_2$ at 2%	$181.46	$282.79	$265.23	$209.11	$146.92	$71.18	-$56.06	-$396.45
$25/tCO$_2$ at 4%	$180.37	$281.94	$264.23	$207.92	$145.72	$69.88	-$57.12	-$397.77
$25/tCO$_2$ at 6%	$180.53	$281.96	$264.32	$208.08	$145.93	$70.18	-$56.73	-$397.10
$25/tCO$_2$ at 8%	$179.49	$281.02	$263.34	$207.08	$144.97	$69.11	-$58.02	-$398.14
$35/tCO$_2$ at 2%	$248.79	$387.35	$363.62	$286.98	$201.83	$98.09	-$77.00	-$542.73
$35/tCO$_2$ at 4%	$256.27	$388.85	$367.83	$294.55	$211.59	$111.65	-$60.40	-$514.35
$35/tCO$_2$ at 6%	$256.12	$388.34	$367.46	$294.38	$211.55	$111.92	-$59.77	-$512.94
$35/tCO$_2$ at 8%	$253.45	$386.40	$365.10	$291.49	$208.56	$108.57	-$62.73	-$516.88
NPV (2014-2023)[2]								
$15/tCO$_2$ at 2%	$846.83	$1,386.91	$1,294.36	$984.24	$665.73	$266.89	-$364.16	-$2,156.16
$15/tCO$_2$ at 4%	$915.27	$1,499.02	$1,399.52	$1,063.65	$719.62	$288.64	-$391.78	-$2,330.50
$15/tCO$_2$ at 6%	$1,016.76	$1,623.16	$1,527.56	$1,179.10	$816.17	$364.99	-$363.56	-$2,408.07
$15/tCO$_2$ at 8%	$1,066.41	$1,732.45	$1,625.63	$1,242.39	$847.96	$353.00	-$440.28	-$2,665.21
$25/tCO$_2$ at 2%	$1,283.43	$2,166.11	$2,017.11	$1,511.87	$998.89	$343.24	-$701.40	-$3,585.10
$25/tCO$_2$ at 4%	$1,339.18	$2,309.53	$2,139.49	$1,585.50	$1,026.89	$307.63	-$831.20	-$3,964.91
$25/tCO$_2$ at 6%	$1,357.62	$2,436.68	$2,240.98	$1,625.33	$1,014.64	$216.18	-$1,035.33	-$4,460.67
$25/tCO$_2$ at 8%	$1,367.58	$2,565.14	$2,339.83	$1,658.89	$991.51	$106.49	-$1,271.98	-$5,006.12
$35/tCO$_2$ at 2%	$1,616.16	$2,864.59	$2,640.28	$1,929.52	$1,218.85	$293.59	-$1,166.62	-$5,145.84
$35/tCO$_2$ at 4%	$1,632.85	$3,001.29	$2,749.99	$1,971.75	$1,203.58	$189.91	-$1,400.53	-$5,699.91
$35/tCO$_2$ at 6%	$1,507.80	$3,071.32	$2,759.66	$1,871.10	$1,021.35	-$127.77	-$1,883.31	-$6,635.67
$35/tCO$_2$ at 8%	$1,190.75	$3,018.34	$2,619.59	$1,578.96	$632.29	-$698.97	-$2,654.00	-$7,958.53

Notes: [1]First year after tax values in 2011 chained USD
[2]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

4.6.2 Regional households

Both RECS and CEX report energy consumption for income brackets by Census Region. Following the same procedure, one can assess the Regional impacts as shown in Figure 4.11. For reference, the first group of data bars in the figure represents the average American household, essentially a consolidation of Figure 4.10. Within each section, the data bars follow the same order as in Figure 4.11. Within each section, the data bars follow the same order as in Figure 4.10, which begins with the average impact for that Region. The average bar is followed by the seven income brackets, from low to high.

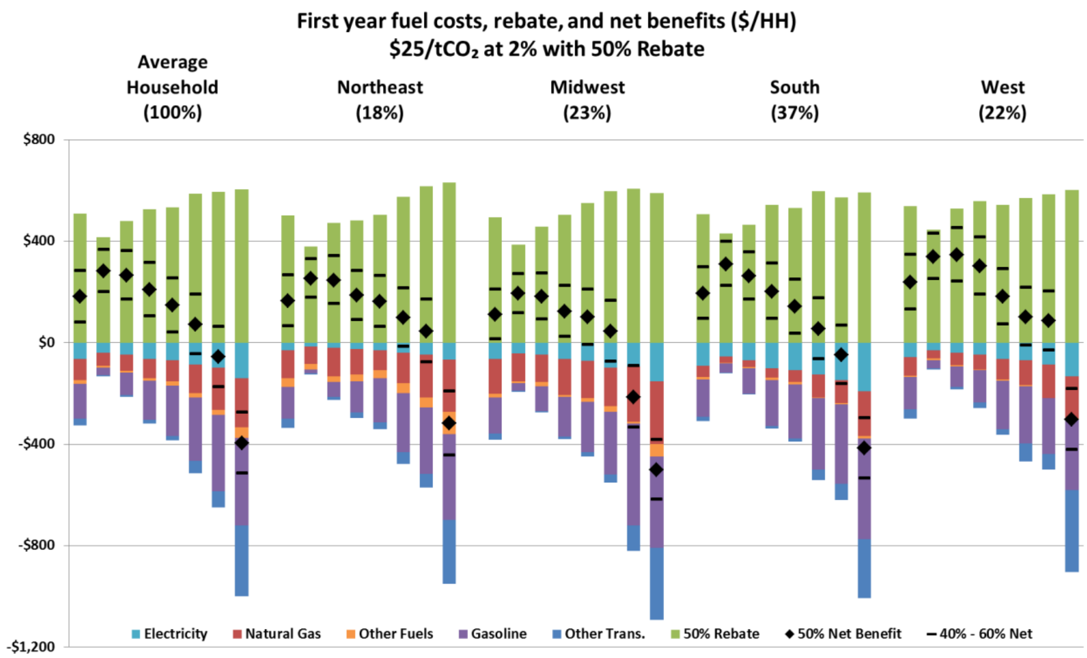

Figure 4.11 Regional impacts to households by income bracket, sorted by region

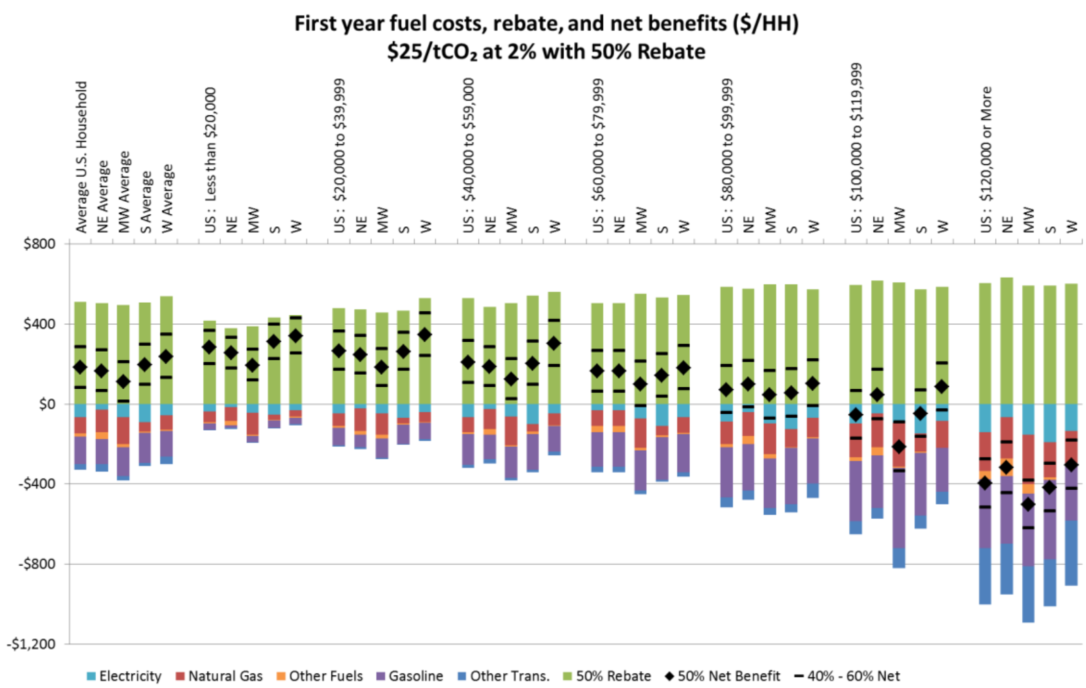

Figure 4.12 Regional impacts to households by income bracket, sorted by income

In general, the income bracket impacts are very similar among Regions. The lowest three income brackets in all Regions will do better than the Region average. As income increases, consumers spend more in energy. As a result, the policy cost for each fuel generally increases with income. Carbon fee impacts to air travel will be shared almost entirely by households in the highest income bracket in each Region. Also, since household occupancy rate typically increases in correlation with income, higher income brackets will receive a larger household rebate, offsetting costs for most income brackets. These details and others are summarized in Table 4.27 for this scenario. (Please see Appendix C.7 for results from other policies.)

Another way to visualize the data is to group the results by income brackets instead of by Regions, as in Figure 4.12. The first group in the figure includes the average American household and the average household in each of the four Regions. A 50% rebate would offset the costs of the carbon fee for households in the first five of seven income brackets, which includes all households making under $100,000. This holds for each Region as well. However, in the NE and W Regions, households making between $100,000 and $119,999 would also have a net positive benefit from a 50% rebate. A 40% rebate would offset the costs to all households earning less than $80,000, the first four brackets. A 60% rebate would give a positive net benefit to the first six income brackets, earning less than $120,000, in all Regions except in the MW. On average, the MW is the most affected by a carbon fee, so the rebate is less effective at offsetting the costs.

Taking this a step further, one can use the *index method* to assess income brackets at the Division level. To do this, it is assumed that the pph for the Region income brackets is the same at the Division level. So, the rebate will look identical for Divisions in the same Region. The result in Figure 4.13 has the same layout and data bar order as Figure 4.11, with the average American household first for reference.

The West Region, on average, is the best off under the policy. However, the Divisional breakdown shows that the highest income category in the Pacific Division will be the hardest hit, due to its additional air travel costs. The next most impacted bracket is the highest income bracket of the East South Central Division in the South

Region. Despite the impact to these two high-earning brackets, the MW Region, on average, receives the least net benefit of the four Regions.

Table 4.27 Net benefits by income bracket

Costs and Benefits to the average household[1]
(\$25/tCO_2 at 2% with 50% rebate)

Market Segment	Households: million	% of total	% of Region	pph	First Year Costs (2014): Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	Total Costs	First Year Rebate: 50% Rebate	Net benefit	% of Income[2]	NPV Net Benefit[3]
Average Household														
Average U.S.	113.6	100.0%		2.57	-\$64.48	-\$83.80	-\$13.66	-\$138.59	-\$26.94	**-\$327.48**	\$508.93	**\$181.46**	0.29%	\$1,283.43
Less than \$20,000	23.7	20.9%		2.10	-\$38.98	-\$51.79	-\$7.67	-\$30.44	-\$3.41	**-\$132.28**	\$415.07	**\$282.79**	2.83%	\$2,166.11
\$20,000 to \$39,999	27.5	24.2%		2.42	-\$47.68	-\$62.30	-\$9.36	-\$88.02	-\$5.87	**-\$213.23**	\$478.47	**\$265.23**	0.88%	\$2,017.11
\$40,000 to \$59,000	21.2	18.7%		2.66	-\$64.13	-\$75.02	-\$11.03	-\$153.32	-\$14.39	**-\$317.89**	\$527.00	**\$209.11**	0.42%	\$1,511.87
\$60,000 to \$79,999	14.2	12.5%		2.69	-\$70.12	-\$83.35	-\$16.90	-\$198.29	-\$17.36	**-\$386.02**	\$532.94	**\$146.92**	0.21%	\$998.89
\$80,000 to \$99,999	9.3	8.2%		2.96	-\$87.11	-\$112.48	-\$16.17	-\$251.35	-\$47.87	**-\$514.98**	\$586.16	**\$71.18**	0.08%	\$343.24
\$100,000 to \$119,999	5.7	5.0%		3.00	-\$98.01	-\$166.73	-\$20.12	-\$300.10	-\$65.71	**-\$650.66**	\$594.60	**-\$56.06**	-0.05%	-\$701.40
\$120,000 or More	12.0	10.6%		3.05	-\$140.92	-\$193.68	-\$41.67	-\$344.40	-\$279.31	**-\$999.97**	\$603.53	**-\$396.45**	-0.33%	-\$3,585.10
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-\$29.51	-\$111.03	-\$33.56	-\$124.95	-\$37.47	**-\$336.52**	\$501.98	**\$165.46**	0.24%	\$1,243.69
Less than \$20,000	4.0	3.5%	19.2%	1.92	-\$14.07	-\$70.33	-\$21.23	-\$14.68	-\$5.01	**-\$125.32**	\$379.18	**\$253.85**	2.54%	\$2,004.53
\$20,000 to \$39,999	4.3	3.8%	20.7%	2.38	-\$20.86	-\$112.09	-\$20.79	-\$60.71	-\$11.01	**-\$225.46**	\$471.26	**\$245.79**	0.82%	\$1,924.68
\$40,000 to \$59,000	3.5	3.1%	16.8%	2.44	-\$25.38	-\$99.74	-\$26.78	-\$123.53	-\$22.08	**-\$297.51**	\$483.18	**\$185.66**	0.37%	\$1,436.93
\$60,000 to \$79,999	2.8	2.5%	13.5%	2.55	-\$30.82	-\$77.60	-\$32.14	-\$172.80	-\$28.12	**-\$341.49**	\$504.38	**\$162.89**	0.23%	\$1,224.66
\$80,000 to \$99,999	1.9	1.7%	9.1%	2.91	-\$40.12	-\$120.54	-\$39.44	-\$230.42	-\$46.89	**-\$477.41**	\$575.83	**\$98.42**	0.11%	\$673.74
\$100,000 to \$119,999	1.5	1.3%	7.2%	3.12	-\$46.20	-\$170.59	-\$39.07	-\$262.66	-\$52.69	**-\$571.21**	\$617.10	**\$45.89**	0.04%	\$224.32
\$120,000 or More	2.8	2.5%	13.5%	3.19	-\$66.88	-\$205.82	-\$87.62	-\$338.16	-\$251.95	**-\$950.43**	\$631.63	**-\$318.80**	-0.27%	-\$2,756.05
Midwest	25.9	22.8%	100.0%	2.49	-\$64.09	-\$136.94	-\$14.18	-\$143.86	-\$23.29	**-\$382.36**	\$493.11	**\$110.75**	0.19%	\$732.22
Less than \$20,000	5.5	4.8%	21.2%	1.96	-\$42.89	-\$109.29	-\$6.62	-\$31.27	-\$3.73	**-\$193.80**	\$387.14	**\$193.34**	1.93%	\$1,441.16
\$20,000 to \$39,999	6.5	5.7%	25.1%	2.31	-\$46.88	-\$107.49	-\$17.52	-\$98.34	-\$5.15	**-\$275.37**	\$457.39	**\$182.02**	0.61%	\$1,361.15
\$40,000 to \$59,000	5.0	4.4%	19.3%	2.55	-\$63.23	-\$143.26	-\$7.28	-\$156.14	-\$10.99	**-\$380.90**	\$504.51	**\$123.60**	0.25%	\$848.89
\$60,000 to \$79,999	3.4	3.0%	13.1%	2.78	-\$71.90	-\$147.11	-\$13.75	-\$199.63	-\$17.18	**-\$449.57**	\$549.58	**\$100.01**	0.14%	\$633.53
\$80,000 to \$99,999	2.0	1.8%	7.7%	3.02	-\$97.72	-\$153.88	-\$20.56	-\$247.06	-\$32.95	**-\$552.17**	\$596.82	**\$44.65**	0.05%	\$63.41
\$100,000 to \$119,999	1.3	1.1%	5.0%	3.06	-\$92.60	-\$219.91	-\$7.41	-\$400.40	-\$100.31	**-\$820.62**	\$606.01	**-\$214.61**	-0.20%	-\$1,848.66
\$120,000 or More	2.1	1.8%	8.1%	2.98	-\$153.59	-\$247.30	-\$46.87	-\$360.53	-\$283.95	**-\$1,092.24**	\$590.27	**-\$501.97**	-0.42%	-\$4,467.96
South	25.9	22.8%	100.0%	2.49	-\$90.53	-\$45.85	-\$8.38	-\$147.86	-\$17.60	**-\$310.22**	\$505.39	**\$195.18**	0.34%	\$1,164.07
Less than \$20,000	10.0	8.8%	38.6%	2.18	-\$54.06	-\$25.30	-\$3.20	-\$36.08	-\$2.40	**-\$121.04**	\$431.31	**\$310.27**	3.10%	\$2,267.63
\$20,000 to \$39,999	10.7	9.4%	41.3%	2.35	-\$69.29	-\$26.80	-\$5.53	-\$99.37	-\$2.70	**-\$203.69**	\$465.75	**\$262.07**	0.87%	\$1,809.42
\$40,000 to \$59,000	8.1	7.1%	31.3%	2.74	-\$100.01	-\$38.20	-\$10.30	-\$180.36	-\$10.79	**-\$339.66**	\$542.22	**\$202.56**	0.41%	\$1,177.53
\$60,000 to \$79,999	4.6	4.0%	17.8%	2.69	-\$107.89	-\$47.65	-\$10.37	-\$211.94	-\$11.30	**-\$389.15**	\$531.58	**\$142.43**	0.20%	\$651.23
\$80,000 to \$99,999	3.2	2.8%	12.4%	3.01	-\$125.40	-\$91.40	-\$2.47	-\$280.14	-\$42.17	**-\$541.58**	\$596.13	**\$54.55**	0.06%	-\$109.48
\$100,000 to \$119,999	1.6	1.4%	6.2%	2.89	-\$147.40	-\$91.40	-\$5.16	-\$313.46	-\$63.24	**-\$620.66**	\$572.23	**-\$48.43**	-0.04%	-\$1,071.60
\$120,000 or More	3.9	3.4%	15.1%	2.99	-\$191.19	-\$175.63	-\$10.40	-\$398.48	-\$232.73	**-\$1,008.43**	\$592.16	**-\$416.27**	-0.35%	-\$4,218.52
West	24.8	21.8%	100.0%	2.72	-\$57.41	-\$71.79	-\$5.42	-\$128.94	-\$36.87	**-\$300.43**	\$537.77	**\$237.34**	0.37%	\$2,012.32
Less than \$20,000	4.3	3.8%	17.3%	2.25	-\$30.10	-\$32.21	-\$5.66	-\$33.35	-\$4.48	**-\$105.79**	\$445.16	**\$339.36**	3.39%	\$2,797.84
\$20,000 to \$39,999	6.0	5.3%	24.2%	2.67	-\$39.03	-\$50.28	-\$4.43	-\$80.28	-\$9.24	**-\$183.26**	\$528.51	**\$345.25**	1.15%	\$2,880.26
\$40,000 to \$59,000	4.6	4.0%	18.5%	2.82	-\$47.72	-\$57.84	-\$3.12	-\$127.85	-\$20.19	**-\$256.73**	\$558.75	**\$302.02**	0.60%	\$2,554.08
\$60,000 to \$79,999	3.3	2.9%	13.3%	2.74	-\$65.40	-\$79.21	-\$4.79	-\$192.42	-\$20.31	**-\$362.12**	\$543.13	**\$181.01**	0.26%	\$1,575.72
\$80,000 to \$99,999	2.2	1.9%	8.9%	2.89	-\$70.21	-\$96.36	-\$4.79	-\$225.32	-\$72.27	**-\$468.93**	\$571.22	**\$102.29**	0.11%	\$980.89
\$100,000 to \$119,999	1.4	1.2%	5.6%	2.96	-\$85.31	-\$133.84	\$0.00	-\$219.84	-\$60.70	**-\$499.69**	\$585.16	**\$85.47**	0.08%	\$814.68
\$120,000 or More	3.2	2.8%	12.9%	3.04	-\$133.23	-\$164.41	-\$4.67	-\$278.37	-\$324.62	**-\$905.30**	\$601.79	**-\$303.51**	-0.25%	-\$2,297.34

Notes: [1]First year after tax values in 2011 chained USD (unless otherwise noted)
[2]Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

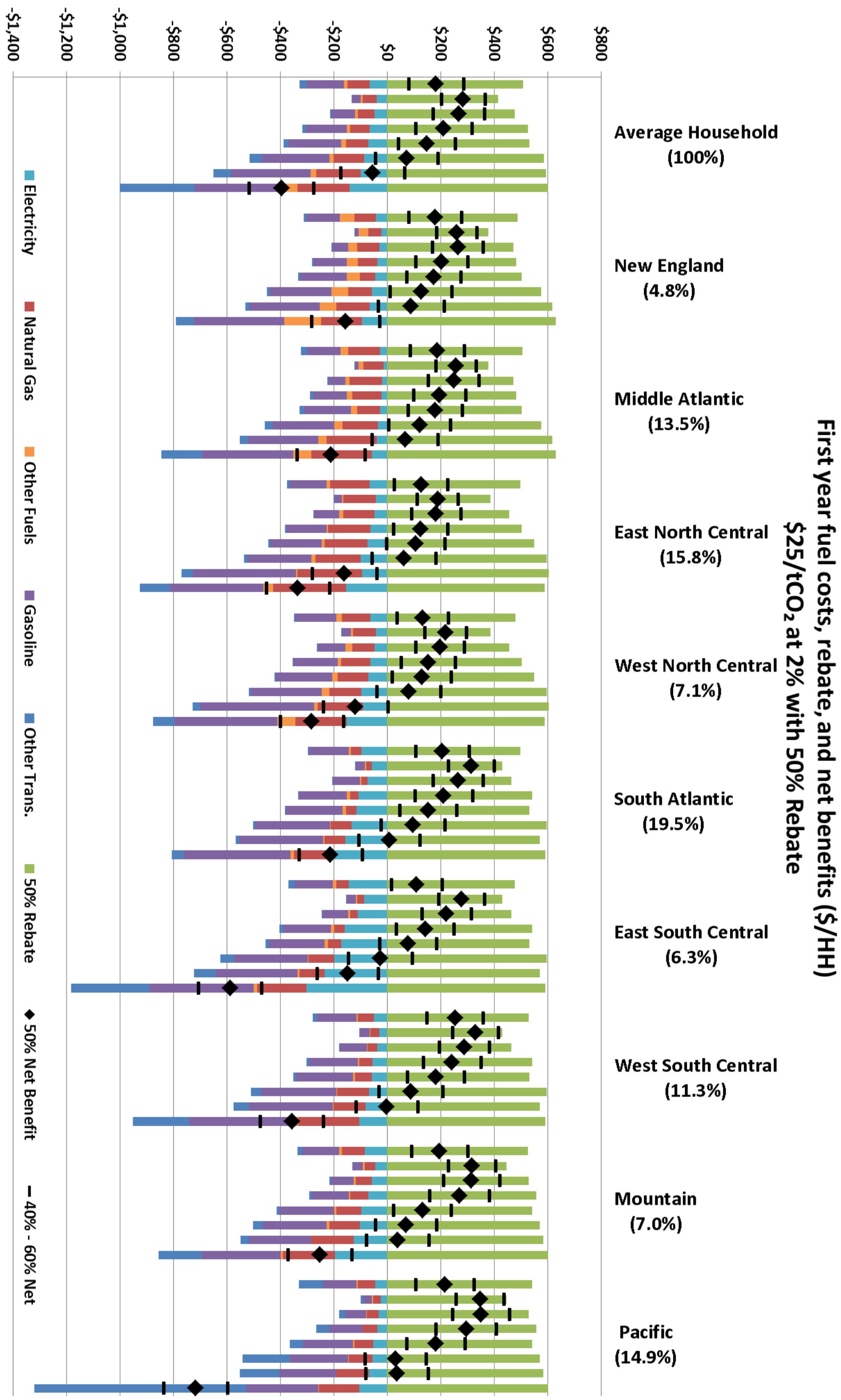

Figure 4.13 Impacts to households by income bracket in each Division

4.7 HOUSEHOLD IMPACT SUMMARY

This chapter provided a description of how to couple CEX and RECS, both very rich consumer expenditure datasets, and integrate them with NEMS forecasts. When combined, they enable the assessment of carbon fee and dividend policy impacts on average households across the U.S., by geographic region down to several individual states, and by income distribution.

The primary residential fuels are electricity, natural gas, and gasoline. The consumer price for each of these fuels is expected to rise over the next decade, even in the absence of a carbon policy. Residential electricity prices will rise 22% from 11.5 cents/kWh (nominal) in 2013 to 14.0 cents/kWh in 2023. Under a \$25/tCO_2 at 2% carbon policy, electricity prices will rise an additional 16% to 16.2 cents/kWh in 2023 (a 41% increase over 2013). Similarly, residential natural gas prices will rise 39% without a policy from 10.8 nominal \$/MMBTU in 2013 to 15.1 \$/MMBTU in 2023. Under the policy, they will rise an additional 19% to 18.1 \$/MMBTU in 2023. While there are only minor differences between geographic regions in the Reference scenario (no policy), under the policy, some Divisions, mostly in the Midwest and the South, will see significantly higher rate increases.

The average American household spends roughly 10% of total household expenditure on energy. In 2011, that was about \$5,100, with more than half from gasoline expenditure. Energy prices will rise in the absence of a carbon policy, but under a \$25/tCO_2 at 2% policy, the average American household will face an increase in cost of \$327 from all fuels combined in 2014. The same household will also receive a \$508 rebate (from a 50% rebate policy), which more than compensates the average American household for the additional fuel costs. This trend continues every year for the next ten years.

Different regions face different combinations of climatological and latitudinal differences that drive demand. Local decisions about fuel mix affect how impactful a carbon policy will be. And the number of occupants in a household determines the rebate amount. So assessing at the smallest geographical region possible is preferred to a assessing at the national or even a Region or Division level. RECS provides energy expenditures to the state level for the 16 most populous states, and the remaining states are collected in groups of mostly three or four adjacent states. This allows one to nearly isolate impacts due to existing fuel mix decisions. Most states or collections of states will receive a net positive benefit from a 50% rebate.

Even within a state, consumers have varying incomes and make different choices about energy consumption. Ideally, one could evaluate household energy expenditures at the state level by income bracket. Unfortunately, the data does not support this level of detail. Still, the methods described above do allow for Census Region and Division level income bracket assessments. The seven brackets described above are in $20,000 increments, starting with households earning ‘less than $20,000’ annually (after taxes) and ending with ‘$120,000 or more’ annually. The analysis shows that all households earning less than $100,000 (first five brackets) will receive a net positive benefit from a 50% rebate in the first year. This covers 84% of all American households. From a Regional perspective, a 40% rebate will keep all households earning less than $80,000 (first four brackets) positive, and a 60% rebate will do the same for all households earning less than $120,000 (first six brackets), except in the MW Region.

So, in general, most households in most states and in most income brackets will see a net positive direct benefit from a 50% rebate. Ideally, one could evaluate the energy expenditures in every state by income bracket. The data certainly does not provide the detail to support this type of analysis. Even without the income breakdown, evaluating just the geographic regions properly demands the smallest region possible. For example, from the Regional perspective, the current analysis shows that average MW Region household will incur the highest increased energy expenditures from the carbon fee. Yet, from a Divisional perspective, the East South Central Division in the S Region will see the highest costs. When aggregated to the Region level, these strong impacts are muted by Divisions that have a lower level of impact.

One can extend this issue to the limit of the current analysis. Consider the aggregate collection of states: UT, ID, WY, and MT. These are all in the Mountain North sub-Division of the W Region, and receive the highest net benefit of any state(s) evaluated. When it comes to carbon emissions, ID is one of the lowest per capita emitters, while the other three are some of the largest emitters per person. So it is unlikely that the carbon fee costs seen by this aggregate is uniform across all four states. Furthermore, this group receives the largest household rebate, driven by the higher average occupancy in UT raising the average for the aggregate. According to the U.S. Census, UT had an occupancy rate of 3.09 (greater than any other state or aggregate), while MT, WY, and ID had 2.37, 2.48, and 2.66 respectively (Census, 2010). Of these last three, only ID had a higher occupancy rate the average American household. So, it is likely that ID, with the low per capita emissions and above average occupancy has earned the high net benefit from the policy.

These aggregation issues highlight the importance of resolving the data to the finest level possible for analysis. But to achieve this requires RECS staff to redouble their efforts, isolate more than just the 16 most populous states, and include transportation expenses in their survey. Until then, this analysis has been taken as far as possible with the current data structure.

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Chapter 5

INTEGRATING REVENUE RECYCLING WITHIN NEMS

5.1 INTRODUCTION

The previous two chapters described the general impacts from a range of U.S. Carbon fee and dividend policies. Chapter 3 showed that a carbon fee has the potential to significantly reduce carbon emissions with a proportionally much smaller effect on the overall U.S. economy. Chapter 4 showed that returning 50% of the revenues as a rebate to households will more than offset direct policy costs to about 90% of all American households. These results answer the study's intended questions. This chapter takes it a step further to integrate the two pieces together within the modeling framework by investigating different revenue recycling options available in NEMS. This revenue recycling analysis provides insight into the positive multiplier effects that a rebate would have on the economy, as well as the limitations of NEMS in providing that information.

The carbon policies, as described in Chapter 3, will raise significant annual revenues. How those revenues are returned to consumers and businesses can reduce the carbon fee impacts on economic growth while still reducing emissions and providing sufficient rebate to households. Ideally, this analysis would be entirely integrated within the model framework and enable the model to account for spillovers, feedbacks, and rebound effects. Unfortunately, the model is not set up to evaluate carbon fee and rebate policies, only economic sensitivities to carbon price. What follows is an exploration of what is possible within NEMS, showing that the current framework is only adequate to identify ranges of impacts.

Section 5.2 begins with a comparison of the default revenue recycling methods available in NEMS, and how to modify the code to recycle revenues beyond the default methods. Section 5.3 compares the impacts of different revenue recycling methods on the economy.

Section 5.4 will discuss how EIA protects energy-intense and trade-exposed (EITE) industries in NEMS, which will demonstrate that the levers readily accessible to the user are not sufficient for a detailed revenue recycling analysis. Finally, Section 5.5 will summarize these NEMS revenue recycling methods and limitations.

5.2 Revenue recycling methods in NEMS

5.2.1 Default options

NEMS has several default options for how its macroeconomic calculations treat the use of carbon fee revenues. These options were described in greater detail in Section 2.2, but are summarized here for convenience.

The desired revenue recycling option is set with the *mactax* flag in the *scedes* (scenario description) text file. Default values for *mactax* range from 0 to 5. A value of 0 turns carbon pricing off (i.e., no revenues), while settings 1-5 turn carbon pricing on with binary control over how revenues are recycled through the economy: *mactax* 1 and 2 return revenues to consumers and business (respectively) in a revenue-neutral manner; *mactax* 3 is deficit reduction; while *mactax* 4 and 5 return revenues to consumers and business (respectively) in a deficit-neutral manner. None of the default options allow for a mixture of deficit reduction, residential rebates, and other policy expenditures. The default options are an all-or-nothing configuration. (Please see Section 2.3.2 for an explanation of deficit-neutral and revenue-neutral).

All of these default revenue recycling options are problematic in the model for different reasons, and Section 2.2 described several of these issues. For example, returning revenues ‘to consumers’ is effectively a personal tax rebate, but income- and tax-related information in NEMS is computed in-aggregate by the macroeconomic activity module (MAM). However, most of the total tax receipts collected are from the wealthiest Americans (CBO, 2013). So, returning revenues ‘to consumers’ effectively reduces the taxes on the wealthiest Americans and has little to no impact on the poorest. This fails to capture the fiscal multiplier effect of giving money to lower income residents. A per capita rebate would likely have a greater re-spending effect since low income transfers are generally believed to be higher (Elmendorf and Furman, 2008; Johnson et al., 2004).

Similarly, returning revenues ‘to businesses’ is effectively a corporate tax rebate, but corporate income and taxes are also computed in-aggregate. The wealthiest corporations pay most of total U.S. corporate taxes (TPC, 2011), so, reducing aggregate corporate tax receipts effectively gives a tax break to the wealthiest corporations in America –oil companies, banks, and high-tech companies.

The scenarios described in Chapter 3 use *mactax* = 4, which returns the revenues to consumers in a deficit neutral manner. This setting was chosen for several reasons. First, this study is primarily interested in identifying impacts to residential consumers (households in particular), and setting *mactax* = 4 recycles all revenues back to households (minus what is required to keep from increasing the deficit). This was sufficient to explore the economic impacts and to assess the scale of the percentage rebate required to make certain households whole. Second, EIA sets *mactax* = 4 for published NEMS carbon price sensitivity side cases described in Appendix D of the AEO2013 (EIA, 2013a). Third, different default revenue options do not materially affect GDP, net CO_2 emissions, or residential energy prices differently (see Appendix A.7 for an example).

Rebating to aggregate income tax payers (consumers or businesses) in the model allows for a coarse representation of a re-spending effect, but is at least better than nothing. The macroeconomic results may not be very different between recycling options in the model, but there are some subtle differences in other details. So, fully integrating the actual rebate percentage into the model calculations may be necessary to capture these details.

5.2.2 Modifying the default methods

The limitation of using the default settings is far from ideal. For example, the Boxer–Sanders Climate Protection Act intended to return 60% of carbon fee revenues to consumers in the form of a dividend or rebate, another 25% would be applied to the deficit, and the remaining amount would help support energy efficiency programs and protect EITE industries (Boxer and Sanders, 2013). Yet, none of the default revenue recycling options allow for a mixture of deficit reduction, residential rebates, and other policy expenditures. Fortunately, it is possible to combine the *mactax* settings in the MAM, but EIA provides no documentation for doing this, nor do they define the associated variables and settings already in the code.

The NEMS interface with the MAM is the ***mcevcode.txt*** file, which is used to pass values and settings to the MAM. In ***mcevcode.txt***, *mactax* is already defined, and existing mactax operations can be combined (once one deciphers what takes place under each *mactax* value). Combining these operations requires defining a new *mactax* = 6 mode within the ***mcevcode.txt*** file framework to redirect the revenues in the MAM appropriately. This new *mactax* = 6 option uses the same variables as EIA uses in the default options, but scales the total rebate according to the percentage of revenues desired for each sector.

For example, splitting the revenues between consumers and businesses is not possible with the default options. However, if one were to scale the total revenues by 50% and give that to consumers (using *mactax* = 4 parameterization) and to businesses (using *mactax* = 5 parameterization), the result would be a 50/50 split of the revenues between the two groups. In this same manner, one could, for example, split the revenues into 25% to deficit reduction, 60% to consumers, and 15% to businesses, which would more closely match the allocations under the Boxer–Sanders Bill.

(Please see Appendix A.8 for the pertinent modified ***mcevcode.txt*** code, and the code definitions and settings).

5.3 DISTRIBUTION OF REVENUES TO CONSUMERS AND BUSINESSES

Chapter 4 showed that a 50% rebate was sufficient to offset the direct increase in energy costs from a carbon fee for most households. The analysis was based on NEMS results assuming 100% return of the revenues to consumers by using *mactax* = 4. However, integrating the 50% rebate should provide a more precise result. This section compares several revenue recycling results under the same carbon policy: all revenues are returned to consumers (*mactax* = 4), all revenues are returned to businesses (*mactax* = 5), all revenues are used for deficit reduction (*mactax* = 3), and all revenues are split evenly between consumers and businesses (*mactax* = 6, which is a combination of *mactax* =4 and *mactax* = 5).

As discussed in Section 2.3.2, using the revenues to pay down the deficit effectively removes that money from the economy. In reality, a lower federal deficit would enable the government to purchase more goods and services so the economy would indirectly benefit. However, the value of the deficit plays no part in MAM calculations. So in the model, this revenue recycling method essentially removes the money from the table. Returning revenues to consumers reduces total aggregate personal taxes. Since the carbon fee will impose an increase in energy prices, receiving a tax rebate will help alleviate the burden of the tax on consumers, which will in turn increase consumer demand for energy-based products and services. Similarly, returning revenues to businesses will give corporations some tax relief.

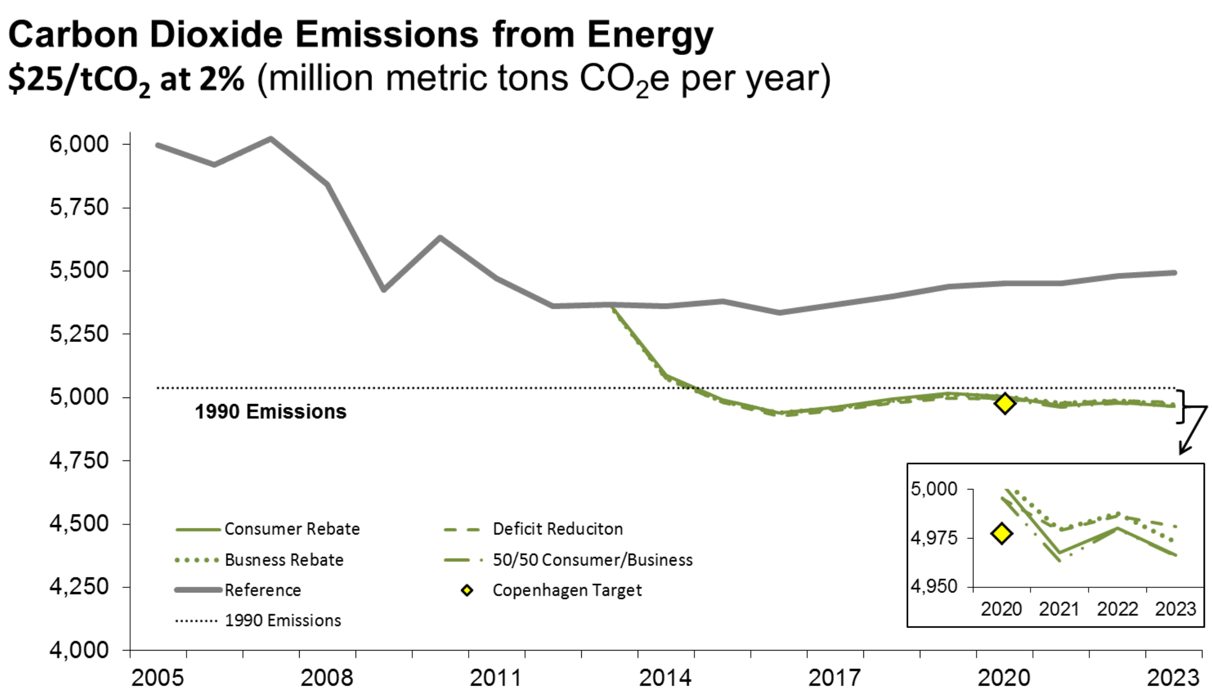
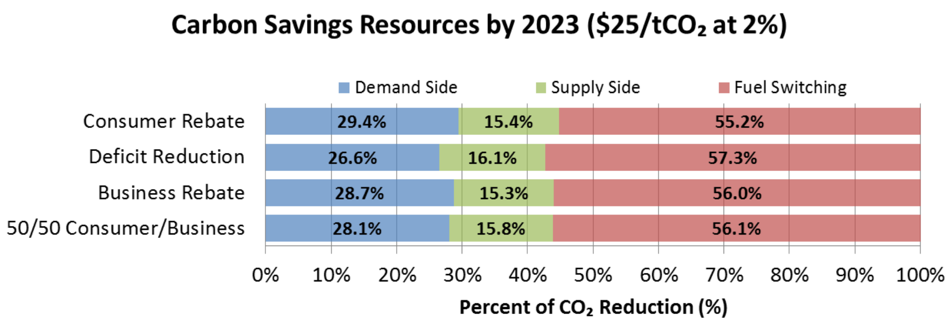


Figure 5.1 Emissions reductions from different revenue recycling methods

As previously discussed, the macroeconomic differences between various revenue recycling methods are relatively small. This is illustrated in Figure 5.1, which shows the revenue recycling method will have little effect on total carbon emission reductions. The inset of the figure shows that by 2023, a straight consumer rebate or a 50/50 mix of consumer/business rebate will improve emission reductions slightly. Using the revenues to pay down the deficit will produce a slightly lower reduction in emissions. Since the carbon emissions are nearly identical, all of these scenarios will raise about the same amount of revenues over the first ten years of the policies.



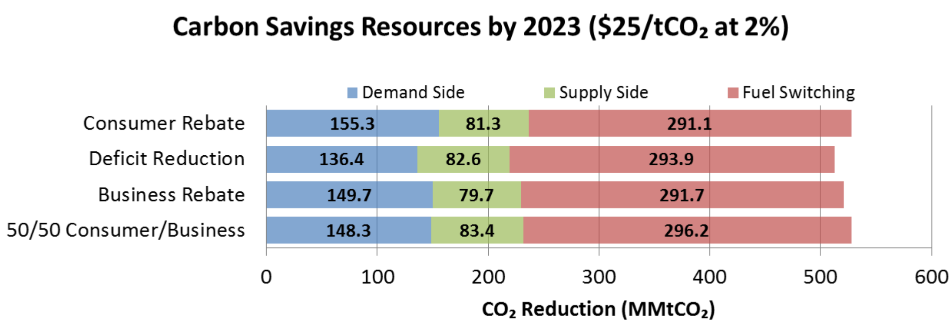


Figure 5.2 Sources of carbon reduction

Since the carbon fee and escalation rate is the same between scenarios, they all experience the same general financial drivers toward reducing carbon emissions. Yet an analysis of how the avoided emissions are achieved shows that some methods encourage more fuel switching and others more efficiency. Figure 5.2 shows that a consumer rebate will encourage consumers to retrofit and replace technology for better demand side efficiency, which requires less fuel switching. Using the revenues to pay down the deficit, on the other hand, limits demand side efficiency. The lack of subsidies forces energy suppliers to switch fuels and improve supply side efficiency to compensate for the higher energy prices. Apart from minor differences in fuel switching, the final fuel mix is generally the same between the revenue recycling policies.

GDP values in 2023 are very similar to the Reference scenario, with relatively small overall impacts after ten years. However, Figure 5.3 shows that although they all converge to similar long-term values, the short-term impacts are different based on the chosen recycling method. Deficit reduction has the greatest initial shock to GDP, since the entire economy feels the burden of the carbon fee, but neither consumers nor businesses receive any rebate to help transition to the new low-carbon economy. A full rebate to businesses may look beneficial in the long run, but in the first few years consumers are faced with higher prices and no relief. A combination of consumer and business rebate will both alleviate the initial shock to GDP and help consumers and businesses adjust their expenditures and technologies choices driven by the new energy prices.

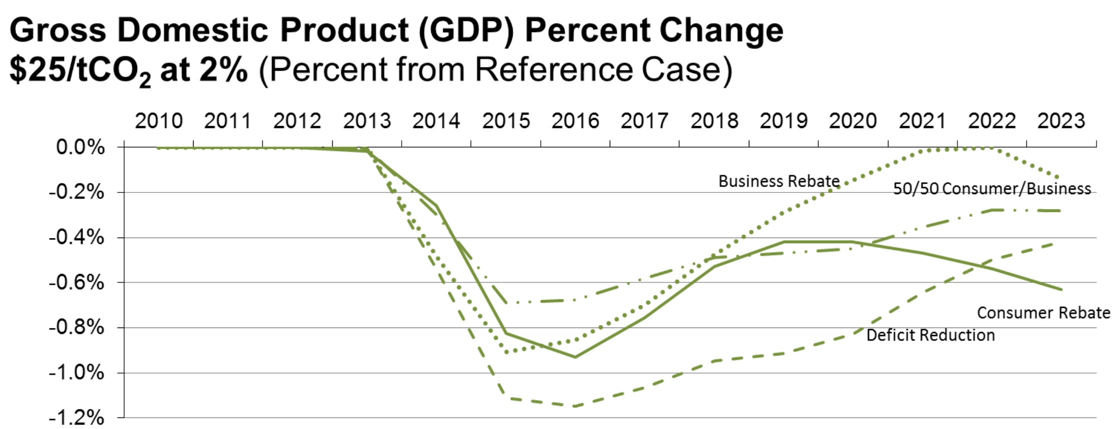


Figure 5.3 Emissions reductions from different revenue recycling methods

While the relative differences in GDP trajectories are important, the overall GDP impact is small. So there is little difference between carbon and energy intensities between recycling methods. Figure 5.4 shows that each scenario follows about the same path. The figure inset highlights the last few years of the policies, indicating that the business rebate scenario and the 50/50 scenario will reduce energy intensity the most (i.e. further left on the x-axis), but the 50/50 scenario will also reduce carbon intensity more than the others (i.e. further down on the y-axis).

The review of the macroeconomic impacts indicates that there is not a significant 'big picture' difference between revenue recycling methods when it comes to emissions and intensities. However, the varying annual GDP impacts suggest looking at sectoral differences.

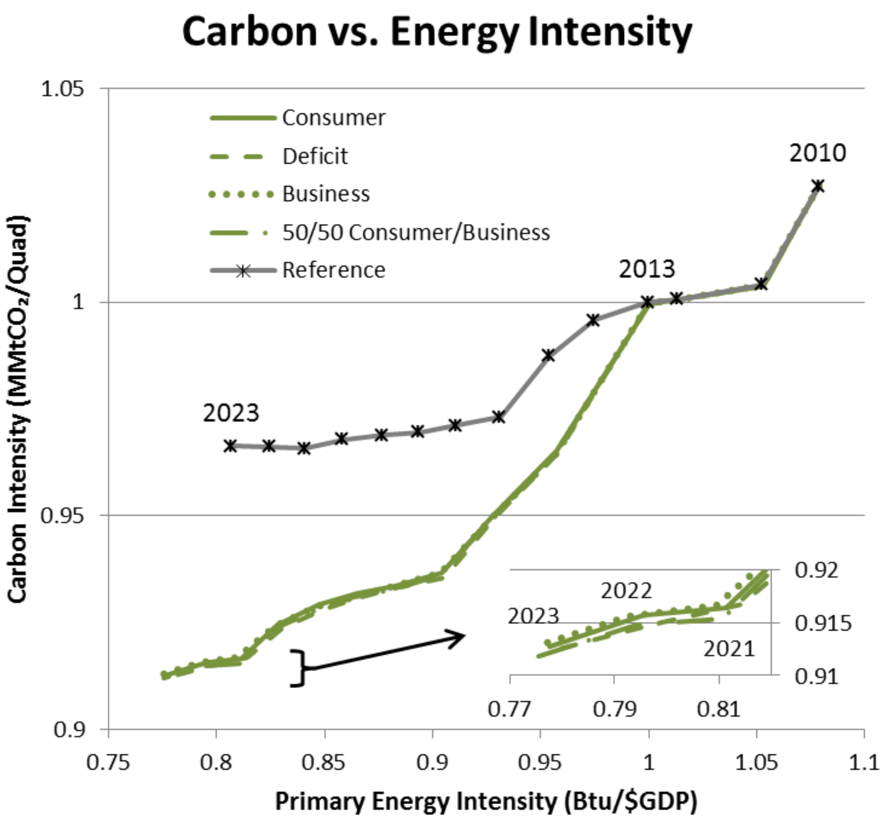


Figure 5.4 Carbon intensity vs. Energy intensity

Figure 5.5 shows energy consumption within the Commercial and Residential building sectors is effectively independent of the rebate method. The Transportation sector is a little more sensitive, but the total spread is still relatively small. The primary response from any of the carbon fees analyzed in Chapter 3 is to decarbonize the electricity sector. While energy demand in the Transportation sector varies between revenue recycling modes, the response is behavioral (as discussed in Section 3.4.2). So, returning revenues to businesses and consumers helps alleviate the carbon tax burden. The difference between the deficit reduction line and the 50/50 line is effectively a rebound effect when given the tax break.

Table 5.1 shows the avoided emissions for each sector for the major carbon fuel types. The table confirms that the building sectors will see significant avoided emissions from the electricity sector, but there is little difference between different rebate methods. In the Transportation sector, decarbonizing electricity has very little impact on total sector emissions. Also, avoided transportation emissions from other fuels converge to similar values by 2023.

More so than the other three demand sectors, the Industrial sector seems dependent on the recycling method, which will be addressed shortly. Overall avoided emission in this sector is similar between revenue recycling methods, but the emissions from non-electric fuels varies more significantly. The widest swing is in use of coal, where emissions range from 6% reduction in emissions under a corporate tax rebate to a 1% increase under deficit reduction method.

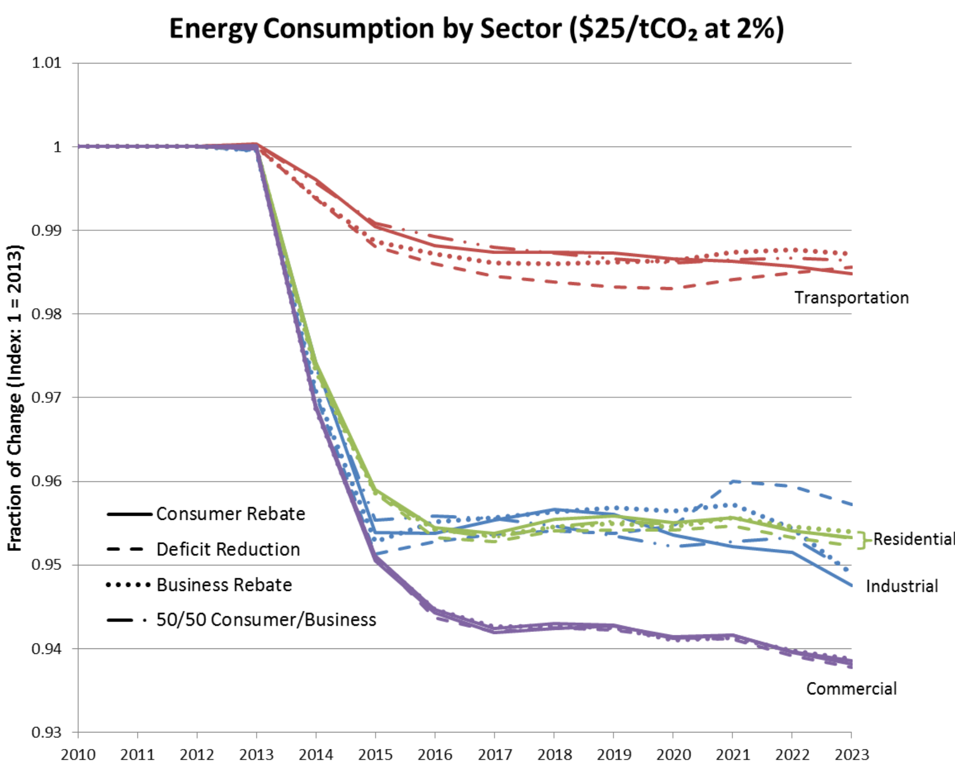


Figure 5.5 Change in energy consumption by sector from different revenue rebate methods

Table 5.1 Avoided emissions by sector

Avoided emissions by sector and fuel in 2023

	Industrial Sector					Transportation Sector					Residential Sector					Commercial Sector				
	Petroleum	Natural Gas	Coal	Electricity	Total Sector	Petroleum	Natural Gas	Coal	Electricity	Total Sector	Petroleum	Natural Gas	Coal	Electricity	Total Sector	Petroleum	Natural Gas	Coal	Electricity	Total Sector
Reference sceanrio total emissions (MMtCO$_2$)																				
Reference 2013	339.8	434.1	154.2	556.7	1484.7	1771.3	41.2	0.0	3.7	1816.3	81.1	261.4	0.7	763.9	1107.1	42.9	177.3	4.9	735.8	960.9
Reference 2023	350.8	502.0	159.9	620.0	1632.7	1763.4	43.2	0.0	5.2	1811.9	68.0	242.4	0.6	761.8	1072.7	46.1	180.9	4.9	744.8	976.8
Difference	11.0	67.9	5.8	63.3	148.0	-8.0	2.1	0.0	1.5	-4.4	-13.1	-19.1	-0.1	-2.1	-34.4	3.2	3.6	0.0	9.1	15.8
Difference (%)	3.1%	13.5%	3.6%	10.2%	9.1%	-0.5%	4.8%	0.0%	28.4%	-0.2%	-19.2%	-7.9%	-18.3%	-0.3%	-3.2%	6.9%	2.0%	0.0%	1.2%	1.6%
Policy scenario total emissions in 2023 (MMtCO$_2$)																				
Consumer Rebate	345.0	485.3	158.8	470.5	1459.6	1736.2	43.0	0.0	4.4	1783.5	66.9	235.0	0.6	608.5	911.0	44.6	171.1	4.9	589.3	809.9
Deficit Reduction	346.4	489.3	161.4	477.5	1474.6	1737.8	43.1	0.0	4.4	1785.2	66.9	235.0	0.6	608.6	911.1	44.6	171.0	4.9	589.7	810.1
Business Rebate	346.4	486.8	150.6	475.1	1458.8	1740.6	43.0	0.0	4.4	1788.0	66.9	235.0	0.6	611.3	913.9	44.6	171.1	4.9	591.6	812.2
50/50 Mix	345.7	485.8	158.8	470.6	1460.9	1739.1	43.0	0.0	4.4	1786.5	66.9	234.9	0.6	607.6	910.0	44.6	171.0	4.9	588.2	808.7
Policy scenario avoided emissions from Reference in 2023 (MMtCO$_2$)																				
Consumer Rebate	-5.8	-16.7	-1.1	-149.5	-173.1	-27.2	-0.2	0.0	-0.9	-28.3	-1.1	-7.4	0.0	-153.3	-161.7	-1.5	-9.8	0.0	-155.6	-166.9
Deficit Reduction	-4.4	-12.7	1.4	-142.5	-158.1	-25.6	-0.2	0.0	-0.9	-26.6	-1.1	-7.4	0.0	-153.1	-161.6	-1.5	-10.0	0.0	-155.1	-166.6
Business Rebate	-4.4	-15.2	-9.4	-144.9	-173.9	-22.8	-0.2	0.0	-0.8	-23.8	-1.1	-7.3	0.0	-150.4	-158.8	-1.5	-9.8	0.0	-153.2	-164.5
50/50 Mix	-5.1	-16.2	-1.1	-149.4	-171.8	-24.3	-0.2	0.0	-0.9	-25.4	-1.1	-7.4	0.0	-154.2	-162.7	-1.5	-9.9	0.0	-156.7	-168.1
Policy scenario percent difference from Reference in 2023 (%)																				
Consumer Rebate	-1.7%	-3.3%	-0.7%	-24.1%	-10.6%	-1.5%	-0.6%	0.0%	-16.6%	-1.6%	-1.6%	-3.0%	0.0%	-20.1%	-15.1%	-3.3%	-5.4%	0.1%	-20.9%	-17.1%
Deficit Reduction	-1.2%	-2.5%	0.9%	-23.0%	-9.7%	-1.5%	-0.4%	0.0%	-16.6%	-1.5%	-1.6%	-3.0%	0.0%	-20.1%	-15.1%	-3.3%	-5.5%	0.1%	-20.8%	-17.1%
Business Rebate	-1.3%	-3.0%	-5.9%	-23.4%	-10.7%	-1.3%	-0.5%	0.0%	-15.9%	-1.3%	-1.5%	-3.0%	0.0%	-19.7%	-14.8%	-3.2%	-5.4%	0.1%	-20.6%	-16.8%
50/50 Mix	-1.5%	-3.2%	-0.7%	-24.1%	-10.5%	-1.4%	-0.5%	0.0%	-16.5%	-1.4%	-1.5%	-3.1%	0.0%	-20.2%	-15.2%	-3.3%	-5.5%	0.1%	-21.0%	-17.2%

Table 5.2 and Figure 5.6 compare the ten-year Industrial sector LMDI decomposition results. In all scenarios, the activity effect is lower indicating a reduction in value of shipments (activity) from the Reference scenario. First, returning revenues to consumers has the biggest impact to value of shipments. Interestingly, the deficit reduction method will impact value of shipments the least. The structure effect is very similar between rebate methods, indicating very little difference in industry mode shares from different recycling methods. Emissions reductions from the energy intensity effect and carbon intensity effect are largest with the business rebate and smallest with the consumer rebate. Combined, the deficit reduction will reduce emission less other rebate methods. Overall, however, the differences between rebate methods are relatively subtle and difficult to disentangle.

Table 5.2 Industrial sector LMDI comparison of revenue recycling methods

	Total effects on carbon emissions (2013 - 2023)				
	Activity	Structure	Energy Intensity	Carbon Intensity	Total
Total effect ($MMtCO_2$)					
Reference	427.3	-68.6	-148.0	-62.7	148.0
Consumer Rebate	377.8	-85.9	-159.0	-157.2	-24.3
Deficit Reduction	399.0	-86.3	-162.8	-159.0	-9.1
Business Rebate	388.1	-87.4	-166.3	-159.4	-25.0
50/50 Consumer/Business	382.1	-87.3	-159.5	-158.1	-22.8
Percent from Reference					
Reference	0.0%	0.0%	0.0%	0.0%	0.0%
Consumer Rebate	-11.6%	25.2%	7.4%	150.8%	-116.4%
Deficit Reduction	-6.6%	25.9%	10.0%	153.5%	-106.2%
Business Rebate	-9.2%	27.5%	12.4%	154.2%	-116.9%
50/50 Consumer/Business	-10.6%	27.4%	7.7%	152.2%	-115.4%

Digging deeper, one can also look at the industry-specific LMDI decomposition shown in Table 5.3. The table aggregates the different effects from each recycling method together for comparison. In the table, adding the effects from activity, energy intensity, and carbon intensity to the 2013 emissions (column 2) will equal total emissions in 2023 for each rebate method.

The first three industries in Table 5.3 make up the non-manufacturing portion of the sector. All three are relatively insensitive to the recycling method, as evident in the relatively constant values between methods in the effects from changes in activity, energy intensity, and carbon intensity. As a result the total emission in 2023 from each is also consistent among them.

The same is true for the non-energy intense manufacturing industries as well (those not highlighted). Even within the energy intense industries, most are relatively insensitive to the revenue recycling method, including Food, Paper, Glass, Cement and Lime, and Aluminum industries. This does not say the carbon policy doesn't affect these industries; in fact all of them are measurably impacted by the carbon policy as shown when comparing to the Reference scenario impacts in Table 5.3 (and as discussed in Section 3.4.5). However, the impact to these industries is not materially affected by the revenue recycling choice in the model. Even the 'Balance of Manufacturing' exhibits only modest difference between methods.

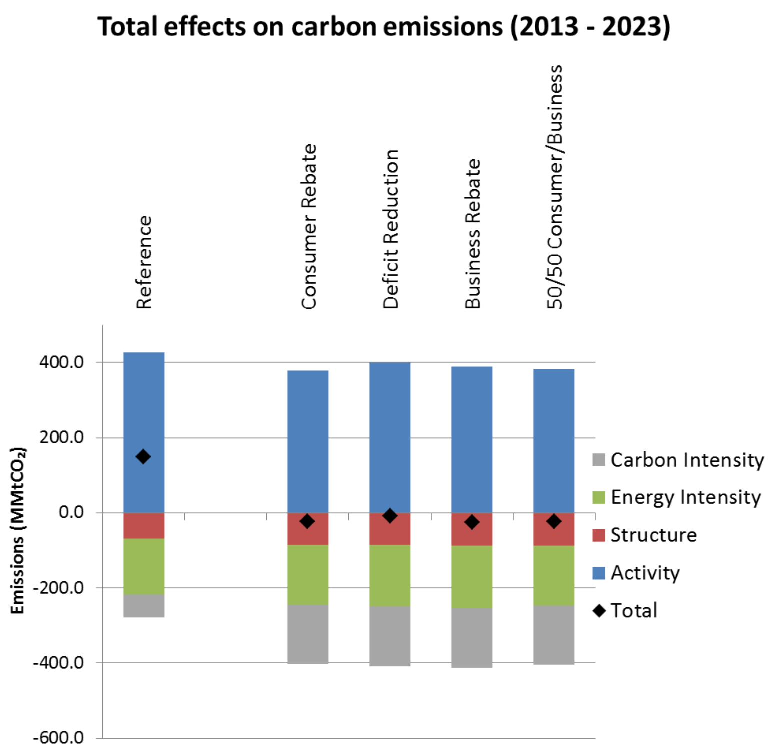


Figure 5.6 Industrial sector LMDI comparison of revenue recycling methods

Only three industries are impacted differently by the choice of revenue recycling method: Refining, Bulk Chemical, and Iron and Steel industries. These three represent only 11% of the Industrial sector in 2013. The Refining\ industry will experience more contraction (activity) under a Consumer rebate and less under the

Deficit reduction or Business rebate method. However, the Business rebate will reduce emissions significantly with respect to changes in carbon and energy intensities.

In the Bulk Chemical and Iron and Steel industries, energy and carbon intensities are not affected much by the revenue recycling method. However both will see less impact to value of shipments under the Deficit reduction or Business rebate. The 50/50 rebate falls in the middle for all three industries. Thus, for these three industries, a Business rebate or Deficit reduction will achieve the most carbon savings with minimal impact to the value of shipments. (Please see Table 3.9 for complete Reference scenario results for comparison and see Appendix B.14 for complete LMDI details on each of revenue recycling method scenario).

So, the choice of revenue recycling method will only impact a few industries, and, generally speaking, a 100% Business rebate method would maximize emission savings while minimizing impact to the value of shipments from these few industries. Yet, a rebate to consumers on the order of 50% is necessary to keep most households whole under a carbon fee and dividend policy. This suggests that the 50/50 option is perhaps the more appropriate to assess the impact from such a policy. However, this method will have the greatest negative impact on the Industrial sector, according to the model.

However, in NEMS, the 100% Business and 100% Consumer rebate options effectively give the wealthiest corporations and households a tax break. Section 2.3.2 showed that these recipients typically save rebates such as these and don't re-spend them, which in corporations leads to shareholder benefits. So the re-spending effect expected from a rebate given to lower income households, for example, will not be realized within the NEMS framework. So, despite the analysis above, how relevant any of these rebate options actually are in minimizing impacts is unclear. What is clear, and what NEMS is designed to do, is that the carbon policies (irrelevant of revenue recycling options) will have an impact on the economy and certain industries are impacted more than others. The next section will discuss how to protect these industries.

Table 5.3 Industry-specific LMDI comparison under rebate methods.

	2013		LMDI Decomposition results of $25/t$CO_2$ at 2% (2013 - 2023)																			
			Activity effect					Energy Intensity effect					Carbon Intensity effect					Total Emissions ($MMtCO_2$)				
Industry	Mode Share[1] (% of sector)	Total Emissions ($MMtCO_2$)	Cons. Rebate	Deficit Redux	Bus. Rebate	50/50	Ref.	Cons. Rebate	Deficit Redux	Bus. Rebate	50/50	Ref.	Cons. Rebate	Deficit Redux	Bus. Rebate	50/50	Ref.	Cons. Rebate	Deficit Redux	Bus. Rebate	50/50	Ref.
Agriculture	4.5%	67.9	9.7	9.9	9.9	10.0	10.4	-7.9	-8.0	-8.0	-7.9	-7.9	-4.8	-4.9	-4.8	-4.9	-1.9	64.9	65.0	65.0	65.0	68.6
Mining	7.3%	54.7	4.5	4.7	4.6	4.5	5.1	-0.1	-0.1	-0.1	-0.1	0.4	-8.6	-8.3	-8.5	-8.6	-3.6	50.5	51.0	50.7	50.5	56.7
Construction	14.7%	71.0	32.9	34.0	33.6	33.2	33.2	-12.2	-12.5	-12.4	-12.3	-12.2	-3.6	-3.6	-3.6	-3.7	-0.9	88.1	88.9	88.7	88.2	91.0
--> Refining Industry[2]	7.1%	255.1	-5.5	-4.6	-4.6	-5.1	-1.5	-1.5	-1.7	-7.9	-1.5	5.6	-10.8	-10.8	-13.0	-10.9	-8.4	237.4	237.7	229.4	237.7	250.6
Food Industry[2]	9.2%	97.8	20.6	20.4	20.8	20.7	22.5	-10.7	-10.7	-10.8	-10.7	-10.7	-12.9	-13.0	-12.8	-12.9	-3.5	94.9	94.6	95.1	94.8	106.3
Wood Products	1.4%	18.5	4.5	4.7	4.7	4.6	5.3	-0.6	-0.6	-0.6	-0.6	-0.7	-4.2	-4.2	-4.2	-4.2	-1.7	18.2	18.4	18.4	18.3	21.4
Paper Industry[2]	2.1%	66.8	14.7	15.8	14.9	15.0	17.6	-4.8	-5.0	-4.8	-4.9	-5.3	-14.3	-14.7	-14.4	-14.4	-9.2	62.4	63.0	62.5	62.6	70.1
--> Bulk Chemical Industry[2]	1.9%	235.9	47.8	51.2	48.6	48.1	60.1	-20.3	-21.1	-20.5	-20.3	-22.8	-28.4	-28.4	-28.1	-28.4	-14.7	235.1	237.7	236.0	235.3	259.0
Plastics	2.8%	39.0	4.5	4.8	4.7	4.6	7.8	-7.0	-7.1	-7.1	-7.0	-7.4	-6.9	-7.0	-6.8	-7.0	-1.1	29.6	29.7	29.8	29.6	38.4
Glass Industry[2]	0.3%	18.7	5.1	5.5	5.3	5.1	6.3	-1.3	-1.3	-1.3	-1.3	-1.2	-1.8	-1.8	-1.8	-1.8	-0.5	20.8	21.2	21.0	20.8	23.3
Cement and Lime Industry[2]	0.1%	30.9	11.2	11.7	11.5	11.3	12.8	-3.3	-3.5	-3.4	-3.3	-3.7	-2.4	-2.5	-2.4	-2.5	-1.1	36.4	36.7	36.6	36.5	39.0
--> Iron and Steel Industries[2]	1.9%	126.7	36.0	42.5	37.6	35.9	48.5	-23.2	-24.6	-23.6	-23.2	-25.2	-7.8	-7.8	-7.7	-7.8	-0.2	131.7	136.8	133.1	131.6	149.8
Aluminum Industry[2]	0.5%	50.7	7.7	8.3	7.8	7.7	17.9	-12.9	-13.1	-12.9	-12.9	-5.8	-9.0	-9.2	-8.9	-9.1	-4.1	36.5	36.8	36.6	36.4	58.7
Fabricated Metal Products	4.4%	39.1	6.4	7.0	6.7	6.4	7.4	-5.5	-5.6	-5.5	-5.5	-5.2	-6.5	-6.6	-6.4	-6.6	-1.4	33.5	33.9	33.8	33.5	39.9
Machinery	5.0%	25.0	8.7	9.7	9.1	8.7	10.7	-5.5	-5.6	-5.6	-5.5	-5.2	-4.9	-5.1	-4.9	-5.0	-0.7	23.3	24.0	23.6	23.2	29.8
Computers	6.2%	28.7	12.2	13.3	12.6	12.4	13.7	-6.5	-6.8	-6.6	-6.6	-6.4	-5.7	-5.7	-5.7	-5.8	-2.0	28.6	29.4	29.0	28.7	33.9
Transportation Equipment	12.1%	58.4	15.0	15.8	15.8	15.4	17.9	-11.0	-11.2	-11.2	-11.1	-10.8	-10.4	-10.7	-10.4	-10.5	-1.7	51.9	52.4	52.7	52.1	63.9
Electrical Equipment	1.6%	7.8	2.8	3.1	3.0	2.8	3.2	-1.6	-1.7	-1.7	-1.6	-1.6	-1.4	-1.4	-1.4	-1.4	-0.2	7.5	7.7	7.7	7.5	9.2
Balance of Manufacturing	14.1%	191.1	52.9	54.8	54.3	53.4	60.1	-23.0	-22.9	-22.5	-23.1	-21.8	-12.7	-13.2	-13.7	-12.6	-5.8	208.3	209.8	209.1	208.8	223.2
Total	100.0%	1483.8	291.9	312.6	300.7	294.8	358.7	-159.0	-162.8	-166.3	-159.5	-148.0	-157.2	-159.0	-159.4	-158.1	-62.7	1459.6	1474.6	1458.8	1460.9	1632.7

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

5.4 PROTECTING ENERGY-EXPOSED AND TRADE-EXPOSED (EITE) INDUSTRIES[44]

The previous section showed that the choice of revenue recycling method will only impact a few industries, but the way the revenues are recycled in the model makes it unclear if the results are an accurate representation of realistic economic response. Even beyond questions about revenue recycling options in the model, however, is how to model protection for industries suddenly at risk when a carbon policy is enacted.

There are two classes of industries that may need some protection under a carbon policy and they need protection for different reasons. First, energy-intense (EI) industries may require additional time to decarbonize their energy supply chain. Allowing for a carbon price to ramp in slower than it does for the rest of the economy may provide ample time to shift fuels or technologies. Second, trade-exposed (TE) industries are those that face unfair export competition since global competitors not subject to a carbon price will have an unfair advantage.

When EIA is asked through official channels to evaluate a climate or carbon policy, the policies usually includes some protection for EITE industries. This often requires EIA to modify the raw NEMS code to accommodate the request. This section will describe how EIA does this and show why it is not sufficient.

5.4.1 Energy intense industries

At-risk industries could be offered carbon tax offsets, which would be phased out over time allowing energy intense industries an adjustment period. These may simply be lump sum transfers to the industry which will satisfy their shareholders; however, there are often strings attached to some or all of that money. For example, the Boxer-Sanders Climate Protection Act planned to use 15% of the carbon fee revenues to cover a wide range of policy measures aimed at helping consumers and business reduce energy and carbon intensity. This included investing in manufacturing to promote energy efficiency which would mitigate the effects a carbon price; creating a

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[44] Thanks to Russell Tarver and Elizabeth Sendich for explaining EIA's process for protecting EITE industries. Please see the EIA Waxman–Markey analysis (EIA, 2009a) for a further description.

sustainable technologies finance program to leverage investments in clean energy; and the weatherization of a million homes a year (Boxer and Sanders, 2013).

All recently proposed climate policies evaluated by EIA have included similar measures. In addition to Boxer–Sanders, others include the Lieberman–Warner Climate Security Act (EIA, 2008a), the Low Carbon Economy Act (EIA, 2008b), the Waxman–Markey American Clean Energy and Security Act (EIA, 2009a), the American Power act (EIA, 2010a), and Carbon Limits and Energy for America's Renewal (CLEAR) Act (EIA, 2010b).

These studies also included provisions for trade exposed industries, or a border tax assessment (BTA). This is an import tax levied by carbon-taxing countries on goods manufactured in non-carbon-taxing countries. The BTA adjustments help ensure a level playing field in international trade while internalizing the costs of climate damage into prices of goods and services. Under, Boxer–Sanders, for example, all import fuels and products would be charged the same carbon fee that domestic participants pay, unless the exporting nation has a similar carbon policy.

Within NEMS, implementing protection for either energy-intense industries or trade-exposed industries is very limited. First, in the model, one cannot currently adjust carbon fees to a subsection of the economy. Second, the carbon fee revenue recycling methods discussed above apply to reducing corporate taxes, personal income taxes, the deficit, or some combination. There is no other method for returning revenues to any other agent in the model. Third, the only lever used by EIA for all EITE concessions is to adjust fuel prices. These limitations are significant.

For energy-intense industries EIA adjusts their fuel prices proportional to the carbon intensity of each fuel. The intent is to simulate the fuel price without the cost adder of the carbon fee. At first blush this makes sense. However, there are some significant implications for implementing it this way. To begin, this direct price adjustment takes place at the beginning of the model iteration, so it effectively removes, or at least dampens, the incentive for agents in the model to reduce carbon emissions.

Also, Industrial sector fuel prices and aggregate quantities are derived endogenously throughout the model time horizon based on supply and demand, as well as feedbacks and spillovers from other sectors. However, when EIA applies adjusted fuel prices for these particular industries, it does so exogenously. EIA will run the model, then take the endogenous prices and manually scale them according to the provisions in the bill for each industry. These new prices are then applied to the MAM using the ***mcevcode.txt*** file. Then EIA will re-run they model (now with exogenous energy prices for certain industries), but the new price scheme is out of sync with the rest of the model. The MAM and the foresight in the EMM respond to the energy policy implemented in the other modules of NEMS which is now skewed by fixed prices in one sector. Furthermore, carbon fee revenues are out of balance since NEMS doesn't know about pre-recycled revenues through the manipulation of fuel prices. Accommodating trade-exposed industries in the model is more difficult and problematic. (Please see Appendix A.9 for details and code examples for adjusting fuel prices in NEMS).

5.4.2 Trade exposed industries

There is a large volume of international trade in fossil fuels and in goods produced with fossil fuels. Carbon emissions are a global externality, so carbon policies must be designed with international considerations in mind. Since different counties have different carbon policies (or none), the tax rates to produce goods and services from fossil fuels is also different. This poses a problem when these goods are traded. The principles of free trade suggest that everyone is better off if those who can produce a good at lowest cost do so. However a country without a carbon price produces carbon-intensive goods at what looks like a lower cost because the nominal price of the good does not include the full costs of production, thus not a comparative advantage (Metcalf and Weisbach, 2009).

There are two sides to a BTA. It imposes a tax when a product is imported and provides a rebate for any carbon tax paid when a product is exported. The difficulty is determining the carbon content of exported or imported goods. NEMS uses the IHS

Global international market and MAM solutions, which adjust for world trade; however, NEMS cannot access the trade variables. NEMS doesn't know which countries imports are coming, so doesn't know if the originating country has an equivalent carbon fee. So NEMS cannot adjust the carbon content of import goods. For export goods, EIA gives trade-exposed industries a tax break for the portion of goods set for export in a manner similar to those given to energy intense industries.

Only a fraction of an industry's products are intended for export. NEMS does not allow for splitting a given industry into trade-exposed and non-exposed portions, so EIA makes an assessment on export percentages for each industry (based on historical data), and scales the carbon price accordingly. So if 5% of an industry's products are exported, then EIA determines the carbon cost adder and scales it by 5%; such that the industry (as a whole) is still exposed to 95% of carbon fee to cover domestic product sales.[45] Once this has been determined, EIA uses the same energy price lever to apply the tax breaks in the model. (Please see Appendix A.9 for details and code examples for adjusting fuel prices in NEMS).

These methods are problematic for many reasons. EIA hard-codes prices which derails the ability to capture spillovers and other dynamic price effects. They also reduce incentives for reducing carbon intensity both domestically and internationally. These methods may affect the model results, but it is doubtful these changes represent realistic policy responses any more than the basic revenue recycling methods do.

5.5 Summary of Revenue Recycling and EITE Protection in NEMS

There are several ways to recycle revenues back into the economy in NEMS. The simplest is to use the default revenue recycling methods. These give revenues to consumers, businesses, or deficit reduction, which can be combined by modifying the NEMS interface with the MAM. Comparisons of these different methods in the model, however, show there is very little dependence on which method is chosen.

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[45] In practice, this is more complicated, because this scaling is done for each fuel type. So maybe 5% of an industry's products made with natural gas are exported, and only 3% of products are made from coal-fired electricity are exported. So, in practice this can be very complicated. Furthermore, this emphasizes how subjective the process can be.

These default methods in NEMS return revenues to consumers by reducing the aggregate corporate or aggregate personal income tax. This is problematic for several reasons. First, most of the aggregate corporate taxes are paid by the wealthiest corporations, and most of the aggregate personal income taxes are paid by the wealthiest households. So, reducing the aggregate tax receipts in the model effectively gives only the wealthiest corporations and households a tax break. This ignores the positive fiscal multipliers, since lower income households and (by extension) corporations tend to re-spend rebates or dividends quickly and locally.

Second, carbon tax revenue rebates will most likely be tied to energy efficiency measures or decarbonizing activities, but there is no way to do this in the model. In reality, when a corporation receives a lump sum transfer of money, there are several likely paths the money might follow. The company could reinvest that money into R&D or upgrades which will compound the gains by reducing carbon intensity to avoid future carbon taxes. The company could also stick the money in a box or into a safe financial investment. However, the more likely scenario is that this money will get returned to shareholders. In the model, when money is returned to businesses untethered to energy or carbon efficiency improvements, the richest corporations (who pay most of the taxes) receive a tax break, which effectively gives the money to investors.

This means there is no systematic method for protecting EITE industries in the model either. The way EIA currently accomplishes this is to run the model based on the climate policy, extract energy prices, modify those prices as desired, then hard-code new prices back into the model. This cripples the model ability to endogenously solve for feedbacks and spillovers, and also eliminates the financial incentive for the modified industries to reduce carbon emissions.

NEMS is designed to assess the macroeconomic and sectoral economics of existing policies. It does this well since all of the demand sectors in NEMS, at their core, are bottom-up appliance stock models. For example, in the NEMS Residential building sector, demand for energy services (e.g., lighting, water heating, and space cooling) is the starting point in the determination of Residential energy consumption

(Wilkerson et al., 2013). Based on some appliance choice rules and prices, consumers in the model choose appliance technologies and fuel types to meet their service demand. Aggregating the chosen appliances will identify total Residential energy demand by technology and fuel.

In the Industrial sector, each industry is represented with a similarly detailed engineering process model, and each step in the processes is governed by technology possibility curves[46] (TPC). For example, the cement and lime industry model includes all of the major engineering pieces required to produce cement and lime. The cement industry uses either a dry or wet process and the model includes details about the drying, grinding, blending, and clinker production from raw materials. The model also includes the finishing, grinding and mixing of the final product. The lime industry portion includes primary and secondary crushing of the raw materials, as well as and kiln heating, cooling, screening and milling of the final products. Like the residential appliance stock model, Cement and Lime representatives can chose each piece of the process, based on cost and efficiency, and the aggregate of all the pieces determines the industry energy consumption.

Each industry is represented with varying engineering detail in a process-model framework. The only other logical alternative to exogenously modifying energy prices for these industries (in the current model framework) is to alter the TPCs. However, in effect, one would also need to know the value of R&D for each industry to know how much funding will accelerate the annual improvement in TPC. Ideally, if one could direct a portion of revenues to specific industries, the model would account for all associated feedbacks. This would more effectively target specific industries. Unfortunately, despite the engineering detail for each industry, the model has very little overlying financial structure with very limited levers for user control.

So, while NEMS adequately assesses the macroeconomic and sectoral economics of existing policies, the model provides insufficient methods for returning

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[46] Technology Possibility Curves (TPC) are efficiency rates and learning rates for each part of the process flow in each industry. TPCs are very much like the Autonomous Energy Efficiency Improvement (AEEI) included in most integrated assessment models.

revenues to consumers or corporations. There is also no realistic method for capturing energy efficiency programs which are included as part of most energy policies. One step that would greatly improve this is for EIA to properly capture transfer of payments to specific industries. Another improvement would be for EIA to include some income distributional levels for consumers and corporations. However, this would also require significant modification of the NEMS code to incorporate a different underlying framework with much greater bottom up financial detail.

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Chapter 6

DISCUSSION AND SUMMARY

This study evaluated the impacts from a suite of carbon fee and dividend policies on both the U.S. energy-economic infrastructure and U.S. households. The policies evaluated have carbon prices of \$15, \$25, and \$35 per metric ton of CO_2 (tCO_2), each escalating annually by 2%, 4%, 6%, and 8% (12 carbon price scenarios in total). Each policy begins in 2014 and the analysis is through 2023, the first ten years. These scenarios were chosen to align with a policy discussion drafted by the U.S. House of Representatives Committee on Energy and Commerce (Waxman et al., 2013).

A portion of the total all-sector revenues is returned to households in the form of a per capita rebate. Rebates of 40%, 50%, and 60% of the revenues were chosen for this study based on the similar Boxer–Sanders Climate Protection Act proposed recently in the U.S. Senate (Boxer and Sanders, 2013).

Section 6.1 highlights the key results from this study. Section 6.2 expands on these and discusses the findings and analysis limitations. Sections 6.3 and 6.4 summarize policy and modeling implications, respectively. Finally Section 6.5 describes future work that could extend the usefulness of this research.

6.1 KEY RESULTS

It is important to note that the results from this study underestimate the benefits of the carbon fee and dividend policies, as the model framework does not account for some important economic responses. The key results are outlined below, with further description, including modeling limitations, discussed in Section 6.2.

Significant carbon savings can be achieved with minimal GDP impact. In the current post-recession, post-shale gas economy, relative small carbon fees can garner significant carbon reductions with minimal GDP impact. The full range of policies evaluated will reduce energy-related carbon emissions by 5% to 24% below the

Reference scenario by 2023, while reducing GDP by 0.4% to 1.6%. These GDP impacts represent a 2- to 8-month delay in achieving a given wealth level.

Most of these policies meet the U.S. commitment to the Copenhagen Accord. The minimum policy scenario to do this is a \$25/tCO_2 tax escalating at 2% annually.

Avoided carbon will be due primarily to switching away from coal. About 85% of the avoided carbon will come from decarbonizing electricity generation, predominantly by switching from coal-fired electricity generation to natural gas-fired generation. Nearly all of this change occurs within the first few years of the policy as the electricity supply sector dispatches natural gas generators instead of coal-fired generators.

Very little carbon savings will come from the Transportation sector. These policies will not induce any measureable fuel switching in the Transportation sector. The small amount of avoided carbon in this sector will result from a reduction in demand. These policies would need to be coupled with additional measures such as vehicle efficiency standards to have significant impact to this sector.

Very little carbon savings will come from efficiency in the Residential or Commercial building sectors. Nearly all of avoided emissions from the building sectors result from a cleaner electricity supply, with very little resulting from increased efficiency within the sectors. This is partly due to the relatively low price increase to households from these policies, but also an artifact of very high discount rates assigned to the majority of both building sectors in the model.

These policies will raise significant revenues. These polices would raise from \$850 billion to \$2.2 trillion (undiscounted) over the decade. Returning about half of this to consumers leaves a substantial amount available to protect energy-intense and trade-exposed industries, and to fund energy efficiency and carbon reduction measures.

The average American household will see a net positive benefit from per capita rebate of 50% of the revenues. The average household will see between 4% to 11% increase in direct energy costs, depending on the policy. However, as the aggressiveness of the policy increases, the revenues increase such that the rebate will more than offset the cost increases in every policy in this study. Keep in mind that this is the average American household, and some households will see a net cost, depending on income level.

A 65% rebate would compensate the average American household for both the direct costs and estimated indirect costs.

These carbon fee and dividend policies are progressive. While lower income households spend a larger portion of their income on energy, they tend to spend less total money on energy. The per capita-based revenue rebate will therefore more than offset the total direct costs of the fees to lower income households.

Returning 50% of revenues to households will offset the direct policy costs for 84% of all households. This accounts for all households earning less than $100,000 per year (but less than 30% of the aggregate wealth). Returning 60% of the revenues will offset the direct costs to American households earning less than $120,000 per year (89% of all households). This result remains consistent for income distributions in each Census Region.

A 40% rebate will offset the average policy costs in all Regions. Differences in energy supply and consumption lead to average households in the West and Northeast Regions will be slightly better off than households in the Midwest and South.

A 50% rebate will more than offset the direct costs to the average household in every state.

6.2 Discussion

A price on carbon will increase the cost for energy-related products and services. This will have impacts across the U.S. energy-economic spectrum, including on U.S. macroeconomics, total carbon emissions, energy supply and demand in each sector, and the cost of energy to households. Returning a portion of the carbon tax revenues to consumers in the form of a rebate can offset the costs to households, eliminating the regressive nature of a carbon tax, and also help alleviate other energy-economic impacts. The following sections summarize the methods and models, discuss impacts from the policies, and describe some of the modeling limitations.

6.2.1 Review of models and methods in this study

When evaluating U.S. carbon fee and dividend policies, policymakers want to know the impacts to the economy and to their constituents. So, for economic analyses to affect sound policymaking, they must consider policy impacts both to the U.S. energy economy and to American households. This requires a detailed general equilibrium model of the U.S. energy-economic system. The model used for this study is the National Energy Modeling System (NEMS) due to its position as the U.S. Government's forecasting and modeling tool. NEMS is the tool typically used by members of Congress to evaluate major energy-related legislative proposals, and it is designed to assess U.S. macroeconomic impacts from such policies. (Please see Section 2.3 for NEMS background and details on how to modify and run the model).

However, NEMS does not include any consumer expenditure or income distributional details, so a comprehensive policy assessment requires one to combine NEMS macroeconomic results with external expenditure datasets. For this study, two expenditure surveys became essential for capturing total household energy-related expenses at the desired geographic resolution. These surveys are the Residential Energy Consumption Survey (RECS) from the Energy Information Administration (EIA), and the Consumer Expenditure (CEX) survey from the Bureau of Labor Statistics. RECS provides state-level energy-related household expenditures, but does not include any vehicle or travel expenditures. Energy expenditures on travel are obtained from CEX. (Please see Section 4.2 for a detailed description of both datasets.

The NEMS output provides a forecast of residential energy prices (e.g., electricity, natural gas, and gasoline), and total aggregate consumption. For the Reference scenario (no policy case), the total expenditure in a given year in the Residential sector for a given fuel is the product of price and total quantity consumed. Under a carbon policy, the price for energy increases, which decreases demand, and the total expenditure for each fuel changes. The expenditure difference between the policy and the Reference scenario represents the change in total direct costs[47] for that fuel type. Historical expenditure data from RECS and CEX can then be applied to the total costs for each fuel to identify the per-household cost for each fuel. (This model is introduced in Section 2.5 and defined in detail in Section 4.2)

6.2.2 U.S. Macroeconomic, fiscal, and environmental impacts

6.2.2.1 Environmental and macroeconomic impacts

Lower natural gas prices, some energy efficiency, and several economic crises have combined to significantly reduce U.S. CO_2 emissions levels over most of the last decade (Burtraw and Woerman, 2012). Despite this recent decline, EIA projects a small, but steady, increase in energy-related carbon emissions over the next decade as the economy slowly recovers (EIA, 2013a). In 2013, carbon emissions were 5,369 $MMtCO_2$, and in the absence of a carbon policy, this is anticipated to grow by 2.3% to 5,494 $MMtCO_2$ by 2023.

Over the next decade, the policies modeled here will reduce emissions by between 5% and 24% from the Reference forecast scenario, depending on the aggressiveness of the policy scenario. Under the Copenhagen Accord, the U.S. has committed to reducing its economy-wide greenhouse gas emissions to "in the range of 17% below" 2005 levels by 2020 (UNFCCC, 2010). Of the policies evaluated, the

[47] Direct costs are represented by the increase in costs for energy-related products and services. Indirect costs refer to the increase in non-energy-related products and services as a result of the higher energy prices. (Please see Section 1.3 for a discussion on potential differences)

most lenient case to achieve this target is a carbon fee of \$25/tCO_2 escalating annually by 2%, which reduces carbon emissions 10% below the Reference scenario by 2023. Thus, this scenario is a good threshold policy for policymakers to focus on.

The significant carbon reductions described above reduce U.S. GDP by 0.4% to 1.6%, and they will raise revenues ranging from \$0.8 trillion to \$2.2 trillion in aggregate (undiscounted) from 2014 to 2023 (\$0.7 trillion to \$1.8 trillion NPV at 4% discount rate). The 10% carbon reduction projected from the threshold policy (\$25/tCO_2 at 2%), will reduce U.S. GDP by only 0.6% in 2023, a \$129 billion reduction to a \$20.5 trillion economy in 2023. This loss in GDP represents a delay in achieving a certain level of wealth, since the economy will need to churn away for a period of time to achieve the same level of GDP achieved in the Reference case. However, for the threshold policy, this delay would be just 3 months. The full suite of policies evaluated represents a delay in wealth from 1.7 months to about 8 months. Thus, these carbon scenarios can produce significant emissions reduction with a relatively small adjustment in the energy sector and the economy.

A carbon tax would have a lower administrative costs than an equivalent cap-and-trade, and could be more cost-effective depending on how it is implemented (Goulder and Schein, 2013; Gupta et al., 2007). Furthermore, a carbon tax does not require the reliance on uncertain predictions about the future to analyze potential changes in behavior (unlike under a cap-and-trade policy, where prices are highly uncertain). This is especially true in today's world of post-recession, post-shale gas boom, where a moderate carbon fee can reduce sufficient emissions to meet the Copenhagen Accord target with only modest effects on GDP.

The Waxman–Markey American Clean Energy and Security Act (ACES) of 2009 would have unwittingly met the Copenhagen Accord target. However, that pre-shale gas, pre-recession economy would have required more than \$35/tCO_2 escalating at around 6% annually and would have barely meet the Accord by 2020 (EIA, 2009a). As a cap-and-trade scheme, about two-thirds of those reductions would have come from international and domestic offsets, many of which would have contributed to a bank of emissions allowances that would have reappeared as emissions in later years

(Burtraw and Woerman, 2012). Avoided carbon emissions from a carbon fee policy, on the other hand, would be avoided permanently.

In the current study, about 85% of the avoided carbon will come from decarbonizing electricity generation, predominantly by switching from coal-fired electricity generation to natural gas-fired generation. Nearly all of this change occurs within the first few years of the policy as the electricity supply sector dispatches natural gas plants, instead of coal-fired plants. Since existing natural gas plants have excess capacity, the electricity sector immediately dispatches more natural gas plants and fewer coal plants when faced with elevated operating costs. Throughout the rest of the decade, additional avoided carbon from electricity generation will come from an increase in renewables. The remainder of non-electric, avoided carbon emissions will come from reduced demand in all sectors, either through energy efficiency improvements or behavior change.

6.2.2.2 Sectoral impacts

6.2.2.2.1 Building sectors

Since most of the avoided carbon will come from the electricity sector, and electricity is a dominant energy source for the Residential buildings, Commercial buildings, and Industrial sectors, each of these sectors will account for roughly one third of the total avoided carbon. In the two buildings sectors in particular, almost all of the avoided emissions come as a direct benefit of a cleaner electricity supply. Wilkerson et al., (2013) showed that the two building sectors in NEMS are relatively stiff with respect to energy efficiency, due primarily to the very large discount rates governing the majority of the sectors. This lack of flexibility in the underlying model parameters implies more rigidity in the economy than actually exists (Koomey, 2002).

6.2.2.2.2 Transportation sector

By contrast, the Transportation demand sector in the model will see very little change from these policies. The dominant fuels in Transportation are petroleum-based with little opportunity for quickly reducing the carbon- or energy-intensity of vehicles. So, any avoided carbon from this sector will come from a reduction in demand or activity.

Even the most stringent policy evaluated here shows similar results: most of the avoided emissions come from the electricity sector and almost no avoided carbon or energy savings will come from the Transportation sector. This result is not unsurprising, since similar results have been shown in other U.S. climate policy analyses, such as for Waxman–Markey (EIA, 2009a).

In an attempt to gain some movement in the Transportation sector, Waxman–Markey proposed energy-efficient vehicle vouchers. Others have suggested less comprehensive, but more targeted carbon policies. For example, Orans et al., (2010) proposed a carbon tax on the electricity sector, which would capture most of the savings in the current study, coupled with transportation-specific (and building-specific) measures since these decisions-makers often do not take advantage of economic incentives for more energy efficient options. The proposal's authors explain that non-economic factors tend to be more important to consumers than fuel-efficiency, and consumers tend to pay more attention to the vehicle sticker price than its long-term operating costs. As a solution, the proposal recommends 'feebates'[48] for new vehicles, together with improved vehicle performance standards, as the two best strategies to reduce emissions from the Transportation sector. And this sector is an important one to address, as it was responsible for a third (33%) of U.S. CO_2, in 2013

6.2.2.2.3 Industrial sector

The structure of the Transportation, Commercial, and Residential demand sectors are fairly homogenous, and some of the activity in these sectors includes substitutes (e.g., freight trains and commercial vehicles, large and small office buildings, and single family and multi-family homes). However, activity in the Industrial sector is represented by individual industries, each experiencing different impacts, and these are not likely to serve as substitutes for each other.

[48] A 'feebate' is a revenue neutral fee and rebate incentive for new vehicle purchases. The buyer of a new energy efficiency vehicle would receive a rebate based on the performance relative to the standard vehicle. The buyer of a new non-energy efficient vehicle would be charged a fee based on how poorly the vehicle performs relative to the reference vehicle specifications. By design, the fees collected will pay for program implementation and all rebates. Orans, et al., (2010) and others believe such a program can overcome the upfront cost barrier to consumers' investment decisions.

Activity in the Industrial sector is characterized by the value of shipments (VS). This is a surrogate for industry-specific GDP, which is not computed in NEMS. The VS is gross output minus inventories and reflects the level of domestic production. It includes all shipments–intermediate as well as final goods– and includes the cost of energy, unlike GDP by industry. (Please see Section 2.4.3.4 for further definition). Energy-intense industries, such as Plastics, Iron and Steel, and Aluminum will incur the most reduction in activity (VS). Under the \$25/tCO_2 at 2% policy, these industries see a reduction in VS of 6.6%, 7.0%, and 13.8%, respectively, by 2023 relative to the Reference scenario. These three industries will also see the largest reduction in energy intensity (BTUs/\$VS) over the next decade due to energy efficiency improvements.

In other industries, however, a reduction in activity is matched with a roughly equivalent reduction in energy consumption; thus energy intensity for other industries remains roughly constant. This is likely a result of simply scaling back production under the new energy prices.

The model also shows that every industry will reduce exposure to carbon fees by reducing carbon intensity; indeed, nearly all industries will decrease carbon intensity at least twice as much as that projected in the Reference scenario. In many industries, this is a direct benefit of a cleaner electricity supply, such as for Wood products, Paper, Fabricated Metals, Aluminum, Machinery, Computers, Transportation Equipment, and Electrical Equipment, since electricity accounts for at least half of the energy consumed within these industries. For others, carbon emissions are reduced by directly switching away from coal and other higher carbon fuels (e.g., fuel oil) to natural gas and electricity.

6.2.2.2.4 Sector emissions and associated revenues

In 2013, the breakdown of total emissions contribution by the Buildings and Industrial Sectors was: nearly 28% for Industrial, 21% for Residential buildings, and 18% for Commercial buildings. These percentages roughly correlate with the portion of total carbon tax revenues generated from each sector in the first year of a policy.

Over the first decade, the Industrial sector will contribute roughly 29% of the annual revenues under all of these policies. However, for the remaining sectors, the aggressiveness of the policy can dramatically affect their percentage of revenues. The Transportation sector will see very little reduction in emissions even under the most aggressive policy modeled here, though could be responsible for as much as 42% of total revenues in 2023. The Residential and Commercial building sectors will see roughly a 10% to 40% reduction depending on the policy, while they might contribute as little as 16% and 13% of the revenue, respectively. Under a $25/tCO2 at 2% policy, revenues from the Transportation sector would be 36% of total revenues, while the building sectors would contribute 18% and 16%.

6.2.3 Household impacts

As described above, these carbon fees will raise significant revenues with minimal effect on U.S. GDP. The usual concern with such a result is the potential for disparity in distributional and interregional impacts. To mitigate the costs to households, the Boxer–Sanders Climate Protection Act of 2013 (which proposed a \$20/tCO_2 escalating annually at 5.6%) planned to return 60% of the carbon fee revenues to households on a per capita basis (Boxer and Sanders, 2013). That rebate percentage has been shown to sufficiently offset the direct energy costs from the carbon fee to nearly every household market segment, including the average household in all four Census Regions (Northeast, Midwest, South, West), and the first four of five income quintile brackets (households earning up to $120,000 per year) (Wilkerson et al., 2014a). Assessing the impact of the rebate on households from such a policy is critical to a comprehensive policy analysis.

6.2.3.1 Household expenditure data

To extend the NEMS results to analyze impacts to households, this study uses the CEX and RECS expenditure data sets. Previous studies have used CEX for similar assessments (e.g., Blonz et al., 2011; Hassett et al., 2009; Mathur and Morris, 2014; Metcalf, 2008b), however this is the first study to the author's knowledge to incorporate the RECS dataset. The primary advantage of the RECS data is the geographical resolution which far exceeds that of the CEX.

Both data sets include household energy expenditures at the national level and at the level of the four Census Regions. However, consumers in neighboring states (indeed even within a state) have different incomes, are faced with different drivers of energy demand, and make different choices about energy consumption. So evaluating impacts at the state level would be more informative than Regional aggregate impacts, which dampen out extreme conditions. The latest RECS (EIA, 2013d) also summarizes energy expenditure in nine Census Divisions and each of the 16 most-populous states (representing 63% of the U.S. population). However, RECS does not include any transportation-related expenses, which account for more than half of the average American household energy-related expenditures (BLS, 2013b), so the CEX is still needed to estimate household travel expenditures. (Please see Section 4.2.2 for a detailed description, comparison, and application of the two datasets).

6.2.3.2 Average American household

The primary residential fuels are electricity, natural gas, and gasoline. The consumer price for each of these fuels is projected in the model to rise over the next decade, even in the absence of a carbon policy. Residential electricity prices will rise 22% from 11.5 cents/kWh (nominal) in 2013 to 14.0 cents/kWh in 2023. Under a \$25/tCO_2 at 2% carbon policy, electricity prices will rise an additional 16% over the Reference case, to 16.2 cents/kWh in 2023 (41% increase over 2013). Similarly, residential natural gas prices will rise 39% without a policy from 10.8 nominal \$/MMBTU in 2013 to 15.1 \$/MMBTU in 2023. Under the policy, natural gas price will rise an additional 19% to 18.1 \$/MMBTU in 2023. While there are only minor differences between geographic regions in the Reference scenario, under the policy, some Divisions, mostly in the Midwest and the South, will see significantly higher rate increases due to higher dependency on coal. These price increases are more than offset with the rebate.

The average American household spends roughly 10% of total household expenditure on energy. In 2011, that was about $5,100, with more than half spent on gasoline (BLS, 2013a). Energy prices will rise in the absence of a carbon policy, but under a $25/tCO2 at 2% policy, the average American household will face an additional increase in direct energy cost of $327 (about 6%) from all fuels combined in 2014 (first year of the policy). A 50% rebate of carbon fee revenues to the same household in 2014 would be $508, which would more than compensate the average American household for the additional fuel costs. This net trend continues every year for the next ten years.

The positive net benefit shown for the $25/tCO2 at 2% policy is representative of all of the carbon policies modeled in this study. A higher initial price of carbon or faster annual escalation rate will further increase residential energy prices. However, the higher carbon fees will also increase revenues, thus allowing for a larger rebate. A rebate of 50% of the revenues will have a similar net benefit to the average American household under any of these carbon policies. Thus, carbon fee and dividend policies, such as these, allow policymakers to focus more on the balance of avoided carbon and industry impacts, since households will garner similar protection in all cases.

These and subsequent household results are an assessment of direct energy costs to households resulting from a price on carbon. Other studies using a CEX-based analysis have computed the indirect costs to households as well, which include the increased cost of non-energy related goods and services resulting from increased energy cost (e.g., Hassett et al., 2009; Mathur and Morris, 2014). Depending on the method used to determine the indirect costs, the indirect impact could range from about half to about equal to the direct costs.

Due to the complexity of the calculations for these other studies, the assessments of indirect costs are only for the first year of their static or modeled policies. As a result, they do not account for dynamic effects, such as a reduction in emissions, escalating tax rates, macroeconomic feedbacks, efficiency gains, or even consumer responses to increased energy prices (all results captured in NEMS for the direct costs). Nonetheless, if one believes the indirect costs are equal to the direct costs reported above, then a rebate of about 65% would be necessary to just compensate the average American household for both the direct increase in the cost of energy and the indirect increase in the cost of other goods and services.

6.2.3.3 Impacts by income

A carbon tax by itself is regressive. While lower income households spend less money altogether on energy than do wealthy households, they spend a larger portion of their household income on energy. Therefore, lower income households spend a disproportionate amount of their income on energy-related goods and services (Hsu, 2011). Properly designed, a carbon tax coupled with a dividend could mitigate regressive impacts to lower income households, as well as lessen the shock to energy-intense or trade-exposed industries.

The seven income brackets described in Chapter 4 are in $20,000 income increments, starting with households earning ‘less than $20,000’ annually (after taxes) and ending with ‘$120,000 or more’. With a per capita rebate of 50% of the revenues, all households earning under $100,000 dollars (84% of all households) will be compensated for the direct costs to energy from the tax. Furthermore, the lowest income brackets will receive the highest net benefit, making the rebate very progressive. A rebate of 60% of the revenues is sufficient to compensate households earning under $120,000 (89% of all households).

One important caveat is that while a 50% rebate will progressively protect 84% of all American households, this represents less than 30% of the aggregate wealth. As described in Section 2.3.2, households in the highest income quintile (wealthiest 20% of American households) contribute nearly 70% of all U.S. income taxes. So while these carbon fee and dividend policies can protect 84% of all households (on average), the remaining 16% of the wealthiest households representing the majority of money spent on energy and U.S. tax receipts will see a net cost.

Ideally, one could evaluate household energy expenditures at the state level by income bracket. Unfortunately, the survey data does not support this level of detail. Still, the methods defined in this study do allow for Census Region and Division level income bracket assessments. From a Regional perspective, a 40% rebate will keep all households earning less than $80,000 (first four brackets) positive, and a 60% rebate will do the same for all households earning less than $120,000 (first six brackets), except in the MW Region.

6.2.3.4 Impacts by region and state

Different regions face different climatological and latitudinal drivers for energy demand. Local decisions about fuel mix also affect how impactful a carbon policy will be. In general, due mainly to a lower dependence on coal, average households in the Northeast and West Census Regions will be slightly better off than households in the South and the Midwest. The Census Divisions within each of these four Regions also demonstrate disparity, with even further disparity among individual states. So assessing household impacts at the smallest geographical region possible will more accurately identify which states are more exposed to household impacts from policies.

Using the current releases of RECS allows one to assess average household impacts at the state level for the 16 most populous states (which account for 63% of the U.S. population), and small collections of neighboring states. When applying a 50% rebate, all states and small aggregates of states will see a net positive benefit. All but a few will remain positive under a 40% rebate. Over the first ten years of the policy, the highest costs associated with the carbon fees are projected in Michigan, Texas, New Jersey, and the aggregate of Washington D.C., Maryland, West Virginia, and Delaware. This is due in part to the higher than average number of residents per household in each of these areas. Fortunately, while the number of occupants is a driver of energy demand, it also defines the household rebate. So, these states will be compensated by a higher rebate than most other states.

One can extend the regional disparity issue to the limit of the current analysis. Consider the aggregate collection of states: UT, ID, WY, and MT. These are all in the Mountain North sub-Division of the West Region, and receive (in aggregate) the highest net benefit of any state (or collection of states) evaluated. When it comes to carbon emissions, ID is one of the lowest per capita emitters, while the other three are some of the highest. So it is unlikely that the direct carbon fee costs seen by this aggregate group is uniform across all four states. Furthermore, this group receives the largest household rebate, driven by the higher average occupancy in UT. Of the other three states, only ID had a higher occupancy rate than the average American household. So, it is likely that only ID, with the low per capita emissions and above average occupancy, would earn the highest net benefit from the policy, while the others in this grouping may be slightly worse off than the aggregate.

These aggregation issues highlight the importance of resolving the data to the finest level possible for analysis. But to achieve this requires RECS staff to redouble their efforts, isolate more than just the 16 most populous states, and include transportation expenses in their survey.

6.2.4 Additional impacts not captured

6.2.4.1 General limitations

The results presented in this study are a product of the tools available to policymakers today. However the projected impacts to GDP are likely overstated and underestimate the benefits of a carbon-fee dividend policy (or any energy policy). For example, NEMS does not account for improvements in U.S. public health and related reductions in healthcare expenditures associated with reduced air pollution brought about by the program. These benefits are significant. The costs of pollution damages from some industries, such as coal-fired power plants, have been estimated to be greater than the amount those industries contribute to GDP (Muller et al., 2011). The policies modeled in this study will induce coal plants to shut down early, for which the costs to GDP are included, while the corresponding human health benefits are not.

The projected impacts to GDP are also limited by the core assumptions in NEMS. The model does not fully account for the possibility of induced innovation, which would likely be spurred by a price on carbon. This induced innovation in the context of climate policy has the potential to significantly lower compliance costs and increase social welfare, which would reduce impact to GDP (Goulder and Mathai, 2000), while maintaining the environmental benefits of the program.

Additional benefits not captured by this analysis are related to how revenue from rebates would be recycled through the economy. Although core to such a comprehensive analysis, NEMS unfortunately has a very simplistic method to simulate revenue recycling. Indeed, it is one of NEMS' most significant limitations in assessing impacts from a carbon fee. This is the primary subject of Chapter 5. However, the next few sections summarize how NEMS treats revenue recycling to highlight the limitation for policy analysis.

While NEMS does a good job at assessing the macroeconomic and sectoral economics of existing policies, there is no realistic method for returning revenues to specific consumers or corporations, or even on a per capita basis. Using the options available in NEMS, one can give revenues to *consumers*, to *businesses*, to reduce the *deficit*, or some combination of these (with some additional coding).

6.2.4.2 Models default settings are regressive

NEMS only tracks aggregate personal or corporate incomes and taxes and includes no framework for income distributions. So, returning revenues to *consumers* in NEMS reduces total aggregate personal income tax receipts. However, most of the total aggregate income taxes in reality are paid by the wealthiest individuals. Households in the highest income quintile (wealthiest 20% of American households) contribute nearly 70% of all U.S. income taxes, and the top two quintiles (wealthiest 40%) pay more than 85% of all income taxes. In contrast, households in the lowest quintile contribute less than 0.5% to aggregate U.S. income tax receipts (CBO, 2013). So, returning revenues to *consumers* in the model effectively reduces the taxes on the wealthiest Americans and has little impact, if any, on the poorest. Thus, the application of the tax rebate in this manner in NEMS is very regressive.

Similarly, returning revenues to *businesses* is effectively a reduction in corporate tax receipts, but corporate income and taxes are also computed in-aggregate. Corporate tax receipts relative to wealth distribution are even more skewed than in households. The wealthiest 0.1% pay almost 85% of all U.S. corporate taxes. The wealthiest 5% of all corporations pay over 95% of all taxes (TPC, 2011). So, reducing aggregate corporate tax receipts effectively gives a tax break to the wealthiest corporations in America –oil companies, banks, pharmaceuticals, and high-tech companies. This is further compounded, when one considers that the wealthiest people also own most of the shares of these corporations, thus returning revenues to *businesses* or *consumers* effectively gives a tax break to the same individuals.

6.2.4.3 Missing fiscal multipliers from low-income transfers

Returning revenues to the wealthiest households fails to capture the fiscal multiplier effect of giving money to lower income residents. The multiplier is a measure of the effectiveness of government spending. Lower income households, with a multiplier greater than 1, tend to spend more of their dividends and rebates quickly and locally. Higher income households tend to save more and spend less of a rebate, thus having a multiplier less than 1. A rebate given to a lower income household will compound or multiply further once spent, since money spent locally also tends to be re-spent quickly and locally. Additionally, greater household spending (and re-spending) encourages firms to hire more employees, which further increases household income and spending (Elmendorf and Furman, 2008; Johnson et al., 2004).

6.2.4.4 No realistic protection for energy-intense or trade-exposed industries

Most proposed energy policies include provisions for trade-exposed industries through a border tax assessment (BTA). This is an import tax levied by carbon-taxing countries on goods manufactured in non-carbon-taxing countries. The BTA adjustments help ensure a level playing field in international trade while internalizing the costs of climate damage into prices of goods and services. Under Boxer–Sanders, for example, all import fuels and products would be charged the same carbon fee that domestic participants pay, unless the exporting nation has a similar carbon policy. However, NEMS is a model of the U.S., not the world, and its characterization of trade and import is very coarse and limited.

Similarly, a policy provision may help alleviate the sudden burden of a carbon fee to energy-intense industries. Each proposed bill is different, but could provide, for example, a slower implementation or delay of a carbon fee or some other form of tax relief to those industries. In reality, protecting energy-intense and trade-exposed (EITE) industries could mean lump sum transfers or alternate carbon or energy prices to affected industries. However, the limited revenue recycling options in NEMS means there is no realistic method for modeling EITE industry protection.

First, in the model, one cannot currently adjust carbon fees to a subsection of the economy. Second, the revenue recycling methods discussed above apply to reducing aggregate corporate taxes, aggregate personal income taxes, the deficit, or some combination. There is no other method for returning revenues to any other agent in the model. Third, the only lever used by EIA for all EITE concessions is to manually adjust fuel prices. EIA overwrites endogenously derived energy prices for particular industries with modified (now exogenous) prices to simulate some form of tax relief. This hampers the model's ability to properly capture spillovers and eliminates incentives for the modified industries to reduce carbon emissions.

Combined, these limitations are significant.

6.2.4.5 Cannot tie rebates to energy efficiency measures

Finally, a portion of carbon tax revenue rebates will likely be tied to energy efficiency measures or other decarbonizing activities. For example, Boxer–Sanders planned to use 15% of the carbon fee revenues to cover a wide range of policy measures aimed at helping consumers and businesses reduce energy and carbon intensity. This included: investing in manufacturing to promote energy efficiency and mitigate the effects of a carbon price, creating a sustainable technologies finance program to leverage investments in clean energy, and the weatherization of a million homes a year (Boxer and Sanders, 2013).

However, as discussed with respect to EITE industries, there is currently no realistic way to implement such a policy in NEMS. In reality, when a corporation receives a lump sum transfer of money, there are several likely paths the money might follow. The company could reinvest that money into R&D or upgrades, which will compound the gains by reducing carbon intensity to avoid future carbon taxes. The company could also put the money into a safe financial investment. However, the more likely scenario is that this money will be returned to shareholders. In the model, when money is returned to *businesses*, untethered to energy or carbon efficiency improvements, the richest corporations receive a tax break, which effectively gives the money to their investors.

The result of all of these limitations is that the revenue recycling methods available in NEMS will underestimate the fiscal benefits of returning money to the economy. Consequently, negative impacts to GDP and individual sectors reported in this study are likely overstated. One step that would greatly improve this is for EIA to properly capture transfer of payments to specific industries. Another improvement would be for EIA to include some income distributional levels for consumers and corporations. This would also require an overhaul of NEMS to incorporate a different underlying framework and much denser bottom up financial detail.

6.3 POLICY IMPLICATIONS

These carbon fee and dividend polices can significantly reduce emissions with minimal impact to GDP. Of the scenarios evaluated for this study, the most lenient policy to meet the U.S. commitment to the Copenhagen Accord (17% reduction in emission from 2005 levels) is \$25/tCO_2 tax escalating annually at 2%. This policy will reduce emissions by 10% from the Reference scenario over the next decade. This will only reduce GDP by 0.6% in 2023, which represents only a 3-months delay in wealth. Thus, in the current post-shale gas, post-recession economic environment, a good place to start policy discussions is around a carbon price of \$25/tCO2 at escalating annually at 2%.

The primary energy-economy response to these carbon policies is to decarbonize the electricity sector. About 85% of avoided emissions are a result of switching away from coal in the electricity sector. The carbon price increases the cost of coal-fired generation such that natural gas-fired generators become more affordable, so most of the coal-fired reduction occurs in the first year of the policy as electricity providers dispatch natural gas plants instead of coal plants. Since the electricity sector will bear the bulk of the economic transformation from such a policy, any measures designed to ease this supply sector transition will help electricity providers as well as consumers of electricity (households, businesses, and whole industries).

Because most of the avoided emissions come from the electricity sector, the Transportation sector is expected to see very little change from these policies. Yet, transportation emissions are responsible for 33% of all U.S. energy-related emissions. So any policy that seeks to reduce vehicle emissions will need to include transportation-specific measures such as 'feebates' for new vehicles and increased fuel economy requirements.

The direct increase in energy costs to households is largely offset by rebating a portion of the tax revenues to households on a per capita basis. For the average American household a rebate of 50% of the revenues is more than adequate to offset the additional costs to household energy prices. This finding holds across all carbon fee and escalation scenarios modeled here. Thus a carbon fee and rebate policy is a relatively robust method for reducing emissions without negatively affecting average households. This allows policy makers to focus more on the desired carbon emissions reduction instead of having to balance it against impacts to policymakers' constituents (households).

A per capita rebate is very progressive; it will benefit lower income households more than upper income households. A 50% rebate will protect average American households earning less than $100,000 (after tax), and a 60% rebate will protect households earning less than $120,000 (these represent 84% and 89% of all households, respectively).

When considering state-level household impacts a 50% rebate is sufficient to protect all average households in every state, and a 40% rebate will protect households in all but a few states.

In summary, a carbon fee of \$25/tCO_2 escalating annually at 2% is a good baseline policy scenario. This will reduce significant carbon emissions without much cost to the economy as a whole. Coupling this carbon fee with a per capita rebate of 40-60% will protect the lowest income households and still provide sufficient revenues to fund measures designed to reduce energy demand or carbon intensity, and protect exposed industries.

6.4 POLICY MODELING IMPLICATIONS

All models are simplified representations of the real world activities or environments they seek to evaluate. Given the complexity required to evaluate energy-economic interactions, it is no surprise how few modeling tools are available to evaluate fiscal and energy policy. New models, and improvements to current models, would enhance understanding and perspectives of policy impacts to emissions, households, and the broader economy.

Policy makers and researchers would significantly benefit from having more models available. Comparisons of results between models would narrow the uncertainty of estimates, increase model reliability, and improve understanding of results. It would also open up a community-based infrastructure to support energy-economic model diagnosis, validation, model improvement, and documentation. Inter-model comparisons will also provide a level of confidence not achievable by any other method (EMF, 2014; PCMDI, 2014).

The energy-economic model used for this study, NEMS, is arguably the most influential energy model in the United States. EIA uses NEMS to generate the federal government's annual long-term forecast of national energy consumption and to evaluate prospective federal energy policies (EIA, 2009b). NEMS is considered such an important tool that other models are calibrated to its forecasts, in both government and academic practice. Consequently, it has a significant influence over expert opinions of plausible energy futures. However, there are several improvements EIA could make to the model and documentation to allow for more transparency in the model and its results, and for better evaluation of distributional impacts.

First, EIA should make NEMS more transparent by better clarifying assumptions and model structure. EIA already documents each supply, demand, and conversion module (some 20-plus documents annually), which show improved clarity and detail every year, and for which the community is grateful. However, apart from continuing to improve this documentation, better integration of these documents would help the community trace the treatment of parameters used between modules. For example, some variables change names between modules, like *mactax* for defining the tax revenue recycling method, which changes to *taxmode* in the macroeconomic activity module. Currently, it is up to the user to discover this disparity while attempting to trace variables between modules.

Second, NEMS should include measures of economic welfare that can be used to evaluate the efficiency and equity of policies. With no income distribution defined, it is currently not possible to use NEMS alone to assess the positive impacts of rebates on lower income households, and subsequently, the economy as a whole. Without these and other economic welfare hooks, the model's usefulness in evaluating complex fiscal and economic policies is limited.

Third, the model's few revenue recycling options limit how well the overall economic impacts can be reliably estimated. Apart from the distributional impacts discussed in the previous paragraph, having the ability to recycle revenue to individual industries or sectors would allow for more reliable estimates of economic policy implications. This would be especially helpful in the protection of EITE industries. For example, the ability to endogenously alter carbon prices to individual sectors would be useful, but may still have a revenue balance or parity issue. More importantly, having the ability to return revenues to specific industries would begin to capture the appropriate feedbacks and spillovers from tax measures designed to protect specific industries.

Fourth, the research community, technology innovators, and policy makers would all benefit from more complete reporting of NEMS results. A comprehensive examination of key energy-economic drivers in any sector is currently not possible with the current NEMS outputs, as demonstrated in Section 2.4.3. The lack of key indicators illustrates the constant struggle analysts have in utilizing model forecast results for a structured analysis. The inconsistency and sparseness of model outputs impede efforts to correlate model forecasts with historical studies.

These recommendations are in line with those suggested by a recent National Research Council study (Nordhaus et al., 2013), and would represent a significant improvement in NEMS ability to assess U.S. energy and welfare economics.

6.5 FUTURE WORK

The work presented here estimates carbon policy impacts to both the U.S. economy and households in different income brackets and in specific states and regions. To achieve this, this study combines the NEMS macroeconomic and sectoral results with external household expenditure survey data to provide a more comprehensive analysis than has been available previously. As with any research, there are limitations, and many of these have already been discussed. However, several extensions to the study would be useful to policymakers and are described below.

6.5.1 Assessment of energy macroeconomic disparity among Census Divisions

The current study shows the impacts of a carbon tax to the macroeconomics and demand sectors for the U.S. as a whole. However, U.S. regions vary in their energy consumption drivers, carbon intensity, energy prices, affluence, or general economic make-up. NEMS provides most energy and limited economic data at the level of the nine Census Divisions. An assessment of the energy-economic disparity among Census Divisions could be quite revealing. Some examples include: more industry is in the south; states with advantageous commercial tax incentives attracting a disproportionately higher corporate density; differing population and housing densities driving different fuel and energy choices; states with better public transportation providing more alternative travel options. These types of analyses would guide policy makers on how to minimize macroeconomic impacts to each region. They would also help regional leaders better prepare for potential policies, by showing vulnerabilities in their region.

6.5.2 Additional demographic analysis

This study focused on impacts by household income bracket distributions. There are several other demographic aggregations provided by RECS and CEX that could provide additional interesting insights. For example, impact by age of household occupants is important in assessing lifetime consumption effects of a carbon tax. A rural vs. urban household analysis might show disparity of energy availability and delivery costs. And household by climate region could help separate climatological drivers from local fuel mix choices with regard to impact on household costs.

6.5.3 Updating research as datasets gain higher resolution

Finally, the methods shown here have been suggested by others, improved and extended by this Author, and have proven to be an effective process for comprehensively evaluating state-level impacts from carbon fee and dividend policies. These methods should be repeated and refined as more state-specific data becomes available. For example, RECS is updated about every four years, and EIA is expecting to extend the state-level energy consumption beyond the 16 states provided in the most recent RECS; however, the next survey will likely not be published until 2016 or later.

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A.1 LIST OF TABLES FOR APPENDIX A

List of Tables

A.2 BRIEF HISTORY OF NEMS[49]

NEMS is a technology-rich energy-economic equilibrium model that is a hybrid of “top-down” and “bottom-up” approaches: the model includes economy-wide general equilibrium effects, but uses a detailed engineering-economic approach to generate energy demand from individual technologies and detailed economic sub-sectors (EIA, 2009b; Gabriel et al., 2001). The model includes thousands of input parameters drawn from EIA energy use surveys, consultants’ reports, and model developers’ expert opinions.

The NEMS approach to analyzing the energy economy is best understood in the context of its development. NEMS is the third major model developed for the U.S. Department of Energy’s national mid-term to long-term forecasting and policy analysis applications. In 1974, the Federal Energy Administration (the organizational precursor to the EIA) developed the Project Independence Evaluation System (PIES) (NRC, 1992, p. 129). PIES operated by combining a set of econometric demand equations with a linear programming model that incorporated supply side constraints (Ahn and Hogan, 1982). Congressional interest in medium-term energy forecasting led to the development of the second major federal government model, the Intermediate

[49] Thanks to Danny Cullenward for helping track down this history. Part of this text was originally intended for Wilkerson, et al., (2013), but was trimmed there for length.

Future Forecasting System (IFFS), which was capable of examining near- and medium-term projections in greater detail. IFFS employed a modular structure, with different sub-models for each constituent part of the energy system; an integrating module coordinated the mathematical convergence process to solve the entire system for a single, equilibrium solution (Murphy, 1983; Murphy et al., 1988). Thus, IFFS can be viewed as an extension of the basic PIES optimization framework, with significantly expanded sectoral details and computational complexity.

Three other energy-modeling systems used by the U.S. Department of Energy for U.S. markets are worth a brief mention (NRC, 1992, Appendix E). First, from 1979-1981, EIA used the Long-Term Energy Analysis Program (LEAP) for forecasts to the year 2020. LEAP was a configuration of the Generalized Equilibrium Modeling System (GEMS), developed by the Stanford Research Institute. Second, EIA also began using the Short-Term Integrated Forecasting System (STIFS) in 1972 to generate two-year energy forecasts. STIFS was eventually replaced by the Regional Short-Term Energy Model (RSTEM), which is in use today. Third, a model called FOSSIL was developed at Dartmouth College under U.S. DOE sponsorship (Backus and Amlin, 2009). A subsequent version, called FOSSIL2, replaced PIES at EIA for several years. Although the FOSSIL model family is no longer in use at EIA, it served as the basis for the ENERGY 2020 model, which was recently used to evaluate California's climate policy for the state's A.B. 32 Scoping Plan (CARB, 2008; Systemic Solutions, 2008).

In 1990, the U.S. Department of Energy requested the formation of a committee at the National Research Council to study the development of a comprehensive national energy-environment model. After two years of study, that committee produced a series of recommendations that served as the blueprint for the development of NEMS (NRC, 1992). NEMS is a technology-rich energy-economic equilibrium model that is a hybrid of "top-down" and "bottom-up" approaches: the model includes economy-wide general equilibrium effects, but uses a detailed engineering-economic approach to generate energy demand from individual technologies and detailed economic sub-sectors (EIA, 2009b; Gabriel et al., 2001).

The model includes thousands of input parameters drawn from EIA energy use surveys, consultants' reports, and model developers' expert opinions. NEMS is much more complicated than its predecessors, especially in terms of the number of input parameters and structural equations used to forecast energy, economic, and environmental outcomes. Nevertheless, NEMS may be considered philosophically continuous with its predecessors, in the sense that it applies an economic optimization approach to a rich set of input parameters and economic equations.

A.3 Obtaining and installing NEMS

NEMS is developed by the EIA and paid for by U.S. taxpayers. As a result, the model is free to users outside EIA once the user explains the research intent and promises no further distribution of the code. However, that is where the ease and simplicity stops. To engage and run NEMS requires more than a dozen additional software packages and programing environments, several of which are costly, as well as painstaking to install, configure, and integrate. The list includes compilers, programming environments, an operating system emulator, multiple optimization packages and the necessary solver links. Even the models' macroeconomic module (MAM), which determines international and intra-sector feedbacks, has been developed by commercial groups external to EIA.

To engage and run NEMS requires a number of additional software packages beyond the provided source code and input files. NEMS is written in FORTRAN so compiling and/or linking objects requires the Intel Visual FORTRAN Compiler, which, in turn, requires the Microsoft Visual Studio Development Environment. The compiler and development environment are designed for the Microsoft Windows platform. However, NEMS was originally developed to run on the UNIX operating system, so now requires a UNIX-emulator. Prior to AEO2013, EIA required the use of a proprietary emulator, MKS Toolkit, but now allows (falling short of 'encourages') the use of the free and open source Cygwin UNIX emulator. With these operating environments installed, one could install and run the core NEMS code. However, this set up will not reproduce any published EIA results.

EIA also relies on contracts and external developers to help keep the algorithms up to date with current U.S. energy-economic system philosophy. This has led to a suite of additional tools, each solving a particular piece of the energy economic system, all of which are necessary to replicate the AEO results. The model's energy price calculations, which are used in the Electricity Market Module, the Coal Market Module, and the Petroleum Market Module, are computed using the Optimization Modeling Library (OML), developed by Ketron Optimization. The OML files are available on the NEMS distribution disk, however, a license and secure hardware need to be obtained from Ketron. The Xpress optimizer from the Fair-Isaac Corporation (FICO) is used in the Electricity Capacity Planning module. EIA has made arrangements with FICO to provide a single license of the Xpress solver to a limited number of organizations who want to use it for NEMS; however, the Xpress optimizer requires the GAMS optimization programing environment. Once GAMS is obtained, only the link to the solver is required to engage the FICO Xpress. EIA is also evaluating AIMMS as a potential modeling package for use in NEMS for some modeling components as early as AEO2014.

In addition, NEMS uses a software suite from IHS Global Insight called the Macroeconomic Activity Module (MAM). The MAM includes projections about macroeconomic variables, such as growth in Gross Domestic Product (GDP), as well as the relationships between these variables, such as the effect of changes in the construction sector on GDP. The IHS macroeconomic software also requires the EViews statistical econometric package.

Furthermore, due to budget shortfalls, some of EIA's end use energy consumption surveys were delayed or redacted. As a result, EIA adopted a proprietary database from McGraw-Hill to parameterize the commercial buildings sector data in the AEO2011 version (EIA, 2011, p. 30). The 2011 McGraw-Hill database is still the most recent database, and is also used for both the AEO2012 and 2013 versions of the code.

Beyond these explicit tools and datasets, there are several additional software tools (e.g., Python) that help in the preparation of NEMS setup files. Without each of these additional scripts, libraries, and code, along with the required supporting software environments, the affected variables would generally behave in an exogenous manner and change based solely on preset growth rates or expectations.

All of the ‘bells and whistles’ were secured for the current setup at Stanford University, which is key in computing any changes to energy prices resulting from changes in the model’s baseline assumptions. These tools, however, are not inexpensive –even at educational pricing. Allowing the use of Cygwin UNIX emulator instead of MKS Toolkit saves about $800. However, the more expensive, unavoidable pieces include the MAM ($10,500), the McGraw-Hill database ($3,000), GAMS and the Xpress interface for ($1,240) and EViews ($800). Other software requirements cost on the order of a few hundred dollars (e.g. Intel Visual FORTRAN) or are free (e.g., Visual Studio, Cygwin, Python).

A.4 Running NEMS and convergence criteria

When a NEMS run is initiated, it computes each year in sequence through the entire time horizon, ending in the year 2040 by default. Each run takes nearly four hours on a relatively fast desktop computer. At the end of that cycle, NEMS evaluates the convergence criteria and determines if the run has sufficiently converged on a solution. If it has not, the model uses the current solution as the input to the next cycle and starts over.

EIA combines several convergence criteria into a single number with a range of 0-4.0, which the NEMS documentation compares to a grade-point average (GPA) rating scale. The GPA is calculated for each year in the cycle then the worst three years are averaged to get a single number for the run. The user can set the desired convergence threshold GPA and a few other parameters such as minimum and maximum number of cycles. If the minimum number of cycles has passed and the criteria have been met, the run will terminate. Significant detail and justification of the inputs to the convergence criteria can be found in the NEMS Integrating Module documentation (EIA, 2010c). The default GPA defined with our copy of NEMS 2013 was 3.94, and it was left at this setting for all of the scenarios described in this document.

The number of cycles required for convergence depends on the significance of the change from the base case input parameters. Subtle changes may only increase the number of cycles by a few, while substantial changes may lead to several more cycles. Reproducing the published AEO2013 base case scenario results required two cycles, while all other scenarios in this study converged anywhere from four – twelve cycles.

For more aggressive scenarios (e.g. high carbon fees), NEMS can experience some convergence problems due to discontinuities. Supply and demand curves are considered and generally treated as continuous functions; however, some NEMS modules contain linear programs, which translate the curves to step-wise linear functions. Depending on the step size of these new functions and the convergence criteria, such discontinuities can cause significant problems in the solution process.

The following paragraph is EIA's own an example of this from NEMS documentation of the Integrating Module (EIA, 2013b, pg 35):

> *Several modules incorporate algorithms that yield these discontinuous results. For example, the international module outputs a set of crude oil supply curves and petroleum product import supply curves which Liquid Fuels Market Module translates to step curves for input to a linear program, representing refinery operations and solving for fuel prices and refinery fuel demands to minimize costs. This type of approach yields discontinuous petroleum pricing and fuel demands. The Electricity Fuel Dispatch submodule is also implemented as a linear program and contains discontinuities due to the nature of the merit-order plant dispatch. The coal distribution model is also a linear program. Thus, each of these models introduces discontinuities into the NEMS solution process.*

The Integrating Module documentation continues from this with several plots illustrating the issue.

A.5 REPRODUCING THE EIA PUBLISHED RESULTS

Once all the components and supporting software are installed and linked together, the next order of business is to verify the local copy reproduces the published 2013 Annual Energy Outlook (AEO2013) results (EIA, 2013a). The model and its supporting software were configured according the 'installation disk' package provided by EIA then the Reference scenario was repeated with the local installation.

Table A.1 shows the macroeconomic indicators from the published AEO2013 Reference scenario. Table A.2 shows the same macroeconomic indicators obtained from the local installation. Table A.3 shows the ratio of the two results, where the index = 1 represents the AEO result.

Table A.3 shows that all macroeconomic indicators match to three significant figures, despite individual scenario parameters changing by over 30%. Therefore, the local copy is confirmed to accurately reproduce the EIA's published reference case projections published in the AEO2013. Thus, the local Stanford University installation provides a reliable means of assessing what EIA's official copy of NEMS would project for the same scenarios modeled here. Nevertheless, this analysis is independent and should not be confused with official government policy analysis. As a result, outputs from the scenarios described throughout this document are designated as coming from NEMS-Stanford.

Table A.1 Published AEO Reference case key macroeconomic indicators

Indicator	Sector	Year							% Annual Growth					
		2010	2015	2020	2025	2030	2035	2040	2010-2040	2010-15	2015-20	2020-25	2025-30	2030-40
Annual Final Energy	Residential	21.76	20.42	20.62	21.08	21.65	22.25	23.08	0.2%	-1.3%	0.2%	0.4%	0.5%	0.6%
(Quads)	Commercial	18.09	17.90	18.37	19.04	19.72	20.37	21.13	0.5%	-0.2%	0.5%	0.7%	0.7%	0.7%
	Industrial	30.93	32.21	34.76	35.46	35.11	35.26	36.16	0.5%	0.8%	1.5%	0.4%	-0.2%	0.3%
	Transport	27.57	27.18	27.30	26.75	26.33	26.54	27.27	0.0%	-0.3%	0.1%	-0.4%	-0.3%	0.4%
	Total	98.35	97.72	101.04	102.34	102.81	104.41	107.64	0.3%	-0.1%	0.7%	0.3%	0.1%	0.5%
Annual Final Energy	*Residential*	*22%*	*21%*	*20%*	*21%*	*21%*	*21%*	*21%*						
(Percent of total)	*Commercial*	*18%*	*18%*	*18%*	*19%*	*19%*	*20%*	*20%*						
	Industrial	*31%*	*33%*	*34%*	*35%*	*34%*	*34%*	*34%*						
	Transport	*28%*	*28%*	*27%*	*26%*	*26%*	*25%*	*25%*						
	Total	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*						
Gross Domestic Product														
(2000 $billions)		$ 13,063	$ 14,679	$ 16,859	$ 18,985	$ 21,355	$ 24,095	$ 27,277	2.5%	2.4%	2.8%	2.4%	2.4%	2.5%
(Index: 2010 = 1)		*1.00*	*1.12*	*1.29*	*1.45*	*1.63*	*1.84*	*2.09*						
Population														
(Millions)		310.06	324.59	340.45	356.46	372.41	388.35	404.39	0.9%	0.9%	1.0%	0.9%	0.9%	0.8%
(Index: 2010 = 1)		*1.00*	*1.05*	*1.10*	*1.15*	*1.20*	*1.25*	*1.30*						
Labor Force														
(Millions)		153.89	158.82	164.73	169.32	174.90	182.31	190.65	0.7%	0.6%	0.7%	0.6%	0.7%	0.9%
(Index: 2010 = 1)		*1.00*	*1.03*	*1.07*	*1.10*	*1.14*	*1.18*	*1.24*						
Housing Starts														
(millions of housholds)		0.64	1.64	1.89	1.90	1.89	1.89	1.89	3.7%	20.9%	2.8%	0.1%	-0.1%	0.0%
(Index: 2010 = 1)		*1.00*	*2.59*	*2.98*	*2.99*	*2.98*	*2.97*	*2.98*						
Comemercial Fllor Space														
(billions of sqft)		81.1	84.1	89.1	93.9	98.1	103.0	108.8	1.0%	0.7%	1.2%	1.1%	0.9%	1.0%
(Index: 2010 = 1)		*1.00*	*1.04*	*1.10*	*1.16*	*1.21*	*1.27*	*1.34*						

Table A.2 NEMS-Stanford Reference case key macroeconomic indicators

Indicator	Sector	Year							% Annual Growth					
		2010	2015	2020	2025	2030	2035	2040	2010-2040	2010-15	2015-20	2020-25	2025-30	2030-40
Annual Final Energy	Residential	21.76	20.43	20.61	21.07	21.63	22.24	23.09	0.2%	-1.3%	0.2%	0.4%	0.5%	0.7%
(Quads)	Commercial	18.09	17.91	18.36	19.03	19.70	20.36	21.14	0.5%	-0.2%	0.5%	0.7%	0.7%	0.7%
	Industrial	30.93	32.20	34.76	35.46	35.12	35.25	36.14	0.5%	0.8%	1.5%	0.4%	-0.2%	0.3%
	Transport	27.57	27.18	27.30	26.75	26.32	26.51	27.23	0.0%	-0.3%	0.1%	-0.4%	-0.3%	0.3%
	Total	98.35	97.72	101.03	102.31	102.76	104.36	107.60	0.3%	-0.1%	0.7%	0.3%	0.1%	0.5%
Annual Final Energy	*Residential*	*22%*	*21%*	*20%*	*21%*	*21%*	*21%*	*21%*						
(Percent of total)	*Commercial*	*18%*	*18%*	*18%*	*19%*	*19%*	*20%*	*20%*						
	Industrial	*31%*	*33%*	*34%*	*35%*	*34%*	*34%*	*34%*						
	Transport	*28%*	*28%*	*27%*	*26%*	*26%*	*25%*	*25%*						
	Total	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*						
Gross Domestic Product														
(2000 $billions)		$ 13,063	$ 14,679	$ 16,859	$ 18,985	$ 21,355	$ 24,095	$ 27,277	2.5%	2.4%	2.8%	2.4%	2.4%	2.5%
(Index: 2010 = 1)		*1.00*	*1.12*	*1.29*	*1.45*	*1.63*	*1.84*	*2.09*						
Population														
(Millions)		310.06	324.59	340.45	356.46	372.41	388.35	404.39	0.9%	0.9%	1.0%	0.9%	0.9%	0.8%
(Index: 2010 = 1)		*1.00*	*1.05*	*1.10*	*1.15*	*1.20*	*1.25*	*1.30*						
Labor Force														
(Millions)		153.89	158.82	164.73	169.32	174.90	182.31	190.65	0.7%	0.6%	0.7%	0.6%	0.7%	0.9%
(Index: 2010 = 1)		*1.00*	*1.03*	*1.07*	*1.10*	*1.14*	*1.18*	*1.24*						
Housing Starts														
(millions of housholds)		0.64	1.64	1.89	1.90	1.89	1.89	1.89	3.7%	20.9%	2.8%	0.1%	-0.1%	0.0%
(Index: 2010 = 1)		*1.00*	*2.59*	*2.98*	*2.99*	*2.98*	*2.97*	*2.98*						
Comemercial Fllor Space														
(billions of sqft)		81.1	84.1	89.1	93.9	98.1	103.0	108.8	1.0%	0.7%	1.2%	1.1%	0.9%	1.0%
(Index: 2010 = 1)		*1.00*	*1.04*	*1.10*	*1.16*	*1.21*	*1.27*	*1.34*						

Table A.3 Difference between published AEO Reference and NEMS-Stanford Reference Scenarios (Index 1 = AEO)

Indicator	Sector	Year							% Annual Growth					
		2010	2015	2020	2025	2030	2035	2040	2010-2040	2010-15	2015-20	2020-25	2025-30	2030-40
Annual Final Energy	Residential	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(Quads)	Commercial	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Industrial	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Transport	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Total													
Annual Final Energy	*Residential*													
(Percent of total)	*Commercial*													
	Industrial													
	Transport													
	Total													
Gross Domestic Product														
(2000 $billions)		$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000						
(Index: 2010 = 1)														
Population														
(Millions)		$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000						
(Index: 2010 = 1)														
Labor Force														
(Millions)		$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000						
(Index: 2010 = 1)														
Housing Starts														
(millions of housholds)		$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000						
(Index: 2010 = 1)														
Comemercial Fllor Space														
(billions of sqft)		$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000	$ 1.000						
(Index: 2010 = 1)														

A.6 NEMS FORESIGHT

This study is interested in only the first ten years for the policy, so ideally one would be able to run NEMS for 10-15 years instead of the default 25 years.[50] However, this imposes a problem with the NEMS solution that was not immediately resolvable. When otherwise identical policy scenarios are run through 2025 and 2040, they produce different results. This is a consequence of foresight parameters in the electricity market module (EMM) in NEMS.

The EMM has expectation arrays that extend 30 years beyond the regular model horizon arrays, but theoretically at some point they tend to matter less. One use for foresight in NEMS is to determine what new power plant should be built to meet expected future demand. This becomes more important as the model run approaches

[50] Running for three years past the final year of interest would help minimize model convergence issues for the ten years of interest, since the last three years often exhibit the worst convergence scores

the run time horizon (variable *LASTYR*), and less important in the early years since variable costs (e.g., fuel and carbon prices) are explicitly defined in the model setup. For example, let *LASTYR = 2040,* and that electricity demand will require a new power plant in 2038. NEMS will determine the lifetime expected cost of different electric generation technologies based on expectations of future fuel and carbon prices for the next 30 years (28 years beyond the end of the model run) to determine the least cost option.

For carbon prices, *UPCARGRW* variable in the ***emmcntl.txt*** file controls post-*LASTYR* expectations for the carbon allowance price. The default setting 0.05, or 5%, thus increasing post-*LASTYR* allowances by 5% per year. There are several other expectation parameters in ***emmcntl.txt*** covering various demand parameters, fuel prices, and more.

However, setting these foresight parameters does not completely resolve the issue. The \$25t/CO_2 at 2% scenario was used to test for foresight control. *UPCARGRW* was set to 2% and the model was run to 2026 and 2040. Since the only exogenous parameter change is the escalating carbon price, these two scenarios should have provided nearly identical results through 2026. Unfortunately, several key macroeconomic parameters (including CO_2 emissions and GDP) were not consistent between the two runs. The differences, according to EIA, are a result of dynamic changes occurring as a result of the carbon fee. Just escalating the fees does not capture annual spillovers and other secondary impacts which are not captured in the foresight parameters. The explanation by EIA was not very satisfying. The recommendation was to always run through *LASTYR* = 2040, since that is the configuration under which the foresight algorithms were developed.

A.7 Differences between NEMS default revenue recycling options

For any given policy, one can run all five default revenue recycling options to investigate the differences between them. For example, using the Boxer-Sanders Climate Protection Act policy scenario as a backdrop (\$20/tCO2 at 5.6%), one can show that all *mactax* options produce similar reduction in carbon emissions and GDP. Table A.4 shows that the Reference scenario emissions will slowly rise from 5,369 $MMtCO_2$ in 2013 to almost 5,500 $MMtCO_2$ in 2023. All five revenue recycling options reduce emissions by more than 10% by 2023, and all are within a few tenths of a percentage point. The table also shows that the Reference scenario GDP will rise from $15.6 trillion in 2013 to $20.5 trillion in 2023. The difference in the impact to GDP from each policy scenario is also within a few tenths of a percent of each other.

Table A.4 Macroeconomic differences between NEMS default revenue recycling methods

Boxer-Sanders Climate Protection Act ($20/$tCO_2$ at 5.6%)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Emissions ($MMtCO_2$)											
Reference	5,369	5,361	5,381	5,335	5,367	5,400	5,438	5,452	5,452	5,480	5,494
Scenario percent difference											
mactax 1	0.0%	-4.3%	-6.3%	-6.8%	-7.2%	-7.5%	-8.1%	-8.8%	-9.5%	-10.0%	-10.5%
mactax 2	0.0%	-4.5%	-6.4%	-6.8%	-7.2%	-7.4%	-7.9%	-8.5%	-9.2%	-9.8%	-10.3%
mactax 3	0.0%	-4.4%	-6.5%	-6.8%	-7.2%	-7.5%	-7.9%	-8.5%	-9.0%	-9.6%	-10.1%
mactax 4	0.0%	-4.4%	-6.3%	-6.8%	-7.2%	-7.3%	-7.8%	-8.5%	-9.4%	-9.9%	-10.5%
mactax 5	0.0%	-4.5%	-6.4%	-6.8%	-7.1%	-7.4%	-7.8%	-8.4%	-9.0%	-9.7%	-10.2%
GDP (Billions of Chained 2011 USD)											
Reference	$15,642	$16,089	$16,639	$17,149	$17,674	$18,153	$18,640	$19,112	$19,557	$20,027	$20,518
Scenario percent difference											
mactax 1	0.0%	-0.1%	-0.4%	-0.5%	-0.5%	-0.5%	-0.5%	-0.6%	-0.5%	-0.5%	-0.5%
mactax 2	0.0%	-0.4%	-0.7%	-0.6%	-0.6%	-0.5%	-0.4%	-0.4%	-0.3%	-0.2%	-0.2%
mactax 3	0.0%	-0.4%	-0.9%	-1.0%	-0.9%	-0.9%	-0.9%	-0.8%	-0.7%	-0.6%	-0.6%
mactax 4	0.0%	-0.2%	-0.7%	-0.8%	-0.7%	-0.5%	-0.4%	-0.4%	-0.5%	-0.6%	-0.7%
mactax 5	0.0%	-0.4%	-0.8%	-0.7%	-0.6%	-0.5%	-0.3%	-0.2%	-0.1%	-0.1%	-0.2%

A.8 Definition of *mactax* = 6 within the mcevcode.txt file.

The interface between NEMS and the MAM is through the ***mcevcode.txt*** file. This file is 60 pages long and very little of it is modified to account for a new *mactax* = 6 revenue recycling method. Consequently, only the relevant parts are included here.

The syntax for the code here is the scripted language required for eViews econometric software which the MAM is written in. Also, *mactax* in NEMS becomes *taxmode* in the MAM. Since the code below is for the MAM, the name *taxmode* is used here. Furthermore, any block of code added for this study has been set in bold for clarification.

Near the top of ***mcevcode.txt*** file (before anything important is defined), scale factors are generated (*genr*) for deficit reduction (*pct_def*), consumer rebate (*pct_con*), and business rebate (*pct_bus*). These values must add to 1, or 100%, so the third term is derived from the first two.

```
'*****************************************
'* jtw insert distribution percentages  *
'*****************************************
' fraction of tax revenues to direct to deficit, consumers, and
      businesses
genr pct_con = 0.50
genr pct_bus = 0.50
genr pct_def = 1.00 - pct_con - pct_bus
```

There are several sections that mention the various recycling methods, but don't require modification when adding a new method. For example, shortly after the code above, ***mcevcode.txt*** constructs the *altmod* model. After several pages of appending variables and associated data to *altmod*, comes a description for value added tax (VAT). The definition of each *taxmode* is simply a comment for the readers' benefit. Following the commented *taxmode* definitions is an IF-THEN block that executes if taxmode is not zero (IF *taxmode* <>0), which assigns the emissions revenues (*emisrev_total_a*) to the variable *tximgfoth_a*. So, one can add an additional commented definition line for *taxmode = 6* if desired (as shown below), but it is not necessary. This occurs several times throughout the document. EIA's in-line comments are sufficient for some of this.

```
'******************************************************
'* Create model objects altmod and ratiomod          *
'******************************************************

'Construct model altmod of alternative NEMS energy price and
      consumption assumptions.
model altmod
```

<snip>

```
'Federal excise tax accruals other than for a VAT.
'taxmode=0 no tax; default energy price and quantity sim
'taxmode=1 returns tax collections to consumers, revenue neutral
'taxmode=2 returns tax collections to business, revenue neutral
```

```
'taxmode=3 deficit reduction
'taxmode=4 returns tax collections to consumers, deficit neutral
'taxmode=5 returns tax collections to business, deficit neutral
'taxmode=6 pct_def to deficit reduction, returns pct_con to
      consumers, the remainder to businesses, deficit neutral

if (taxmode <> 0) then
  altmod.append @identity tximgfoth_a  = (emisrev_total_a +
      emisrev_cover_a) * jpgdp_a
endif
```

<snip>

```
if (taxmode <> 0) then
  ratiomod.append @identity tximgfoth_r      = tximgfoth_a_0
  'Dummy variable for tximgfoth_r. Quadratic match average makes a
      mess of year
  ' prior to revenue collection. The dummy variable corrects for
      this.
  ratiomod.append @identity tximgfoth_dmy_r  = tximgfoth_r>0
endif
```

<snip>

```
'Dummy variable for txgfoth_r. Quadratic match average makes a mess
      of year
' prior to revenue collection. The dummy variable corrects for
      this. The setconvert
' prevents the quadratic match average from making a mess of the
      dummy variable.
if (taxmode <> 0) then
  TXIMGFOTH_dmy_r_0.setconvert r
endif
```

<snip>

Eventually, one will arrive at the definitions for the default revenue recycling options. The following block of code defines the variables needed for each recycling method.

```
if (taxmode <> 0) then
   genr tximgfoth_a_1  = tximgfoth_a
 endif
 if (taxmode = 1 or taxmode = 4) then
```

```
    genr txpgf_a        = 0.
    genr txpgf_a_1      = txpgf_a
  endif
  if (taxmode = 2 or taxmode = 5) then
    genr txcorpgf_a     = 0.
    genr txcorpgf_a_1   = txcorpgf_a
  endif
  if (taxmode = 4 or taxmode = 5) then
    genr netsavgffe     = netsavgffe_0
  endif
```

If *taxmode* = 0, then there is no tax do no revenues, so setting *tximgfoth_a_1* = *tximgfoth_a* ensures there is no residual value. Otherwise (if *taxmode* <> 0), then the difference between *tximgfoth_a* and *tximgfoth_a_1*will define the total revenues.

If revenues are to be returned to consumers (*taxmode* = 1 or 4), then the return of tax collections to households is done by lowering personal federal tax receipts (*txpgf*). The code above creates and initializes an add factor, *txpgf_a*, and an override for other computational purposes, *txpgf_a_1*, for the *txpgf* equation. The difference between *txpgf_a* and *txpgf_a_1* will be eventually be the amount distributed to households.

Similarly, if revenues are to be returned to businesses (*taxmode* = 2 or 5), then the return of tax collections to corporations is done by lowering corporate tax receipts (*txcorpgf*). The following code creates and initializes an add factor, *txcorpgf_a*, and an override for other computational purposes, *txcorpgf_a_1*, for the *txcorpgf* equation. The difference between *txcorpgf_a* and *txcorpgf_a_1* will eventually be the amount distributed to corporations.

Finally, if the returns are to be done in a deficit neutral manner (*taxmode* = 4 or 5), then the full-employment federal NIPA budget surplus, *netsavgffe*, is initialized for further assessment.

To define *taxmode* = 6 one needs to combine *taxmode* =4 and *taxmode* = 5 definitions. So, immediately following the previous block of code, one needs to insert the following block. This initializes all of the necessary variables for deficit neutral revenue recycling split between households and corporations

```
  if (taxmode = 6) then
```

```
    genr txpgf_a         = 0.
    genr txpgf_a_1       = txpgf_a

    genr txcorpgf_a      = 0.
    genr txcorpgf_a_1    = txcorpgf_a

    genr netsavgffe      = netsavgffe_0
  endif
```

<snip>

The tax revenues are initially redistributed in the following block of code. The default options are all-or-nothing. However the *taxmode* = 6 block of code added below the default options splits the revenues between households and corporations. In this example, *pct_con* and *pct_bus* are both 50% (0.05). These could have been set to any value. If, for example, one wanted to also pay down the deficit with some of the revenues, then nothing would change here (except for the balance of returns to consumers and businesses would be lower, of course). This section only defines what is recycled back into the economy. Any deficit reduction will be handled in the next set of code.

```
 if (taxmode <> 0) then
    tximgfoth_a_1 = tximgfoth_a +
       ({%wfpathpwd}eviewsdb::tximgfoth_dmy_r_0*{%wfpathpwd}eviewsdb
       ::tximgfoth_r_0)
  endif
  if (taxmode = 1 or taxmode = 4) then
    txpgf_a_1     = txpgf_a      -
       ({%wfpathpwd}eviewsdb::tximgfoth_dmy_r_0*{%wfpathpwd}eviewsdb
       ::tximgfoth_r_0)
  endif
  if (taxmode = 2 or taxmode = 5) then
    txcorpgf_a_1  = txcorpgf_a   -
       ({%wfpathpwd}eviewsdb::tximgfoth_dmy_r_0*{%wfpathpwd}eviewsdb
       ::tximgfoth_r_0)
  endif

  if (taxmode = 6) then
    txpgf_a_1     = txpgf_a      -
       ({%wfpathpwd}eviewsdb::tximgfoth_dmy_r_0*{%wfpathpwd}eviewsdb
       ::tximgfoth_r_0*pct_con)
    txcorpgf_a_1  = txcorpgf_a   -
       ({%wfpathpwd}eviewsdb::tximgfoth_dmy_r_0*{%wfpathpwd}eviewsdb
       ::tximgfoth_r_0*pct_bus)
  endif
```

<snip>

Finally, the amount returned to consumers or businesses is passed from the MAM (i.e. eViews calculations) to NEMS to be used as inputs for the remaining energy economic calculations. The added block of code for *taxmode* = 6 assigns a portion to consumers and businesses, then assigns any remaining revenues to the deficit.

```
if (taxmode = 1 or taxmode = 4) then
  m_us2010c.override(m)  TXIMGFOTH_A TXPGF_A
  m_us2010c.addassign(v) TXPGF
endif
if (taxmode = 4) then
  m_us2010c.control      TXPGF_A NETSAVGFFE NETSAVGFFE
endif
if (taxmode = 2 or taxmode = 5) then
  m_us2010c.override(m)  TXIMGFOTH_A TXCORPGF_A
  m_us2010c.addassign(v) TXCORPGF
endif
if (taxmode = 5) then
  m_us2010c.control      TXCORPGF_A NETSAVGFFE NETSAVGFFE
endif
if (taxmode = 3) then
  m_us2010c.override(m)  TXIMGFOTH_A
endif


if (taxmode = 6) then
  m_us2010c.override(m)  TXPGF_A
  m_us2010c.addassign(v) TXPGF

  m_us2010c.override(m)  TXCORPGF_A
  m_us2010c.addassign(v) TXCORPGF

 'put remainder to deficit
  m_us2010c.override(m)  TXIMGFOTH_A
endif
```

<snip>

So, once *taxmode* = 6 has been entered as described above, the only change necessary for alternate scenarios is to alter the distributions, or percentages, to be assigned to each group (consumers, businesses, and deficit reduction). This can be done on the first page of the code as shown above.

A.9 ACCOMMODATING EITE INDUSTRIES IN NEMS

EIA provided guidance on modifying fuel prices to protect energy-intense and trade-exposed industries.

A.9.1 ENERGY INTENSE INDUSTRIES

Protecting energy intense industries requires two steps. First, adjust the prices in the model to account for explicit tax breaks. Second, adjust the revenue amount to account for the pre-recycled tax revenues.

EIA collects reference and policy scenario energy prices for the following terms. These are found by exploiting the ***mcevcode.txt*** interface between NEMS and the MAM.

```
WPI051  Endog   Eq1450  Producer price index--coal
WPI053  Endog   Eq1452  Producer price index--gas fuels
WPI054  Endog   Eq1454  Producer price index--electric power
WPI055  Endog   Eq1497  Producer price index--utility natural gas
WPI0561 Endog   Eq1455  Producer price index--crude petroleum
WPI057  Endog   Eq1513  Producer price index--refined petroleum
      products
WPI05   Endog   Eq1674  Producer price index--fuels, related
      products & power
```

Using these endogenous prices, EIA decides what the new energy prices will be based on the language in the policy they are evaluating. They compute an alternative *WPI05* with the following equation:

```
WPI05  = WPI05(-1)  * ((0.0355  * WPI051  + 0.1042  * WPI053  +
      0.3011  * WPI054  + 0.1590  * WPI055  + 0.0950  * WPI0561  +
      0.3053  * WPI057 )  / (0.0355  * WPI051(-1)  + 0.1042  *
      WPI053(-1)  + 0.3011  * WPI054(-1)  + 0.1590  * WPI055(-1)  +
      0.0950  * WPI0561(-1)  + 0.3053  * WPI057(-1)))
```

EIA then implements the alternative energy price assumptions by hard coding these values near the bottom of the ***GET_USMACRO*** subroutine in the ***mcevsubs*** MAM program file. This will overwrite the energy prices used in the output by industry model with the assumptions.

This process intends to simulate the carbon fee and a rebate or allowance to protect the EITE industry. However, NEMS will still collect the entire amount of revenues without any knowledge that some of the revenues have already been returned exogenously. So, the revenue available for return to the rest of the economy will need to be adjusted by that amount.

A.9.2 TRADE EXPOSED INDUSTRIES

To protect trade exposed industries, policies often stipulate a border tax assessment (BTA), which is an import tax levied by carbon-taxing countries on goods manufactured in non-carbon-taxing countries. The BTA adjustments help ensure a level playing field in international trade while internalizing the costs of climate damage into prices of goods and services. However, NEMS is a model of the U.S., not the world, and its characterization of trade and import is very coarse and limited.

To get around this, EIA will provide domestic industries with a rebate that tries to eliminate the carbon fee on export goods. First, this diminishes the incentive for decarbonizing the manufacturing process within these industries. Second, this is very subjective since one also needs to know the fraction of a company's goods which are exported. The intent is to eliminate the carbon ee on export goods, but retain the fee on domestic goods.

To accomplish this, EIA makes an assessment of what fraction of goods from a particular industry are exported (say 5%). EIA will then scale carbon fee by 0.95. Using this new carbon fee, EIA will adjust prices to these industries in the same manner defined above for energy intense industries.

B.1 LIST OF TABLES AND FIGURES FOR APPENDIX B

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B.2 LMDI METHOD I DERIVATION SUMMARY

The LMDI Method I can be applied as a multiplicative or an additive decomposition, where the multiplicative effectively determines index annual growth rates and the additive determines index percentages. Choosing one or the other is a user preference and depends on the intended audience of the study results. Fortunately, the LMDI is one of the few methods that have an explicit correlation between the two decomposition approaches, so one only needs to derive one or the other. Of particular interest for this study is to evaluate the percent impacts from each index of the identities, so what follows is a brief summary of the additive derivation; however, for explicit derivations and proofs of both the LMDI I methods, one can review Ang (2005) or Ang et al., (2009).

To begin, assume V is an energy-related aggregate with n factors. Subscript i represents the sub-category for which the structural change is to be studied. At that sub-category level, assume that the aggregate is the product of the factors: $V_i = x_{1,i}x_{2,i}x_{3,i} \cdots x_{n,i}$. Then the general index decomposition analysis identity is:

$$V = \sum_i V_i = \sum_i x_{1,i}x_{2,i}x_{3,i} \cdots x_{n,i} \qquad \textbf{B.1}$$

The total additive aggregate change from time = 0 to t will decompose to:

$$\Delta V_{tot} = V^t - V^0 = \Delta V_{x_1} + \Delta V_{x_2} + \Delta V_{x_3} \cdots \Delta V_{x_n} \qquad \textbf{B.2}$$

Where the subscript tot represents the total or overall change and right-hand side (RHS) terms identify the effects associated with the respective factors. The LMDI general formula for the effect of the k_{th} factor on the RHS is:

$$\Delta V_{x_k} = \sum_i \frac{V_i^t - V_i^0}{\ln(V_i^t) - \ln(V_i^0)} \ln\left(\frac{x_{k_i}^t}{x_{k_i}^0}\right) \qquad \textbf{B.3}$$

To illustrate this, take a simple three-term expansion of the industrial sector, in which activity, structure, and intensity are provided for each subsector. The total energy consumption (E) is the sum-product the three terms:

$$E = \sum_i E_i = \sum_i A \frac{A_i}{A} \frac{E_i}{A_i} = \sum_i A S_i I_i \qquad \textbf{B.4}$$

Where A (=$\sum_i A_i$) is the total activity in the sector, S_i (=A_i/A) is the structural share of each subsector, and I_i (=E_i/A_i) is the energy intensity of each subsector. The change in total energy consumption is then defined as:

$$\Delta E_{tot} = E^t - E^0 = \Delta E_{act} + \Delta E_{str} + \Delta E_{int} \qquad \textbf{B.5}$$

Where the subscripts act, str, and int denote the effects associated with the overall activity level, structure, and sectoral energy intensity, respectively. Each of the RHS terms in Equation B.5 will take the form of Equation B.3, leading to Equation B.6.

$$\begin{aligned}
\Delta E_{act} &= \sum_i \frac{E_i^t - E_i^0}{\ln(E_i^t) - \ln(E_i^0)} \ln\left(\frac{A^t}{A^0}\right) \\
\Delta E_{str} &= \sum_i \frac{E_i^t - E_i^0}{\ln(E_i^t) - \ln(E_i^0)} \ln\left(\frac{S_i^t}{S_i^0}\right) \\
\Delta E_{int} &= \sum_i \frac{E_i^t - E_i^0}{\ln(E_i^t) - \ln(E_i^0)} \ln\left(\frac{I_i^t}{I_i^0}\right)
\end{aligned} \qquad \textbf{B.6}$$

If this example formulation describes a two-industry sector, the LMDI framework is very straightforward, but one must ensure proper bookkeeping of each nested subscripted value. This becomes more tedious when computing a five-factor LMDI decomposition, where one must keep track of subsector i industry values and multiple fuel types j within each subsector.

A full expansion of the industrial sector to evaluate contributions to industrial emissions[51] would include the fuel-type energy mix fraction M_{ij} (=E_{ij}/E_i) and carbon intensity F_{ij} (=C_{ij}/E_{ij}):

$$C = \sum_{jk} C_{ij} = \sum_{jk} A \frac{A_i}{A} \frac{E_i}{A_i} \frac{E_{ij}}{E_i} \frac{C_{ij}}{E_{ij}} = \sum_{jk} AS_i I_i M_{ij} F_{ij} \qquad \textbf{B.7}$$

The decomposition framework would expand Equation B.4 to include the additional two terms, where subscripts mix and emf denote the effects associated with the sectoral energy mix and emission factor (or carbon intensity), respectively.

$$\Delta C_{tot} = C^t - C^0 = \Delta C_{act} + \Delta C_{str} + \Delta C_{int} + \Delta C_{mix} + \Delta C_{emf} \qquad \textbf{B.8}$$

Similarly, Equation B.6 would expand for each RHS term to provide Equation B.9.

$$\begin{aligned}
\Delta C_{act} &= \sum_i \frac{C_i^t - C_i^0}{\ln(C_i^t) - \ln(C_i^0)} \ln\left(\frac{A^t}{A^0}\right) \\
\Delta C_{str} &= \sum_i \frac{C_i^t - C_i^0}{\ln(C_i^t) - \ln(C_i^0)} \ln\left(\frac{S_i^t}{S_i^0}\right) \\
\Delta C_{int} &= \sum_i \frac{C_i^t - C_i^0}{\ln(C_i^t) - \ln(C_i^0)} \ln\left(\frac{I_i^t}{I_i^0}\right) \qquad \textbf{B.9} \\
\Delta C_{mix} &= \sum_i \frac{C_i^t - C_i^0}{\ln(C_i^t) - \ln(C_i^0)} \ln\left(\frac{M_{ij}^t}{M_{ij}^0}\right) \\
\Delta C_{emf} &= \sum_i \frac{C_i^t - C_i^0}{\ln(C_i^t) - \ln(C_i^0)} \ln\left(\frac{F_{ij}^t}{F_{ij}^0}\right)
\end{aligned}$$

[51] In all these LMDI decomposition equations, one can use carbon emission (e.g., ΔC_{tot}) or CO_2 emissions (e.g., $\Delta CO_{2_{tot}}$), as long as it is used consistently on both sides of the equation.

B.3 LMDI DECOMPOSITION OF U.S. ECONOMY

Below is the LMDI Kaya decomposition for each year of each scenario showing the individual effects on annual changes in carbon emissions. The total effects over the first ten years of the policy (2013-2023) are shown in Table B.1and Figure B.1. Annual changes for each scenario are reported below that.

Table B.1 Kaya parameter effects from each scenario

Effect on emissions from each Kaya parameter (2013-2023)

Scenario	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
Total effect ($MMtCO_2$)						
Reference	515.31	958.44	-1177.03	14.71	-186.41	125.03
$15/t$CO_2$ at 2%	501.36	911.98	-1217.01	-24.99	-338.85	-167.51
$15/t$CO_2$ at 4%	498.41	903.32	-1223.30	-31.91	-376.13	-229.61
$15/t$CO_2$ at 6%	494.88	892.33	-1222.46	-47.83	-418.97	-302.06
$15/t$CO_2$ at 8%	490.46	879.44	-1221.18	-63.76	-475.09	-390.13
$25/t$CO_2$ at 2%	490.02	879.69	-1237.69	-63.62	-470.55	-402.16
$25/t$CO_2$ at 4%	484.22	863.26	-1243.05	-79.73	-546.71	-521.99
$25/t$CO_2$ at 6%	478.72	845.66	-1248.41	-108.71	-602.40	-635.14
$25/t$CO_2$ at 8%	473.28	830.25	-1244.16	-141.06	-662.75	-744.45
$35/t$CO_2$ at 2%	478.85	848.05	-1261.16	-98.28	-599.35	-631.90
$35/t$CO_2$ at 4%	471.94	828.31	-1253.24	-135.62	-677.65	-766.27
$35/t$CO_2$ at 6%	462.40	802.57	-1248.91	-177.96	-796.08	-957.98
$35/t$CO_2$ at 8%	450.03	759.11	-1228.80	-212.63	-964.20	-1196.50
Percent from Reference						
Reference	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
$15/t$CO_2$ at 2%	-2.7%	-4.8%	3.4%	-269.8%	81.8%	-234.0%
$15/t$CO_2$ at 4%	-3.3%	-5.8%	3.9%	-316.9%	101.8%	-283.6%
$15/t$CO_2$ at 6%	-4.0%	-6.9%	3.9%	-425.1%	124.8%	-341.6%
$15/t$CO_2$ at 8%	-4.8%	-8.2%	3.8%	-533.3%	154.9%	-412.0%
$25/t$CO_2$ at 2%	-4.9%	-8.2%	5.2%	-532.4%	152.4%	-421.6%
$25/t$CO_2$ at 4%	-6.0%	-9.9%	5.6%	-641.8%	193.3%	-517.5%
$25/t$CO_2$ at 6%	-7.1%	-11.8%	6.1%	-838.8%	223.2%	-608.0%
$25/t$CO_2$ at 8%	-8.2%	-13.4%	5.7%	-1058.7%	255.5%	-695.4%
$35/t$CO_2$ at 2%	-7.1%	-11.5%	7.1%	-767.9%	221.5%	-605.4%
$35/t$CO_2$ at 4%	-8.4%	-13.6%	6.5%	-1021.7%	263.5%	-712.9%
$35/t$CO_2$ at 6%	-10.3%	-16.3%	6.1%	-1309.4%	327.1%	-866.2%
$35/t$CO_2$ at 8%	-12.7%	-20.8%	4.4%	-1545.0%	417.3%	-1057.0%

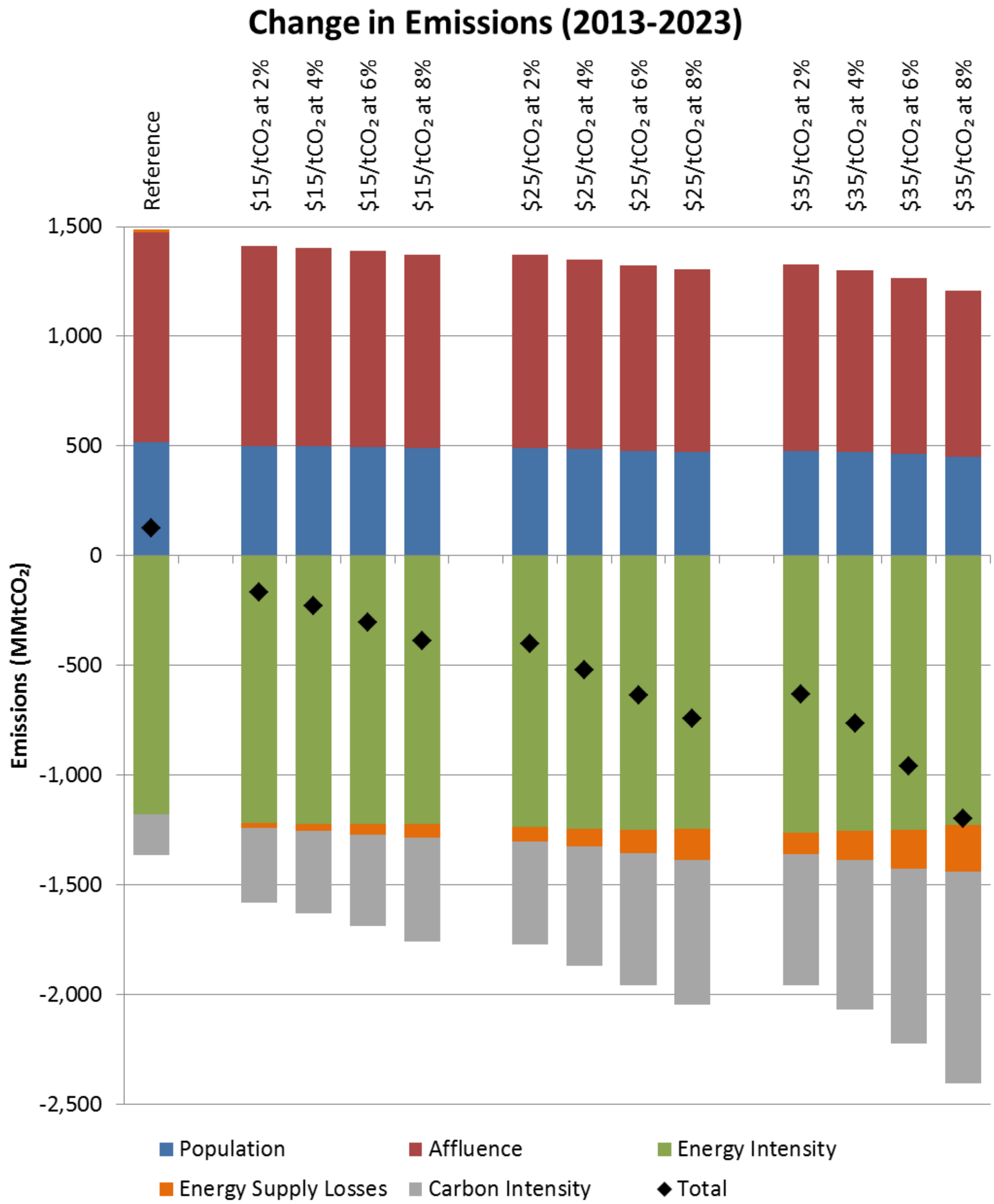

Figure B.1 Kaya parameter effects from each scenario

Table B.2 Kaya parameter effects from Reference scenario

Effects on carbon emissions from Reference scenario (MMtCO₂)

	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	51.9	99.4	-134.4	-1.9	-22.8	-7.7
2014 - 2015	51.9	128.7	-94.2	-22.0	-45.0	19.3
2015 - 2016	51.6	110.2	-110.9	-17.0	-78.9	-45.1
2016 - 2017	51.3	110.0	-121.0	1.8	-10.5	31.5
2017 - 2018	51.4	92.6	-110.3	8.2	-8.4	33.5
2018 - 2019	51.4	91.9	-115.3	13.5	-4.0	37.6
2019 - 2020	51.4	84.7	-125.1	9.1	-5.8	14.3
2020 - 2021	51.1	74.4	-119.5	6.0	-11.9	0.2
[illegible]	[illegible]	[illegible]	-115.9	10.3	2.7	27.1
[illegible]	[illegible]	[illegible]	-125.9	7.3	0.2	14.5
[illegible]	[illegible]	[illegible]	-1177.0	14.7	-186.4	125.0

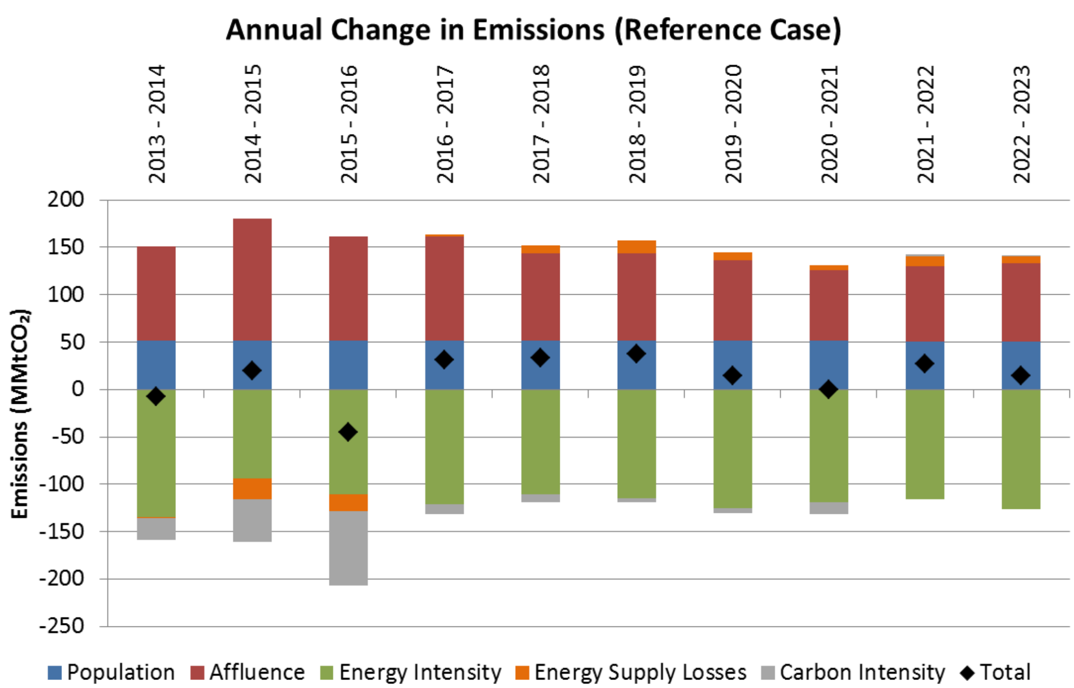

Figure B.2 Kaya parameter effects from Reference scenario

Table B.3 Kaya parameter effects from $15/tCO$_2$ at 2% scenario

Effects on carbon emissions from $15/tCO$_2$ at 2% scenario (MMtCO$_2$)

	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	51.1	88.7	-157.4	-38.3	-124.9	-180.8
2014 - 2015	49.9	106.6	-111.6	-29.5	-63.6	-48.2
2015 - 2016	49.3	103.3	-111.6	-10.6	-62.9	-32.5
2016 - 2017	49.1	112.6	-122.5	0.9	-15.7	24.3
2017 - 2018	49.1	97.3	-112.4	10.0	-10.2	33.8
2018 - 2019	49.2	91.9	-114.0	14.8	-9.1	32.8
2019 - 2020	49.0	80.3	-123.0	7.2	-22.8	-9.2
2020 - 2021	48.6	67.5	-113.0	6.3	-16.0	-6.6
2021 - 2022	48.2	70.8	-110.8	6.0	-4.2	10.1
2022 - 2023	47.7	73.8	-116.9	8.2	-4.0	8.8
2013 - 2023	501.4	912.0	-1217.0	-25.0	-338.9	-167.5

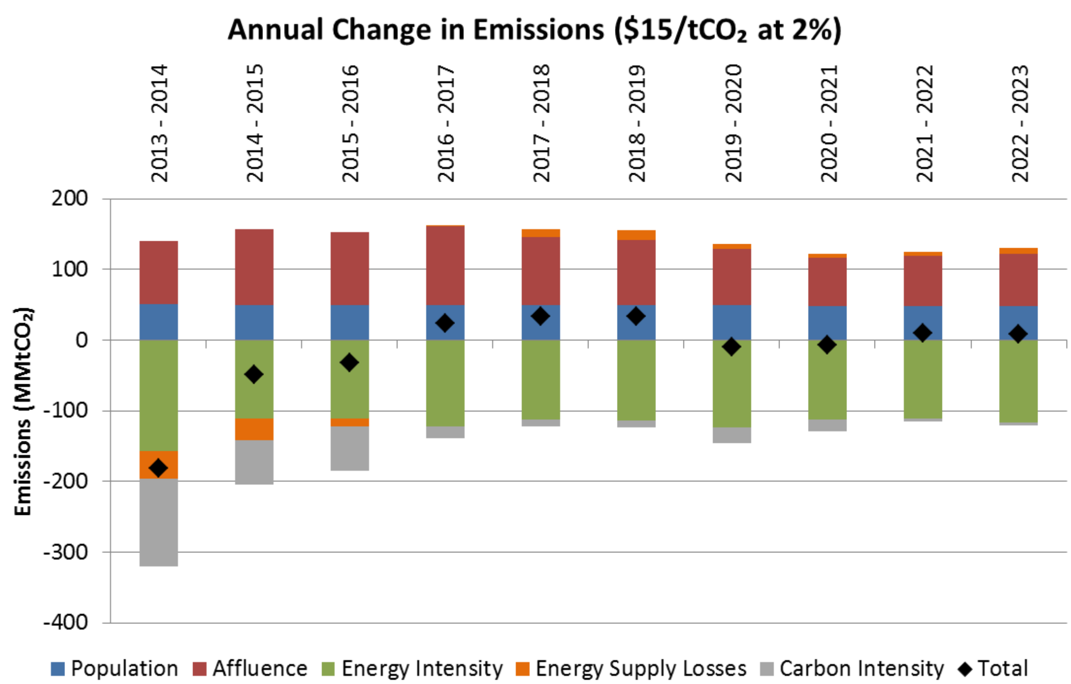

Figure B.3 Kaya parameter effects from $15/tCO$_2$ at 2% scenario

Table B.4 Kaya parameter effects from $15/tCO$_2$ at 4% scenario

Effects on carbon emissions from $15/tCO$_2$ at 4% scenario (MMtCO$_2$)

	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	51.1	89.0	-157.5	-36.9	-120.9	-175.2
2014 - 2015	49.9	106.0	-111.8	-31.8	-68.6	-56.3
2015 - 2016	49.3	102.5	-112.9	-12.5	-68.3	-41.9
2016 - 2017	49.0	112.1	-122.6	0.3	-17.8	21.0
2017 - 2018	49.0	96.5	-112.9	7.2	-15.6	24.1
2018 - 2019	48.9	91.1	-114.9	14.4	-10.3	29.2
2019 - 2020	48.7	79.6	-123.3	6.2	-25.4	-14.2
2020 - 2021	48.2	66.8	-112.7	6.6	-24.3	-15.2
2021 - 2022	47.8	69.9	-109.5	4.6	-11.4	1.4
2022 - 2023	47.2	72.6	-123.2	9.6	-8.8	-2.6
2013 - 2023	498.4	903.3	-1223.3	-31.9	-376.1	-229.6

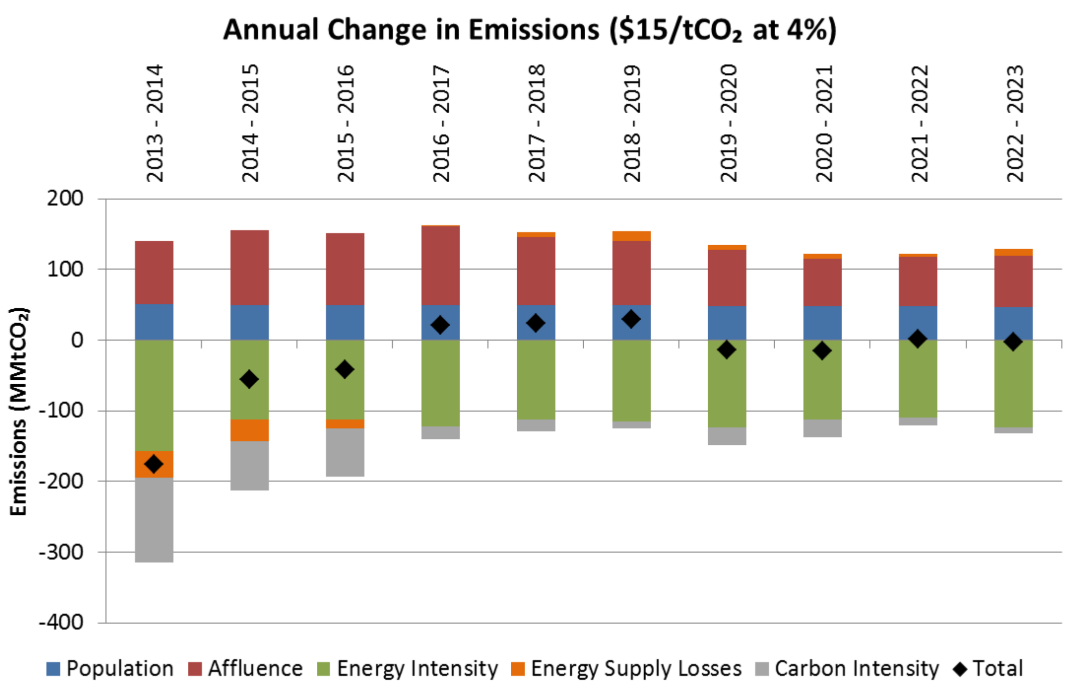

Figure B.4 Kaya parameter effects from $15/tCO$_2$ at 4% scenario

Table B.5 Kaya parameter effects from \$15/tCO_2 at 6% scenario

Effects on carbon emissions from \$15/tCO_2 at 6% scenario ($MMtCO_2$)

	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	51.1	89.0	-157.0	-38.2	-126.7	-181.9
2014 - 2015	49.8	105.9	-112.6	-31.7	-69.2	-57.9
2015 - 2016	49.1	101.3	-113.4	-15.4	-76.6	-55.0
2016 - 2017	48.8	110.8	-123.2	1.3	-12.8	24.9
2017 - 2018	48.7	95.4	-113.5	6.2	-22.1	14.8
2018 - 2019	48.7	89.8	-114.8	12.7	-12.1	24.3
2019 - 2020	48.4	78.5	-124.0	4.7	-30.5	-22.8
2020 - 2021	47.8	65.7	-113.3	4.4	-29.7	-25.1
2021 - 2022	47.3	69.0	-107.1	1.7	-22.0	-11.2
2022 - 2023	46.6	71.4	-123.0	5.9	-13.0	-12.1
2013 - 2023	494.9	892.3	-1222.5	-47.8	-419.0	-302.1

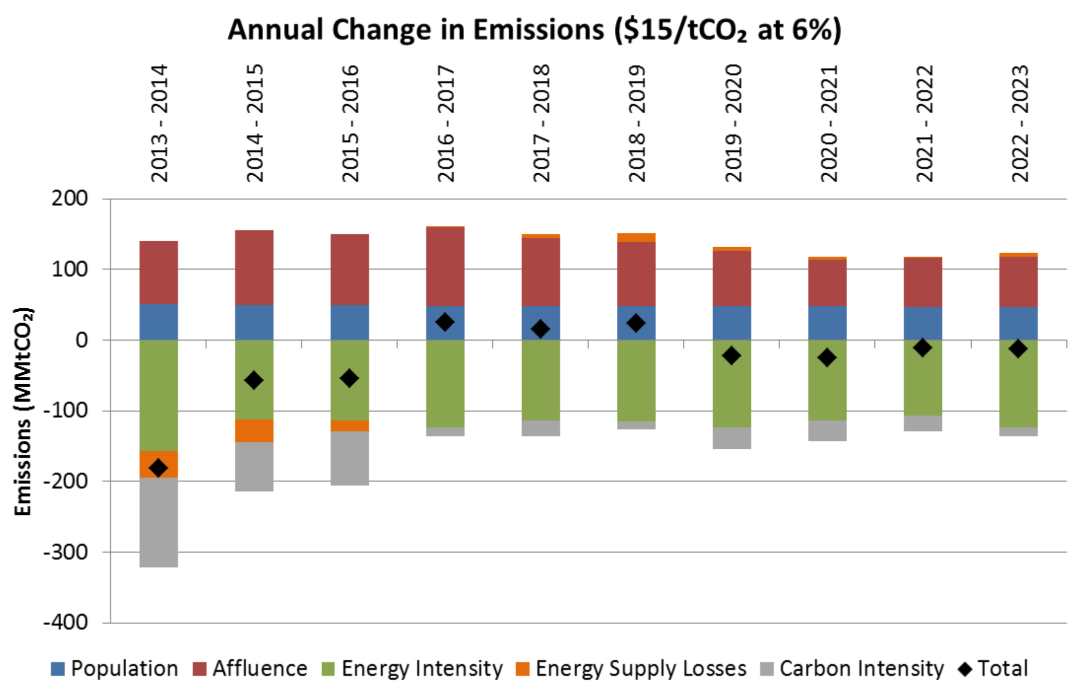

Figure B.5 Kaya parameter effects from \$15/tCO_2 at 6% scenario

Table B.6 Kaya parameter effects from $15/tCO$_2$ at 8% scenario

Effects on carbon emissions from $15/tCO$_2$ at 8% scenario (MMtCO$_2$)

	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	51.0	89.1	-156.9	-37.4	-128.3	-182.4
2014 - 2015	49.7	105.6	-112.6	-33.7	-80.2	-71.2
2015 - 2016	48.9	100.0	-114.5	-17.4	-82.0	-64.9
2016 - 2017	48.4	108.7	-124.1	-2.1	-24.5	6.5
2017 - 2018	48.3	93.8	-113.5	4.1	-21.2	11.4
2018 - 2019	48.2	88.2	-115.5	11.2	-16.2	15.9
2019 - 2020	47.8	77.2	-123.7	3.4	-33.1	-28.4
2020 - 2021	47.1	64.6	-112.8	2.6	-48.6	-47.0
2021 - 2022	46.5	67.8	-104.3	0.9	-11.7	-0.8
2022 - 2023	45.9	69.9	-123.1	3.7	-25.5	-29.2
2013 - 2023	490.5	879.4	-1221.2	-63.8	-475.1	-390.1

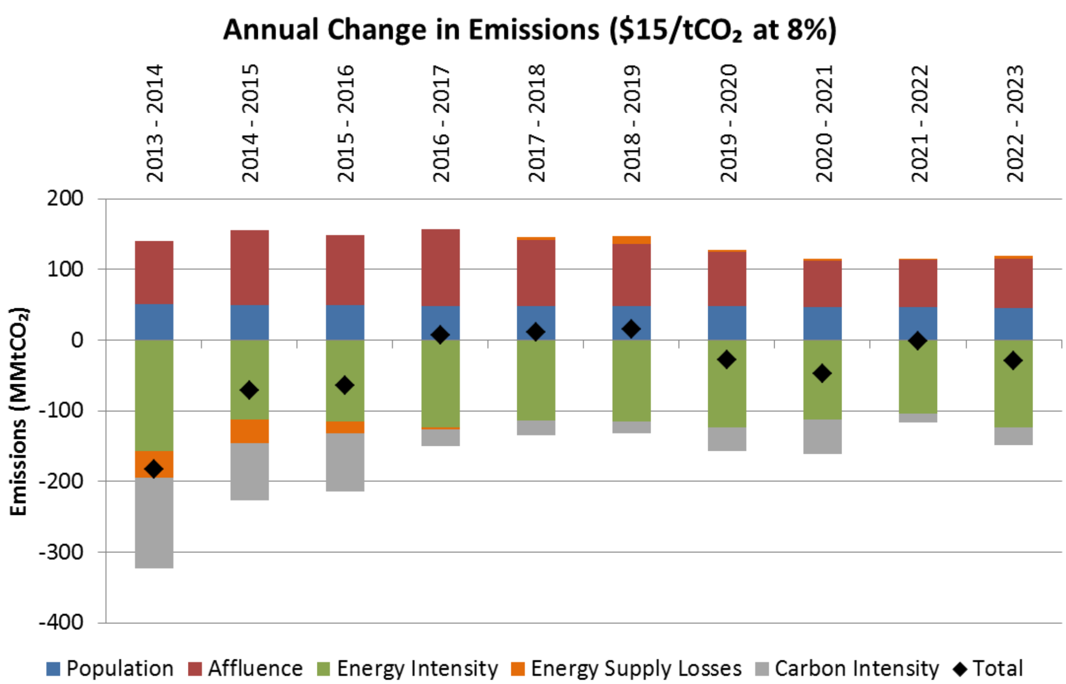

Table B.7 Kaya parameter effects from $15/tCO$_2$ at 8% scenario

Table B.8 Kaya parameter effects from $25/tCO$_2$ at 2% scenario

Effects on carbon emissions from $25/tCO$_2$ at 2% scenario (MMtCO$_2$)	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	50.6	84.3	-171.2	-58.2	-184.4	-279.0
2014 - 2015	48.7	92.1	-121.6	-35.4	-80.3	-96.6
2015 - 2016	47.8	96.9	-114.0	-13.8	-69.9	-53.0
2016 - 2017	47.5	110.4	-120.7	0.0	-15.8	21.4
2017 - 2018	47.5	97.0	-111.4	9.9	-9.7	33.3
2018 - 2019	47.5	90.5	-112.6	11.8	-13.9	23.3
2019 - 2020	47.3	77.9	-120.3	5.4	-25.5	-15.1
2020 - 2021	46.7	65.5	-110.4	6.9	-43.9	-35.2
2021 - 2022	46.2	68.6	-101.4	3.0	-3.8	12.6
2022 - 2023	45.7	70.1	-119.6	6.0	-16.1	-13.9
2013 - 2023	490.0	879.7	-1237.7	-63.6	-470.5	-402.2

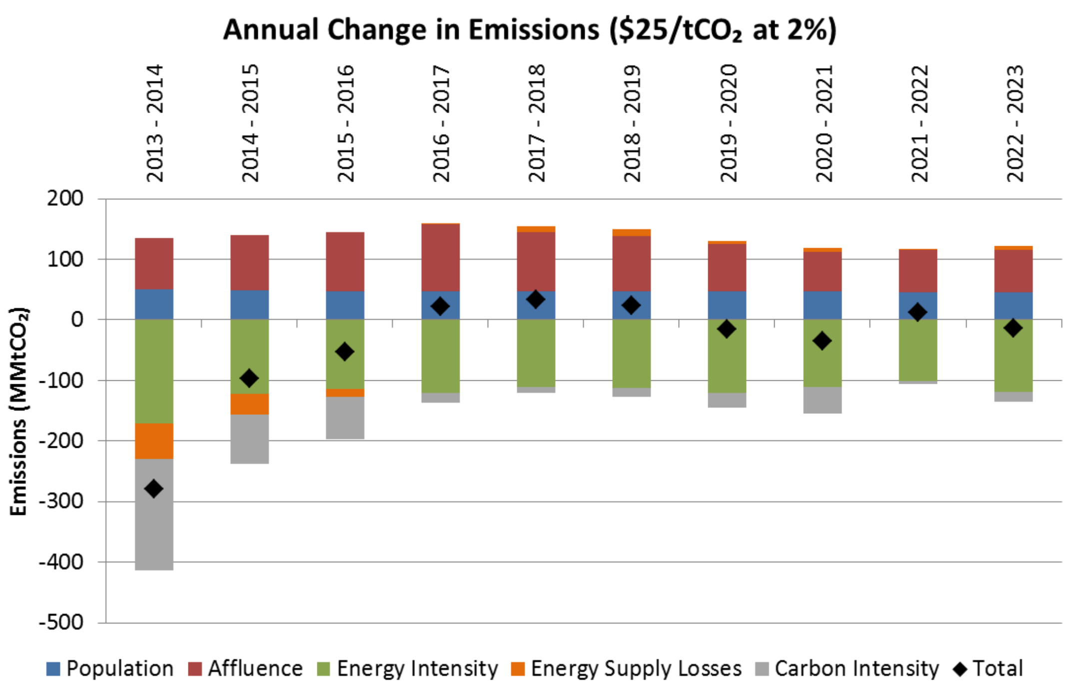

Figure B.6 Kaya parameter effects from $25/tCO$_2$ at 2% scenario

Table B.9 Kaya parameter effects from $25/tCO$_2$ at 4% scenario

Effects on carbon emissions from $25/tCO$_2$ at 4% scenario (MMtCO$_2$)

	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	50.5	84.1	-171.2	-58.6	-194.6	-289.7
2014 - 2015	48.5	91.2	-121.9	-38.9	-98.6	-119.7
2015 - 2016	47.4	94.8	-115.0	-18.9	-85.3	-76.9
2016 - 2017	46.9	108.3	-121.0	0.7	-15.7	19.2
2017 - 2018	46.9	95.0	-111.6	8.1	-15.5	22.9
2018 - 2019	46.8	88.3	-113.1	9.2	-22.5	8.6
2019 - 2020	46.5	76.6	-118.9	6.7	-25.5	-14.7
2020 - 2021	45.9	64.4	-107.9	3.3	-47.8	-42.1
2021 - 2022	45.3	66.0	-107.5	2.6	-21.8	-15.5
2022 - 2023	44.6	67.8	-118.9	4.7	-12.3	-14.1
2013 - 2023	484.2	863.3	-1243.0	-79.7	-546.7	-522.0

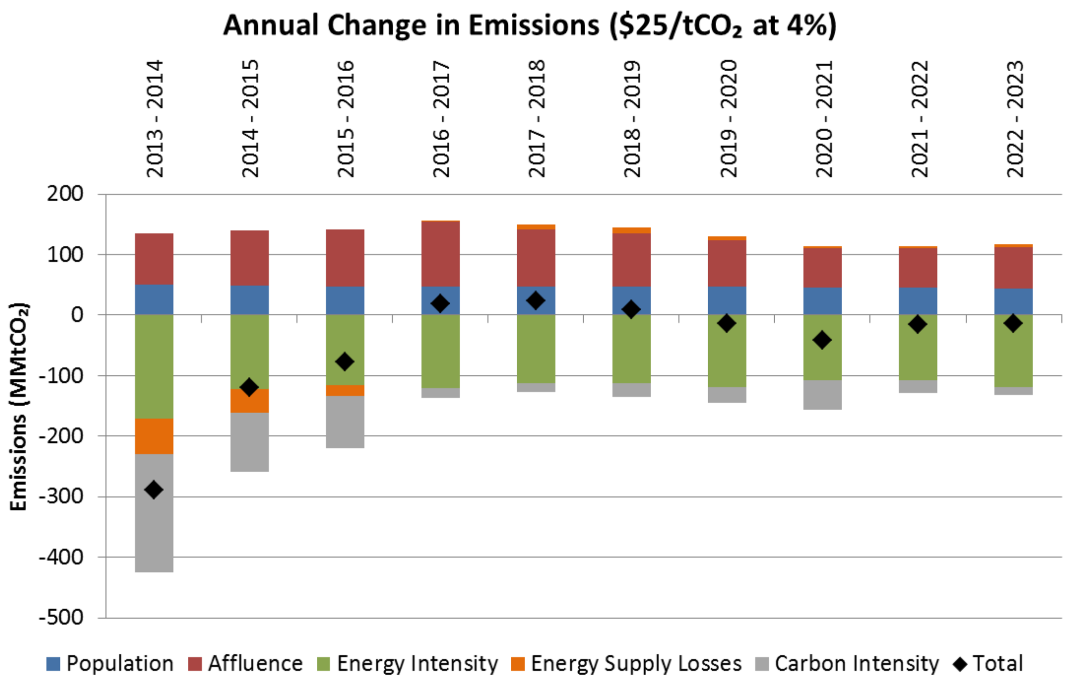

Figure B.7 Kaya parameter effects from $25/tCO$_2$ at 4% scenario

Table B.10 Kaya parameter effects from \$25/tCO_2 at 6% scenario

Effects on carbon emissions from \$25/tCO_2 at 6% scenario ($MMtCO_2$)						
	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	50.5	84.2	-171.1	-58.8	-195.5	-290.6
2014 - 2015	48.5	91.2	-122.2	-38.9	-96.8	-118.2
2015 - 2016	47.2	92.9	-117.0	-26.8	-104.5	-108.2
2016 - 2017	46.5	105.2	-122.9	-3.2	-23.8	1.8
2017 - 2018	46.4	92.2	-112.8	4.7	-23.4	7.0
2018 - 2019	46.2	86.2	-113.3	7.6	-26.1	0.6
2019 - 2020	45.7	74.6	-118.9	1.8	-34.9	-31.7
2020 - 2021	45.0	62.4	-108.8	1.2	-57.4	-57.6
2021 - 2022	44.3	64.8	-107.2	2.9	-16.6	-11.8
2022 - 2023	43.6	66.5	-118.5	-0.8	-17.2	-26.4
2013 - 2023	478.7	845.7	-1248.4	-108.7	-602.4	-635.1

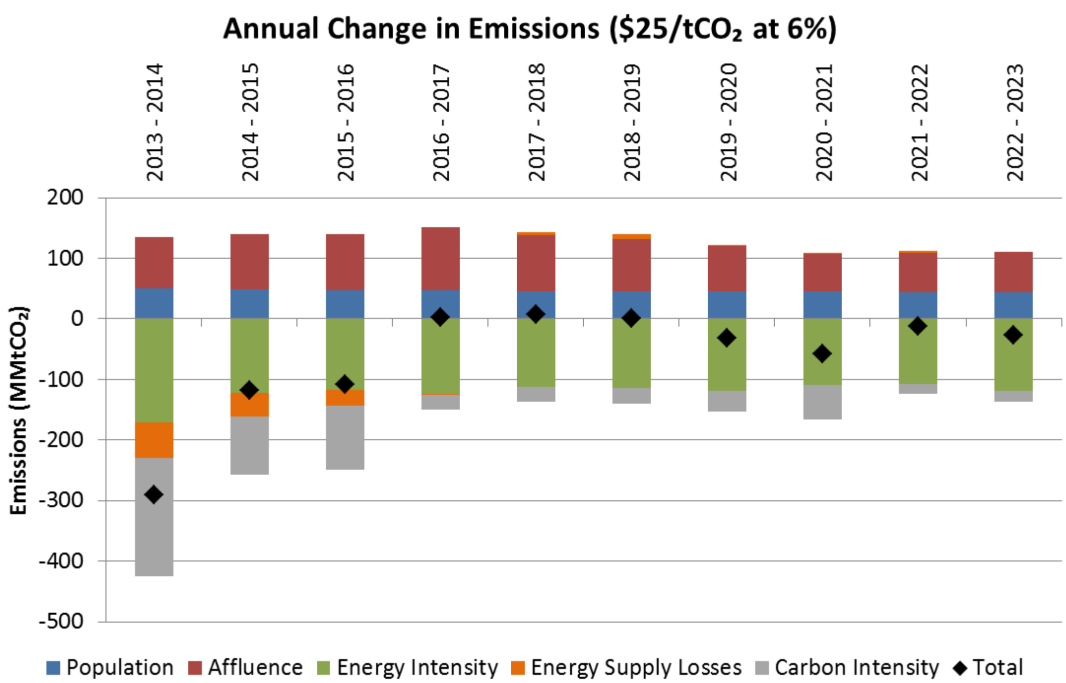

Figure B.8 Kaya parameter effects from \$25/tCO_2 at 6% scenario

Table B.11 Kaya parameter effects from $25/tCO$_2$ at 8% scenario

Effects on carbon emissions from $25/tCO$_2$ at 8% scenario (MMtCO$_2$)

	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	50.5	84.1	-171.2	-60.4	-199.7	-296.6
2014 - 2015	48.3	90.5	-122.7	-45.0	-103.4	-132.1
2015 - 2016	46.9	90.3	-120.1	-33.6	-125.2	-141.6
2016 - 2017	45.9	101.8	-124.7	-6.0	-36.4	-19.4
2017 - 2018	45.6	89.3	-114.1	0.5	-32.0	-10.7
2018 - 2019	45.2	83.6	-112.5	2.5	-37.5	-18.7
2019 - 2020	44.6	73.1	-111.1	-2.5	-41.5	-37.4
2020 - 2021	43.9	61.2	-106.9	-3.5	-47.3	-52.6
2021 - 2022	43.3	63.6	-104.9	6.1	-11.0	-3.0
2022 - 2023	42.6	65.2	-116.3	-1.2	-22.6	-32.3
2013 - 2023	473.3	830.2	-1244.2	-141.1	-662.7	-744.5

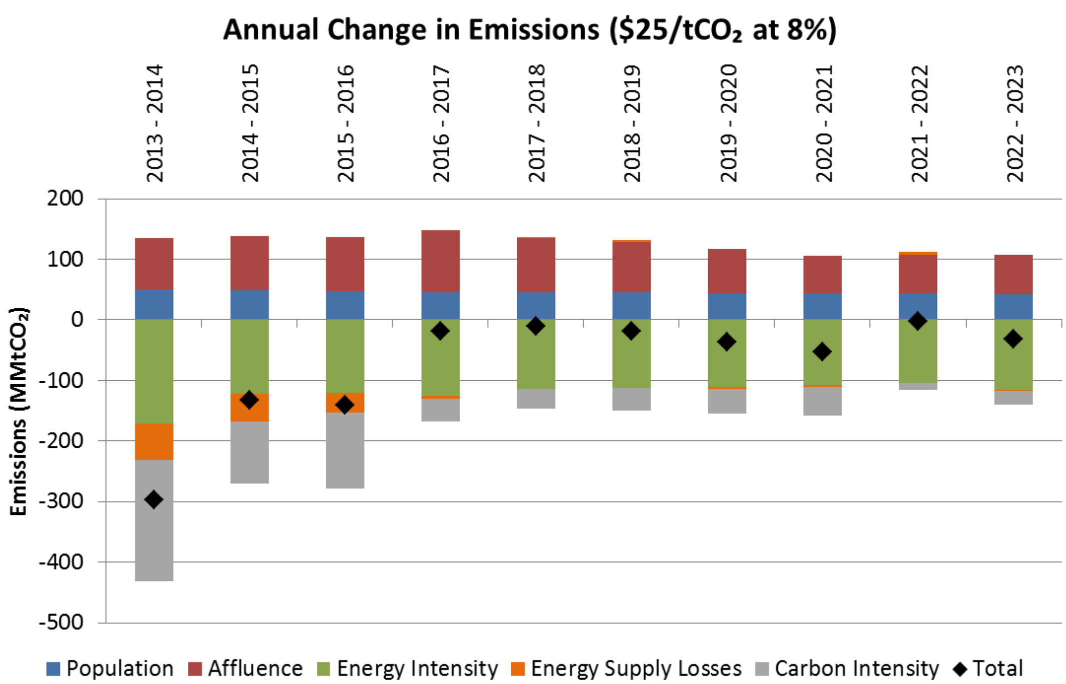

Figure B.9 Kaya parameter effects from $25/tCO$_2$ at 8% scenario

Table B.12 Kaya parameter effects from $35/tCO$_2$ at 2% scenario

Effects on carbon emissions from $35/tCO$_2$ at 2% scenario (MMtCO$_2$)

	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	50.1	79.9	-182.4	-77.7	-247.1	-377.3
2014 - 2015	47.4	77.9	-130.9	-47.3	-120.4	-173.3
2015 - 2016	46.1	90.8	-114.2	-14.2	-77.0	-68.5
2016 - 2017	45.7	108.0	-118.0	1.2	-12.9	24.0
2017 - 2018	45.7	95.1	-110.0	5.9	-15.5	21.2
2018 - 2019	45.6	89.1	-111.1	11.0	-17.0	17.7
2019 - 2020	45.4	76.6	-115.5	7.5	-26.5	-12.6
2020 - 2021	44.8	62.7	-108.0	2.5	-51.4	-49.4
2021 - 2022	44.2	64.4	-105.5	7.2	-10.6	-0.3
2022 - 2023	43.6	66.5	-115.7	3.6	-11.4	-13.4
2013 - 2023	478.9	848.0	-1261.2	-98.3	-599.4	-631.9

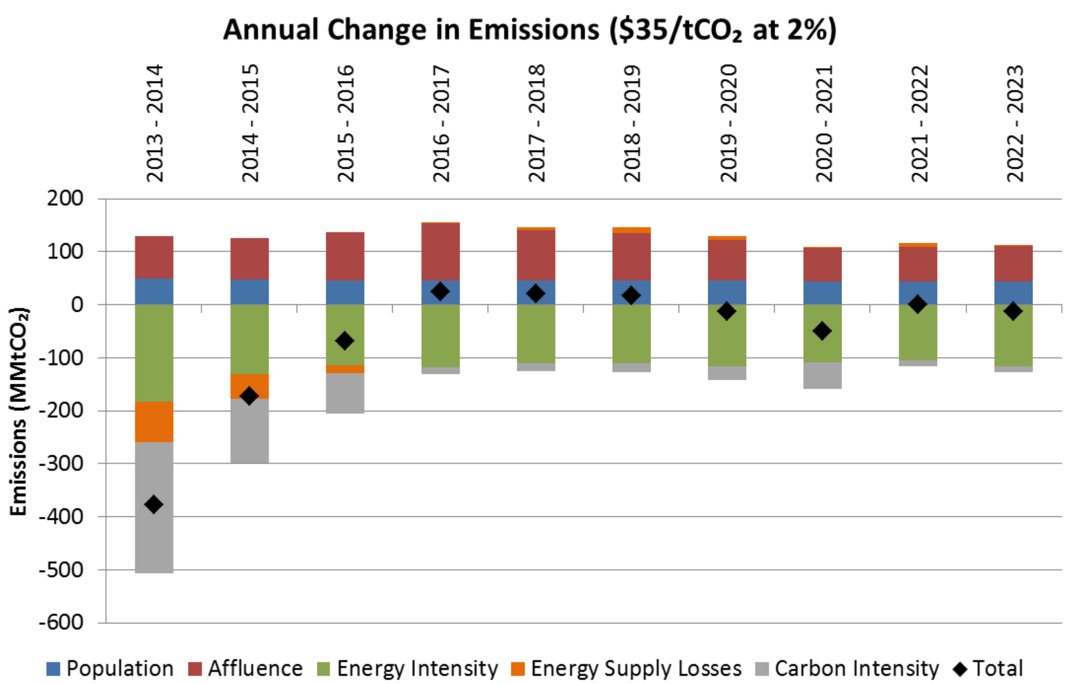

Figure B.10 Kaya parameter effects from $35/tCO$_2$ at 2% scenario

Table B.13 Kaya parameter effects from $35/tCO$_2$ at 4% scenario

Effects on carbon emissions from $35/tCO$_2$ at 4% scenario (MMtCO$_2$)

	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	50.1	79.8	-182.2	-77.8	-246.1	-376.1
2014 - 2015	47.3	77.9	-131.1	-47.2	-123.2	-176.4
2015 - 2016	45.8	88.2	-117.5	-26.5	-103.7	-113.7
2016 - 2017	45.1	103.7	-118.9	-3.0	-29.9	-3.0
2017 - 2018	44.8	91.6	-111.8	1.7	-25.7	0.6
2018 - 2019	44.6	85.6	-111.1	6.1	-29.0	-3.8
2019 - 2020	44.1	74.2	-107.8	-1.4	-44.6	-35.4
2020 - 2021	43.5	61.5	-104.4	0.5	-41.6	-40.6
2021 - 2022	42.9	63.1	-103.5	7.8	-8.7	1.6
2022 - 2023	42.4	65.0	-113.4	2.0	-15.5	-19.5
2013 - 2023	471.9	828.3	-1253.2	-135.6	-677.7	-766.3

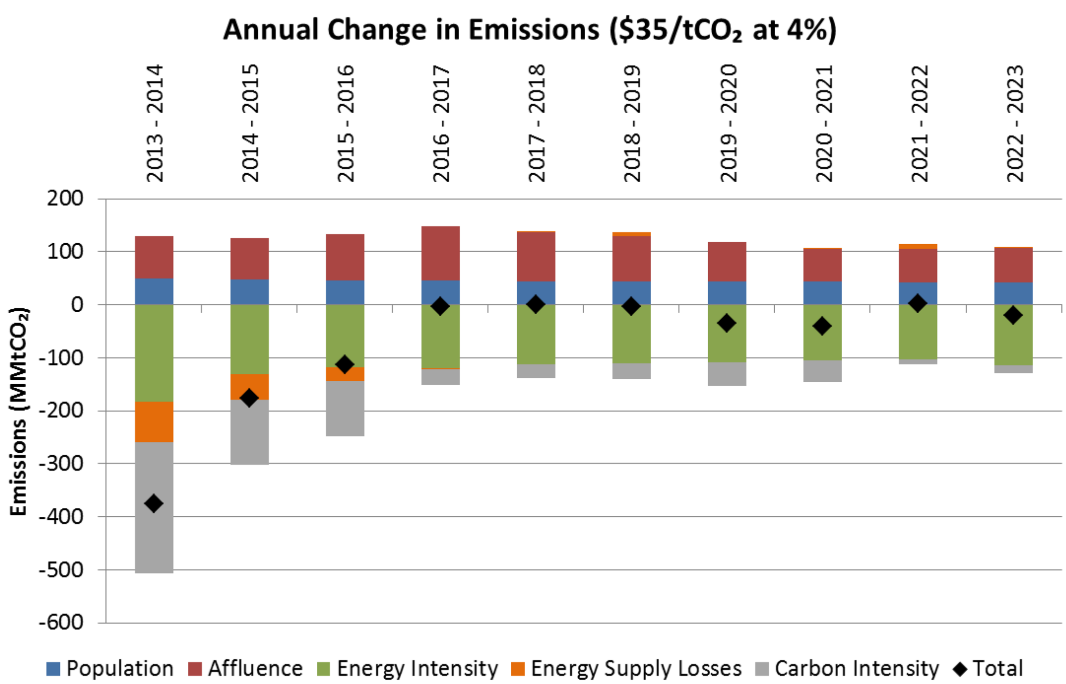

Figure B.11 Kaya parameter effects from $35/tCO$_2$ at 4% scenario

Table B.14 Kaya parameter effects from $35/tCO$_2$ at 6% scenario

Effects on carbon emissions from $35/tCO$_2$ at 6% scenario (MMtCO$_2$)

	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	50.1	79.8	-182.1	-78.3	-252.0	-382.5
2014 - 2015	47.2	77.1	-131.8	-50.1	-127.5	-185.0
2015 - 2016	45.3	82.8	-122.5	-42.8	-161.9	-199.1
2016 - 2017	44.0	96.8	-121.8	-7.5	-47.5	-36.0
2017 - 2018	43.5	87.5	-107.0	-4.7	-39.8	-20.5
2018 - 2019	43.1	82.8	-104.3	1.9	-36.8	-13.3
2019 - 2020	42.5	71.4	-113.2	-1.7	-56.6	-57.7
2020 - 2021	41.8	59.6	-101.9	-1.5	-25.4	-27.4
2021 - 2022	41.3	61.4	-98.8	2.8	-15.2	-8.5
2022 - 2023	40.6	63.2	-109.8	1.3	-23.3	-28.0
2013 - 2023	462.4	802.6	-1248.9	-178.0	-796.1	-958.0

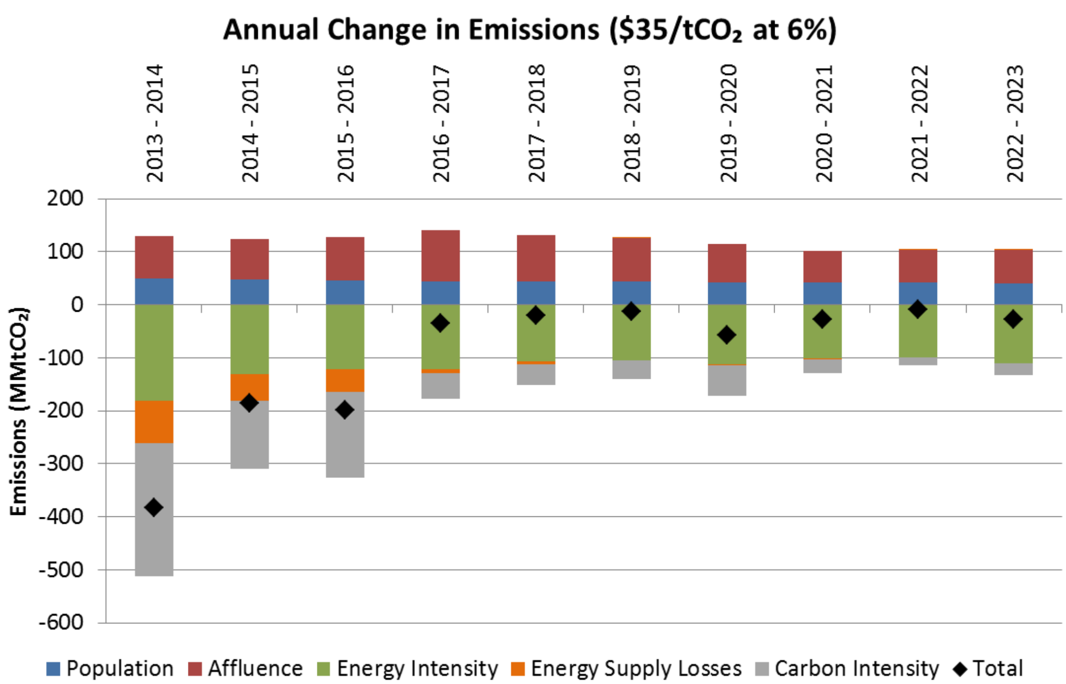

Figure B.12 Kaya parameter effects from $35/tCO$_2$ at 6% scenario

Table B.15 Kaya parameter effects from $35/tCO$_2$ at 8% scenario

Effects on carbon emissions from $35/tCO$_2$ at 8% scenario (MMtCO$_2$)

	Population	Affluence	Energy Intensity	Energy Supply Losses	Carbon Intensity	Total
2013 - 2014	50.0	79.7	-181.7	-78.3	-266.5	-396.8
2014 - 2015	47.0	77.0	-131.5	-49.5	-146.3	-203.3
2015 - 2016	44.4	78.1	-124.5	-61.7	-245.9	-309.7
2016 - 2017	42.3	90.6	-122.6	-14.1	-78.7	-82.4
2017 - 2018	41.6	82.4	-102.7	-2.9	-43.3	-25.0
2018 - 2019	41.2	78.3	-96.4	-1.4	-44.3	-22.7
2019 - 2020	40.6	67.5	-107.7	-2.4	-40.1	-42.1
2020 - 2021	39.9	52.1	-101.5	-7.2	-32.8	-49.4
2021 - 2022	39.2	51.5	-94.1	0.4	-31.0	-34.1
2022 - 2023	38.5	59.9	-105.3	0.9	-24.9	-31.0
2013 - 2023	450.0	759.1	-1228.8	-212.6	-964.2	-1196.5

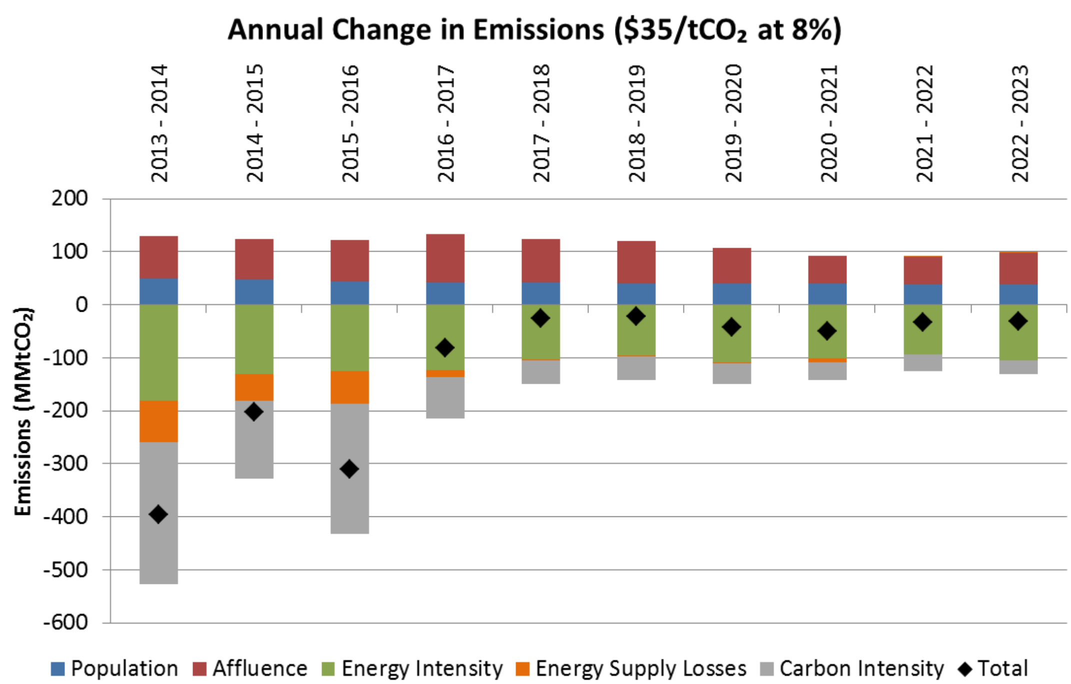

Figure B.13 Kaya parameter effects from $35/tCO$_2$ at 8% scenario

B.4 AVOIDED EMISSIONS BY SECTOR AND FUEL TYPE

Table B.16 Avoided emissions by sector and fuel in 2023.

	Industrial Sector					Transportation Sector					Residential Sector					Commercial Sector				
	Petroleum	Natural Gas	Coal	Electricity	Total Sector	Petroleum	Natural Gas	Coal	Electricity	Total Sector	Petroleum	Natural Gas	Coal	Electricity	Total Sector	Petroleum	Natural Gas	Coal	Electricity	Total Sector
Reference sceanrio total emissions ($MMtCO_2$)																				
Reference 2013	339.8	434.1	154.2	556.7	1484.7	1771.3	41.2	0.0	3.7	1816.3	81.1	261.4	0.7	763.9	1107.1	42.9	177.3	4.9	735.8	960.9
Reference 2023	350.8	502.0	159.9	620.0	1632.7	1763.4	43.2	0.0	5.2	1811.9	68.0	242.4	0.6	761.8	1072.7	46.1	180.9	4.9	744.8	976.8
Difference	11.0	67.9	5.8	63.3	148.0	-8.0	2.1	0.0	1.5	-4.4	-13.1	-19.1	-0.1	-2.1	-34.4	3.2	3.6	0.0	9.1	15.8
Difference (%)	3.1%	13.5%	3.6%	10.2%	9.1%	-0.5%	4.8%	0.0%	28.4%	-0.2%	-19.2%	-7.9%	-18.3%	-0.3%	-3.2%	6.9%	2.0%	0.0%	1.2%	1.6%
Policy scenario total emissions in 2023 ($MMtCO_2$)																				
$\$15/tCO_2$ at 2%	346.4	490.6	160.1	536.4	1533.5	1748.3	43.0	0.0	4.8	1796.1	67.4	238.1	0.6	679.4	985.4	45.2	175.1	4.9	660.8	885.9
$\$15/tCO_2$ at 4%	345.8	490.3	152.3	521.0	1509.4	1745.6	43.1	0.0	4.7	1793.3	67.3	237.6	0.6	662.5	967.9	45.1	174.5	4.9	644.1	868.5
$\$15/tCO_2$ at 6%	345.1	488.9	156.4	499.5	1490.0	1741.1	43.2	0.0	4.6	1788.8	67.1	236.7	0.6	639.1	943.5	44.9	173.3	4.9	620.9	844.0
$\$15/tCO_2$ at 8%	344.3	488.4	159.0	473.2	1465.0	1737.2	43.4	0.0	4.4	1784.9	67.0	235.9	0.6	609.9	913.3	44.7	172.3	4.9	591.7	813.5
$\$25/tCO_2$ at 2%	345.0	485.1	158.8	471.2	1460.1	1736.3	42.9	0.0	4.4	1783.6	66.9	235.1	0.6	609.2	911.8	44.6	171.2	4.9	590.0	810.7
$\$25/tCO_2$ at 4%	344.9	483.5	150.1	440.7	1419.2	1731.1	43.2	0.0	4.1	1778.4	66.8	233.9	0.6	573.7	875.0	44.4	169.6	4.9	555.5	774.4
$\$25/tCO_2$ at 6%	344.0	482.5	147.6	408.9	1383.0	1725.5	43.4	0.0	3.9	1772.8	66.6	232.7	0.6	539.8	839.7	44.1	168.0	4.9	522.2	739.2
$\$25/tCO_2$ at 8%	343.5	481.6	156.9	375.1	1357.1	1720.4	43.6	0.0	3.7	1767.7	66.4	231.4	0.6	502.0	800.3	43.8	166.2	4.9	485.3	700.2
$\$35/tCO_2$ at 2%	344.8	479.1	147.0	409.6	1380.4	1725.0	42.9	0.0	4.0	1771.9	66.5	232.2	0.6	543.9	843.2	44.1	167.3	4.9	525.9	742.1
$\$35/tCO_2$ at 4%	343.4	478.2	156.6	370.2	1348.5	1717.5	43.1	0.0	3.6	1764.3	66.3	230.8	0.6	496.6	794.4	43.7	165.6	4.9	479.4	693.6
$\$35/tCO_2$ at 6%	342.1	477.8	149.4	320.6	1289.9	1709.6	44.0	0.0	3.2	1756.9	66.1	229.8	0.6	435.1	731.5	43.4	164.5	4.9	419.0	631.9
$\$35/tCO_2$ at 8%	338.5	483.4	153.5	251.4	1226.7	1697.9	44.4	0.0	2.6	1745.0	65.9	228.6	0.6	352.7	647.7	43.0	164.1	4.9	338.7	550.7
Policy scenario avoided emissions from Reference in 2023 ($MMtCO_2$)																				
$\$15/tCO_2$ at 2%	-4.4	-11.4	0.2	-83.6	-99.2	-15.1	-0.3	0.0	-0.4	-15.8	-0.6	-4.3	0.0	-82.4	-87.3	-0.9	-5.9	0.0	-84.1	-90.8
$\$15/tCO_2$ at 4%	-5.0	-11.6	-7.6	-99.0	-123.3	-17.8	-0.2	0.0	-0.5	-18.5	-0.7	-4.8	0.0	-99.2	-104.8	-1.1	-6.5	0.0	-100.8	-108.3
$\$15/tCO_2$ at 6%	-5.7	-13.0	-3.5	-120.5	-142.7	-22.3	-0.1	0.0	-0.7	-23.0	-0.8	-5.7	0.0	-122.7	-129.2	-1.2	-7.7	0.0	-123.9	-132.8
$\$15/tCO_2$ at 8%	-6.5	-13.6	-0.9	-146.8	-167.7	-26.2	0.1	0.0	-0.9	-27.0	-1.0	-6.5	0.0	-151.9	-159.4	-1.5	-8.7	0.0	-153.1	-163.2
$\$25/tCO_2$ at 2%	-5.8	-16.9	-1.1	-148.7	-172.6	-27.0	-0.3	0.0	-0.9	-28.2	-1.1	-7.3	0.0	-152.5	-160.9	-1.5	-9.7	0.0	-154.8	-166.1
$\$25/tCO_2$ at 4%	-5.9	-18.5	-9.8	-179.3	-213.5	-32.3	-0.1	0.0	-1.1	-33.5	-1.2	-8.4	0.0	-188.0	-197.7	-1.7	-11.3	0.0	-189.3	-202.4
$\$25/tCO_2$ at 6%	-6.7	-19.5	-12.4	-211.1	-249.7	-37.9	0.2	0.0	-1.3	-39.0	-1.4	-9.7	0.0	-222.0	-233.0	-2.0	-13.0	0.0	-222.6	-237.6
$\$25/tCO_2$ at 8%	-7.3	-20.3	-3.1	-244.8	-275.6	-43.0	0.4	0.0	-1.6	-44.2	-1.6	-11.0	0.0	-259.8	-272.4	-2.3	-14.7	0.0	-259.5	-276.6
$\$35/tCO_2$ at 2%	-6.0	-22.8	-13.0	-210.4	-252.3	-38.4	-0.3	0.0	-1.3	-40.0	-1.5	-10.2	0.0	-217.9	-229.5	-2.0	-13.6	0.0	-219.0	-234.6
$\$35/tCO_2$ at 4%	-7.4	-23.8	-3.3	-249.7	-284.2	-45.9	-0.1	0.0	-1.6	-47.6	-1.7	-11.5	0.0	-265.1	-278.3	-2.4	-15.3	0.0	-265.5	-283.1
$\$35/tCO_2$ at 6%	-8.7	-24.2	-10.5	-299.4	-342.7	-53.7	0.8	0.0	-2.0	-55.0	-1.9	-12.6	0.0	-326.7	-341.2	-2.7	-16.4	0.0	-325.8	-344.9
$\$35/tCO_2$ at 8%	-12.3	-18.6	-6.5	-368.5	-405.9	-65.4	1.1	0.0	-2.6	-66.9	-2.1	-13.8	0.0	-409.1	-425.0	-3.1	-16.8	0.0	-406.2	-426.1
Policy scenario percent difference from Reference in 2023 (%)																				
$\$15/tCO_2$ at 2%	-1.3%	-2.3%	0.1%	-13.5%	-6.1%	-0.9%	-0.6%	0.0%	-8.2%	-0.9%	-0.9%	-1.8%	0.0%	-10.8%	-8.1%	-2.0%	-3.2%	0.1%	-11.3%	-9.3%
$\$15/tCO_2$ at 4%	-1.4%	-2.3%	-4.8%	-16.0%	-7.6%	-1.0%	-0.4%	0.0%	-10.2%	-1.0%	-1.1%	-2.0%	0.0%	-13.0%	-9.8%	-2.3%	-3.6%	0.1%	-13.5%	-11.1%
$\$15/tCO_2$ at 6%	-1.6%	-2.6%	-2.2%	-19.4%	-8.7%	-1.3%	-0.2%	0.0%	-13.1%	-1.3%	-1.2%	-2.3%	0.0%	-16.1%	-12.0%	-2.7%	-4.2%	0.1%	-16.6%	-13.6%
$\$15/tCO_2$ at 8%	-1.8%	-2.7%	-0.6%	-23.7%	-10.3%	-1.5%	0.3%	0.0%	-16.7%	-1.5%	-1.4%	-2.7%	0.0%	-19.9%	-14.9%	-3.2%	-4.8%	0.1%	-20.6%	-16.7%
$\$25/tCO_2$ at 2%	-1.7%	-3.4%	-0.7%	-24.0%	-10.6%	-1.5%	-0.7%	0.0%	-16.5%	-1.6%	-1.6%	-3.0%	0.0%	-20.0%	-15.0%	-3.3%	-5.4%	0.1%	-20.8%	-17.0%
$\$25/tCO_2$ at 4%	-1.7%	-3.7%	-6.1%	-28.9%	-13.1%	-1.8%	-0.2%	0.0%	-20.9%	-1.8%	-1.8%	-3.5%	0.0%	-24.7%	-18.4%	-3.8%	-6.3%	0.2%	-25.4%	-20.7%
$\$25/tCO_2$ at 6%	-1.9%	-3.9%	-7.7%	-34.0%	-15.3%	-2.1%	0.4%	0.0%	-25.1%	-2.2%	-2.0%	-4.0%	0.0%	-29.1%	-21.7%	-4.4%	-7.2%	0.2%	-29.9%	-24.3%
$\$25/tCO_2$ at 8%	-2.1%	-4.0%	-1.9%	-39.5%	-16.9%	-2.4%	0.9%	0.0%	-30.0%	-2.4%	-2.3%	-4.5%	0.0%	-34.1%	-25.4%	-5.1%	-8.2%	0.2%	-34.8%	-28.3%
$\$35/tCO_2$ at 2%	-1.7%	-4.5%	-8.1%	-33.9%	-15.5%	-2.2%	-0.7%	0.0%	-24.5%	-2.2%	-2.1%	-4.2%	0.0%	-28.6%	-21.4%	-4.4%	-7.5%	0.2%	-29.4%	-24.0%
$\$35/tCO_2$ at 4%	-2.1%	-4.7%	-2.1%	-40.3%	-17.4%	-2.6%	-0.3%	0.0%	-30.5%	-2.6%	-2.4%	-4.8%	0.0%	-34.8%	-25.9%	-5.1%	-8.5%	0.2%	-35.6%	-29.0%
$\$35/tCO_2$ at 6%	-2.5%	-4.8%	-6.6%	-48.3%	-21.0%	-3.0%	1.9%	0.0%	-38.7%	-3.0%	-2.8%	-5.2%	0.0%	-42.9%	-31.8%	-5.9%	-9.1%	0.3%	-43.7%	-35.3%
$\$35/tCO_2$ at 8%	-3.5%	-3.7%	-4.0%	-59.4%	-24.9%	-3.7%	2.6%	0.0%	-49.4%	-3.7%	-3.1%	-5.7%	0.0%	-53.7%	-39.6%	-6.7%	-9.3%	0.4%	-54.5%	-43.6%

B.5 EMISSIONS FROM ELECTRICITY GENERATION BY TECHNOLOGY TYPE

NEMS does not write out emission by technology for the electricity sector in its standard output file. However, the electricity market module (EMM) does export very useful information at the end of each NEMS cycle. The output file is ***emmdb.mdb*** which is a MS Access database file. There are about 170 tables of data, only some of which are included in the standard NEMS output. One of these tables, ***DCAP_DEF*** includes the definition for each power plant type (See Table B.5-1).

For this study, the 32 types of resources in NEMS are collapsed into ten technology types. For example, coal build before or after 1965, with or without a scrubber, and even now steam coal are combined into a "conventional coal" category for this study. Advanced coal, with and without carbon capture and sequestration (CCS) are aggregated into an "advanced coal" category. NEMS has so little CCS before the end of this study, 2023, so separating them out would only add to the confusion on already-dense plots.

The ***emmdb.mdb*** file also includes about 60 pre-defined queries of the data tables including one defining the dispatch output by plant type ***dospt***. This query identifies the capacity, generation, and various emissions (e.g., CO_2, mercury, SO_x) linked to the plant ID from ***DCAP_DEF*** by EMM region (there are 22 EMM regions). These emissions are reported here in short tons rather than metric tons, requiring a simple conversion (2000/2204) for comparison with the regular NEMS output data. For this study, the emissions are aggregated as defined above into a U.S. total emissions by plant type category.

One caveat to this output data is that, unlike the standard NEMS outputs, the ***emmdb.mdb*** file excludes Alaska and Hawaii because they are not included in the EMM plant database or the 22 continental regions NEMS explicitly models. So, this study determines the shares of total emissions by plant type from the ***emmdb.mdb*** output then applies those shares total sector emissions from the standard NEMS output.[52]

Table B.17 Industrial Sector Reference scenario activity

DCAP_DEF table data from ***emmdb.mdb***		This study's designation
DCAP_INDEX	DCAP_NAME	Technology type
1	Coal Steam pre- 1965	Coal (conv.)
2	Coal Steam post- 1965	Coal (conv.)
3	Coal Steam with Scrubber	Coal (conv.)
4	New Coal Steam	Coal (conv.)
5	New Advanced Coal	Coal (adv.)
6	New Adv. Coal with Sequestration	Coal (adv.)
7	Oil Steam	ST (oil and gas)
8	Gas Steam	ST (oil and gas)
9	Oil/Gas Steam	ST (oil and gas)
10	Oil Turbine	CT (conv.)
11	Gas Turbine	CT (conv.)
12	Oil/Gas Turbine	CT (conv.)
13	Advanced Turbine	CT (adv.)
14	Oil Combined Cycle	CC (conv.)
15	Gas Combined Cycle	CC (conv.)
16	Oil/Gas Combined Cycle	CC (conv.)
17	Advanced Combined Cycle	CC (adv.)
18	Adv. Combined Cyc w/Sequestration	CC (adv.)
19	Fuel Cell	Other
20	Conventional Nuclear	Nuclear
21	Advanced Nuclear	Nuclear
22	Wood/Biomass	Renewables
23	Geothermal	Renewables
24	Municipal Solid Waste	Renewables
25	Conventional Hydroelectric	Renewables
26	Reversible Hydroelectric	Other
27	Wind	Renewables
28	Wind OffShore	Renewables
29	Solar Thermal	Renewables
30	Solar Photovoltaic	Renewables
31	Distributed Generation-Base	Other
32	Distributed Generation-Peak	Other

[52] Thanks to Laura Martin of EIA for identifying the existence of this EMM output data and helping to understand the data and its cryptic table, query, and field names.

B.6 ELECTRICITY SECTOR LMDI DECOMPOSITION RESULTS

Activity is in the electricity sector is total electricity generation (e.g., kWh) and structure is the fraction of electricity supplied by each generating technology (e.g., combined cycle, conventional coal, etc.). Energy intensity is energy input required per unit of generation (BTU/kWh) and carbon intensity is the carbon emissions of the input fuels (CO_2/BTU). Ten-year results are reported in Table B.18 and Figure B.14, followed by annual results for each policy scenario.

Table B.18 Ten-year effects on carbon for each scenario

Effects on carbon emissions from 2013-2023 (MMtCO_2)					
Scenario	Activity	Structure	Energy Intensity	Carbon Intensity	Total
Reference	200.1	-49.1	-31.3	-49.1	70.6
\$15/tCO_2 at 2%	124.2	-140.0	-37.9	-124.5	-178.1
\$15/tCO_2 at 4%	114.3	-162.1	-39.4	-140.1	-227.3
\$15/tCO_2 at 6%	99.9	-198.5	-41.2	-156.3	-296.0
\$15/tCO_2 at 8%	83.4	-243.4	-42.5	-176.8	-379.3
\$25/tCO_2 at 2%	73.9	-241.4	-41.7	-174.8	-384.0
\$25/tCO_2 at 4%	60.3	-311.9	-44.4	-189.3	-485.2
\$25/tCO_2 at 6%	37.1	-382.9	-48.6	-190.4	-584.8
\$25/tCO_2 at 8%	14.7	-468.9	-51.0	-190.7	-695.9
\$35/tCO_2 at 2%	33.1	-369.7	-48.8	-190.7	-576.1
\$35/tCO_2 at 4%	8.6	-460.3	-52.4	-194.4	-698.6
\$35/tCO_2 at 6%	-12.5	-625.3	-48.2	-179.9	-866.0
\$35/tCO_2 at 8%	-54.9	-838.2	-43.3	-172.0	-1108.5

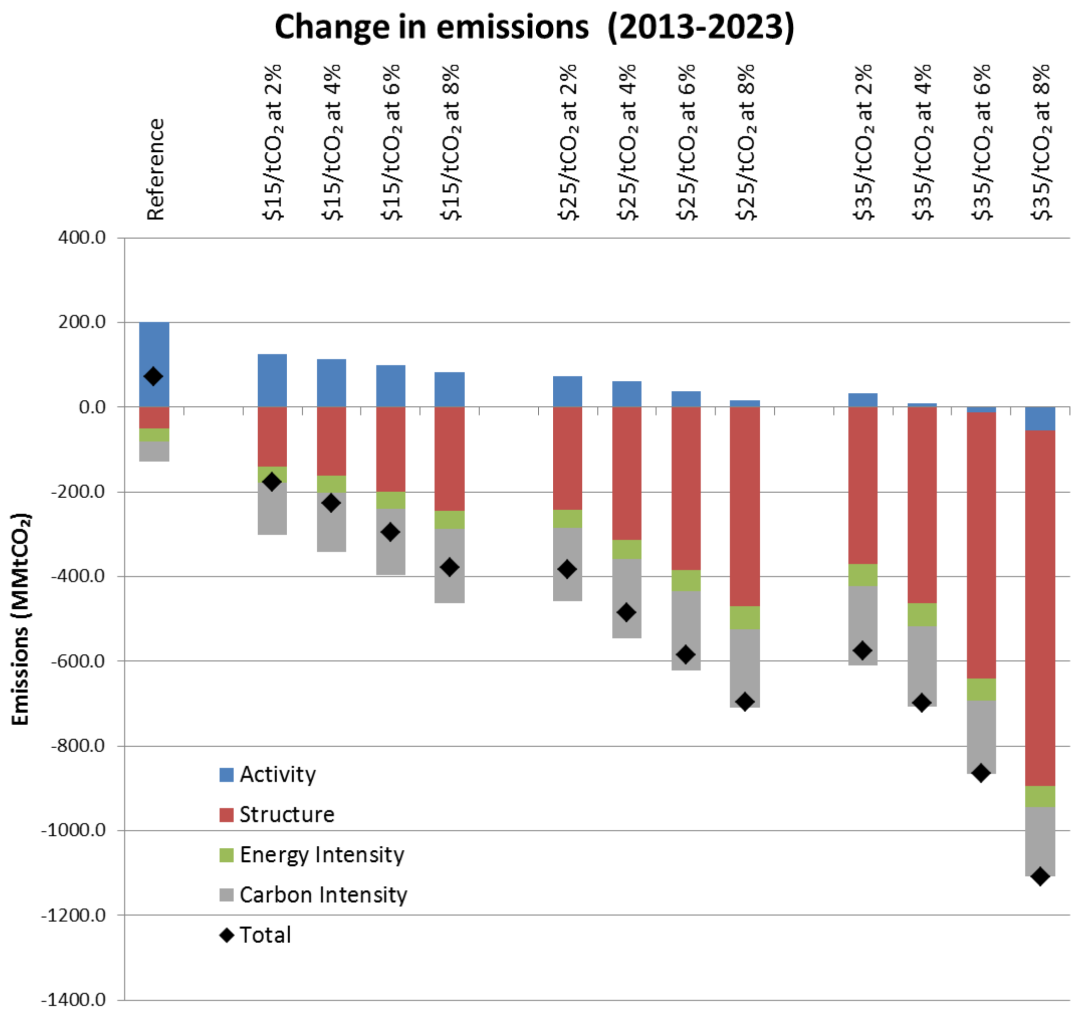

Figure B.14 Ten-year effects on carbon for each scenario

Table B.19 Annual effects on carbon on Reference scenario

Effects on carbon emissions on Reference scenario (MMtCO2)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	17.6	-9.7	-9.6	-2.0	-3.7
2014 - 2015	28.1	-24.0	-22.4	0.9	-17.4
2015 - 2016	17.1	-68.3	-3.2	-8.9	-63.3
2016 - 2017	22.2	6.1	-0.6	-5.9	21.8
2017 - 2018	20.3	8.8	0.6	-4.6	25.1
2018 - 2019	26.4	15.8	1.5	-7.3	36.4
2019 - 2020	14.2	14.2	1.0	-10.3	19.1
2020 - 2021	13.1	0.9	0.1	-7.4	6.7
2021 - 2022	19.9	8.4	0.6	1.1	30.0
2022 - 2023	18.1	-0.8	0.6	-2.1	15.8
2013 - 2023[1]	200.1	-49.5	-32.0	-48.1	70.6

notes: [1] Colums do not sum directly to ten-year result due to log formulation

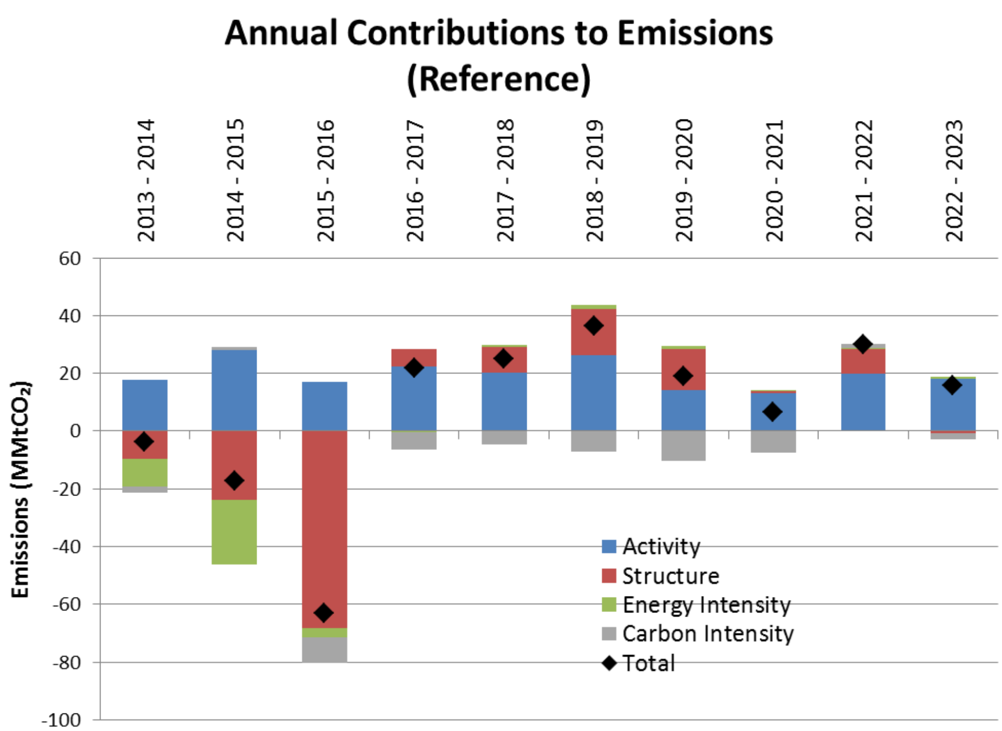

Figure B.15 Annual effects on emissions from Reference scenario

Table B.20 Annual effects on emissions from $15/tCO$_2$ at 2% scenario

Effects on carbon emissions on $15/tCO$_2$ at 2% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	-3.3	-133.6	-20.2	-2.9	-160.0
2014 - 2015	1.5	-40.5	-23.7	-3.5	-66.2
2015 - 2016	6.7	-45.9	1.1	-8.5	-46.6
2016 - 2017	18.7	10.7	-1.6	-14.7	13.1
2017 - 2018	20.1	17.2	1.3	-13.4	25.2
2018 - 2019	22.7	25.4	2.1	-18.3	31.8
2019 - 2020	11.7	12.1	0.4	-26.1	-1.9
2020 - 2021	10.7	3.7	0.1	-12.4	2.1
2021 - 2022	15.5	2.0	0.6	-3.4	14.8
2022 - 2023	12.3	4.0	1.0	-7.7	9.6
2013 - 2023[1]	124.2	-140.4	-38.7	-123.3	-178.1

notes: [1] Colums do not sum directly to ten-year result due to log formulation

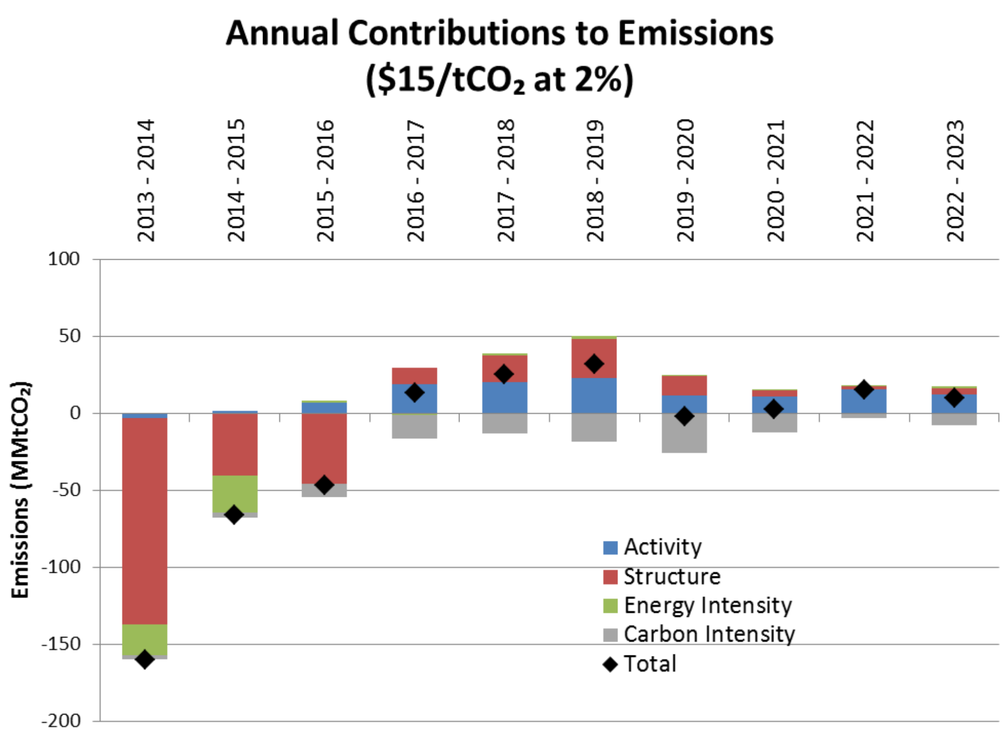

Table B.21 Annual effects on emissions from $15/tCO$_2$ at 2% scenario

Table B.22 Annual effects on emissions from $15/tCO$_2$ at 4% scenario

Effects on carbon emissions on \$15/tCO$_2$ at 4% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	-3.4	-128.4	-19.8	-2.9	-154.5
2014 - 2015	0.9	-47.9	-24.1	-2.9	-74.1
2015 - 2016	5.2	-53.7	1.3	-8.0	-55.3
2016 - 2017	17.7	10.1	-1.9	-15.6	10.3
2017 - 2018	18.6	11.5	0.0	-13.9	16.1
2018 - 2019	21.1	23.7	1.9	-17.6	29.0
2019 - 2020	10.3	9.7	0.3	-26.5	-6.2
2020 - 2021	9.9	5.1	0.4	-21.3	-5.9
2021 - 2022	14.3	-0.7	0.6	-9.1	5.1
2022 - 2023	12.6	1.7	0.6	-6.8	8.0
2013 - 2023[1]	114.2	-162.6	-40.3	-138.7	-227.3

notes: [1] Colums do not sum directly to ten-year result due to log formulation

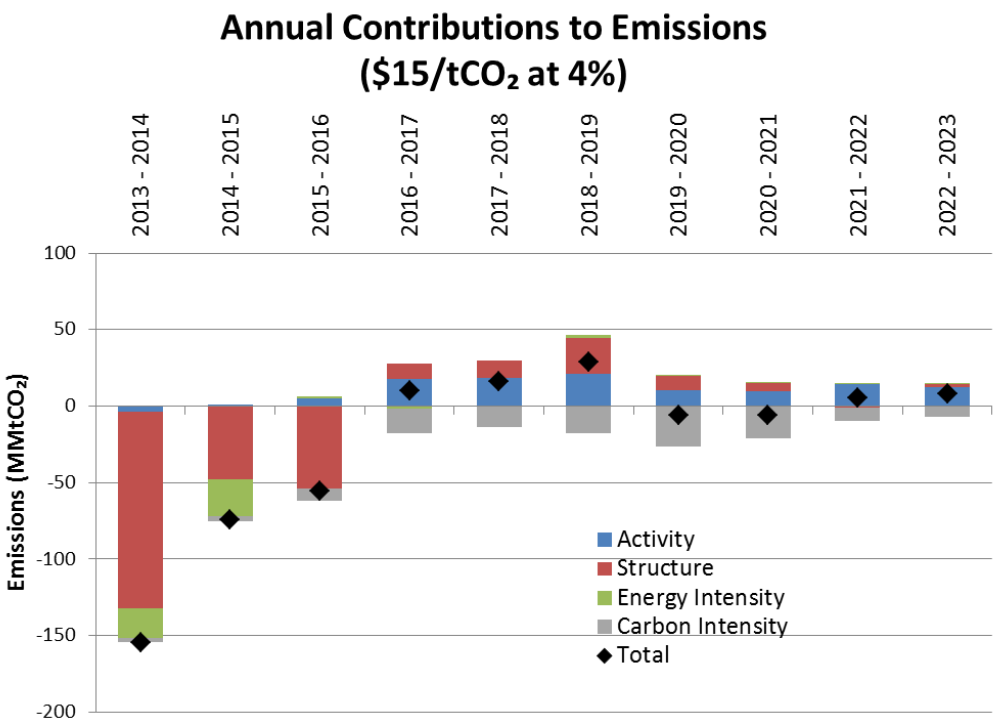

Figure B.16 Annual effects on emissions from \$15/tCO$_2$ at 4% scenario

Table B.23 Annual effects on emissions from \$15/tCO_2 at 6% scenario

Effects on carbon emissions on \$15/tCO_2 at 6% scenario ($MMtCO_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	-3.5	-134.9	-19.5	-3.5	-161.5
2014 - 2015	0.5	-48.6	-24.5	-2.6	-75.1
2015 - 2016	4.0	-62.5	0.2	-8.5	-66.9
2016 - 2017	16.3	14.8	-1.8	-14.3	14.9
2017 - 2018	17.2	7.9	0.1	-17.2	8.0
2018 - 2019	19.9	18.8	2.0	-16.0	24.6
2019 - 2020	9.1	3.7	0.4	-26.9	-13.8
2020 - 2021	7.9	0.5	0.0	-23.2	-14.9
2021 - 2022	11.7	-4.8	0.4	-18.1	-10.7
2022 - 2023	10.9	-2.6	-0.6	-8.5	-0.8
2013 - 2023[1]	99.9	-199.2	-42.3	-154.4	-296.0

notes: [1] Colums do not sum directly to ten-year result due to log formulation

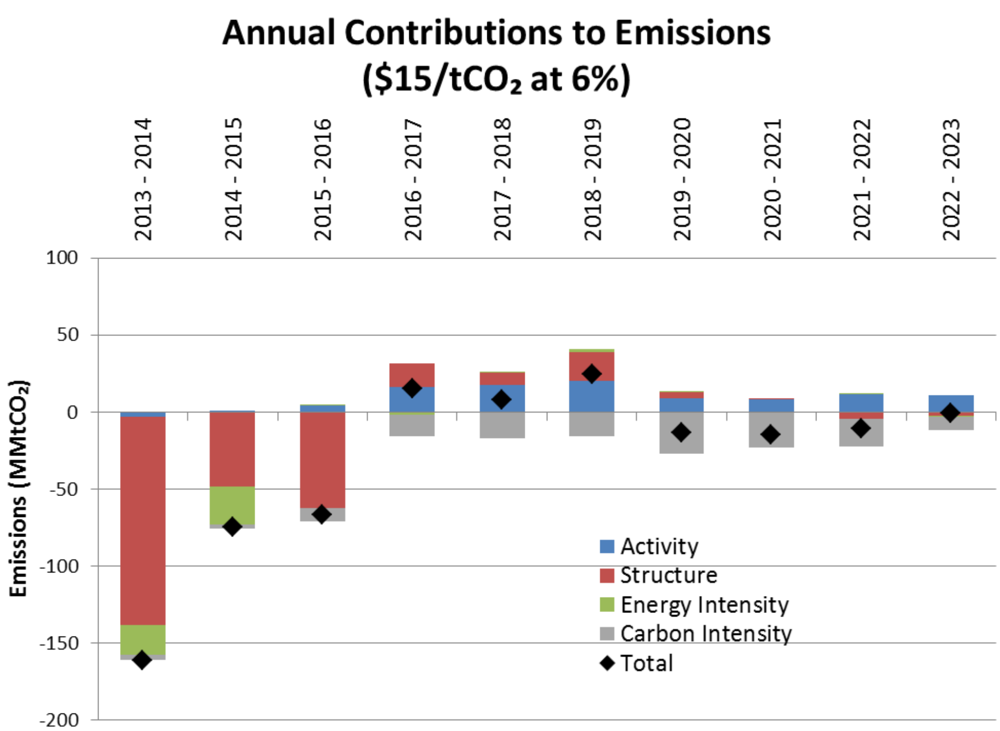

Figure B.17 Annual effects on emissions from \$15/tCO_2 at 6% scenario

Table B.24 Annual effects on emissions from $15/tCO$_2$ at 8% scenario

Effects on carbon emissions on $15/tCO$_2$ at 8% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	-3.7	-135.7	-19.4	-3.0	-161.9
2014 - 2015	-0.1	-60.3	-24.4	-3.4	-88.2
2015 - 2016	2.1	-69.7	0.0	-8.3	-76.0
2016 - 2017	14.3	3.6	-2.5	-17.1	-1.7
2017 - 2018	14.5	4.1	0.1	-13.8	4.9
2018 - 2019	17.4	16.9	1.2	-17.7	17.8
2019 - 2020	6.8	2.6	0.3	-28.4	-18.8
2020 - 2021	5.9	-4.0	-0.2	-37.8	-36.1
2021 - 2022	11.5	-6.8	0.2	-7.6	-2.7
2022 - 2023	9.4	-7.5	-0.7	-17.9	-16.7
2013 - 2023[1]	83.3	-244.2	-43.9	-174.5	-379.3

notes: [1] Colums do not sum directly to ten-year result due to log formulation

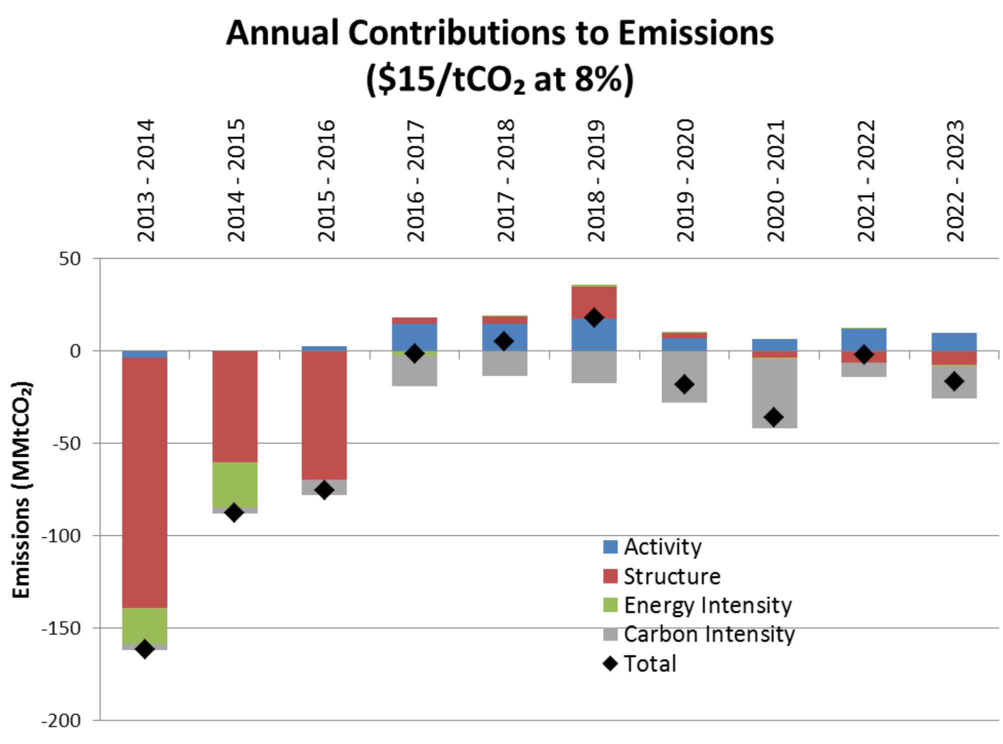

Figure B.18 Annual effects on emissions from $15/tCO$_2$ at 8% scenario

Table B.25 Annual effects on emissions from $25/$tCO_2$ at 2% scenario

Effects on carbon emissions on $25/$tCO_2$ at 2% scenario ($MMtCO_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	-14.0	-204.2	-26.0	-4.9	-249.1
2014 - 2015	-13.0	-62.3	-24.0	-3.5	-102.8
2015 - 2016	-2.1	-56.1	1.8	-6.1	-62.5
2016 - 2017	14.5	13.9	-1.9	-16.0	10.6
2017 - 2018	17.8	21.4	0.8	-15.2	24.8
2018 - 2019	19.0	19.4	2.7	-18.7	22.5
2019 - 2020	8.7	9.0	0.1	-25.1	-7.3
2020 - 2021	9.2	5.0	0.8	-40.6	-25.6
2021 - 2022	13.1	0.4	0.5	-5.3	8.7
2022 - 2023	12.0	-3.7	0.1	-11.7	-3.3
2013 - 2023[1]	73.9	-242.2	-43.1	-172.6	-384.0

notes: [1] Colums do not sum directly to ten-year result due to log formulation

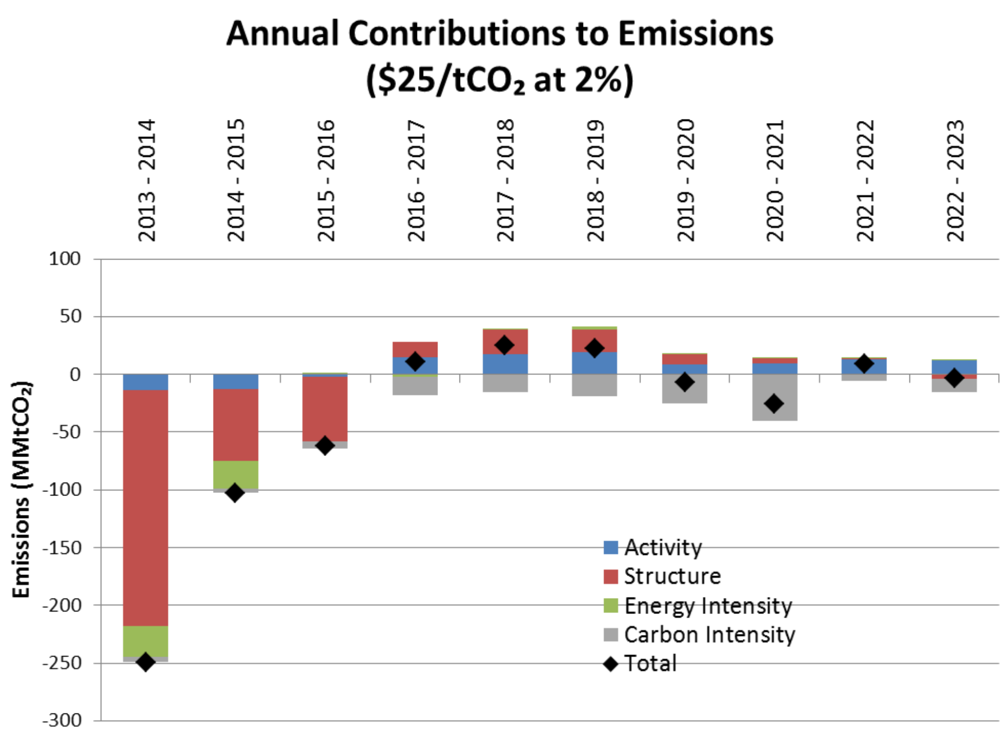

Figure B.19 Annual effects on emissions from $25/$tCO_2$ at 2% scenario

Table B.26 Annual effects on emissions from \$25/tCO_2 at 4% scenario

Effects on carbon emissions on \$25/tCO_2 at 4% scenario ($MMtCO_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	-14.2	-215.0	-26.1	-4.4	-259.6
2014 - 2015	-13.6	-83.0	-24.5	-3.9	-125.0
2015 - 2016	-2.9	-75.0	-0.2	-6.8	-85.0
2016 - 2017	12.7	12.8	-0.6	-15.0	9.9
2017 - 2018	15.5	14.9	0.7	-15.4	15.6
2018 - 2019	17.2	9.9	1.7	-19.6	9.1
2019 - 2020	7.1	15.3	0.4	-28.8	-6.0
2020 - 2021	7.3	-0.2	0.3	-41.2	-33.9
2021 - 2022	12.3	-7.1	-0.3	-13.3	-8.4
2022 - 2023	10.0	-5.1	-0.4	-6.4	-1.9
2013 - 2023[1]	60.3	-312.9	-46.2	-186.4	-485.2

notes: [1] Colums do not sum directly to ten-year result due to log formulation

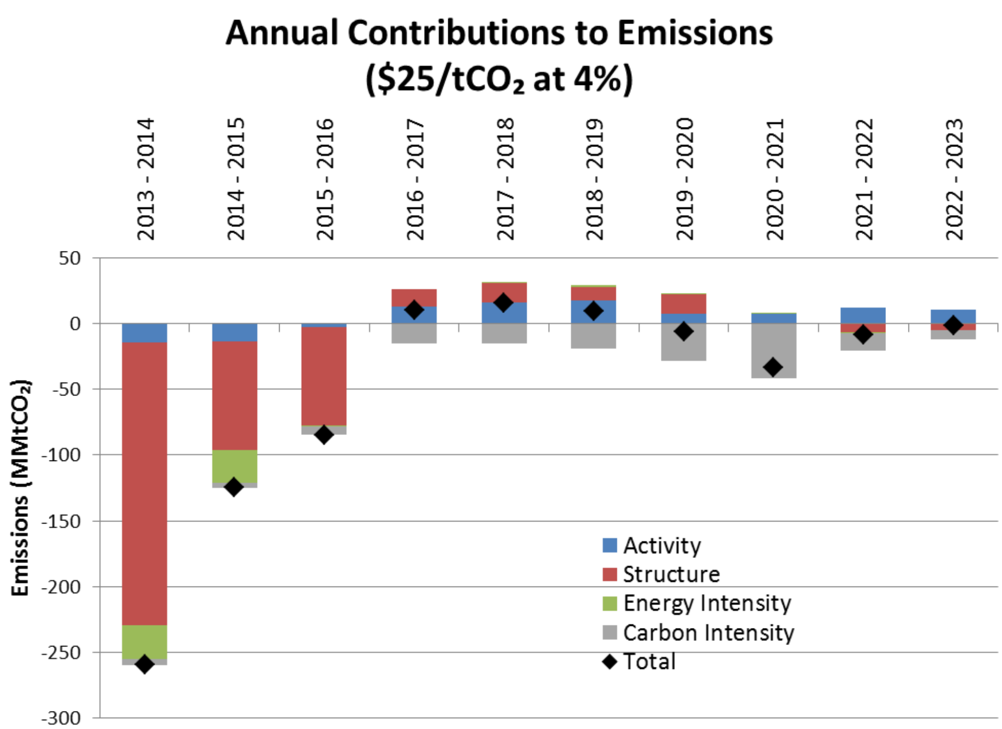

Figure B.20 Annual effects on emissions from \$25/tCO_2 at 4% scenario

Table B.27 Annual effects on emissions from \$25/tCO_2 at 6% scenario

Effects on carbon emissions on \$25/tCO_2 at 6% scenario ($MMtCO_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	-14.2	-215.9	-26.2	-4.4	-260.7
2014 - 2015	-14.0	-82.8	-24.9	-1.7	-123.4
2015 - 2016	-5.2	-98.5	-0.7	-10.0	-114.4
2016 - 2017	8.4	1.2	-1.2	-13.5	-5.1
2017 - 2018	11.9	4.4	0.5	-15.1	1.8
2018 - 2019	13.7	9.2	0.6	-21.0	2.5
2019 - 2020	5.5	1.6	-0.8	-28.6	-22.2
2020 - 2021	5.9	-5.9	-0.9	-45.6	-46.4
2021 - 2022	9.3	-6.7	-0.4	-6.2	-3.9
2022 - 2023	7.3	-14.3	-0.9	-5.1	-12.9
2013 - 2023[1]	37.0	-384.4	-51.1	-186.4	-584.8

notes: [1] Colums do not sum directly to ten-year result due to log formulation

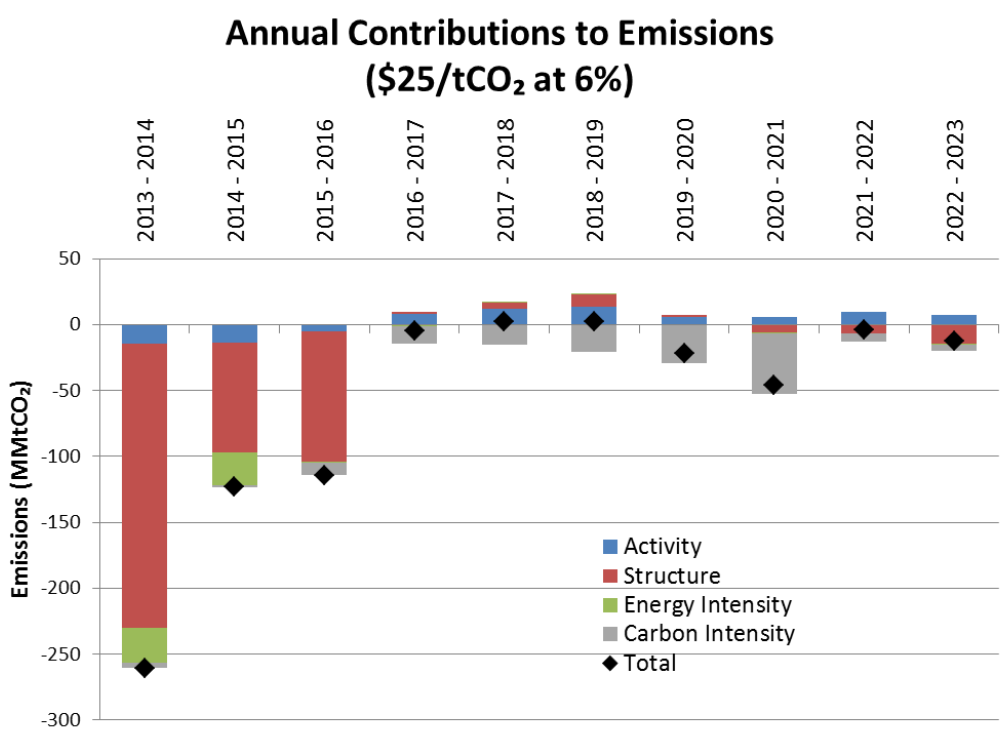

Figure B.21 Annual effects on emissions from \$25/tCO_2 at 6% scenario

Table B.28 Annual effects on emissions from \$25/tCO_2 at 8% scenario

Effects on carbon emissions on \$25/tCO_2 at 8% scenario ($MMtCO_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	-14.5	-218.7	-27.6	-5.0	-265.8
2014 - 2015	-15.1	-97.9	-22.8	-2.9	-138.6
2015 - 2016	-8.3	-122.1	-4.0	-9.1	-143.5
2016 - 2017	4.6	-15.8	-1.3	-15.8	-28.3
2017 - 2018	7.8	-6.7	-0.4	-15.9	-15.2
2018 - 2019	11.8	-1.1	-0.6	-20.9	-10.9
2019 - 2020	2.9	-6.1	-0.5	-33.2	-37.0
2020 - 2021	-0.4	-8.9	-0.7	-29.1	-39.1
2021 - 2022	12.7	-3.8	-0.3	-4.7	3.8
2022 - 2023	4.7	-18.1	-1.2	-6.7	-21.3
2013 - 2023[1]	14.7	-470.9	-54.3	-185.4	-695.9

notes: [1] Colums do not sum directly to ten-year result due to log formulation

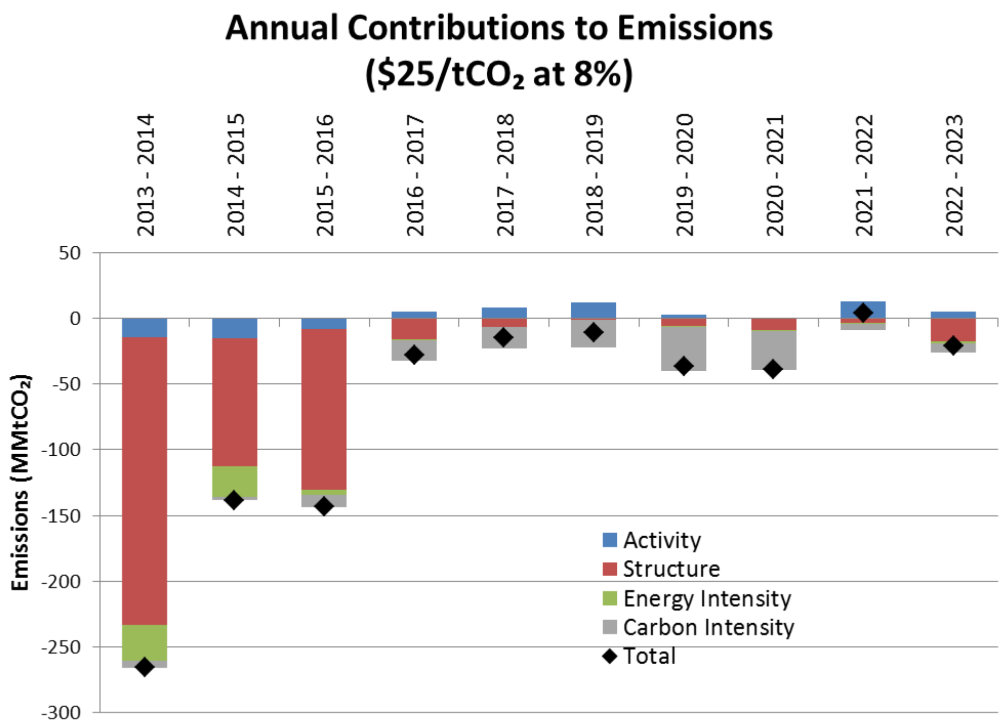

Figure B.22 Annual effects on emissions from \$25/tCO_2 at 8% scenario

Table B.29 Annual effects on emissions from $35/tCO$_2$ at 2% scenario

Effects on carbon emissions on $35/tCO$_2$ at 2% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	-24.1	-276.7	-31.7	-6.9	-339.4
2014 - 2015	-24.8	-114.6	-23.5	-4.4	-167.3
2015 - 2016	-5.6	-63.2	0.2	-5.3	-73.9
2016 - 2017	12.3	15.5	0.1	-14.3	13.7
2017 - 2018	12.7	13.6	0.2	-13.3	13.3
2018 - 2019	16.7	20.9	0.1	-21.0	16.8
2019 - 2020	8.9	13.9	1.2	-29.3	-5.4
2020 - 2021	5.6	-1.8	-0.1	-42.5	-38.9
2021 - 2022	11.6	1.2	0.1	-6.2	6.7
2022 - 2023	8.9	-6.5	-0.5	-3.6	-1.7
2013 - 2023[1]	33.0	-370.9	-50.9	-187.4	-576.1

notes: [1] Colums do not sum directly to ten-year result due to log formulation

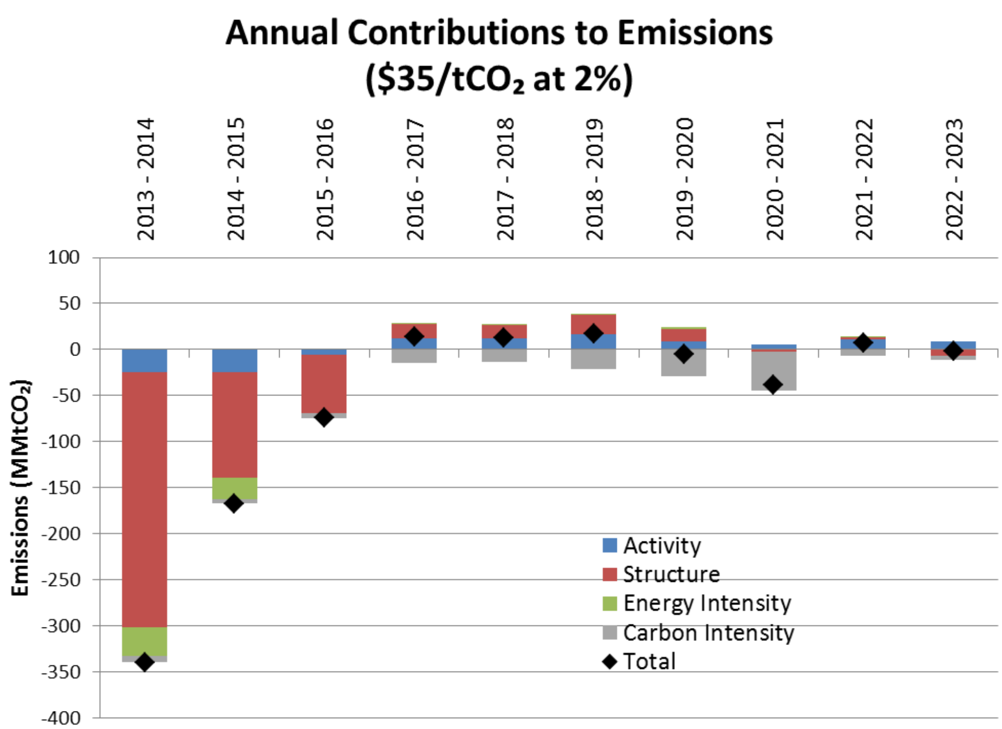

Figure B.23 Annual effects on emissions from $35/tCO$_2$ at 2% scenario

Table B.30 Annual effects on emissions from \$35/tCO$_2$ at 4% scenario

Effects on carbon emissions on \$35/tCO$_2$ at 4% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	-24.3	-277.3	-31.1	-5.9	-338.6
2014 - 2015	-25.1	-114.4	-21.8	-6.0	-167.3
2015 - 2016	-9.0	-98.3	-3.2	-4.9	-115.5
2016 - 2017	6.9	2.1	-1.3	-15.7	-8.1
2017 - 2018	8.4	-0.4	0.0	-14.8	-6.8
2018 - 2019	11.7	11.8	-0.8	-22.2	0.5
2019 - 2020	5.7	-2.6	0.2	-31.9	-28.6
2020 - 2021	2.3	-6.3	-1.1	-32.8	-37.9
2021 - 2022	13.4	1.1	0.1	-4.5	10.2
2022 - 2023	7.3	-10.4	-0.6	-2.7	-6.4
2013 - 2023[1]	8.6	-462.1	-55.5	-189.6	-698.6

notes: [1] Colums do not sum directly to ten-year result due to log formulation

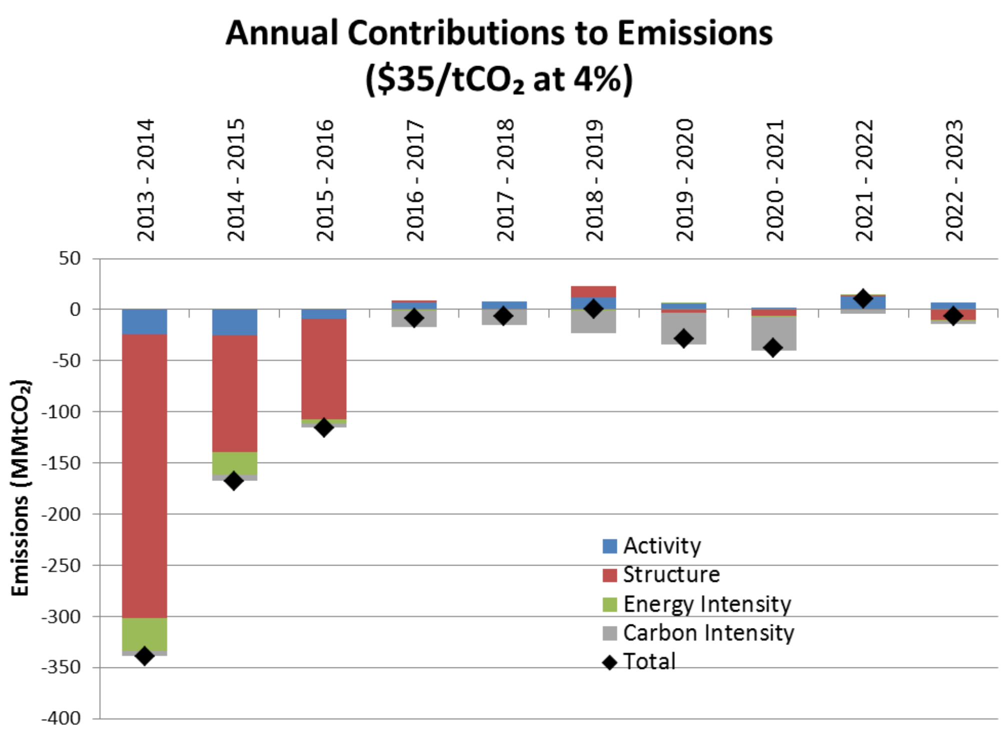

Figure B.24 Annual effects on emissions from \$35/tCO$_2$ at 4% scenario

Table B.31 Annual effects on emissions from \$35/tCO_2 at 6% scenario

Effects on carbon emissions on \$35/tCO_2 at 6% scenario (MMtCO_2)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	-24.7	-281.4	-30.8	-7.3	-344.1
2014 - 2015	-26.2	-126.2	-23.1	-1.9	-177.4
2015 - 2016	-17.6	-162.5	-4.9	-11.1	-196.2
2016 - 2017	1.6	-21.3	-1.4	-14.8	-35.9
2017 - 2018	1.3	-7.7	0.1	-17.9	-24.2
2018 - 2019	12.9	-2.5	-1.4	-21.4	-12.4
2019 - 2020	3.4	-19.5	-0.1	-32.9	-49.1
2020 - 2021	5.5	-11.0	-0.7	-7.1	-13.4
2021 - 2022	11.5	-8.9	-0.5	-0.9	1.2
2022 - 2023	4.6	-15.1	0.9	-5.0	-14.6
2013 - 2023[1]	-12.5	-628.1	-53.0	-172.3	-866.0

notes: [1] Colums do not sum directly to ten-year result due to log formulation

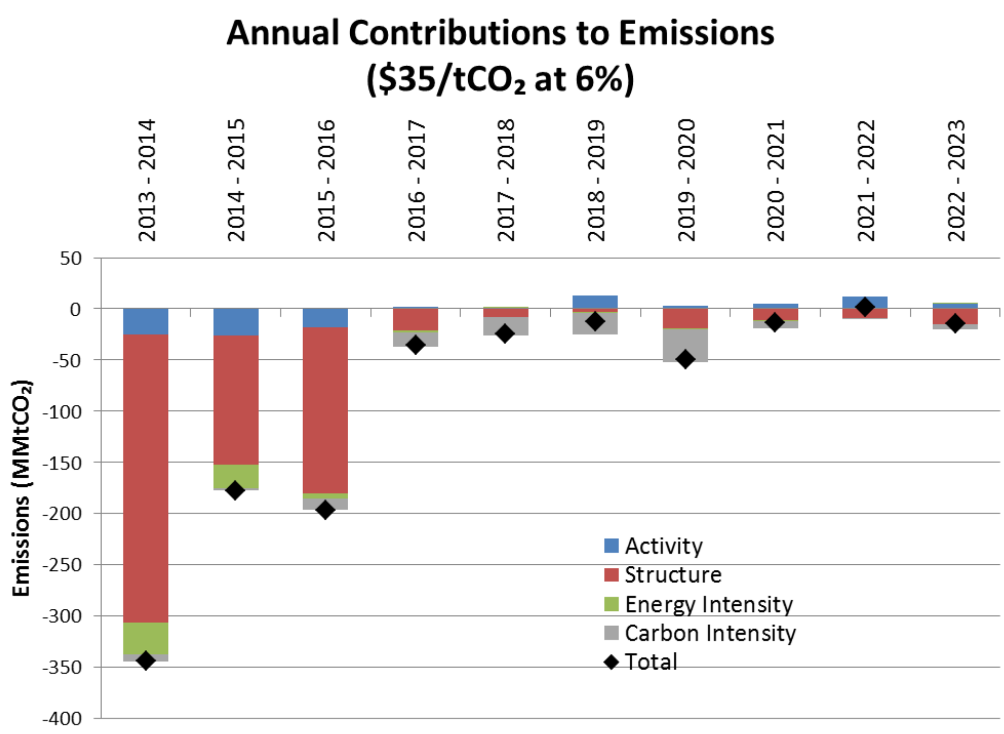

Figure B.25 Annual effects on emissions from \$35/tCO_2 at 6% scenario

Table B.32 Annual effects on emissions from \$35/tCO_2 at 8% scenario

Effects on carbon emissions on \$35/tCO_2 at 8% scenario (MMtCO_2)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	-25.0	-295.9	-31.5	-7.9	-360.3
2014 - 2015	-26.6	-137.9	-22.1	-5.6	-192.2
2015 - 2016	-28.7	-264.3	-11.5	-9.1	-313.5
2016 - 2017	-6.0	-51.3	-1.7	-17.2	-76.2
2017 - 2018	4.3	-17.6	-0.5	-16.8	-30.5
2018 - 2019	8.3	-16.4	0.5	-17.3	-25.0
2019 - 2020	3.2	-23.4	-0.6	-8.3	-29.1
2020 - 2021	-6.4	-22.9	1.2	-6.6	-34.7
2021 - 2022	2.7	-18.3	2.0	-11.0	-24.6
2022 - 2023	2.0	-20.1	-0.2	-4.1	-22.4
2013 - 2023[1]	-54.8	-841.2	-48.1	-164.4	-1108.5

notes: [1] Colums do not sum directly to ten-year result due to log formulation

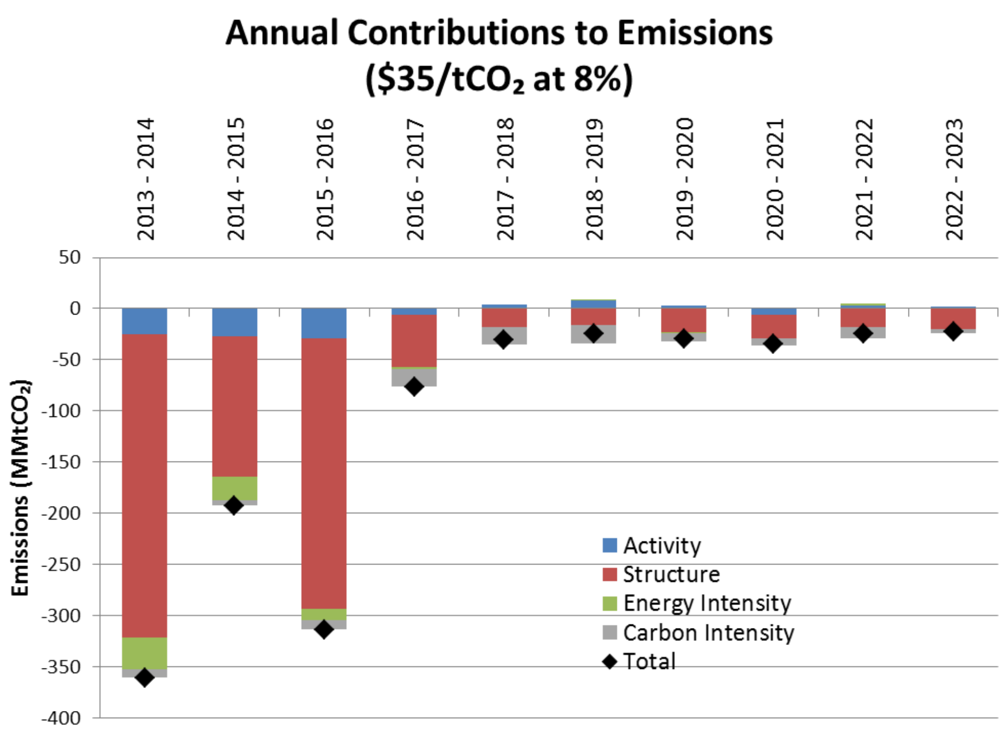

Figure B.26 Annual effects on emissions from \$35/tCO_2 at 8% scenario

B.7 Residential sector LMDI decomposition results

Activity in the Residential sector is represented by total number of households (HH). Energy Intensity is the energy demand per HH. Fuel mix represents the fraction of the energy supplied by each fuel type, and carbon intensity is the amount of carbon in each of those fuels. Ten-year results are reported in Table B.33 and Figure B.27, followed by the annual results for each scenario.

Table B.33 Ten-year effects on carbon from all scenarios

	Total effects on carbon emissions (2013 - 2023)				
	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
Total effect ($MMtCO_2$)					
Reference	109.1	-134.3	46.0	-55.5	-34.7
$15/$tCO_2$ at 2%	104.3	-146.5	39.8	-119.4	-121.8
$15/$tCO_2$ at 4%	103.3	-147.5	38.5	-133.6	-139.2
$15/$tCO_2$ at 6%	101.9	-149.0	37.1	-153.9	-163.8
$15/$tCO_2$ at 8%	100.2	-150.0	35.2	-178.9	-193.6
$25/$tCO_2$ at 2%	100.1	-153.0	35.0	-177.5	-195.4
$25/$tCO_2$ at 4%	98.0	-153.8	33.0	-209.6	-232.4
$25/$tCO_2$ at 6%	95.9	-155.9	30.6	-238.6	-268.0
$25/$tCO_2$ at 8%	93.5	-156.9	28.2	-272.0	-307.3
$35/$tCO_2$ at 2%	96.1	-157.6	30.9	-233.9	-264.4
$35/$tCO_2$ at 4%	93.1	-158.3	27.8	-275.4	-312.8
$35/$tCO_2$ at 6%	89.2	-156.4	24.0	-332.8	-376.0
$35/$tCO_2$ at 8%	83.5	-156.5	16.9	-403.4	-459.4
Percent from Reference					
Reference	0.0%	0.0%	0.0%	0.0%	0.0%
$15/$tCO_2$ at 2%	-4.4%	9.1%	-13.5%	115.0%	251.2%
$15/$tCO_2$ at 4%	-5.3%	9.9%	-16.3%	140.5%	301.6%
$15/$tCO_2$ at 6%	-6.6%	10.9%	-19.4%	177.2%	372.6%
$15/$tCO_2$ at 8%	-8.2%	11.7%	-23.6%	222.1%	458.3%
$25/$tCO_2$ at 2%	-8.3%	13.9%	-24.0%	219.5%	463.5%
$25/$tCO_2$ at 4%	-10.2%	14.5%	-28.3%	277.4%	570.2%
$25/$tCO_2$ at 6%	-12.2%	16.0%	-33.6%	329.5%	672.9%
$25/$tCO_2$ at 8%	-14.3%	16.8%	-38.8%	389.7%	786.2%
$35/$tCO_2$ at 2%	-11.9%	17.3%	-32.9%	321.1%	662.6%
$35/$tCO_2$ at 4%	-14.7%	17.9%	-39.6%	395.8%	802.0%
$35/$tCO_2$ at 6%	-18.3%	16.4%	-48.0%	499.2%	984.4%
$35/$tCO_2$ at 8%	-23.5%	16.5%	-63.3%	626.3%	1225.1%

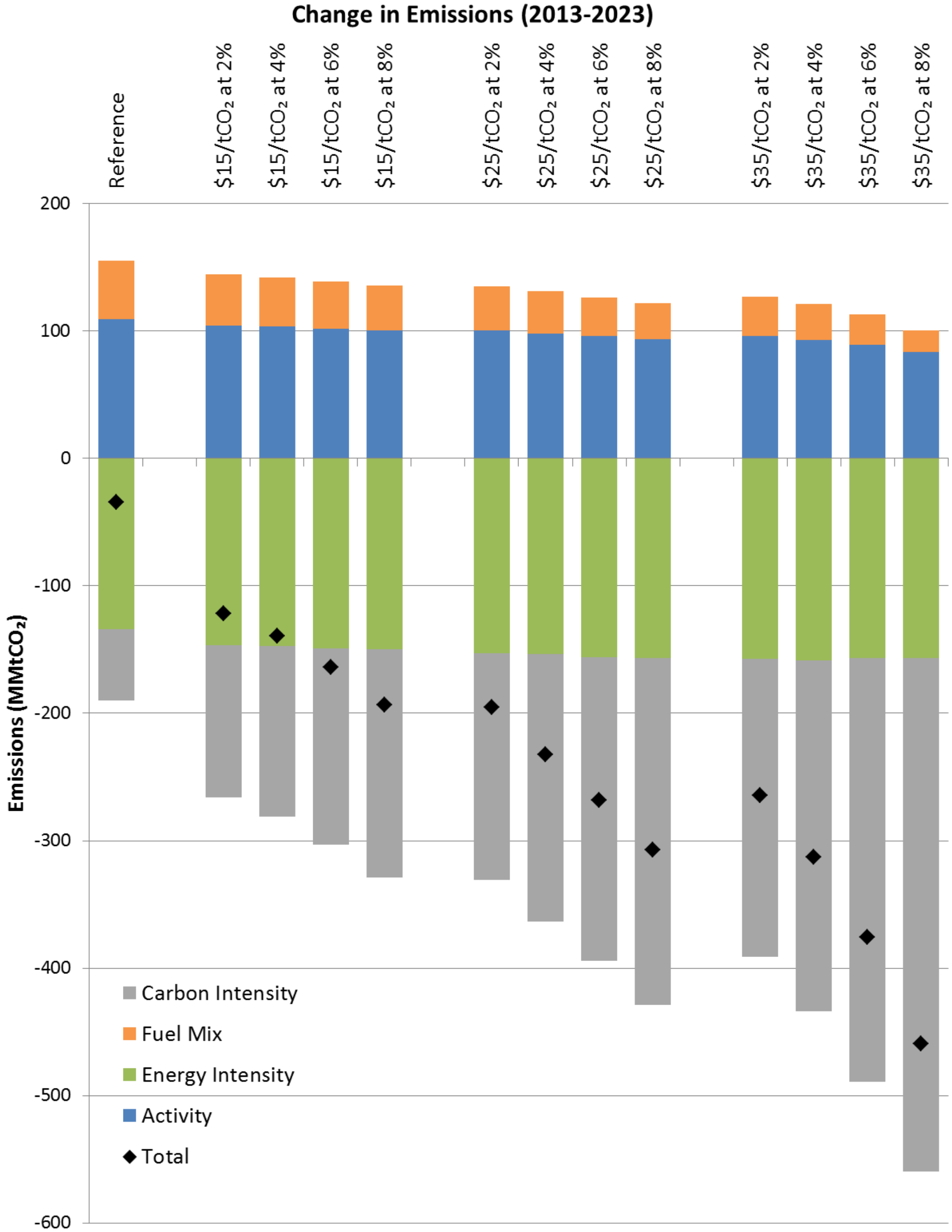

Figure B.27 Ten-year effects on carbon from all scenarios

Table B.34 Annual effects on emissions from Reference scenario

Effects on carbon emissions from Reference scenario ($MMtCO_2$)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	7.4	-29.2	13.2	-9.5	-18.1
2014 - 2015	10.1	-13.3	2.8	-16.9	-17.4
2015 - 2016	11.0	-13.5	3.2	-30.8	-30.1
2016 - 2017	11.7	-13.1	3.8	-1.2	1.2
2017 - 2018	11.6	-12.1	4.5	1.0	5.0
2018 - 2019	11.5	-9.6	4.7	3.5	10.1
2019 - 2020	11.2	-12.5	1.9	1.3	2.0
2020 - 2021	10.8	-10.1	2.9	-3.9	-0.3
2021 - 2022	10.5	-9.4	3.5	3.4	8.0
2022 - 2023	10.5	-8.8	4.0	-0.7	4.9
2013 - 2023[1]	109.1	-134.3	46.0	-55.5	-34.7

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

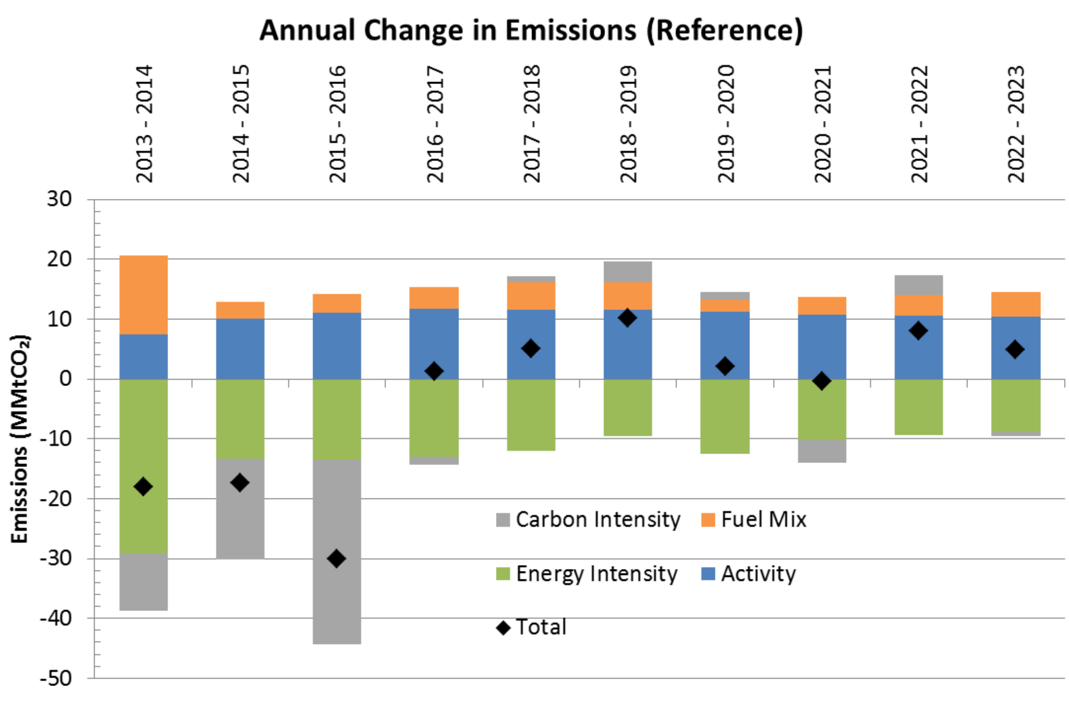

Figure B.28 Annual effects on emissions from Reference scenario

Table B.35 Annual effects on emissions from \$15/tCO_2 at 2% scenario

Effects on carbon emissions from \$15/tCO_2 at 2% scenario ($MMtCO_2$)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	7.1	-35.3	12.9	-59.8	-75.2
2014 - 2015	9.3	-20.0	1.1	-25.3	-34.9
2015 - 2016	10.2	-16.1	1.7	-21.0	-25.1
2016 - 2017	10.8	-12.2	3.0	-3.0	-1.4
2017 - 2018	10.8	-10.5	4.0	1.2	5.5
2018 - 2019	10.8	-8.6	4.1	2.9	9.2
2019 - 2020	10.5	-11.5	1.6	-5.4	-4.8
2020 - 2021	10.0	-9.5	2.5	-4.5	-1.5
2021 - 2022	9.7	-8.8	3.0	-0.6	3.3
2022 - 2023	9.6	-8.5	3.1	-1.1	3.1
2013 - 2023[1]	104.3	-146.5	39.8	-119.4	-121.8

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

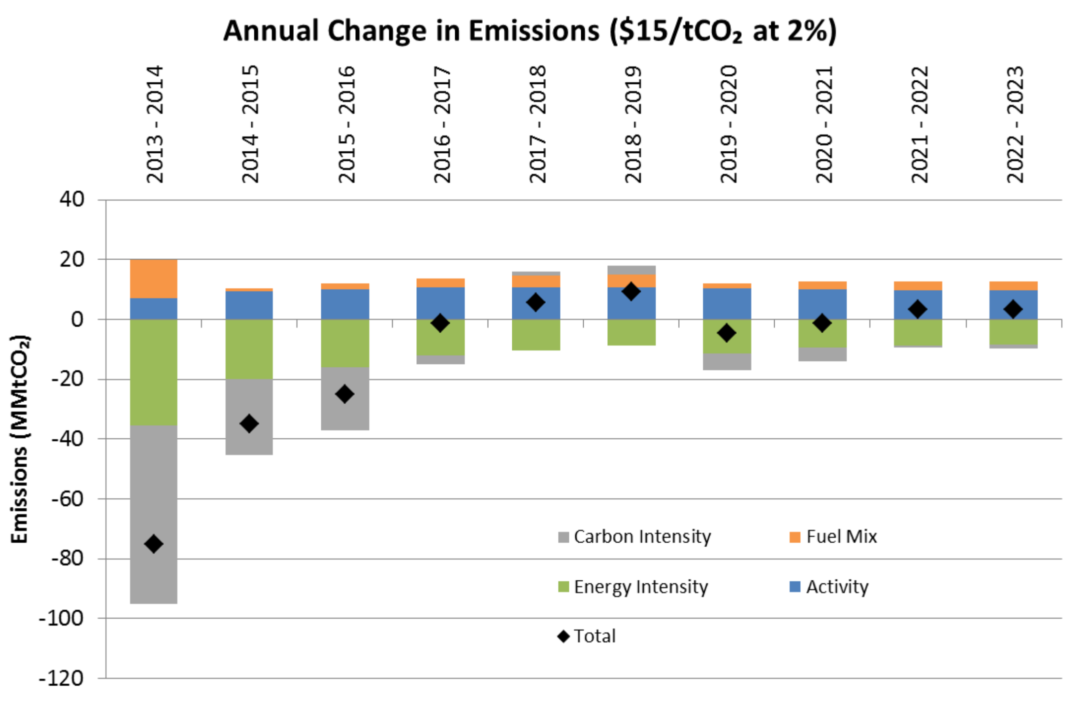

Figure B.29 Annual effects on emissions from \$15/tCO_2 at 2% scenario

Table B.36 Annual effects on emissions from \$15/tCO_2 at 4% scenario

Effects on carbon emissions from \$15/tCO_2 at 4% scenario (MtCO_2)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	7.1	-35.3	12.8	-57.7	-73.1
2014 - 2015	9.3	-20.1	1.1	-28.0	-37.7
2015 - 2016	10.1	-16.4	1.6	-23.6	-28.3
2016 - 2017	10.8	-12.5	2.9	-3.7	-2.5
2017 - 2018	10.8	-10.8	3.9	-1.6	2.2
2018 - 2019	10.7	-8.9	3.9	2.5	8.2
2019 - 2020	10.4	-11.6	1.5	-6.4	-6.2
2020 - 2021	9.8	-9.5	2.4	-7.1	-4.4
2021 - 2022	9.5	-8.8	2.9	-3.7	-0.1
2022 - 2023	9.4	-8.5	3.0	-1.4	2.5
2013 - 2023[1]	103.3	-147.5	38.5	-133.6	-139.2

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

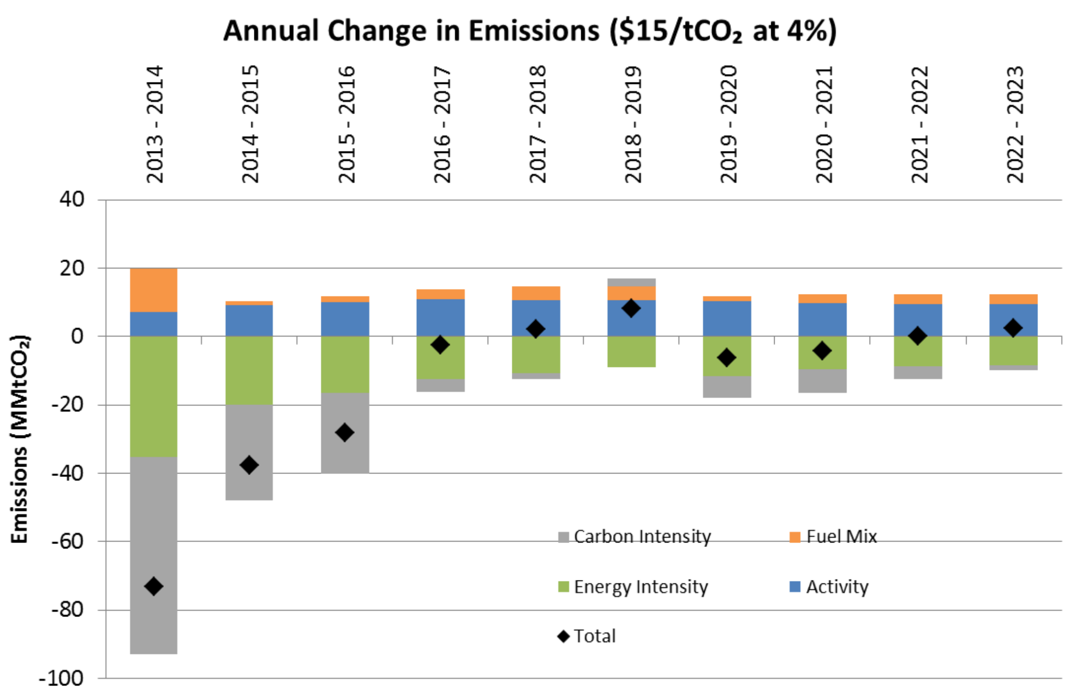

Figure B.30 Annual effects on emissions from \$15/tCO_2 at 4% scenario

Table B.37 Annual effects on emissions from \$15/tCO_2 at 6% scenario

Effects on carbon emissions from \$15/tCO_2 at 6% scenario ($MMtCO_2$)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	7.1	-35.3	12.9	-60.3	-75.7
2014 - 2015	9.2	-20.2	1.1	-28.2	-38.1
2015 - 2016	10.1	-16.8	1.7	-27.4	-32.5
2016 - 2017	10.7	-12.6	2.8	-1.5	-0.6
2017 - 2018	10.7	-11.0	3.7	-4.1	-0.6
2018 - 2019	10.6	-9.0	3.8	1.4	6.7
2019 - 2020	10.2	-11.9	1.5	-8.7	-9.0
2020 - 2021	9.7	-9.9	2.3	-9.7	-7.6
2021 - 2022	9.3	-9.1	2.6	-8.7	-5.8
2022 - 2023	9.2	-8.6	2.7	-4.0	-0.7
2013 - 2023[1]	101.9	-149.0	37.1	-153.9	-163.8

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

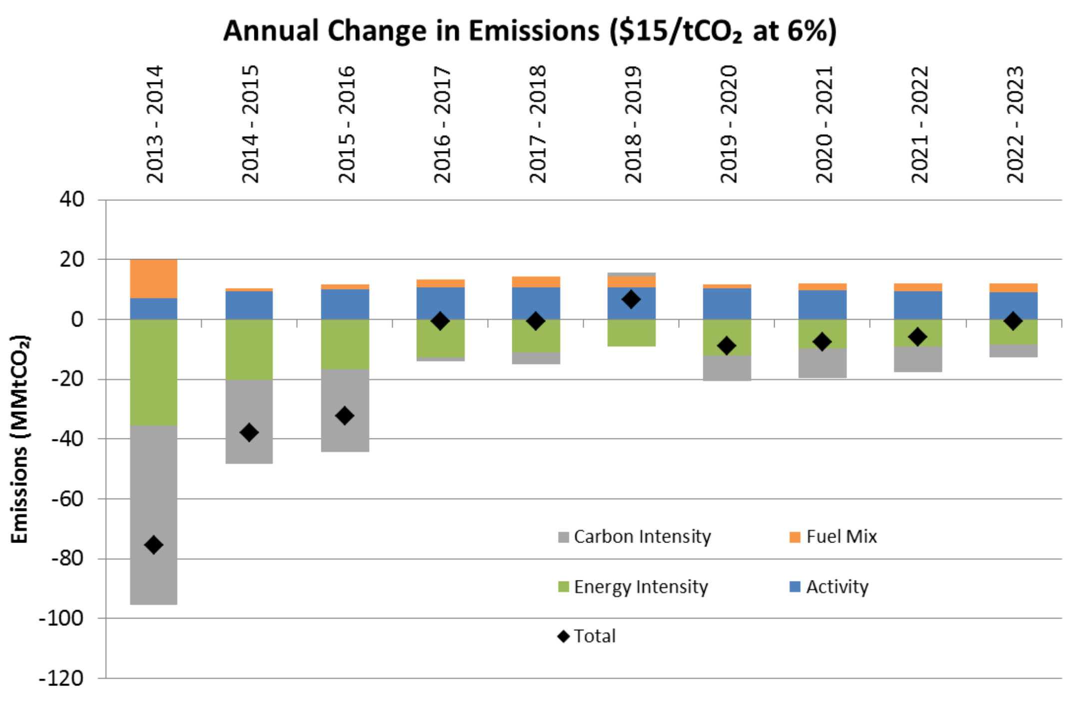

Figure B.31 Annual effects on emissions from \$15/tCO_2 at 6% scenario

Table B.38 Annual effects on emissions from $15/tCO$_2$ at 8% scenario

Effects on carbon emissions from $15/tCO$_2$ at 8% scenario (MMtCO$_2$)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	7.0	-35.2	12.7	-60.4	-75.9
2014 - 2015	9.2	-20.2	1.0	-32.8	-42.8
2015 - 2016	10.0	-17.1	1.5	-30.1	-35.6
2016 - 2017	10.5	-13.1	2.7	-6.8	-6.7
2017 - 2018	10.5	-11.3	3.5	-4.3	-1.6
2018 - 2019	10.4	-9.3	3.5	-0.3	4.3
2019 - 2020	10.0	-12.0	1.3	-9.9	-10.6
2020 - 2021	9.4	-9.9	2.1	-16.9	-15.2
2021 - 2022	9.1	-9.2	2.4	-5.2	-2.9
2022 - 2023	8.9	-8.7	2.5	-9.3	-6.5
2013 - 2023[1]	100.2	-150.0	35.2	-178.9	-193.6

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

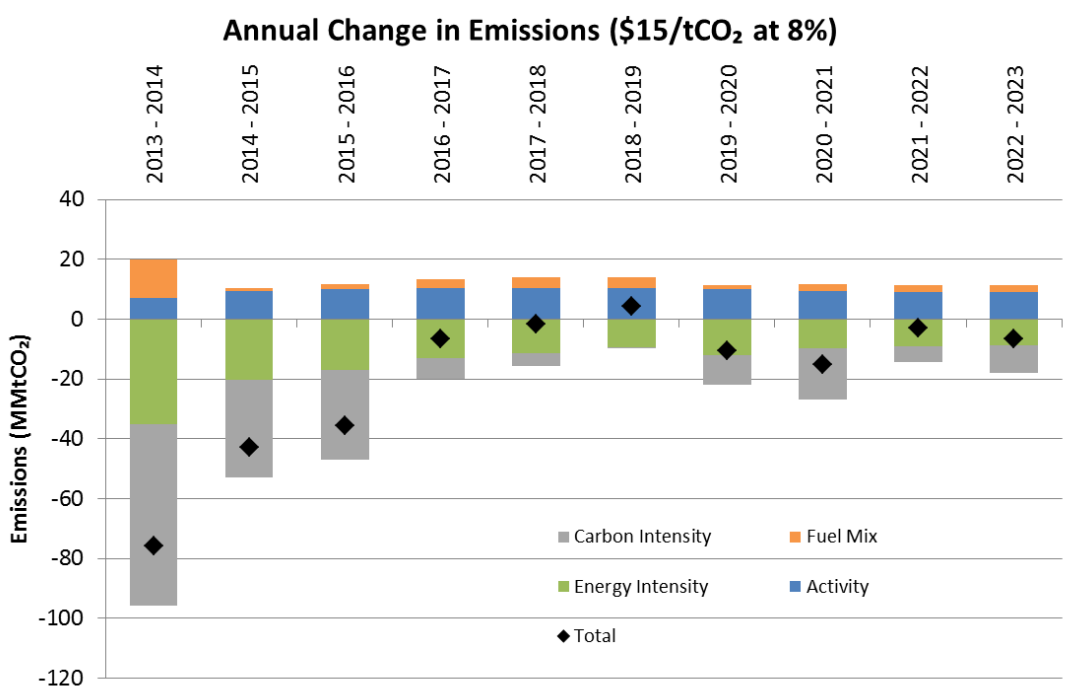

Figure B.32 Annual effects on emissions from $15/tCO$_2$ at 8% scenario

Table B.39 Annual effects on emissions from $25/tCO$_2$ at 2% scenario

Effects on carbon emissions from $25/tCO$_2$ at 2% scenario (MMtCO$_2$)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	6.8	-39.0	12.6	-89.1	-108.6
2014 - 2015	8.8	-23.8	0.1	-33.5	-48.3
2015 - 2016	9.6	-18.0	1.0	-23.7	-31.1
2016 - 2017	10.2	-12.0	2.5	-2.4	-1.8
2017 - 2018	10.2	-9.7	3.5	1.7	5.8
2018 - 2019	10.2	-8.1	3.5	0.6	6.1
2019 - 2020	9.9	-10.9	1.4	-6.5	-6.2
2020 - 2021	9.4	-8.8	2.2	-13.9	-11.2
2021 - 2022	9.0	-8.2	2.5	-1.9	1.4
2022 - 2023	8.9	-7.9	2.6	-5.2	-1.5
2013 - 2023[1]	100.1	-153.0	35.0	-177.5	-195.4

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

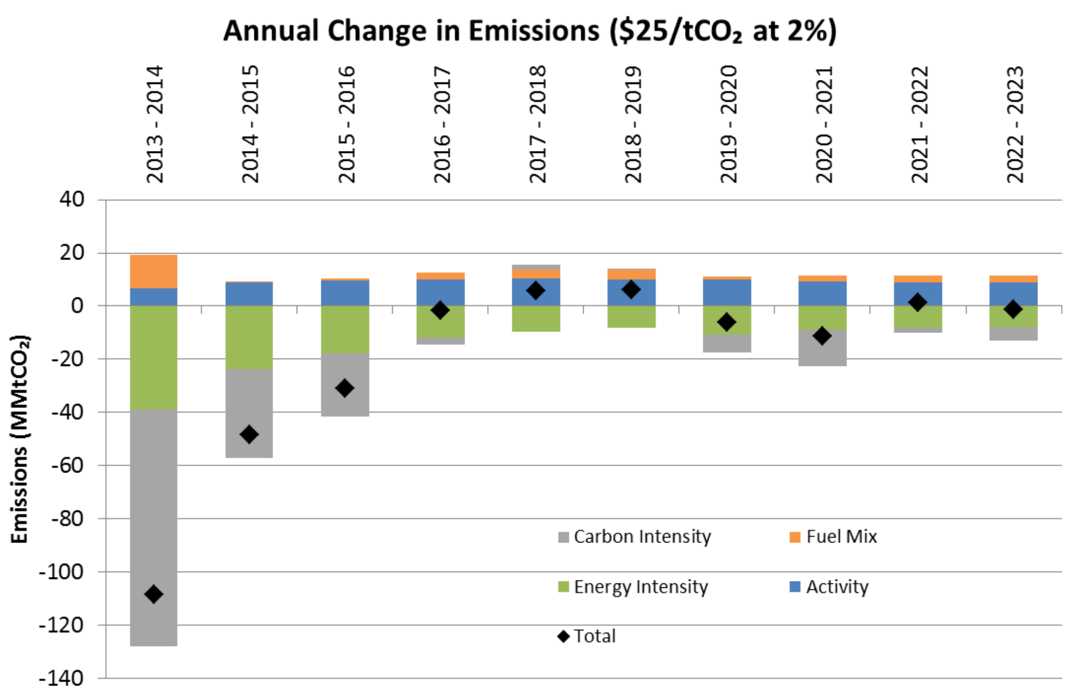

Figure B.33 Annual effects on emissions from $25/tCO$_2$ at 2% scenario

Table B.40 Annual effects on emissions from $25/tCO$_2$ at 4% scenario

Effects on carbon emissions from $25/tCO$_2$ at 4% scenario (MMtCO$_2$)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	6.8	-38.9	12.5	-92.9	-112.5
2014 - 2015	8.7	-23.9	0.1	-41.5	-56.5
2015 - 2016	9.4	-18.2	1.0	-31.6	-39.4
2016 - 2017	9.9	-12.2	2.3	-2.0	-1.9
2017 - 2018	10.0	-10.0	3.2	-0.8	2.4
2018 - 2019	9.9	-8.3	3.2	-3.5	1.3
2019 - 2020	9.6	-10.8	1.1	-5.6	-5.6
2020 - 2021	9.0	-8.7	1.9	-16.4	-14.2
2021 - 2022	8.7	-8.3	2.2	-7.4	-4.7
2022 - 2023	8.5	-8.0	2.3	-4.0	-1.1
2013 - 2023[1]	98.0	-153.8	33.0	-209.6	-232.4

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

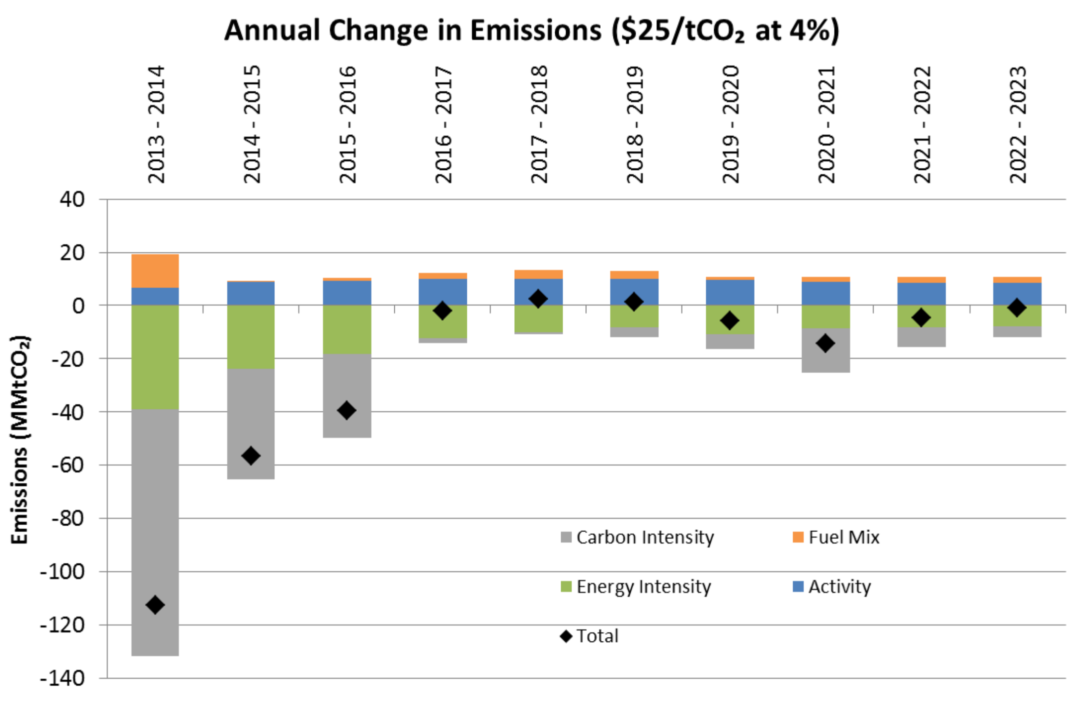

Figure B.34 Annual effects on emissions from $25/tCO$_2$ at 4% scenario

Table B.41 Annual effects on emissions from \$25/tCO_2 at 6% scenario

Effects on carbon emissions from \$25/tCO_2 at 6% scenario (MMtCO_2)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	6.8	-38.9	12.5	-93.3	-112.9
2014 - 2015	8.7	-23.9	0.1	-40.8	-55.9
2015 - 2016	9.3	-18.8	0.9	-41.6	-50.2
2016 - 2017	9.8	-13.0	2.1	-6.2	-7.3
2017 - 2018	9.7	-10.7	2.9	-4.6	-2.6
2018 - 2019	9.6	-8.7	2.8	-4.9	-1.1
2019 - 2020	9.3	-11.0	1.0	-10.7	-11.5
2020 - 2021	8.7	-8.9	1.7	-20.2	-18.7
2021 - 2022	8.3	-8.2	1.9	-4.8	-2.8
2022 - 2023	8.2	-7.8	2.0	-7.2	-4.9
2013 - 2023[1]	95.9	-155.9	30.6	-238.6	-268.0

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

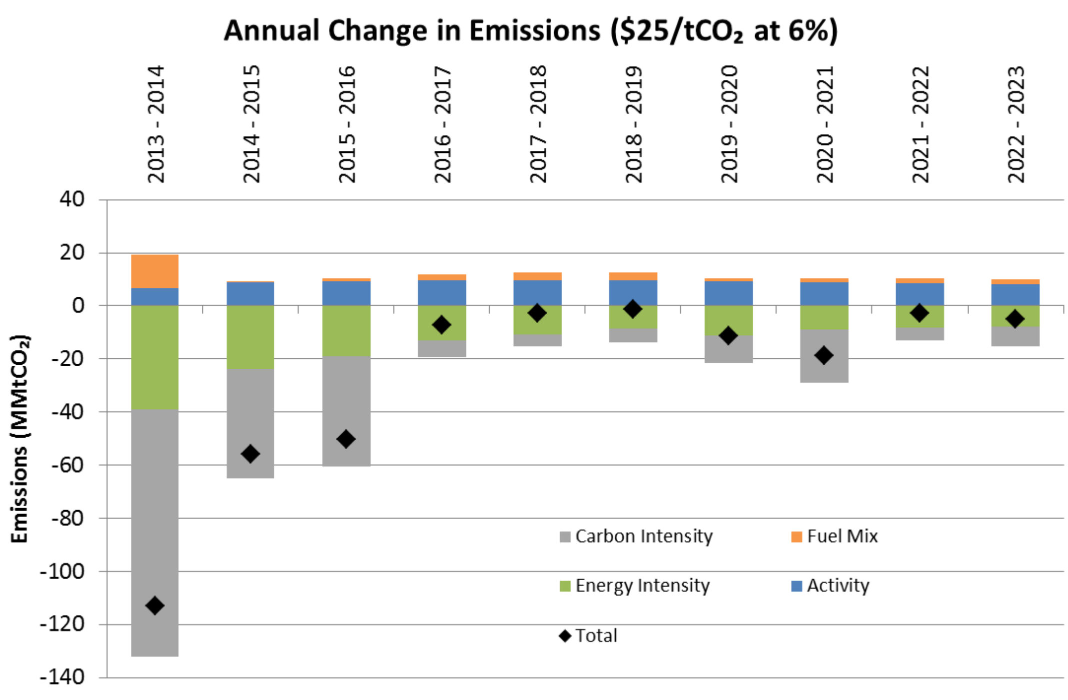

Figure B.35 Annual effects on emissions from \$25/tCO_2 at 6% scenario

Table B.42 Annual effects on emissions from $25/tCO$_2$ at 8% scenario

Effects on carbon emissions from $25/tCO$_2$ at 8% scenario (MMtCO$_2$)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	6.8	-38.9	12.5	-95.4	-115.1
2014 - 2015	8.7	-24.1	0.2	-45.6	-60.8
2015 - 2016	9.2	-19.6	0.8	-51.8	-61.4
2016 - 2017	9.5	-13.9	1.9	-11.7	-14.2
2017 - 2018	9.4	-11.1	2.5	-8.9	-8.1
2018 - 2019	9.2	-8.6	2.5	-10.7	-7.6
2019 - 2020	8.8	-10.6	0.8	-15.1	-16.0
2020 - 2021	8.3	-8.5	1.3	-17.9	-16.7
2021 - 2022	8.0	-8.1	1.6	-1.4	0.0
2022 - 2023	7.8	-7.8	1.6	-8.9	-7.3
2013 - 2023[1]	93.5	-156.9	28.2	-272.0	-307.3

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

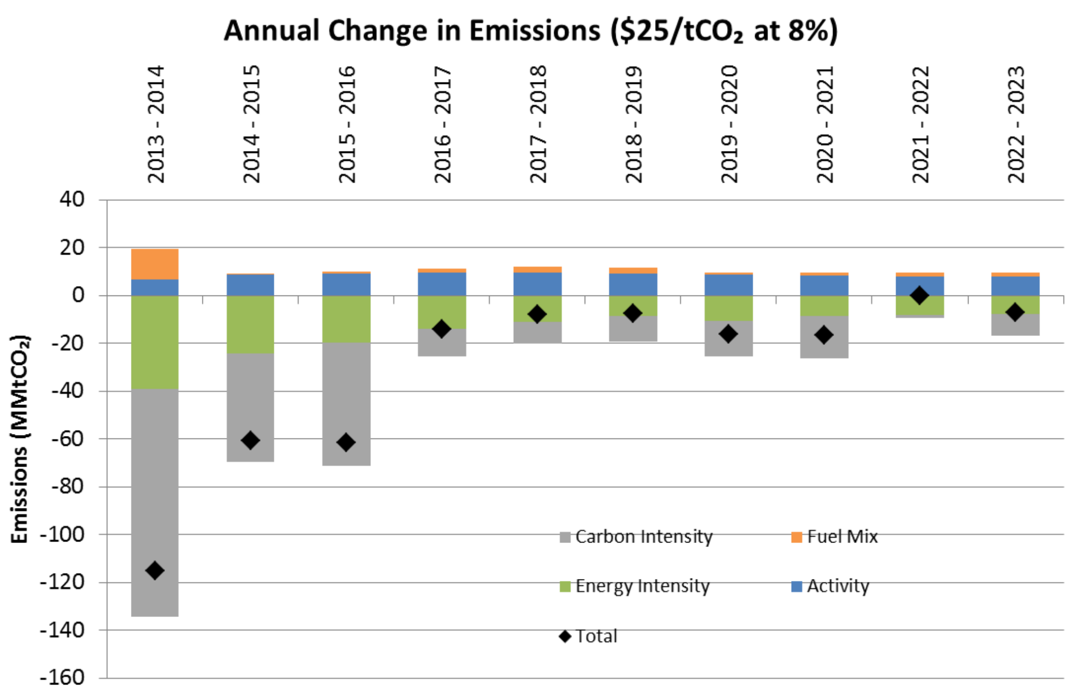

Figure B.36 Annual effects on emissions from $25/tCO$_2$ at 8% scenario

Table B.43 Annual effects on emissions from \$35/tCO_2 at 2% scenario

Effects on carbon emissions from \$35/tCO_2 at 2% scenario ($MMtCO_2$)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	6.6	-42.2	12.3	-119.4	-142.6
2014 - 2015	8.3	-26.9	-0.6	-53.0	-72.2
2015 - 2016	8.9	-18.8	0.5	-26.6	-36.0
2016 - 2017	9.5	-11.5	2.0	-0.3	-0.3
2017 - 2018	9.5	-9.0	3.0	-1.3	2.2
2018 - 2019	9.5	-7.3	2.9	-0.5	4.6
2019 - 2020	9.2	-10.0	1.1	-5.5	-5.2
2020 - 2021	8.7	-8.3	1.7	-17.7	-15.6
2021 - 2022	8.3	-7.7	2.0	-1.4	1.2
2022 - 2023	8.3	-7.3	2.1	-3.6	-0.5
2013 - 2023[1]	96.1	-157.6	30.9	-233.9	-264.4

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

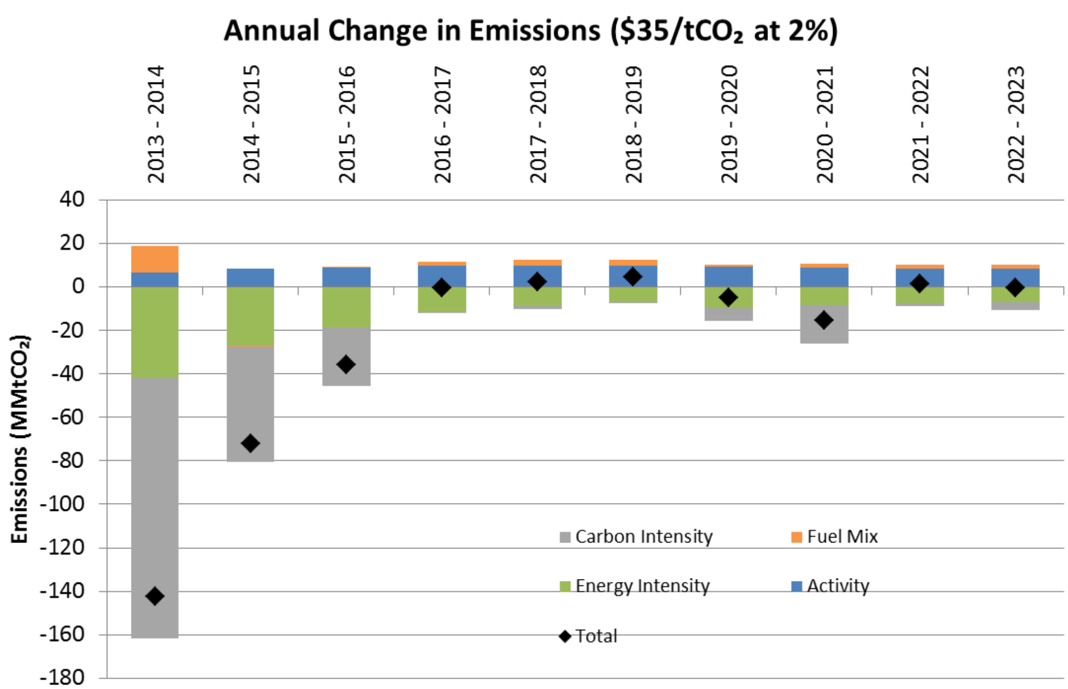

Figure B.37 Annual effects on emissions from \$35/tCO_2 at 2% scenario

Table B.44 Annual effects on emissions from $35/tCO$_2$ at 4% scenario

Effects on carbon emissions from $35/tCO$_2$ at 4% scenario (MMtCO$_2$)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	6.6	-42.1	12.3	-118.9	-142.2
2014 - 2015	8.3	-27.0	-0.6	-53.8	-73.2
2015 - 2016	8.8	-19.6	0.4	-41.1	-51.6
2016 - 2017	9.2	-12.5	1.8	-7.5	-9.0
2017 - 2018	9.2	-9.7	2.6	-6.5	-4.5
2018 - 2019	9.0	-7.6	2.5	-6.2	-2.3
2019 - 2020	8.7	-9.6	0.8	-16.0	-16.2
2020 - 2021	8.2	-7.9	1.3	-14.6	-12.9
2021 - 2022	7.9	-7.5	1.6	-0.1	1.9
2022 - 2023	7.8	-7.1	1.7	-5.2	-2.9
2013 - 2023[1]	93.1	-158.3	27.8	-275.4	-312.8

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

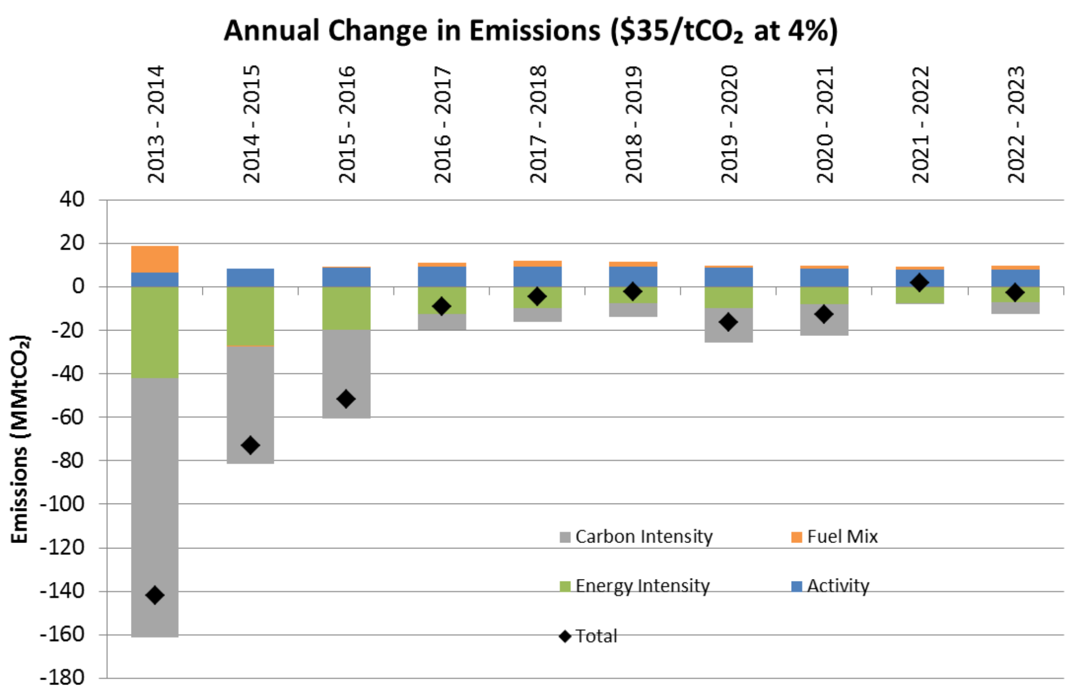

Figure B.38 Annual effects on emissions from $35/tCO$_2$ at 4% scenario

Table B.45 Annual effects on emissions from $35/tCO$_2$ at 6% scenario

Effects on carbon emissions from $35/tCO$_2$ at 6% scenario (MMtCO$_2$)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	6.6	-42.1	12.2	-121.2	-144.5
2014 - 2015	8.2	-27.2	-0.6	-56.4	-76.0
2015 - 2016	8.5	-21.1	0.1	-68.8	-81.2
2016 - 2017	8.7	-13.5	1.2	-15.4	-19.0
2017 - 2018	8.6	-9.9	1.9	-13.3	-12.7
2018 - 2019	8.4	-7.4	1.9	-10.5	-7.5
2019 - 2020	8.1	-8.8	0.6	-19.1	-19.3
2020 - 2021	7.6	-7.0	1.0	-9.3	-7.8
2021 - 2022	7.3	-6.5	1.2	-3.9	-2.0
2022 - 2023	7.2	-6.6	1.2	-7.9	-6.0
2013 - 2023[1]	89.2	-156.4	24.0	-332.8	-376.0

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

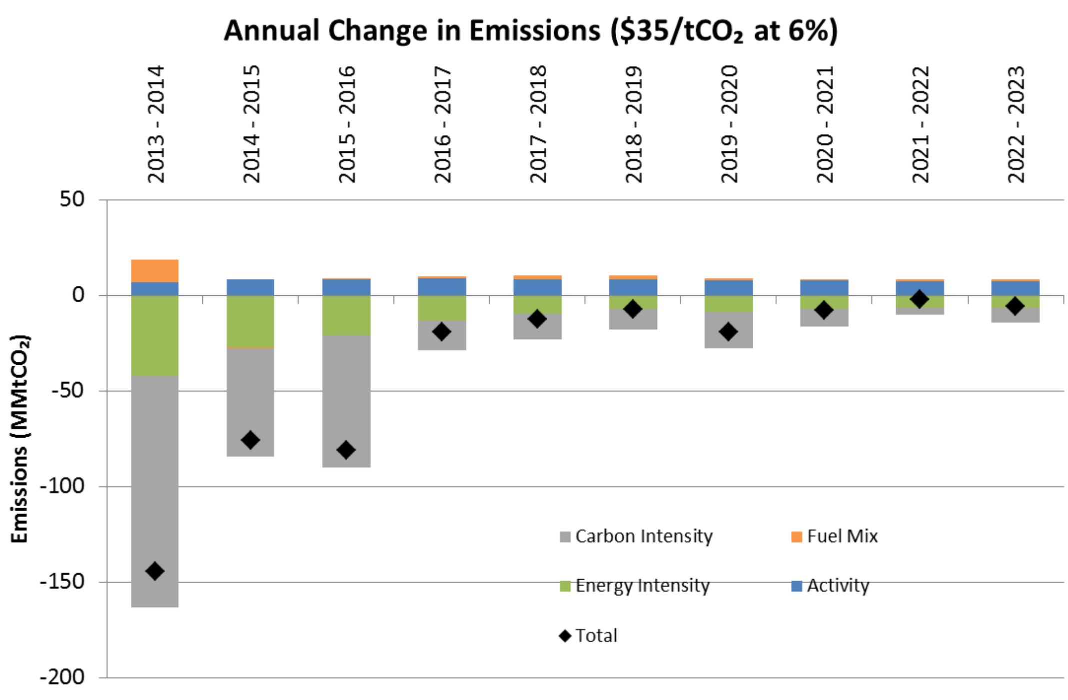

Figure B.39 Annual effects on emissions from $35/tCO$_2$ at 6% scenario

Table B.46 Annual effects on emissions from \$35/tCO$_2$ at 8% scenario

Effects on carbon emissions from \$35/tCO$_2$ at 8% scenario (MMtCO$_2$)

	Activity	Energy Intensity	Fuel Mix	Carbon Intensity	Total
2013 - 2014	6.6	-41.9	12.1	-126.5	-149.8
2014 - 2015	8.1	-27.0	-0.6	-63.2	-82.7
2015 - 2016	8.2	-21.9	0.1	-107.3	-120.9
2016 - 2017	8.0	-13.9	0.7	-29.4	-34.5
2017 - 2018	7.8	-9.8	1.2	-13.6	-14.4
2018 - 2019	7.6	-6.9	1.1	-14.6	-12.7
2019 - 2020	7.3	-7.9	0.2	-12.8	-13.3
2020 - 2021	6.8	-8.1	-0.1	-12.7	-14.1
2021 - 2022	6.4	-7.0	0.2	-9.6	-10.0
2022 - 2023	6.3	-6.5	0.4	-7.3	-7.1
2013 - 2023[1]	83.5	-156.5	16.9	-403.4	-459.4

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

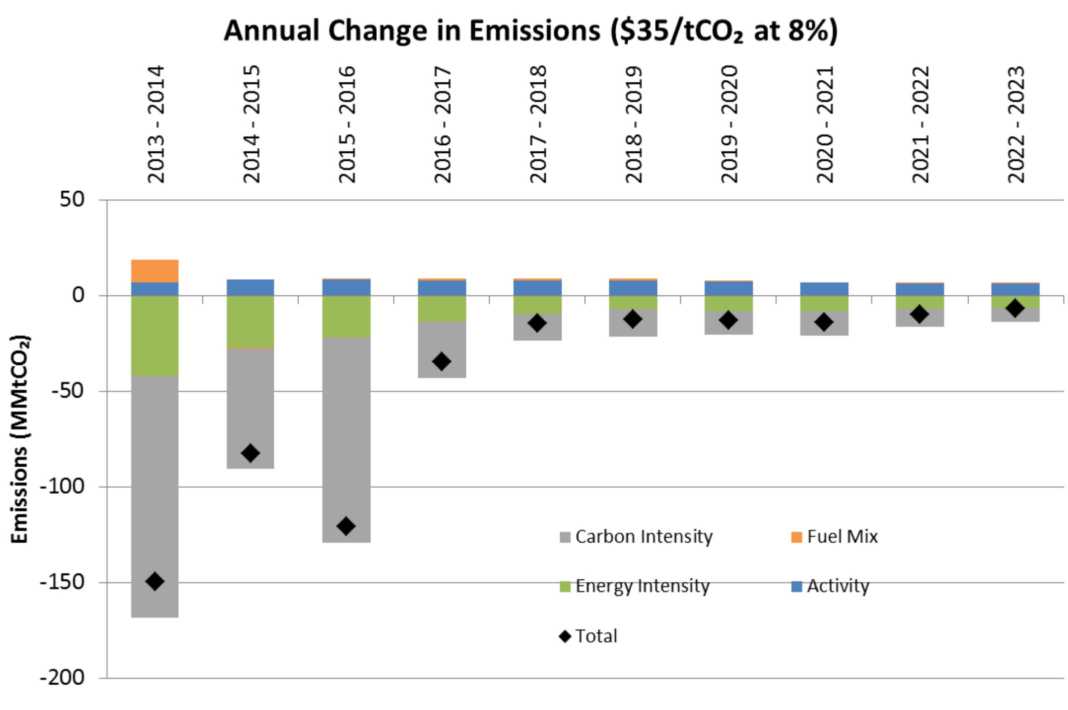

Figure B.40 Annual effects on emissions from \$35/tCO$_2$ at 8% scenario

B.8 Commercial sector mode-specific energy intensity

This section includes further detail about energy intensity between building types in the commercial buildings demand sector.

Figure B.41 shows the Reference scenario energy intensity profiles for all modes in the sector. Several of these modes are specifically identified on the chart including those with the largest energy intensity (food service, healthcare, and food sales) and smallest energy intensity (Warehouse and assembly). None of these is surprising. Food Service and Food Sales consume intense energy all day and night with ovens, stoves, lighting, and refrigeration. Similarly, Healthcare facilities generally operate all day and night, every day of the week, which requires substantial health and life support systems and specific climate and humidity controls.

Warehouses, on the other hand, are the least energy intense since they are generally large, open structures with little supporting equipment and climate controls. The Assembly mode includes conference centers which may draw ample energy through the day, but are balanced with less frequently used assembly buildings such as churches. The remaining modes are bunched together near the average in the 75-100 MBTU/sqft range. The Building average dashed line is the average energy intensity for energy that can be attributed to specific building types, while the Sector average dash-dot line is the average for the entire sector including the ancillary services (so this matches the sector average red line in Figure 3.43).

All building types are expected to decrease energy intensity over the next decade in the Reference scenario. Figure B.42 highlights this general decline across the sector. Apart from the hiccup in 2012, nearly all modes will experience at least a 4% decrease from 2013 to 2023. The exception is Large Offices, which will only see a net reduction of 0.6% in energy intensity. Mercantile/Service mode represents more than 20% of the sector floorspace and expects to see 4.1% reduction. Warehouses expect to conserve the most in the reference case and will reduce energy intensity by 8.1% followed closely by Small Offices at 7.0% reduction.

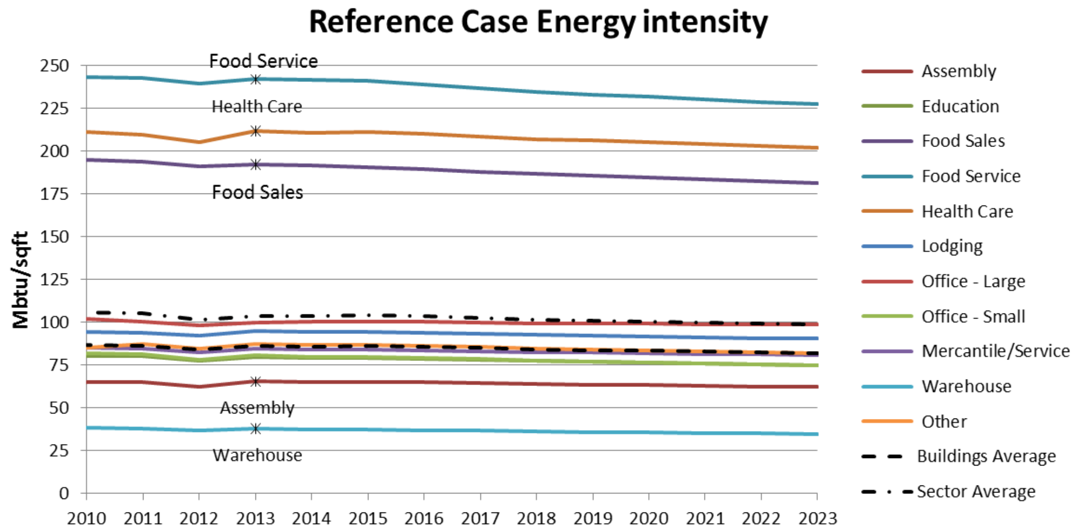

Figure B.41 Reference case energy intesnty of Commercial sector modes

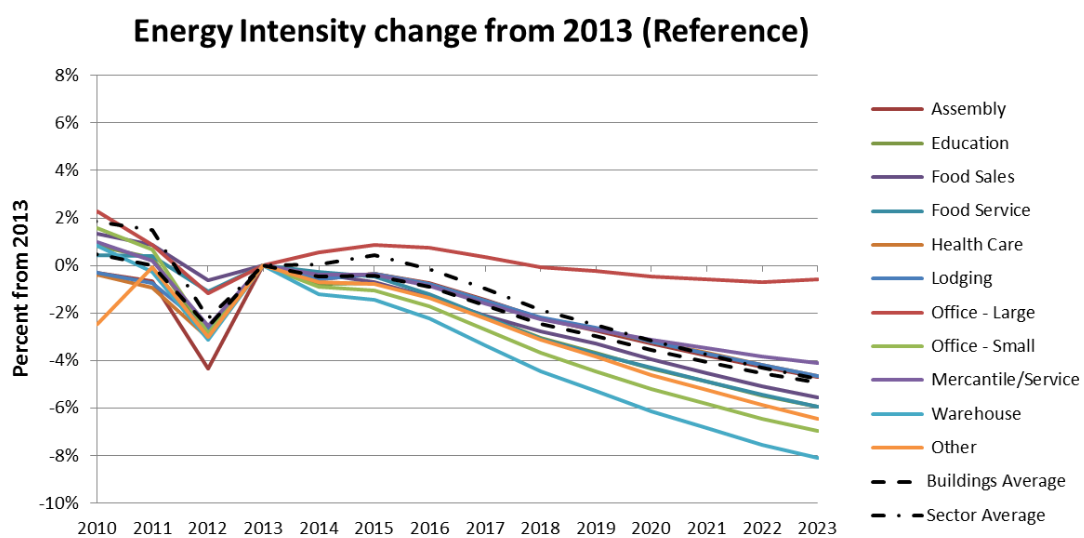

Figure B.42 Reference case energy intesnty of Commercial sector modes

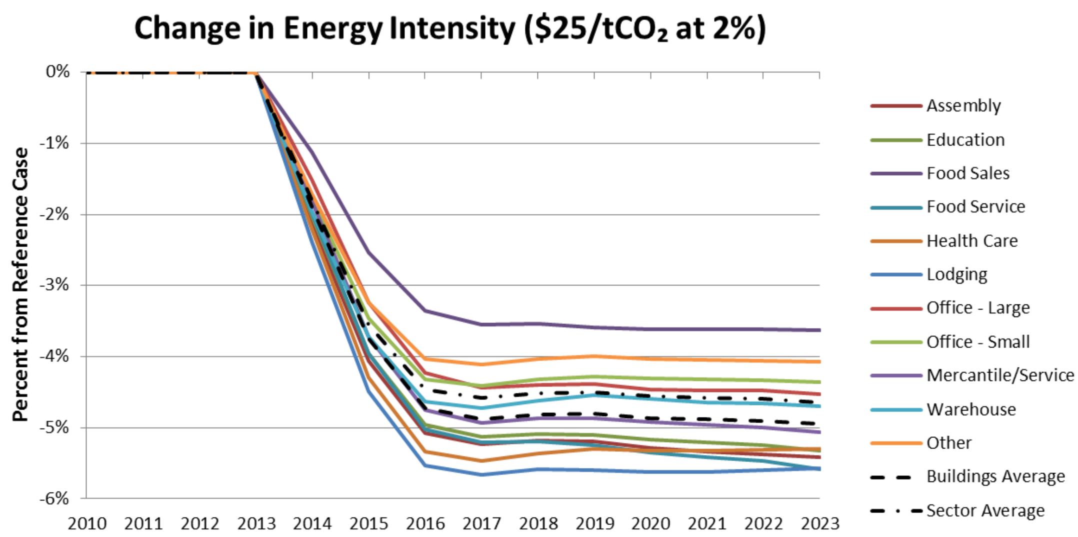

Figure B.43 Energy intesnity reducitos from sample scenario

Figure B.43 shows that the policy scenario (the $25/tCO$_2$ at 2%) will further reduce the 2023 savings by an additional 3.6% to 5.6%. Food Sales will see the least additional savings at 3.6%, and Lodging is on the high end at 5.6% reduction in energy intensity. These are in addition to the reference case scenario expected reductions. Nearly all building types experience rapid savings in the first few years of the policy, such that by 2016 nearly all economic improvements are undertaken. This response pattern occurs in all policy scenarios.

The response is due in part to how the Commercial module estimates consumer behavior. The model structure is a constrained lifecycle cost minimization using risk-adjusted time preference premium (discount rates). The least-cost approach employed here drives consumers with high discount rates (most have 50% to 1000% discount rates!) to make financial decisions based on upfront capital cost and less on long-term operating costs. Any additional reduction in energy intensity by 2016 is strictly from the adoption of energy efficient technologies by the small fraction of decision makers driven more by long-term costs (Wilkerson et al., 2013). Since the model is relatively stiff to efficiency improvements, if one believes the incentives are stronger in reality, then more efficiency savings could be expected.

B.9 Extracting Commercial sector building-type emissions data

The standard NEMS output includes a forecast for floor area and energy per building type, but it does not include emissions by building type. However, the NEMS sector framework is an appliance stock and building shell model, so this data is certainly calculated during the run enabling NEMS to aggregate total sector emissions. To retrieve this data, EIA provided an MS Excel workbook, ***DB_commercial.xlsm*** which allows one to import a restart file from a completed NEMS run to extract the emissions data.[53] For this study, this tool is used to extract energy by fuel and building type. Emissions factors can then be applied to compute emissions by building type.

The ***DB_commercial.xlsm*** workbook is effectively one big macro. To begin, the workbook must be moved to the directory containing the output files of the NEMS scenario to be evaluated. When initiated, the macro looks for appropriate files in the run directory then populates several diagnostic and summary pivot tables and charts. After a NEMS scenario has properly converged, the code will automatically remove temporary and otherwise unnecessary files from the directory and compress the remaining files to save disk space. So, to run the macro, one needs to manually un-compress the two files ***kdbout.txt*** and ***ksdout.txt***. These, combined with the restart file for the scenario are the only files the workbook needs. Once initialed, the macro takes several seconds to produce the organized output.

One can now modify the pivot table on the *EndUseEnergyPivot* tab to obtain the necessary cross section of energy consumption. The original structure isolated building type per Census Divisions. For this study, only the total U.S. energy consumption by fuel type is desired. The pivot table provides energy end-use by fuel for each building type. This includes primarily electricity, natural gas, and petroleum products.

[53] Thanks to Kevin Jarzomski and Erin Boedecker at EIA for providing this tool and explaining its contents and how to use it.

B.10 COMMERCIAL SECTOR DECOMPOSITION

Activity in the Commercial sector is represented by total floor area in square feet (sqft), and structure is the fraction share of total area for each of the 11 building types in NEMS. Energy Intensity is the energy demand per sqft. Fuel mix represents the fraction of the energy supplied by each fuel type, and carbon intensity is the amount of carbon in each of those fuels. Ten-year results are reported in Table B.47 and Figure B.44, followed by the annual results for each scenario.

Table B.47 Ten-year effects on carbon emissions from all scenarios

	Total effects on carbon emissions (2013 - 2023)					
	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
Total effect ($MMtCO_2$)						
Reference	134.6	6.7	-68.2	21.4	-145.4	-50.9
$15/t$CO_2$ at 2%	129.8	6.4	-101.3	20.9	-193.2	-137.5
$15/t$CO_2$ at 4%	128.6	6.3	-105.1	20.3	-207.3	-157.3
$15/t$CO_2$ at 6%	127.0	6.2	-110.5	20.2	-228.0	-185.0
$15/t$CO_2$ at 8%	124.9	6.1	-115.5	19.3	-254.7	-219.8
$25/t$CO_2$ at 2%	125.1	6.1	-122.2	19.5	-246.6	-218.1
$25/t$CO_2$ at 4%	122.6	5.9	-127.3	19.7	-282.8	-261.9
$25/t$CO_2$ at 6%	120.1	5.8	-135.0	19.0	-312.6	-302.7
$25/t$CO_2$ at 8%	117.2	5.7	-141.2	18.5	-349.8	-349.7
$35/t$CO_2$ at 2%	120.5	5.8	-138.5	19.7	-303.5	-296.0
$35/t$CO_2$ at 4%	116.8	5.6	-144.7	18.0	-350.8	-355.0
$35/t$CO_2$ at 6%	111.7	5.4	-147.2	16.5	-422.2	-435.8
$35/t$CO_2$ at 8%	104.5	5.0	-152.6	8.9	-506.9	-541.1
Percent from Reference						
Reference	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
$15/t$CO_2$ at 2%	-3.6%	-4.6%	48.6%	-2.2%	32.9%	170.0%
$15/t$CO_2$ at 4%	-4.4%	-5.5%	54.2%	-5.2%	42.6%	208.8%
$15/t$CO_2$ at 6%	-5.6%	-6.9%	62.1%	-5.4%	56.8%	263.3%
$15/t$CO_2$ at 8%	-7.2%	-8.6%	69.4%	-9.6%	75.2%	331.6%
$25/t$CO_2$ at 2%	-7.1%	-8.7%	79.3%	-8.6%	69.6%	328.2%
$25/t$CO_2$ at 4%	-8.9%	-10.7%	86.7%	-7.7%	94.5%	414.2%
$25/t$CO_2$ at 6%	-10.8%	-12.9%	98.1%	-11.2%	115.0%	494.4%
$25/t$CO_2$ at 8%	-13.0%	-15.2%	107.1%	-13.7%	140.5%	586.6%
$35/t$CO_2$ at 2%	-10.4%	-12.6%	103.1%	-8.1%	108.8%	481.2%
$35/t$CO_2$ at 4%	-13.2%	-15.6%	112.3%	-15.7%	141.2%	597.0%
$35/t$CO_2$ at 6%	-17.0%	-19.5%	115.9%	-23.0%	190.3%	755.7%
$35/t$CO_2$ at 8%	-22.4%	-25.4%	123.8%	-58.4%	248.6%	962.5%

Figure B.44 Ten-year effects on carbon emissions from all scenarios

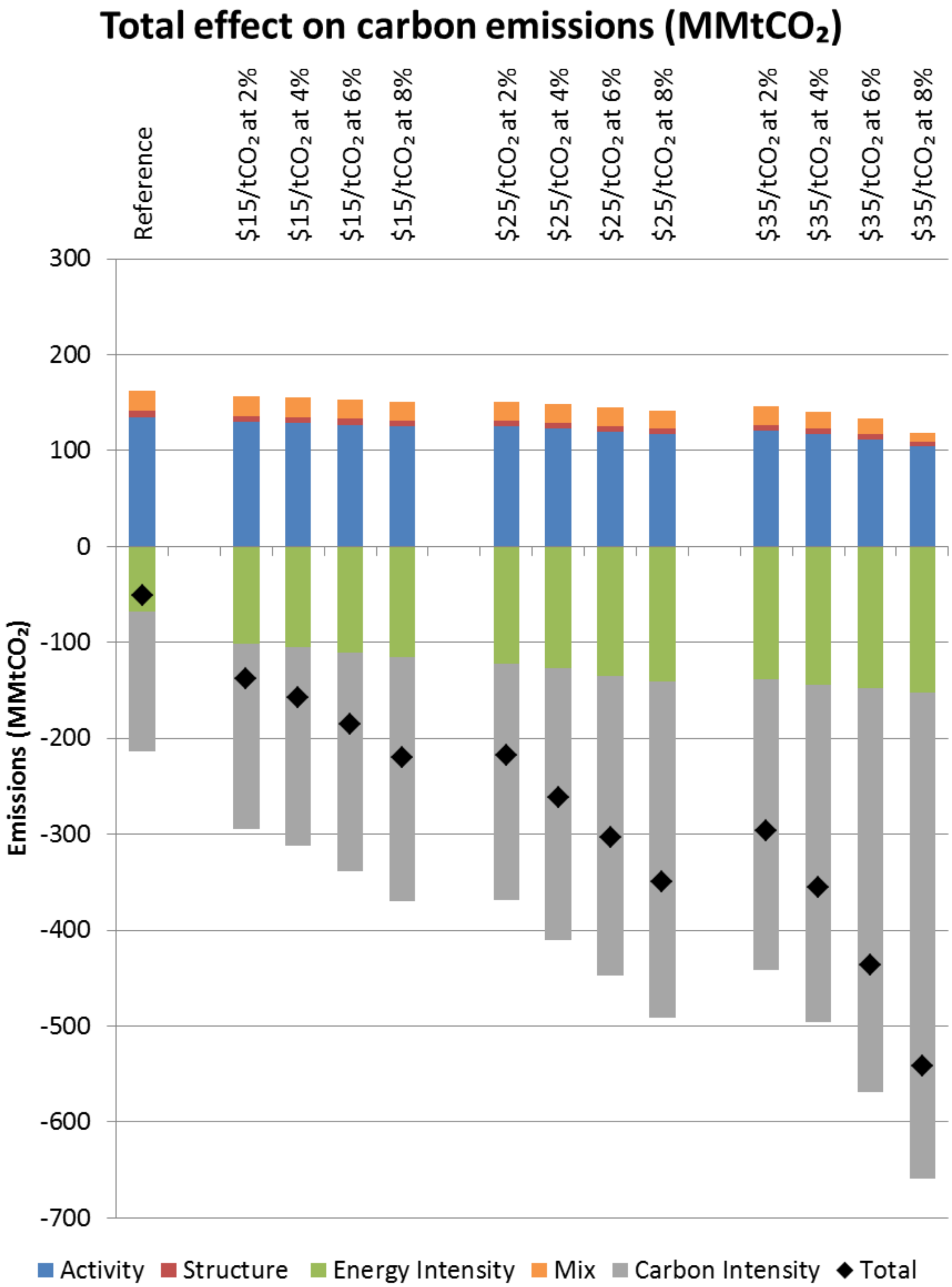

Table B.48 Annual effects on emissions from Reference scenario

	Effects on carbon emissions from Reference scenario ($MMtCO_2$)					
	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.9	0.3	-6.5	9.3	-15.5	-3.5
2014 - 2015	10.6	0.5	-0.1	-1.0	-34.7	-24.7
2015 - 2016	12.2	0.9	-6.7	0.7	-47.6	-40.6
2016 - 2017	13.9	1.0	-10.0	1.7	-6.3	0.3
2017 - 2018	14.9	0.9	-10.0	2.3	-4.2	3.9
2018 - 2019	15.4	0.7	-7.0	2.1	-4.3	6.9
2019 - 2020	14.8	0.7	-7.8	1.5	-5.9	3.4
2020 - 2021	14.4	0.6	-6.6	1.2	-13.3	-3.7
2021 - 2022	13.8	0.5	-6.6	1.3	-3.1	6.0
2022 - 2023	13.1	0.5	-5.4	1.8	-8.8	1.1
2013 - 2023[1]	134.6	6.7	-68.2	21.4	-145.4	-50.9

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

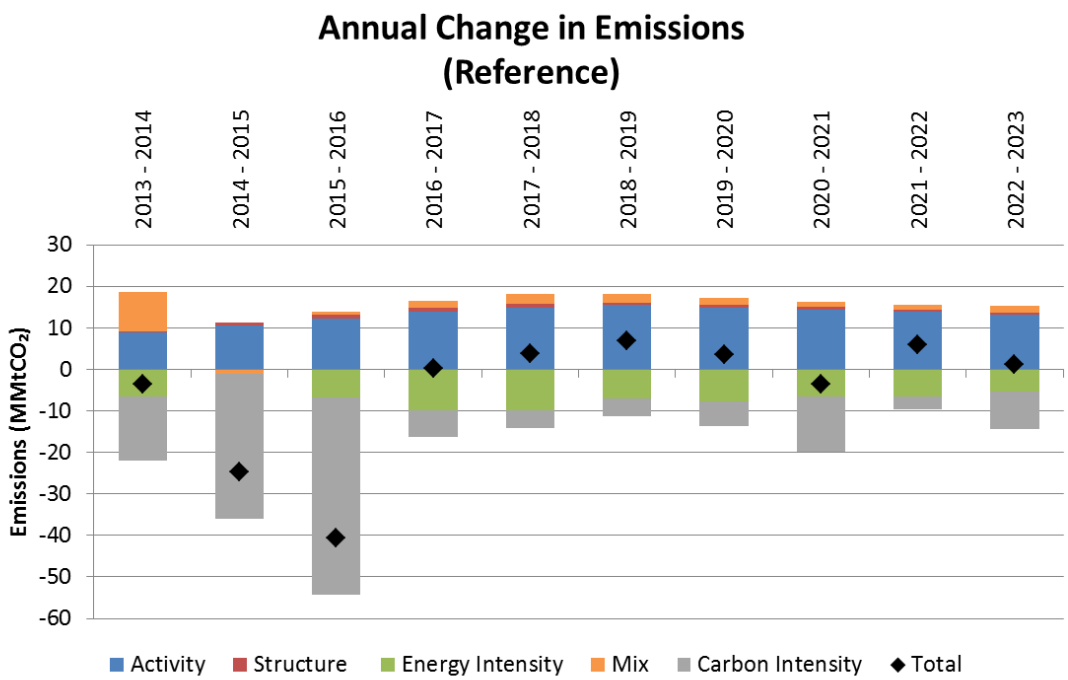

Figure B.45 Annual effects on emissions from Reference scenario

Table B.49 Annual effects on emissions from \$15/tCO_2 at 2% scenario

Effects on carbon emissions from \$15/tCO_2 at 2% scenario (MtCO_2)

	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.6	0.3	-20.9	12.5	-69.3	-68.8
2014 - 2015	10.0	0.4	-14.0	-0.1	-32.2	-35.8
2015 - 2016	11.3	0.8	-12.5	0.1	-28.3	-28.6
2016 - 2017	12.9	0.9	-9.9	0.6	-7.8	-3.4
2017 - 2018	13.9	0.8	-8.7	1.5	-4.2	3.4
2018 - 2019	14.6	0.7	-6.5	1.4	-4.6	5.7
2019 - 2020	14.1	0.7	-7.6	1.2	-14.3	-5.8
2020 - 2021	13.6	0.6	-6.4	1.1	-13.6	-4.8
2021 - 2022	12.9	0.4	-6.3	1.1	-7.5	0.6
2022 - 2023	12.2	0.4	-5.7	1.1	-8.2	-0.1
2013 - 2023[1]	129.8	6.4	-101.3	20.9	-193.2	-137.5

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

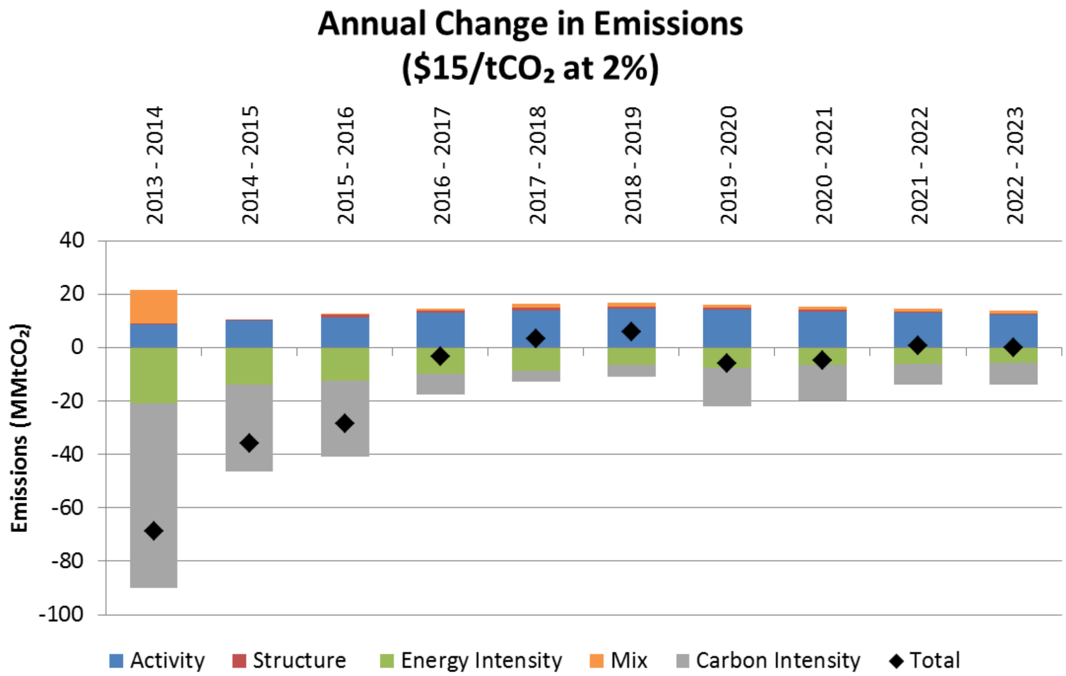

Figure B.46 Annual effects on emissions from \$15/tCO_2 at 2% scenario

Table B.50 Annual effects on emissions from $15/tCO$_2$ at 4% scenario

Effects on carbon emissions from $15/tCO$_2$ at 4% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.7	0.3	-20.7	12.4	-66.7	-66.0
2014 - 2015	10.1	0.4	-14.3	-0.1	-35.5	-39.4
2015 - 2016	11.3	0.8	-13.3	0.1	-31.1	-32.2
2016 - 2017	12.8	0.9	-10.6	0.6	-8.0	-4.3
2017 - 2018	13.8	0.8	-9.4	1.5	-7.2	-0.4
2018 - 2019	14.5	0.6	-7.0	1.3	-4.4	5.0
2019 - 2020	14.0	0.7	-8.2	1.1	-15.0	-7.4
2020 - 2021	13.4	0.6	-6.5	1.0	-16.8	-8.4
2021 - 2022	12.7	0.4	-6.5	1.0	-11.3	-3.7
2022 - 2023	12.0	0.4	-5.8	1.1	-8.2	-0.5
2013 - 2023[1]	128.6	6.3	-105.1	20.3	-207.3	-157.3

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

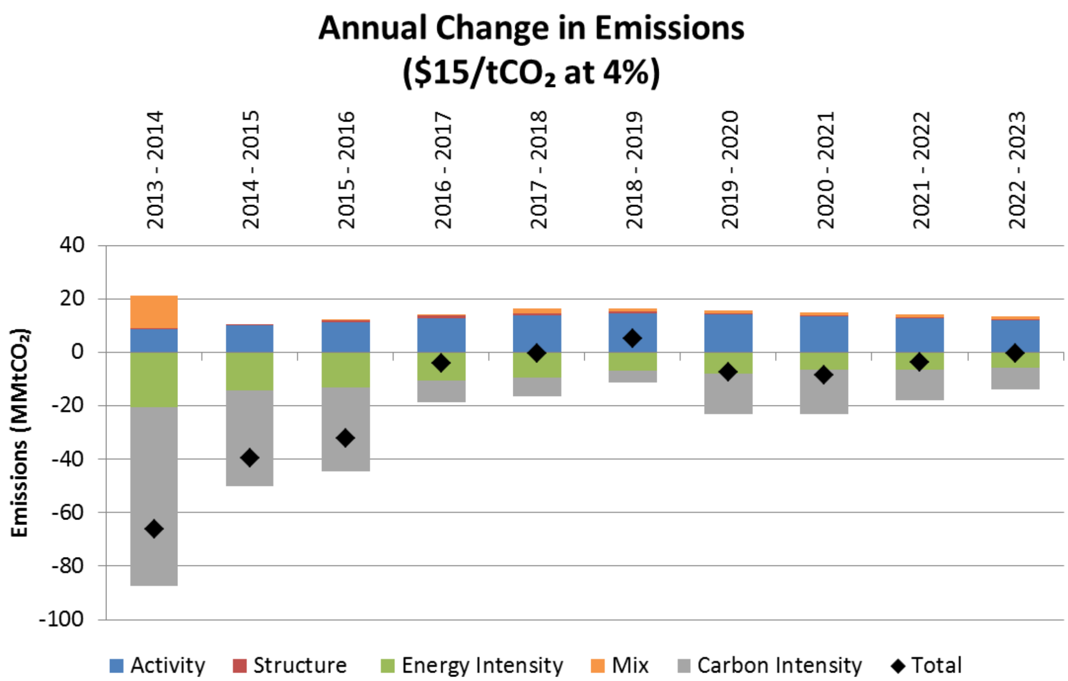

Figure B.47 Annual effects on emissions from $15/tCO$_2$ at 4% scenario

Table B.51 Annual effects on emissions from \$15/tCO_2 at 6% scenario

	Effects on carbon emissions from \$15/tCO_2 at 6% scenario ($MMtCO_2$)					
	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.6	0.3	-20.9	12.4	-69.9	-69.5
2014 - 2015	10.0	0.4	-14.6	0.0	-35.5	-39.7
2015 - 2016	11.2	0.8	-14.1	0.3	-35.6	-37.3
2016 - 2017	12.7	0.9	-11.1	0.6	-4.5	-1.3
2017 - 2018	13.7	0.8	-9.9	1.5	-10.0	-3.9
2018 - 2019	14.4	0.6	-7.4	1.3	-5.4	3.5
2019 - 2020	13.8	0.7	-8.9	1.3	-17.2	-10.3
2020 - 2021	13.2	0.5	-7.5	1.0	-19.1	-11.8
2021 - 2022	12.5	0.4	-7.3	1.0	-17.0	-10.5
2022 - 2023	11.7	0.4	-6.2	0.9	-11.0	-4.2
2013 - 2023[1]	127.0	6.2	-110.5	20.2	-228.0	-185.0

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

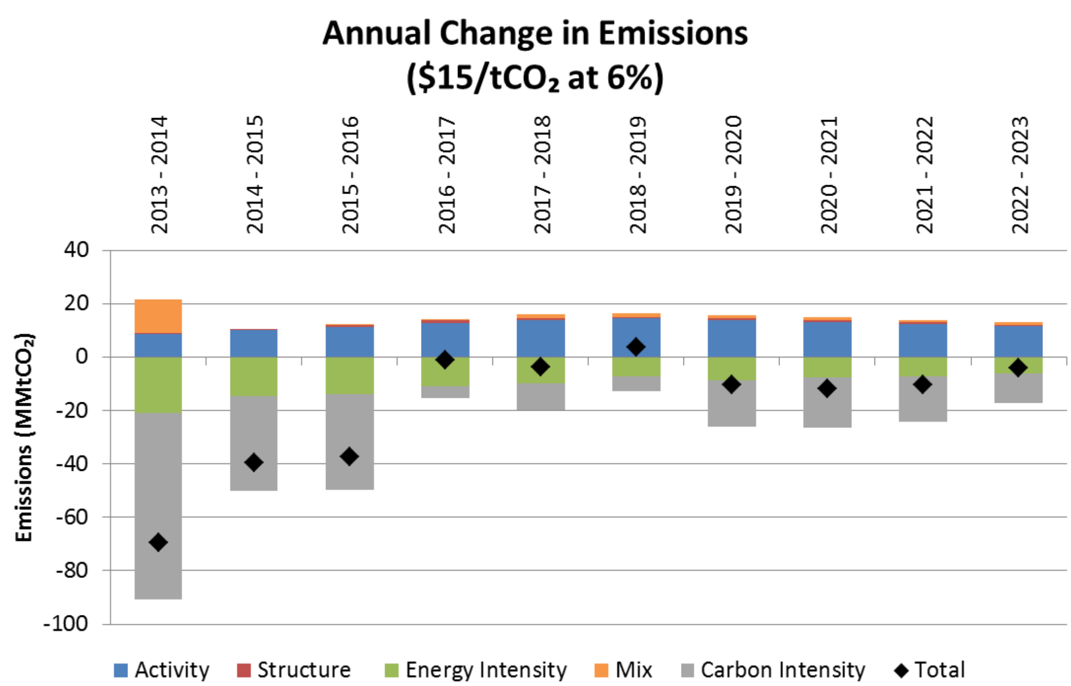

Figure B.48 Annual effects on emissions from \$15/tCO_2 at 6% scenario

Table B.52 Annual effects on emissions from $15/tCO$_2$ at 8% scenario

Effects on carbon emissions from $15/tCO$_2$ at 8% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.6	0.3	-20.7	12.3	-70.4	-69.9
2014 - 2015	10.0	0.4	-14.8	0.0	-41.6	-46.1
2015 - 2016	11.2	0.8	-14.8	0.3	-38.4	-41.0
2016 - 2017	12.6	0.9	-12.2	0.7	-10.6	-8.6
2017 - 2018	13.5	0.8	-10.8	1.5	-9.3	-4.3
2018 - 2019	14.1	0.6	-8.2	1.2	-6.6	1.1
2019 - 2020	13.5	0.7	-9.5	1.0	-17.9	-12.2
2020 - 2021	12.9	0.5	-7.7	0.9	-28.3	-21.8
2021 - 2022	12.1	0.4	-7.7	1.0	-11.7	-5.8
2022 - 2023	11.4	0.4	-6.6	1.0	-17.3	-11.2
2013 - 2023[1]	124.9	6.1	-115.5	19.3	-254.7	-219.8

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

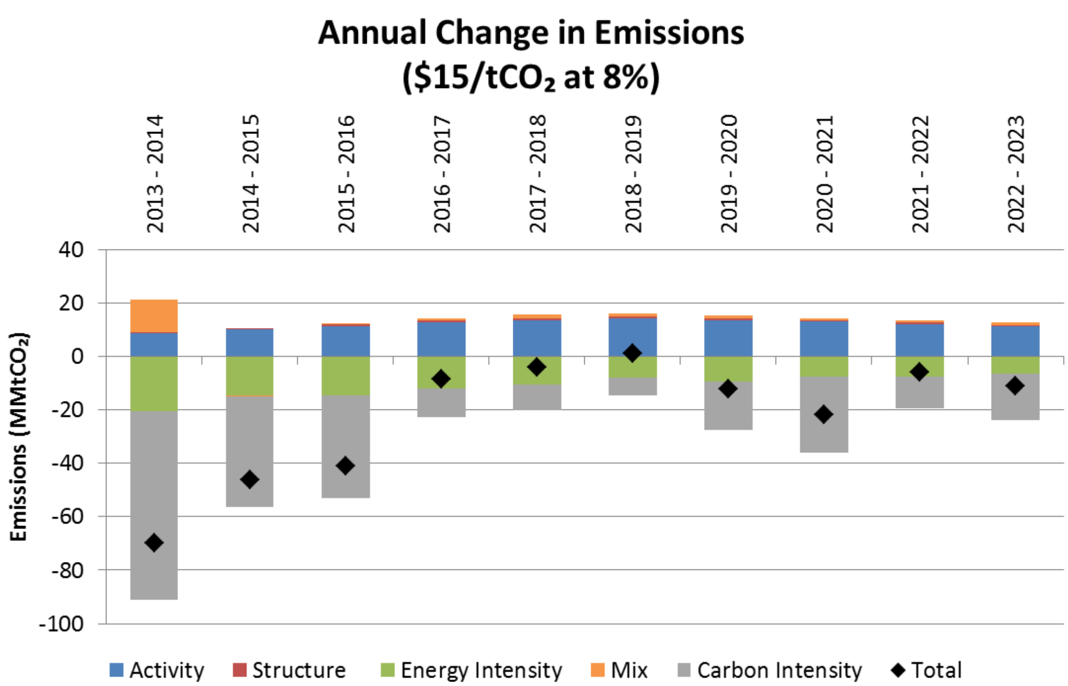

Figure B.49 Annual effects on emissions from $15/tCO$_2$ at 8% scenario

Table B.53 Annual effects on emissions from \$25/tCO_2 at 2% scenario

Effects on carbon emissions from \$25/tCO_2 at 2% scenario (MtCO_2)

	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.5	0.3	-29.5	14.2	-100.8	-107.3
2014 - 2015	9.7	0.4	-21.8	0.2	-35.6	-47.0
2015 - 2016	10.8	0.8	-17.3	-0.1	-27.3	-33.1
2016 - 2017	12.1	0.9	-10.7	0.2	-5.4	-3.0
2017 - 2018	13.2	0.8	-8.3	1.1	-3.1	3.7
2018 - 2019	13.9	0.6	-6.2	1.0	-7.3	2.0
2019 - 2020	13.5	0.7	-7.6	0.8	-15.2	-7.9
2020 - 2021	12.8	0.5	-6.1	0.7	-26.0	-18.0
2021 - 2022	12.1	0.4	-5.9	0.7	-9.0	-1.7
2022 - 2023	11.4	0.4	-5.2	0.8	-13.3	-5.9
2013 - 2023[1]	125.1	6.1	-122.2	19.5	-246.6	-218.1

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

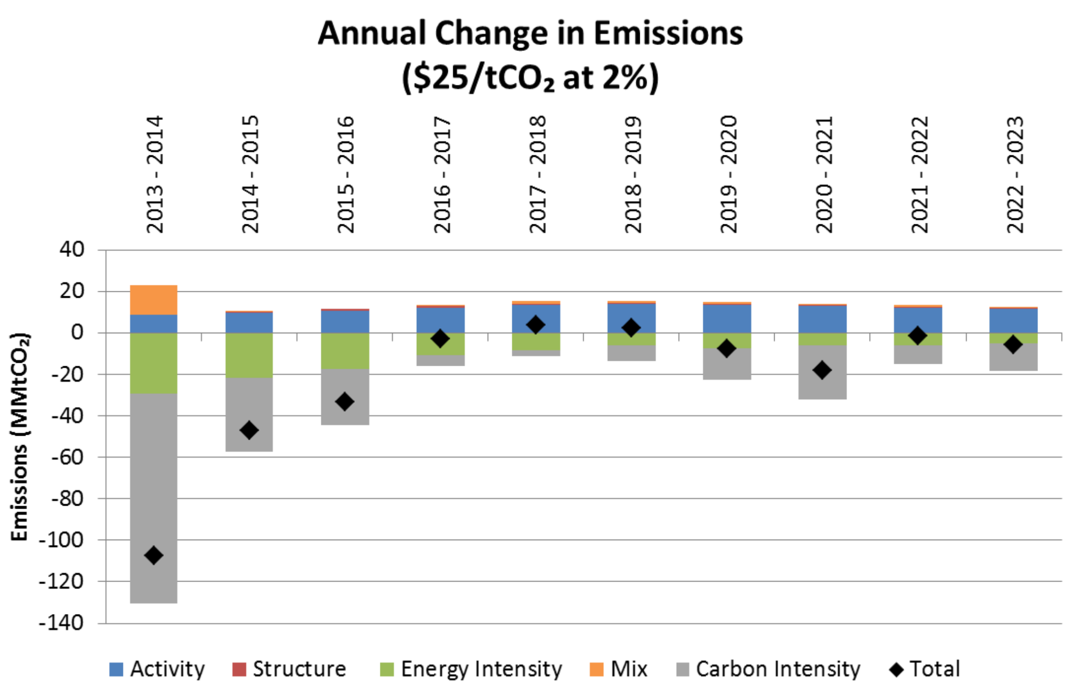

Figure B.50 Annual effects on emissions from \$25/tCO_2 at 2% scenario

Table B.54 Annual effects on emissions from \$25/tCO_2 at 4% scenario

Effects on carbon emissions from \$25/tCO_2 at 4% scenario (MMtCO_2)

	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.5	0.3	-29.5	14.1	-106.0	-112.6
2014 - 2015	9.6	0.4	-22.0	0.4	-46.4	-58.0
2015 - 2016	10.6	0.7	-17.9	0.3	-37.5	-43.8
2016 - 2017	11.8	0.8	-11.3	0.4	-3.9	-2.2
2017 - 2018	12.9	0.8	-9.0	1.1	-5.6	0.1
2018 - 2019	13.5	0.6	-7.0	1.0	-11.7	-3.6
2019 - 2020	13.0	0.6	-7.9	0.6	-13.1	-6.7
2020 - 2021	12.4	0.5	-6.3	0.6	-28.9	-21.7
2021 - 2022	11.6	0.4	-6.6	0.8	-15.2	-9.0
2022 - 2023	10.9	0.4	-5.8	0.8	-10.6	-4.3
2013 - 2023[1]	122.6	5.9	-127.3	19.7	-282.8	-261.9

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

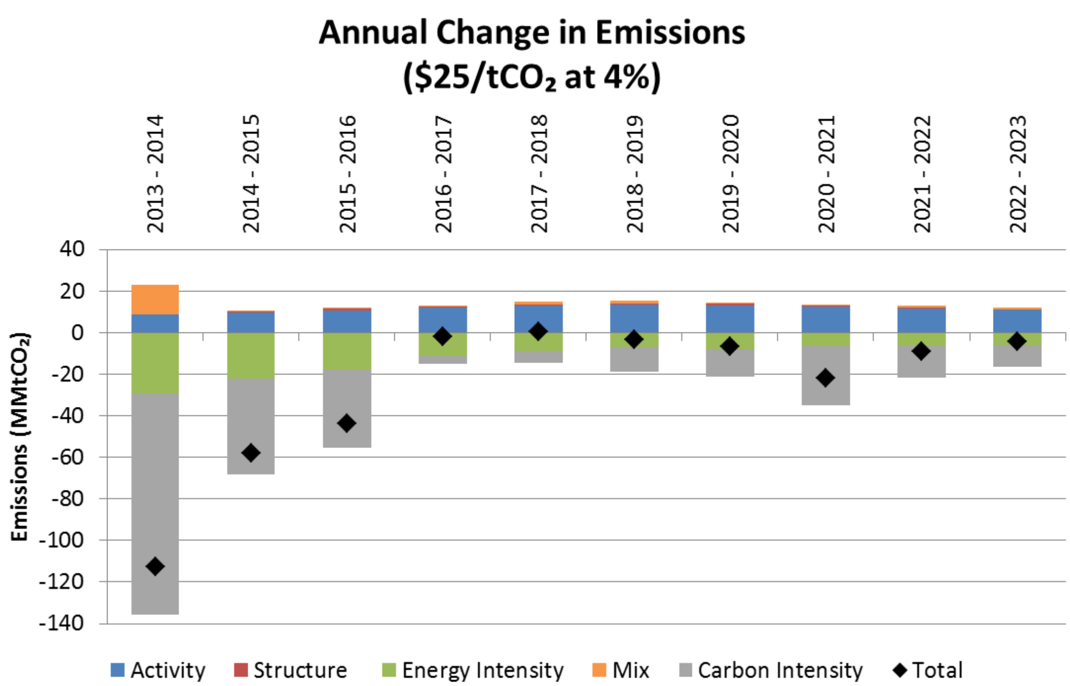

Figure B.51 Annual effects on emissions from \$25/tCO_2 at 4% scenario

Table B.55 Annual effects on emissions from \$25/tCO$_2$ at 6% scenario

Effects on carbon emissions from \$25/tCO$_2$ at 6% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.5	0.3	-29.4	14.1	-106.6	-113.2
2014 - 2015	9.6	0.4	-22.2	0.4	-45.3	-57.1
2015 - 2016	10.5	0.7	-19.4	0.5	-50.0	-57.7
2016 - 2017	11.7	0.8	-13.1	0.5	-7.9	-8.0
2017 - 2018	12.6	0.8	-10.6	1.1	-8.9	-5.1
2018 - 2019	13.2	0.6	-7.8	0.8	-12.5	-5.8
2019 - 2020	12.6	0.6	-9.0	0.7	-18.8	-13.9
2020 - 2021	12.0	0.5	-7.2	0.6	-32.9	-27.1
2021 - 2022	11.2	0.4	-6.8	0.6	-11.2	-5.8
2022 - 2023	10.5	0.3	-5.9	0.6	-14.5	-9.0
2013 - 2023[1]	120.1	5.8	-135.0	19.0	-312.6	-302.7

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

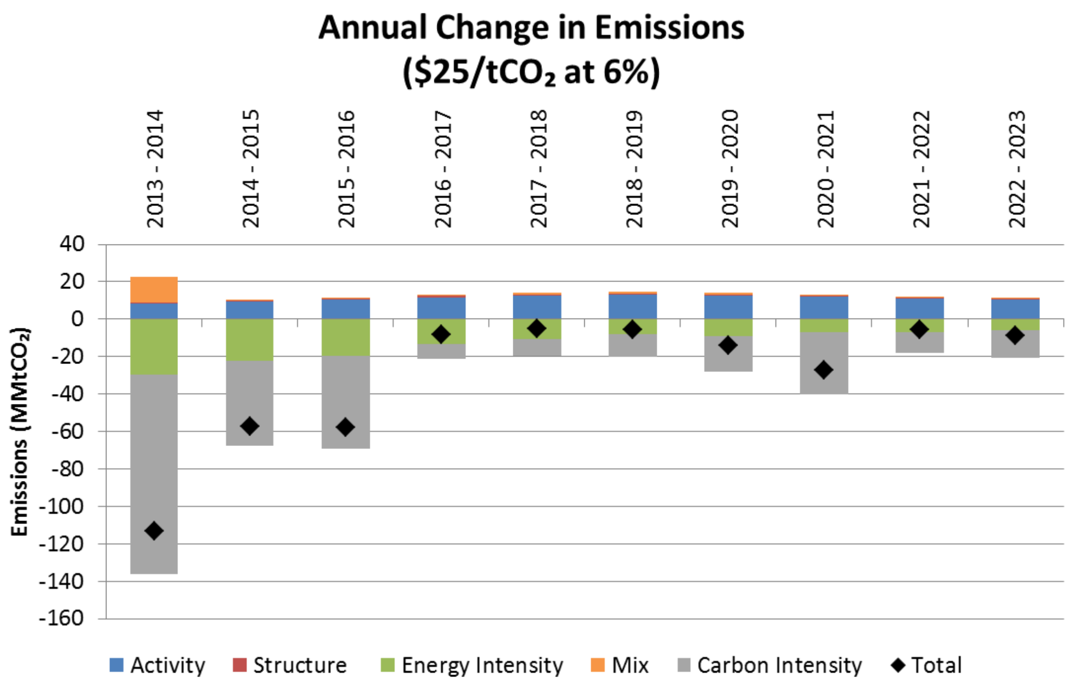

Figure B.52 Annual effects on emissions from \$25/tCO$_2$ at 6% scenario

Table B.56 Annual effects on emissions from \$25/tCO_2 at 8% scenario

Effects on carbon emissions from \$25/tCO_2 at 8% scenario ($MMtCO_2$)	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.5	0.3	-29.5	14.1	-109.4	-116.0
2014 - 2015	9.5	0.4	-22.8	0.6	-51.3	-63.5
2015 - 2016	10.3	0.7	-21.1	0.8	-62.7	-71.9
2016 - 2017	11.4	0.8	-15.1	0.7	-13.5	-15.7
2017 - 2018	12.2	0.7	-11.8	1.1	-13.4	-11.2
2018 - 2019	12.6	0.5	-8.1	0.8	-19.8	-13.9
2019 - 2020	12.0	0.6	-8.8	0.6	-24.6	-20.2
2020 - 2021	11.4	0.5	-6.9	0.4	-29.5	-24.2
2021 - 2022	10.7	0.3	-7.2	0.4	-5.5	-1.3
2022 - 2023	10.0	0.3	-6.3	0.3	-16.2	-11.8
2013 - 2023[1]	117.2	5.7	-141.2	18.5	-349.8	-349.7

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

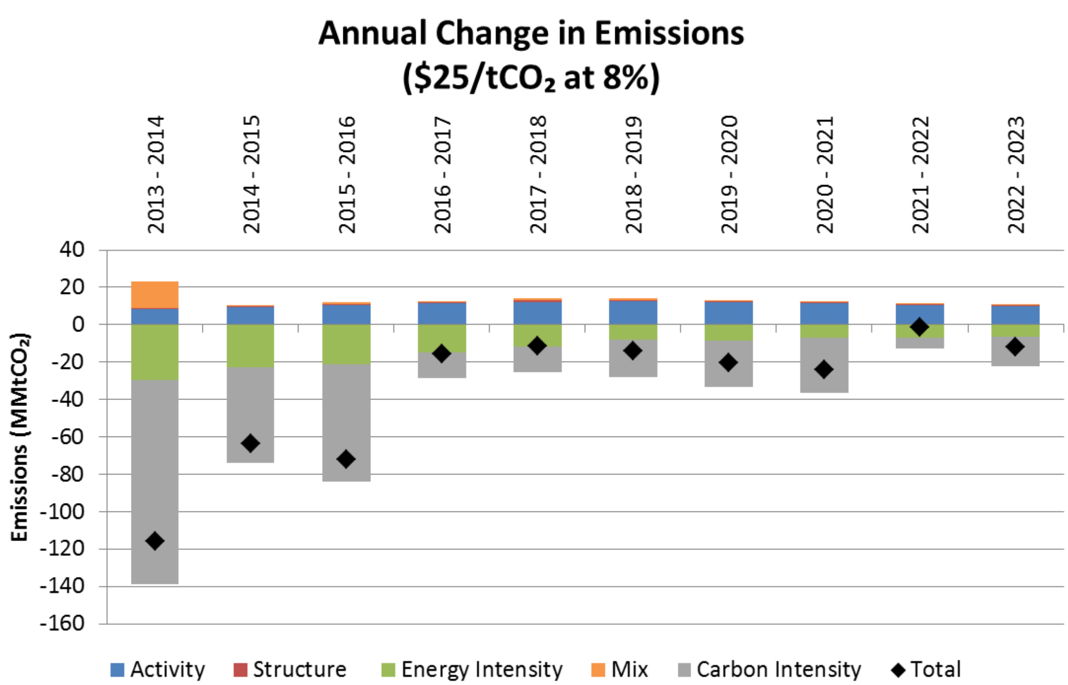

Figure B.53 Annual effects on emissions from \$25/tCO_2 at 8% scenario

Table B.57 Annual effects on emissions from \$35/tCO$_2$ at 2% scenario

Effects on carbon emissions from \$35/tCO$_2$ at 2% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.4	0.3	-37.2	15.6	-134.7	-147.7
2014 - 2015	9.2	0.4	-28.4	0.7	-56.2	-74.2
2015 - 2016	10.0	0.7	-19.7	0.1	-28.6	-37.5
2016 - 2017	11.2	0.8	-10.8	0.1	-1.5	-0.2
2017 - 2018	12.3	0.7	-7.9	0.9	-6.7	-0.7
2018 - 2019	13.0	0.6	-5.5	0.6	-8.5	0.3
2019 - 2020	12.6	0.6	-7.1	0.5	-13.6	-6.9
2020 - 2021	12.0	0.5	-6.0	0.5	-30.8	-23.8
2021 - 2022	11.3	0.4	-5.9	0.5	-7.4	-1.1
2022 - 2023	10.6	0.3	-4.8	0.5	-10.8	-4.2
2013 - 2023[1]	120.5	5.8	-138.5	19.7	-303.5	-296.0

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

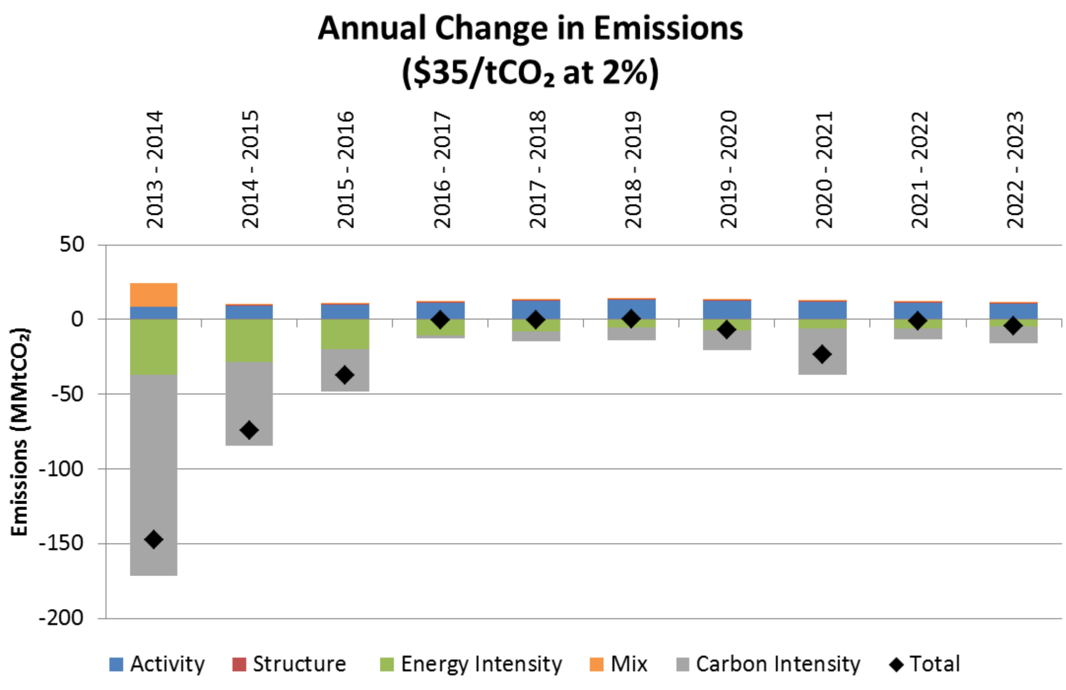

Figure B.54 Annual effects on emissions from \$35/tCO$_2$ at 2% scenario

Table B.58 Annual effects on emissions from \$35/tCO_2 at 4% scenario

Effects on carbon emissions from \$35/tCO_2 at 4% scenario (MMtCO_2)

	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.4	0.3	-37.2	15.6	-134.1	-147.0
2014 - 2015	9.2	0.4	-28.8	0.7	-57.1	-75.5
2015 - 2016	9.9	0.7	-21.5	0.2	-47.4	-58.1
2016 - 2017	11.0	0.8	-12.8	0.2	-9.3	-10.2
2017 - 2018	11.8	0.7	-9.6	0.9	-11.9	-8.1
2018 - 2019	12.4	0.5	-6.3	0.5	-15.2	-8.0
2019 - 2020	11.9	0.6	-7.4	0.4	-27.3	-21.9
2020 - 2021	11.3	0.4	-5.9	0.3	-26.0	-19.9
2021 - 2022	10.6	0.3	-5.9	0.3	-4.9	0.4
2022 - 2023	10.0	0.3	-4.9	0.3	-12.4	-6.7
2013 - 2023[1]	116.8	5.6	-144.7	18.0	-350.8	-355.0

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

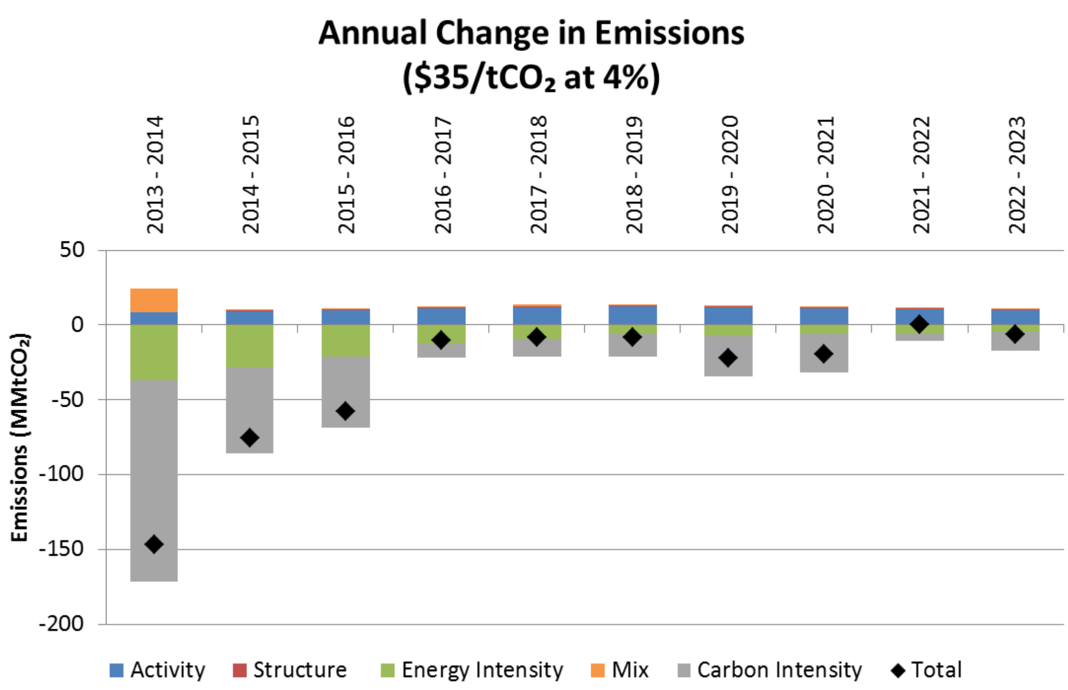

Figure B.55 Annual effects on emissions from \$35/tCO_2 at 4% scenario

Table B.59 Annual effects on emissions from \$35/tCO_2 at 6% scenario

Effects on carbon emissions from \$35/tCO_2 at 6% scenario ($MMtCO_2$)

	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.4	0.3	-37.2	15.5	-137.2	-150.2
2014 - 2015	9.2	0.4	-29.2	1.0	-60.3	-78.9
2015 - 2016	9.7	0.7	-24.8	0.5	-83.5	-97.4
2016 - 2017	10.4	0.7	-15.3	0.2	-17.8	-21.8
2017 - 2018	11.1	0.6	-10.4	0.5	-20.1	-18.4
2018 - 2019	11.5	0.5	-6.4	0.3	-20.2	-14.4
2019 - 2020	10.9	0.5	-6.7	0.2	-31.6	-26.6
2020 - 2021	10.4	0.4	-4.9	0.2	-18.8	-12.7
2021 - 2022	9.8	0.3	-4.7	0.2	-10.6	-4.9
2022 - 2023	9.2	0.3	-4.5	0.2	-15.6	-10.5
2013 - 2023[1]	111.7	5.4	-147.2	16.5	-422.2	-435.8

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

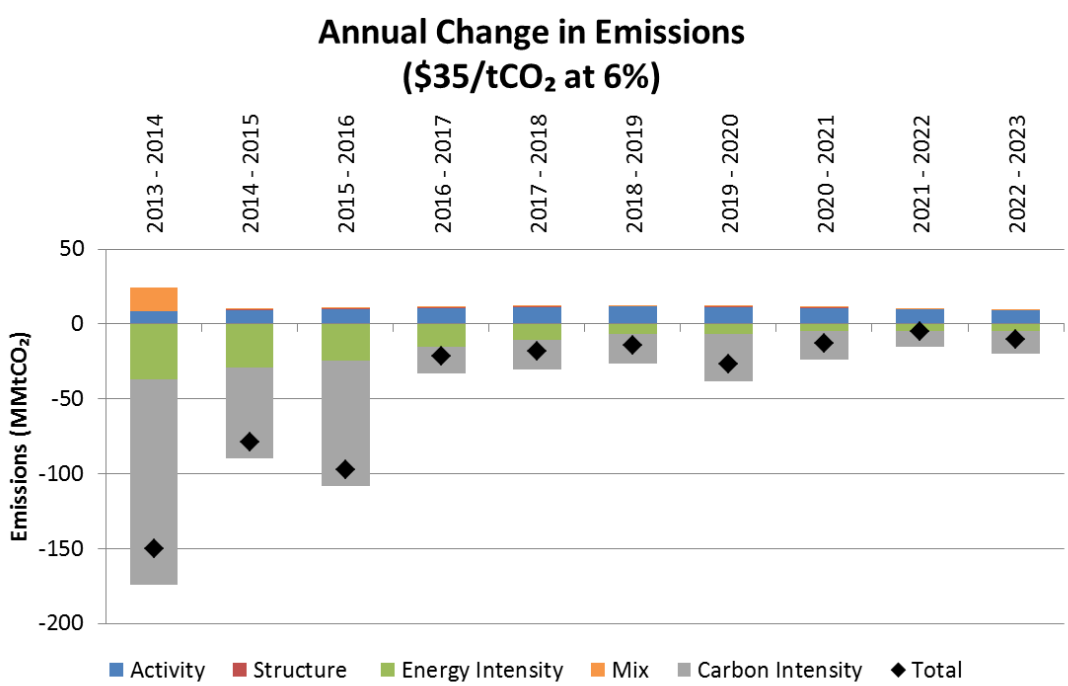

Figure B.56 Annual effects on emissions from \$35/tCO_2 at 6% scenario

Table B.60 Annual effects on emissions from $35/tCO$_2$ at 8% scenario

Effects on carbon emissions from $35/tCO$_2$ at 8% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Mix	Carbon Intensity	Total
2013 - 2014	8.3	0.3	-37.1	15.3	-144.5	-157.7
2014 - 2015	9.1	0.4	-29.2	1.0	-69.7	-88.4
2015 - 2016	9.2	0.6	-26.6	1.0	-136.3	-152.0
2016 - 2017	9.5	0.7	-16.4	0.2	-36.0	-42.1
2017 - 2018	9.9	0.6	-10.6	0.3	-19.3	-19.1
2018 - 2019	10.3	0.4	-6.0	-0.1	-25.2	-20.7
2019 - 2020	9.8	0.4	-6.1	-0.1	-22.1	-18.1
2020 - 2021	9.3	0.3	-7.1	-1.0	-20.2	-18.7
2021 - 2022	8.7	0.3	-5.7	-0.6	-16.5	-13.9
2022 - 2023	8.0	0.2	-4.8	-0.5	-13.3	-10.4
2013 - 2023[1]	104.5	5.0	-152.6	8.9	-506.9	-541.1

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

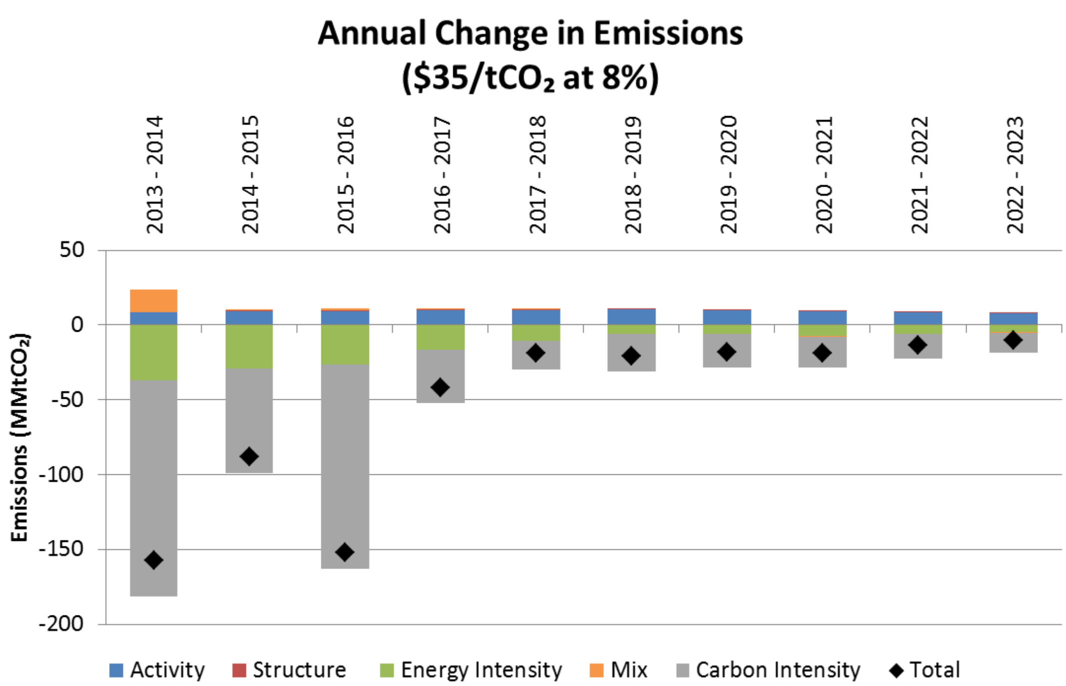

Figure B.57 Annual effects on emissions from $35/tCO$_2$ at 8% scenario

B.11 Industrial Sector Activity from the MAM for the Reference Case

Table B.61 Industrial Sector Reference scenario activity

Industrial Sector and Subsector Activity	2010	2013	2023	2010-2023 (Floating Scale)	2010-2023 (Fixed Scale)
Total Sector Activity (Billion 2011$)	**6553.2**	**7085.5**	**9323.4**		
Subsector Mode Shares Industrial Value of Shipments					
Agriculture/Forestry/Fishing/Hunting	5.0%	4.5%	4.0%		
Mining	6.9%	7.3%	6.1%		
Construction	15.2%	14.7%	16.9%		
Food Products	9.5%	9.2%	8.7%		
Beverages and Tobacco Products	1.6%	1.4%	1.1%		
Textile Mills and Products	0.8%	0.8%	0.5%		
Apparel	0.2%	0.3%	0.2%		
Wood Products	1.3%	1.4%	1.3%		
Furniture and Related Products	0.9%	0.9%	0.8%		
Paper Products	2.4%	2.2%	2.1%		
Printing	1.3%	1.1%	0.8%		
Chemical Manufacturing	10.4%	9.7%	10.3%		
Petroleum and Coal Products	7.8%	7.5%	5.7%		
Plastics and Rubber Products	2.7%	2.8%	2.6%		
Leather and Leather Products	0.1%	0.1%	0.0%		
Stone, Clay, and Glass Products	1.3%	1.3%	1.3%		
Primary Metals Industry	3.2%	3.4%	3.5%		
Fabricated Metal Products	4.3%	4.4%	4.0%		
Machinery	4.8%	5.0%	5.7%		
Computers and Electronics	6.7%	6.2%	7.3%		
Transportation Equipment	9.7%	12.1%	12.4%		
Electrical Equipment	1.7%	1.6%	1.8%		
Miscellaneous Manufacturing	2.2%	2.3%	2.9%		
Total	100.0%	100.0%	100.0%		

The subsector aggregate values used by NEMS are shown in Table 3.3, but some are provided from the MAM with further disaggregation. In the table, the first three subsectors represent the non-manufacturing segment of the industrial sector, while the rest are the manufacturing portion. In the reference scenario, the total Industrial sector activity will grow steadily from $7,086 billion in 2013 to $9,157 billion in 2023. The four largest industries in 2013 are Construction, Chemical Manufacturing, Transportation Equipment and food Products. All four of these segments are growing, but the first three are also capturing a larger share of the sector by 2023.

The table also includes two columns of spark lines. Both line represent the same data for each mode from 2010-2023 to show the general trend in the activity of each mode. The only difference is in the axes. In the first spark line column, the axes are floating independently to illustrate the general behavior within each mode, but the second line forces all spark lines in the table to have the same axis, bounded by the smallest (Leather and Leather Products) and largest (Construction) values. Combined the two spark lines show the general trend in a given industry (floating), and the relevance of that change to the entire set of industries (fixed). For example, the Petroleum and Coal Products is dominated almost entirely by the refining industry. Refinery activity fluctuates over the duration, which illustrates that refinery costs and production are driven by commodity prices which also fluctuate. However, overall, the impact to the magnitude of activity is relatively small. The minimum and maximum data points are also identified on each spark line (red and black respectively) to further help illustrate the general trends in each mode.

B.12 Industrial sector LMDI decomposition

Activity in the Industrial sector is value of shipments (VS) which is a surrogate for Industrial sector GDP. Structure is the fraction of VS for each industry. Energy intensity is the energy use per $VS, and carbon intensity is the amount of carbon in a unit of fuel in each industry. Ten-year results are reported in Table B.62 and Figure B.58, followed by the annual results for each scenario.

Table B.62 Ten-year effects on carbon emissions from all scenarios

	Total effects on carbon emissions (2013 - 2023)				
	Activity	Structure	Energy Intensity	Carbon Intensity	Total
Total effect ($MMtCO_2$)					
Reference	427.3	-68.6	-148.0	-62.7	148.0
$15/t$CO_2$ at 2%	397.6	-77.9	-158.3	-111.9	49.5
$15/t$CO_2$ at 4%	392.1	-78.0	-163.6	-125.3	25.3
$15/t$CO_2$ at 6%	386.1	-80.8	-158.6	-140.7	6.0
$15/t$CO_2$ at 8%	379.0	-83.3	-155.1	-159.1	-18.6
$25/t$CO_2$ at 2%	377.7	-85.8	-159.0	-156.6	-23.7
$25/t$CO_2$ at 4%	368.2	-87.2	-163.3	-182.6	-64.8
$25/t$CO_2$ at 6%	357.6	-90.7	-163.6	-204.6	-101.2
$25/t$CO_2$ at 8%	349.8	-94.8	-156.0	-226.1	-127.1
$35/t$CO_2$ at 2%	357.6	-90.8	-169.1	-201.3	-103.6
$35/t$CO_2$ at 4%	347.5	-95.8	-156.9	-229.7	-134.8
$35/t$CO_2$ at 6%	333.2	-99.9	-154.3	-272.6	-193.6
$35/t$CO_2$ at 8%	311.1	-102.5	-140.9	-323.8	-256.0
Percent from Reference					
Reference	0.0%	0.0%	0.0%	0.0%	0.0%
$15/t$CO_2$ at 2%	-6.9%	13.6%	6.9%	78.5%	-66.6%
$15/t$CO_2$ at 4%	-8.2%	13.7%	10.5%	99.9%	-82.9%
$15/t$CO_2$ at 6%	-9.6%	17.8%	7.1%	124.4%	-95.9%
$15/t$CO_2$ at 8%	-11.3%	21.5%	4.7%	153.8%	-112.6%
$25/t$CO_2$ at 2%	-11.6%	25.1%	7.4%	149.8%	-116.0%
$25/t$CO_2$ at 4%	-13.8%	27.1%	10.3%	191.2%	-143.8%
$25/t$CO_2$ at 6%	-16.3%	32.2%	10.5%	226.3%	-168.4%
$25/t$CO_2$ at 8%	-18.1%	38.2%	5.3%	260.6%	-185.9%
$35/t$CO_2$ at 2%	-16.3%	32.4%	14.2%	221.0%	-170.0%
$35/t$CO_2$ at 4%	-18.7%	39.8%	6.0%	266.3%	-191.1%
$35/t$CO_2$ at 6%	-22.0%	45.7%	4.2%	334.7%	-230.8%
$35/t$CO_2$ at 8%	-27.2%	49.4%	-4.8%	416.4%	-273.0%

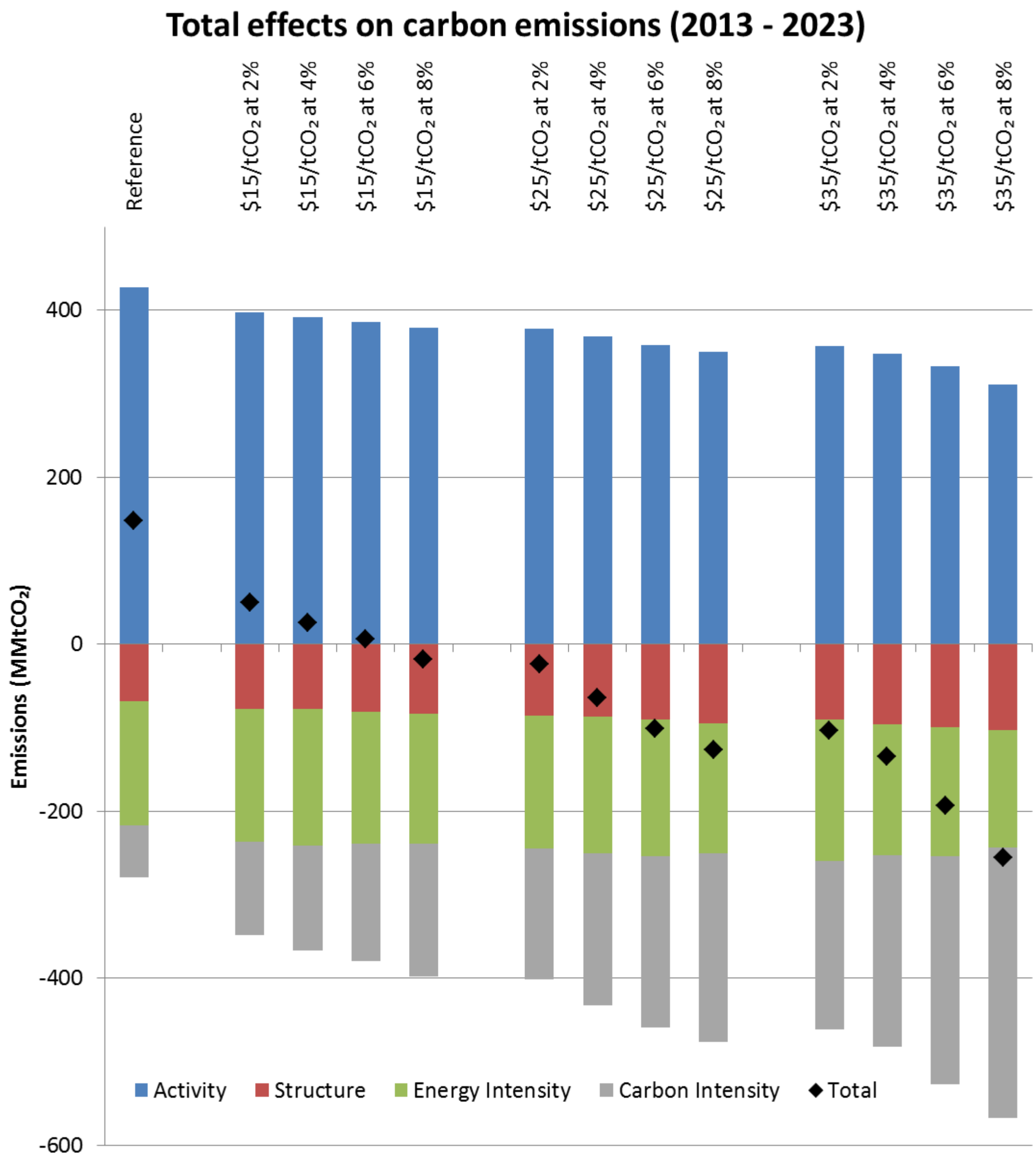

Figure B.58 Ten-year effects on carbon emissions from all scenarios

Table B.63 Annual effects on emissions from Reference scenario

Effects on carbon emissions from Reference scenario ($MMtCO_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	49.7	-16.1	-21.3	-7.2	5.1
2014 - 2015	74.9	-4.3	-15.9	-18.8	35.9
2015 - 2016	55.6	-9.3	-15.0	-25.9	5.4
2016 - 2017	49.9	-6.2	-16.4	-2.8	24.6
2017 - 2018	41.4	-5.3	-11.5	-2.9	21.8
2018 - 2019	39.2	-4.1	-16.9	0.0	18.2
2019 - 2020	31.9	-5.8	-15.2	-1.4	9.5
2020 - 2021	28.6	-5.1	-15.9	-4.6	3.1
2021 - 2022	31.4	-4.6	-13.9	1.8	14.8
2022 - 2023	23.4	-5.5	-9.1	1.0	9.7
2013 - 2023[1]	427.3	-68.6	-148.0	-62.7	148.0

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

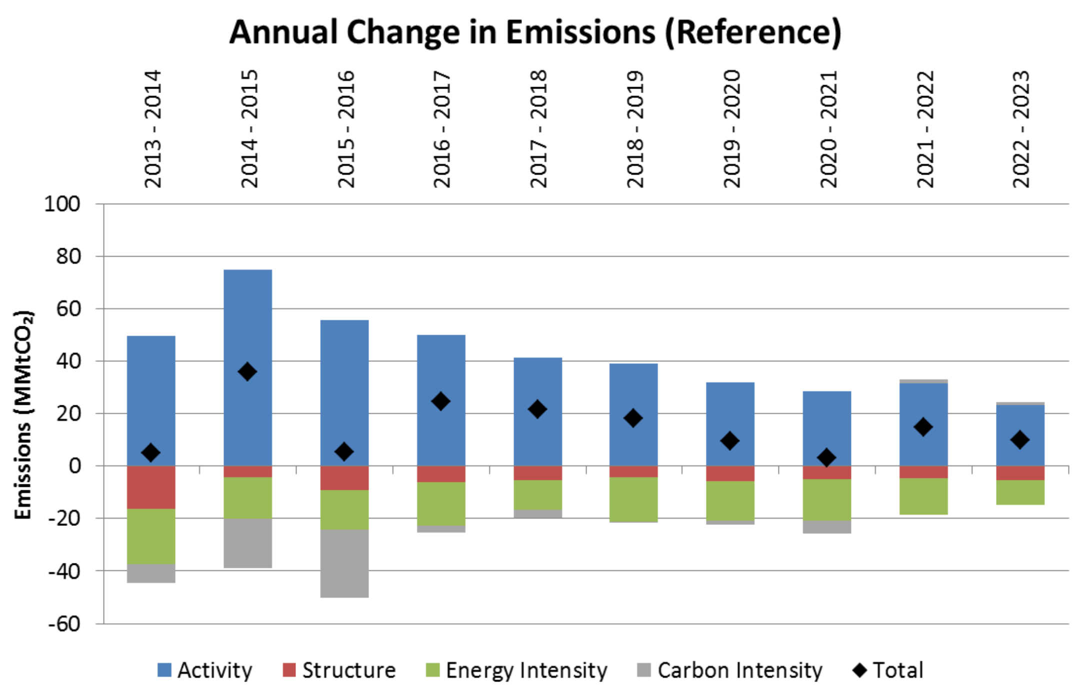

Figure B.59 Annual effects on emissions from Reference scenario

Table B.64 Annual effects on emissions from \$15/tCO_2 at 2% scenario

Effects on carbon emissions from \$15/tCO_2 at 2% scenario (MMtCO_2)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	40.4	-21.7	-24.1	-42.7	-48.1
2014 - 2015	62.0	-9.3	-16.4	-26.3	10.0
2015 - 2016	52.2	-7.7	-14.9	-19.3	10.3
2016 - 2017	51.0	-4.7	-19.9	-3.2	23.2
2017 - 2018	43.5	-5.6	-13.9	-2.7	21.3
2018 - 2019	39.0	-4.8	-16.8	-1.5	15.9
2019 - 2020	29.5	-6.3	-15.1	-6.8	1.3
2020 - 2021	25.3	-5.2	-14.7	-5.6	-0.2
2021 - 2022	27.4	-4.4	-15.0	-1.1	7.0
2022 - 2023	20.1	-5.1	-7.2	0.9	8.7
2013 - 2023[1]	397.6	-77.9	-158.3	-111.9	49.5

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

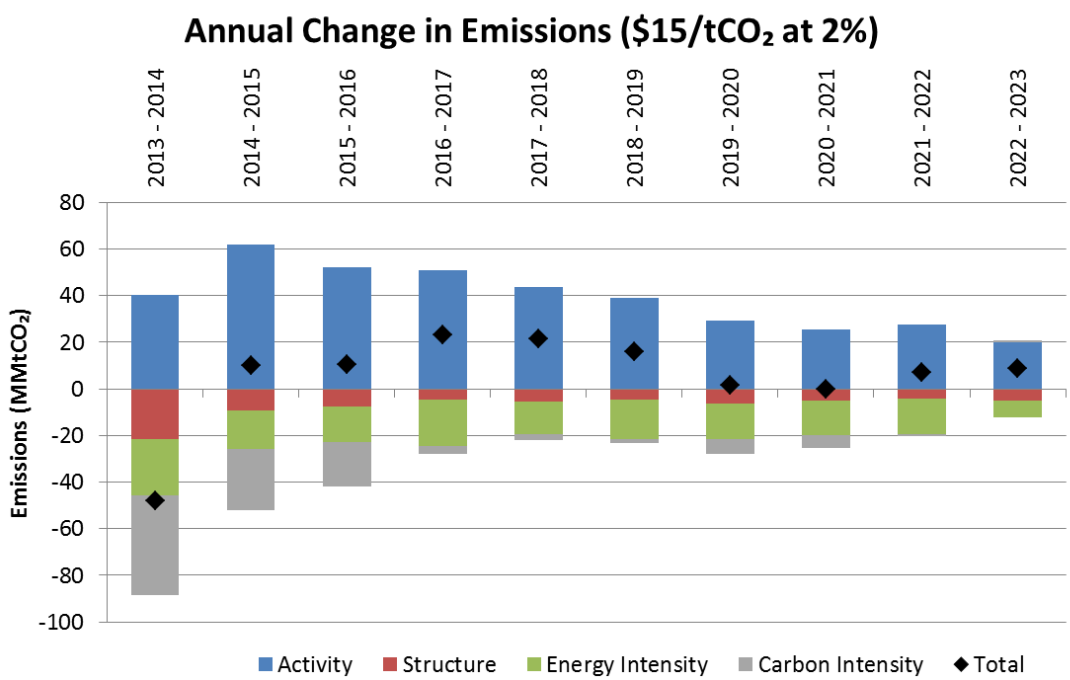

Figure B.60 Annual effects on emissions from \$15/tCO_2 at 2% scenario

Table B.65 Annual effects on emissions from $15/tCO$_2$ at 4% scenario

Effects on carbon emissions from $15/tCO$_2$ at 4% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	40.5	-21.6	-24.2	-41.4	-46.7
2014 - 2015	61.5	-9.5	-16.2	-28.1	7.7
2015 - 2016	51.8	-8.0	-15.3	-21.2	7.3
2016 - 2017	50.7	-4.7	-19.5	-4.0	22.5
2017 - 2018	43.0	-5.7	-13.8	-4.8	18.6
2018 - 2019	38.6	-5.0	-17.3	-1.9	14.5
2019 - 2020	29.0	-6.5	-15.1	-7.8	-0.3
2020 - 2021	25.0	-5.2	-14.5	-8.0	-2.7
2021 - 2022	27.0	-4.6	-13.9	-3.1	5.5
2022 - 2023	19.6	-5.2	-13.6	-1.9	-1.1
2013 - 2023[1]	392.1	-78.0	-163.6	-125.3	25.3

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

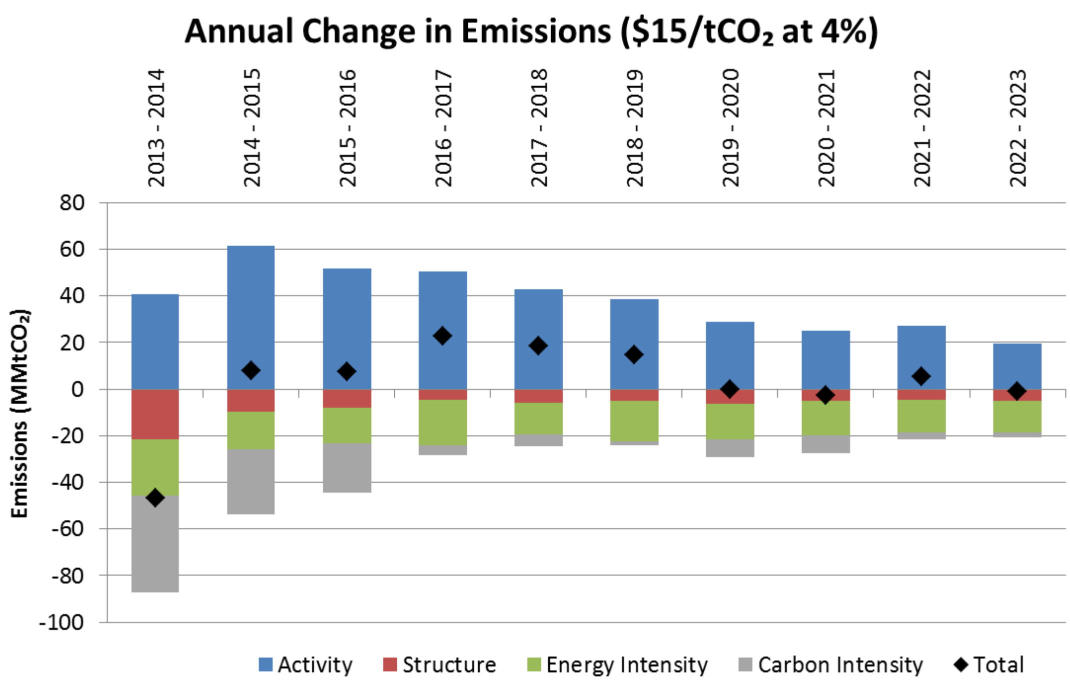

Figure B.61 Annual effects on emissions from $15/tCO$_2$ at 4% scenario

Table B.66 Annual effects on emissions from \$15/tCO_2 at 6% scenario

Effects on carbon emissions from \$15/tCO_2 at 6% scenario ($MMtCO_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	40.5	-21.6	-23.5	-44.0	-48.4
2014 - 2015	61.3	-9.6	-16.4	-28.4	7.0
2015 - 2016	50.9	-8.6	-14.3	-24.3	3.7
2016 - 2017	49.9	-5.0	-19.3	-2.7	23.0
2017 - 2018	42.3	-5.7	-14.2	-6.8	15.6
2018 - 2019	37.8	-5.2	-16.9	-2.9	12.7
2019 - 2020	28.4	-6.9	-15.1	-9.4	-3.0
2020 - 2021	24.3	-5.6	-14.4	-10.0	-5.7
2021 - 2022	26.5	-4.9	-10.9	-5.8	5.0
2022 - 2023	19.2	-5.4	-13.8	-3.8	-3.8
2013 - 2023[1]	386.1	-80.8	-158.6	-140.7	6.0

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

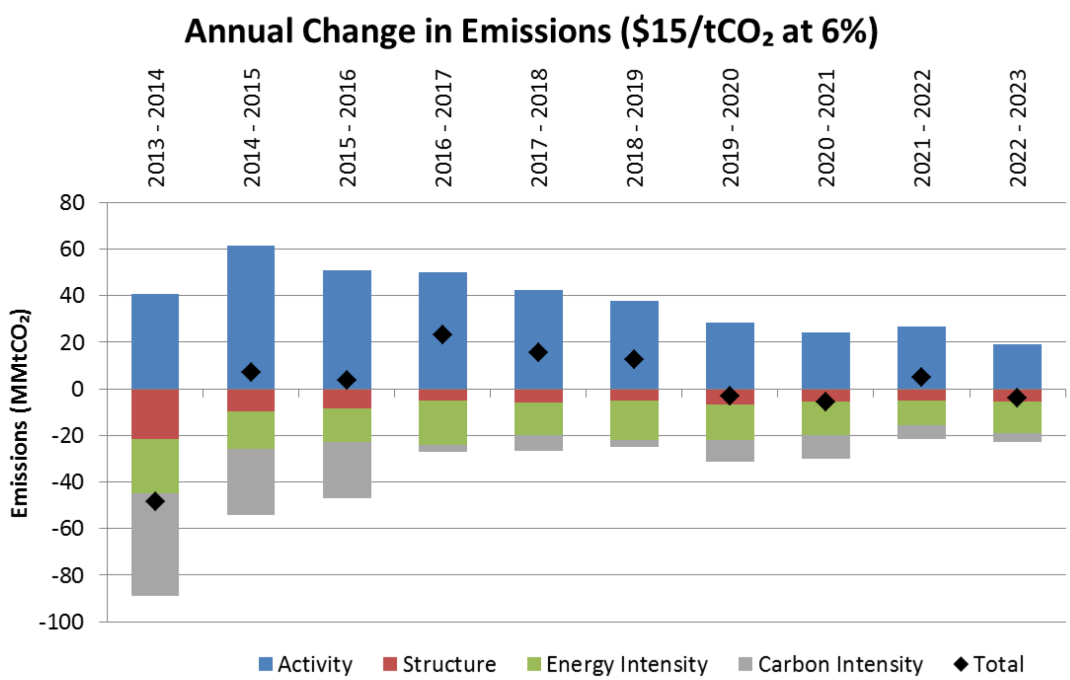

Figure B.62 Annual effects on emissions from \$15/tCO_2 at 6% scenario

Table B.67 Annual effects on emissions from $15/tCO$_2$ at 8% scenario

Effects on carbon emissions from $15/tCO$_2$ at 8% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	40.7	-21.2	-23.7	-44.3	-48.6
2014 - 2015	61.0	-9.7	-16.2	-31.7	3.4
2015 - 2016	50.0	-9.1	-14.4	-26.4	0.1
2016 - 2017	48.6	-5.6	-19.0	-6.7	17.3
2017 - 2018	41.3	-6.1	-13.6	-7.1	14.6
2018 - 2019	36.8	-5.5	-16.8	-4.5	10.0
2019 - 2020	27.8	-6.9	-15.3	-10.4	-4.7
2020 - 2021	24.0	-5.6	-14.6	-15.7	-11.9
2021 - 2022	25.8	-5.3	-8.2	-2.5	9.9
2022 - 2023	18.7	-5.8	-14.0	-7.6	-8.8
2013 - 2023[1]	379.0	-83.3	-155.1	-159.1	-18.6

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

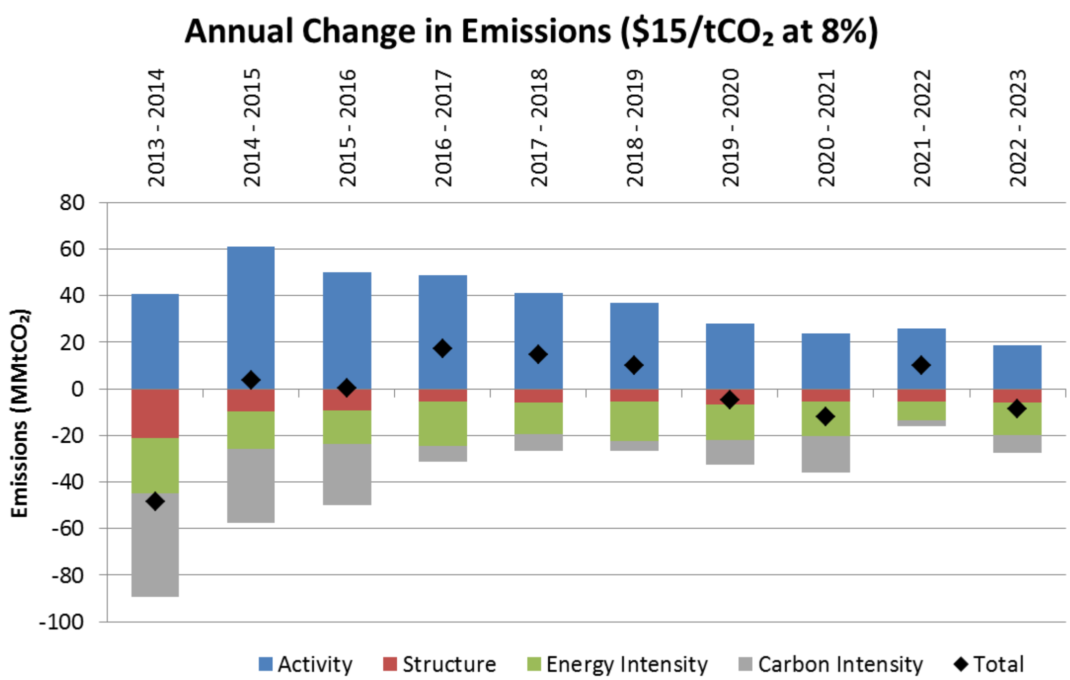

Figure B.63 Annual effects on emissions from $15/tCO$_2$ at 8% scenario

Table B.68 Annual effects on emissions from \$25/tCO_2 at 2% scenario

Effects on carbon emissions from \$25/tCO_2 at 2% scenario (MtCO_2)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	35.6	-24.8	-24.2	-63.1	-76.5
2014 - 2015	53.6	-12.5	-16.4	-32.3	-7.5
2015 - 2016	48.8	-7.9	-14.7	-21.6	4.7
2016 - 2017	49.7	-4.3	-19.2	-3.9	22.3
2017 - 2018	43.6	-5.4	-14.8	-2.4	21.1
2018 - 2019	38.2	-5.3	-16.8	-3.6	12.6
2019 - 2020	28.4	-6.8	-14.6	-8.0	-1.1
2020 - 2021	24.7	-5.4	-14.8	-13.3	-8.8
2021 - 2022	26.5	-4.7	-8.4	0.4	13.8
2022 - 2023	18.8	-5.3	-13.2	-4.6	-4.3
2013 - 2023[1]	377.7	-85.8	-159.0	-156.6	-23.7

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

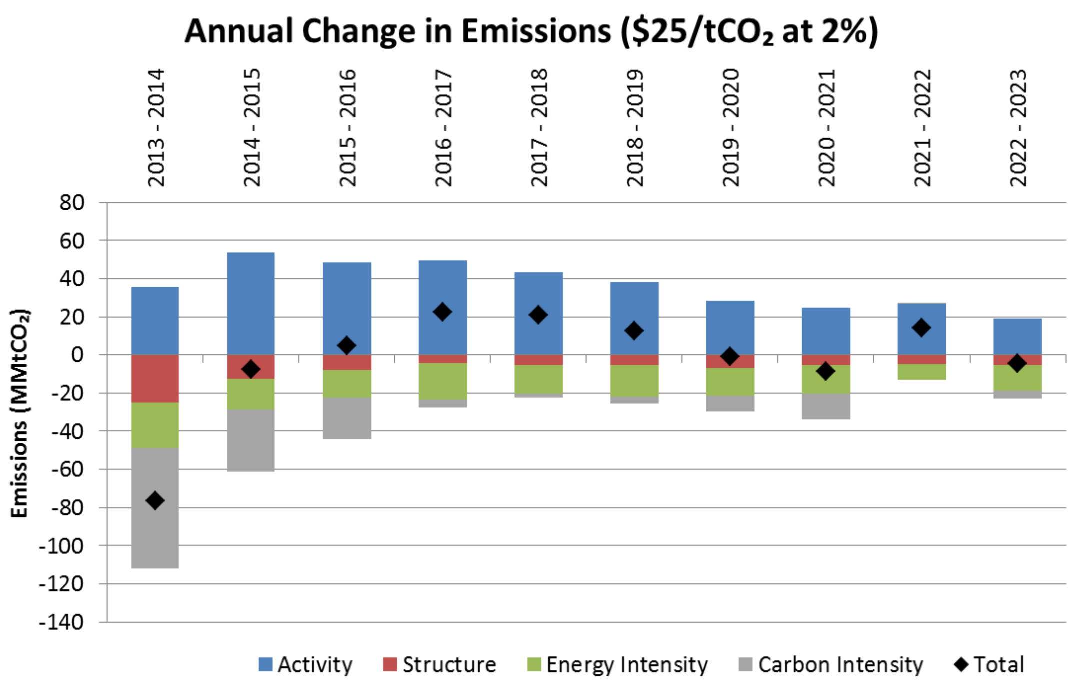

Figure B.64 Annual effects on emissions from \$25/tCO_2 at 2% scenario

Table B.69 Annual effects on emissions from \$25/tCO_2 at 4% scenario

Effects on carbon emissions from \$25/tCO_2 at 4% scenario (MtCO_2)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	35.5	-24.8	-24.2	-65.9	-79.5
2014 - 2015	53.0	-12.7	-16.1	-38.1	-13.9
2015 - 2016	47.4	-8.6	-14.5	-26.9	-2.5
2016 - 2017	48.6	-4.8	-19.0	-3.8	21.1
2017 - 2018	42.4	-5.6	-14.7	-4.5	17.7
2018 - 2019	37.1	-5.5	-17.3	-6.3	7.9
2019 - 2020	27.9	-6.8	-13.9	-7.8	-0.6
2020 - 2021	24.3	-5.3	-13.5	-14.8	-9.3
2021 - 2022	25.2	-5.2	-14.5	-6.6	-1.0
2022 - 2023	18.0	-5.5	-13.5	-3.7	-4.7
2013 - 2023[1]	368.2	-87.2	-163.3	-182.6	-64.8

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

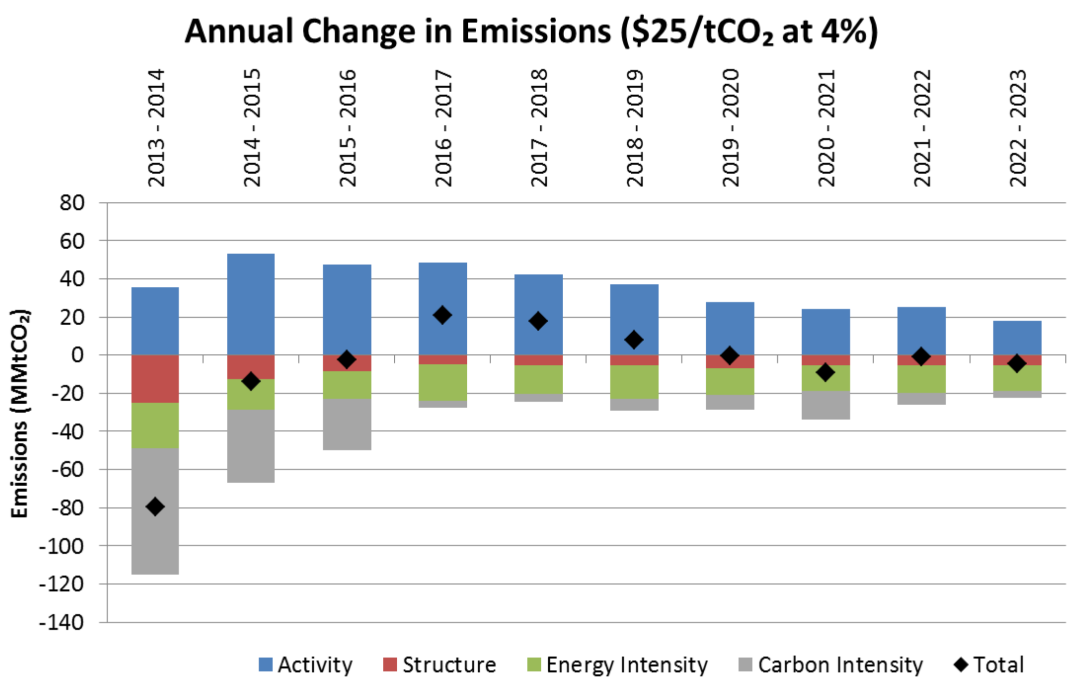

Figure B.65 Annual effects on emissions from \$25/tCO_2 at 4% scenario

Table B.70 Annual effects on emissions from \$25/tCO_2 at 6% scenario

Effects on carbon emissions from \$25/tCO_2 at 6% scenario (MtCO_2)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	35.5	-24.8	-24.1	-66.2	-79.6
2014 - 2015	52.9	-12.8	-15.9	-37.7	-13.5
2015 - 2016	46.1	-9.5	-14.5	-34.0	-11.8
2016 - 2017	46.7	-5.9	-18.6	-7.0	15.3
2017 - 2018	40.7	-6.1	-14.2	-7.4	13.0
2018 - 2019	35.9	-5.8	-16.8	-8.0	5.4
2019 - 2020	26.7	-7.1	-13.7	-11.2	-5.2
2020 - 2021	23.4	-5.9	-14.2	-18.3	-15.0
2021 - 2022	24.8	-5.4	-15.5	-4.8	-0.8
2022 - 2023	17.6	-5.8	-14.1	-6.4	-8.8
2013 - 2023[1]	357.6	-90.7	-163.6	-204.6	-101.2

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

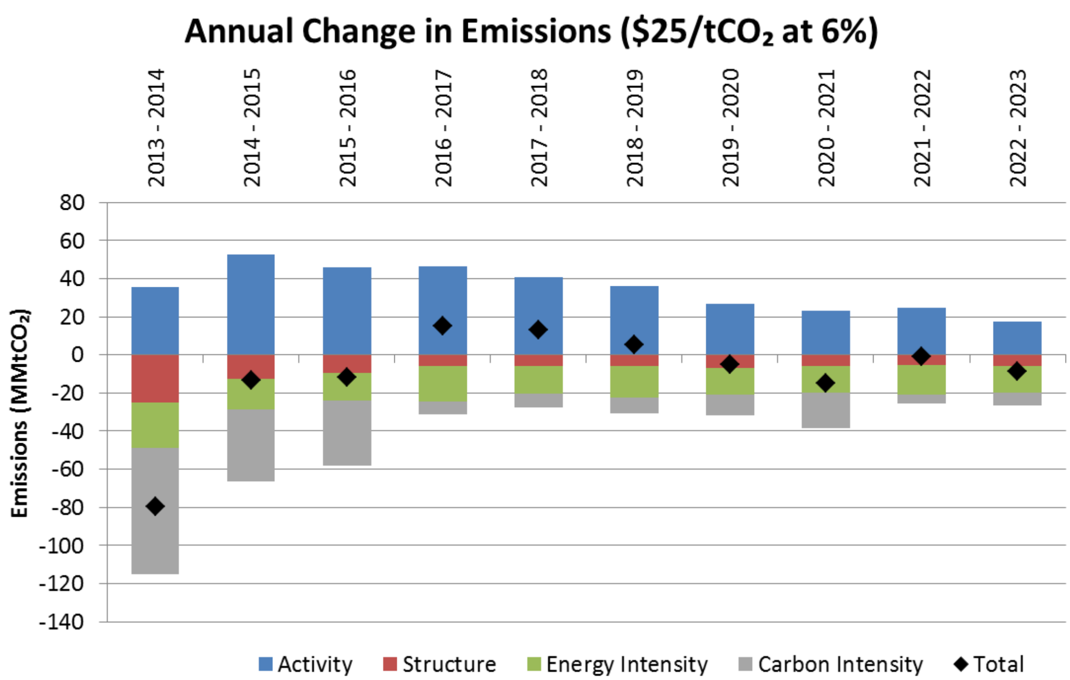

Figure B.66 Annual effects on emissions from \$25/tCO_2 at 6% scenario

Table B.71 Annual effects on emissions from \$25/tCO$_2$ at 8% scenario

Effects on carbon emissions from \$25/tCO$_2$ at 8% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	35.5	-24.8	-24.2	-67.8	-81.3
2014 - 2015	52.3	-13.1	-15.7	-41.0	-17.5
2015 - 2016	44.2	-10.7	-14.0	-41.1	-21.6
2016 - 2017	44.7	-6.9	-18.0	-10.9	8.8
2017 - 2018	38.9	-6.6	-14.4	-11.0	6.9
2018 - 2019	34.5	-6.0	-16.9	-12.2	-0.5
2019 - 2020	26.2	-7.1	-7.7	-12.7	-1.3
2020 - 2021	23.1	-5.8	-14.4	-16.5	-13.5
2021 - 2022	24.5	-5.6	-14.7	-2.0	2.3
2022 - 2023	17.5	-5.7	-13.6	-7.6	-9.4
2013 - 2023[1]	349.8	-94.8	-156.0	-226.1	-127.1

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

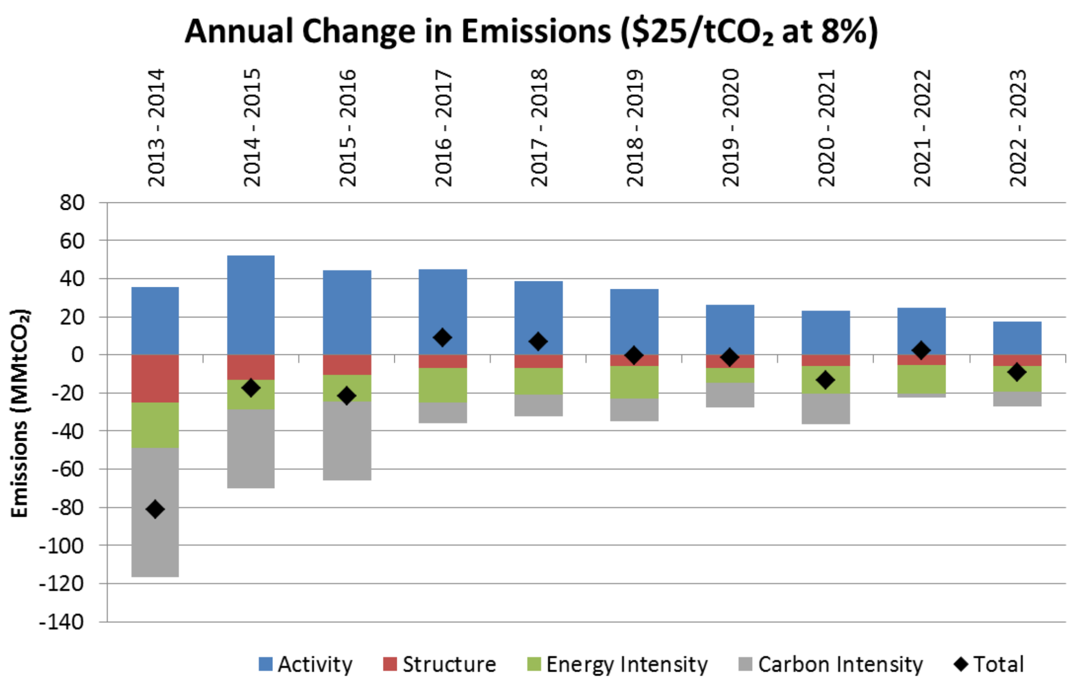

Figure B.67 Annual effects on emissions from \$25/tCO$_2$ at 8% scenario

Table B.72 Annual effects on emissions from $35/tCO$_2$ at 2% scenario

Effects on carbon emissions from $35/tCO$_2$ at 2% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	31.2	-27.6	-23.4	-84.1	-103.9
2014 - 2015	45.4	-15.7	-16.5	-46.0	-32.8
2015 - 2016	45.7	-7.7	-13.8	-23.3	0.9
2016 - 2017	48.4	-4.2	-18.1	-3.1	23.0
2017 - 2018	42.7	-5.9	-15.5	-5.0	16.4
2018 - 2019	38.1	-5.4	-18.4	-4.6	9.6
2019 - 2020	28.0	-6.2	-13.8	-7.6	0.4
2020 - 2021	23.3	-5.8	-14.9	-16.2	-13.6
2021 - 2022	24.5	-5.2	-15.5	-2.3	1.6
2022 - 2023	17.7	-4.9	-14.3	-3.7	-5.2
2013 - 2023[1]	357.6	-90.8	-169.1	-201.3	-103.6

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

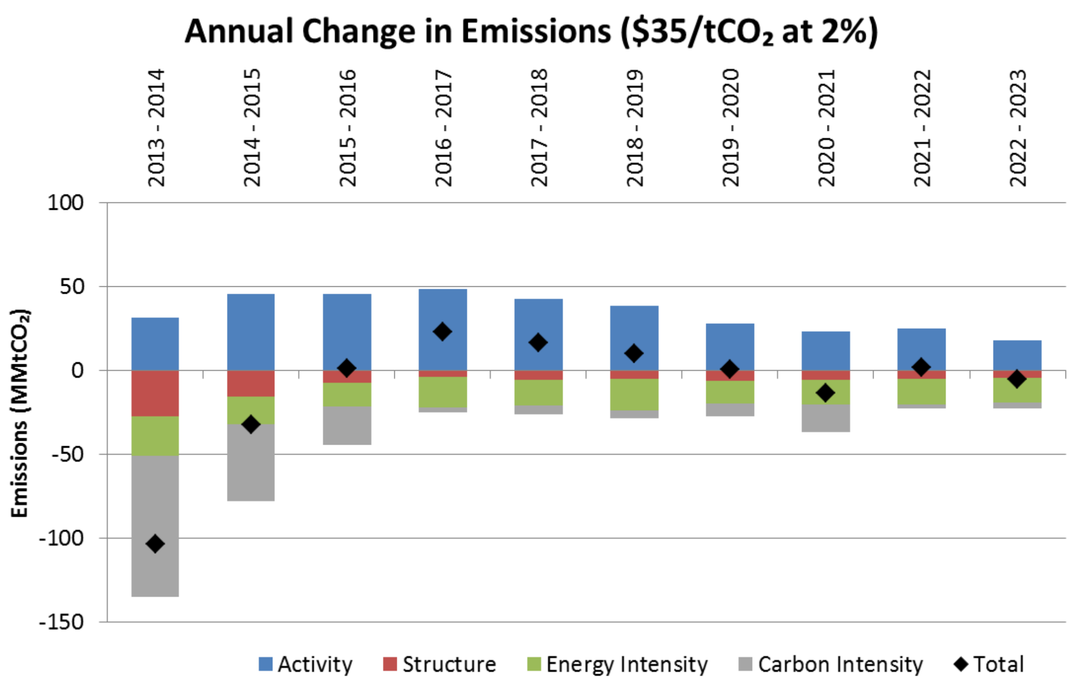

Figure B.68 Annual effects on emissions from $35/tCO$_2$ at 2% scenario

Table B.73 Annual effects on emissions from \$35/tCO_2 at 4% scenario

Effects on carbon emissions from \$35/tCO_2 at 4% scenario ($MMtCO_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	31.1	-27.5	-22.8	-84.6	-103.7
2014 - 2015	45.3	-15.8	-16.1	-46.9	-33.4
2015 - 2016	43.8	-8.8	-14.1	-33.3	-12.4
2016 - 2017	45.9	-5.5	-15.9	-9.2	15.3
2017 - 2018	40.5	-6.7	-15.3	-8.5	10.0
2018 - 2019	36.0	-5.9	-17.5	-9.3	3.3
2019 - 2020	27.1	-6.5	-7.7	-13.3	-0.3
2020 - 2021	23.3	-5.4	-14.6	-13.6	-10.3
2021 - 2022	24.1	-5.7	-14.7	-1.0	2.7
2022 - 2023	17.5	-5.3	-13.5	-4.9	-6.1
2013 - 2023[1]	347.5	-95.8	-156.9	-229.7	-134.8

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

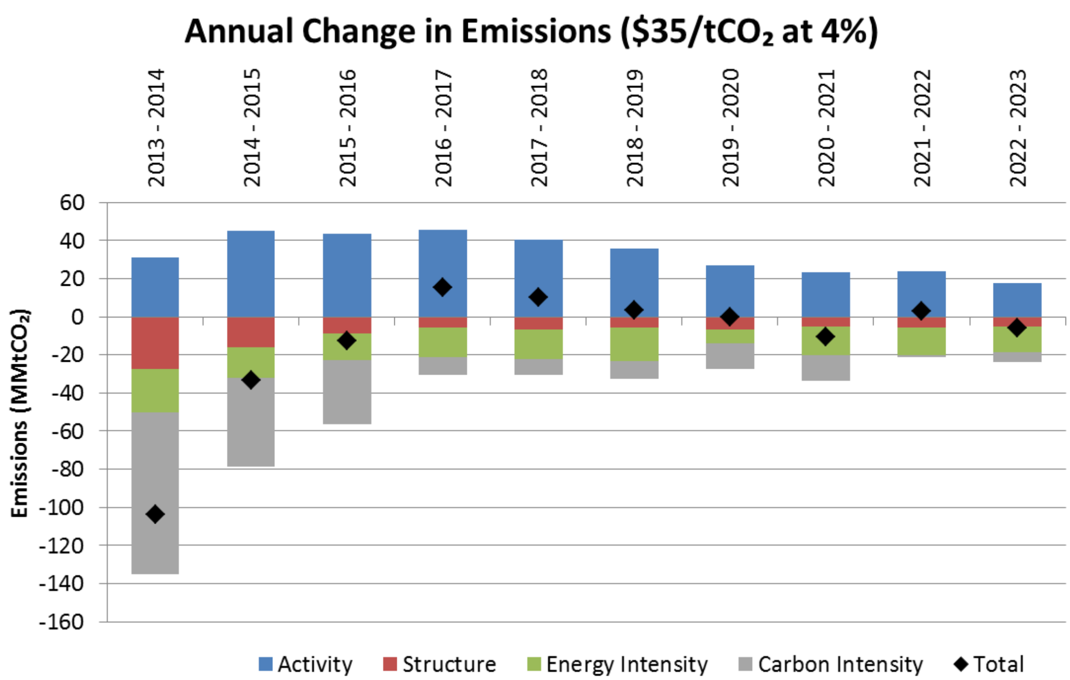

Figure B.69 Annual effects on emissions from \$35/tCO_2 at 4% scenario

Table B.74 Annual effects on emissions from \$35/tCO$_2$ at 6% scenario

Effects on carbon emissions from \$35/tCO$_2$ at 6% scenario (MMtCO$_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	31.1	-27.5	-22.4	-86.3	-105.2
2014 - 2015	44.7	-16.2	-16.0	-48.8	-36.3
2015 - 2016	40.1	-11.0	-14.0	-52.5	-37.5
2016 - 2017	42.2	-6.9	-15.6	-14.8	4.9
2017 - 2018	38.5	-6.2	-12.4	-13.4	6.5
2018 - 2019	34.7	-6.0	-13.5	-10.5	4.7
2019 - 2020	25.6	-7.5	-13.9	-18.9	-14.7
2020 - 2021	22.2	-5.9	-14.1	-9.5	-7.3
2021 - 2022	23.8	-5.1	-13.7	-4.9	0.1
2022 - 2023	17.6	-5.1	-13.4	-7.7	-8.7
2013 - 2023[1]	333.2	-99.9	-154.3	-272.6	-193.6

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

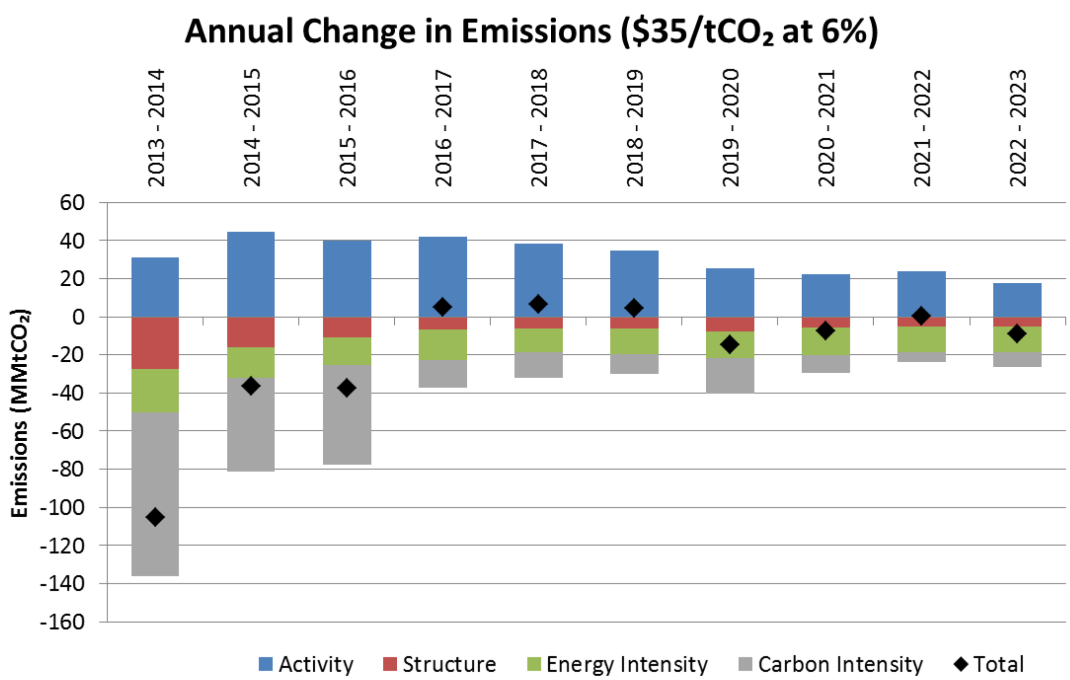

Figure B.70 Annual effects on emissions from \$35/tCO$_2$ at 6% scenario

Table B.75 Annual effects on emissions from $35/tCO$_2$ at 8% scenario

Effects on carbon emissions from $35/tCO$_2$ at 8% scenario ($MMtCO_2$)

	Activity	Structure	Energy Intensity	Carbon Intensity	Total
2013 - 2014	31.0	-27.3	-22.4	-90.2	-108.9
2014 - 2015	44.5	-16.0	-15.9	-53.7	-41.1
2015 - 2016	37.0	-12.8	-13.3	-79.5	-68.6
2016 - 2017	39.0	-8.1	-14.9	-25.1	-9.1
2017 - 2018	36.0	-6.0	-10.4	-13.7	6.0
2018 - 2019	32.9	-6.2	-8.4	-12.4	5.9
2019 - 2020	24.3	-7.4	-13.4	-14.1	-10.5
2020 - 2021	18.0	-5.9	-13.3	-12.9	-14.2
2021 - 2022	18.6	-5.0	-11.1	-9.4	-6.9
2022 - 2023	17.1	-4.6	-13.5	-7.6	-8.6
2013 - 2023[1]	311.1	-102.5	-140.9	-323.8	-256.0

Notes: [1] Columns do not sum directly to ten-year result due to log formulation

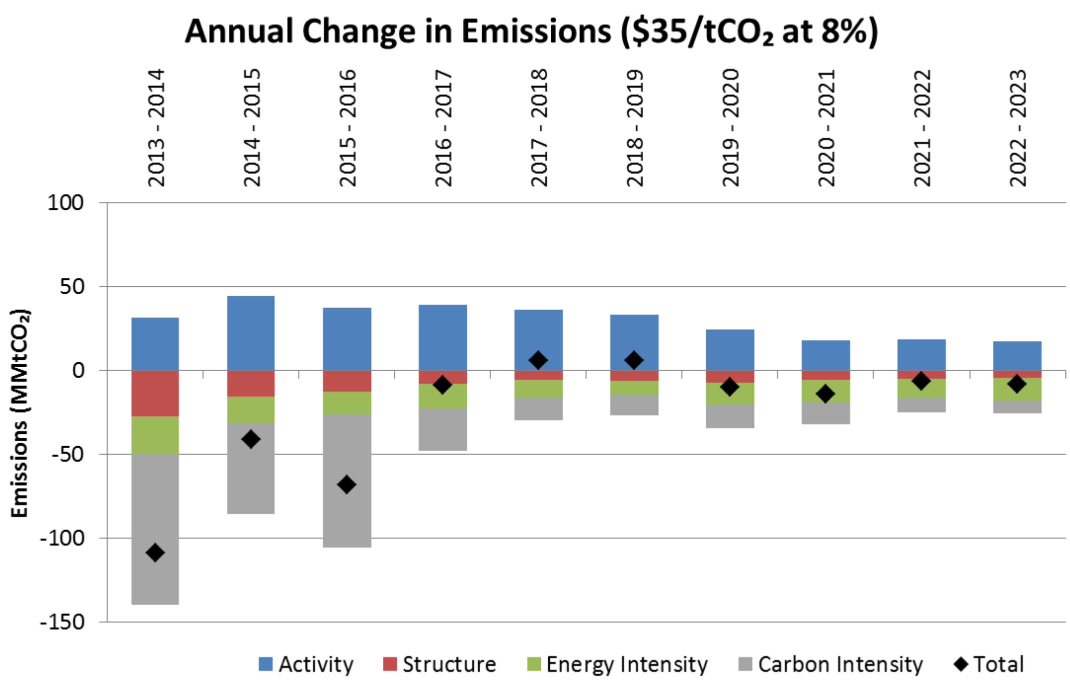

Figure B.71 Annual effects on emissions from $35/tCO$_2$ at 8% scenario

B.13 Industry-specific LMDI decomposition

Table B.76 shows the Reference scenario effects from activity, energy intensity, and carbon intensity on each industry in NEMS. Tables for each policy scenario follow.

Table B.76 Industry-specific decomposition results for Reference scenario

			Reference				
	2013		2013 - 2023			2023	
Industry	Mode Share[1] (% of sector)	Total Emissions ($MMtCO_2$)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions ($MMtCO_2$)	Mode Share[1] (% of sector)
Agriculture	4.5%	67.9	10.4	-7.9	-1.9	68.6	4.0%
Mining	7.3%	54.7	5.1	0.4	-3.6	56.7	6.1%
Construction	14.7%	71.0	33.2	-12.2	-0.9	91.0	16.9%
Refining Industry[2]	7.1%	254.9	-1.5	5.6	-8.4	250.6	5.4%
Food Industry[2]	9.2%	98.1	22.5	-10.7	-3.5	106.3	8.7%
Wood Products	1.4%	18.6	5.3	-0.7	-1.7	21.4	1.3%
Paper Industry[2]	2.2%	67.0	17.6	-5.3	-9.2	70.1	2.1%
Bulk Chemical Industry[2]	4.6%	236.3	60.1	-22.8	-14.7	259.0	4.4%
Plastics	2.8%	39.1	7.8	-7.4	-1.1	38.4	2.6%
Glass Industry[2]	0.3%	18.8	6.3	-1.2	-0.5	23.3	0.3%
Cement and Lime Industry[2]	0.1%	31.0	12.8	-3.7	-1.1	39.0	0.1%
Iron and Steel Industries[2]	1.9%	126.9	48.5	-25.2	-0.2	149.8	2.1%
Aluminum Industry[2]	0.5%	50.8	17.9	-5.8	-4.1	58.7	0.6%
Fabricated Metal Products	4.4%	39.2	7.4	-5.2	-1.4	39.9	4.0%
Machinery	5.0%	25.0	10.7	-5.2	-0.7	29.8	5.7%
Computers	6.2%	28.7	13.7	-6.4	-2.0	33.9	7.3%
Transportation Equipment	12.1%	58.5	17.9	-10.8	-1.7	63.9	12.4%
Electrical Equipment	1.6%	7.8	3.2	-1.6	-0.2	9.2	1.8%
Balance of Manufacturing	14.1%	190.8	60.1	-21.8	-5.8	223.2	14.4%
Total	100.0%	1484.7	358.7	-148.0	-62.7	1632.7	100.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.77 Industry-specific decomposition results for \$15/tCO_2 at 2% policy

	2013		Policy Scenario (\$15/tCO_2 at 2%) 2013 - 2023			2023		Percent difference from Reference 2013 - 2023				
Industry	Mode Share[1] (% of sector)	Total Emissions (MtCO_2)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share
Agriculture	4.5%	67.9	10.0	-7.9	-3.2	66.8	4.0%	-3.9%	-0.4%	-72.1%	-2.6%	1.2%
Mining	7.3%	54.7	4.7	-0.1	-5.8	53.6	6.3%	-8.0%	-113.6%	-61.2%	-5.4%	3.2%
Construction	14.7%	71.0	32.9	-12.2	-2.0	89.6	17.1%	-0.8%	0.2%	-131.1%	-1.6%	1.1%
Refining Industry[2]	7.1%	255.1	-3.9	0.5	-8.8	242.9	5.5%	-158.9%	-91.6%	-5.3%	-3.1%	1.9%
Food Industry[2]	9.2%	97.9	21.5	-10.7	-8.5	100.2	8.7%	-4.4%	0.0%	-140.9%	-5.8%	0.5%
Wood Products	1.4%	18.5	4.9	-0.7	-3.0	19.7	1.4%	-7.8%	8.3%	-73.4%	-7.7%	0.8%
Paper Industry[2]	2.1%	66.9	15.8	-5.0	-11.9	65.8	2.1%	-10.1%	5.8%	-29.6%	-6.2%	-0.2%
Bulk Chemical Industry[2]	4.6%	236.0	53.4	-21.4	-22.3	245.7	4.4%	-11.1%	6.0%	-52.3%	-5.1%	-0.3%
Plastics	2.8%	39.0	5.8	-7.2	-4.3	33.4	2.5%	-25.0%	2.4%	-286.9%	-13.0%	-2.8%
Glass Industry[2]	0.3%	18.8	5.6	-1.2	-1.2	22.0	0.3%	-10.0%	-2.0%	-154.2%	-5.9%	-1.2%
Cement and Lime Industry[2]	0.1%	30.9	12.0	-3.5	-1.8	37.6	0.1%	-6.8%	5.1%	-63.1%	-3.5%	-0.6%
Iron and Steel Industries[2]	1.9%	126.7	41.5	-24.1	-4.4	139.7	2.0%	-14.4%	4.6%	-1821.3%	-6.8%	-2.2%
Aluminum Industry[2]	0.5%	50.7	11.5	-11.3	-6.4	44.4	0.5%	-35.8%	-94.7%	-55.1%	-24.4%	-8.4%
Fabricated Metal Products	4.4%	39.1	6.8	-5.4	-4.1	36.4	4.1%	-8.2%	-2.5%	-199.7%	-8.8%	0.9%
Machinery	5.0%	25.0	9.6	-5.4	-3.0	26.1	5.6%	-10.7%	-4.6%	-306.1%	-12.3%	-0.4%
Computers	6.2%	28.7	12.8	-6.5	-3.8	31.2	7.2%	-6.1%	-0.9%	-88.8%	-8.0%	-0.7%
Transportation Equipment	12.1%	58.4	16.2	-11.0	-6.4	57.3	12.2%	-9.3%	-1.2%	-276.4%	-10.2%	-1.1%
Electrical Equipment	1.6%	7.8	3.0	-1.6	-0.9	8.2	1.8%	-7.9%	-1.6%	-322.0%	-10.3%	0.5%
Balance of Manufacturing	14.1%	190.9	55.7	-23.7	-10.1	212.9	14.1%	-7.3%	-8.5%	-73.5%	-4.6%	-1.7%
Total	100.0%	1484.0	319.7	-158.3	-111.9	1533.5	100.0%	-10.9%	-6.9%	-78.5%	-6.1%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.78 Industry-specific decomposition results for \$15/tCO_2 at 4% policy

	2013		Policy Scenario (\$15/tCO_2 at 4%)					Percent difference from Reference				
			2013 - 2023			2023		2013 - 2023				
Industry	Mode Share[1] (% of sector)	Total Emissions (MMtCO_2)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share
Agriculture	4.5%	67.8	10.0	-7.9	-3.5	66.4	4.0%	-4.3%	0.0%	-88.9%	-3.1%	1.3%
Mining	7.3%	54.7	4.6	0.1	-6.5	53.0	6.3%	-10.0%	-79.5%	-79.9%	-6.5%	3.2%
Construction	14.7%	71.0	32.8	-12.2	-2.3	89.3	17.1%	-1.1%	0.4%	-163.0%	-2.0%	1.2%
Refining Industry[2]	7.1%	255.1	-4.2	-5.3	-11.5	234.2	5.5%	-176.4%	-195.2%	-36.8%	-6.5%	1.9%
Food Industry[2]	9.2%	97.9	21.3	-10.7	-9.7	98.8	8.7%	-5.3%	0.6%	-173.1%	-7.0%	0.5%
Wood Products	1.4%	18.5	4.8	-0.6	-3.3	19.4	1.4%	-9.5%	12.1%	-90.4%	-9.4%	0.7%
Paper Industry[2]	2.1%	66.9	15.6	-4.9	-12.5	65.0	2.1%	-11.2%	6.8%	-36.4%	-7.3%	-0.2%
Bulk Chemical Industry[2]	4.6%	236.0	52.5	-21.1	-24.2	243.2	4.4%	-12.6%	7.3%	-64.8%	-6.1%	-0.5%
Plastics	2.8%	39.0	5.6	-7.1	-5.0	32.5	2.5%	-28.4%	3.3%	-349.2%	-15.4%	-3.1%
Glass Industry[2]	0.3%	18.8	5.5	-1.2	-1.3	21.7	0.3%	-11.7%	-1.8%	-185.0%	-7.0%	-1.4%
Cement and Lime Industry[2]	0.1%	30.9	11.8	-3.5	-1.9	37.3	0.1%	-7.9%	5.9%	-76.9%	-4.2%	-0.7%
Iron and Steel Industries[2]	1.9%	126.7	40.4	-23.9	-5.3	137.9	2.0%	-16.6%	5.5%	-2233.2%	-8.0%	-2.6%
Aluminum Industry[2]	0.5%	50.7	10.7	-11.7	-7.0	42.7	0.5%	-40.3%	-101.8%	-69.3%	-27.4%	-9.1%
Fabricated Metal Products	4.4%	39.1	6.7	-5.4	-4.7	35.7	4.1%	-9.5%	-2.3%	-242.5%	-10.5%	1.0%
Machinery	5.0%	25.0	9.4	-5.4	-3.5	25.4	5.6%	-12.3%	-4.7%	-372.0%	-14.6%	-0.4%
Computers	6.2%	28.7	12.7	-6.5	-4.2	30.7	7.2%	-7.0%	-1.0%	-106.6%	-9.4%	-0.6%
Transportation Equipment	12.1%	58.4	16.0	-10.9	-7.4	56.0	12.2%	-10.8%	-0.7%	-338.5%	-12.2%	-1.1%
Electrical Equipment	1.6%	7.8	2.9	-1.6	-1.0	8.0	1.8%	-9.3%	-1.3%	-392.7%	-12.3%	0.5%
Balance of Manufacturing	14.1%	191.1	55.2	-23.8	-10.5	212.0	14.1%	-8.0%	-8.9%	-81.2%	-5.0%	-1.7%
Total	100.0%	1484.1	314.2	-163.6	-125.3	1509.4	100.0%	-12.4%	-10.5%	-99.9%	-7.6%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.79 Industry-specific decomposition results for \$15/tCO_2 at 6% policy

Industry	2013		Policy Scenario (\$15/tCO_2 at 6%)					Percent difference from Reference				
			2013 - 2023			2023		2013 - 2023				
	Mode Share[1] (% of sector)	Total Emissions (MMtCO_2)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share
Agriculture	4.5%	67.9	9.9	-7.8	-4.0	65.8	4.0%	-5.2%	0.4%	-118.4%	-4.0%	1.5%
Mining	7.3%	54.7	4.5	0.2	-7.5	52.0	6.3%	-12.7%	-43.5%	-108.1%	-8.3%	3.3%
Construction	14.7%	71.0	32.7	-12.1	-2.9	88.7	17.1%	-1.4%	0.6%	-224.3%	-2.6%	1.5%
Refining Industry[2]	7.1%	254.9	-4.7	-2.4	-10.9	236.8	5.5%	-213.2%	-143.4%	-30.4%	-5.5%	1.9%
Food Industry[2]	9.2%	97.9	21.0	-10.6	-11.2	97.1	8.7%	-6.6%	1.0%	-216.7%	-8.7%	0.7%
Wood Products	1.4%	18.6	4.6	-0.6	-3.7	18.9	1.4%	-12.1%	14.8%	-111.6%	-11.6%	0.5%
Paper Industry[2]	2.1%	66.9	15.3	-4.9	-13.4	64.0	2.1%	-12.6%	8.0%	-45.3%	-8.7%	-0.2%
Bulk Chemical Industry[2]	4.6%	236.0	50.7	-20.7	-26.2	239.8	4.4%	-15.6%	9.0%	-79.0%	-7.4%	-0.8%
Plastics	2.8%	39.0	5.2	-7.0	-5.9	31.2	2.5%	-33.4%	4.5%	-436.9%	-18.6%	-3.6%
Glass Industry[2]	0.3%	18.8	5.3	-1.2	-1.5	21.3	0.3%	-14.6%	-1.7%	-233.1%	-8.7%	-1.8%
Cement and Lime Industry[2]	0.1%	30.9	11.5	-3.4	-2.2	36.9	0.1%	-9.9%	7.4%	-98.4%	-5.3%	-1.0%
Iron and Steel Industries[2]	1.9%	126.7	38.6	-23.5	-6.5	135.4	2.0%	-20.3%	6.9%	-2725.5%	-9.6%	-3.4%
Aluminum Industry[2]	0.5%	50.7	9.6	-12.2	-8.0	40.2	0.5%	-46.2%	-108.7%	-94.3%	-31.6%	-10.3%
Fabricated Metal Products	4.4%	39.1	6.5	-5.4	-5.6	34.7	4.1%	-11.3%	-2.4%	-306.0%	-13.0%	1.1%
Machinery	5.0%	25.0	9.1	-5.4	-4.2	24.5	5.6%	-14.8%	-4.6%	-467.4%	-17.8%	-0.6%
Computers	6.2%	28.7	12.5	-6.5	-4.9	29.8	7.2%	-8.6%	-0.8%	-140.5%	-12.0%	-0.5%
Transportation Equipment	12.1%	58.4	15.5	-10.9	-8.9	54.2	12.2%	-13.2%	-0.3%	-428.0%	-15.2%	-1.2%
Electrical Equipment	1.6%	7.8	2.8	-1.6	-1.2	7.8	1.8%	-11.3%	-1.0%	-488.3%	-15.1%	0.5%
Balance of Manufacturing	14.1%	191.0	54.4	-22.5	-12.0	210.9	14.1%	-9.4%	-3.3%	-106.3%	-5.5%	-1.8%
Total	100.0%	1484.0	305.3	-158.6	-140.7	1490.0	100.0%	-14.9%	-7.1%	-124.4%	-8.7%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.80 Industry-specific decomposition results for \$15/tCO_2 at 8% policy

Industry	2013		Policy Scenario (\$15/tCO_2 at 8%) 2013 - 2023			2023		Percent difference from Reference 2013 - 2023				
	Mode Share[1] (% of sector)	Total Emissions (MMtCO_2)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share
Agriculture	4.5%	67.8	9.8	-7.8	-4.8	65.0	4.1%	-6.3%	0.9%	-158.4%	-5.2%	1.7%
Mining	7.3%	54.7	4.3	0.5	-8.9	50.6	6.3%	-16.6%	25.9%	-147.5%	-10.7%	3.3%
Construction	14.7%	71.0	32.5	-12.1	-3.6	87.8	17.2%	-1.9%	1.1%	-306.6%	-3.5%	1.7%
Refining Industry[2]	7.1%	254.9	-5.2	-0.6	-11.1	237.9	5.5%	-243.3%	-111.2%	-33.2%	-5.1%	2.0%
Food Industry[2]	9.2%	97.9	20.6	-10.5	-13.2	94.8	8.8%	-8.1%	1.9%	-271.8%	-10.8%	0.8%
Wood Products	1.4%	18.5	4.5	-0.6	-4.2	18.2	1.4%	-15.3%	19.9%	-141.5%	-14.7%	0.4%
Paper Industry[2]	2.1%	66.8	15.1	-4.8	-14.4	62.7	2.1%	-14.3%	9.7%	-56.5%	-10.5%	-0.1%
Bulk Chemical Industry[2]	4.6%	236.0	48.9	-20.2	-28.9	235.7	4.4%	-18.7%	11.1%	-97.6%	-9.0%	-1.1%
Plastics	2.8%	39.0	4.8	-6.9	-7.1	29.8	2.5%	-38.6%	6.0%	-539.3%	-22.4%	-4.1%
Glass Industry[2]	0.3%	18.7	5.1	-1.2	-1.8	20.9	0.3%	-17.9%	-1.5%	-283.6%	-10.6%	-2.2%
Cement and Lime Industry[2]	0.1%	30.9	11.3	-3.4	-2.4	36.4	0.1%	-12.2%	9.2%	-124.4%	-6.6%	-1.3%
Iron and Steel Industries[2]	1.9%	126.7	36.7	-23.1	-7.9	132.3	2.0%	-24.3%	8.5%	-3369.9%	-11.7%	-4.2%
Aluminum Industry[2]	0.5%	50.7	8.4	-12.4	-9.3	37.4	0.5%	-52.9%	-113.1%	-125.0%	-36.3%	-11.7%
Fabricated Metal Products	4.4%	39.1	6.4	-5.4	-6.6	33.5	4.1%	-13.4%	-2.2%	-379.7%	-16.0%	1.2%
Machinery	5.0%	25.0	8.8	-5.4	-5.0	23.4	5.6%	-17.7%	-4.4%	-576.1%	-21.6%	-0.7%
Computers	6.2%	28.7	12.2	-6.4	-5.6	28.8	7.2%	-10.5%	-0.2%	-179.0%	-15.0%	-0.4%
Transportation Equipment	12.1%	58.4	15.1	-10.8	-10.7	52.0	12.2%	-15.8%	0.4%	-535.2%	-18.6%	-1.2%
Electrical Equipment	1.6%	7.8	2.8	-1.6	-1.4	7.5	1.8%	-13.6%	-0.4%	-600.6%	-18.3%	0.5%
Balance of Manufacturing	14.1%	190.9	53.7	-22.4	-12.0	210.2	14.1%	-10.6%	-2.7%	-107.1%	-5.8%	-1.8%
Total	100.0%	1483.5	295.6	-155.1	-159.1	1465.0	100.0%	-17.6%	-4.7%	-153.8%	-10.3%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.81 Industry-specific decomposition results for $\$25/tCO_2$ at 2% policy

	2013		Policy Scenario ($\$25/tCO_2$ at 2%)					Percent difference from Reference				
			2013 - 2023			2023		2013 - 2023				
Industry	Mode Share[1] (% of sector)	Total Emissions ($MMtCO_2$)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions ($MMtCO_2$)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions ($MMtCO_2$)	Mode Share
Agriculture	4.5%	67.9	9.7	-7.9	-4.8	64.9	4.1%	-6.6%	-0.3%	-158.9%	-5.4%	1.7%
Mining	7.3%	54.7	4.5	-0.2	-8.5	50.6	6.3%	-12.0%	-138.1%	-136.8%	-10.8%	3.8%
Construction	14.7%	71.0	32.9	-12.2	-3.6	88.1	17.2%	-0.7%	0.2%	-303.8%	-3.2%	2.2%
Refining Industry[2]	7.1%	255.1	-5.4	-1.6	-10.7	237.4	5.5%	-258.4%	-129.0%	-28.2%	-5.3%	1.9%
Food Industry[2]	9.2%	97.8	20.6	-10.7	-12.9	94.9	8.8%	-8.2%	0.3%	-263.6%	-10.8%	0.8%
Wood Products	1.4%	18.5	4.5	-0.6	-4.2	18.3	1.4%	-14.4%	14.4%	-139.7%	-14.5%	0.6%
Paper Industry[2]	2.1%	66.8	14.7	-4.8	-14.3	62.5	2.1%	-16.2%	9.1%	-55.5%	-10.9%	-0.4%
Bulk Chemical Industry[2]	4.6%	235.9	47.7	-20.3	-28.3	235.1	4.4%	-20.6%	11.0%	-93.0%	-9.2%	-1.5%
Plastics	2.8%	39.0	4.5	-7.0	-6.9	29.6	2.4%	-41.8%	4.7%	-526.0%	-23.0%	-4.9%
Glass Industry[2]	0.3%	18.7	5.1	-1.3	-1.8	20.8	0.3%	-18.4%	-3.6%	-282.5%	-10.8%	-2.3%
Cement and Lime Industry[2]	0.1%	30.9	11.2	-3.3	-2.4	36.4	0.1%	-12.4%	9.9%	-123.2%	-6.6%	-1.4%
Iron and Steel Industries[2]	1.9%	126.7	36.0	-23.2	-7.8	131.8	2.0%	-25.6%	8.1%	-3288.8%	-12.1%	-4.6%
Aluminum Industry[2]	0.5%	50.7	7.8	-12.9	-9.0	36.6	0.5%	-56.5%	-120.9%	-118.4%	-37.7%	-13.1%
Fabricated Metal Products	4.4%	39.1	6.4	-5.5	-6.5	33.5	4.1%	-13.9%	-3.9%	-372.9%	-16.1%	1.2%
Machinery	5.0%	25.0	8.7	-5.5	-4.9	23.3	5.6%	-18.5%	-6.4%	-563.3%	-21.9%	-0.9%
Computers	6.2%	28.7	12.2	-6.5	-5.7	28.6	7.3%	-10.8%	-1.6%	-181.5%	-15.6%	-0.3%
Transportation Equipment	12.1%	58.4	15.0	-11.0	-10.5	51.9	12.2%	-16.2%	-1.4%	-519.7%	-18.7%	-1.2%
Electrical Equipment	1.6%	7.8	2.8	-1.6	-1.4	7.5	1.8%	-13.4%	-2.1%	-589.4%	-18.3%	0.6%
Balance of Manufacturing	14.1%	191.1	52.9	-23.0	-12.5	208.5	14.1%	-11.9%	-5.7%	-114.2%	-6.6%	-2.1%
Total	100.0%	1483.8	292.0	-159.0	-156.6	1460.1	100.0%	-18.6%	-7.4%	-149.8%	-10.6%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.82 Industry-specific decomposition results for \$25/tCO_2 at 4% policy

	2013		Policy Scenario (\$25/tCO_2 at 4%)					Percent difference from Reference				
			2013 - 2023			2023		2013 - 2023				
Industry	Mode Share[1] (% of sector)	Total Emissions (MMtCO_2)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share
Agriculture	4.5%	67.9	9.6	-7.8	-5.8	63.8	4.1%	-7.9%	0.4%	-213.4%	-6.9%	1.9%
Mining	7.3%	54.7	4.3	0.1	-10.4	48.8	6.3%	-16.5%	-64.5%	-189.2%	-13.9%	3.7%
Construction	14.7%	71.0	32.7	-12.1	-4.6	87.0	17.3%	-1.3%	0.8%	-419.2%	-4.5%	2.5%
Refining Industry[2]	7.1%	255.2	-6.0	-7.9	-14.1	227.1	5.5%	-293.8%	-242.8%	-68.9%	-9.4%	1.9%
Food Industry[2]	9.2%	97.9	20.2	-10.6	-15.0	92.4	8.8%	-9.9%	0.8%	-323.5%	-13.0%	1.0%
Wood Products	1.4%	18.6	4.3	-0.6	-4.8	17.4	1.4%	-18.2%	16.4%	-176.6%	-18.4%	0.4%
Paper Industry[2]	2.1%	66.8	14.4	-4.7	-15.5	61.0	2.1%	-18.2%	10.4%	-68.7%	-13.0%	-0.4%
Bulk Chemical Industry[2]	4.6%	236.0	45.5	-19.7	-31.4	230.4	4.4%	-24.3%	13.3%	-114.2%	-11.0%	-1.9%
Plastics	2.8%	39.0	4.1	-6.9	-8.2	28.0	2.4%	-47.7%	6.5%	-642.0%	-27.1%	-5.5%
Glass Industry[2]	0.3%	18.8	4.9	-1.3	-2.1	20.3	0.3%	-22.0%	-3.5%	-347.8%	-13.1%	-2.8%
Cement and Lime Industry[2]	0.1%	31.0	10.9	-3.3	-2.8	35.8	0.1%	-15.0%	12.0%	-156.1%	-8.2%	-1.7%
Iron and Steel Industries[2]	1.9%	126.7	33.9	-22.8	-9.4	128.4	2.0%	-30.1%	9.7%	-4009.2%	-14.3%	-5.5%
Aluminum Industry[2]	0.5%	50.7	6.7	-13.1	-10.6	33.8	0.5%	-62.5%	-124.7%	-156.0%	-42.5%	-14.4%
Fabricated Metal Products	4.4%	39.1	6.2	-5.4	-7.7	32.2	4.1%	-16.1%	-3.6%	-456.7%	-19.3%	1.4%
Machinery	5.0%	25.0	8.4	-5.5	-5.8	22.1	5.6%	-21.4%	-5.8%	-683.0%	-25.8%	-1.0%
Computers	6.2%	28.7	11.9	-6.5	-6.9	27.2	7.3%	-13.3%	-0.4%	-241.0%	-19.9%	-0.1%
Transportation Equipment	12.1%	58.4	14.5	-10.9	-12.4	49.6	12.2%	-19.2%	-0.7%	-633.4%	-22.4%	-1.3%
Electrical Equipment	1.6%	7.8	2.7	-1.6	-1.7	7.2	1.8%	-15.8%	-1.3%	-721.1%	-21.9%	0.7%
Balance of Manufacturing	14.1%	191.0	51.9	-22.6	-13.5	206.9	14.1%	-13.5%	-3.8%	-131.3%	-7.3%	-2.2%
Total	100.0%	1484.0	281.0	-163.3	-182.6	1419.2	100.0%	-21.7%	-10.3%	-191.2%	-13.1%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.83 Industry-specific decomposition results for $25/t$CO_2$ at 6% policy

	2013		Policy Scenario ($25/t$CO_2$ at 6%)					Percent difference from Reference				
			2013 - 2023			2023		2013 - 2023				
Industry	Mode Share[1] (% of sector)	Total Emissions (MMtCO_2)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share
Agriculture	4.5%	67.9	9.4	-7.8	-6.7	62.8	4.1%	-9.5%	0.5%	-259.9%	-8.4%	2.2%
Mining	7.3%	54.7	4.1	0.4	-12.2	47.1	6.3%	-20.2%	8.5%	-239.2%	-16.9%	3.9%
Construction	14.7%	71.0	32.6	-12.0	-5.4	86.1	17.4%	-1.6%	1.4%	-513.3%	-5.4%	3.0%
Refining Industry[2]	7.1%	255.2	-7.1	-9.2	-15.7	223.2	5.5%	-366.9%	-265.6%	-88.0%	-10.9%	2.1%
Food Industry[2]	9.2%	97.8	19.8	-10.5	-17.0	90.1	8.8%	-11.8%	1.8%	-381.3%	-15.3%	1.2%
Wood Products	1.4%	18.6	4.1	-0.5	-5.4	16.7	1.3%	-22.5%	23.5%	-211.2%	-22.0%	0.0%
Paper Industry[2]	2.1%	66.8	14.0	-4.6	-16.7	59.5	2.1%	-20.3%	12.3%	-81.4%	-15.1%	-0.3%
Bulk Chemical Industry[2]	4.6%	236.0	42.6	-19.0	-34.4	225.2	4.3%	-29.2%	16.5%	-134.7%	-13.1%	-2.6%
Plastics	2.8%	39.0	3.5	-6.8	-9.4	26.4	2.4%	-54.9%	8.2%	-748.0%	-31.3%	-6.3%
Glass Industry[2]	0.3%	18.8	4.6	-1.3	-2.3	19.7	0.3%	-26.9%	-3.3%	-403.4%	-15.4%	-3.5%
Cement and Lime Industry[2]	0.1%	31.0	10.5	-3.2	-3.1	35.2	0.1%	-18.3%	14.6%	-184.8%	-9.8%	-2.3%
Iron and Steel Industries[2]	1.9%	126.7	31.0	-22.4	-11.0	124.3	1.9%	-36.0%	11.2%	-4705.2%	-17.0%	-6.9%
Aluminum Industry[2]	0.5%	50.7	5.1	-14.7	-12.0	29.2	0.5%	-71.6%	-152.0%	-189.8%	-50.3%	-16.4%
Fabricated Metal Products	4.4%	39.1	6.0	-5.4	-8.7	31.0	4.1%	-18.5%	-3.6%	-533.1%	-22.4%	1.6%
Machinery	5.0%	25.0	8.1	-5.5	-6.6	20.9	5.6%	-24.8%	-6.0%	-790.7%	-29.8%	-1.2%
Computers	6.2%	28.7	11.5	-6.4	-7.8	25.9	7.3%	-15.7%	0.3%	-288.1%	-23.5%	0.0%
Transportation Equipment	12.1%	58.4	13.9	-10.9	-14.2	47.3	12.2%	-22.4%	-0.1%	-738.1%	-26.0%	-1.4%
Electrical Equipment	1.6%	7.8	2.6	-1.6	-1.9	6.8	1.8%	-18.6%	-0.8%	-843.5%	-25.6%	0.7%
Balance of Manufacturing	14.1%	191.1	50.7	-22.2	-14.0	205.7	14.0%	-15.6%	-1.7%	-140.4%	-7.8%	-2.3%
Total	100.0%	1484.2	267.0	-163.6	-204.6	1383.0	100.0%	-25.6%	-10.5%	-226.3%	-15.3%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.84 Industry-specific decomposition results for \$25/tCO$_2$ at 8% policy

	2013		Policy Scenario (\$25/tCO$_2$ at 8%)					Percent difference from Reference				
			2013 - 2023			2023		2013 - 2023				
Industry	Mode Share[1] (% of sector)	Total Emissions (MMtCO$_2$)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO$_2$)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO$_2$)	Mode Share
Agriculture	4.5%	67.9	9.3	-7.8	-7.8	61.5	4.1%	-11.0%	0.7%	-320.3%	-10.3%	2.4%
Mining	7.3%	54.7	4.0	0.7	-14.3	45.1	6.3%	-23.1%	81.2%	-298.8%	-20.4%	4.1%
Construction	14.7%	71.0	32.5	-12.0	-6.6	84.9	17.4%	-2.1%	2.1%	-642.8%	-6.7%	3.4%
Refining Industry[2]	7.1%	255.2	-7.5	-2.1	-14.4	231.2	5.5%	-396.3%	-137.2%	-71.4%	-7.7%	2.1%
Food Industry[2]	9.2%	97.8	19.4	-10.5	-19.2	87.6	8.8%	-13.6%	2.3%	-441.9%	-17.6%	1.4%
Wood Products	1.4%	18.6	3.9	-0.5	-6.1	15.8	1.3%	-26.8%	27.7%	-250.8%	-26.1%	-0.3%
Paper Industry[2]	2.1%	66.8	13.6	-4.5	-18.0	58.0	2.1%	-22.4%	13.7%	-95.4%	-17.3%	-0.3%
Bulk Chemical Industry[2]	4.6%	236.0	40.1	-18.4	-37.4	220.2	4.3%	-33.3%	19.0%	-155.5%	-15.0%	-3.2%
Plastics	2.8%	39.0	3.0	-6.6	-10.6	24.8	2.4%	-61.2%	10.0%	-859.6%	-35.4%	-7.2%
Glass Industry[2]	0.3%	18.8	4.3	-1.2	-2.6	19.2	0.3%	-31.3%	-3.0%	-467.3%	-17.9%	-4.3%
Cement and Lime Industry[2]	0.1%	31.0	10.1	-3.1	-3.5	34.5	0.1%	-21.4%	17.4%	-218.5%	-11.5%	-2.8%
Iron and Steel Industries[2]	1.9%	126.7	28.5	-22.0	-12.6	120.6	1.9%	-41.2%	12.7%	-5419.0%	-19.5%	-8.1%
Aluminum Industry[2]	0.5%	50.8	3.9	-16.7	-13.4	24.5	0.5%	-78.3%	-187.0%	-224.4%	-58.2%	-17.9%
Fabricated Metal Products	4.4%	39.1	5.8	-5.4	-9.9	29.7	4.1%	-20.9%	-3.5%	-615.1%	-25.6%	1.8%
Machinery	5.0%	25.0	7.7	-5.5	-7.5	19.8	5.6%	-27.8%	-5.8%	-903.6%	-33.6%	-1.4%
Computers	6.2%	28.7	11.1	-6.3	-9.2	24.3	7.3%	-18.7%	1.5%	-353.2%	-28.3%	0.1%
Transportation Equipment	12.1%	58.4	13.4	-10.8	-16.0	45.0	12.2%	-25.3%	0.4%	-846.6%	-29.5%	-1.5%
Electrical Equipment	1.6%	7.8	2.5	-1.6	-2.2	6.5	1.8%	-21.2%	0.0%	-973.4%	-29.2%	0.7%
Balance of Manufacturing	14.1%	191.0	49.5	-21.6	-15.0	204.0	14.0%	-17.5%	1.1%	-157.2%	-8.6%	-2.5%
Total	100.0%	1484.2	255.0	-156.0	-226.1	1357.1	100.0%	-28.9%	-5.3%	-260.6%	-16.9%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.85 Industry-specific decomposition results for $35/tCO$_2$ at 2% policy

	2013		Policy Scenario ($35/tCO$_2$ at 2%) 2013 - 2023			Policy Scenario 2023		Percent difference from Reference 2013 - 2023				
Industry	Mode Share[1] (% of sector)	Total Emissions (MMtCO$_2$)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO$_2$)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO$_2$)	Mode Share
Agriculture	4.5%	67.9	9.4	-7.9	-6.6	62.7	4.1%	-9.6%	-0.8%	-258.6%	-8.6%	2.2%
Mining	7.3%	54.7	4.2	-0.2	-11.6	47.2	6.3%	-18.4%	-136.7%	-222.0%	-16.7%	4.1%
Construction	14.7%	71.0	32.8	-12.1	-5.4	86.3	17.4%	-1.0%	0.8%	-510.7%	-5.2%	3.2%
Refining Industry[2]	7.1%	255.2	-7.1	-11.1	-15.5	221.5	5.5%	-366.0%	-299.0%	-85.4%	-11.6%	1.9%
Food Industry[2]	9.2%	97.8	19.9	-10.7	-16.7	90.3	8.8%	-11.6%	0.4%	-370.6%	-15.1%	1.2%
Wood Products	1.4%	18.6	4.2	-0.6	-5.3	16.8	1.4%	-20.9%	16.9%	-206.2%	-21.4%	0.3%
Paper Industry[2]	2.1%	66.8	13.8	-4.7	-16.4	59.5	2.1%	-21.5%	11.2%	-78.8%	-15.2%	-0.7%
Bulk Chemical Industry[2]	4.6%	235.9	42.5	-19.2	-33.5	225.7	4.3%	-29.3%	15.5%	-128.5%	-12.8%	-2.7%
Plastics	2.8%	39.0	3.4	-6.8	-9.1	26.4	2.4%	-55.9%	7.1%	-727.3%	-31.1%	-6.8%
Glass Industry[2]	0.3%	18.8	4.6	-1.3	-2.3	19.8	0.3%	-26.1%	-5.0%	-392.7%	-15.1%	-3.4%
Cement and Lime Industry[2]	0.1%	31.0	10.5	-3.2	-3.1	35.3	0.1%	-17.7%	14.6%	-181.6%	-9.5%	-2.2%
Iron and Steel Industries[2]	1.9%	126.7	31.1	-22.7	-10.7	124.5	1.9%	-35.8%	10.2%	-4559.6%	-16.9%	-6.9%
Aluminum Industry[2]	0.5%	50.7	4.8	-16.7	-12.2	26.7	0.5%	-73.2%	-186.3%	-194.8%	-54.6%	-16.9%
Fabricated Metal Products	4.4%	39.1	6.0	-5.5	-8.6	31.0	4.1%	-18.7%	-4.7%	-521.5%	-22.2%	1.5%
Machinery	5.0%	25.0	8.0	-5.5	-6.5	21.0	5.6%	-25.0%	-7.2%	-773.0%	-29.6%	-1.4%
Computers	6.2%	28.7	11.5	-6.5	-7.7	26.0	7.3%	-15.7%	-0.8%	-282.6%	-23.4%	0.1%
Transportation Equipment	12.1%	58.4	13.9	-11.0	-13.9	47.4	12.2%	-22.2%	-1.3%	-724.0%	-25.8%	-1.4%
Electrical Equipment	1.6%	7.8	2.6	-1.6	-1.9	6.9	1.8%	-18.1%	-2.0%	-819.8%	-25.1%	0.9%
Balance of Manufacturing	14.1%	191.2	50.5	-21.9	-14.3	205.5	14.0%	-15.9%	-0.4%	-145.4%	-7.9%	-2.5%
Total	100.0%	1484.0	266.8	-169.1	-201.3	1380.4	100.0%	-25.6%	-14.2%	-221.0%	-15.5%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.86 Industry-specific decomposition results for $35/t$CO_2$ at 4% policy

Industry	2013 Mode Share[1] (% of sector)	2013 Total Emissions (MMtCO_2)	Policy Scenario ($35/t$CO_2$ at 4%) 2013 - 2023 Activity effect	Energy Intensity effect	Carbon Intensity effect	2023 Total Emissions (MMtCO_2)	2023 Mode Share[1] (% of sector)	Percent difference from Reference 2013 - 2023 Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share
Agriculture	4.5%	67.9	9.2	-7.9	-7.9	61.3	4.1%	-11.5%	-0.6%	-326.6%	-10.7%	2.4%
Mining	7.3%	54.7	3.9	0.2	-14.0	44.8	6.3%	-23.7%	-46.9%	-290.0%	-20.9%	4.1%
Construction	14.7%	71.0	32.6	-12.1	-6.7	84.9	17.5%	-1.6%	1.4%	-656.0%	-6.8%	3.8%
Refining Industry[2]	7.1%	254.9	-8.0	-3.5	-14.3	229.1	5.5%	-426.5%	-163.0%	-71.1%	-8.6%	2.0%
Food Industry[2]	9.2%	97.7	19.4	-10.6	-19.3	87.2	8.8%	-13.8%	1.5%	-445.7%	-18.0%	1.5%
Wood Products	1.4%	18.6	3.9	-0.6	-6.2	15.7	1.3%	-26.1%	21.9%	-255.2%	-26.5%	0.0%
Paper Industry[2]	2.1%	66.8	13.4	-4.6	-18.0	57.5	2.1%	-24.0%	13.3%	-95.9%	-17.9%	-0.6%
Bulk Chemical Industry[2]	4.6%	235.9	39.4	-18.4	-37.6	219.3	4.3%	-34.4%	19.0%	-156.5%	-15.3%	-3.4%
Plastics	2.8%	39.0	2.8	-6.6	-10.7	24.5	2.4%	-63.4%	9.8%	-870.4%	-36.3%	-7.7%
Glass Industry[2]	0.3%	18.7	4.3	-1.3	-2.7	19.1	0.3%	-31.7%	-4.1%	-472.4%	-18.2%	-4.3%
Cement and Lime Industry[2]	0.1%	31.0	10.1	-3.0	-3.5	34.5	0.1%	-21.5%	17.9%	-222.5%	-11.6%	-2.8%
Iron and Steel Industries[2]	1.9%	126.7	28.0	-22.1	-12.8	119.7	1.9%	-42.3%	12.3%	-5496.8%	-20.1%	-8.4%
Aluminum Industry[2]	0.5%	50.7	3.5	-16.7	-13.5	23.9	0.5%	-80.6%	-186.7%	-227.6%	-59.2%	-19.0%
Fabricated Metal Products	4.4%	39.1	5.8	-5.4	-10.0	29.4	4.1%	-21.7%	-3.9%	-624.1%	-26.2%	1.7%
Machinery	5.0%	25.0	7.6	-5.5	-7.6	19.5	5.6%	-29.0%	-6.1%	-915.6%	-34.4%	-1.7%
Computers	6.2%	28.6	11.0	-6.4	-9.2	24.1	7.3%	-19.2%	0.9%	-356.8%	-28.9%	0.2%
Transportation Equipment	12.1%	58.4	13.3	-10.8	-16.2	44.6	12.2%	-25.7%	-0.1%	-860.5%	-30.2%	-1.4%
Electrical Equipment	1.6%	7.8	2.5	-1.6	-2.2	6.4	1.8%	-21.6%	-0.4%	-988.0%	-29.8%	0.8%
Balance of Manufacturing	14.1%	191.0	49.0	-19.9	-17.2	202.9	14.0%	-18.4%	8.5%	-195.2%	-9.1%	-2.6%
Total	100.0%	1483.3	251.7	-156.9	-229.7	1348.5	100.0%	-29.8%	-6.0%	-266.3%	-17.4%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.87 Industry-specific decomposition results for $35/tCO$_2$ at 6% policy

Industry	2013 Mode Share[1] (% of sector)	2013 Total Emissions ($MMtCO_2$)	Policy Scenario ($35/t$CO_2$ at 6%) 2013 - 2023 Activity effect	Policy Scenario 2013 - 2023 Energy Intensity effect	Policy Scenario 2013 - 2023 Carbon Intensity effect	Policy Scenario 2023 Total Emissions ($MMtCO_2$)	Policy Scenario 2023 Mode Share[1] (% of sector)	Percent difference from Reference 2013 - 2023 Activity effect	Percent difference Energy Intensity effect	Percent difference Carbon Intensity effect	Percent difference Total Emissions ($MMtCO_2$)	Percent difference Mode Share
Agriculture	4.5%	67.9	9.0	-7.9	-9.3	59.7	4.1%	-13.6%	0.0%	-402.6%	-13.0%	2.8%
Mining	7.3%	54.7	3.7	0.4	-16.5	42.3	6.3%	-29.0%	7.7%	-360.6%	-25.4%	4.1%
Construction	14.7%	71.0	32.6	-12.0	-8.1	83.5	17.6%	-1.7%	1.9%	-817.4%	-8.3%	4.6%
Refining Industry[2]	7.1%	254.9	-8.9	-6.8	-18.2	221.1	5.5%	-484.6%	-221.8%	-117.6%	-11.8%	2.0%
Food Industry[2]	9.2%	97.7	18.7	-10.3	-22.8	83.3	8.8%	-16.7%	3.8%	-545.0%	-21.7%	1.8%
Wood Products	1.4%	18.6	3.6	-0.5	-7.2	14.4	1.3%	-32.0%	34.1%	-315.0%	-32.4%	-0.5%
Paper Industry[2]	2.1%	66.8	12.9	-4.4	-20.0	55.2	2.1%	-26.8%	16.2%	-117.4%	-21.2%	-0.5%
Bulk Chemical Industry[2]	4.6%	235.9	35.3	-17.3	-43.2	210.7	4.3%	-41.2%	23.8%	-195.0%	-18.6%	-4.3%
Plastics	2.8%	39.0	2.2	-6.3	-13.0	21.8	2.3%	-72.2%	14.2%	-1078.3%	-43.2%	-8.8%
Glass Industry[2]	0.3%	18.7	3.8	-1.2	-3.2	18.1	0.3%	-38.7%	-1.6%	-593.0%	-22.3%	-5.5%
Cement and Lime Industry[2]	0.1%	31.0	9.5	-2.9	-4.1	33.4	0.1%	-26.1%	22.2%	-276.9%	-14.2%	-3.6%
Iron and Steel Industries[2]	1.9%	126.7	24.1	-21.4	-15.7	113.7	1.8%	-50.4%	15.2%	-6751.3%	-24.1%	-10.4%
Aluminum Industry[2]	0.5%	50.7	2.2	-15.7	-15.4	21.8	0.5%	-87.5%	-170.4%	-272.6%	-62.8%	-21.2%
Fabricated Metal Products	4.4%	39.1	5.5	-5.3	-12.0	27.3	4.1%	-25.6%	-1.4%	-773.1%	-31.7%	2.0%
Machinery	5.0%	25.0	7.0	-5.3	-9.2	17.6	5.5%	-34.2%	-2.8%	-1128.0%	-41.1%	-2.1%
Computers	6.2%	28.7	10.4	-6.1	-11.2	21.8	7.3%	-23.6%	4.4%	-453.6%	-35.8%	0.3%
Transportation Equipment	12.1%	58.4	12.5	-10.5	-19.5	40.9	12.2%	-30.3%	3.2%	-1054.9%	-36.0%	-1.5%
Electrical Equipment	1.6%	7.8	2.4	-1.5	-2.8	5.8	1.8%	-26.2%	3.3%	-1237.0%	-36.3%	0.7%
Balance of Manufacturing	14.1%	191.1	46.8	-19.2	-21.1	197.6	14.0%	-22.0%	12.0%	-262.6%	-11.5%	-2.9%
Total	100.0%	1483.5	233.3	-154.3	-272.6	1289.9	100.0%	-35.0%	-4.2%	-334.7%	-21.0%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.88 Industry-specific decomposition results for \$35/tCO_2 at 8% policy

Industry	2013 Mode Share[1] (% of sector)	2013 Total Emissions ($MMtCO_2$)	Policy Scenario (\$35/tCO_2 at 8%) 2013 - 2023 Activity effect	Policy Scenario 2013 - 2023 Energy Intensity effect	Policy Scenario 2013 - 2023 Carbon Intensity effect	Policy Scenario 2023 Total Emissions ($MMtCO_2$)	Policy Scenario 2023 Mode Share[1] (% of sector)	Percent difference from Reference 2013 - 2023 Activity effect	Percent difference Energy Intensity effect	Percent difference Carbon Intensity effect	Percent difference Total Emissions ($MMtCO_2$)	Percent difference Mode Share
Agriculture	4.5%	67.9	8.6	-7.8	-11.0	57.6	4.1%	-17.4%	0.6%	-493.5%	-15.9%	3.4%
Mining	7.3%	54.7	3.1	0.9	-19.0	39.7	6.4%	-38.9%	113.8%	-429.0%	-29.9%	4.3%
Construction	14.7%	71.0	31.3	-11.7	-9.8	80.8	17.7%	-5.6%	4.5%	-1009.1%	-11.3%	4.7%
Refining Industry[2]	7.1%	254.9	-10.7	-1.7	-20.0	222.4	5.5%	-605.6%	-131.4%	-139.2%	-11.2%	2.4%
Food Industry[2]	9.2%	97.7	17.8	-9.6	-28.5	77.3	8.9%	-20.6%	10.2%	-706.1%	-27.3%	2.6%
Wood Products	1.4%	18.6	3.2	0.0	-8.4	13.4	1.3%	-38.6%	95.5%	-382.1%	-37.5%	-0.8%
Paper Industry[2]	2.1%	66.7	12.3	-3.8	-22.3	52.9	2.1%	-30.2%	28.0%	-142.1%	-24.5%	-0.7%
Bulk Chemical Industry[2]	4.6%	235.8	32.8	-15.9	-51.0	201.7	4.2%	-45.5%	30.1%	-248.1%	-22.1%	-4.4%
Plastics	2.8%	39.0	1.4	-5.9	-16.5	18.0	2.3%	-82.0%	19.2%	-1389.8%	-53.2%	-9.8%
Glass Industry[2]	0.3%	18.7	3.3	-1.2	-3.9	16.9	0.3%	-46.7%	0.8%	-749.7%	-27.5%	-6.4%
Cement and Lime Industry[2]	0.1%	30.9	8.8	-2.7	-4.9	32.1	0.1%	-31.7%	26.2%	-349.3%	-17.7%	-4.2%
Iron and Steel Industries[2]	1.9%	126.7	19.6	-20.8	-19.6	105.9	1.8%	-59.5%	17.6%	-8448.3%	-29.3%	-12.5%
Aluminum Industry[2]	0.5%	50.4	-1.2	-13.1	-18.5	17.6	0.4%	-106.7%	-124.8%	-347.8%	-70.0%	-27.2%
Fabricated Metal Products	4.4%	39.1	4.9	-5.2	-15.2	23.7	4.1%	-33.0%	1.6%	-1002.6%	-40.7%	2.4%
Machinery	5.0%	25.0	6.1	-5.3	-11.6	14.2	5.5%	-42.8%	-1.8%	-1459.3%	-52.3%	-2.4%
Computers	6.2%	28.6	9.6	-5.9	-13.1	19.2	7.3%	-30.1%	8.2%	-549.1%	-43.5%	0.2%
Transportation Equipment	12.1%	58.3	11.1	-10.0	-25.1	34.3	12.2%	-38.1%	7.7%	-1389.5%	-46.3%	-1.6%
Electrical Equipment	1.6%	7.8	2.1	-1.5	-3.5	4.9	1.8%	-35.2%	8.1%	-1582.2%	-46.4%	0.2%
Balance of Manufacturing	14.1%	191.1	44.5	-19.5	-21.9	194.2	14.0%	-25.9%	10.4%	-276.2%	-13.0%	-2.8%
Total	100.0%	1482.8	208.6	-140.9	-323.8	1226.7	100.0%	-41.8%	4.8%	-416.4%	-24.9%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

B.14 INDUSTRY-SPECIFIC LMDI FROM REVENUE RECYCLING METHODS

Table B.89 Industry-specific LMDI comparison under consumer rebate

	Consumer Rebate												
			Policy Scenario (\$25/tCO_2 at 2%)					Percent difference from Reference					
	2013		2013 - 2023			2023		2013 - 2023					
Industry	Mode Share[1] (% of sector)	Total Emissions ($MMtCO_2$)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions ($MMtCO_2$)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions ($MMtCO_2$)	Mode Share	
Agriculture	4.5%	67.9	9.7	-7.9	-4.8	64.9	4.1%	-6.6%	-0.3%	-159.6%	-5.4%	1.7%	
Mining	7.3%	54.7	4.5	-0.1	-8.6	50.5	6.3%	-12.0%	-128.3%	-139.0%	-10.8%	3.7%	
Construction	14.7%	71.0	32.9	-12.2	-3.6	88.1	17.2%	-0.8%	0.3%	-305.4%	-3.2%	2.2%	
Refining Industry[2]	7.1%	255.1	-5.5	-1.5	-10.8	237.4	5.5%	-260.6%	-127.8%	-28.7%	-5.3%	1.9%	
Food Industry[2]	9.2%	97.8	20.6	-10.7	-12.9	94.9	8.8%	-8.2%	0.3%	-263.6%	-10.8%	0.8%	
Wood Products	1.4%	18.5	4.5	-0.6	-4.2	18.2	1.4%	-14.5%	13.6%	-141.0%	-14.7%	0.6%	
Paper Industry[2]	2.1%	66.8	14.7	-4.8	-14.3	62.4	2.1%	-16.2%	9.2%	-55.9%	-10.9%	-0.5%	
Bulk Chemical Industry[2]	4.6%	235.9	47.8	-20.3	-28.4	235.1	4.4%	-20.5%	10.9%	-93.7%	-9.2%	-1.5%	
Plastics	2.8%	39.0	4.5	-7.0	-6.9	29.6	2.4%	-41.8%	4.6%	-526.9%	-23.0%	-4.9%	
Glass Industry[2]	0.3%	18.8	5.1	-1.3	-1.8	20.8	0.3%	-18.5%	-3.8%	-283.7%	-10.8%	-2.3%	
Cement and Lime Industry[2]	0.1%	30.9	11.2	-3.3	-2.4	36.4	0.1%	-12.4%	9.9%	-123.7%	-6.6%	-1.4%	
Iron and Steel Industries[2]	1.9%	126.7	36.0	-23.2	-7.8	131.7	2.0%	-25.6%	8.1%	-3308.3%	-12.1%	-4.6%	
Aluminum Industry[2]	0.5%	50.7	7.7	-12.9	-9.0	36.5	0.5%	-56.9%	-121.5%	-118.5%	-37.8%	-13.2%	
Fabricated Metal Products	4.4%	39.1	6.4	-5.5	-6.5	33.5	4.1%	-13.8%	-4.1%	-372.7%	-16.1%	1.2%	
Machinery	5.0%	25.0	8.7	-5.5	-4.9	23.3	5.6%	-18.5%	-6.5%	-561.7%	-21.9%	-0.9%	
Computers	6.2%	28.7	12.2	-6.5	-5.7	28.6	7.3%	-10.8%	-1.7%	-183.1%	-15.6%	-0.3%	
Transportation Equipment	12.1%	58.4	15.0	-11.0	-10.4	51.9	12.2%	-16.2%	-1.7%	-517.9%	-18.7%	-1.2%	
Electrical Equipment	1.6%	7.8	2.8	-1.6	-1.4	7.5	1.8%	-13.3%	-2.2%	-591.4%	-18.3%	0.7%	
Balance of Manufacturing	14.1%	191.0	52.9	-23.0	-12.7	208.3	14.1%	-11.9%	-5.3%	-118.6%	-6.7%	-2.1%	
Total	100.0%	1483.9	291.9	-159.0	-157.2	1459.6	100.0%	-18.6%	-7.4%	-150.8%	-10.6%	0.0%	

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.90 Industry-specific LMDI comparison under deficit reduction

	Deficit Reduction											
			Policy Scenario ($25/tCO$_2$ at 2%)					Percent difference from Reference				
	2013		2013 - 2023			2023		2013 - 2023				
Industry	Mode Share[1] (% of sector)	Total Emissions (MMtCO$_2$)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO$_2$)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO$_2$)	Mode Share
Agriculture	4.5%	67.9	9.9	-8.0	-4.9	65.0	4.0%	-4.6%	-1.1%	-161.9%	-5.2%	0.9%
Mining	7.3%	54.7	4.7	-0.1	-8.3	51.0	6.3%	-9.5%	-113.7%	-131.7%	-10.0%	2.8%
Construction	14.7%	71.0	34.0	-12.5	-3.6	88.9	17.2%	2.5%	-2.0%	-310.7%	-2.4%	2.1%
Refining Industry[2]	7.1%	254.9	-4.6	-1.7	-10.8	237.7	5.4%	-206.7%	-130.7%	-29.3%	-5.1%	1.0%
Food Industry[2]	9.2%	97.8	20.4	-10.7	-13.0	94.6	8.6%	-9.0%	0.2%	-267.0%	-11.0%	-0.4%
Wood Products	1.4%	18.5	4.7	-0.6	-4.2	18.4	1.3%	-11.2%	8.5%	-141.8%	-14.1%	0.2%
Paper Industry[2]	2.2%	66.8	15.8	-5.0	-14.7	63.0	2.1%	-9.9%	4.8%	-59.5%	-10.1%	0.3%
Bulk Chemical Industry[2]	4.6%	235.9	51.2	-21.1	-28.4	237.7	4.4%	-14.9%	7.3%	-93.6%	-8.2%	-1.3%
Plastics	2.8%	39.0	4.8	-7.1	-7.0	29.7	2.4%	-38.4%	3.7%	-532.2%	-22.6%	-5.2%
Glass Industry[2]	0.3%	18.8	5.5	-1.3	-1.8	21.2	0.3%	-11.9%	-6.5%	-286.3%	-9.3%	-2.1%
Cement and Lime Industry[2]	0.1%	30.9	11.7	-3.5	-2.5	36.7	0.1%	-9.0%	6.7%	-125.3%	-5.8%	-1.5%
Iron and Steel Industries[2]	1.9%	126.8	42.5	-24.6	-7.8	136.8	2.0%	-12.3%	2.6%	-3325.5%	-8.7%	-2.1%
Aluminum Industry[2]	0.5%	50.7	8.3	-13.1	-9.2	36.8	0.5%	-53.3%	-124.3%	-123.6%	-37.4%	-13.0%
Fabricated Metal Products	4.4%	39.1	7.0	-5.6	-6.6	33.9	4.1%	-4.9%	-6.1%	-380.6%	-15.0%	1.6%
Machinery	5.0%	25.0	9.7	-5.6	-5.1	24.0	5.7%	-9.1%	-7.8%	-584.7%	-19.3%	0.9%
Computers	6.2%	28.7	13.3	-6.8	-5.7	29.4	7.4%	-2.9%	-5.6%	-184.3%	-13.3%	1.1%
Transportation Equipment	12.1%	58.4	15.8	-11.2	-10.7	52.4	12.2%	-11.6%	-3.0%	-533.3%	-18.0%	-1.2%
Electrical Equipment	1.6%	7.8	3.1	-1.7	-1.4	7.7	1.8%	-4.1%	-5.2%	-600.1%	-15.9%	1.9%
Balance of Manufacturing	14.1%	191.1	54.8	-22.9	-13.2	209.8	14.0%	-8.7%	-5.0%	-126.7%	-6.0%	-2.5%
Total	100.0%	1483.7	312.6	-162.8	-159.0	1474.6	100.0%	-12.8%	-10.0%	-153.5%	-9.7%	0.0%

Notes [1] Share of Value of Shipments (VS)

[2] Energy Intense Industries (as identified by EIA)

Table B.91 Industry-specific LMDI comparison under business rebate

	2013		Business Rebate — Policy Scenario ($25/t$CO_2$ at 2%) 2013 - 2023			2023		Percent difference from Reference 2013 - 2023				
Industry	Mode Share[1] (% of sector)	Total Emissions (MMtCO_2)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO_2)	Mode Share
Agriculture	4.5%	67.9	9.9	-8.0	-4.8	65.0	4.0%	-4.7%	-1.2%	-157.8%	-5.1%	1.2%
Mining	7.3%	54.7	4.6	-0.1	-8.5	50.7	6.3%	-11.2%	-123.2%	-135.7%	-10.5%	3.0%
Construction	14.7%	71.0	33.6	-12.4	-3.6	88.7	17.2%	1.4%	-1.2%	-302.1%	-2.6%	2.2%
Refining Industry[2]	7.1%	254.9	-4.6	-7.9	-13.0	229.4	5.4%	-201.0%	-241.6%	-55.7%	-8.4%	1.4%
Food Industry[2]	9.2%	97.8	20.8	-10.8	-12.8	95.1	8.7%	-7.4%	-0.4%	-260.5%	-10.6%	0.1%
Wood Products	1.4%	18.6	4.7	-0.6	-4.2	18.4	1.4%	-11.6%	11.1%	-140.2%	-13.9%	0.6%
Paper Industry[2]	2.2%	66.8	14.9	-4.8	-14.4	62.5	2.1%	-15.2%	8.2%	-56.4%	-10.8%	-0.4%
Bulk Chemical Industry[2]	4.6%	236.0	48.6	-20.5	-28.1	236.0	4.4%	-19.1%	10.0%	-91.9%	-8.9%	-1.8%
Plastics	2.8%	39.0	4.7	-7.1	-6.8	29.8	2.4%	-39.3%	3.9%	-518.7%	-22.4%	-5.0%
Glass Industry[2]	0.3%	18.8	5.3	-1.3	-1.8	21.0	0.3%	-16.0%	-5.3%	-280.0%	-10.2%	-2.4%
Cement and Lime Industry[2]	0.1%	31.0	11.5	-3.4	-2.4	36.6	0.1%	-10.6%	8.8%	-122.1%	-6.1%	-1.5%
Iron and Steel Industries[2]	1.9%	126.8	37.6	-23.6	-7.7	133.1	2.0%	-22.5%	6.6%	-3253.2%	-11.2%	-4.0%
Aluminum Industry[2]	0.5%	50.7	7.8	-12.9	-8.9	36.6	0.5%	-56.5%	-122.2%	-116.1%	-37.6%	-13.7%
Fabricated Metal Products	4.4%	39.1	6.7	-5.5	-6.4	33.8	4.1%	-9.8%	-5.6%	-367.6%	-15.3%	1.3%
Machinery	5.0%	25.0	9.1	-5.6	-4.9	23.6	5.6%	-14.6%	-7.7%	-558.4%	-20.6%	-0.3%
Computers	6.2%	28.7	12.6	-6.6	-5.7	29.0	7.3%	-7.6%	-3.3%	-181.6%	-14.6%	0.4%
Transportation Equipment	12.1%	58.4	15.8	-11.2	-10.4	52.7	12.3%	-11.8%	-2.9%	-513.3%	-17.5%	-0.6%
Electrical Equipment	1.6%	7.8	3.0	-1.7	-1.4	7.7	1.8%	-7.6%	-4.2%	-585.4%	-16.5%	2.0%
Balance of Manufacturing	14.1%	191.0	54.3	-22.5	-13.7	209.1	14.0%	-9.7%	-3.2%	-135.5%	-6.3%	-2.2%
Total	100.0%	1483.8	300.7	-166.3	-159.4	1458.8	100.0%	-16.2%	-12.4%	-154.2%	-10.7%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

Table B.92 Industry-specific LMDI comparison under 50/50 consumer/business rebate

	2013		50/50 Consumer/Business Policy Scenario ($25/tCO$_2$ at 2%) 2013 - 2023			2023		Percent difference from Reference 2013 - 2023				
Industry	Mode Share[1] (% of sector)	Total Emissions (MMtCO$_2$)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO$_2$)	Mode Share[1] (% of sector)	Activity effect	Energy Intensity effect	Carbon Intensity effect	Total Emissions (MMtCO$_2$)	Mode Share
Agriculture	4.5%	67.8	10.0	-7.9	-4.9	65.0	4.1%	-4.1%	-0.9%	-163.6%	-5.2%	1.8%
Mining	7.3%	54.7	4.5	-0.1	-8.6	50.5	6.3%	-11.8%	-124.4%	-140.7%	-10.9%	3.5%
Construction	14.7%	71.0	33.2	-12.3	-3.7	88.2	17.2%	0.1%	-0.3%	-313.3%	-3.1%	2.1%
Refining Industry[2]	7.1%	255.1	-5.1	-1.5	-10.9	237.7	5.4%	-235.3%	-126.7%	-29.9%	-5.1%	1.8%
Food Industry[2]	9.2%	97.8	20.7	-10.7	-12.9	94.8	8.7%	-8.0%	0.1%	-265.4%	-10.8%	0.6%
Wood Products	1.4%	18.5	4.6	-0.6	-4.2	18.3	1.4%	-12.9%	10.9%	-143.0%	-14.6%	0.7%
Paper Industry[2]	2.2%	66.8	15.0	-4.9	-14.4	62.6	2.1%	-14.4%	7.9%	-57.2%	-10.7%	0.1%
Bulk Chemical Industry[2]	4.6%	235.9	48.1	-20.3	-28.4	235.3	4.4%	-20.0%	10.8%	-94.1%	-9.2%	-1.5%
Plastics	2.8%	38.9	4.6	-7.0	-7.0	29.6	2.4%	-40.4%	4.5%	-530.7%	-22.9%	-4.8%
Glass Industry[2]	0.3%	18.7	5.1	-1.3	-1.8	20.8	0.3%	-18.2%	-4.5%	-285.7%	-10.9%	-2.6%
Cement and Lime Industry[2]	0.1%	30.9	11.3	-3.3	-2.5	36.5	0.1%	-11.8%	10.0%	-125.2%	-6.5%	-1.5%
Iron and Steel Industries[2]	1.9%	126.7	35.9	-23.2	-7.8	131.6	2.0%	-25.9%	8.0%	-3313.0%	-12.2%	-4.7%
Aluminum Industry[2]	0.5%	50.7	7.7	-12.9	-9.1	36.4	0.5%	-57.0%	-121.3%	-121.2%	-38.1%	-13.3%
Fabricated Metal Products	4.4%	39.1	6.4	-5.5	-6.6	33.5	4.1%	-13.0%	-4.4%	-375.6%	-16.1%	1.2%
Machinery	5.0%	25.0	8.7	-5.5	-5.0	23.2	5.6%	-18.9%	-6.4%	-565.5%	-22.2%	-1.1%
Computers	6.2%	28.7	12.4	-6.6	-5.8	28.7	7.3%	-9.6%	-2.2%	-186.8%	-15.5%	-0.2%
Transportation Equipment	12.1%	58.3	15.4	-11.1	-10.5	52.1	12.3%	-13.8%	-2.3%	-524.1%	-18.4%	-0.8%
Electrical Equipment	1.6%	7.8	2.8	-1.6	-1.4	7.5	1.8%	-11.8%	-2.6%	-595.8%	-18.0%	0.8%
Balance of Manufacturing	14.1%	191.2	53.4	-23.1	-12.6	208.8	14.1%	-11.1%	-6.1%	-116.7%	-6.4%	-2.2%
Total	100.0%	1483.7	294.8	-159.5	-158.1	1460.9	100.0%	-17.8%	-7.7%	-152.2%	-10.5%	0.0%

Notes [1] Share of Value of Shipments (VS)
[2] Energy Intense Industries (as identified by EIA)

C.1 LIST OF TABLES FOR APPENDIX C

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C.2 Spanning the 2009 housing crisis

The RECS data are from 2009 and the CEX data are from 2011, so combining them raises two monetary issues: the expenditures are in different dollar-years, and the datasets are from different sides of the 2009 housing crisis. The first issue is easily resolved by inflating the 2009 RECS energy expenditures to 2011 so the monies are of the same vintage. The second requires some work.

From the 2009 RECS, it is not possible to know how residential consumers reacted to the housing crisis, and the next survey report is not expected for a few more years. However, the CEX is an annual report and has expenditure data for both 2009 and 2011. One can evaluate the change in expenditures for each fuel between these two years in the CEX data, and scale the RECS 2009 data by the same ratio. The following tables show energy-related consumption for 2009 (Table C.1), for 2011 (Table C.2), and the ratio of 2011/2009 (Table C.3).

The ratios for each fuel type in Table C.3 are the growth factors between 2009 and 2011. Although only the first three fuel types from the 2009 RECS data need to be scaled, all are shown here for convenience. Natural gas expenditures declined (0.87) between 2009 and 2011, electricity remained about the same (1.03), and other fuels increased (1.11).

Table C.1 CEX energy-related consumption data for 2009

Market Segment	Households in Segment		Expenditure			Energy Expenditure by Fuel Type				
			Total	On Energy		Natural Gas	Electricity	Fuel Oil	Gasoline	Other
	(thousands)	(% of total)	($/HH)	($/HH)	(% of total)	($/HH)	($/HH)	($/HH)	($/HH)	($/HH)
Average Household										
Average Consumer Unit	120,847	100%	$49,067	$4,466	9.1%	$483	$1,377	$141	$1,986	$479
By Income Quintiles										
Lowest 20 percent (Q1)	24,165	20%	$21,611	$2,390	11.1%	$276	$943	$78	$926	$167
Second 20 percent (Q2)	24,120	20%	$31,382	$3,442	11.0%	$387	$1,235	$102	$1,498	$220
Third 20 percent (Q3)	24,212	20%	$41,150	$4,243	10.3%	$458	$1,364	$136	$1,982	$303
Fourth 20 percent (Q4)	24,154	20%	$56,879	$5,194	9.1%	$556	$1,517	$170	$2,457	$494
Highest 20 percent (Q5)	24,196	20%	$94,244	$7,062	7.5%	$739	$1,825	$220	$3,067	$1,211
By Region										
Northeast	22,411	18.5%	$53,868	$4,928	9.1%	$719	$1,306	$434	$1,787	$682
Midwest	27,536	22.8%	$46,551	$4,281	9.2%	$695	$1,119	$114	$1,933	$420
South	43,819	36.3%	$45,749	$4,464	9.8%	$266	$1,719	$62	$2,103	$314
West	27,080	22.4%	$53,005	$4,282	8.1%	$424	$1,143	$57	$2,018	$640
By Household Income										
Less than $5,000 (HH1)	4,749,000	3.9%	$22,731	$2,245	9.9%	$260	$824	$49	$932	$180
$5,000 to $9,999 (HH2)	5,203,000	4.3%	$18,032	$2,027	11.2%	$242	$847	$62	$761	$115
$10,000 to $14,999 (HH3)	7,726,000	6.4%	$21,741	$2,357	10.8%	$281	$953	$78	$894	$151
$15,000 to $19,999 (HH4)	7,669,000	6.3%	$23,706	$2,842	12.0%	$310	$1,104	$105	$1,110	$213
$20,000 to $29,999 (HH5)	15,022,000	12.4%	$29,397	$3,353	11.4%	$380	$1,218	$109	$1,450	$196
$30,000 to $39,999 (HH6)	13,053,000	10.8%	$35,929	$3,766	10.5%	$422	$1,293	$116	$1,689	$246
$40,000 to $49,999 (HH7)	11,444,000	9.5%	$39,553	$4,152	10.5%	$469	$1,338	$115	$1,955	$275
$50,000 to $69,999 (HH8)	17,799,000	14.7%	$48,900	$4,764	9.7%	$488	$1,445	$172	$2,250	$409
$70,000 to $79,999 (HH9)	6,640,000	5.5%	$57,833	$5,269	9.1%	$580	$1,518	$154	$2,470	$547
$80,000 to $99,999 (HH10)	9,951,000	8.2%	$65,027	$5,613	8.6%	$601	$1,604	$179	$2,669	$560
$100,000 to $119,999 (HH11)	7,260,000	6.0%	$76,140	$6,203	8.1%	$615	$1,621	$195	$2,942	$830
$120,000 to $149,999 (HH12)	5,882,000	4.9%	$85,806	$6,789	7.9%	$736	$1,814	$169	$3,090	$980
$150,000 and more (HH13)	8,447,000	7.0%	$124,306	$8,403	6.8%	$882	$2,075	$282	$3,257	$1,907

Table C.2 CEX energy-related consumption data for 2011

Market Segment	Households in Segment		Expenditure			Energy Expenditure by Fuel Type				
			Total	On Energy		Natural Gas	Electricity	Fuel Oil	Gasoline	Other
	(thousands)	(% of total)	($/HH)	($/HH)	(% of total)	($/HH)	($/HH)	($/HH)	($/HH)	($/HH)
Average Household										
Average Consumer Unit	122,287	100%	$49,705	$5,171	10.4%	$420	$1,423	$157	$2,655	$516
By Income Quintiles										
Lowest 20 percent (Q1)	24,435	20%	$22,001	$2,722	12.4%	$243	$985	$85	$1,227	$182
Second 20 percent (Q2)	24,429	20%	$32,092	$3,876	12.1%	$338	$1,234	$119	$1,981	$204
Third 20 percent (Q3)	24,473	20%	$42,403	$5,016	11.8%	$386	$1,429	$140	$2,694	$367
Fourth 20 percent (Q4)	24,520	20%	$57,460	$6,015	10.5%	$472	$1,603	$170	$3,295	$475
Highest 20 percent (Q5)	24,430	20%	$94,551	$8,217	8.7%	$659	$1,863	$270	$4,073	$1,352
By Region										
Northeast	22,538	18.4%	$54,547	$5,661	10.4%	$596	$1,338	$487	$2,510	$730
Midwest	27,107	22.2%	$47,192	$5,031	10.7%	$600	$1,225	$121	$2,632	$453
South	44,901	36.7%	$45,699	$5,204	11.4%	$243	$1,763	$70	$2,794	$334
West	27,741	22.7%	$54,745	$4,853	8.9%	$387	$1,135	$64	$2,569	$698
By Household Income										
Less than $5,000 (HH1)	4,978	4.1%	$22,960	$2,578	11.2%	$241	$909	$49	$1,148	$231
$5,000 to $9,999 (HH2)	5,449	4.5%	$20,884	$2,470	11.8%	$201	$900	$100	$1,112	$157
$10,000 to $14,999 (HH3)	8,170	6.7%	$19,959	$2,667	13.4%	$229	$1,006	$87	$1,172	$173
$15,000 to $19,999 (HH4)	7,745	6.3%	$24,806	$3,220	13.0%	$316	$1,127	$113	$1,487	$177
$20,000 to $29,999 (HH5)	14,460	11.8%	$30,398	$3,830	12.6%	$324	$1,215	$132	$1,971	$188
$30,000 to $39,999 (HH6)	13,328	10.9%	$36,769	$4,299	11.7%	$371	$1,302	$97	$2,247	$282
$40,000 to $49,999 (HH7)	11,347	9.3%	$40,306	$4,977	12.3%	$380	$1,433	$142	$2,679	$343
$50,000 to $69,999 (HH8)	17,376	14.2%	$50,034	$5,471	10.9%	$427	$1,516	$158	$2,961	$409
$70,000 to $79,999 (HH9)	7,385	6.0%	$57,977	$6,003	10.4%	$462	$1,600	$169	$3,345	$427
$80,000 to $99,999 (HH10)	10,456	8.6%	$65,390	$6,643	10.2%	$522	$1,662	$187	$3,612	$660
$100,000 to $119,999 (HH11)	7,045	5.8%	$76,496	$7,298	9.5%	$603	$1,710	$228	$3,921	$836
$120,000 to $149,999 (HH12)	6,107	5.0%	$87,239	$8,048	9.2%	$598	$1,760	$267	$4,150	$1,273
$150,000 and more (HH13)	8,440	6.9%	$123,056	$9,551	7.8%	$779	$2,147	$331	$4,267	$2,027

Table C.3 CEX energy-related consumption changes between 2009 and 2011

Market Segment	Change in Households in Segment (thousands)	Change in Households in Segment (% of total)	Change in Expenditure: Total ($/HH)	Change in Expenditure: On Energy ($/HH)	Change in Expenditure: On Energy (% of total)	Change in Energy Expenditure by Fuel Type: Natural Gas ($/HH)	Electricity ($/HH)	Fuel Oil ($/HH)	Gasoline ($/HH)	Other ($/HH)
Average Household										
Average Consumer Unit	1.01	1.00	1.01	1.16	1.14	0.87	1.03	1.11	1.34	1.08
By Income Quintiles										
Lowest 20 percent (Q1)	1.01	1.00	1.02	1.14	1.12	0.88	1.04	1.09	1.33	1.09
Second 20 percent (Q2)	1.01	1.00	1.02	1.13	1.10	0.87	1.00	1.17	1.32	0.93
Third 20 percent (Q3)	1.01	1.00	1.03	1.18	1.15	0.84	1.05	1.03	1.36	1.21
Fourth 20 percent (Q4)	1.02	1.00	1.01	1.16	1.15	0.85	1.06	1.00	1.34	0.96
Highest 20 percent (Q5)	1.01	1.00	1.00	1.16	1.16	0.89	1.02	1.23	1.33	1.12
By Region										
Northeast	1.01	0.99	1.01	1.15	1.13	0.83	1.02	1.12	1.40	1.07
Midwest	0.98	0.97	1.01	1.18	1.16	0.86	1.09	1.06	1.36	1.08
South	1.02	1.01	1.00	1.17	1.17	0.91	1.03	1.13	1.33	1.06
West	1.02	1.01	1.03	1.13	1.10	0.91	0.99	1.12	1.27	1.09
By Household Income										
Less than $5,000 (HH1)	0.00	1.04	1.01	1.15	1.14	0.93	1.10	1.00	1.23	1.28
$5,000 to $9,999 (HH2)	0.00	1.03	1.16	1.22	1.05	0.83	1.06	1.61	1.46	1.37
$10,000 to $14,999 (HH3)	0.00	1.05	0.92	1.13	1.23	0.81	1.06	1.12	1.31	1.15
$15,000 to $19,999 (HH4)	0.00	1.00	1.05	1.13	1.08	1.02	1.02	1.08	1.34	0.83
$20,000 to $29,999 (HH5)	0.00	0.95	1.03	1.14	1.10	0.85	1.00	1.21	1.36	0.96
$30,000 to $39,999 (HH6)	0.00	1.01	1.02	1.14	1.12	0.88	1.01	0.84	1.33	1.15
$40,000 to $49,999 (HH7)	0.00	0.98	1.02	1.20	1.18	0.81	1.07	1.23	1.37	1.25
$50,000 to $69,999 (HH8)	0.00	0.96	1.02	1.15	1.12	0.88	1.05	0.92	1.32	1.00
$70,000 to $79,999 (HH9)	0.00	1.10	1.00	1.14	1.14	0.80	1.05	1.10	1.35	0.78
$80,000 to $99,999 (HH10)	0.00	1.04	1.01	1.18	1.18	0.87	1.04	1.04	1.35	1.18
$100,000 to $119,999 (HH11)	0.00	0.96	1.00	1.18	1.17	0.98	1.05	1.17	1.33	1.01
$120,000 to $149,999 (HH12)	0.00	1.03	1.02	1.19	1.17	0.81	0.97	1.58	1.34	1.30
$150,000 and more (HH13)	0.00	0.99	0.99	1.14	1.15	0.88	1.03	1.17	1.31	1.06

C.3 Re-aggregating CEX using public-use microdata (PUMD) [54]

The published CEX tables have good resolution for some segments, such as household income brackets. However, the categories do not necessarily match the NEMS categories (see Table C.4). So, to combine the two datasets, one must re-aggregate the CEX household data from the PUMD to match the NEMS brackets.

Table C.4 Comparison of household income distribution overlap between CEX and RECS

CES Market Segments	RECS Market Segments
Less than $5k (HH1)	Less than $20k (HH1)
$5k to <$10k (HH2)	
$10k to <$15k (HH3)	
$15k to <$20k (HH4)	
$20k to <$30k (HH5)	$20k to <$40k (HH2)
$30k to <$40k (HH6)	
$40k to <$50k (HH7)	$40k to <$60k (HH3)
$50k to <$70k (HH8)	$40k to <$60k (HH3) / $60k to <$80k (HH4)
$70k to <$80k (HH9)	$60k to <$80k (HH4)
$80k to <$100k (HH10)	$80k to <$100k (HH5)
$100k to <$120k (HH11)	$100k to <$120k (HH6)
$120k to <$150k (HH12)	$120k and more (HH7)
$150k and more (HH13)	

C.3.1 Understanding the data

Staff members from both the RECS and the CEX survey teams strongly discourage re-aggregating to more refined categories. This is primarily due to how representative each surveyed household is to the region or category. For an extreme example, say the desired re-aggregation of household income brackets is every $1,000 from $0 through $150,000 (so 150 household income brackets instead of the published thirteen brackets). If none of the interviewed households reported total income between, say, $41,000 and $41,999, then this bracket would have no data. Furthermore, if only one

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[54] Thanks to Adam Reichenberger and Mark Vendemia at BLS for helping to explain the data, its limitations and how to re-aggregate.

of the interviewed households happens to fall within this bracket, this house cannot be considered representative of all American households earning between $41,000 and $41,999.

For a less extreme example, say one wants to re-aggregate the data to isolate each state. The micro data may only include a few households from a particular state (or even none in the case of some states). These few households could not statistically represent all households within the state. Even re-aggregating to the Census Division is discouraged since some of the state identifiers are deleted for privacy protection of the interviewee (if only a few households were interviewed in a particular state, it would be a simple process to align the data with the household).

However, this study requires aggregating to less resolved income brackets. Instead of the thirteen household income brackets in the CEX, the data need to be aggregated into seven brackets to match the RECS household income levels. The proper method for doing this is to follow the same process used by the CEX analysts to derive the mean expenditures for each item and the standard errors of the new collections. The CEX website offers plenty of guidance on the process. To begin, there is an excellent introduction guide (BLS, 2012a) and more advanced user guide (BLS, 2012b) which describe the pieces of the CES. Digging into the interview survey microdata requires an understanding of the cryptic variable naming convention (BLS, 2012c). Calculating the population-weighted means and the standard errors are described separately (Swanson, 2012) and to a lesser extent in the advanced user guide. Despite all of the documentation, re-aggregating the CEX is not a trivial undertaking.

There are several levels to theCEX, but this study only requires the quarterly *Interview* survey data stored in quarterly files with the format FMLIYYQ (e.g., FMLI112 is the family interview data for 2011- 2nd quarter).[55] During an interview, the consumer unit (i.e. household) is asked to report expenditures for the prior three months. For an April interview, the expenditures in the Q2 file are for January, February, and March (all occurring in Q1). However, an interview in May, which is also found in the Q2 file, includes two months from the previous quarter (February and March) and one from the current quarter (April). Consequently, each expenditure item has two inputs: previous quarter (PQ) and current quarter (CQ). For example, natural gas expenditures in a quarterly file will be found under the variables NTLGASPQ and NTLGASCQ. Thus five quarterly files are needed to be able to account for the entire year. The CEX PUMD files include five corresponding quarterly files: FMLI111, FMLI112, FMLI113, FMLI114, and FMLI121, which are called Qtr1-Qtr5 here for convenience, where Qtr1 refers to data from the file FMLI111 and Qtr5 refers to data from FMLI121.

Each participating household may not have participated in all quarterly surveys, so there are a different number of households in each quarterly file. Furthermore, each household interviewed represents a larger number of households, so each has a population weighting value which was determined by BLS prior to choosing the interview household. Re-computing the means requires some simple calculations. First the total expenditures (X) for a given segment (s) and fuel type (i) is effectively the sum of the weighted individual expenditures:

$$X_{s,i} = \sum_{i=1}^{\mathrm{n}} (w * e_i) \qquad \textbf{C.1}$$

However, it’s not quite that straightforward. The individual expenditures are either from the previous quarter or the current quarter and could include 1, 2, or 3

[55] The other big piece of the CEX is the *Diary* which details all of the sub-categories of consumption, such as bacon, ham, or sausage which are then aggregated into ‘pork’ for the survey public report. However, there is no finer detail in the Diary files on energy expenditures.

months of either quarter. So, to account for the different subtleties here, the weighted expenditures from CQ and PQ are summed; one from the current quarter (from files Qtr1-Qtr4) and another from the previous quarter (from files Qtr2-Qtr5). Next, each is divide by four to sort out the number of months. Then the mean is simply the total expenditure divided by the sum of the weights (equivalent to total households)

Calculating the variance and standard error (SE) is also not very straightforward. Standard textbook formulas for computing variances usually assume the survey's data come from a "simple random sample" of households. Those formulas do not apply to the CEX because, like most real-world surveys, the survey does not collect data from a simple random sample of households. Instead, the CEX draws a stratified random sample of geographic areas then draws a systematic sample of households within each selected area.

The specific technique used for the CEX is called "balanced repeated replication" (BRR). For the CEX, geographic areas are divided into 43 subgroups called "strata." Households within each stratum are randomly divided into two "half samples." So there are 43 strata with 2 half samples per stratum, making 2^{43} (~9 trillion) different estimates of the mean expenditure that can be computed from exactly half of the data. By carefully picking 44 estimates in a balanced way (hence the name of the technique), the same variance estimate can be obtained without calculating all 9 trillion estimates of the mean expenditure to get a reasonable variance estimate. The unbiased estimate can be found by utilizing the half sample (*HS*) and full sample (*FS*) components.

$$SE(\bar{X}) = \sqrt{V(\bar{X})} \approx \sqrt{\frac{1}{44}\sum_{HS=1}^{44}(\bar{X}_{HS} - \bar{X}_{FS})^2} \qquad \textbf{C.2}$$

C.3.2 RE-AGGREGATING

This study is only interested in re-aggregating the two transportation fuel types but all five fuel types are first re-aggregated to the original levels to verify the data are being properly processed. The variables needed are:

- Fuel types for previous and current quarter…
  - Natural gas: NTLGASPQ, NTLGASCQ
  - Electricity: ELCTRCPQ, ELCTRCCQ
  - Fuel oil and other Fuels: ALLFULPQ, ALLFULCQ
  - Gasoline: GASMOPQ, GASMOCQ
  - Public and other transportation: PUBTRAPQ, PUBTRACQ
- Population weighting: FINLWT21
- BRR estimates: WTREP01-WTREP44
- Income before taxes: FINCBTXM (Imputed results by CEX staff)
- Region: REGION

The first step is to prove the local set up can closely match the mean values for published CEX market segments. This is shown for two categories: Census Regions in Table C.5 and household income brackets in Table C.6. Matching the published mean values exactly is not expected since BLS alters (removes or changes) some data before making the PUMD available. However BLS claims this only happens in hundreds of cases, yet there are 21,000 surveys. So while the local calculations will not match exactly, they should be roughly reproduce the BLS results.

Table C.5 Comparison of published means and re-computed means and standard errors

	Published Mean Expenditures							Index of Re-computed to Published Means						
Market Segment	# of Members	# of Earners	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.	# of Members	# of Earners	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	2.5	1.3	$420	$1,423	$157	$2,655	$516	1.00	0.98	1.00	1.00	1.00	1.00	1.00
NE	2.4	1.3	$596	$1,338	$487	$2,510	$730	1.01	0.98	1.00	1.00	1.00	0.99	1.01
MW	2.4	1.3	$600	$1,225	$121	$2,632	$453	1.01	1.00	1.00	1.00	0.96	1.00	1.02
S	2.5	1.2	$243	$1,763	$70	$2,794	$334	1.01	1.02	1.01	1.00	1.01	1.00	1.01
W	2.6	1.3	$387	$1,135	$64	$2,569	$698	1.00	1.02	1.01	1.00	1.00	1.00	1.03

	Re-Computed Mean Expenditures							Computed Standard Error						
Market Segment	# of Members	# of Earners	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.	# of Members	# of Earners	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	2.50	1.27	$418.89	$1,422.40	$156.87	$2,653.81	$518.22	2.55E-10	0.009	$12.98	$21.49	$9.81	$30.44	$17.55
NE	2.43	1.28	$594.12	$1,335.60	$488.49	$2,497.28	$733.94	0.033	0.018	$42.89	$32.72	$39.22	$69.88	$32.50
MW	2.44	1.30	$597.96	$1,221.89	$116.75	$2,625.36	$459.88	0.050	0.025	$35.38	$71.26	$15.84	$101.04	$43.38
S	2.52	1.23	$244.35	$1,759.41	$70.97	$2,791.31	$336.86	0.032	0.020	$18.52	$40.44	$11.39	$56.79	$24.37
W	2.61	1.33	$390.55	$1,136.45	$63.88	$2,573.74	$715.54	0.070	0.019	$14.36	$14.56	$20.69	$61.08	$42.67

Table C.5 shows the results of re-computing the expenditures for the four Census Regions. The shaded values are published data from the CEX, while the other three quadrants of the table are computed for comparison. Using methods recommended by BLS, the expenditures of the average American household and the four Regions for all five fuel types can reasonably be repeated.

Similar results are found when looking at the income brackets. The re-computed means match the published means well for all five fuel types in all market segments with a few minor exceptions (see Table C.6). The 'Other Fuels' expenditures seem to wander, especially in the lower income brackets. This re-aggregation overestimates the expenditure from HH1 and HH3, yet underestimates expenditures in HH2. While it would be nice to match the published data better, these categories will be averaged together into a single category when aggregating to match the seven RECS household income brackets (see Table C.4).

Table C.6 Comparison of published income distribution means and re-computed means and standard errors

	Published Mean Expenditures							Index of Re-computed to Published Means						
Market Segment	# of Members	# of Earners	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.	# of Members	# of Earners	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	2.5	1.3	$420	$1,423	$157	$2,655	$516	1.00	0.98	1.00	1.00	1.00	1.00	1.00
HH1	1.7	0.5	$241	$909	$49	$1,148	$231	1.01	1.07	0.94	0.98	1.18	0.99	0.97
HH2	1.7	0.5	$201	$900	$100	$1,112	$157	1.00	0.96	1.00	1.01	0.91	0.98	1.09
HH3	1.6	0.4	$229	$1,006	$87	$1,172	$173	1.03	1.06	1.00	1.01	1.10	1.02	1.00
HH4	2.0	0.6	$316	$1,127	$113	$1,487	$177	0.98	0.95	0.97	0.99	1.00	0.98	0.99
HH5	2.2	0.8	$324	$1,215	$132	$1,971	$188	0.99	1.05	1.00	1.00	0.99	1.00	1.07
HH6	2.4	1.1	$371	$1,302	$97	$2,247	$282	1.00	1.02	0.99	1.01	1.01	1.01	1.00
HH7	2.6	1.3	$380	$1,433	$142	$2,679	$343	0.99	0.99	1.00	0.99	0.97	1.00	0.98
HH8	2.7	1.5	$427	$1,516	$158	$2,961	$409	1.01	1.02	1.01	1.00	0.99	1.00	1.01
HH9	2.8	1.7	$462	$1,600	$169	$3,345	$427	1.01	1.01	1.00	0.99	1.06	1.00	1.03
HH10	3.0	1.8	$522	$1,662	$187	$3,612	$660	0.99	1.01	1.01	0.98	0.98	0.99	1.04
HH11	3.2	2.0	$603	$1,710	$228	$3,921	$836	0.99	0.96	0.99	1.00	0.97	1.00	0.96
HH12	3.1	2.0	$598	$1,760	$267	$4,150	$1,273	1.00	1.01	0.98	1.00	1.10	0.98	0.99
HH13	3.2	2.0	$779	$2,147	$331	$4,267	$2,027	0.98	0.99	0.98	1.00	0.93	1.00	0.95

	Re-Computed Mean Expenditures							Computed Standard Error						
Market Segment	# of Members	# of Earners	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.	# of Members	# of Earners	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	2.50	1.27	$418.89	$1,422.40	$156.87	$2,653.81	$518.22	2.55E-10	0.009	$12.98	$21.49	$9.81	$30.44	$17.55
HH1	1.71	0.53	$226.84	$888.96	$57.60	$1,141.50	$222.98	0.062	0.038	$28.29	$61.05	$11.11	$67.94	$34.92
HH2	1.71	0.48	$201.88	$904.93	$91.04	$1,094.68	$171.91	0.050	0.028	$16.93	$44.95	$13.66	$59.23	$24.15
HH3	1.64	0.43	$229.88	$1,019.58	$95.95	$1,199.38	$173.53	0.035	0.019	$13.03	$36.63	$18.31	$44.79	$29.97
HH4	1.96	0.57	$307.37	$1,110.18	$112.59	$1,463.29	$175.49	0.039	0.019	$17.70	$48.91	$20.58	$46.84	$22.31
HH5	2.18	0.84	$324.61	$1,217.97	$131.12	$1,977.19	$201.93	0.041	0.025	$17.56	$30.30	$18.35	$52.24	$20.06
HH6	2.41	1.12	$368.21	$1,308.78	$98.02	$2,265.53	$282.82	0.036	0.019	$17.72	$30.70	$10.68	$53.21	$29.07
HH7	2.58	1.29	$378.61	$1,423.39	$138.38	$2,675.54	$336.36	0.039	0.019	$20.87	$32.38	$19.21	$57.20	$33.36
HH8	2.73	1.53	$432.23	$1,522.19	$157.18	$2,972.95	$411.25	0.027	0.015	$22.74	$34.57	$16.84	$61.69	$28.69
HH9	2.82	1.72	$460.74	$1,590.40	$179.13	$3,361.03	$439.62	0.046	0.026	$19.03	$38.15	$34.87	$78.88	$44.27
HH10	2.96	1.82	$526.42	$1,635.55	$182.66	$3,575.47	$687.91	0.034	0.021	$23.32	$34.70	$22.68	$66.41	$66.61
HH11	3.17	1.93	$598.81	$1,704.26	$220.32	$3,906.83	$805.91	0.038	0.022	$30.72	$43.99	$32.48	$90.33	$103.16
HH12	3.11	2.03	$583.20	$1,761.35	$293.11	$4,086.16	$1,254.02	0.047	0.031	$29.80	$52.20	$54.28	$116.99	$151.04
HH13	3.13	1.97	$765.79	$2,143.70	$308.80	$4,249.12	$1,924.08	0.038	0.023	$31.03	$65.79	$39.34	$90.77	$101.33

Table C.7 New income distribution means standard errors for the U.S. and each region

U.S.

Computed Mean Expenditures						
Market Segment	# of Members	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	2.50	$418.89	$1,422.40	$156.87	$2,653.81	$518.22
HH1	1.76	$246.35	$997.21	$92.29	$1,244.24	$183.51
HH2	2.29	$345.57	$1,261.63	$115.20	$2,115.83	$240.83
HH3	2.62	$397.61	$1,459.89	$145.63	$2,792.47	$377.21
HH4	2.80	$451.99	$1,563.99	$168.97	$3,175.71	$414.22
HH5	2.96	$526.42	$1,635.55	$182.66	$3,575.47	$687.91
HH6	3.17	$598.81	$1,704.26	$220.32	$3,906.83	$805.91
HH7	3.12	$694.27	$1,993.93	$302.66	$4,185.29	$1,661.62

Computed Standard Error						
Market Segment	# of Members	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	2.55E-10	$12.98	$21.49	$9.81	$30.44	$17.55
HH1	0.028	$12.66	$31.74	$10.42	$28.16	$13.65
HH2	0.028	$15.93	$26.59	$9.60	$40.15	$17.66
HH3	0.027	$17.69	$28.84	$16.72	$49.37	$29.30
HH4	0.033	$21.02	$30.80	$22.88	$53.79	$33.79
HH5	0.034	$23.32	$34.70	$22.68	$66.41	$66.61
HH6	0.038	$30.72	$43.99	$32.48	$90.33	$103.16
HH7	0.033	$24.97	$44.96	$25.39	$67.62	$103.29

Northeast

Computed Mean Expenditures						
Market Segment	# of Members	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	2.43	$594.12	$1,335.60	$488.49	$2,497.28	$733.94
HH1	1.62	$304.59	$694.34	$275.70	$860.44	$266.91
HH2	2.08	$475.36	$1,078.73	$378.78	$1,749.61	$395.76
HH3	2.44	$606.31	$1,329.36	$418.33	$2,495.75	$560.29
HH4	2.66	$660.78	$1,527.20	$489.31	$2,951.75	$632.40
HH5	2.96	$713.35	$1,606.92	$555.91	$3,408.60	$816.55
HH6	3.10	$744.30	$1,590.45	$668.15	$3,639.22	$865.63
HH7	3.10	$911.47	$2,057.93	$846.51	$4,129.28	$1,892.86

Computed Standard Error						
Market Segment	# of Members	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	0.033	$42.89	$32.72	$39.22	$69.88	$32.50
HH1	0.042	$29.34	$48.83	$48.79	$70.99	$38.59
HH2	0.058	$44.80	$42.31	$42.14	$89.62	$41.87
HH3	0.084	$62.82	$73.97	$83.66	$84.58	$68.54
HH4	0.072	$77.18	$47.42	$90.93	$142.40	$106.11
HH5	0.080	$66.47	$79.13	$91.74	$155.34	$120.60
HH6	0.074	$41.39	$98.18	$112.99	$255.79	$194.07
HH7	0.065	$78.47	$87.21	$73.21	$124.82	$215.00

Midwest

Computed Mean Expenditures						
Market Segment	# of Members	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	2.44	$597.96	$1,221.89	$116.75	$2,625.36	$459.88
HH1	1.57	$381.33	$800.71	$79.38	$1,227.11	$181.22
HH2	2.25	$576.52	$1,144.67	$74.83	$2,176.09	$213.12
HH3	2.54	$605.59	$1,286.27	$142.18	$2,742.07	$311.22
HH4	2.70	$624.88	$1,365.97	$193.11	$3,100.48	$389.12
HH5	3.06	$727.91	$1,477.09	$92.27	$3,449.18	$538.83
HH6	3.22	$791.19	$1,501.68	$178.38	$4,390.99	$940.15
HH7	3.25	$852.55	$1,651.64	$133.82	$4,166.69	$1,581.80

Computed Standard Error						
Market Segment	# of Members	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	0.050	$35.38	$71.26	$15.84	$101.04	$43.38
HH1	0.081	$57.07	$91.81	$17.02	$39.69	$32.91
HH2	0.068	$41.43	$79.84	$20.42	$97.38	$38.96
HH3	0.071	$45.91	$64.96	$21.22	$104.96	$53.75
HH4	0.066	$45.43	$57.75	$50.83	$142.16	$47.23
HH5	0.078	$50.15	$54.51	$31.14	$156.06	$76.32
HH6	0.085	$65.73	$95.98	$73.38	$215.26	$340.93
HH7	0.057	$49.95	$83.45	$30.69	$172.59	$182.36

South

Computed Mean Expenditures						
Market Segment	# of Members	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	2.52	$244.35	$1,759.41	$70.97	$2,791.31	$336.86
HH1	1.85	$161.85	$1,325.24	$58.36	$1,380.19	$123.46
HH2	2.34	$182.17	$1,572.75	$67.76	$2,290.49	$130.82
HH3	2.71	$207.78	$1,827.34	$55.80	$3,085.83	$261.51
HH4	2.83	$247.45	$1,914.90	$54.65	$3,345.08	$267.67
HH5	3.03	$311.79	$2,043.40	$81.72	$3,845.75	$517.04
HH6	3.17	$371.69	$2,170.26	$65.66	$4,068.05	$633.21
HH7	3.10	$515.93	$2,462.67	$145.69	$4,586.72	$1,214.69

Computed Standard Error						
Market Segment	# of Members	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	0.032	$18.52	$40.44	$11.39	$56.79	$24.37
HH1	0.048	$14.91	$50.21	$11.19	$49.24	$18.03
HH2	0.063	$17.74	$48.87	$10.63	$57.31	$24.09
HH3	0.066	$21.19	$53.00	$9.77	$93.62	$47.23
HH4	0.051	$26.45	$66.58	$13.76	$90.95	$54.59
HH5	0.070	$42.95	$67.80	$15.77	$116.35	$79.54
HH6	0.054	$41.92	$72.58	$20.24	$156.22	$92.96
HH7	0.073	$35.33	$102.22	$47.13	$118.53	$137.63

West

Computed Mean Expenditures						
Market Segment	# of Members	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	2.61	$390.55	$1,136.45	$63.88	$2,573.74	$715.54
HH1	1.94	$213.20	$811.44	$25.07	$1,306.45	$243.38
HH2	2.40	$300.51	$973.67	$33.60	$2,027.10	$349.37
HH3	2.69	$350.14	$1,112.89	$71.58	$2,558.16	$516.57
HH4	2.97	$456.89	$1,243.10	$92.11	$3,138.27	$518.08
HH5	2.78	$495.33	$1,209.29	$60.95	$3,396.01	$977.20
HH6	3.16	$591.70	$1,312.39	$82.88	$3,354.44	$895.55
HH7	3.07	$603.53	$1,630.14	$121.21	$3,774.67	$2,071.09

Computed Standard Error						
Market Segment	# of Members	Nat. Gas	Elec.	Other Fuels	Gasoline	Other Trans.
All	0.070	$14.36	$14.56	$20.69	$61.08	$42.67
HH1	0.059	$16.02	$57.99	$5.24	$75.20	$37.85
HH2	0.119	$17.66	$37.06	$5.69	$93.76	$39.18
HH3	0.112	$27.78	$51.88	$25.18	$99.17	$73.58
HH4	0.132	$33.45	$52.23	$44.90	$111.93	$69.55
HH5	0.092	$34.11	$32.02	$28.88	$103.15	$225.05
HH6	0.104	$87.20	$100.14	$35.04	$149.86	$199.97
HH7	0.080	$22.11	$56.75	$57.53	$147.68	$267.11

Once the reproduction of the CEX results matches well, one can compute the means and SE for the RECS income brackets. Table C.7 shows the CEX data mapped to the less refined RECS household income brackets for the U.S. and each region. These values represent the average American household within each bracket.

C.4 ELECTRICITY PRICES BY SECTOR (2011 $/MMBTU)

Nominal electricity prices in terms of $/kWh are tangible to the average consumer, and these are shown in Section 4.3. However, not all electricity is created equally in terms of carbon emissions, and therefore, the differences in policy costs associated with fossil-fueled electricity generation. For the household impact analysis, one really needs a more universal cost per unit measure to compare with total consumption, such as $/MMBTU. Table C.8 illustrates what this looks like under the Reference scenario and the $25/t$CO_2$ at 2% scenario.

Table C.8 Electricity prices by demand sector (2011$/MMBTU)

	Electricity Prices (2011 $/MMBtu)											
Sector	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total % from 2013
Reference Scenario												
Residential	32.5	33.0	33.1	33.6	33.9	33.9	33.7	33.6	33.7	33.7	33.7	3.6%
Commercial	27.8	27.8	27.7	28.2	28.6	28.7	28.6	28.6	28.7	28.7	28.6	3.1%
Industrial	18.1	18.0	17.9	18.4	18.7	18.8	18.7	18.8	18.9	19.0	19.1	5.3%
Transportation	30.6	30.1	29.9	30.0	30.0	30.0	29.8	29.6	29.5	29.5	29.7	-3.0%
All Sectors Average	26.9	27.1	26.9	27.4	27.6	27.7	27.5	27.5	27.6	27.6	27.7	2.7%
Policy Scenario ($25/t$CO_2$ at 2%)												
Residential	32.5	35.2	38.0	38.7	38.7	38.5	38.4	38.3	38.3	38.3	38.5	18.2%
Commercial	27.7	30.2	33.0	33.9	34.1	34.2	34.2	34.1	34.0	34.0	34.0	22.8%
Industrial	18.1	20.9	22.8	23.4	23.6	23.6	23.7	23.6	23.6	23.8	24.0	32.1%
Transportation	30.5	32.2	35.2	35.5	35.1	35.0	34.7	34.4	34.2	34.3	34.5	13.1%
All Sectors Average	26.9	29.6	32.1	32.7	32.8	32.8	32.7	32.6	32.6	32.7	32.8	21.8%
Percent Difference												
Residential	0.0%	6.7%	15.0%	15.1%	14.1%	13.7%	14.2%	13.9%	13.6%	13.7%	14.1%	
Commercial	0.0%	8.6%	19.1%	20.0%	19.4%	19.3%	19.6%	18.9%	18.3%	18.5%	19.0%	
Industrial	0.0%	15.6%	27.3%	27.4%	26.2%	25.5%	26.2%	25.8%	25.1%	25.2%	25.4%	
Transportation	0.0%	6.8%	18.1%	18.2%	16.9%	16.5%	16.6%	16.3%	16.0%	16.3%	16.3%	
All Sectors Average	0.0%	9.3%	19.2%	19.6%	18.8%	18.4%	18.9%	18.5%	18.0%	18.2%	18.6%	

C.5 Electric power sector fuel mix by Census Division

Table C.9 New England electric power sector fuel mix

Electric Power Sector : New England								
$25/tCO₂ at 2%	Trillion Btu			Share of sector			% Change from 2013	
	Reference		Policy	Reference		Policy	Reference	Policy
Resource	2013	2023	2023	2013	2023	2023	2013 - 2023	2013 - 2023
Liquid Fuels	3.9	1.1	1.0	0.4%	0.1%	0.1%	-72%	-75%
Natural Gas	469.1	456.5	417.0	44.3%	42.7%	41.2%	-3%	-11%
Steam Coal	52.4	30.8	8.8	5.0%	2.9%	0.9%	-41%	-83%
Nuclear	377.9	404.9	404.9	35.7%	37.9%	40.0%	7%	7%
Renewable	116.1	144.6	143.4	11.0%	13.5%	14.2%	25%	24%
Electricity Imports	39.0	30.9	36.5	3.7%	2.9%	3.6%	-21%	-6%
Total	1058.4	1068.8	1011.6	100%	100%	100%	1%	-4%

Table C.10 Mid Atlantic electric power sector fuel mix

Electric Power Sector : Middle Atlantic								
$25/tCO₂ at 2%	Trillion Btu			Share of sector			% Change from 2013	
	Reference		Policy	Reference		Policy	Reference	Policy
Resource	2013	2023	2023	2013	2023	2023	2013 - 2023	2013 - 2023
Liquid Fuels	18.4	7.1	6.0	0.5%	0.2%	0.2%	-61%	-67%
Natural Gas	876.5	822.9	872.7	21.6%	19.9%	22.4%	-6%	0%
Steam Coal	1174.5	1139.4	789.1	28.9%	27.6%	20.3%	-3%	-33%
Nuclear	1577.0	1661.4	1661.4	38.9%	40.2%	42.7%	5%	5%
Renewable	378.7	476.4	533.1	9.3%	11.5%	13.7%	26%	41%
Electricity Imports	33.0	26.1	30.9	0.8%	0.6%	0.8%	-21%	-6%
Total	4058.0	4133.4	3893.2	100%	100%	100%	2%	-4%

Table C.11 East North Central electric power sector fuel mix

Electric Power Sector : East North Central								
$25/tCO₂ at 2%	Trillion Btu			Share Percentage			% Change from 2013	
	Reference		Policy	Reference		Policy	Reference	Policy
Resource	2013	2023	2023	2013	2023	2023	2013 - 2023	2013 - 2023
Liquid Fuels	15.4	13.7	11.7	0.2%	0.2%	0.2%	-11%	-24%
Natural Gas	553.2	580.0	918.1	8.7%	8.8%	15.5%	5%	66%
Steam Coal	3946.3	3946.9	2575.2	62.0%	60.2%	43.5%	0%	-35%
Nuclear	1572.8	1684.7	1684.7	24.7%	25.7%	28.5%	7%	7%
Renewable	262.6	320.7	716.7	4.1%	4.9%	12.1%	22%	173%
Electricity Imports	11.8	9.4	11.1	0.2%	0.1%	0.2%	-21%	-6%
Total	6362.0	6555.3	5917.4	1	1	1	3%	-7%

Table C.12 West North Central electric power sector fuel mix

Electric Power Sector : West North Central

$25/tCO$_2$ at 2%	Trillion Btu			Share Percentage			% Change from 2013	
	Reference		Policy	Reference		Policy	Reference	Policy
Resource	2013	2023	2023	2013	2023	2023	2013 - 2023	2013 - 2023
Liquid Fuels	9.4	7.2	7.3	0.3%	0.2%	0.2%	-24%	-22%
Natural Gas	46.0	69.2	98.2	1.3%	1.9%	3.1%	50%	113%
Steam Coal	2338.3	2374.8	1716.7	68.5%	66.8%	54.5%	2%	-27%
Nuclear	468.3	519.1	519.1	13.7%	14.6%	16.5%	11%	11%
Renewable	526.3	563.8	781.9	15.4%	15.9%	24.8%	7%	49%
Electricity Imports	26.2	20.8	24.5	0.8%	0.6%	0.8%	-21%	-6%
Total	3414.5	3554.9	3147.7	1	1	1	4%	-8%

Table C.13 South Atlantic electric power sector fuel mix

Electric Power Sector : South Atlantic

$25/tCO$_2$ at 2%	Trillion Btu			Share Percentage			% Change from 2013	
	Reference		Policy	Reference		Policy	Reference	Policy
Resource	2013	2023	2023	2013	2023	2023	2013 - 2023	2013 - 2023
Liquid Fuels	18.2	20.3	17.8	0.3%	0.2%	0.2%	12%	-2%
Natural Gas	1767.6	1830.5	1939.9	26.8%	22.2%	25.2%	4%	10%
Steam Coal	2587.6	3312.4	2434.2	39.3%	40.2%	31.6%	28%	-6%
Nuclear	1974.8	2579.9	2579.9	30.0%	31.3%	33.5%	31%	31%
Renewable	243.2	488.4	722.3	3.7%	5.9%	9.4%	101%	197%
Electricity Imports	0.0	0.0	0.0	0.0%	0.0%	0.0%		
Total	6591.4	8231.5	7694.1	1	1	1	25%	17%

Table C.14 East South Central electric power sector fuel mix

Electric Power Sector : East South Central

$25/tCO$_2$ at 2%	Trillion Btu			Share Percentage			% Change from 2013	
	Reference		Policy	Reference		Policy	Reference	Policy
Resource	2013	2023	2023	2013	2023	2023	2013 - 2023	2013 - 2023
Liquid Fuels	8.3	7.7	6.8	0.2%	0.2%	0.2%	-8%	-19%
Natural Gas	722.5	676.1	709.7	19.2%	17.3%	19.5%	-6%	-2%
Steam Coal	2017.0	1928.2	1494.8	53.6%	49.3%	41.1%	-4%	-26%
Nuclear	792.6	968.3	968.3	21.1%	24.7%	26.6%	22%	22%
Renewable	219.6	334.7	458.1	5.8%	8.5%	12.6%	52%	109%
Electricity Imports	0.0	0.0	0.0	0.0%	0.0%	0.0%		
Total	3759.9	3915.0	3637.7	1	1	1	4%	-3%

Table C.15 West South Central electric power sector fuel mix

Electric Power Sector : West South Central

$25/tCO$_2$ at 2%	Trillion Btu			Share Percentage			% Change from 2013	
	Reference		Policy	Reference		Policy	Reference	Policy
Resource	2013	2023	2023	2013	2023	2023	2013 - 2023	2013 - 2023
Liquid Fuels	28.7	8.3	5.7	0.5%	0.1%	0.1%	-71%	-80%
Natural Gas	2374.1	2369.2	2707.0	39.9%	38.5%	48.9%	0%	14%
Steam Coal	2301.6	2468.1	1326.9	38.7%	40.1%	24.0%	7%	-42%
Nuclear	739.0	798.9	798.9	12.4%	13.0%	14.4%	8%	8%
Renewable	512.1	517.8	702.8	8.6%	8.4%	12.7%	1%	37%
Electricity Imports	-1.9	-1.5	-1.8	0.0%	0.0%	0.0%	-21%	-6%
Total	5953.5	6160.8	5539.5	1	1	1	3%	-7%

Table C.16 Mountain electric power sector fuel mix

Electric Power Sector : Mountain

$25/tCO$_2$ at 2%	Trillion Btu			Share Percentage			% Change from 2013	
	Reference		Policy	Reference		Policy	Reference	Policy
Resource	2013	2023	2023	2013	2023	2023	2013 - 2023	2013 - 2023
Liquid Fuels	15.8	16.0	15.0	0.5%	0.4%	0.5%	1%	-5%
Natural Gas	334.6	497.1	403.9	10.1%	13.6%	12.3%	49%	21%
Steam Coal	2085.7	2139.8	1806.0	62.7%	58.7%	55.0%	3%	-13%
Nuclear	324.1	324.9	324.9	9.7%	8.9%	9.9%	0%	0%
Renewable	564.2	667.8	734.7	17.0%	18.3%	22.4%	18%	30%
Electricity Imports	0.8	0.7	0.8	0.0%	0.0%	0.0%	-21%	-6%
Total	3325.1	3646.3	3285.3	1	1	1	10%	-1%

Table C.17 Pacific electric power sector fuel mix

Electric Power Sector : Pacific

$25/tCO$_2$ at 2%	Trillion Btu			Share Percentage			% Change from 2013	
	Reference		Policy	Reference		Policy	Reference	Policy
Resource	2013	2023	2023	2013	2023	2023	2013 - 2023	2013 - 2023
Liquid Fuels	87.3	96.6	93.7	2.4%	2.4%	2.3%	11%	7%
Natural Gas	1247.2	1152.2	1136.6	34.4%	28.8%	27.6%	-8%	-9%
Steam Coal	162.2	115.1	114.4	4.5%	2.9%	2.8%	-29%	-29%
Nuclear	275.8	470.5	470.5	7.6%	11.7%	11.4%	71%	71%
Renewable	1853.1	2172.0	2305.4	51.1%	54.2%	56.0%	17%	24%
Electricity Imports	-1.4	-1.1	-1.3	0.0%	0.0%	0.0%	-21%	-6%
Total	3624.2	4005.3	4119.3	1	1	1	11%	14%

C.6 State-level results

Table C.18 Net Impacts from $15/tCO$_2$ at 2% scenario with 50% Rebate

	Costs and Benefits to the average household ($15/tCO$_2$ at 2% with 50% rebate)											
	Households			First Year Costs (2014)						First Year Rebate		
Market Segment	million	% of total	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-$38.55	-$50.20	-$8.16	-$84.18	-$16.36	**-$197.45**	$311.25	**$113.80**	$846.83
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-$15.54	-$67.15	-$19.77	-$76.39	-$22.76	**-$201.62**	$307.00	**$105.38**	$1,388.79
New England Division	5.5	4.8%	2.47	-$25.19	-$49.46	-$31.49	-$76.27	-$5.95	**-$188.37**	$298.96	**$110.59**	$1,494.74
MA	2.5	2.2%	2.44	-$18.91	-$83.54	-$13.55	-$76.27	-$5.95	**-$198.22**	$295.76	**$97.54**	$1,411.73
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-$31.12	-$27.84	-$52.15	-$76.27	-$5.95	**-$193.33**	$301.95	**$108.62**	$1,463.41
Middle Atlantic Division	15.3	13.5%	2.56	-$12.13	-$73.54	-$15.55	-$76.45	-$13.91	**-$191.57**	$309.75	**$118.18**	$1,465.91
NY	7.2	6.3%	2.58	-$9.62	-$73.72	-$19.08	-$76.45	-$13.91	**-$192.77**	$311.94	**$119.17**	$1,525.01
PA	4.9	4.3%	2.43	-$13.01	-$27.48	-$22.76	-$76.45	-$13.91	**-$153.61**	$293.58	**$139.97**	$1,562.76
NJ	3.2	2.8%	2.73	-$17.32	-$104.90	-$2.14	-$76.45	-$13.91	**-$214.71**	$330.02	**$115.31**	$1,408.82
Total Midwest Region	25.9	22.8%	2.49	-$38.95	-$81.80	-$8.56	-$85.67	-$14.14	**-$229.12**	$301.58	**$72.45**	$986.41
East North Central Division	17.9	15.8%	2.52	-$38.57	-$89.78	-$6.87	-$86.53	-$5.68	**-$227.42**	$305.21	**$77.79**	$1,052.84
IL	4.8	4.2%	2.54	-$43.09	-$101.17	-$1.44	-$86.53	-$5.68	**-$237.91**	$307.32	**$69.41**	$980.20
MI	3.8	3.3%	2.68	-$31.97	-$136.54	-$11.75	-$86.53	-$5.68	**-$272.47**	$324.14	**$51.67**	$952.77
WI	2.3	2.0%	2.36	-$34.88	-$65.66	-$12.68	-$86.53	-$5.68	**-$205.42**	$285.31	**$79.89**	$1,022.57
IN, OH	7.0	6.2%	2.48	-$40.68	-$69.33	-$5.11	-$86.53	-$5.68	**-$207.32**	$299.95	**$92.62**	$1,134.10
West North Central Division	8.1	7.1%	2.42	-$39.24	-$63.14	-$12.53	-$83.91	-$4.00	**-$202.82**	$293.28	**$90.46**	$1,075.61
MO	2.3	2.0%	2.48	-$46.44	-$62.80	-$6.96	-$83.91	-$4.00	**-$204.11**	$299.71	**$95.60**	$1,080.38
IA, MN, ND,SD	3.9	3.4%	2.41	-$38.68	-$52.26	-$29.66	-$83.91	-$4.00	**-$208.51**	$291.63	**$83.12**	$1,001.77
KS, NE	1.8	1.6%	2.38	-$36.08	-$100.94	$0.00	-$83.91	-$4.00	**-$224.92**	$288.20	**$63.28**	$897.08
Total South Region	42.1	37.1%	2.55	-$54.08	-$27.50	-$5.05	-$90.52	-$10.69	**-$187.84**	$309.09	**$121.25**	$1,307.41
South Atlantic Division	22.2	19.5%	2.52	-$56.66	-$22.90	-$5.68	-$90.66	-$2.07	**-$177.97**	$305.46	**$127.49**	$1,421.03
VA	3.0	2.6%	2.60	-$49.98	-$49.48	-$6.02	-$90.66	-$2.07	**-$198.21**	$315.25	**$117.04**	$1,397.18
GA	3.5	3.1%	2.69	-$48.99	-$66.83	-$0.47	-$90.66	-$2.07	**-$209.02**	$326.15	**$117.14**	$1,434.07
FL	7.0	6.2%	2.42	-$72.98	-$1.04	-$1.49	-$90.66	-$2.07	**-$168.25**	$292.43	**$124.18**	$1,288.37
DC, DE, MD, WV	3.4	3.0%	2.57	-$56.99	-$58.17	-$19.26	-$90.66	-$2.07	**-$227.15**	$310.69	**$83.54**	$1,085.84
NC, SC	5.4	4.8%	2.48	-$44.40	-$19.11	-$6.84	-$90.66	-$2.07	**-$163.08**	$299.85	**$136.77**	$1,536.09
East South Central Division	7.1	6.3%	2.41	-$87.42	-$28.52	-$6.63	-$88.83	-$13.44	**-$224.84**	$292.17	**$67.33**	$1,145.38
TN	2.4	2.1%	2.47	-$78.23	-$26.40	$0.00	-$88.83	-$13.44	**-$206.91**	$299.02	**$92.12**	$1,367.05
AL, KY, MS	4.6	4.0%	2.39	-$96.10	-$30.93	-$9.85	-$88.83	-$13.44	**-$239.15**	$288.88	**$49.73**	$991.99
West South Central Division	12.8	11.3%	2.68	-$29.94	-$35.71	-$2.99	-$91.21	-$9.68	**-$169.53**	$324.48	**$154.94**	$1,310.64
TX	8.5	7.5%	2.74	-$35.78	-$34.10	-$0.84	-$91.21	-$9.68	**-$171.60**	$332.17	**$160.57**	$1,252.28
AR, LA, OK	4.2	3.7%	2.55	-$20.89	-$40.91	-$11.20	-$91.21	-$9.68	**-$173.89**	$308.54	**$134.65**	$1,294.88
Total West Region	24.8	21.8%	2.72	-$35.62	-$42.72	-$3.30	-$78.38	-$22.40	**-$182.43**	$328.89	**$146.46**	$1,819.50
Mountain Division	7.9	7.0%	2.67	-$55.78	-$50.28	-$5.77	-$90.50	-$11.10	**-$213.42**	$322.98	**$109.57**	$1,406.81
Mountain North Sub-Div.	3.9	3.4%	2.72	-$33.44	-$75.12	-$9.40	-$90.50	-$11.10	**-$219.55**	$328.62	**$109.07**	$1,514.34
CO	1.9	1.7%	2.33	-$24.21	-$84.41	-$17.01	-$90.50	-$11.10	**-$227.22**	$281.43	**$54.21**	$1,010.29
ID, MT, UT, WY	2.0	1.8%	3.08	-$43.58	-$66.79	$0.00	-$90.50	-$11.10	**-$211.96**	$373.26	**$161.30**	$1,990.11
Mountain South Sub-Div.	4.0	3.5%	2.62	-$82.74	-$30.85	-$3.07	-$90.50	-$11.10	**-$218.26**	$317.15	**$98.89**	$1,191.10
AZ	2.3	2.0%	2.59	-$102.71	-$18.89	-$1.58	-$90.50	-$11.10	**-$224.77**	$313.61	**$88.84**	$1,016.31
NM, NV	1.7	1.5%	2.66	-$59.16	-$51.67	$0.00	-$90.50	-$11.10	**-$212.42**	$321.66	**$109.24**	$1,393.06
Pacific Division	16.9	14.9%	2.74	-$25.94	-$39.26	-$2.18	-$72.96	-$54.68	**-$195.02**	$331.98	**$136.96**	$1,801.00
CA	12.2	10.7%	2.82	-$23.53	-$37.59	-$1.55	-$72.96	-$54.68	**-$190.31**	$340.79	**$150.48**	$1,928.52
AK, HI, OR, WA	4.7	4.1%	2.55	-$32.77	-$43.74	-$3.47	-$72.96	-$54.68	**-$207.61**	$308.85	**$101.24**	$1,464.02

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

Table C.19 Net Impacts from \$15/tCO_2 at 4% scenario with 50% Rebate

Costs and Benefits to the average household (\$15/tCO_2 at 4% with 50% rebate)

Market Segment	Households: million	Households: % of total	Households: pph	First Year Costs (2014): Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	Total Costs	First Year Rebate: 50% Rebate	Net benefit	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-\$38.88	-\$49.04	-\$8.08	-\$83.98	-\$16.32	**-\$196.30**	\$311.61	**\$115.31**	\$915.27
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-\$17.39	-\$65.27	-\$19.66	-\$76.05	-\$22.71	**-\$201.08**	\$307.35	**\$106.27**	\$1,493.85
New England Division	5.5	4.8%	2.47	-\$25.14	-\$48.19	-\$31.31	-\$75.93	-\$5.94	**-\$186.51**	\$299.30	**\$112.79**	\$1,670.53
MA	2.5	2.2%	2.44	-\$18.87	-\$81.40	-\$13.47	-\$75.93	-\$5.94	**-\$195.61**	\$296.10	**\$100.49**	\$1,572.62
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-\$31.05	-\$27.13	-\$51.85	-\$75.93	-\$5.94	**-\$191.90**	\$302.30	**\$110.40**	\$1,645.09
Middle Atlantic Division	15.3	13.5%	2.56	-\$14.65	-\$71.44	-\$15.46	-\$76.10	-\$13.87	**-\$191.53**	\$310.10	**\$118.57**	\$1,554.72
NY	7.2	6.3%	2.58	-\$11.62	-\$71.61	-\$18.97	-\$76.10	-\$13.87	**-\$192.18**	\$312.29	**\$120.12**	\$1,627.14
PA	4.9	4.3%	2.43	-\$15.72	-\$26.70	-\$22.64	-\$76.10	-\$13.87	**-\$155.03**	\$293.92	**\$138.89**	\$1,652.00
NJ	3.2	2.8%	2.73	-\$20.92	-\$101.90	-\$2.12	-\$76.10	-\$13.87	**-\$214.92**	\$330.40	**\$115.48**	\$1,478.76
Total Midwest Region	25.9	22.8%	2.49	-\$38.51	-\$80.15	-\$8.45	-\$85.80	-\$14.11	**-\$227.03**	\$301.92	**\$74.89**	\$1,068.95
East North Central Division	17.9	15.8%	2.52	-\$38.61	-\$87.93	-\$6.78	-\$85.94	-\$5.66	**-\$224.92**	\$305.56	**\$80.64**	\$1,135.32
IL	4.8	4.2%	2.54	-\$43.13	-\$99.08	-\$1.43	-\$85.94	-\$5.66	**-\$235.25**	\$307.67	**\$72.43**	\$1,053.71
MI	3.8	3.3%	2.68	-\$32.01	-\$133.72	-\$11.61	-\$85.94	-\$5.66	**-\$268.94**	\$324.51	**\$55.57**	\$1,036.11
WI	2.3	2.0%	2.36	-\$34.91	-\$64.30	-\$12.52	-\$85.94	-\$5.66	**-\$203.34**	\$285.63	**\$82.29**	\$1,103.89
IN, OH	7.0	6.2%	2.48	-\$40.72	-\$67.90	-\$5.05	-\$85.94	-\$5.66	**-\$205.27**	\$300.29	**\$95.02**	\$1,219.92
West North Central Division	8.1	7.1%	2.42	-\$37.83	-\$61.97	-\$12.38	-\$85.50	-\$3.99	**-\$201.65**	\$293.61	**\$91.96**	\$1,175.95
MO	2.3	2.0%	2.48	-\$44.77	-\$61.63	-\$6.87	-\$85.50	-\$3.99	**-\$202.76**	\$300.06	**\$97.29**	\$1,181.91
IA, MN, ND,SD	3.9	3.4%	2.41	-\$37.28	-\$51.29	-\$29.29	-\$85.50	-\$3.99	**-\$207.35**	\$291.96	**\$84.61**	\$1,096.81
KS, NE	1.8	1.6%	2.38	-\$34.78	-\$99.06	\$0.00	-\$85.50	-\$3.99	**-\$223.33**	\$288.53	**\$65.21**	\$983.91
Total South Region	42.1	37.1%	2.55	-\$54.37	-\$26.88	-\$4.98	-\$90.02	-\$10.66	**-\$186.91**	\$309.44	**\$122.53**	\$1,407.75
South Atlantic Division	22.2	19.5%	2.52	-\$57.32	-\$22.36	-\$5.61	-\$90.24	-\$2.06	**-\$177.60**	\$305.81	**\$128.21**	\$1,527.14
VA	3.0	2.6%	2.60	-\$50.56	-\$48.33	-\$5.95	-\$90.24	-\$2.06	**-\$197.14**	\$315.61	**\$118.47**	\$1,505.29
GA	3.5	3.1%	2.69	-\$49.55	-\$65.28	-\$0.46	-\$90.24	-\$2.06	**-\$207.60**	\$326.53	**\$118.93**	\$1,546.50
FL	7.0	6.2%	2.42	-\$73.82	-\$1.02	-\$1.48	-\$90.24	-\$2.06	**-\$168.63**	\$292.77	**\$124.14**	\$1,377.25
DC, DE, MD, WV	3.4	3.0%	2.57	-\$57.65	-\$56.81	-\$19.03	-\$90.24	-\$2.06	**-\$225.80**	\$311.05	**\$85.25**	\$1,168.28
NC, SC	5.4	4.8%	2.48	-\$44.91	-\$18.66	-\$6.76	-\$90.24	-\$2.06	**-\$162.64**	\$300.19	**\$137.55**	\$1,654.53
East South Central Division	7.1	6.3%	2.41	-\$87.32	-\$27.88	-\$6.53	-\$88.25	-\$13.41	**-\$223.39**	\$292.50	**\$69.11**	\$1,238.80
TN	2.4	2.1%	2.47	-\$78.15	-\$25.81	\$0.00	-\$88.25	-\$13.41	**-\$205.62**	\$299.37	**\$93.75**	\$1,478.50
AL, KY, MS	4.6	4.0%	2.39	-\$95.99	-\$30.24	-\$9.70	-\$88.25	-\$13.41	**-\$237.60**	\$289.21	**\$51.62**	\$1,072.68
West South Central Division	12.8	11.3%	2.68	-\$29.81	-\$34.93	-\$2.94	-\$90.62	-\$9.65	**-\$167.96**	\$324.85	**\$156.89**	\$1,413.21
TX	8.5	7.5%	2.74	-\$35.62	-\$33.35	-\$0.82	-\$90.62	-\$9.65	**-\$170.06**	\$332.55	**\$162.49**	\$1,347.75
AR, LA, OK	4.2	3.7%	2.55	-\$20.80	-\$40.01	-\$11.03	-\$90.62	-\$9.65	**-\$172.11**	\$308.89	**\$136.78**	\$1,400.49
Total West Region	24.8	21.8%	2.72	-\$35.54	-\$41.73	-\$3.25	-\$78.47	-\$22.34	**-\$181.33**	\$329.26	**\$147.93**	\$1,984.79
Mountain Division	7.9	7.0%	2.67	-\$55.52	-\$49.16	-\$5.68	-\$90.50	-\$11.07	**-\$211.93**	\$323.35	**\$111.42**	\$1,536.87
Mountain North Sub-Div.	3.9	3.4%	2.72	-\$33.29	-\$73.44	-\$9.26	-\$90.50	-\$11.07	**-\$217.56**	\$328.99	**\$111.43**	\$1,653.58
CO	1.9	1.7%	2.33	-\$24.10	-\$82.52	-\$16.76	-\$90.50	-\$11.07	**-\$224.95**	\$281.75	**\$56.80**	\$1,108.57
ID, MT, UT, WY	2.0	1.8%	3.08	-\$43.38	-\$65.30	\$0.00	-\$90.50	-\$11.07	**-\$210.25**	\$373.68	**\$163.44**	\$2,167.98
Mountain South Sub-Div.	4.0	3.5%	2.62	-\$82.37	-\$30.16	-\$3.03	-\$90.50	-\$11.07	**-\$217.13**	\$317.51	**\$100.38**	\$1,304.33
AZ	2.3	2.0%	2.59	-\$102.25	-\$18.47	-\$1.55	-\$90.50	-\$11.07	**-\$223.84**	\$313.97	**\$90.13**	\$1,116.14
NM, NV	1.7	1.5%	2.66	-\$58.90	-\$50.51	\$0.00	-\$90.50	-\$11.07	**-\$210.98**	\$322.03	**\$111.06**	\$1,521.86
Pacific Division	16.9	14.9%	2.74	-\$25.95	-\$38.32	-\$2.15	-\$73.09	-\$54.55	**-\$194.05**	\$332.36	**\$138.32**	\$1,966.34
CA	12.2	10.7%	2.82	-\$23.53	-\$36.69	-\$1.52	-\$73.09	-\$54.55	**-\$189.38**	\$341.18	**\$151.80**	\$2,103.95
AK, HI, OR, WA	4.7	4.1%	2.55	-\$32.78	-\$42.69	-\$3.41	-\$73.09	-\$54.55	**-\$206.51**	\$309.20	**\$102.69**	\$1,602.72

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

Table C.20 Net Impacts from \$15/tCO_2 at 6% scenario with 50% Rebate

Costs and Benefits to the average household
(\$15/tCO_2 at 6% with 50% rebate)

Market Segment	Households: million	Households: % of total	Households: pph	First Year Costs (2014): Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	First Year Rebate: 50% Rebate	**Net benefit**	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-$38.89	-$49.99	-$8.23	-$76.76	-$14.92	**-$188.80**	$311.19	**$122.39**	$1,016.76
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-$17.49	-$66.85	-$20.14	-$70.61	-$20.76	**-$195.85**	$306.93	**$111.09**	$1,613.79
New England Division	5.5	4.8%	2.47	-$24.88	-$49.23	-$32.07	-$70.41	-$5.43	**-$182.03**	$298.90	**$116.87**	$1,734.59
MA	2.5	2.2%	2.44	-$18.67	-$83.17	-$13.79	-$70.41	-$5.43	**-$191.48**	$295.70	**$104.22**	$1,642.89
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-$30.73	-$27.71	-$53.11	-$70.41	-$5.43	**-$187.39**	$301.89	**$114.49**	$1,691.43
Middle Atlantic Division	15.3	13.5%	2.56	-$14.88	-$73.22	-$15.83	-$70.69	-$12.68	**-$187.31**	$309.68	**$122.37**	$1,699.11
NY	7.2	6.3%	2.58	-$11.80	-$73.40	-$19.43	-$70.69	-$12.68	**-$187.99**	$311.87	**$123.88**	$1,773.70
PA	4.9	4.3%	2.43	-$15.96	-$27.36	-$23.19	-$70.69	-$12.68	**-$149.88**	$293.52	**$143.64**	$1,811.28
NJ	3.2	2.8%	2.73	-$21.24	-$104.44	-$2.17	-$70.69	-$12.68	**-$211.23**	$329.95	**$118.72**	$1,620.90
Total Midwest Region	25.9	22.8%	2.49	-$38.38	-$81.54	-$8.58	-$73.95	-$12.90	**-$215.35**	$301.51	**$86.16**	$1,253.06
East North Central Division	17.9	15.8%	2.52	-$38.04	-$89.50	-$6.89	-$72.15	-$5.18	**-$211.75**	$305.14	**$93.40**	$1,371.10
IL	4.8	4.2%	2.54	-$42.49	-$100.86	-$1.45	-$72.15	-$5.18	**-$222.12**	$307.26	**$85.14**	$1,281.76
MI	3.8	3.3%	2.68	-$31.53	-$136.11	-$11.79	-$72.15	-$5.18	**-$256.76**	$324.07	**$67.31**	$1,251.71
WI	2.3	2.0%	2.36	-$34.39	-$65.45	-$12.72	-$72.15	-$5.18	**-$189.89**	$285.25	**$95.36**	$1,341.02
IN, OH	7.0	6.2%	2.48	-$40.11	-$69.12	-$5.12	-$72.15	-$5.18	**-$191.68**	$299.88	**$108.20**	$1,467.71
West North Central Division	8.1	7.1%	2.42	-$38.60	-$62.92	-$12.54	-$77.62	-$3.64	**-$195.31**	$293.22	**$97.91**	$1,265.34
MO	2.3	2.0%	2.48	-$45.68	-$62.58	-$6.96	-$77.62	-$3.64	**-$196.48**	$299.65	**$103.17**	$1,271.05
IA, MN, ND,SD	3.9	3.4%	2.41	-$38.04	-$52.08	-$29.67	-$77.62	-$3.64	**-$201.05**	$291.57	**$90.51**	$1,181.06
KS, NE	1.8	1.6%	2.38	-$35.48	-$100.58	$0.00	-$77.62	-$3.64	**-$217.33**	$288.14	**$70.81**	$1,049.96
Total South Region	42.1	37.1%	2.55	-$54.27	-$27.44	-$5.07	-$83.53	-$9.75	**-$180.05**	$309.02	**$128.96**	$1,532.81
South Atlantic Division	22.2	19.5%	2.52	-$57.65	-$22.83	-$5.72	-$83.77	-$1.89	**-$171.85**	$305.39	**$133.54**	$1,660.91
VA	3.0	2.6%	2.60	-$50.85	-$49.33	-$6.06	-$83.77	-$1.89	**-$191.90**	$315.18	**$123.28**	$1,630.73
GA	3.5	3.1%	2.69	-$49.84	-$66.63	-$0.47	-$83.77	-$1.89	**-$202.60**	$326.08	**$123.48**	$1,671.94
FL	7.0	6.2%	2.42	-$74.25	-$1.04	-$1.50	-$83.77	-$1.89	**-$162.46**	$292.37	**$129.91**	$1,505.46
DC, DE, MD, WV	3.4	3.0%	2.57	-$57.98	-$57.99	-$19.38	-$83.77	-$1.89	**-$221.02**	$310.62	**$89.61**	$1,263.48
NC, SC	5.4	4.8%	2.48	-$45.17	-$19.05	-$6.89	-$83.77	-$1.89	**-$156.76**	$299.79	**$143.02**	$1,798.33
East South Central Division	7.1	6.3%	2.41	-$88.01	-$28.47	-$6.64	-$81.83	-$12.26	**-$217.21**	$292.10	**$74.90**	$1,349.21
TN	2.4	2.1%	2.47	-$78.77	-$26.35	$0.00	-$81.83	-$12.26	**-$199.21**	$298.96	**$99.75**	$1,609.45
AL, KY, MS	4.6	4.0%	2.39	-$96.76	-$30.88	-$9.86	-$81.83	-$12.26	**-$231.58**	$288.82	**$57.24**	$1,168.83
West South Central Division	12.8	11.3%	2.68	-$28.49	-$35.66	-$2.99	-$84.08	-$8.82	**-$160.04**	$324.41	**$164.36**	$1,535.64
TX	8.5	7.5%	2.74	-$34.05	-$34.04	-$0.84	-$84.08	-$8.82	**-$161.83**	$332.10	**$170.27**	$1,465.94
AR, LA, OK	4.2	3.7%	2.55	-$19.88	-$40.84	-$11.19	-$84.08	-$8.82	**-$164.82**	$308.47	**$143.65**	$1,519.03
Total West Region	24.8	21.8%	2.72	-$35.85	-$42.41	-$3.28	-$73.17	-$20.42	**-$175.12**	$328.82	**$153.70**	$2,158.41
Mountain Division	7.9	7.0%	2.67	-$55.68	-$49.98	-$5.74	-$75.31	-$10.12	**-$196.83**	$322.91	**$126.08**	$1,693.35
Mountain North Sub-Div.	3.9	3.4%	2.72	-$33.38	-$74.67	-$9.37	-$75.31	-$10.12	**-$202.84**	$328.55	**$125.70**	$1,804.71
CO	1.9	1.7%	2.33	-$24.17	-$83.91	-$16.94	-$75.31	-$10.12	**-$210.44**	$281.37	**$70.92**	$1,208.59
ID, MT, UT, WY	2.0	1.8%	3.08	-$43.50	-$66.39	$0.00	-$75.31	-$10.12	**-$195.32**	$373.18	**$177.86**	$2,367.87
Mountain South Sub-Div.	4.0	3.5%	2.62	-$82.60	-$30.67	-$3.06	-$75.31	-$10.12	**-$201.75**	$317.08	**$115.33**	$1,456.52
AZ	2.3	2.0%	2.59	-$102.53	-$18.78	-$1.57	-$75.31	-$10.12	**-$208.31**	$313.54	**$105.23**	$1,263.10
NM, NV	1.7	1.5%	2.66	-$59.06	-$51.36	$0.00	-$75.31	-$10.12	**-$195.84**	$321.60	**$125.75**	$1,678.27
Pacific Division	16.9	14.9%	2.74	-$26.32	-$38.93	-$2.16	-$72.21	-$49.86	**-$189.48**	$331.91	**$142.43**	$2,139.08
CA	12.2	10.7%	2.82	-$23.87	-$37.29	-$1.53	-$72.21	-$49.86	**-$184.75**	$340.72	**$155.96**	$2,289.09
AK, HI, OR, WA	4.7	4.1%	2.55	-$33.25	-$43.38	-$3.43	-$72.21	-$49.86	**-$202.12**	$308.78	**$106.66**	$1,742.61

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

Table C.21 Net Impacts from \$15/tCO_2 at 8% scenario with 50% Rebate

Costs and Benefits to the average household (\$15/tCO_2 at 8% with 50% rebate)

Market Segment	Households			First Year Costs (2014)						First Year Rebate		
	million	% of total	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-\$39.65	-\$48.57	-\$8.16	-\$76.69	-\$14.90	**-\$187.98**	\$311.06	**\$123.08**	\$1,066.41
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-\$16.43	-\$65.16	-\$20.04	-\$70.59	-\$20.74	**-\$192.95**	\$306.81	**\$113.86**	\$1,691.20
New England Division	5.5	4.8%	2.47	-\$24.44	-\$47.96	-\$31.91	-\$70.40	-\$5.42	**-\$180.13**	\$298.78	**\$118.65**	\$1,893.30
MA	2.5	2.2%	2.44	-\$18.34	-\$81.02	-\$13.72	-\$70.40	-\$5.42	**-\$188.91**	\$295.58	**\$106.67**	\$1,788.86
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-\$30.18	-\$27.00	-\$52.84	-\$70.40	-\$5.42	**-\$185.84**	\$301.77	**\$115.93**	\$1,850.97
Middle Atlantic Division	15.3	13.5%	2.56	-\$13.59	-\$71.37	-\$15.76	-\$70.68	-\$12.67	**-\$184.07**	\$309.56	**\$125.49**	\$1,757.50
NY	7.2	6.3%	2.58	-\$10.77	-\$71.54	-\$19.33	-\$70.68	-\$12.67	**-\$185.00**	\$311.75	**\$126.75**	\$1,852.95
PA	4.9	4.3%	2.43	-\$14.58	-\$26.67	-\$23.07	-\$70.68	-\$12.67	**-\$147.67**	\$293.40	**\$145.73**	\$1,873.54
NJ	3.2	2.8%	2.73	-\$19.40	-\$101.81	-\$2.16	-\$70.68	-\$12.67	**-\$206.72**	\$329.82	**\$123.10**	\$1,642.23
Total Midwest Region	25.9	22.8%	2.49	-\$39.09	-\$79.43	-\$8.49	-\$74.05	-\$12.89	**-\$213.94**	\$301.39	**\$87.45**	\$1,327.34
East North Central Division	17.9	15.8%	2.52	-\$38.74	-\$87.23	-\$6.82	-\$72.02	-\$5.17	**-\$209.98**	\$305.02	**\$95.04**	\$1,449.42
IL	4.8	4.2%	2.54	-\$43.28	-\$98.30	-\$1.43	-\$72.02	-\$5.17	**-\$220.21**	\$307.13	**\$86.93**	\$1,347.31
MI	3.8	3.3%	2.68	-\$32.12	-\$132.66	-\$11.67	-\$72.02	-\$5.17	**-\$253.64**	\$323.95	**\$70.30**	\$1,323.82
WI	2.3	2.0%	2.36	-\$35.03	-\$63.79	-\$12.58	-\$72.02	-\$5.17	**-\$188.60**	\$285.13	**\$96.53**	\$1,422.72
IN, OH	7.0	6.2%	2.48	-\$40.86	-\$67.37	-\$5.07	-\$72.02	-\$5.17	**-\$190.49**	\$299.76	**\$109.28**	\$1,553.11
West North Central Division	8.1	7.1%	2.42	-\$39.30	-\$61.19	-\$12.40	-\$78.16	-\$3.64	**-\$194.69**	\$293.10	**\$98.41**	\$1,351.51
MO	2.3	2.0%	2.48	-\$46.51	-\$60.86	-\$6.89	-\$78.16	-\$3.64	**-\$196.06**	\$299.53	**\$103.47**	\$1,354.82
IA, MN, ND,SD	3.9	3.4%	2.41	-\$38.73	-\$50.65	-\$29.34	-\$78.16	-\$3.64	**-\$200.53**	\$291.45	**\$90.92**	\$1,262.05
KS, NE	1.8	1.6%	2.38	-\$36.13	-\$97.81	\$0.00	-\$78.16	-\$3.64	**-\$215.75**	\$288.03	**\$72.28**	\$1,116.56
Total South Region	42.1	37.1%	2.55	-\$54.96	-\$26.86	-\$5.01	-\$83.55	-\$9.74	**-\$180.11**	\$308.90	**\$128.79**	\$1,628.34
South Atlantic Division	22.2	19.5%	2.52	-\$57.69	-\$22.34	-\$5.66	-\$83.76	-\$1.88	**-\$171.33**	\$305.27	**\$133.94**	\$1,761.20
VA	3.0	2.6%	2.60	-\$50.89	-\$48.27	-\$5.99	-\$83.76	-\$1.88	**-\$190.80**	\$315.06	**\$124.26**	\$1,730.64
GA	3.5	3.1%	2.69	-\$49.88	-\$65.20	-\$0.46	-\$83.76	-\$1.88	**-\$201.19**	\$325.95	**\$124.77**	\$1,774.71
FL	7.0	6.2%	2.42	-\$74.31	-\$1.02	-\$1.49	-\$83.76	-\$1.88	**-\$162.46**	\$292.25	**\$129.79**	\$1,585.85
DC, DE, MD, WV	3.4	3.0%	2.57	-\$58.03	-\$56.75	-\$19.18	-\$83.76	-\$1.88	**-\$219.60**	\$310.50	**\$90.90**	\$1,329.64
NC, SC	5.4	4.8%	2.48	-\$45.20	-\$18.64	-\$6.81	-\$83.76	-\$1.88	**-\$156.30**	\$299.67	**\$143.37**	\$1,916.47
East South Central Division	7.1	6.3%	2.41	-\$87.43	-\$27.87	-\$6.55	-\$81.87	-\$12.25	**-\$215.96**	\$291.99	**\$76.02**	\$1,464.47
TN	2.4	2.1%	2.47	-\$78.24	-\$25.80	\$0.00	-\$81.87	-\$12.25	**-\$198.16**	\$298.84	**\$100.68**	\$1,744.48
AL, KY, MS	4.6	4.0%	2.39	-\$96.11	-\$30.23	-\$9.73	-\$81.87	-\$12.25	**-\$230.18**	\$288.71	**\$58.52**	\$1,270.47
West South Central Division	12.8	11.3%	2.68	-\$31.05	-\$34.92	-\$2.95	-\$84.12	-\$8.82	**-\$161.85**	\$324.28	**\$162.43**	\$1,620.38
TX	8.5	7.5%	2.74	-\$37.10	-\$33.33	-\$0.82	-\$84.12	-\$8.82	**-\$164.20**	\$331.96	**\$167.77**	\$1,538.41
AR, LA, OK	4.2	3.7%	2.55	-\$21.67	-\$39.99	-\$11.04	-\$84.12	-\$8.82	**-\$165.63**	\$308.35	**\$142.72**	\$1,612.80
Total West Region	24.8	21.8%	2.72	-\$38.65	-\$40.58	-\$3.24	-\$72.72	-\$20.40	**-\$175.59**	\$328.69	**\$153.10**	\$2,302.58
Mountain Division	7.9	7.0%	2.67	-\$53.36	-\$48.17	-\$5.68	-\$75.57	-\$10.11	**-\$192.88**	\$322.78	**\$129.90**	\$1,828.17
Mountain North Sub-Div.	3.9	3.4%	2.72	-\$31.99	-\$71.97	-\$9.26	-\$75.57	-\$10.11	**-\$198.89**	\$328.41	**\$129.53**	\$1,943.04
CO	1.9	1.7%	2.33	-\$23.16	-\$80.87	-\$16.74	-\$75.57	-\$10.11	**-\$206.45**	\$281.25	**\$74.80**	\$1,297.58
ID, MT, UT, WY	2.0	1.8%	3.08	-\$41.69	-\$63.99	\$0.00	-\$75.57	-\$10.11	**-\$191.36**	\$373.03	**\$181.67**	\$2,552.81
Mountain South Sub-Div.	4.0	3.5%	2.62	-\$79.16	-\$29.56	-\$3.02	-\$75.57	-\$10.11	**-\$197.41**	\$316.95	**\$119.54**	\$1,577.62
AZ	2.3	2.0%	2.59	-\$98.26	-\$18.10	-\$1.55	-\$75.57	-\$10.11	**-\$203.59**	\$313.42	**\$109.83**	\$1,372.29
NM, NV	1.7	1.5%	2.66	-\$56.60	-\$49.50	\$0.00	-\$75.57	-\$10.11	**-\$191.77**	\$321.47	**\$129.69**	\$1,811.83
Pacific Division	16.9	14.9%	2.74	-\$31.59	-\$37.11	-\$2.13	-\$71.44	-\$49.81	**-\$192.10**	\$331.78	**\$139.68**	\$2,269.25
CA	12.2	10.7%	2.82	-\$28.65	-\$35.54	-\$1.51	-\$71.44	-\$49.81	**-\$186.96**	\$340.58	**\$153.62**	\$2,434.06
AK, HI, OR, WA	4.7	4.1%	2.55	-\$39.91	-\$41.35	-\$3.39	-\$71.44	-\$49.81	**-\$205.90**	\$308.66	**\$102.76**	\$1,833.19

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

Table C.22 Net Impacts from $25/tCO$_2$ at 2% scenario with 50% Rebate

Costs and Benefits to the average household ($25/tCO$_2$ at 2% with 50% rebate)

Market Segment	Households			First Year Costs (2014)						First Year Rebate		
	million	% of total	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-$64.48	-$83.80	-$13.66	-$138.59	-$26.94	**-$327.48**	$508.93	**$181.46**	$1,283.43
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-$29.51	-$111.03	-$33.56	-$124.95	-$37.47	**-$336.52**	$501.98	**$165.46**	$2,077.83
New England Division	5.5	4.8%	2.47	-$41.71	-$81.76	-$53.44	-$124.78	-$9.80	**-$311.50**	$488.83	**$177.34**	$2,391.56
MA	2.5	2.2%	2.44	-$31.31	-$138.11	-$22.98	-$124.78	-$9.80	**-$326.99**	$483.60	**$156.62**	$2,227.72
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-$51.52	-$46.02	-$88.49	-$124.78	-$9.80	**-$320.62**	$493.72	**$173.11**	$2,358.35
Middle Atlantic Division	15.3	13.5%	2.56	-$25.19	-$121.61	-$26.40	-$125.01	-$22.90	**-$321.11**	$506.47	**$185.37**	$2,144.81
NY	7.2	6.3%	2.58	-$19.97	-$121.90	-$32.39	-$125.01	-$22.90	**-$322.17**	$510.05	**$187.88**	$2,273.83
PA	4.9	4.3%	2.43	-$27.02	-$45.44	-$38.65	-$125.01	-$22.90	**-$259.02**	$480.04	**$221.01**	$2,326.32
NJ	3.2	2.8%	2.73	-$35.96	-$173.47	-$3.63	-$125.01	-$22.90	**-$360.96**	$539.62	**$178.66**	$1,957.45
Total Midwest Region	25.9	22.8%	2.49	-$64.09	-$136.94	-$14.18	-$143.86	-$23.29	**-$382.36**	$493.11	**$110.75**	$1,551.62
East North Central Division	17.9	15.8%	2.52	-$64.20	-$150.22	-$11.39	-$139.31	-$9.35	**-$374.47**	$499.05	**$124.58**	$1,659.75
IL	4.8	4.2%	2.54	-$71.72	-$169.29	-$2.40	-$139.31	-$9.35	**-$392.05**	$502.51	**$110.45**	$1,524.81
MI	3.8	3.3%	2.68	-$53.22	-$228.46	-$19.50	-$139.31	-$9.35	**-$449.84**	$530.01	**$80.17**	$1,458.56
WI	2.3	2.0%	2.36	-$58.05	-$109.86	-$21.03	-$139.31	-$9.35	**-$337.60**	$466.51	**$128.91**	$1,640.82
IN, OH	7.0	6.2%	2.48	-$67.71	-$116.01	-$8.47	-$139.31	-$9.35	**-$340.85**	$490.45	**$149.60**	$1,809.40
West North Central Division	8.1	7.1%	2.42	-$63.06	-$105.85	-$20.71	-$153.09	-$6.58	**-$349.28**	$479.54	**$130.26**	$1,684.52
MO	2.3	2.0%	2.48	-$74.63	-$105.28	-$11.50	-$153.09	-$6.58	**-$351.08**	$490.07	**$138.98**	$1,698.37
IA, MN, ND,SD	3.9	3.4%	2.41	-$62.15	-$87.62	-$49.01	-$153.09	-$6.58	**-$358.45**	$476.85	**$118.40**	$1,568.18
KS, NE	1.8	1.6%	2.38	-$57.97	-$169.22	$0.00	-$153.09	-$6.58	**-$386.86**	$471.24	**$84.38**	$1,360.97
Total South Region	42.1	37.1%	2.55	-$90.53	-$45.85	-$8.38	-$147.86	-$17.60	**-$310.22**	$505.39	**$195.18**	$2,003.88
South Atlantic Division	22.2	19.5%	2.52	-$96.42	-$38.07	-$9.46	-$148.20	-$3.41	**-$295.55**	$499.46	**$203.91**	$2,194.31
VA	3.0	2.6%	2.60	-$85.05	-$82.27	-$10.03	-$148.20	-$3.41	**-$328.95**	$515.47	**$186.52**	$2,138.38
GA	3.5	3.1%	2.69	-$83.36	-$111.12	-$0.77	-$148.20	-$3.41	**-$346.86**	$533.30	**$186.44**	$2,183.77
FL	7.0	6.2%	2.42	-$124.19	-$1.74	-$2.49	-$148.20	-$3.41	**-$280.02**	$478.16	**$198.14**	$1,979.79
DC, DE, MD, WV	3.4	3.0%	2.57	-$96.98	-$96.71	-$32.07	-$148.20	-$3.41	**-$377.37**	$508.02	**$130.65**	$1,610.28
NC, SC	5.4	4.8%	2.48	-$75.54	-$31.77	-$11.40	-$148.20	-$3.41	**-$270.31**	$490.29	**$219.98**	$2,402.54
East South Central Division	7.1	6.3%	2.41	-$143.25	-$47.60	-$10.96	-$144.99	-$22.13	**-$368.92**	$477.73	**$108.80**	$1,821.53
TN	2.4	2.1%	2.47	-$128.20	-$44.06	$0.00	-$144.99	-$22.13	**-$339.38**	$488.94	**$149.56**	$2,185.99
AL, KY, MS	4.6	4.0%	2.39	-$157.48	-$51.62	-$16.27	-$144.99	-$22.13	**-$392.49**	$472.36	**$79.86**	$1,568.59
West South Central Division	12.8	11.3%	2.68	-$49.18	-$59.74	-$4.93	-$148.90	-$15.93	**-$278.67**	$530.56	**$251.88**	$1,942.01
TX	8.5	7.5%	2.74	-$58.76	-$57.03	-$1.38	-$148.90	-$15.93	**-$282.00**	$543.13	**$261.13**	$1,821.09
AR, LA, OK	4.2	3.7%	2.55	-$34.32	-$68.42	-$18.47	-$148.90	-$15.93	**-$286.04**	$504.50	**$218.46**	$1,952.37
Total West Region	24.8	21.8%	2.72	-$57.41	-$71.79	-$5.42	-$128.94	-$36.87	**-$300.43**	$537.77	**$237.34**	$2,905.93
Mountain Division	7.9	7.0%	2.67	-$83.78	-$85.08	-$9.49	-$137.70	-$18.27	**-$334.32**	$528.11	**$193.80**	$2,299.49
Mountain North Sub-Div.	3.9	3.4%	2.72	-$50.22	-$127.11	-$15.47	-$137.70	-$18.27	**-$348.77**	$537.32	**$188.55**	$2,421.17
CO	1.9	1.7%	2.33	-$36.37	-$142.83	-$27.98	-$137.70	-$18.27	**-$363.15**	$460.16	**$97.01**	$1,586.17
ID, MT, UT, WY	2.0	1.8%	3.08	-$65.45	-$113.02	$0.00	-$137.70	-$18.27	**-$334.44**	$610.32	**$275.88**	$3,211.38
Mountain South Sub-Div.	4.0	3.5%	2.62	-$124.28	-$52.20	-$5.05	-$137.70	-$18.27	**-$337.51**	$518.57	**$181.06**	$2,001.36
AZ	2.3	2.0%	2.59	-$154.27	-$31.97	-$2.59	-$137.70	-$18.27	**-$344.81**	$512.79	**$167.98**	$1,753.30
NM, NV	1.7	1.5%	2.66	-$88.87	-$87.42	$0.00	-$137.70	-$18.27	**-$332.26**	$525.96	**$193.70**	$2,282.06
Pacific Division	16.9	14.9%	2.74	-$44.76	-$65.70	-$3.58	-$125.02	-$90.02	**-$329.09**	$542.83	**$213.74**	$2,860.32
CA	12.2	10.7%	2.82	-$40.59	-$62.92	-$2.54	-$125.02	-$90.02	**-$321.10**	$557.23	**$236.13**	$3,071.10
AK, HI, OR, WA	4.7	4.1%	2.55	-$56.55	-$73.20	-$5.68	-$125.02	-$90.02	**-$350.47**	$505.01	**$154.53**	$2,302.77

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

Table C.23 Net Impacts from $25/tCO$_2$ at 4% scenario with 50% Rebate

Costs and Benefits to the average household ($25/tCO$_2$ at 4% with 50% rebate)

Market Segment	Households			First Year Costs (2014)						First Year Rebate		
	million	% of total	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-$65.12	-$83.24	-$13.64	-$138.62	-$26.94	**-$327.56**	$507.93	**$180.37**	$1,339.18
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-$28.11	-$110.20	-$33.56	-$125.05	-$37.48	**-$334.40**	$500.99	**$166.59**	$2,218.62
New England Division	5.5	4.8%	2.47	-$41.35	-$81.18	-$53.43	-$124.88	-$9.80	**-$310.64**	$487.87	**$177.22**	$2,515.63
MA	2.5	2.2%	2.44	-$31.04	-$137.12	-$22.98	-$124.88	-$9.80	**-$325.83**	$482.65	**$156.82**	$2,339.51
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-$51.07	-$45.69	-$88.48	-$124.88	-$9.80	**-$319.92**	$492.74	**$172.82**	$2,477.72
Middle Atlantic Division	15.3	13.5%	2.56	-$23.43	-$120.69	-$26.40	-$125.12	-$22.90	**-$318.53**	$505.47	**$186.94**	$2,307.66
NY	7.2	6.3%	2.58	-$18.57	-$120.98	-$32.39	-$125.12	-$22.90	**-$319.96**	$509.04	**$189.08**	$2,436.02
PA	4.9	4.3%	2.43	-$25.13	-$45.10	-$38.65	-$125.12	-$22.90	**-$256.90**	$479.09	**$222.19**	$2,510.35
NJ	3.2	2.8%	2.73	-$33.44	-$172.16	-$3.63	-$125.12	-$22.90	**-$357.24**	$538.55	**$181.31**	$2,124.20
Total Midwest Region	25.9	22.8%	2.49	-$64.12	-$135.85	-$14.13	-$144.03	-$23.29	**-$381.42**	$492.13	**$110.71**	$1,643.88
East North Central Division	17.9	15.8%	2.52	-$63.98	-$149.06	-$11.35	-$139.31	-$9.35	**-$373.05**	$498.06	**$125.01**	$1,771.98
IL	4.8	4.2%	2.54	-$71.48	-$167.97	-$2.39	-$139.31	-$9.35	**-$390.50**	$501.51	**$111.02**	$1,628.15
MI	3.8	3.3%	2.68	-$53.04	-$226.69	-$19.44	-$139.31	-$9.35	**-$447.83**	$528.96	**$81.13**	$1,536.41
WI	2.3	2.0%	2.36	-$57.85	-$109.01	-$20.97	-$139.31	-$9.35	**-$336.49**	$465.58	**$129.10**	$1,755.29
IN, OH	7.0	6.2%	2.48	-$67.48	-$115.11	-$8.45	-$139.31	-$9.35	**-$339.70**	$489.48	**$149.78**	$1,940.44
West North Central Division	8.1	7.1%	2.42	-$63.59	-$104.94	-$20.63	-$153.61	-$6.58	**-$349.34**	$478.59	**$129.25**	$1,767.76
MO	2.3	2.0%	2.48	-$75.26	-$104.37	-$11.46	-$153.61	-$6.58	**-$351.27**	$489.09	**$137.82**	$1,784.39
IA, MN, ND,SD	3.9	3.4%	2.41	-$62.68	-$86.86	-$48.83	-$153.61	-$6.58	**-$358.55**	$475.90	**$117.36**	$1,645.27
KS, NE	1.8	1.6%	2.38	-$58.46	-$167.76	$0.00	-$153.61	-$6.58	**-$386.41**	$470.31	**$83.90**	$1,407.76
Total South Region	42.1	37.1%	2.55	-$91.03	-$45.55	-$8.35	-$147.97	-$17.60	**-$310.51**	$504.39	**$193.88**	$2,098.00
South Atlantic Division	22.2	19.5%	2.52	-$96.55	-$37.83	-$9.44	-$148.31	-$3.41	**-$295.53**	$498.47	**$202.94**	$2,306.64
VA	3.0	2.6%	2.60	-$85.17	-$81.74	-$10.00	-$148.31	-$3.41	**-$328.62**	$514.45	**$185.83**	$2,242.01
GA	3.5	3.1%	2.69	-$83.47	-$110.41	-$0.77	-$148.31	-$3.41	**-$346.37**	$532.24	**$185.87**	$2,287.51
FL	7.0	6.2%	2.42	-$124.36	-$1.73	-$2.48	-$148.31	-$3.41	**-$280.28**	$477.21	**$196.93**	$2,078.38
DC, DE, MD, WV	3.4	3.0%	2.57	-$97.11	-$96.09	-$31.98	-$148.31	-$3.41	**-$376.90**	$507.01	**$130.11**	$1,670.64
NC, SC	5.4	4.8%	2.48	-$75.65	-$31.57	-$11.36	-$148.31	-$3.41	**-$270.30**	$489.32	**$219.02**	$2,533.52
East South Central Division	7.1	6.3%	2.41	-$141.87	-$47.29	-$10.91	-$145.09	-$22.14	**-$367.29**	$476.78	**$109.49**	$1,937.64
TN	2.4	2.1%	2.47	-$126.96	-$43.78	$0.00	-$145.09	-$22.14	**-$337.97**	$487.97	**$150.00**	$2,327.43
AL, KY, MS	4.6	4.0%	2.39	-$155.96	-$51.29	-$16.19	-$145.09	-$22.14	**-$390.67**	$471.42	**$80.75**	$1,667.54
West South Central Division	12.8	11.3%	2.68	-$51.45	-$59.34	-$4.91	-$149.01	-$15.93	**-$280.64**	$529.50	**$248.87**	$2,007.02
TX	8.5	7.5%	2.74	-$61.47	-$56.65	-$1.37	-$149.01	-$15.93	**-$284.44**	$542.06	**$257.61**	$1,870.98
AR, LA, OK	4.2	3.7%	2.55	-$35.90	-$67.96	-$18.38	-$149.01	-$15.93	**-$287.19**	$503.50	**$216.31**	$2,026.96
Total West Region	24.8	21.8%	2.72	-$61.06	-$71.49	-$5.40	-$128.62	-$36.88	**-$303.46**	$536.70	**$233.25**	$3,057.16
Mountain Division	7.9	7.0%	2.67	-$100.95	-$84.31	-$9.45	-$138.05	-$18.27	**-$351.03**	$527.07	**$176.04**	$2,363.19
Mountain North Sub-Div.	3.9	3.4%	2.72	-$60.52	-$125.95	-$15.41	-$138.05	-$18.27	**-$358.20**	$536.26	**$178.06**	$2,505.44
CO	1.9	1.7%	2.33	-$43.82	-$141.53	-$27.87	-$138.05	-$18.27	**-$369.55**	$459.25	**$89.71**	$1,614.87
ID, MT, UT, WY	2.0	1.8%	3.08	-$78.87	-$111.99	$0.00	-$138.05	-$18.27	**-$347.18**	$609.11	**$261.93**	$3,346.75
Mountain South Sub-Div.	4.0	3.5%	2.62	-$149.76	-$51.72	-$5.03	-$138.05	-$18.27	**-$362.84**	$517.55	**$154.70**	$2,024.23
AZ	2.3	2.0%	2.59	-$185.89	-$31.68	-$2.58	-$138.05	-$18.27	**-$376.48**	$511.77	**$135.29**	$1,742.78
NM, NV	1.7	1.5%	2.66	-$107.08	-$86.62	$0.00	-$138.05	-$18.27	**-$350.03**	$524.92	**$174.89**	$2,340.88
Pacific Division	16.9	14.9%	2.74	-$41.89	-$65.62	-$3.57	-$124.40	-$90.04	**-$325.52**	$541.75	**$216.24**	$3,022.88
CA	12.2	10.7%	2.82	-$37.98	-$62.84	-$2.53	-$124.40	-$90.04	**-$317.80**	$556.13	**$238.33**	$3,249.26
AK, HI, OR, WA	4.7	4.1%	2.55	-$52.91	-$73.11	-$5.67	-$124.40	-$90.04	**-$346.13**	$504.00	**$157.88**	$2,424.16

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

Table C.24 Net Impacts from \$25/tCO_2 at 6% scenario with 50% Rebate

Costs and Benefits to the average household (\$25/tCO_2 at 6% with 50% rebate)

Market Segment	Households			First Year Costs (2014)						First Year Rebate		
	million	% of total	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-\$65.19	-\$83.21	-\$13.61	-\$138.47	-\$26.91	**-\$327.38**	\$507.91	**\$180.53**	\$1,357.62
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-\$27.41	-\$110.21	-\$33.46	-\$124.59	-\$37.44	**-\$333.11**	\$500.98	**\$167.87**	\$2,337.23
New England Division	5.5	4.8%	2.47	-\$41.42	-\$81.14	-\$53.27	-\$124.42	-\$9.79	**-\$310.04**	\$487.85	**\$177.81**	\$2,656.59
MA	2.5	2.2%	2.44	-\$31.09	-\$137.06	-\$22.91	-\$124.42	-\$9.79	**-\$325.27**	\$482.63	**\$157.36**	\$2,458.96
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-\$51.15	-\$45.67	-\$88.21	-\$124.42	-\$9.79	**-\$319.25**	\$492.73	**\$173.48**	\$2,618.24
Middle Atlantic Division	15.3	13.5%	2.56	-\$22.46	-\$120.71	-\$26.31	-\$124.66	-\$22.88	**-\$317.02**	\$505.46	**\$188.44**	\$2,434.04
NY	7.2	6.3%	2.58	-\$17.80	-\$121.00	-\$32.29	-\$124.66	-\$22.88	**-\$318.63**	\$509.03	**\$190.40**	\$2,572.35
PA	4.9	4.3%	2.43	-\$24.09	-\$45.11	-\$38.53	-\$124.66	-\$22.88	**-\$255.26**	\$479.08	**\$223.82**	\$2,667.84
NJ	3.2	2.8%	2.73	-\$32.06	-\$172.18	-\$3.61	-\$124.66	-\$22.88	**-\$355.39**	\$538.54	**\$183.15**	\$2,225.16
Total Midwest Region	25.9	22.8%	2.49	-\$64.24	-\$135.82	-\$14.13	-\$143.46	-\$23.27	**-\$380.91**	\$492.12	**\$111.21**	\$1,658.90
East North Central Division	17.9	15.8%	2.52	-\$64.14	-\$149.03	-\$11.35	-\$138.43	-\$9.34	**-\$372.29**	\$498.05	**\$125.76**	\$1,798.28
IL	4.8	4.2%	2.54	-\$71.65	-\$167.94	-\$2.39	-\$138.43	-\$9.34	**-\$389.75**	\$501.50	**\$111.75**	\$1,631.62
MI	3.8	3.3%	2.68	-\$53.17	-\$226.65	-\$19.43	-\$138.43	-\$9.34	**-\$447.02**	\$528.95	**\$81.93**	\$1,535.03
WI	2.3	2.0%	2.36	-\$58.00	-\$108.99	-\$20.96	-\$138.43	-\$9.34	**-\$335.71**	\$465.57	**\$129.87**	\$1,796.48
IN, OH	7.0	6.2%	2.48	-\$67.65	-\$115.09	-\$8.44	-\$138.43	-\$9.34	**-\$338.95**	\$489.46	**\$150.52**	\$1,985.08
West North Central Division	8.1	7.1%	2.42	-\$63.63	-\$104.90	-\$20.63	-\$153.66	-\$6.57	**-\$349.40**	\$478.58	**\$129.19**	\$1,792.69
MO	2.3	2.0%	2.48	-\$75.31	-\$104.34	-\$11.46	-\$153.66	-\$6.57	**-\$351.34**	\$489.08	**\$137.74**	\$1,802.39
IA, MN, ND,SD	3.9	3.4%	2.41	-\$62.72	-\$86.83	-\$48.83	-\$153.66	-\$6.57	**-\$358.61**	\$475.89	**\$117.28**	\$1,663.68
KS, NE	1.8	1.6%	2.38	-\$58.50	-\$167.70	\$0.00	-\$153.66	-\$6.57	**-\$386.44**	\$470.30	**\$83.86**	\$1,394.14
Total South Region	42.1	37.1%	2.55	-\$90.70	-\$45.56	-\$8.34	-\$147.46	-\$17.58	**-\$309.65**	\$504.38	**\$194.73**	\$2,141.02
South Atlantic Division	22.2	19.5%	2.52	-\$95.86	-\$37.85	-\$9.43	-\$147.77	-\$3.40	**-\$294.31**	\$498.46	**\$204.15**	\$2,443.38
VA	3.0	2.6%	2.60	-\$84.56	-\$81.79	-\$9.99	-\$147.77	-\$3.40	**-\$327.51**	\$514.44	**\$186.92**	\$2,363.18
GA	3.5	3.1%	2.69	-\$82.87	-\$110.48	-\$0.77	-\$147.77	-\$3.40	**-\$345.30**	\$532.23	**\$186.93**	\$2,405.47
FL	7.0	6.2%	2.42	-\$123.47	-\$1.73	-\$2.48	-\$147.77	-\$3.40	**-\$278.85**	\$477.20	**\$198.35**	\$2,205.11
DC, DE, MD, WV	3.4	3.0%	2.57	-\$96.42	-\$96.15	-\$31.95	-\$147.77	-\$3.40	**-\$375.69**	\$507.00	**\$131.30**	\$1,740.72
NC, SC	5.4	4.8%	2.48	-\$75.10	-\$31.59	-\$11.35	-\$147.77	-\$3.40	**-\$269.22**	\$489.31	**\$220.09**	\$2,691.58
East South Central Division	7.1	6.3%	2.41	-\$143.05	-\$47.28	-\$10.91	-\$144.62	-\$22.11	**-\$367.97**	\$476.77	**\$108.80**	\$2,029.46
TN	2.4	2.1%	2.47	-\$128.02	-\$43.77	\$0.00	-\$144.62	-\$22.11	**-\$338.52**	\$487.96	**\$149.44**	\$2,453.74
AL, KY, MS	4.6	4.0%	2.39	-\$157.26	-\$51.28	-\$16.20	-\$144.62	-\$22.11	**-\$391.47**	\$471.41	**\$79.94**	\$1,734.54
West South Central Division	12.8	11.3%	2.68	-\$50.85	-\$59.33	-\$4.91	-\$148.52	-\$15.92	**-\$279.52**	\$529.49	**\$249.97**	\$1,872.48
TX	8.5	7.5%	2.74	-\$60.76	-\$56.64	-\$1.37	-\$148.52	-\$15.92	**-\$283.21**	\$542.04	**\$258.83**	\$1,678.06
AR, LA, OK	4.2	3.7%	2.55	-\$35.48	-\$67.95	-\$18.39	-\$148.52	-\$15.92	**-\$286.26**	\$503.49	**\$217.23**	\$1,966.18
Total West Region	24.8	21.8%	2.72	-\$62.51	-\$71.37	-\$5.39	-\$129.74	-\$36.84	**-\$305.84**	\$536.69	**\$230.85**	\$3,256.24
Mountain Division	7.9	7.0%	2.67	-\$103.62	-\$84.35	-\$9.44	-\$135.42	-\$18.25	**-\$351.08**	\$527.05	**\$175.97**	\$2,518.49
Mountain North Sub-Div.	3.9	3.4%	2.72	-\$62.12	-\$126.02	-\$15.40	-\$135.42	-\$18.25	**-\$357.20**	\$536.25	**\$179.05**	\$2,655.30
CO	1.9	1.7%	2.33	-\$44.98	-\$141.60	-\$27.84	-\$135.42	-\$18.25	**-\$368.10**	\$459.24	**\$91.14**	\$1,690.57
ID, MT, UT, WY	2.0	1.8%	3.08	-\$80.95	-\$112.05	\$0.00	-\$135.42	-\$18.25	**-\$346.67**	\$609.09	**\$262.42**	\$3,567.05
Mountain South Sub-Div.	4.0	3.5%	2.62	-\$153.72	-\$51.75	-\$5.03	-\$135.42	-\$18.25	**-\$364.17**	\$517.53	**\$153.37**	\$2,167.89
AZ	2.3	2.0%	2.59	-\$190.81	-\$31.70	-\$2.58	-\$135.42	-\$18.25	**-\$378.75**	\$511.76	**\$133.01**	\$1,874.20
NM, NV	1.7	1.5%	2.66	-\$109.91	-\$86.67	\$0.00	-\$135.42	-\$18.25	**-\$350.25**	\$524.90	**\$174.65**	\$2,495.32
Pacific Division	16.9	14.9%	2.74	-\$42.75	-\$65.43	-\$3.55	-\$127.19	-\$89.94	**-\$328.86**	\$541.74	**\$212.88**	\$3,212.96
CA	12.2	10.7%	2.82	-\$38.77	-\$62.66	-\$2.52	-\$127.19	-\$89.94	**-\$321.08**	\$556.11	**\$235.03**	\$3,457.97
AK, HI, OR, WA	4.7	4.1%	2.55	-\$54.00	-\$72.89	-\$5.64	-\$127.19	-\$89.94	**-\$349.67**	\$503.99	**\$154.32**	\$2,564.86

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

Table C.25 Net Impacts from $25/tCO$_2$ at 8% scenario with 50% Rebate

Costs and Benefits to the average household ($25/tCO$_2$ at 8% with 50% rebate)

Market Segment	Households: million	Households: % of total	Households: pph	First Year Costs (2014): Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	First Year Rebate: 50% Rebate	**Net benefit**	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-$65.54	-$83.70	-$13.64	-$138.09	-$26.84	**-$327.82**	$507.30	**$179.49**	$1,367.58
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-$28.70	-$110.66	-$33.47	-$124.52	-$37.34	**-$334.68**	$500.37	**$165.69**	$2,436.66
New England Division	5.5	4.8%	2.47	-$42.18	-$81.46	-$53.29	-$124.35	-$9.76	**-$311.05**	$487.27	**$176.22**	$2,776.57
MA	2.5	2.2%	2.44	-$31.66	-$137.59	-$22.92	-$124.35	-$9.76	**-$326.29**	$482.05	**$155.76**	$2,551.90
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-$52.10	-$45.85	-$88.25	-$124.35	-$9.76	**-$320.31**	$492.14	**$171.83**	$2,739.90
Middle Atlantic Division	15.3	13.5%	2.56	-$23.94	-$121.20	-$26.33	-$124.59	-$22.81	**-$318.87**	$504.85	**$185.98**	$2,543.64
NY	7.2	6.3%	2.58	-$18.97	-$121.50	-$32.30	-$124.59	-$22.81	**-$320.18**	$508.42	**$188.24**	$2,690.57
PA	4.9	4.3%	2.43	-$25.67	-$45.29	-$38.55	-$124.59	-$22.81	**-$256.91**	$478.50	**$221.59**	$2,817.01
NJ	3.2	2.8%	2.73	-$34.17	-$172.89	-$3.62	-$124.59	-$22.81	**-$358.07**	$537.89	**$179.82**	$2,307.07
Total Midwest Region	25.9	22.8%	2.49	-$64.66	-$136.73	-$14.17	-$143.09	-$23.20	**-$381.85**	$491.53	**$109.68**	$1,654.73
East North Central Division	17.9	15.8%	2.52	-$64.60	-$150.05	-$11.38	-$138.24	-$9.31	**-$373.58**	$497.45	**$123.87**	$1,804.46
IL	4.8	4.2%	2.54	-$72.17	-$169.08	-$2.40	-$138.24	-$9.31	**-$391.20**	$500.90	**$109.70**	$1,614.18
MI	3.8	3.3%	2.68	-$53.56	-$228.19	-$19.49	-$138.24	-$9.31	**-$448.79**	$528.31	**$79.53**	$1,492.13
WI	2.3	2.0%	2.36	-$58.42	-$109.73	-$21.02	-$138.24	-$9.31	**-$336.72**	$465.02	**$128.30**	$1,822.88
IN, OH	7.0	6.2%	2.48	-$68.13	-$115.87	-$8.47	-$138.24	-$9.31	**-$340.03**	$488.88	**$148.85**	$2,018.58
West North Central Division	8.1	7.1%	2.42	-$63.96	-$105.56	-$20.70	-$152.93	-$6.55	**-$349.70**	$478.01	**$128.30**	$1,804.01
MO	2.3	2.0%	2.48	-$75.70	-$104.99	-$11.50	-$152.93	-$6.55	**-$351.67**	$488.50	**$136.82**	$1,808.97
IA, MN, ND,SD	3.9	3.4%	2.41	-$63.04	-$87.38	-$49.00	-$152.93	-$6.55	**-$358.90**	$475.32	**$116.42**	$1,667.67
KS, NE	1.8	1.6%	2.38	-$58.80	-$168.75	$0.00	-$152.93	-$6.55	**-$387.04**	$469.74	**$82.69**	$1,355.02
Total South Region	42.1	37.1%	2.55	-$90.71	-$45.90	-$8.37	-$147.38	-$17.53	**-$309.89**	$503.77	**$193.88**	$2,220.81
South Atlantic Division	22.2	19.5%	2.52	-$95.79	-$38.09	-$9.45	-$147.69	-$3.39	**-$294.41**	$497.86	**$203.45**	$2,524.11
VA	3.0	2.6%	2.60	-$84.50	-$82.30	-$10.02	-$147.69	-$3.39	**-$327.90**	$513.82	**$185.92**	$2,425.90
GA	3.5	3.1%	2.69	-$82.81	-$111.17	-$0.77	-$147.69	-$3.39	**-$345.85**	$531.59	**$185.74**	$2,462.57
FL	7.0	6.2%	2.42	-$123.38	-$1.74	-$2.48	-$147.69	-$3.39	**-$278.69**	$476.63	**$197.94**	$2,270.68
DC, DE, MD, WV	3.4	3.0%	2.57	-$96.35	-$96.76	-$32.04	-$147.69	-$3.39	**-$376.23**	$506.39	**$130.16**	$1,740.89
NC, SC	5.4	4.8%	2.48	-$75.05	-$31.79	-$11.38	-$147.69	-$3.39	**-$269.31**	$488.72	**$219.41**	$2,803.43
East South Central Division	7.1	6.3%	2.41	-$144.38	-$47.66	-$10.95	-$144.54	-$22.05	**-$369.58**	$476.20	**$106.61**	$2,083.17
TN	2.4	2.1%	2.47	-$129.21	-$44.12	$0.00	-$144.54	-$22.05	**-$339.92**	$487.37	**$147.45**	$2,547.10
AL, KY, MS	4.6	4.0%	2.39	-$158.72	-$51.70	-$16.26	-$144.54	-$22.05	**-$393.27**	$470.84	**$77.57**	$1,759.49
West South Central Division	12.8	11.3%	2.68	-$50.22	-$59.83	-$4.93	-$148.43	-$15.87	**-$279.28**	$528.86	**$249.57**	$1,981.89
TX	8.5	7.5%	2.74	-$60.01	-$57.12	-$1.38	-$148.43	-$15.87	**-$282.81**	$541.39	**$258.58**	$1,782.06
AR, LA, OK	4.2	3.7%	2.55	-$35.04	-$68.52	-$18.46	-$148.43	-$15.87	**-$286.34**	$502.88	**$216.55**	$2,064.39
Total West Region	24.8	21.8%	2.72	-$62.55	-$71.77	-$5.43	-$128.60	-$36.74	**-$305.08**	$536.05	**$230.96**	$3,398.73
Mountain Division	7.9	7.0%	2.67	-$95.99	-$84.99	-$9.49	-$138.52	-$18.20	**-$347.19**	$526.42	**$179.23**	$2,621.07
Mountain North Sub-Div.	3.9	3.4%	2.72	-$57.54	-$126.97	-$15.48	-$138.52	-$18.20	**-$356.72**	$535.60	**$178.89**	$2,743.42
CO	1.9	1.7%	2.33	-$41.67	-$142.68	-$27.99	-$138.52	-$18.20	**-$369.06**	$458.69	**$89.63**	$1,697.93
ID, MT, UT, WY	2.0	1.8%	3.08	-$74.99	-$112.90	$0.00	-$138.52	-$18.20	**-$344.61**	$608.36	**$263.75**	$3,732.10
Mountain South Sub-Div.	4.0	3.5%	2.62	-$142.40	-$52.15	-$5.06	-$138.52	-$18.20	**-$356.32**	$516.91	**$160.59**	$2,264.29
AZ	2.3	2.0%	2.59	-$176.76	-$31.94	-$2.59	-$138.52	-$18.20	**-$368.01**	$511.15	**$143.14**	$1,961.15
NM, NV	1.7	1.5%	2.66	-$101.82	-$87.33	$0.00	-$138.52	-$18.20	**-$345.87**	$524.27	**$178.40**	$2,597.67
Pacific Division	16.9	14.9%	2.74	-$46.50	-$65.72	-$3.58	-$124.15	-$89.70	**-$329.65**	$541.09	**$211.44**	$3,340.72
CA	12.2	10.7%	2.82	-$42.16	-$62.94	-$2.54	-$124.15	-$89.70	**-$321.50**	$555.44	**$233.95**	$3,608.94
AK, HI, OR, WA	4.7	4.1%	2.55	-$58.73	-$73.22	-$5.69	-$124.15	-$89.70	**-$351.50**	$503.39	**$151.89**	$2,630.67

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

Table C.26 Net Impacts from \$35/tCO_2 at 2% scenario with 50% Rebate

Costs and Benefits to the average household
(\$35/tCO_2 at 2% with 50% rebate)

Market Segment	Households			First Year Costs (2014)						First Year Rebate		
	million	% of total	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-\$89.17	-\$116.54	-\$18.95	-\$188.77	-\$36.69	**-\$450.13**	\$698.91	**\$248.79**	\$1,616.16
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-\$40.06	-\$152.71	-\$47.01	-\$171.47	-\$51.04	**-\$462.29**	\$689.37	**\$227.08**	\$2,725.35
New England Division	5.5	4.8%	2.47	-\$60.25	-\$112.63	-\$74.82	-\$171.22	-\$13.35	**-\$432.27**	\$671.31	**\$239.04**	\$3,088.64
MA	2.5	2.2%	2.44	-\$45.23	-\$190.25	-\$32.18	-\$171.22	-\$13.35	**-\$452.23**	\$664.13	**\$211.90**	\$2,851.88
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-\$74.42	-\$63.40	-\$123.89	-\$171.22	-\$13.35	**-\$446.28**	\$678.02	**\$231.75**	\$3,046.89
Middle Atlantic Division	15.3	13.5%	2.56	-\$32.92	-\$167.19	-\$36.98	-\$171.58	-\$31.19	**-\$439.86**	\$695.54	**\$255.68**	\$2,842.17
NY	7.2	6.3%	2.58	-\$26.09	-\$167.60	-\$45.38	-\$171.58	-\$31.19	**-\$441.83**	\$700.45	**\$258.62**	\$2,999.15
PA	4.9	4.3%	2.43	-\$35.30	-\$62.48	-\$54.15	-\$171.58	-\$31.19	**-\$354.70**	\$659.23	**\$304.54**	\$3,127.10
NJ	3.2	2.8%	2.73	-\$46.98	-\$238.49	-\$5.08	-\$171.58	-\$31.19	**-\$493.32**	\$741.06	**\$247.74**	\$2,600.69
Total Midwest Region	25.9	22.8%	2.49	-\$89.71	-\$190.46	-\$19.52	-\$190.87	-\$31.72	**-\$522.28**	\$677.18	**\$154.91**	\$1,984.31
East North Central Division	17.9	15.8%	2.52	-\$89.93	-\$208.85	-\$15.69	-\$186.91	-\$12.73	**-\$514.11**	\$685.34	**\$171.23**	\$2,141.70
IL	4.8	4.2%	2.54	-\$100.47	-\$235.35	-\$3.30	-\$186.91	-\$12.73	**-\$538.76**	\$690.09	**\$151.33**	\$1,948.57
MI	3.8	3.3%	2.68	-\$74.56	-\$317.62	-\$26.86	-\$186.91	-\$12.73	**-\$618.68**	\$727.86	**\$109.18**	\$1,822.28
WI	2.3	2.0%	2.36	-\$81.32	-\$152.73	-\$28.97	-\$186.91	-\$12.73	**-\$462.67**	\$640.65	**\$177.99**	\$2,140.48
IN, OH	7.0	6.2%	2.48	-\$94.85	-\$161.28	-\$11.67	-\$186.91	-\$12.73	**-\$467.45**	\$673.53	**\$206.08**	\$2,364.57
West North Central Division	8.1	7.1%	2.42	-\$88.12	-\$147.42	-\$28.45	-\$198.90	-\$8.96	**-\$471.85**	\$658.55	**\$186.70**	\$2,152.38
MO	2.3	2.0%	2.48	-\$104.29	-\$146.63	-\$15.81	-\$198.90	-\$8.96	**-\$474.58**	\$673.00	**\$198.42**	\$2,172.82
IA, MN, ND,SD	3.9	3.4%	2.41	-\$86.86	-\$122.03	-\$67.34	-\$198.90	-\$8.96	**-\$484.08**	\$654.85	**\$170.77**	\$2,000.93
KS, NE	1.8	1.6%	2.38	-\$81.02	-\$235.67	\$0.00	-\$198.90	-\$8.96	**-\$524.55**	\$647.16	**\$122.61**	\$1,680.07
Total South Region	42.1	37.1%	2.55	-\$124.43	-\$63.53	-\$11.53	-\$203.00	-\$23.97	**-\$426.44**	\$694.05	**\$267.60**	\$2,565.29
South Atlantic Division	22.2	19.5%	2.52	-\$132.42	-\$52.67	-\$13.06	-\$203.41	-\$4.64	**-\$406.19**	\$685.91	**\$279.71**	\$2,856.83
VA	3.0	2.6%	2.60	-\$116.81	-\$113.82	-\$13.83	-\$203.41	-\$4.64	**-\$452.51**	\$707.89	**\$255.38**	\$2,757.52
GA	3.5	3.1%	2.69	-\$114.49	-\$153.74	-\$1.07	-\$203.41	-\$4.64	**-\$477.34**	\$732.37	**\$255.03**	\$2,803.86
FL	7.0	6.2%	2.42	-\$170.57	-\$2.40	-\$3.43	-\$203.41	-\$4.64	**-\$384.44**	\$656.65	**\$272.20**	\$2,584.67
DC, DE, MD, WV	3.4	3.0%	2.57	-\$133.19	-\$133.80	-\$44.25	-\$203.41	-\$4.64	**-\$519.29**	\$697.65	**\$178.36**	\$2,029.52
NC, SC	5.4	4.8%	2.48	-\$103.75	-\$43.96	-\$15.72	-\$203.41	-\$4.64	**-\$371.48**	\$673.31	**\$301.83**	\$3,145.71
East South Central Division	7.1	6.3%	2.41	-\$195.95	-\$66.00	-\$15.02	-\$199.10	-\$30.14	**-\$506.23**	\$656.06	**\$149.83**	\$2,359.76
TN	2.4	2.1%	2.47	-\$175.37	-\$61.10	\$0.00	-\$199.10	-\$30.14	**-\$465.72**	\$671.46	**\$205.74**	\$2,855.76
AL, KY, MS	4.6	4.0%	2.39	-\$215.41	-\$71.59	-\$22.31	-\$199.10	-\$30.14	**-\$538.56**	\$648.68	**\$110.12**	\$2,014.77
West South Central Division	12.8	11.3%	2.68	-\$68.32	-\$82.90	-\$6.75	-\$204.46	-\$21.70	**-\$384.13**	\$728.61	**\$344.48**	\$2,402.33
TX	8.5	7.5%	2.74	-\$81.64	-\$79.14	-\$1.89	-\$204.46	-\$21.70	**-\$388.83**	\$745.88	**\$357.05**	\$2,218.60
AR, LA, OK	4.2	3.7%	2.55	-\$47.68	-\$94.95	-\$25.28	-\$204.46	-\$21.70	**-\$394.06**	\$692.82	**\$298.76**	\$2,444.16
Total West Region	24.8	21.8%	2.72	-\$80.17	-\$101.33	-\$7.44	-\$176.88	-\$50.22	**-\$416.06**	\$738.51	**\$322.46**	\$3,791.76
Mountain Division	7.9	7.0%	2.67	-\$130.11	-\$119.70	-\$13.00	-\$187.35	-\$24.88	**-\$475.05**	\$725.25	**\$250.20**	\$2,913.63
Mountain North Sub-Div.	3.9	3.4%	2.72	-\$78.00	-\$178.83	-\$21.21	-\$187.35	-\$24.88	**-\$490.27**	\$737.90	**\$247.63**	\$3,077.50
CO	1.9	1.7%	2.33	-\$56.48	-\$200.95	-\$38.35	-\$187.35	-\$24.88	**-\$508.02**	\$631.94	**\$123.92**	\$1,951.86
ID, MT, UT, WY	2.0	1.8%	3.08	-\$101.65	-\$159.01	\$0.00	-\$187.35	-\$24.88	**-\$472.89**	\$838.14	**\$365.25**	\$4,141.06
Mountain South Sub-Div.	4.0	3.5%	2.62	-\$193.02	-\$73.44	-\$6.93	-\$187.35	-\$24.88	**-\$485.62**	\$712.15	**\$226.53**	\$2,499.01
AZ	2.3	2.0%	2.59	-\$239.59	-\$44.98	-\$3.55	-\$187.35	-\$24.88	**-\$500.36**	\$704.21	**\$203.85**	\$2,152.16
NM, NV	1.7	1.5%	2.66	-\$138.01	-\$123.00	\$0.00	-\$187.35	-\$24.88	**-\$473.24**	\$722.29	**\$249.05**	\$2,885.99
Pacific Division	16.9	14.9%	2.74	-\$56.18	-\$92.92	-\$4.92	-\$172.20	-\$122.62	**-\$448.83**	\$745.46	**\$296.63**	\$3,748.84
CA	12.2	10.7%	2.82	-\$50.94	-\$88.99	-\$3.49	-\$172.20	-\$122.62	**-\$438.24**	\$765.24	**\$327.00**	\$4,034.89
AK, HI, OR, WA	4.7	4.1%	2.55	-\$70.97	-\$103.52	-\$7.81	-\$172.20	-\$122.62	**-\$477.12**	\$693.52	**\$216.40**	\$2,992.21

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

Table C.27 Net Impacts from $35/t$CO_2$ at 4% scenario with 50% Rebate

Costs and Benefits to the average household ($35/t$CO_2$ at 4% with 50% rebate)

Market Segment	Households			First Year Costs (2014)						First Year Rebate		
	million	% of total	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-$88.96	-$116.56	-$18.94	-$182.51	-$35.47	**-$442.45**	$698.72	**$256.27**	$1,632.85
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-$38.34	-$152.72	-$46.97	-$167.65	-$49.35	**-$455.03**	$689.18	**$234.15**	$2,809.54
New England Division	5.5	4.8%	2.47	-$59.66	-$112.65	-$74.75	-$167.31	-$12.91	**-$427.28**	$671.13	**$243.85**	$3,244.28
MA	2.5	2.2%	2.44	-$44.79	-$190.28	-$32.15	-$167.31	-$12.91	**-$447.43**	$663.95	**$216.51**	$2,982.18
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-$73.69	-$63.41	-$123.78	-$167.31	-$12.91	**-$441.10**	$677.84	**$236.74**	$3,202.17
Middle Atlantic Division	15.3	13.5%	2.56	-$30.80	-$167.20	-$36.95	-$167.80	-$30.15	**-$432.90**	$695.34	**$262.44**	$2,917.17
NY	7.2	6.3%	2.58	-$24.41	-$167.61	-$45.34	-$167.80	-$30.15	**-$435.31**	$700.26	**$264.95**	$3,096.50
PA	4.9	4.3%	2.43	-$33.03	-$62.48	-$54.11	-$167.80	-$30.15	**-$347.57**	$659.05	**$311.48**	$3,230.52
NJ	3.2	2.8%	2.73	-$43.96	-$238.51	-$5.07	-$167.80	-$30.15	**-$485.49**	$740.86	**$255.37**	$2,626.10
Total Midwest Region	25.9	22.8%	2.49	-$90.13	-$190.47	-$19.52	-$176.98	-$30.67	**-$507.77**	$677.00	**$169.23**	$2,104.73
East North Central Division	17.9	15.8%	2.52	-$90.09	-$208.85	-$15.69	-$172.19	-$12.31	**-$499.13**	$685.15	**$186.02**	$2,308.28
IL	4.8	4.2%	2.54	-$100.65	-$235.35	-$3.30	-$172.19	-$12.31	**-$523.80**	$689.90	**$166.10**	$2,092.14
MI	3.8	3.3%	2.68	-$74.69	-$317.63	-$26.86	-$172.19	-$12.31	**-$603.67**	$727.66	**$123.99**	$1,941.41
WI	2.3	2.0%	2.36	-$81.47	-$152.74	-$28.97	-$172.19	-$12.31	**-$447.67**	$640.48	**$192.81**	$2,324.36
IN, OH	7.0	6.2%	2.48	-$95.02	-$161.29	-$11.67	-$172.19	-$12.31	**-$452.48**	$673.34	**$220.87**	$2,558.13
West North Central Division	8.1	7.1%	2.42	-$89.06	-$147.45	-$28.45	-$186.70	-$8.66	**-$460.32**	$658.37	**$198.05**	$2,212.83
MO	2.3	2.0%	2.48	-$105.40	-$146.65	-$15.80	-$186.70	-$8.66	**-$463.22**	$672.82	**$209.59**	$2,229.70
IA, MN, ND,SD	3.9	3.4%	2.41	-$87.78	-$122.05	-$67.34	-$186.70	-$8.66	**-$472.53**	$654.67	**$182.14**	$2,055.02
KS, NE	1.8	1.6%	2.38	-$81.88	-$235.72	$0.00	-$186.70	-$8.66	**-$512.96**	$646.98	**$134.02**	$1,686.14
Total South Region	42.1	37.1%	2.55	-$124.96	-$63.53	-$11.52	-$198.46	-$23.17	**-$421.64**	$693.86	**$272.21**	$2,586.41
South Atlantic Division	22.2	19.5%	2.52	-$132.61	-$52.68	-$13.05	-$198.88	-$4.49	**-$401.71**	$685.72	**$284.01**	$2,894.68
VA	3.0	2.6%	2.60	-$116.98	-$113.84	-$13.83	-$198.88	-$4.49	**-$448.02**	$707.70	**$259.68**	$2,787.03
GA	3.5	3.1%	2.69	-$114.65	-$153.78	-$1.07	-$198.88	-$4.49	**-$472.86**	$732.17	**$259.31**	$2,830.57
FL	7.0	6.2%	2.42	-$170.81	-$2.40	-$3.43	-$198.88	-$4.49	**-$380.01**	$656.47	**$276.46**	$2,585.21
DC, DE, MD, WV	3.4	3.0%	2.57	-$133.38	-$133.84	-$44.23	-$198.88	-$4.49	**-$514.82**	$697.46	**$182.64**	$1,986.93
NC, SC	5.4	4.8%	2.48	-$103.90	-$43.97	-$15.72	-$198.88	-$4.49	**-$366.95**	$673.13	**$306.17**	$3,229.16
East South Central Division	7.1	6.3%	2.41	-$197.13	-$65.99	-$15.02	-$194.61	-$29.15	**-$501.90**	$655.88	**$153.97**	$2,442.47
TN	2.4	2.1%	2.47	-$176.42	-$61.09	$0.00	-$194.61	-$29.15	**-$461.27**	$671.27	**$210.00**	$2,978.84
AL, KY, MS	4.6	4.0%	2.39	-$216.71	-$71.58	-$22.31	-$194.61	-$29.15	**-$534.35**	$648.50	**$114.15**	$2,068.33
West South Central Division	12.8	11.3%	2.68	-$69.06	-$82.88	-$6.75	-$199.89	-$20.98	**-$379.56**	$728.41	**$348.84**	$2,373.11
TX	8.5	7.5%	2.74	-$82.53	-$79.13	-$1.89	-$199.89	-$20.98	**-$384.41**	$745.67	**$361.26**	$2,150.92
AR, LA, OK	4.2	3.7%	2.55	-$48.20	-$94.93	-$25.28	-$199.89	-$20.98	**-$389.27**	$692.63	**$303.36**	$2,455.00
Total West Region	24.8	21.8%	2.72	-$79.28	-$101.38	-$7.45	-$173.23	-$48.56	**-$409.88**	$738.31	**$328.43**	$3,982.21
Mountain Division	7.9	7.0%	2.67	-$129.77	-$119.78	-$13.01	-$184.64	-$24.06	**-$471.25**	$725.05	**$253.80**	$3,063.42
Mountain North Sub-Div.	3.9	3.4%	2.72	-$77.80	-$178.94	-$21.21	-$184.64	-$24.06	**-$486.64**	$737.70	**$251.06**	$3,203.82
CO	1.9	1.7%	2.33	-$56.33	-$201.07	-$38.36	-$184.64	-$24.06	**-$504.46**	$631.76	**$127.30**	$1,987.22
ID, MT, UT, WY	2.0	1.8%	3.08	-$101.39	-$159.11	$0.00	-$184.64	-$24.06	**-$469.19**	$837.91	**$368.73**	$4,354.08
Mountain South Sub-Div.	4.0	3.5%	2.62	-$192.52	-$73.49	-$6.93	-$184.64	-$24.06	**-$481.63**	$711.96	**$230.33**	$2,651.73
AZ	2.3	2.0%	2.59	-$238.97	-$45.01	-$3.55	-$184.64	-$24.06	**-$496.23**	$704.02	**$207.79**	$2,301.84
NM, NV	1.7	1.5%	2.66	-$137.65	-$123.07	$0.00	-$184.64	-$24.06	**-$469.42**	$722.10	**$252.68**	$3,035.53
Pacific Division	16.9	14.9%	2.74	-$55.01	-$92.95	-$4.92	-$168.12	-$118.55	**-$439.56**	$745.26	**$305.70**	$3,927.58
CA	12.2	10.7%	2.82	-$49.89	-$89.02	-$3.49	-$168.12	-$118.55	**-$429.07**	$765.03	**$335.96**	$4,236.82
AK, HI, OR, WA	4.7	4.1%	2.55	-$69.49	-$103.56	-$7.81	-$168.12	-$118.55	**-$467.54**	$693.33	**$225.79**	$3,109.28

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

Table C.28 Net Impacts from \$35/tCO_2 at 6% scenario with 50% Rebate

Costs and Benefits to the average household (\$35/tCO_2 at 6% with 50% rebate)

Market Segment	Households: million	Households: % of total	Households: pph	First Year Costs (2014): Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	First Year Rebate: 50% Rebate	**Net benefit**	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-\$89.23	-\$116.28	-\$19.06	-\$181.94	-\$35.36	**-\$441.88**	\$698.00	**\$256.12**	\$1,507.80
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-\$37.97	-\$151.81	-\$47.36	-\$167.09	-\$49.19	**-\$453.42**	\$688.46	**\$235.04**	\$2,803.98
New England Division	5.5	4.8%	2.47	-\$59.58	-\$111.94	-\$75.37	-\$166.77	-\$12.87	**-\$426.52**	\$670.43	**\$243.91**	\$3,298.77
MA	2.5	2.2%	2.44	-\$44.72	-\$189.09	-\$32.41	-\$166.77	-\$12.87	**-\$445.86**	\$663.26	**\$217.39**	\$3,017.56
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-\$73.59	-\$63.01	-\$124.80	-\$166.77	-\$12.87	**-\$441.03**	\$677.13	**\$236.10**	\$3,248.55
Middle Atlantic Division	15.3	13.5%	2.56	-\$30.32	-\$166.22	-\$37.26	-\$167.23	-\$30.06	**-\$431.09**	\$694.62	**\$263.53**	\$2,915.65
NY	7.2	6.3%	2.58	-\$24.04	-\$166.62	-\$45.72	-\$167.23	-\$30.06	**-\$433.67**	\$699.53	**\$265.86**	\$3,109.37
PA	4.9	4.3%	2.43	-\$32.52	-\$62.11	-\$54.56	-\$167.23	-\$30.06	**-\$346.48**	\$658.37	**\$311.88**	\$3,269.39
NJ	3.2	2.8%	2.73	-\$43.28	-\$237.10	-\$5.12	-\$167.23	-\$30.06	**-\$482.79**	\$740.09	**\$257.30**	\$2,583.44
Total Midwest Region	25.9	22.8%	2.49	-\$89.21	-\$190.13	-\$19.62	-\$176.06	-\$30.57	**-\$505.59**	\$676.29	**\$170.70**	\$1,878.68
East North Central Division	17.9	15.8%	2.52	-\$89.87	-\$208.68	-\$15.78	-\$171.15	-\$12.27	**-\$497.74**	\$684.44	**\$186.70**	\$2,068.58
IL	4.8	4.2%	2.54	-\$100.39	-\$235.15	-\$3.32	-\$171.15	-\$12.27	**-\$522.29**	\$689.18	**\$166.89**	\$1,807.38
MI	3.8	3.3%	2.68	-\$74.50	-\$317.36	-\$27.01	-\$171.15	-\$12.27	**-\$602.29**	\$726.91	**\$124.62**	\$1,679.69
WI	2.3	2.0%	2.36	-\$81.26	-\$152.61	-\$29.13	-\$171.15	-\$12.27	**-\$446.42**	\$639.81	**\$193.39**	\$2,122.97
IN, OH	7.0	6.2%	2.48	-\$94.78	-\$161.15	-\$11.74	-\$171.15	-\$12.27	**-\$451.09**	\$672.64	**\$221.56**	\$2,337.68
West North Central Division	8.1	7.1%	2.42	-\$86.74	-\$146.74	-\$28.58	-\$186.00	-\$8.64	**-\$456.70**	\$657.69	**\$200.99**	\$2,069.12
MO	2.3	2.0%	2.48	-\$102.65	-\$145.95	-\$15.88	-\$186.00	-\$8.64	**-\$459.12**	\$672.12	**\$212.99**	\$2,064.81
IA, MN, ND,SD	3.9	3.4%	2.41	-\$85.49	-\$121.46	-\$67.65	-\$186.00	-\$8.64	**-\$469.25**	\$653.99	**\$184.74**	\$1,900.16
KS, NE	1.8	1.6%	2.38	-\$79.75	-\$234.59	\$0.00	-\$186.00	-\$8.64	**-\$508.98**	\$646.31	**\$137.33**	\$1,505.46
Total South Region	42.1	37.1%	2.55	-\$125.10	-\$63.83	-\$11.60	-\$197.74	-\$23.10	**-\$421.36**	\$693.14	**\$271.78**	\$2,485.30
South Atlantic Division	22.2	19.5%	2.52	-\$131.60	-\$52.92	-\$13.14	-\$198.17	-\$4.47	**-\$400.31**	\$685.01	**\$284.70**	\$2,873.07
VA	3.0	2.6%	2.60	-\$116.09	-\$114.36	-\$13.92	-\$198.17	-\$4.47	**-\$447.02**	\$706.96	**\$259.94**	\$2,744.93
GA	3.5	3.1%	2.69	-\$113.78	-\$154.48	-\$1.08	-\$198.17	-\$4.47	**-\$471.98**	\$731.41	**\$259.44**	\$2,781.28
FL	7.0	6.2%	2.42	-\$169.51	-\$2.41	-\$3.45	-\$198.17	-\$4.47	**-\$378.02**	\$655.79	**\$277.77**	\$2,545.47
DC, DE, MD, WV	3.4	3.0%	2.57	-\$132.37	-\$134.44	-\$44.53	-\$198.17	-\$4.47	**-\$513.99**	\$696.74	**\$182.75**	\$1,871.80
NC, SC	5.4	4.8%	2.48	-\$103.11	-\$44.17	-\$15.82	-\$198.17	-\$4.47	**-\$365.75**	\$672.43	**\$306.68**	\$3,246.10
East South Central Division	7.1	6.3%	2.41	-\$198.20	-\$66.30	-\$15.11	-\$193.87	-\$29.05	**-\$502.53**	\$655.20	**\$152.66**	\$2,353.25
TN	2.4	2.1%	2.47	-\$177.38	-\$61.38	\$0.00	-\$193.87	-\$29.05	**-\$461.68**	\$670.57	**\$208.89**	\$2,938.86
AL, KY, MS	4.6	4.0%	2.39	-\$217.89	-\$71.91	-\$22.43	-\$193.87	-\$29.05	**-\$535.15**	\$647.83	**\$112.67**	\$1,941.95
West South Central Division	12.8	11.3%	2.68	-\$70.68	-\$83.29	-\$6.78	-\$199.15	-\$20.91	**-\$380.81**	\$727.65	**\$346.84**	\$2,150.08
TX	8.5	7.5%	2.74	-\$84.45	-\$79.51	-\$1.90	-\$199.15	-\$20.91	**-\$385.93**	\$744.90	**\$358.97**	\$1,873.40
AR, LA, OK	4.2	3.7%	2.55	-\$49.32	-\$95.39	-\$25.42	-\$199.15	-\$20.91	**-\$390.19**	\$691.91	**\$301.72**	\$2,294.88
Total West Region	24.8	21.8%	2.72	-\$81.89	-\$100.75	-\$7.45	-\$173.24	-\$48.40	**-\$411.74**	\$737.54	**\$325.81**	\$4,139.11
Mountain Division	7.9	7.0%	2.67	-\$130.41	-\$119.25	-\$13.05	-\$176.62	-\$23.98	**-\$463.31**	\$724.30	**\$260.99**	\$3,152.03
Mountain North Sub-Div.	3.9	3.4%	2.72	-\$78.17	-\$178.16	-\$21.28	-\$176.62	-\$23.98	**-\$478.21**	\$736.93	**\$258.72**	\$3,275.45
CO	1.9	1.7%	2.33	-\$56.61	-\$200.20	-\$38.49	-\$176.62	-\$23.98	**-\$495.89**	\$631.11	**\$135.22**	\$1,974.72
ID, MT, UT, WY	2.0	1.8%	3.08	-\$101.88	-\$158.41	\$0.00	-\$176.62	-\$23.98	**-\$460.89**	\$837.04	**\$376.15**	\$4,506.45
Mountain South Sub-Div.	4.0	3.5%	2.62	-\$193.46	-\$73.17	-\$6.95	-\$176.62	-\$23.98	**-\$474.17**	\$711.22	**\$237.05**	\$2,736.80
AZ	2.3	2.0%	2.59	-\$240.13	-\$44.81	-\$3.56	-\$176.62	-\$23.98	**-\$489.11**	\$703.28	**\$214.17**	\$2,379.30
NM, NV	1.7	1.5%	2.66	-\$138.32	-\$122.54	\$0.00	-\$176.62	-\$23.98	**-\$461.46**	\$721.35	**\$259.89**	\$3,125.46
Pacific Division	16.9	14.9%	2.74	-\$58.59	-\$92.28	-\$4.91	-\$171.73	-\$118.18	**-\$445.69**	\$744.48	**\$298.79**	\$4,067.69
CA	12.2	10.7%	2.82	-\$53.13	-\$88.37	-\$3.49	-\$171.73	-\$118.18	**-\$434.90**	\$764.23	**\$329.34**	\$4,398.02
AK, HI, OR, WA	4.7	4.1%	2.55	-\$74.01	-\$102.81	-\$7.80	-\$171.73	-\$118.18	**-\$474.53**	\$692.61	**\$218.08**	\$3,193.42

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

Table C.29 Net Impacts from $35/tCO$_2$ at 8% scenario with 50% Rebate

Costs and Benefits to the average household ($35/tCO$_2$ at 8% with 50% rebate)

Market Segment	Households			First Year Costs (2014)						First Year Rebate		
	million	% of total	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	NPV[1] Net Benefit
Average Household												
Avg. Consumer Unit	113.6	100.0%	2.57	-$90.60	-$115.07	-$18.98	-$182.24	-$35.42	**-$442.31**	$695.76	**$253.45**	$1,190.75
By Region, Division, Sub-Division, and States												
Total Northeast Region	20.8	18.3%	2.54	-$41.42	-$149.78	-$47.22	-$167.42	-$49.27	**-$455.11**	$686.25	**$231.14**	$2,766.22
New England Division	5.5	4.8%	2.47	-$59.63	-$110.53	-$75.14	-$167.10	-$12.89	**-$425.28**	$668.28	**$243.00**	$3,333.22
MA	2.5	2.2%	2.44	-$44.76	-$186.71	-$32.32	-$167.10	-$12.89	**-$443.77**	$661.13	**$217.36**	$3,015.30
CT, ME, NH, RI, VT	3.0	2.6%	2.49	-$73.64	-$62.22	-$124.43	-$167.10	-$12.89	**-$440.27**	$674.96	**$234.69**	$3,289.46
Middle Atlantic Division	15.3	13.5%	2.56	-$34.99	-$163.96	-$37.15	-$167.55	-$30.11	**-$433.76**	$692.39	**$258.63**	$2,878.56
NY	7.2	6.3%	2.58	-$27.73	-$164.36	-$45.59	-$167.55	-$30.11	**-$435.34**	$697.29	**$261.95**	$3,084.97
PA	4.9	4.3%	2.43	-$37.52	-$61.27	-$54.40	-$167.55	-$30.11	**-$350.85**	$656.26	**$305.40**	$3,279.34
NJ	3.2	2.8%	2.73	-$49.94	-$233.89	-$5.10	-$167.55	-$30.11	**-$486.59**	$737.71	**$251.12**	$2,502.14
Total Midwest Region	25.9	22.8%	2.49	-$89.21	-$188.43	-$19.51	-$176.00	-$30.62	**-$503.77**	$674.12	**$170.36**	$995.65
East North Central Division	17.9	15.8%	2.52	-$90.13	-$206.78	-$15.69	-$170.74	-$12.29	**-$495.64**	$682.25	**$186.61**	$1,900.99
IL	4.8	4.2%	2.54	-$100.69	-$233.02	-$3.30	-$170.74	-$12.29	**-$520.05**	$686.97	**$166.93**	$1,609.55
MI	3.8	3.3%	2.68	-$74.72	-$314.48	-$26.86	-$170.74	-$12.29	**-$599.09**	$724.57	**$125.48**	$1,445.82
WI	2.3	2.0%	2.36	-$81.50	-$151.22	-$28.97	-$170.74	-$12.29	**-$444.73**	$637.76	**$193.03**	$1,989.09
IN, OH	7.0	6.2%	2.48	-$95.06	-$159.69	-$11.67	-$170.74	-$12.29	**-$449.45**	$670.48	**$221.03**	$2,204.96
West North Central Division	8.1	7.1%	2.42	-$86.17	-$145.50	-$28.42	-$186.66	-$8.65	**-$455.40**	$655.58	**$200.18**	-$221.77
MO	2.3	2.0%	2.48	-$101.98	-$144.71	-$15.79	-$186.66	-$8.65	**-$457.80**	$669.96	**$212.17**	-$628.79
IA, MN, ND,SD	3.9	3.4%	2.41	-$84.94	-$120.43	-$67.27	-$186.66	-$8.65	**-$467.95**	$651.89	**$183.94**	-$365.92
KS, NE	1.8	1.6%	2.38	-$79.23	-$232.60	$0.00	-$186.66	-$8.65	**-$507.13**	$644.23	**$137.10**	-$677.86
Total South Region	42.1	37.1%	2.55	-$126.04	-$63.20	-$11.52	-$198.09	-$23.14	**-$421.99**	$690.91	**$268.93**	$2,376.83
South Atlantic Division	22.2	19.5%	2.52	-$130.97	-$52.41	-$13.07	-$198.53	-$4.48	**-$399.45**	$682.81	**$283.36**	$2,807.08
VA	3.0	2.6%	2.60	-$115.53	-$113.25	-$13.84	-$198.53	-$4.48	**-$445.63**	$704.69	**$259.06**	$2,655.17
GA	3.5	3.1%	2.69	-$113.23	-$152.97	-$1.07	-$198.53	-$4.48	**-$470.28**	$729.07	**$258.79**	$2,680.41
FL	7.0	6.2%	2.42	-$168.69	-$2.39	-$3.43	-$198.53	-$4.48	**-$377.52**	$653.68	**$276.16**	$2,463.30
DC, DE, MD, WV	3.4	3.0%	2.57	-$131.73	-$133.13	-$44.28	-$198.53	-$4.48	**-$512.15**	$694.50	**$182.35**	$1,709.90
NC, SC	5.4	4.8%	2.48	-$102.61	-$43.74	-$15.73	-$198.53	-$4.48	**-$365.09**	$670.27	**$305.18**	$3,221.30
East South Central Division	7.1	6.3%	2.41	-$196.46	-$65.64	-$15.00	-$194.19	-$29.10	**-$500.40**	$653.09	**$152.70**	$2,145.44
TN	2.4	2.1%	2.47	-$175.82	-$60.77	$0.00	-$194.19	-$29.10	**-$459.88**	$668.42	**$208.54**	$2,787.12
AL, KY, MS	4.6	4.0%	2.39	-$215.98	-$71.20	-$22.28	-$194.19	-$29.10	**-$532.74**	$645.75	**$113.01**	$1,689.77
West South Central Division	12.8	11.3%	2.68	-$75.94	-$82.46	-$6.74	-$199.50	-$20.95	**-$385.58**	$725.32	**$339.73**	$2,051.33
TX	8.5	7.5%	2.74	-$90.75	-$78.72	-$1.89	-$199.50	-$20.95	**-$391.80**	$742.51	**$350.71**	$1,750.76
AR, LA, OK	4.2	3.7%	2.55	-$53.00	-$94.44	-$25.23	-$199.50	-$20.95	**-$393.12**	$689.69	**$296.58**	$2,212.94
Total West Region	24.8	21.8%	2.72	-$83.83	-$99.73	-$7.41	-$173.78	-$48.48	**-$413.23**	$735.18	**$321.95**	$4,144.23
Mountain Division	7.9	7.0%	2.67	-$131.17	-$118.25	-$12.97	-$179.95	-$24.02	**-$466.36**	$721.98	**$255.62**	$3,094.85
Mountain North Sub-Div.	3.9	3.4%	2.72	-$78.63	-$176.66	-$21.15	-$179.95	-$24.02	**-$480.42**	$734.57	**$254.15**	$3,203.33
CO	1.9	1.7%	2.33	-$56.94	-$198.52	-$38.26	-$179.95	-$24.02	**-$497.68**	$629.08	**$131.40**	$1,828.38
ID, MT, UT, WY	2.0	1.8%	3.08	-$102.47	-$157.08	$0.00	-$179.95	-$24.02	**-$463.53**	$834.36	**$370.83**	$4,504.45
Mountain South Sub-Div.	4.0	3.5%	2.62	-$194.58	-$72.55	-$6.91	-$179.95	-$24.02	**-$478.02**	$708.94	**$230.92**	$2,668.61
AZ	2.3	2.0%	2.59	-$241.53	-$44.44	-$3.54	-$179.95	-$24.02	**-$493.48**	$701.03	**$207.54**	$2,296.73
NM, NV	1.7	1.5%	2.66	-$139.13	-$121.51	$0.00	-$179.95	-$24.02	**-$464.61**	$719.03	**$254.42**	$3,066.66
Pacific Division	16.9	14.9%	2.74	-$61.09	-$91.26	-$4.89	-$171.01	-$118.37	**-$446.63**	$742.09	**$295.46**	$4,052.50
CA	12.2	10.7%	2.82	-$55.40	-$87.40	-$3.47	-$171.01	-$118.37	**-$435.66**	$761.78	**$326.12**	$4,404.61
AK, HI, OR, WA	4.7	4.1%	2.55	-$77.17	-$101.68	-$7.77	-$171.01	-$118.37	**-$476.00**	$690.39	**$214.38**	$3,120.17

Notes:

[1] NPV of first ten years (2014-2023) based on discount rate of 4.0%

C.7 INCOME BRACKETS RESULTS

Table C.30 First year net benefits for income brackets ($15/tCO$_2$ at 2% with 50% rebate)

Costs and Benefits to the average household[1]
($15/tCO$_2$ at 2% with 50% rebate)

Market Segment	Households			pph	First Year Costs (2014)						First Year Rebate			NPV Net Benefit[3]
	million	% of total	% of Region		Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	% of Income[2]	
Average Household														
Average U.S.	113.6	100.0%		2.57	-$38.55	-$50.20	-$8.16	-$84.18	-$16.36	**-$197.45**	$311.25	**$113.80**	0.18%	$846.83
Less than $20,000	23.7	20.9%		2.10	-$23.30	-$31.02	-$4.58	-$18.49	-$2.07	**-$79.46**	$253.85	**$174.38**	1.74%	$1,386.91
$20,000 to $39,999	27.5	24.2%		2.42	-$28.51	-$37.32	-$5.59	-$53.46	-$3.56	**-$128.45**	$292.62	**$164.17**	0.55%	$1,294.36
$40,000 to $59,000	21.2	18.7%		2.66	-$38.34	-$44.95	-$6.59	-$93.12	-$8.74	**-$191.73**	$322.30	**$130.57**	0.26%	$984.24
$60,000 to $79,999	14.2	12.5%		2.69	-$41.92	-$49.93	-$10.10	-$120.44	-$10.54	**-$232.93**	$325.93	**$93.00**	0.13%	$665.73
$80,000 to $99,999	9.3	8.2%		2.96	-$52.08	-$67.38	-$9.66	-$152.67	-$29.08	**-$310.86**	$358.48	**$47.62**	0.05%	$266.89
$100,000 to $119,999	5.7	5.0%		3.00	-$58.59	-$99.88	-$12.02	-$182.27	-$39.91	**-$392.67**	$363.64	**-$29.03**	-0.03%	-$364.16
$120,000 or More	12.0	10.6%		3.05	-$84.25	-$116.03	-$24.89	-$209.18	-$169.65	**-$603.99**	$369.10	**-$234.89**	-0.20%	-$2,156.16
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-$15.54	-$67.15	-$19.77	-$76.39	-$22.76	**-$201.62**	$307.00	**$105.38**	0.15%	$870.75
Less than $20,000	4.0	3.5%	19.2%	1.92	-$7.41	-$42.53	-$12.51	-$8.98	-$3.04	**-$74.47**	$231.90	**$157.42**	1.57%	$1,304.63
$20,000 to $39,999	4.3	3.8%	20.7%	2.38	-$10.99	-$67.79	-$12.25	-$37.12	-$6.69	**-$134.83**	$288.21	**$153.38**	0.51%	$1,280.81
$40,000 to $59,000	3.5	3.1%	16.8%	2.44	-$13.37	-$60.32	-$15.78	-$75.53	-$13.41	**-$178.41**	$295.50	**$117.09**	0.23%	$978.29
$60,000 to $79,999	2.8	2.5%	13.5%	2.55	-$16.23	-$46.93	-$18.94	-$105.65	-$17.08	**-$204.84**	$308.47	**$103.63**	0.15%	$847.92
$80,000 to $99,999	1.9	1.7%	9.1%	2.91	-$21.13	-$72.90	-$23.24	-$140.89	-$28.48	**-$286.63**	$352.16	**$65.53**	0.07%	$536.13
$100,000 to $119,999	1.5	1.3%	7.2%	3.12	-$24.34	-$103.17	-$23.02	-$160.59	-$32.00	**-$343.12**	$377.40	**$34.28**	0.03%	$285.10
$120,000 or More	2.8	2.5%	13.5%	3.19	-$35.23	-$124.48	-$51.62	-$206.76	-$153.03	**-$571.12**	$386.29	**-$184.82**	-0.15%	-$1,534.93
Midwest	25.9	22.8%	100.0%	2.49	-$38.95	-$81.80	-$8.56	-$85.67	-$14.14	**-$229.12**	$301.58	**$72.45**	0.12%	$477.53
Less than $20,000	5.5	4.8%	21.2%	1.96	-$26.07	-$65.29	-$4.00	-$18.62	-$2.26	**-$116.23**	$236.76	**$120.53**	1.21%	$945.28
$20,000 to $39,999	6.5	5.7%	25.1%	2.31	-$28.49	-$64.21	-$10.57	-$58.56	-$3.13	**-$164.96**	$279.73	**$114.77**	0.38%	$871.13
$40,000 to $59,000	5.0	4.4%	19.3%	2.55	-$38.43	-$85.58	-$4.39	-$92.98	-$6.68	**-$228.06**	$308.54	**$80.49**	0.16%	$547.76
$60,000 to $79,999	3.4	3.0%	13.1%	2.78	-$43.70	-$87.88	-$8.30	-$118.88	-$10.44	**-$269.18**	$336.11	**$66.93**	0.10%	$401.81
$80,000 to $99,999	2.0	1.8%	7.7%	3.02	-$59.39	-$91.92	-$12.41	-$147.12	-$20.01	**-$330.85**	$365.00	**$34.15**	0.04%	$41.06
$100,000 to $119,999	1.3	1.1%	5.0%	3.06	-$56.28	-$131.36	-$4.47	-$238.43	-$60.92	**-$491.47**	$370.62	**-$120.84**	-0.11%	-$1,198.64
$120,000 or More	2.1	1.8%	8.1%	2.98	-$93.35	-$147.73	-$28.28	-$214.69	-$172.47	**-$656.52**	$361.00	**-$295.52**	-0.25%	-$2,793.84
South	25.9	22.8%	100.0%	2.49	-$54.08	-$27.50	-$5.05	-$90.52	-$10.69	**-$187.84**	$309.09	**$121.25**	0.21%	$785.85
Less than $20,000	10.0	8.8%	38.6%	2.18	-$32.30	-$15.17	-$1.93	-$22.09	-$1.46	**-$72.95**	$263.78	**$190.83**	1.91%	$1,451.18
$20,000 to $39,999	10.7	9.4%	41.3%	2.35	-$41.39	-$16.07	-$3.33	-$60.83	-$1.64	**-$123.27**	$284.84	**$161.57**	0.54%	$1,171.54
$40,000 to $59,000	8.1	7.1%	31.3%	2.74	-$59.75	-$22.91	-$6.21	-$110.42	-$6.55	**-$205.84**	$331.61	**$125.77**	0.25%	$795.76
$60,000 to $79,999	4.6	4.0%	17.8%	2.69	-$64.46	-$28.58	-$6.25	-$129.75	-$6.86	**-$235.90**	$325.10	**$89.21**	0.13%	$474.82
$80,000 to $99,999	3.2	2.8%	12.4%	3.01	-$74.92	-$54.82	-$1.49	-$171.49	-$25.61	**-$328.34**	$364.58	**$36.24**	0.04%	$18.32
$100,000 to $119,999	1.6	1.4%	6.2%	2.89	-$88.06	-$54.82	-$3.11	-$191.89	-$38.41	**-$376.29**	$349.96	**-$26.33**	-0.02%	-$571.00
$120,000 or More	3.9	3.4%	15.1%	2.99	-$114.22	-$105.34	-$6.27	-$243.94	-$141.35	**-$611.13**	$362.15	**-$248.98**	-0.21%	-$2,498.60
West	24.8	21.8%	100.0%	2.72	-$35.62	-$42.72	-$3.30	-$78.38	-$22.40	**-$182.43**	$328.89	**$146.46**	0.23%	$1,264.54
Less than $20,000	4.3	3.8%	17.3%	2.25	-$18.68	-$19.17	-$3.44	-$20.27	-$2.72	**-$64.28**	$272.25	**$207.97**	2.08%	$1,749.81
$20,000 to $39,999	6.0	5.3%	24.2%	2.67	-$24.22	-$29.92	-$2.70	-$48.80	-$5.61	**-$111.25**	$323.23	**$211.97**	0.71%	$1,803.09
$40,000 to $59,000	4.6	4.0%	18.5%	2.82	-$29.61	-$34.42	-$1.90	-$77.72	-$12.27	**-$155.92**	$341.72	**$185.80**	0.37%	$1,597.12
$60,000 to $79,999	3.3	2.9%	13.3%	2.74	-$40.58	-$47.14	-$2.91	-$116.97	-$12.34	**-$219.94**	$332.17	**$112.23**	0.16%	$993.11
$80,000 to $99,999	2.2	1.9%	8.9%	2.89	-$43.56	-$57.35	-$2.91	-$136.97	-$43.89	**-$284.69**	$349.35	**$64.66**	0.07%	$618.59
$100,000 to $119,999	1.4	1.2%	5.6%	2.96	-$52.93	-$79.66	$0.00	-$133.64	-$36.87	**-$303.09**	$357.87	**$54.78**	0.05%	$533.64
$120,000 or More	3.2	2.8%	12.9%	3.04	-$82.66	-$97.85	-$2.85	-$169.22	-$197.17	**-$549.75**	$368.04	**-$181.71**	-0.15%	-$1,434.01

Notes: [1]First year after tax values in 2011 chained USD (unless otherwise noted)
[2]Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

Table C.31 First year net benefits for income brackets ($15/tCO$_2$ at 4% with 50% rebate)

Costs and Benefits to the average household[1]
($15/tCO$_2$ at 4% with 50% rebate)

Market Segment	Households				First Year Costs (2014)						First Year Rebate			
	million	% of total	% of Region	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	% of Income[2]	NPV Net Benefit[3]
Average Household														
Average U.S.	113.6	100.0%		2.57	-$38.88	-$49.04	-$8.08	-$83.98	-$16.32	**-$196.30**	$311.61	**$115.31**	0.19%	$915.27
Less than $20,000	23.7	20.9%		2.10	-$23.50	-$30.31	-$4.54	-$18.44	-$2.06	**-$78.85**	$254.14	**$175.29**	1.75%	$1,499.02
$20,000 to $39,999	27.5	24.2%		2.42	-$28.75	-$36.46	-$5.54	-$53.33	-$3.56	**-$127.64**	$292.95	**$165.32**	0.55%	$1,399.52
$40,000 to $59,000	21.2	18.7%		2.66	-$38.66	-$43.90	-$6.52	-$92.90	-$8.72	**-$190.71**	$322.67	**$131.96**	0.26%	$1,063.65
$60,000 to $79,999	14.2	12.5%		2.69	-$42.28	-$48.78	-$10.00	-$120.15	-$10.52	**-$231.72**	$326.31	**$94.59**	0.14%	$719.62
$80,000 to $99,999	9.3	8.2%		2.96	-$52.52	-$65.82	-$9.56	-$152.30	-$29.01	**-$309.22**	$358.89	**$49.67**	0.06%	$288.64
$100,000 to $119,999	5.7	5.0%		3.00	-$59.09	-$97.57	-$11.90	-$181.84	-$39.81	**-$390.21**	$364.06	**-$26.16**	-0.02%	-$391.78
$120,000 or More	12.0	10.6%		3.05	-$84.96	-$113.34	-$24.64	-$208.69	-$169.25	**-$600.88**	$369.53	**-$231.36**	-0.19%	-$2,330.50
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-$17.39	-$65.27	-$19.66	-$76.05	-$22.71	**-$201.08**	$307.35	**$106.27**	0.15%	$932.94
Less than $20,000	4.0	3.5%	19.2%	1.92	-$8.29	-$41.34	-$12.44	-$8.94	-$3.04	**-$74.05**	$232.16	**$158.12**	1.58%	$1,408.01
$20,000 to $39,999	4.3	3.8%	20.7%	2.38	-$12.30	-$65.89	-$12.18	-$36.95	-$6.67	**-$133.99**	$288.54	**$154.55**	0.52%	$1,381.09
$40,000 to $59,000	3.5	3.1%	16.8%	2.44	-$14.96	-$58.63	-$15.69	-$75.19	-$13.38	**-$177.85**	$295.84	**$117.99**	0.24%	$1,050.89
$60,000 to $79,999	2.8	2.5%	13.5%	2.55	-$18.17	-$45.62	-$18.83	-$105.17	-$17.04	**-$204.83**	$308.82	**$103.99**	0.15%	$905.68
$80,000 to $99,999	1.9	1.7%	9.1%	2.91	-$23.65	-$70.86	-$23.11	-$140.25	-$28.41	**-$286.27**	$352.57	**$66.29**	0.07%	$565.87
$100,000 to $119,999	1.5	1.3%	7.2%	3.12	-$27.23	-$100.28	-$22.89	-$159.87	-$31.93	**-$342.20**	$377.84	**$35.63**	0.03%	$293.71
$120,000 or More	2.8	2.5%	13.5%	3.19	-$39.42	-$120.99	-$51.33	-$205.83	-$152.67	**-$570.24**	$386.74	**-$183.50**	-0.15%	-$1,681.67
Midwest	25.9	22.8%	100.0%	2.49	-$38.51	-$80.15	-$8.45	-$85.80	-$14.11	**-$227.03**	$301.92	**$74.89**	0.13%	$517.95
Less than $20,000	5.5	4.8%	21.2%	1.96	-$25.77	-$63.97	-$3.95	-$18.65	-$2.26	**-$114.60**	$237.04	**$122.44**	1.22%	$1,020.13
$20,000 to $39,999	6.5	5.7%	25.1%	2.31	-$28.17	-$62.91	-$10.44	-$58.65	-$3.12	**-$163.30**	$280.05	**$116.76**	0.39%	$943.85
$40,000 to $59,000	5.0	4.4%	19.3%	2.55	-$37.99	-$83.85	-$4.34	-$93.12	-$6.66	**-$225.97**	$308.90	**$82.93**	0.17%	$594.58
$60,000 to $79,999	3.4	3.0%	13.1%	2.78	-$43.21	-$86.11	-$8.20	-$119.06	-$10.41	**-$266.98**	$336.50	**$69.52**	0.10%	$437.92
$80,000 to $99,999	2.0	1.8%	7.7%	3.02	-$58.72	-$90.07	-$12.26	-$147.34	-$19.97	**-$328.36**	$365.42	**$37.06**	0.04%	$44.85
$100,000 to $119,999	1.3	1.1%	5.0%	3.06	-$55.64	-$128.72	-$4.42	-$238.79	-$60.78	**-$488.35**	$371.05	**-$117.30**	-0.11%	-$1,281.42
$120,000 or More	2.1	1.8%	8.1%	2.98	-$92.30	-$144.75	-$27.94	-$215.02	-$172.06	**-$652.06**	$361.41	**-$290.65**	-0.24%	-$3,018.39
South	25.9	22.8%	100.0%	2.49	-$54.37	-$26.88	-$4.98	-$90.02	-$10.66	**-$186.91**	$309.44	**$122.53**	0.21%	$843.03
Less than $20,000	10.0	8.8%	38.6%	2.18	-$32.47	-$14.83	-$1.90	-$21.97	-$1.46	**-$72.62**	$264.08	**$191.46**	1.91%	$1,566.05
$20,000 to $39,999	10.7	9.4%	41.3%	2.35	-$41.61	-$15.71	-$3.29	-$60.50	-$1.64	**-$122.74**	$285.17	**$162.43**	0.54%	$1,261.75
$40,000 to $59,000	8.1	7.1%	31.3%	2.74	-$60.06	-$22.39	-$6.12	-$109.80	-$6.54	**-$204.92**	$331.99	**$127.07**	0.25%	$852.25
$60,000 to $79,999	4.6	4.0%	17.8%	2.69	-$64.79	-$27.93	-$6.17	-$129.03	-$6.85	**-$234.77**	$325.47	**$90.71**	0.13%	$504.31
$80,000 to $99,999	3.2	2.8%	12.4%	3.01	-$75.31	-$53.58	-$1.47	-$170.54	-$25.55	**-$326.46**	$365.00	**$38.54**	0.04%	$10.30
$100,000 to $119,999	1.6	1.4%	6.2%	2.89	-$88.52	-$53.58	-$3.07	-$190.83	-$38.32	**-$374.32**	$350.36	**-$23.96**	-0.02%	-$629.78
$120,000 or More	3.9	3.4%	15.1%	2.99	-$114.82	-$102.96	-$6.19	-$242.59	-$141.02	**-$607.57**	$362.57	**-$245.01**	-0.20%	-$2,713.88
West	24.8	21.8%	100.0%	2.72	-$35.54	-$41.73	-$3.25	-$78.47	-$22.34	**-$181.33**	$329.26	**$147.93**	0.23%	$1,383.89
Less than $20,000	4.3	3.8%	17.3%	2.25	-$18.64	-$18.72	-$3.39	-$20.29	-$2.72	**-$63.76**	$272.56	**$208.80**	2.09%	$1,900.49
$20,000 to $39,999	6.0	5.3%	24.2%	2.67	-$24.17	-$29.22	-$2.66	-$48.86	-$5.60	**-$110.50**	$323.60	**$213.10**	0.71%	$1,961.78
$40,000 to $59,000	4.6	4.0%	18.5%	2.82	-$29.54	-$33.62	-$1.87	-$77.81	-$12.24	**-$155.08**	$342.11	**$187.03**	0.37%	$1,741.91
$60,000 to $79,999	3.3	2.9%	13.3%	2.74	-$40.49	-$46.04	-$2.87	-$117.10	-$12.31	**-$218.81**	$332.55	**$113.74**	0.16%	$1,093.10
$80,000 to $99,999	2.2	1.9%	8.9%	2.89	-$43.46	-$56.01	-$2.87	-$137.13	-$43.79	**-$283.26**	$349.75	**$66.49**	0.07%	$691.49
$100,000 to $119,999	1.4	1.2%	5.6%	2.96	-$52.81	-$77.79	$0.00	-$133.79	-$36.78	**-$301.18**	$358.28	**$57.10**	0.05%	$601.94
$120,000 or More	3.2	2.8%	12.9%	3.04	-$82.48	-$95.56	-$2.80	-$169.41	-$196.70	**-$546.96**	$368.46	**-$178.50**	-0.15%	-$1,514.36

Notes: [1]First year after tax values in 2011 chained USD (unless otherwise noted)
[2]Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

Table C.32 First year net benefits for income brackets ($15/tCO$_2$ at 6% with 50% rebate)

Costs and Benefits to the average household[1]
($15/tCO$_2$ at 6% with 50% rebate)

Market Segment	Households				First Year Costs (2014)						First Year Rebate			
	million	% of total	% of Region	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	% of Income[2]	NPV Net Benefit[3]
Average Household														
Average U.S.	113.6	100.0%		2.57	-$38.89	-$49.99	-$8.23	-$76.76	-$14.92	**-$188.80**	$311.19	**$122.39**	0.20%	$1,016.76
Less than $20,000	23.7	20.9%		2.10	-$23.51	-$30.89	-$4.62	-$16.86	-$1.89	**-$77.77**	$253.79	**$176.02**	1.76%	$1,623.16
$20,000 to $39,999	27.5	24.2%		2.42	-$28.76	-$37.17	-$5.64	-$48.75	-$3.25	**-$123.57**	$292.56	**$168.99**	0.56%	$1,527.56
$40,000 to $59,000	21.2	18.7%		2.66	-$38.67	-$44.76	-$6.64	-$84.92	-$7.97	**-$182.97**	$322.23	**$139.26**	0.28%	$1,179.10
$60,000 to $79,999	14.2	12.5%		2.69	-$42.29	-$49.72	-$10.19	-$109.83	-$9.61	**-$221.64**	$325.86	**$104.22**	0.15%	$816.17
$80,000 to $99,999	9.3	8.2%		2.96	-$52.54	-$67.10	-$9.74	-$139.22	-$26.52	**-$295.12**	$358.40	**$63.29**	0.07%	$364.99
$100,000 to $119,999	5.7	5.0%		3.00	-$59.11	-$99.47	-$12.12	-$166.22	-$36.39	**-$373.31**	$363.56	**-$9.74**	-0.01%	-$363.56
$120,000 or More	12.0	10.6%		3.05	-$84.99	-$115.54	-$25.11	-$190.76	-$154.71	**-$571.10**	$369.03	**-$202.08**	-0.17%	-$2,408.07
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-$17.49	-$66.85	-$20.14	-$70.61	-$20.76	**-$195.85**	$306.93	**$111.09**	0.16%	$1,006.82
Less than $20,000	4.0	3.5%	19.2%	1.92	-$8.34	-$42.35	-$12.74	-$8.30	-$2.77	**-$74.50**	$231.85	**$157.35**	1.57%	$1,514.62
$20,000 to $39,999	4.3	3.8%	20.7%	2.38	-$12.37	-$67.49	-$12.47	-$34.31	-$6.10	**-$132.74**	$288.15	**$155.41**	0.52%	$1,484.53
$40,000 to $59,000	3.5	3.1%	16.8%	2.44	-$15.05	-$60.06	-$16.07	-$69.81	-$12.23	**-$173.21**	$295.44	**$122.23**	0.24%	$1,133.39
$60,000 to $79,999	2.8	2.5%	13.5%	2.55	-$18.27	-$46.73	-$19.29	-$97.65	-$15.58	**-$197.51**	$308.40	**$110.89**	0.16%	$981.14
$80,000 to $99,999	1.9	1.7%	9.1%	2.91	-$23.78	-$72.58	-$23.67	-$130.21	-$25.97	**-$276.21**	$352.09	**$75.88**	0.08%	$614.82
$100,000 to $119,999	1.5	1.3%	7.2%	3.12	-$27.39	-$102.72	-$23.44	-$148.43	-$29.19	**-$331.16**	$377.32	**$46.16**	0.04%	$317.82
$120,000 or More	2.8	2.5%	13.5%	3.19	-$39.65	-$123.93	-$52.57	-$191.09	-$139.55	**-$546.79**	$386.21	**-$160.58**	-0.13%	-$1,781.93
Midwest	25.9	22.8%	100.0%	2.49	-$38.38	-$81.54	-$8.58	-$73.95	-$12.90	**-$215.35**	$301.51	**$86.16**	0.15%	$656.81
Less than $20,000	5.5	4.8%	21.2%	1.96	-$25.68	-$65.08	-$4.01	-$16.07	-$2.06	**-$112.91**	$236.71	**$123.81**	1.24%	$1,115.18
$20,000 to $39,999	6.5	5.7%	25.1%	2.31	-$28.07	-$64.00	-$10.60	-$50.55	-$2.86	**-$156.08**	$279.67	**$123.60**	0.41%	$1,082.68
$40,000 to $59,000	5.0	4.4%	19.3%	2.55	-$37.86	-$85.30	-$4.40	-$80.27	-$6.09	**-$213.93**	$308.48	**$94.55**	0.19%	$745.62
$60,000 to $79,999	3.4	3.0%	13.1%	2.78	-$43.06	-$87.60	-$8.32	-$102.62	-$9.52	**-$251.11**	$336.04	**$84.93**	0.12%	$609.38
$80,000 to $99,999	2.0	1.8%	7.7%	3.02	-$58.52	-$91.63	-$12.43	-$127.00	-$18.25	**-$307.84**	$364.92	**$57.09**	0.06%	$222.83
$100,000 to $119,999	1.3	1.1%	5.0%	3.06	-$55.45	-$130.94	-$4.48	-$205.83	-$55.56	**-$452.26**	$370.54	**-$81.72**	-0.07%	-$1,091.68
$120,000 or More	2.1	1.8%	8.1%	2.98	-$91.98	-$147.25	-$28.35	-$185.34	-$157.27	**-$610.19**	$360.92	**-$249.27**	-0.21%	-$2,962.79
South	25.9	22.8%	100.0%	2.49	-$54.27	-$27.44	-$5.07	-$83.53	-$9.75	**-$180.05**	$309.02	**$128.96**	0.23%	$921.72
Less than $20,000	10.0	8.8%	38.6%	2.18	-$32.41	-$15.14	-$1.94	-$20.38	-$1.33	**-$71.20**	$263.72	**$192.53**	1.93%	$1,696.00
$20,000 to $39,999	10.7	9.4%	41.3%	2.35	-$41.54	-$16.04	-$3.34	-$56.14	-$1.50	**-$118.55**	$284.78	**$166.23**	0.55%	$1,370.56
$40,000 to $59,000	8.1	7.1%	31.3%	2.74	-$59.96	-$22.86	-$6.23	-$101.89	-$5.97	**-$196.91**	$331.54	**$134.62**	0.27%	$933.24
$60,000 to $79,999	4.6	4.0%	17.8%	2.69	-$64.68	-$28.51	-$6.27	-$119.73	-$6.26	**-$225.46**	$325.03	**$99.58**	0.14%	$557.69
$80,000 to $99,999	3.2	2.8%	12.4%	3.01	-$75.18	-$54.70	-$1.50	-$158.26	-$23.36	**-$312.98**	$364.50	**$51.52**	0.06%	$29.29
$100,000 to $119,999	1.6	1.4%	6.2%	2.89	-$88.36	-$54.70	-$3.12	-$177.08	-$35.03	**-$358.29**	$349.89	**-$8.40**	-0.01%	-$656.05
$120,000 or More	3.9	3.4%	15.1%	2.99	-$114.62	-$105.10	-$6.29	-$225.11	-$128.90	**-$580.03**	$362.07	**-$217.95**	-0.18%	-$2,878.15
West	24.8	21.8%	100.0%	2.72	-$35.85	-$42.41	-$3.28	-$73.17	-$20.42	**-$175.12**	$328.82	**$153.70**	0.24%	$1,508.17
Less than $20,000	4.3	3.8%	17.3%	2.25	-$18.79	-$19.03	-$3.42	-$18.92	-$2.48	**-$62.64**	$272.19	**$209.55**	2.10%	$2,056.15
$20,000 to $39,999	6.0	5.3%	24.2%	2.67	-$24.37	-$29.70	-$2.68	-$45.55	-$5.12	**-$107.42**	$323.16	**$215.74**	0.72%	$2,125.54
$40,000 to $59,000	4.6	4.0%	18.5%	2.82	-$29.80	-$34.17	-$1.88	-$72.55	-$11.19	**-$149.58**	$341.65	**$192.06**	0.38%	$1,893.90
$60,000 to $79,999	3.3	2.9%	13.3%	2.74	-$40.83	-$46.79	-$2.89	-$109.18	-$11.25	**-$210.95**	$332.10	**$121.15**	0.17%	$1,195.21
$80,000 to $99,999	2.2	1.9%	8.9%	2.89	-$43.83	-$56.92	-$2.89	-$127.86	-$40.03	**-$271.53**	$349.27	**$77.74**	0.09%	$772.78
$100,000 to $119,999	1.4	1.2%	5.6%	2.96	-$53.26	-$79.06	$0.00	-$124.74	-$33.62	**-$290.69**	$357.79	**$67.10**	0.06%	$667.15
$120,000 or More	3.2	2.8%	12.9%	3.04	-$83.18	-$97.12	-$2.82	-$157.96	-$179.80	**-$520.89**	$367.96	**-$152.92**	-0.13%	-$1,562.06

Notes: [1]First year after tax values in 2011 chained USD (unless otherwise noted)
[2]Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

Table C.33 First year net benefits for income brackets ($15/tCO$_2$ at 8% with 50% rebate)

Costs and Benefits to the average household[1]
($15/tCO$_2$ at 8% with 50% rebate)

Market Segment	Households: million	Households: % of total	Households: % of Region	pph	First Year Costs (2014): Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	First Year Rebate: 50% Rebate	**Net benefit**	% of Income[2]	NPV Net Benefit[3]
Average Household														
Average U.S.	113.6	100.0%		2.57	-$39.65	-$48.57	-$8.16	-$76.69	-$14.90	**-$187.98**	$311.06	**$123.08**	0.20%	$1,066.41
Less than $20,000	23.7	20.9%		2.10	-$23.97	-$30.01	-$4.58	-$16.84	-$1.89	**-$77.29**	$253.69	**$176.40**	1.76%	$1,732.45
$20,000 to $39,999	27.5	24.2%		2.42	-$29.32	-$36.11	-$5.59	-$48.70	-$3.25	**-$122.98**	$292.44	**$169.46**	0.56%	$1,625.63
$40,000 to $59,000	21.2	18.7%		2.66	-$39.43	-$43.48	-$6.59	-$84.84	-$7.97	**-$182.31**	$322.10	**$139.79**	0.28%	$1,242.39
$60,000 to $79,999	14.2	12.5%		2.69	-$43.12	-$48.31	-$10.10	-$109.72	-$9.60	**-$220.86**	$325.73	**$104.88**	0.15%	$847.96
$80,000 to $99,999	9.3	8.2%		2.96	-$53.57	-$65.19	-$9.66	-$139.08	-$26.49	**-$293.99**	$358.26	**$64.27**	0.07%	$353.00
$100,000 to $119,999	5.7	5.0%		3.00	-$60.27	-$96.63	-$12.02	-$166.06	-$36.36	**-$371.34**	$363.42	**-$7.92**	-0.01%	-$440.28
$120,000 or More	12.0	10.6%		3.05	-$86.66	-$112.25	-$24.90	-$190.57	-$154.56	**-$568.93**	$368.88	**-$200.06**	-0.17%	-$2,665.21
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-$16.43	-$65.16	-$20.04	-$70.59	-$20.74	**-$192.95**	$306.81	**$113.86**	0.16%	$1,035.89
Less than $20,000	4.0	3.5%	19.2%	1.92	-$7.83	-$41.27	-$12.68	-$8.30	-$2.77	**-$72.85**	$231.75	**$158.91**	1.59%	$1,609.57
$20,000 to $39,999	4.3	3.8%	20.7%	2.38	-$11.61	-$65.78	-$12.41	-$34.30	-$6.09	**-$130.20**	$288.03	**$157.84**	0.53%	$1,565.72
$40,000 to $59,000	3.5	3.1%	16.8%	2.44	-$14.13	-$58.53	-$15.99	-$69.79	-$12.22	**-$170.66**	$295.32	**$124.66**	0.25%	$1,179.70
$60,000 to $79,999	2.8	2.5%	13.5%	2.55	-$17.16	-$45.54	-$19.19	-$97.63	-$15.56	**-$195.08**	$308.28	**$113.20**	0.16%	$1,006.93
$80,000 to $99,999	1.9	1.7%	9.1%	2.91	-$22.33	-$70.74	-$23.55	-$130.19	-$25.94	**-$272.75**	$351.95	**$79.20**	0.09%	$595.71
$100,000 to $119,999	1.5	1.3%	7.2%	3.12	-$25.72	-$100.11	-$23.32	-$148.40	-$29.16	**-$326.71**	$377.17	**$50.46**	0.05%	$264.60
$120,000 or More	2.8	2.5%	13.5%	3.19	-$37.23	-$120.79	-$52.31	-$191.06	-$139.42	**-$540.80**	$386.06	**-$154.74**	-0.13%	-$2,036.06
Midwest	25.9	22.8%	100.0%	2.49	-$39.09	-$79.43	-$8.49	-$74.05	-$12.89	**-$213.94**	$301.39	**$87.45**	0.15%	$683.61
Less than $20,000	5.5	4.8%	21.2%	1.96	-$26.16	-$63.39	-$3.96	-$16.10	-$2.06	**-$111.67**	$236.62	**$124.95**	1.25%	$1,179.84
$20,000 to $39,999	6.5	5.7%	25.1%	2.31	-$28.59	-$62.35	-$10.48	-$50.62	-$2.85	**-$154.89**	$279.56	**$124.67**	0.42%	$1,149.05
$40,000 to $59,000	5.0	4.4%	19.3%	2.55	-$38.56	-$83.10	-$4.36	-$80.37	-$6.08	**-$212.47**	$308.36	**$95.88**	0.19%	$780.51
$60,000 to $79,999	3.4	3.0%	13.1%	2.78	-$43.85	-$85.33	-$8.23	-$102.76	-$9.51	**-$249.67**	$335.90	**$86.23**	0.12%	$632.96
$80,000 to $99,999	2.0	1.8%	7.7%	3.02	-$59.60	-$89.26	-$12.30	-$127.17	-$18.23	**-$306.56**	$364.78	**$58.22**	0.06%	$206.84
$100,000 to $119,999	1.3	1.1%	5.0%	3.06	-$56.47	-$127.56	-$4.43	-$206.10	-$55.50	**-$450.07**	$370.40	**-$79.67**	-0.07%	-$1,197.54
$120,000 or More	2.1	1.8%	8.1%	2.98	-$93.67	-$143.44	-$28.04	-$185.58	-$157.12	**-$607.86**	$360.77	**-$247.09**	-0.21%	-$3,250.18
South	25.9	22.8%	100.0%	2.49	-$54.96	-$26.86	-$5.01	-$83.55	-$9.74	**-$180.11**	$308.90	**$128.79**	0.23%	$968.58
Less than $20,000	10.0	8.8%	38.6%	2.18	-$32.82	-$14.82	-$1.91	-$20.39	-$1.33	**-$71.26**	$263.62	**$192.35**	1.92%	$1,815.04
$20,000 to $39,999	10.7	9.4%	41.3%	2.35	-$42.06	-$15.70	-$3.30	-$56.15	-$1.49	**-$118.71**	$284.67	**$165.96**	0.55%	$1,459.56
$40,000 to $59,000	8.1	7.1%	31.3%	2.74	-$60.72	-$22.38	-$6.16	-$101.91	-$5.97	**-$197.13**	$331.40	**$134.28**	0.27%	$978.70
$60,000 to $79,999	4.6	4.0%	17.8%	2.69	-$65.50	-$27.91	-$6.20	-$119.75	-$6.25	**-$225.61**	$324.90	**$99.29**	0.14%	$570.74
$80,000 to $99,999	3.2	2.8%	12.4%	3.01	-$76.13	-$53.54	-$1.48	-$158.28	-$23.33	**-$312.76**	$364.36	**$51.60**	0.06%	-$5.92
$100,000 to $119,999	1.6	1.4%	6.2%	2.89	-$89.48	-$53.54	-$3.08	-$177.11	-$35.00	**-$358.21**	$349.75	**-$8.46**	-0.01%	-$751.61
$120,000 or More	3.9	3.4%	15.1%	2.99	-$116.07	-$102.87	-$6.22	-$225.15	-$128.78	**-$579.09**	$361.93	**-$217.16**	-0.18%	-$3,164.02
West	24.8	21.8%	100.0%	2.72	-$38.65	-$40.58	-$3.24	-$72.72	-$20.40	**-$175.59**	$328.69	**$153.10**	0.24%	$1,600.54
Less than $20,000	4.3	3.8%	17.3%	2.25	-$20.26	-$18.21	-$3.38	-$18.81	-$2.48	**-$63.13**	$272.08	**$208.95**	2.09%	$2,207.02
$20,000 to $39,999	6.0	5.3%	24.2%	2.67	-$26.27	-$28.42	-$2.65	-$45.28	-$5.11	**-$107.73**	$323.03	**$215.30**	0.72%	$2,275.94
$40,000 to $59,000	4.6	4.0%	18.5%	2.82	-$32.12	-$32.70	-$1.86	-$72.11	-$11.17	**-$149.97**	$341.51	**$191.55**	0.38%	$2,020.89
$60,000 to $79,999	3.3	2.9%	13.3%	2.74	-$44.02	-$44.78	-$2.86	-$108.52	-$11.24	**-$211.42**	$331.97	**$120.55**	0.17%	$1,256.97
$80,000 to $99,999	2.2	1.9%	8.9%	2.89	-$47.26	-$54.47	-$2.86	-$127.08	-$39.99	**-$271.65**	$349.13	**$77.48**	0.09%	$797.35
$100,000 to $119,999	1.4	1.2%	5.6%	2.96	-$57.42	-$75.67	$0.00	-$123.98	-$33.59	**-$290.66**	$357.65	**$66.99**	0.06%	$675.54
$120,000 or More	3.2	2.8%	12.9%	3.04	-$89.68	-$92.95	-$2.79	-$156.99	-$179.63	**-$522.04**	$367.82	**-$154.22**	-0.13%	-$1,746.92

Notes: [1]First year after tax values in 2011 chained USD (unless otherwise noted)
[2]Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

Table C.34 First year net benefits for income brackets ($25/tCO$_2$ at 2% with 50% rebate)

Costs and Benefits to the average household[1]
($25/tCO$_2$ at 2% with 50% rebate)

Market Segment	Households: million	% of total	% of Region	pph	First Year Costs (2014): Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	First Year Rebate: 50% Rebate	**Net benefit**	% of Income[2]	NPV Net Benefit[3]
Average Household														
Average U.S.	113.6	100.0%		2.57	-$64.48	-$83.80	-$13.66	-$138.59	-$26.94	**-$327.48**	$508.93	**$181.46**	0.29%	$1,283.43
Less than $20,000	23.7	20.9%		2.10	-$38.98	-$51.79	-$7.67	-$30.44	-$3.41	**-$132.28**	$415.07	**$282.79**	2.83%	$2,166.11
$20,000 to $39,999	27.5	24.2%		2.42	-$47.68	-$62.30	-$9.36	-$88.02	-$5.87	**-$213.23**	$478.47	**$265.23**	0.88%	$2,017.11
$40,000 to $59,000	21.2	18.7%		2.66	-$64.13	-$75.02	-$11.03	-$153.32	-$14.39	**-$317.89**	$527.00	**$209.11**	0.42%	$1,511.87
$60,000 to $79,999	14.2	12.5%		2.69	-$70.12	-$83.35	-$16.90	-$198.29	-$17.36	**-$386.02**	$532.94	**$146.92**	0.21%	$998.89
$80,000 to $99,999	9.3	8.2%		2.96	-$87.11	-$112.48	-$16.17	-$251.35	-$47.87	**-$514.98**	$586.16	**$71.18**	0.08%	$343.24
$100,000 to $119,999	5.7	5.0%		3.00	-$98.01	-$166.73	-$20.12	-$300.10	-$65.71	**-$650.66**	$594.60	**-$56.06**	-0.05%	-$701.40
$120,000 or More	12.0	10.6%		3.05	-$140.92	-$193.68	-$41.67	-$344.40	-$279.31	**-$999.97**	$603.53	**-$396.45**	-0.33%	-$3,585.10
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-$29.51	-$111.03	-$33.56	-$124.95	-$37.47	**-$336.52**	$501.98	**$165.46**	0.24%	$1,243.69
Less than $20,000	4.0	3.5%	19.2%	1.92	-$14.07	-$70.33	-$21.23	-$14.68	-$5.01	**-$125.32**	$379.18	**$253.85**	2.54%	$2,004.53
$20,000 to $39,999	4.3	3.8%	20.7%	2.38	-$20.86	-$112.09	-$20.79	-$60.71	-$11.01	**-$225.46**	$471.26	**$245.79**	0.82%	$1,924.68
$40,000 to $59,000	3.5	3.1%	16.8%	2.44	-$25.38	-$99.74	-$26.78	-$123.53	-$22.08	**-$297.51**	$483.18	**$185.66**	0.37%	$1,436.93
$60,000 to $79,999	2.8	2.5%	13.5%	2.55	-$30.82	-$77.60	-$32.14	-$172.80	-$28.12	**-$341.49**	$504.38	**$162.89**	0.23%	$1,224.66
$80,000 to $99,999	1.9	1.7%	9.1%	2.91	-$40.12	-$120.54	-$39.44	-$230.42	-$46.89	**-$477.41**	$575.83	**$98.42**	0.11%	$673.74
$100,000 to $119,999	1.5	1.3%	7.2%	3.12	-$46.20	-$170.59	-$39.07	-$262.66	-$52.69	**-$571.21**	$617.10	**$45.89**	0.04%	$224.32
$120,000 or More	2.8	2.5%	13.5%	3.19	-$66.88	-$205.82	-$87.62	-$338.16	-$251.95	**-$950.43**	$631.63	**-$318.80**	-0.27%	-$2,756.05
Midwest	25.9	22.8%	100.0%	2.49	-$64.09	-$136.94	-$14.18	-$143.86	-$23.29	**-$382.36**	$493.11	**$110.75**	0.19%	$732.22
Less than $20,000	5.5	4.8%	21.2%	1.96	-$42.89	-$109.29	-$6.62	-$31.27	-$3.73	**-$193.80**	$387.14	**$193.34**	1.93%	$1,441.16
$20,000 to $39,999	6.5	5.7%	25.1%	2.31	-$46.88	-$107.49	-$17.52	-$98.34	-$5.15	**-$275.37**	$457.39	**$182.02**	0.61%	$1,361.15
$40,000 to $59,000	5.0	4.4%	19.3%	2.55	-$63.23	-$143.26	-$7.28	-$156.14	-$10.99	**-$380.90**	$504.51	**$123.60**	0.25%	$848.89
$60,000 to $79,999	3.4	3.0%	13.1%	2.78	-$71.90	-$147.11	-$13.75	-$199.63	-$17.18	**-$449.57**	$549.58	**$100.01**	0.14%	$633.53
$80,000 to $99,999	2.0	1.8%	7.7%	3.02	-$97.72	-$153.88	-$20.56	-$247.06	-$32.95	**-$552.17**	$596.82	**$44.65**	0.05%	$63.41
$100,000 to $119,999	1.3	1.1%	5.0%	3.06	-$92.60	-$219.91	-$7.41	-$400.40	-$100.31	**-$820.62**	$606.01	**-$214.61**	-0.20%	-$1,848.66
$120,000 or More	2.1	1.8%	8.1%	2.98	-$153.59	-$247.30	-$46.87	-$360.53	-$283.95	**-$1,092.24**	$590.27	**-$501.97**	-0.42%	-$4,467.96
South	25.9	22.8%	100.0%	2.49	-$90.53	-$45.85	-$8.38	-$147.86	-$17.60	**-$310.22**	$505.39	**$195.18**	0.34%	$1,164.07
Less than $20,000	10.0	8.8%	38.6%	2.18	-$54.06	-$25.30	-$3.20	-$36.08	-$2.40	**-$121.04**	$431.31	**$310.27**	3.10%	$2,267.63
$20,000 to $39,999	10.7	9.4%	41.3%	2.35	-$69.29	-$26.80	-$5.53	-$99.37	-$2.70	**-$203.69**	$465.75	**$262.07**	0.87%	$1,809.42
$40,000 to $59,000	8.1	7.1%	31.3%	2.74	-$100.01	-$38.20	-$10.30	-$180.36	-$10.79	**-$339.66**	$542.22	**$202.56**	0.41%	$1,177.53
$60,000 to $79,999	4.6	4.0%	17.8%	2.69	-$107.89	-$47.65	-$10.37	-$211.94	-$11.30	**-$389.15**	$531.58	**$142.43**	0.20%	$651.23
$80,000 to $99,999	3.2	2.8%	12.4%	3.01	-$125.40	-$91.40	-$2.47	-$280.14	-$42.17	**-$541.58**	$596.13	**$54.55**	0.06%	-$109.48
$100,000 to $119,999	1.6	1.4%	6.2%	2.89	-$147.40	-$91.40	-$5.16	-$313.46	-$63.24	**-$620.66**	$572.23	**-$48.43**	-0.04%	-$1,071.60
$120,000 or More	3.9	3.4%	15.1%	2.99	-$191.19	-$175.63	-$10.40	-$398.48	-$232.73	**-$1,008.43**	$592.16	**-$416.27**	-0.35%	-$4,218.52
West	24.8	21.8%	100.0%	2.72	-$57.41	-$71.79	-$5.42	-$128.94	-$36.87	**-$300.43**	$537.77	**$237.34**	0.37%	$2,012.32
Less than $20,000	4.3	3.8%	17.3%	2.25	-$30.10	-$32.21	-$5.66	-$33.35	-$4.48	**-$105.79**	$445.16	**$339.36**	3.39%	$2,797.84
$20,000 to $39,999	6.0	5.3%	24.2%	2.67	-$39.03	-$50.28	-$4.43	-$80.28	-$9.24	**-$183.26**	$528.51	**$345.25**	1.15%	$2,880.26
$40,000 to $59,000	4.6	4.0%	18.5%	2.82	-$47.72	-$57.84	-$3.12	-$127.85	-$20.19	**-$256.73**	$558.75	**$302.02**	0.60%	$2,554.08
$60,000 to $79,999	3.3	2.9%	13.3%	2.74	-$65.40	-$79.21	-$4.79	-$192.42	-$20.31	**-$362.12**	$543.13	**$181.01**	0.26%	$1,575.72
$80,000 to $99,999	2.2	1.9%	8.9%	2.89	-$70.21	-$96.36	-$4.79	-$225.32	-$72.27	**-$468.93**	$571.22	**$102.29**	0.11%	$980.89
$100,000 to $119,999	1.4	1.2%	5.6%	2.96	-$85.31	-$133.84	$0.00	-$219.84	-$60.70	**-$499.69**	$585.16	**$85.47**	0.08%	$814.68
$120,000 or More	3.2	2.8%	12.9%	3.04	-$133.23	-$164.41	-$4.67	-$278.37	-$324.62	**-$905.30**	$601.79	**-$303.51**	-0.25%	-$2,297.34

Notes: [1]First year after tax values in 2011 chained USD (unless otherwise noted)
[2]Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

Table C.35 First year net benefits for income brackets ($25/tCO$_2$ at 4% with 50% rebate)

	Costs and Benefits to the average household[1] ($25/tCO$_2$ at 4% with 50% rebate)													
	Households				First Year Costs (2014)						First Year Rebate			
Market Segment	million	% of total	% of Region	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	% of Income[2]	NPV Net Benefit[3]
Average Household														
Average U.S.	113.6	100.0%		2.57	-$65.12	-$83.24	-$13.64	-$138.62	-$26.94	**-$327.56**	$507.93	**$180.37**	0.29%	$1,339.18
Less than $20,000	23.7	20.9%		2.10	-$39.36	-$51.44	-$7.65	-$30.44	-$3.41	**-$132.31**	$414.25	**$281.94**	2.82%	$2,309.53
$20,000 to $39,999	27.5	24.2%		2.42	-$48.16	-$61.89	-$9.34	-$88.03	-$5.87	**-$213.29**	$477.52	**$264.23**	0.88%	$2,139.49
$40,000 to $59,000	21.2	18.7%		2.66	-$64.76	-$74.52	-$11.01	-$153.34	-$14.40	**-$318.03**	$525.95	**$207.92**	0.42%	$1,585.50
$60,000 to $79,999	14.2	12.5%		2.69	-$70.82	-$82.79	-$16.87	-$198.32	-$17.36	**-$386.16**	$531.88	**$145.72**	0.21%	$1,026.89
$80,000 to $99,999	9.3	8.2%		2.96	-$87.98	-$111.72	-$16.14	-$251.39	-$47.88	**-$515.11**	$585.00	**$69.88**	0.08%	$307.63
$100,000 to $119,999	5.7	5.0%		3.00	-$98.98	-$165.61	-$20.08	-$300.15	-$65.72	**-$650.54**	$593.42	**-$57.12**	-0.05%	-$831.20
$120,000 or More	12.0	10.6%		3.05	-$142.32	-$192.38	-$41.58	-$344.46	-$279.36	**-$1,000.10**	$602.33	**-$397.77**	-0.33%	-$3,964.91
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-$28.11	-$110.20	-$33.56	-$125.05	-$37.48	**-$334.40**	$500.99	**$166.59**	0.24%	$1,324.33
Less than $20,000	4.0	3.5%	19.2%	1.92	-$13.40	-$69.81	-$21.23	-$14.69	-$5.01	**-$124.14**	$378.43	**$254.28**	2.54%	$2,151.60
$20,000 to $39,999	4.3	3.8%	20.7%	2.38	-$19.87	-$111.26	-$20.78	-$60.76	-$11.02	**-$223.69**	$470.32	**$246.64**	0.82%	$2,060.97
$40,000 to $59,000	3.5	3.1%	16.8%	2.44	-$24.18	-$99.00	-$26.78	-$123.63	-$22.08	**-$295.67**	$482.22	**$186.55**	0.37%	$1,531.39
$60,000 to $79,999	2.8	2.5%	13.5%	2.55	-$29.36	-$77.02	-$32.14	-$172.94	-$28.13	**-$339.59**	$503.38	**$163.79**	0.23%	$1,301.90
$80,000 to $99,999	1.9	1.7%	9.1%	2.91	-$38.22	-$119.64	-$39.44	-$230.61	-$46.89	**-$474.80**	$574.69	**$99.88**	0.11%	$704.19
$100,000 to $119,999	1.5	1.3%	7.2%	3.12	-$44.01	-$169.32	-$39.07	-$262.87	-$52.70	**-$567.97**	$615.88	**$47.91**	0.04%	$218.13
$120,000 or More	2.8	2.5%	13.5%	3.19	-$63.72	-$204.28	-$87.61	-$338.43	-$251.99	**-$946.04**	$630.38	**-$315.66**	-0.26%	-$3,003.79
Midwest	25.9	22.8%	100.0%	2.49	-$64.12	-$135.85	-$14.13	-$144.03	-$23.29	**-$381.42**	$492.13	**$110.71**	0.19%	$765.40
Less than $20,000	5.5	4.8%	21.2%	1.96	-$42.91	-$108.42	-$6.60	-$31.31	-$3.73	**-$192.97**	$386.37	**$193.40**	1.93%	$1,536.16
$20,000 to $39,999	6.5	5.7%	25.1%	2.31	-$46.90	-$106.63	-$17.46	-$98.46	-$5.16	**-$274.59**	$456.49	**$181.89**	0.61%	$1,445.32
$40,000 to $59,000	5.0	4.4%	19.3%	2.55	-$63.26	-$142.12	-$7.26	-$156.33	-$10.99	**-$379.95**	$503.51	**$123.55**	0.25%	$890.00
$60,000 to $79,999	3.4	3.0%	13.1%	2.78	-$71.93	-$145.94	-$13.70	-$199.87	-$17.19	**-$448.63**	$548.49	**$99.86**	0.14%	$656.39
$80,000 to $99,999	2.0	1.8%	7.7%	3.02	-$97.77	-$152.66	-$20.49	-$247.35	-$32.95	**-$551.22**	$595.64	**$44.42**	0.05%	$46.38
$100,000 to $119,999	1.3	1.1%	5.0%	3.06	-$92.64	-$218.15	-$7.38	-$400.88	-$100.32	**-$819.38**	$604.81	**-$214.57**	-0.20%	-$2,039.66
$120,000 or More	2.1	1.8%	8.1%	2.98	-$153.66	-$245.33	-$46.71	-$360.97	-$284.00	**-$1,090.66**	$589.10	**-$501.57**	-0.42%	-$4,854.96
South	25.9	22.8%	100.0%	2.49	-$91.03	-$45.55	-$8.35	-$147.97	-$17.60	**-$310.51**	$504.39	**$193.88**	0.34%	$1,197.64
Less than $20,000	10.0	8.8%	38.6%	2.18	-$54.36	-$25.13	-$3.19	-$36.11	-$2.40	**-$121.19**	$430.45	**$309.26**	3.09%	$2,412.01
$20,000 to $39,999	10.7	9.4%	41.3%	2.35	-$69.68	-$26.63	-$5.51	-$99.45	-$2.70	**-$203.95**	$464.83	**$260.87**	0.87%	$1,906.60
$40,000 to $59,000	8.1	7.1%	31.3%	2.74	-$100.57	-$37.95	-$10.26	-$180.50	-$10.79	**-$340.07**	$541.14	**$201.07**	0.40%	$1,206.66
$60,000 to $79,999	4.6	4.0%	17.8%	2.69	-$108.49	-$47.34	-$10.33	-$212.10	-$11.30	**-$389.57**	$530.53	**$140.96**	0.20%	$634.16
$80,000 to $99,999	3.2	2.8%	12.4%	3.01	-$126.11	-$90.81	-$2.46	-$280.35	-$42.17	**-$541.90**	$594.95	**$53.05**	0.06%	-$206.46
$100,000 to $119,999	1.6	1.4%	6.2%	2.89	-$148.22	-$90.81	-$5.14	-$313.69	-$63.25	**-$621.12**	$571.09	**-$50.03**	-0.05%	-$1,250.84
$120,000 or More	3.9	3.4%	15.1%	2.99	-$192.27	-$174.49	-$10.36	-$398.78	-$232.77	**-$1,008.67**	$590.99	**-$417.68**	-0.35%	-$4,684.25
West	24.8	21.8%	100.0%	2.72	-$61.06	-$71.49	-$5.40	-$128.62	-$36.88	**-$303.46**	$536.70	**$233.25**	0.36%	$2,099.11
Less than $20,000	4.3	3.8%	17.3%	2.25	-$32.01	-$32.08	-$5.64	-$33.26	-$4.48	**-$107.47**	$444.28	**$336.80**	3.37%	$2,977.01
$20,000 to $39,999	6.0	5.3%	24.2%	2.67	-$41.51	-$50.07	-$4.42	-$80.08	-$9.24	**-$185.32**	$527.47	**$342.14**	1.14%	$3,051.23
$40,000 to $59,000	4.6	4.0%	18.5%	2.82	-$50.75	-$57.61	-$3.11	-$127.54	-$20.20	**-$259.20**	$557.64	**$298.44**	0.60%	$2,689.27
$60,000 to $79,999	3.3	2.9%	13.3%	2.74	-$69.55	-$78.89	-$4.77	-$191.94	-$20.32	**-$365.47**	$542.06	**$176.59**	0.25%	$1,621.10
$80,000 to $99,999	2.2	1.9%	8.9%	2.89	-$74.66	-$95.96	-$4.77	-$224.77	-$72.28	**-$472.44**	$570.09	**$97.65**	0.11%	$965.23
$100,000 to $119,999	1.4	1.2%	5.6%	2.96	-$90.73	-$133.30	$0.00	-$219.30	-$60.71	**-$504.03**	$584.00	**$79.97**	0.07%	$775.37
$120,000 or More	3.2	2.8%	12.9%	3.04	-$141.69	-$163.74	-$4.66	-$277.68	-$324.68	**-$912.45**	$600.60	**-$311.85**	-0.26%	-$2,630.93

Notes: [1]First year after tax values in 2011 chained USD (unless otherwise noted)
[2]Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

Table C.36 First year net benefits for income brackets ($25/t$CO_2$ at 6% with 50% rebate)

Costs and Benefits to the average household[1]
($25/t$CO_2$ at 6% with 50% rebate)

Market Segment	Households: million	Households: % of total	Households: % of Region	pph	First Year Costs (2014): Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	First Year Rebate: 50% Rebate	**Net benefit**	% of Income[2]	NPV Net Benefit[3]
Average Household														
Average U.S.	113.6	100.0%		2.57	-$65.19	-$83.21	-$13.61	-$138.47	-$26.91	**-$327.38**	$507.91	**$180.53**	0.29%	$1,357.62
Less than $20,000	23.7	20.9%		2.10	-$39.40	-$51.42	-$7.64	-$30.41	-$3.40	**-$132.28**	$414.24	**$281.96**	2.82%	$2,436.68
$20,000 to $39,999	27.5	24.2%		2.42	-$48.20	-$61.86	-$9.33	-$87.94	-$5.86	**-$213.19**	$477.51	**$264.32**	0.88%	$2,240.98
$40,000 to $59,000	21.2	18.7%		2.66	-$64.83	-$74.49	-$10.99	-$153.18	-$14.38	**-$317.86**	$525.94	**$208.08**	0.42%	$1,625.33
$60,000 to $79,999	14.2	12.5%		2.69	-$70.89	-$82.76	-$16.84	-$198.11	-$17.34	**-$385.94**	$531.87	**$145.93**	0.21%	$1,014.64
$80,000 to $99,999	9.3	8.2%		2.96	-$88.06	-$111.68	-$16.11	-$251.12	-$47.83	**-$514.80**	$584.98	**$70.18**	0.08%	$216.18
$100,000 to $119,999	5.7	5.0%		3.00	-$99.08	-$165.54	-$20.04	-$299.82	-$65.65	**-$650.14**	$593.41	**-$56.73**	-0.05%	-$1,035.33
$120,000 or More	12.0	10.6%		3.05	-$142.46	-$192.30	-$41.51	-$344.09	-$279.06	**-$999.42**	$602.32	**-$397.10**	-0.33%	-$4,460.67
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-$27.41	-$110.21	-$33.46	-$124.59	-$37.44	**-$333.11**	$500.98	**$167.87**	0.24%	$1,375.80
Less than $20,000	4.0	3.5%	19.2%	1.92	-$13.07	-$69.81	-$21.17	-$14.64	-$5.01	**-$123.69**	$378.42	**$254.73**	2.55%	$2,288.83
$20,000 to $39,999	4.3	3.8%	20.7%	2.38	-$19.38	-$111.26	-$20.72	-$60.54	-$11.00	**-$222.90**	$470.31	**$247.41**	0.82%	$2,176.55
$40,000 to $59,000	3.5	3.1%	16.8%	2.44	-$23.58	-$99.00	-$26.70	-$123.18	-$22.06	**-$294.51**	$482.21	**$187.70**	0.38%	$1,603.81
$60,000 to $79,999	2.8	2.5%	13.5%	2.55	-$28.63	-$77.03	-$32.04	-$172.30	-$28.10	**-$338.10**	$503.36	**$165.27**	0.24%	$1,357.01
$80,000 to $99,999	1.9	1.7%	9.1%	2.91	-$37.27	-$119.64	-$39.32	-$229.76	-$46.84	**-$472.84**	$574.67	**$101.83**	0.11%	$696.34
$100,000 to $119,999	1.5	1.3%	7.2%	3.12	-$42.92	-$169.33	-$38.95	-$261.90	-$52.64	**-$565.74**	$615.86	**$50.12**	0.05%	$157.98
$120,000 or More	2.8	2.5%	13.5%	3.19	-$62.13	-$204.29	-$87.35	-$337.19	-$251.72	**-$942.68**	$630.37	**-$312.32**	-0.26%	-$3,339.66
Midwest	25.9	22.8%	100.0%	2.49	-$64.24	-$135.82	-$14.13	-$143.46	-$23.27	**-$380.91**	$492.12	**$111.21**	0.19%	$714.46
Less than $20,000	5.5	4.8%	21.2%	1.96	-$42.99	-$108.40	-$6.60	-$31.18	-$3.72	**-$192.89**	$386.36	**$193.47**	1.93%	$1,577.36
$20,000 to $39,999	6.5	5.7%	25.1%	2.31	-$46.99	-$106.61	-$17.45	-$98.06	-$5.15	**-$274.26**	$456.48	**$182.22**	0.61%	$1,472.50
$40,000 to $59,000	5.0	4.4%	19.3%	2.55	-$63.38	-$142.09	-$7.25	-$155.71	-$10.98	**-$379.41**	$503.49	**$124.09**	0.25%	$848.54
$60,000 to $79,999	3.4	3.0%	13.1%	2.78	-$72.07	-$145.91	-$13.70	-$199.07	-$17.17	**-$447.91**	$548.48	**$100.57**	0.14%	$585.16
$80,000 to $99,999	2.0	1.8%	7.7%	3.02	-$97.95	-$152.63	-$20.48	-$246.37	-$32.92	**-$550.35**	$595.63	**$45.28**	0.05%	-$101.31
$100,000 to $119,999	1.3	1.1%	5.0%	3.06	-$92.82	-$218.11	-$7.38	-$399.28	-$100.22	**-$817.80**	$604.80	**-$213.01**	-0.19%	-$2,363.70
$120,000 or More	2.1	1.8%	8.1%	2.98	-$153.95	-$245.28	-$46.69	-$359.53	-$283.69	**-$1,089.14**	$589.08	**-$500.06**	-0.42%	-$5,470.24
South	25.9	22.8%	100.0%	2.49	-$90.70	-$45.56	-$8.34	-$147.46	-$17.58	**-$309.65**	$504.38	**$194.73**	0.34%	$1,173.06
Less than $20,000	10.0	8.8%	38.6%	2.18	-$54.16	-$25.14	-$3.19	-$35.98	-$2.40	**-$120.87**	$430.44	**$309.57**	3.10%	$2,530.10
$20,000 to $39,999	10.7	9.4%	41.3%	2.35	-$69.42	-$26.63	-$5.50	-$99.10	-$2.70	**-$203.35**	$464.82	**$261.46**	0.87%	$1,966.25
$40,000 to $59,000	8.1	7.1%	31.3%	2.74	-$100.21	-$37.96	-$10.26	-$179.87	-$10.78	**-$339.07**	$541.13	**$202.06**	0.40%	$1,173.28
$60,000 to $79,999	4.6	4.0%	17.8%	2.69	-$108.10	-$47.35	-$10.33	-$211.37	-$11.29	**-$388.43**	$530.51	**$142.09**	0.20%	$544.99
$80,000 to $99,999	3.2	2.8%	12.4%	3.01	-$125.65	-$90.83	-$2.46	-$279.37	-$42.13	**-$540.44**	$594.94	**$54.50**	0.06%	-$394.14
$100,000 to $119,999	1.6	1.4%	6.2%	2.89	-$147.68	-$90.83	-$5.14	-$312.60	-$63.19	**-$619.43**	$571.08	**-$48.36**	-0.04%	-$1,542.52
$120,000 or More	3.9	3.4%	15.1%	2.99	-$191.56	-$174.52	-$10.36	-$397.40	-$232.52	**-$1,006.36**	$590.97	**-$415.38**	-0.35%	-$5,317.11
West	24.8	21.8%	100.0%	2.72	-$62.51	-$71.37	-$5.39	-$129.74	-$36.84	**-$305.84**	$536.69	**$230.85**	0.36%	$2,226.26
Less than $20,000	4.3	3.8%	17.3%	2.25	-$32.77	-$32.02	-$5.62	-$33.55	-$4.48	**-$108.45**	$444.27	**$335.82**	3.36%	$3,187.62
$20,000 to $39,999	6.0	5.3%	24.2%	2.67	-$42.50	-$49.98	-$4.41	-$80.78	-$9.23	**-$186.89**	$527.45	**$340.56**	1.14%	$3,260.19
$40,000 to $59,000	4.6	4.0%	18.5%	2.82	-$51.95	-$57.51	-$3.10	-$128.64	-$20.18	**-$261.38**	$557.63	**$296.25**	0.59%	$2,866.73
$60,000 to $79,999	3.3	2.9%	13.3%	2.74	-$71.20	-$78.75	-$4.76	-$193.60	-$20.29	**-$368.61**	$542.05	**$173.44**	0.25%	$1,709.31
$80,000 to $99,999	2.2	1.9%	8.9%	2.89	-$76.43	-$95.80	-$4.76	-$226.71	-$72.20	**-$475.90**	$570.08	**$94.18**	0.10%	$994.80
$100,000 to $119,999	1.4	1.2%	5.6%	2.96	-$92.88	-$133.07	$0.00	-$221.19	-$60.64	**-$507.78**	$583.99	**$76.20**	0.07%	$779.72
$120,000 or More	3.2	2.8%	12.9%	3.04	-$145.05	-$163.46	-$4.65	-$280.09	-$324.33	**-$917.56**	$600.59	**-$316.98**	-0.26%	-$2,911.44

Notes: [1]First year after tax values in 2011 chained USD (unless otherwise noted)
[2]Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

Table C.37 First year net benefits for income brackets ($25/tCO$_2$ at 8% with 50% rebate)

Costs and Benefits to the average household[1]
($25/tCO$_2$ at 8% with 50% rebate)

Market Segment	Households: million	Households: % of total	Households: % of Region	Households: pph	First Year Costs (2014): Electricity	First Year Costs (2014): Natural Gas	First Year Costs (2014): Other Fuels	First Year Costs (2014): Gasoline	First Year Costs (2014): Other Trans.	First Year Costs (2014): **Total Costs**	First Year Rebate: 50% Rebate	First Year Rebate: **Net benefit**	First Year Rebate: % of Income[2]	NPV Net Benefit[3]
Average Household														
Average U.S.	113.6	100.0%		2.57	-$65.54	-$83.70	-$13.64	-$138.09	-$26.84	**-$327.82**	$507.30	**$179.49**	0.29%	$1,367.58
Less than $20,000	23.7	20.9%		2.10	-$39.62	-$51.73	-$7.66	-$30.33	-$3.39	**-$132.72**	$413.74	**$281.02**	2.81%	$2,565.14
$20,000 to $39,999	27.5	24.2%		2.42	-$48.47	-$62.23	-$9.35	-$87.70	-$5.85	**-$213.59**	$476.93	**$263.34**	0.88%	$2,339.83
$40,000 to $59,000	21.2	18.7%		2.66	-$65.18	-$74.94	-$11.01	-$152.76	-$14.34	**-$318.23**	$525.31	**$207.08**	0.41%	$1,658.89
$60,000 to $79,999	14.2	12.5%		2.69	-$71.28	-$83.25	-$16.88	-$197.56	-$17.29	**-$386.27**	$531.23	**$144.97**	0.21%	$991.51
$80,000 to $99,999	9.3	8.2%		2.96	-$88.55	-$112.35	-$16.14	-$250.43	-$47.70	**-$515.17**	$584.28	**$69.11**	0.08%	$106.49
$100,000 to $119,999	5.7	5.0%		3.00	-$99.62	-$166.54	-$20.09	-$299.00	-$65.47	**-$650.71**	$592.69	**-$58.02**	-0.05%	-$1,271.98
$120,000 or More	12.0	10.6%		3.05	-$143.24	-$193.45	-$41.60	-$343.14	-$278.29	**-$999.73**	$601.60	**-$398.14**	-0.33%	-$5,006.12
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-$28.70	-$110.66	-$33.47	-$124.52	-$37.34	**-$334.68**	$500.37	**$165.69**	0.24%	$1,406.68
Less than $20,000	4.0	3.5%	19.2%	1.92	-$13.68	-$70.09	-$21.18	-$14.63	-$4.99	**-$124.57**	$377.96	**$253.39**	2.53%	$2,420.25
$20,000 to $39,999	4.3	3.8%	20.7%	2.38	-$20.29	-$111.71	-$20.73	-$60.50	-$10.97	**-$224.21**	$469.75	**$245.54**	0.82%	$2,278.55
$40,000 to $59,000	3.5	3.1%	16.8%	2.44	-$24.69	-$99.41	-$26.71	-$123.11	-$21.99	**-$295.90**	$481.63	**$185.72**	0.37%	$1,658.25
$60,000 to $79,999	2.8	2.5%	13.5%	2.55	-$29.98	-$77.34	-$32.06	-$172.20	-$28.02	**-$339.60**	$502.76	**$163.16**	0.23%	$1,392.79
$80,000 to $99,999	1.9	1.7%	9.1%	2.91	-$39.02	-$120.13	-$39.34	-$229.63	-$46.71	**-$474.84**	$573.98	**$99.14**	0.11%	$658.65
$100,000 to $119,999	1.5	1.3%	7.2%	3.12	-$44.94	-$170.02	-$38.96	-$261.76	-$52.50	**-$568.18**	$615.12	**$46.95**	0.04%	$59.55
$120,000 or More	2.8	2.5%	13.5%	3.19	-$65.06	-$205.12	-$87.38	-$337.00	-$251.03	**-$945.59**	$629.61	**-$315.98**	-0.26%	-$3,741.17
Midwest	25.9	22.8%	100.0%	2.49	-$64.66	-$136.73	-$14.17	-$143.09	-$23.20	**-$381.85**	$491.53	**$109.68**	0.18%	$642.96
Less than $20,000	5.5	4.8%	21.2%	1.96	-$43.27	-$109.12	-$6.62	-$31.10	-$3.71	**-$193.83**	$385.90	**$192.07**	1.92%	$1,604.25
$20,000 to $39,999	6.5	5.7%	25.1%	2.31	-$47.29	-$107.32	-$17.51	-$97.81	-$5.14	**-$275.07**	$455.93	**$180.86**	0.60%	$1,484.03
$40,000 to $59,000	5.0	4.4%	19.3%	2.55	-$63.79	-$143.04	-$7.28	-$155.31	-$10.95	**-$380.36**	$502.89	**$122.53**	0.25%	$786.97
$60,000 to $79,999	3.4	3.0%	13.1%	2.78	-$72.54	-$146.88	-$13.74	-$198.56	-$17.12	**-$448.84**	$547.82	**$98.98**	0.14%	$492.57
$80,000 to $99,999	2.0	1.8%	7.7%	3.02	-$98.59	-$153.64	-$20.55	-$245.73	-$32.83	**-$551.35**	$594.91	**$43.57**	0.05%	-$270.04
$100,000 to $119,999	1.3	1.1%	5.0%	3.06	-$93.42	-$219.56	-$7.41	-$398.25	-$99.94	**-$818.58**	$604.07	**-$214.52**	-0.20%	-$2,730.53
$120,000 or More	2.1	1.8%	8.1%	2.98	-$154.96	-$246.91	-$46.84	-$358.60	-$282.91	**-$1,090.23**	$588.38	**-$501.85**	-0.42%	-$6,143.90
South	25.9	22.8%	100.0%	2.49	-$90.71	-$45.90	-$8.37	-$147.38	-$17.53	**-$309.89**	$503.77	**$193.88**	0.34%	$1,183.83
Less than $20,000	10.0	8.8%	38.6%	2.18	-$54.17	-$25.32	-$3.20	-$35.96	-$2.40	**-$121.04**	$429.93	**$308.88**	3.09%	$2,677.19
$20,000 to $39,999	10.7	9.4%	41.3%	2.35	-$69.43	-$26.83	-$5.52	-$99.05	-$2.69	**-$203.51**	$464.26	**$260.75**	0.87%	$2,057.91
$40,000 to $59,000	8.1	7.1%	31.3%	2.74	-$100.21	-$38.24	-$10.29	-$179.77	-$10.75	**-$339.26**	$540.48	**$201.22**	0.40%	$1,180.09
$60,000 to $79,999	4.6	4.0%	17.8%	2.69	-$108.11	-$47.70	-$10.36	-$211.25	-$11.26	**-$388.67**	$529.88	**$141.20**	0.20%	$495.79
$80,000 to $99,999	3.2	2.8%	12.4%	3.01	-$125.66	-$91.49	-$2.47	-$279.22	-$42.01	**-$540.85**	$594.22	**$53.37**	0.06%	-$546.24
$100,000 to $119,999	1.6	1.4%	6.2%	2.89	-$147.69	-$91.49	-$5.15	-$312.43	-$63.01	**-$619.79**	$570.39	**-$49.39**	-0.04%	-$1,791.16
$120,000 or More	3.9	3.4%	15.1%	2.99	-$191.58	-$175.80	-$10.39	-$397.18	-$231.88	**-$1,006.83**	$590.26	**-$416.57**	-0.35%	-$5,919.14
West	24.8	21.8%	100.0%	2.72	-$62.55	-$71.77	-$5.43	-$128.60	-$36.74	**-$305.08**	$536.05	**$230.96**	0.36%	$2,295.32
Less than $20,000	4.3	3.8%	17.3%	2.25	-$32.80	-$32.20	-$5.66	-$33.26	-$4.47	**-$108.38**	$443.73	**$335.35**	3.35%	$3,375.99
$20,000 to $39,999	6.0	5.3%	24.2%	2.67	-$42.53	-$50.27	-$4.44	-$80.07	-$9.20	**-$186.50**	$526.82	**$340.32**	1.13%	$3,433.40
$40,000 to $59,000	4.6	4.0%	18.5%	2.82	-$51.99	-$57.83	-$3.12	-$127.51	-$20.12	**-$260.58**	$556.96	**$296.38**	0.59%	$2,996.88
$60,000 to $79,999	3.3	2.9%	13.3%	2.74	-$71.25	-$79.19	-$4.79	-$191.90	-$20.24	**-$367.38**	$541.39	**$174.02**	0.25%	$1,728.25
$80,000 to $99,999	2.2	1.9%	8.9%	2.89	-$76.49	-$96.34	-$4.79	-$224.72	-$72.00	**-$474.34**	$569.39	**$95.05**	0.11%	$940.54
$100,000 to $119,999	1.4	1.2%	5.6%	2.96	-$92.95	-$133.82	$0.00	-$219.25	-$60.47	**-$506.49**	$583.28	**$76.80**	0.07%	$684.76
$120,000 or More	3.2	2.8%	12.9%	3.04	-$145.15	-$164.38	-$4.68	-$277.63	-$323.44	**-$915.27**	$599.86	**-$315.41**	-0.26%	-$3,350.31

Notes: [1]First year after tax values in 2011 chained USD (unless otherwise noted)
[2]Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

Table C.38 First year net benefits for income brackets ($35/tCO$_2$ at 2% with 50% rebate)

Costs and Benefits to the average household[1]
($35/tCO$_2$ at 2% with 50% rebate)

Market Segment	Households				First Year Costs (2014)						First Year Rebate			
	million	% of total	% of Region	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	% of Income[2]	NPV Net Benefit[3]
Average Household														
Average U.S.	113.6	100.0%		2.57	-$89.17	-$116.54	-$18.95	-$188.77	-$36.69	**-$450.13**	$698.91	**$248.79**	0.40%	$1,616.16
Less than $20,000	23.7	20.9%		2.10	-$53.90	-$72.02	-$10.63	-$41.46	-$4.64	**-$182.66**	$570.01	**$387.35**	3.87%	$2,864.59
$20,000 to $39,999	27.5	24.2%		2.42	-$65.94	-$86.65	-$12.98	-$119.89	-$7.99	**-$293.45**	$657.07	**$363.62**	1.21%	$2,640.28
$40,000 to $59,000	21.2	18.7%		2.66	-$88.68	-$104.34	-$15.29	-$208.83	-$19.61	**-$436.75**	$723.72	**$286.98**	0.57%	$1,929.52
$60,000 to $79,999	14.2	12.5%		2.69	-$96.97	-$115.92	-$23.44	-$270.08	-$23.64	**-$530.05**	$731.88	**$201.83**	0.29%	$1,218.85
$80,000 to $99,999	9.3	8.2%		2.96	-$120.47	-$156.43	-$22.42	-$342.35	-$65.21	**-$706.88**	$804.97	**$98.09**	0.11%	$293.59
$100,000 to $119,999	5.7	5.0%		3.00	-$135.54	-$231.87	-$27.90	-$408.75	-$89.50	**-$893.55**	$816.56	**-$77.00**	-0.07%	-$1,166.62
$120,000 or More	12.0	10.6%		3.05	-$194.88	-$269.35	-$57.78	-$469.10	-$380.44	**-$1,371.55**	$828.82	**-$542.73**	-0.45%	-$5,145.84
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-$40.06	-$152.71	-$47.01	-$171.47	-$51.04	**-$462.29**	$689.37	**$227.08**	0.33%	$1,602.01
Less than $20,000	4.0	3.5%	19.2%	1.92	-$19.09	-$96.73	-$29.74	-$20.15	-$6.82	**-$172.54**	$520.72	**$348.18**	3.48%	$2,670.92
$20,000 to $39,999	4.3	3.8%	20.7%	2.38	-$28.32	-$154.17	-$29.11	-$83.32	-$15.00	**-$309.92**	$647.17	**$337.26**	1.12%	$2,535.96
$40,000 to $59,000	3.5	3.1%	16.8%	2.44	-$34.46	-$137.18	-$37.51	-$169.53	-$30.07	**-$408.75**	$663.54	**$254.79**	0.51%	$1,868.24
$60,000 to $79,999	2.8	2.5%	13.5%	2.55	-$41.84	-$106.73	-$45.02	-$237.14	-$38.31	**-$469.04**	$692.65	**$223.62**	0.32%	$1,583.75
$80,000 to $99,999	1.9	1.7%	9.1%	2.91	-$54.46	-$165.79	-$55.24	-$316.23	-$63.86	**-$655.58**	$790.78	**$135.20**	0.15%	$808.37
$100,000 to $119,999	1.5	1.3%	7.2%	3.12	-$62.72	-$234.63	-$54.72	-$360.46	-$71.77	**-$784.30**	$847.46	**$63.16**	0.06%	$174.58
$120,000 or More	2.8	2.5%	13.5%	3.19	-$90.79	-$283.08	-$122.72	-$464.08	-$343.17	**-$1,303.85**	$867.42	**-$436.43**	-0.36%	-$3,912.96
Midwest	25.9	22.8%	100.0%	2.49	-$89.71	-$190.46	-$19.52	-$190.87	-$31.72	**-$522.28**	$677.18	**$154.91**	0.26%	$880.82
Less than $20,000	5.5	4.8%	21.2%	1.96	-$60.03	-$152.01	-$9.12	-$41.49	-$5.08	**-$267.72**	$531.65	**$263.93**	2.64%	$1,861.72
$20,000 to $39,999	6.5	5.7%	25.1%	2.31	-$65.62	-$149.50	-$24.11	-$130.47	-$7.02	**-$376.71**	$628.14	**$251.42**	0.84%	$1,752.36
$40,000 to $59,000	5.0	4.4%	19.3%	2.55	-$88.50	-$199.25	-$10.02	-$207.17	-$14.97	**-$519.91**	$692.83	**$172.92**	0.35%	$1,038.86
$60,000 to $79,999	3.4	3.0%	13.1%	2.78	-$100.64	-$204.60	-$18.92	-$264.86	-$23.40	**-$612.44**	$754.73	**$142.29**	0.20%	$742.42
$80,000 to $99,999	2.0	1.8%	7.7%	3.02	-$136.79	-$214.03	-$28.29	-$327.79	-$44.88	**-$751.78**	$819.61	**$67.83**	0.08%	-$38.97
$100,000 to $119,999	1.3	1.1%	5.0%	3.06	-$129.62	-$305.85	-$10.20	-$531.24	-$136.62	**-$1,113.53**	$832.23	**-$281.30**	-0.26%	-$2,665.38
$120,000 or More	2.1	1.8%	8.1%	2.98	-$215.00	-$343.95	-$64.50	-$478.35	-$386.76	**-$1,488.56**	$810.61	**-$677.95**	-0.56%	-$6,274.71
South	25.9	22.8%	100.0%	2.49	-$124.43	-$63.53	-$11.53	-$203.00	-$23.97	**-$426.44**	$694.05	**$267.60**	0.47%	$1,434.32
Less than $20,000	10.0	8.8%	38.6%	2.18	-$74.30	-$35.05	-$4.40	-$49.53	-$3.27	**-$166.56**	$592.31	**$425.75**	4.26%	$2,995.16
$20,000 to $39,999	10.7	9.4%	41.3%	2.35	-$95.23	-$37.13	-$7.60	-$136.42	-$3.68	**-$280.07**	$639.61	**$359.54**	1.20%	$2,347.11
$40,000 to $59,000	8.1	7.1%	31.3%	2.74	-$137.47	-$52.93	-$14.17	-$247.62	-$14.69	**-$466.87**	$744.62	**$277.75**	0.56%	$1,442.25
$60,000 to $79,999	4.6	4.0%	17.8%	2.69	-$148.29	-$66.02	-$14.27	-$290.97	-$15.39	**-$534.94**	$730.01	**$195.08**	0.28%	$712.76
$80,000 to $99,999	3.2	2.8%	12.4%	3.01	-$172.37	-$126.64	-$3.40	-$384.59	-$57.43	**-$744.43**	$818.66	**$74.23**	0.08%	-$376.37
$100,000 to $119,999	1.6	1.4%	6.2%	2.89	-$202.59	-$126.64	-$7.09	-$430.33	-$86.14	**-$852.81**	$785.83	**-$66.98**	-0.06%	-$1,701.03
$120,000 or More	3.9	3.4%	15.1%	2.99	-$262.79	-$243.34	-$14.31	-$547.06	-$316.99	**-$1,384.49**	$813.21	**-$571.28**	-0.48%	-$6,084.85
West	24.8	21.8%	100.0%	2.72	-$80.17	-$101.33	-$7.44	-$176.88	-$50.22	**-$416.06**	$738.51	**$322.46**	0.50%	$2,588.34
Less than $20,000	4.3	3.8%	17.3%	2.25	-$42.04	-$45.46	-$7.76	-$45.75	-$6.11	**-$147.11**	$611.33	**$464.22**	4.64%	$3,720.57
$20,000 to $39,999	6.0	5.3%	24.2%	2.67	-$54.51	-$70.97	-$6.08	-$110.13	-$12.58	**-$254.27**	$725.80	**$471.53**	1.57%	$3,800.91
$40,000 to $59,000	4.6	4.0%	18.5%	2.82	-$66.64	-$81.65	-$4.28	-$175.39	-$27.51	**-$355.47**	$767.33	**$411.86**	0.82%	$3,336.66
$60,000 to $79,999	3.3	2.9%	13.3%	2.74	-$91.33	-$111.81	-$6.57	-$263.96	-$27.67	**-$501.34**	$745.88	**$244.54**	0.35%	$1,977.88
$80,000 to $99,999	2.2	1.9%	8.9%	2.89	-$98.04	-$136.02	-$6.57	-$309.10	-$98.43	**-$648.15**	$784.45	**$136.30**	0.15%	$1,140.99
$100,000 to $119,999	1.4	1.2%	5.6%	2.96	-$119.13	-$188.93	$0.00	-$301.58	-$82.67	**-$692.31**	$803.59	**$111.28**	0.10%	$889.66
$120,000 or More	3.2	2.8%	12.9%	3.04	-$186.04	-$232.08	-$6.41	-$381.87	-$442.16	**-$1,248.57**	$826.43	**-$422.13**	-0.35%	-$3,425.28

Notes: [1]First year after tax values in 2011 chained USD (unless otherwise noted)
[2]Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

Table C.39 First year net benefits for income brackets ($35/t$CO_2$ at 4% with 50% rebate)

Costs and Benefits to the average household[1]
($35/t$CO_2$ at 4% with 50% rebate)

Market Segment	Households: million	Households: % of total	Households: % of Region	Households: pph	First Year Costs (2014): Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	First Year Rebate: 50% Rebate	**Net benefit**	% of Income[2]	NPV Net Benefit[3]
Average Household														
Average U.S.	113.6	100.0%		2.57	-$88.96	-$116.56	-$18.94	-$182.51	-$35.47	**-$442.45**	$698.72	**$256.27**	0.42%	$1,632.85
Less than $20,000	23.7	20.9%		2.10	-$53.77	-$72.03	-$10.63	-$40.08	-$4.49	**-$181.01**	$569.85	**$388.85**	3.89%	$3,001.29
$20,000 to $39,999	27.5	24.2%		2.42	-$65.78	-$86.66	-$12.98	-$115.91	-$7.73	**-$289.06**	$656.89	**$367.83**	1.23%	$2,749.99
$40,000 to $59,000	21.2	18.7%		2.66	-$88.47	-$104.35	-$15.29	-$201.91	-$18.96	**-$428.97**	$723.52	**$294.55**	0.59%	$1,971.75
$60,000 to $79,999	14.2	12.5%		2.69	-$96.74	-$115.93	-$23.43	-$261.13	-$22.86	**-$520.09**	$731.68	**$211.59**	0.30%	$1,203.58
$80,000 to $99,999	9.3	8.2%		2.96	-$120.18	-$156.45	-$22.41	-$331.01	-$63.04	**-$693.09**	$804.74	**$111.65**	0.12%	$189.91
$100,000 to $119,999	5.7	5.0%		3.00	-$135.22	-$231.91	-$27.89	-$395.20	-$86.53	**-$876.74**	$816.33	**-$60.40**	-0.05%	-$1,400.53
$120,000 or More	12.0	10.6%		3.05	-$194.42	-$269.39	-$57.76	-$453.54	-$367.83	**-$1,342.94**	$828.59	**-$514.35**	-0.43%	-$5,699.91
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-$38.34	-$152.72	-$46.97	-$167.65	-$49.35	**-$455.03**	$689.18	**$234.15**	0.34%	$1,610.36
Less than $20,000	4.0	3.5%	19.2%	1.92	-$18.27	-$96.74	-$29.71	-$19.70	-$6.60	**-$171.03**	$520.58	**$349.55**	3.50%	$2,805.30
$20,000 to $39,999	4.3	3.8%	20.7%	2.38	-$27.10	-$154.18	-$29.09	-$81.46	-$14.50	**-$306.34**	$647.00	**$340.66**	1.14%	$2,633.65
$40,000 to $59,000	3.5	3.1%	16.8%	2.44	-$32.98	-$137.19	-$37.48	-$165.75	-$29.07	**-$402.47**	$663.36	**$260.88**	0.52%	$1,905.27
$60,000 to $79,999	2.8	2.5%	13.5%	2.55	-$40.05	-$106.74	-$44.98	-$231.85	-$37.04	**-$460.66**	$692.46	**$231.81**	0.33%	$1,589.07
$80,000 to $99,999	1.9	1.7%	9.1%	2.91	-$52.13	-$165.80	-$55.20	-$309.18	-$61.74	**-$644.05**	$790.56	**$146.51**	0.16%	$726.05
$100,000 to $119,999	1.5	1.3%	7.2%	3.12	-$60.03	-$234.65	-$54.67	-$352.43	-$69.39	**-$771.17**	$847.23	**$76.05**	0.07%	$23.26
$120,000 or More	2.8	2.5%	13.5%	3.19	-$86.90	-$283.10	-$122.62	-$453.74	-$331.80	**-$1,278.16**	$867.18	**-$410.98**	-0.34%	-$4,401.04
Midwest	25.9	22.8%	100.0%	2.49	-$90.13	-$190.47	-$19.52	-$176.98	-$30.67	**-$507.77**	$677.00	**$169.23**	0.28%	$926.75
Less than $20,000	5.5	4.8%	21.2%	1.96	-$60.31	-$152.02	-$9.12	-$38.47	-$4.91	**-$264.83**	$531.51	**$266.68**	2.67%	$1,934.65
$20,000 to $39,999	6.5	5.7%	25.1%	2.31	-$65.92	-$149.51	-$24.11	-$120.98	-$6.79	**-$367.30**	$627.96	**$260.66**	0.87%	$1,852.31
$40,000 to $59,000	5.0	4.4%	19.3%	2.55	-$88.92	-$199.26	-$10.02	-$192.09	-$14.48	**-$504.77**	$692.64	**$187.87**	0.38%	$1,101.44
$60,000 to $79,999	3.4	3.0%	13.1%	2.78	-$101.11	-$204.62	-$18.92	-$245.59	-$22.63	**-$592.87**	$754.53	**$161.65**	0.23%	$801.93
$80,000 to $99,999	2.0	1.8%	7.7%	3.02	-$137.43	-$214.04	-$28.29	-$303.94	-$43.39	**-$727.09**	$819.39	**$92.30**	0.10%	-$24.00
$100,000 to $119,999	1.3	1.1%	5.0%	3.06	-$130.22	-$305.87	-$10.20	-$492.58	-$132.10	**-$1,070.97**	$832.00	**-$238.97**	-0.22%	-$2,761.08
$120,000 or More	2.1	1.8%	8.1%	2.98	-$216.00	-$343.97	-$64.50	-$443.54	-$373.94	**-$1,441.95**	$810.39	**-$631.56**	-0.53%	-$6,687.25
South	25.9	22.8%	100.0%	2.49	-$124.96	-$63.53	-$11.52	-$198.46	-$23.17	**-$421.64**	$693.86	**$272.21**	0.48%	$1,379.08
Less than $20,000	10.0	8.8%	38.6%	2.18	-$74.62	-$35.05	-$4.40	-$48.43	-$3.17	**-$165.66**	$592.15	**$426.49**	4.26%	$3,117.05
$20,000 to $39,999	10.7	9.4%	41.3%	2.35	-$95.64	-$37.13	-$7.60	-$133.38	-$3.55	**-$277.30**	$639.44	**$362.13**	1.21%	$2,394.61
$40,000 to $59,000	8.1	7.1%	31.3%	2.74	-$138.05	-$52.93	-$14.16	-$242.08	-$14.20	**-$461.43**	$744.42	**$282.99**	0.57%	$1,372.49
$60,000 to $79,999	4.6	4.0%	17.8%	2.69	-$148.92	-$66.02	-$14.26	-$284.47	-$14.88	**-$528.55**	$729.81	**$201.26**	0.29%	$575.42
$80,000 to $99,999	3.2	2.8%	12.4%	3.01	-$173.10	-$126.65	-$3.40	-$375.99	-$55.53	**-$734.67**	$818.44	**$83.77**	0.09%	-$633.67
$100,000 to $119,999	1.6	1.4%	6.2%	2.89	-$203.46	-$126.65	-$7.09	-$420.72	-$83.29	**-$841.20**	$785.62	**-$55.58**	-0.05%	-$2,080.62
$120,000 or More	3.9	3.4%	15.1%	2.99	-$263.91	-$243.35	-$14.30	-$534.84	-$306.48	**-$1,362.88**	$812.99	**-$549.90**	-0.46%	-$6,857.22
West	24.8	21.8%	100.0%	2.72	-$79.28	-$101.38	-$7.45	-$173.23	-$48.56	**-$409.88**	$738.31	**$328.43**	0.51%	$2,697.54
Less than $20,000	4.3	3.8%	17.3%	2.25	-$41.57	-$45.48	-$7.77	-$44.80	-$5.90	**-$145.52**	$611.16	**$465.65**	4.66%	$3,943.95
$20,000 to $39,999	6.0	5.3%	24.2%	2.67	-$53.90	-$71.00	-$6.09	-$107.86	-$12.16	**-$251.00**	$725.60	**$474.60**	1.58%	$4,012.70
$40,000 to $59,000	4.6	4.0%	18.5%	2.82	-$65.89	-$81.68	-$4.28	-$171.77	-$26.59	**-$350.22**	$767.12	**$416.89**	0.83%	$3,506.60
$60,000 to $79,999	3.3	2.9%	13.3%	2.74	-$90.31	-$111.86	-$6.57	-$258.51	-$26.75	**-$493.99**	$745.68	**$251.68**	0.36%	$2,033.69
$80,000 to $99,999	2.2	1.9%	8.9%	2.89	-$96.94	-$136.08	-$6.57	-$302.71	-$95.17	**-$637.47**	$784.24	**$146.77**	0.16%	$1,125.63
$100,000 to $119,999	1.4	1.2%	5.6%	2.96	-$117.80	-$189.01	$0.00	-$295.35	-$79.93	**-$682.09**	$803.37	**$121.28**	0.11%	$833.77
$120,000 or More	3.2	2.8%	12.9%	3.04	-$183.96	-$232.18	-$6.42	-$373.98	-$427.50	**-$1,224.04**	$826.21	**-$397.83**	-0.33%	-$3,803.56

Notes: [1]First year after tax values in 2011 chained USD (unless otherwise noted)
[2]Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

Table C.40 First year net benefits for income brackets ($35/tCO$_2$ at 6% with 50% rebate)

Costs and Benefits to the average household[1]
($35/tCO$_2$ at 6% with 50% rebate)

Market Segment	Households				First Year Costs (2014)						First Year Rebate			
	million	% of total	% of Region	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	% of Income[2]	NPV Net Benefit[3]
Average Household														
Average U.S.	113.6	100.0%		2.57	-$89.23	-$116.28	-$19.06	-$181.94	-$35.36	**-$441.88**	$698.00	**$256.12**	0.42%	$1,507.80
Less than $20,000	23.7	20.9%		2.10	-$53.94	-$71.86	-$10.70	-$39.96	-$4.47	**-$180.93**	$569.26	**$388.34**	3.88%	$3,071.32
$20,000 to $39,999	27.5	24.2%		2.42	-$65.99	-$86.45	-$13.06	-$115.55	-$7.70	**-$288.75**	$656.21	**$367.46**	1.22%	$2,759.66
$40,000 to $59,000	21.2	18.7%		2.66	-$88.74	-$104.10	-$15.38	-$201.27	-$18.90	**-$428.39**	$722.77	**$294.38**	0.59%	$1,871.10
$60,000 to $79,999	14.2	12.5%		2.69	-$97.04	-$115.66	-$23.58	-$260.30	-$22.79	**-$519.37**	$730.92	**$211.55**	0.30%	$1,021.35
$80,000 to $99,999	9.3	8.2%		2.96	-$120.55	-$156.07	-$22.56	-$329.96	-$62.85	**-$691.99**	$803.91	**$111.92**	0.12%	-$127.77
$100,000 to $119,999	5.7	5.0%		3.00	-$135.63	-$231.35	-$28.07	-$393.95	-$86.26	**-$875.25**	$815.48	**-$59.77**	-0.05%	-$1,883.31
$120,000 or More	12.0	10.6%		3.05	-$195.01	-$268.74	-$58.13	-$452.11	-$366.67	**-$1,340.67**	$827.73	**-$512.94**	-0.43%	-$6,635.67
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-$37.97	-$151.81	-$47.36	-$167.09	-$49.19	**-$453.42**	$688.46	**$235.04**	0.34%	$1,535.28
Less than $20,000	4.0	3.5%	19.2%	1.92	-$18.10	-$96.16	-$29.96	-$19.64	-$6.58	**-$170.43**	$520.04	**$349.60**	3.50%	$2,907.17
$20,000 to $39,999	4.3	3.8%	20.7%	2.38	-$26.84	-$153.27	-$29.33	-$81.19	-$14.46	**-$305.08**	$646.32	**$341.24**	1.14%	$2,676.34
$40,000 to $59,000	3.5	3.1%	16.8%	2.44	-$32.66	-$136.38	-$37.79	-$165.20	-$28.98	**-$401.00**	$662.67	**$261.66**	0.52%	$1,865.98
$60,000 to $79,999	2.8	2.5%	13.5%	2.55	-$39.65	-$106.11	-$45.36	-$231.08	-$36.92	**-$459.12**	$691.75	**$232.63**	0.33%	$1,504.22
$80,000 to $99,999	1.9	1.7%	9.1%	2.91	-$51.62	-$164.81	-$55.66	-$308.15	-$61.55	**-$641.79**	$789.74	**$147.95**	0.16%	$524.04
$100,000 to $119,999	1.5	1.3%	7.2%	3.12	-$59.45	-$233.25	-$55.13	-$351.26	-$69.17	**-$768.25**	$846.34	**$78.09**	0.07%	-$264.04
$120,000 or More	2.8	2.5%	13.5%	3.19	-$86.05	-$281.42	-$123.63	-$452.23	-$330.75	**-$1,274.09**	$866.28	**-$407.81**	-0.34%	-$5,123.99
Midwest	25.9	22.8%	100.0%	2.49	-$89.21	-$190.13	-$19.62	-$176.06	-$30.57	**-$505.59**	$676.29	**$170.70**	0.29%	$632.41
Less than $20,000	5.5	4.8%	21.2%	1.96	-$59.70	-$151.75	-$9.16	-$38.27	-$4.89	**-$263.77**	$530.95	**$267.18**	2.67%	$1,840.66
$20,000 to $39,999	6.5	5.7%	25.1%	2.31	-$65.25	-$149.24	-$24.23	-$120.35	-$6.77	**-$365.83**	$627.31	**$261.48**	0.87%	$1,706.64
$40,000 to $59,000	5.0	4.4%	19.3%	2.55	-$88.01	-$198.91	-$10.07	-$191.09	-$14.43	**-$502.51**	$691.92	**$189.41**	0.38%	$819.81
$60,000 to $79,999	3.4	3.0%	13.1%	2.78	-$100.08	-$204.25	-$19.02	-$244.31	-$22.56	**-$590.22**	$753.74	**$163.52**	0.23%	$448.76
$80,000 to $99,999	2.0	1.8%	7.7%	3.02	-$136.03	-$213.66	-$28.44	-$302.35	-$43.25	**-$723.73**	$818.53	**$94.80**	0.11%	-$541.45
$100,000 to $119,999	1.3	1.1%	5.0%	3.06	-$128.90	-$305.32	-$10.25	-$490.01	-$131.68	**-$1,066.16**	$831.13	**-$235.02**	-0.21%	-$3,541.58
$120,000 or More	2.1	1.8%	8.1%	2.98	-$213.80	-$343.36	-$64.84	-$441.22	-$372.76	**-$1,435.98**	$809.55	**-$626.43**	-0.52%	-$7,980.16
South	25.9	22.8%	100.0%	2.49	-$125.10	-$63.83	-$11.60	-$197.74	-$23.10	**-$421.36**	$693.14	**$271.78**	0.48%	$1,207.98
Less than $20,000	10.0	8.8%	38.6%	2.18	-$74.71	-$35.21	-$4.43	-$48.25	-$3.16	**-$165.75**	$591.53	**$425.78**	4.26%	$3,183.36
$20,000 to $39,999	10.7	9.4%	41.3%	2.35	-$95.75	-$37.31	-$7.65	-$132.89	-$3.54	**-$277.14**	$638.77	**$361.63**	1.21%	$2,359.03
$40,000 to $59,000	8.1	7.1%	31.3%	2.74	-$138.21	-$53.18	-$14.25	-$241.20	-$14.16	**-$461.00**	$743.64	**$282.64**	0.57%	$1,175.30
$60,000 to $79,999	4.6	4.0%	17.8%	2.69	-$149.09	-$66.33	-$14.35	-$283.43	-$14.84	**-$528.04**	$729.06	**$201.01**	0.29%	$297.18
$80,000 to $99,999	3.2	2.8%	12.4%	3.01	-$173.30	-$127.24	-$3.42	-$374.63	-$55.35	**-$733.94**	$817.59	**$83.65**	0.09%	-$1,080.84
$100,000 to $119,999	1.6	1.4%	6.2%	2.89	-$203.69	-$127.24	-$7.14	-$419.19	-$83.02	**-$840.28**	$784.80	**-$55.48**	-0.05%	-$2,672.89
$120,000 or More	3.9	3.4%	15.1%	2.99	-$264.21	-$244.49	-$14.39	-$532.90	-$305.51	**-$1,361.50**	$812.14	**-$549.36**	-0.46%	-$7,963.22
West	24.8	21.8%	100.0%	2.72	-$81.89	-$100.75	-$7.45	-$173.24	-$48.40	**-$411.74**	$737.54	**$325.81**	0.50%	$2,779.96
Less than $20,000	4.3	3.8%	17.3%	2.25	-$42.94	-$45.20	-$7.77	-$44.80	-$5.88	**-$146.60**	$610.53	**$463.93**	4.64%	$4,145.59
$20,000 to $39,999	6.0	5.3%	24.2%	2.67	-$55.68	-$70.56	-$6.09	-$107.86	-$12.13	**-$252.32**	$724.85	**$472.53**	1.58%	$4,202.20
$40,000 to $59,000	4.6	4.0%	18.5%	2.82	-$68.07	-$81.18	-$4.28	-$171.78	-$26.51	**-$351.82**	$766.32	**$414.50**	0.83%	$3,652.00
$60,000 to $79,999	3.3	2.9%	13.3%	2.74	-$93.29	-$111.16	-$6.58	-$258.53	-$26.67	**-$496.22**	$744.90	**$248.68**	0.36%	$2,073.45
$80,000 to $99,999	2.2	1.9%	8.9%	2.89	-$100.14	-$135.23	-$6.58	-$302.74	-$94.87	**-$639.55**	$783.42	**$143.87**	0.16%	$1,077.65
$100,000 to $119,999	1.4	1.2%	5.6%	2.96	-$121.69	-$187.84	$0.00	-$295.37	-$79.68	**-$684.57**	$802.54	**$117.97**	0.11%	$758.50
$120,000 or More	3.2	2.8%	12.9%	3.04	-$190.03	-$230.74	-$6.42	-$374.01	-$426.15	**-$1,227.36**	$825.35	**-$402.01**	-0.34%	-$4,297.69

Notes: [1]First year after tax values in 2011 chained USD (unless otherwise noted)
[2]Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
[3]NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%

Table C.41 First year net benefits for income brackets ($35/tCO$_2$ at 8% with 50% rebate)

Costs and Benefits to the average household¹
($35/tCO$_2$ at 8% with 50% rebate)

Market Segment	Households				First Year Costs (2014)						First Year Rebate			
	million	% of total	% of Region	pph	Electricity	Natural Gas	Other Fuels	Gasoline	Other Trans.	**Total Costs**	50% Rebate	**Net benefit**	% of Income²	NPV Net Benefit³
Average Household														
Average U.S.	113.6	100.0%		2.57	-$90.60	-$115.07	-$18.98	-$182.24	-$35.42	**-$442.31**	$695.76	**$253.45**	0.41%	$1,190.75
Less than $20,000	23.7	20.9%		2.10	-$54.77	-$71.11	-$10.65	-$40.02	-$4.48	**-$181.03**	$567.44	**$386.40**	3.86%	$3,018.34
$20,000 to $39,999	27.5	24.2%		2.42	-$67.00	-$85.55	-$13.00	-$115.74	-$7.71	**-$289.01**	$654.11	**$365.10**	1.22%	$2,619.59
$40,000 to $59,000	21.2	18.7%		2.66	-$90.10	-$103.02	-$15.32	-$201.60	-$18.93	**-$428.97**	$720.45	**$291.49**	0.58%	$1,578.96
$60,000 to $79,999	14.2	12.5%		2.69	-$98.53	-$114.46	-$23.48	-$260.73	-$22.82	**-$520.01**	$728.57	**$208.56**	0.30%	$632.29
$80,000 to $99,999	9.3	8.2%		2.96	-$122.40	-$154.45	-$22.46	-$330.50	-$62.95	**-$692.76**	$801.33	**$108.57**	0.12%	-$698.97
$100,000 to $119,999	5.7	5.0%		3.00	-$137.71	-$228.95	-$27.94	-$394.60	-$86.40	**-$875.60**	$812.87	**-$62.73**	-0.06%	-$2,654.00
$120,000 or More	12.0	10.6%		3.05	-$198.00	-$265.95	-$57.87	-$452.86	-$367.27	**-$1,341.95**	$825.08	**-$516.88**	-0.43%	-$7,958.53
By Region														
Northeast	20.8	18.3%	100.0%	2.54	-$41.42	-$149.78	-$47.22	-$167.42	-$49.27	**-$455.11**	$686.25	**$231.14**	0.33%	$1,436.56
Less than $20,000	4.0	3.5%	19.2%	1.92	-$19.74	-$94.88	-$29.87	-$19.67	-$6.59	**-$170.76**	$518.37	**$347.61**	3.48%	$2,982.48
$20,000 to $39,999	4.3	3.8%	20.7%	2.38	-$29.28	-$151.22	-$29.24	-$81.35	-$14.48	**-$305.57**	$644.25	**$338.68**	1.13%	$2,688.91
$40,000 to $59,000	3.5	3.1%	16.8%	2.44	-$35.63	-$134.55	-$37.68	-$165.52	-$29.03	**-$402.41**	$660.54	**$258.13**	0.52%	$1,803.15
$60,000 to $79,999	2.8	2.5%	13.5%	2.55	-$43.27	-$104.69	-$45.22	-$231.53	-$36.98	**-$461.68**	$689.53	**$227.84**	0.33%	$1,401.70
$80,000 to $99,999	1.9	1.7%	9.1%	2.91	-$56.32	-$162.61	-$55.49	-$308.75	-$61.65	**-$644.82**	$787.21	**$142.39**	0.16%	$304.73
$100,000 to $119,999	1.5	1.3%	7.2%	3.12	-$64.86	-$230.13	-$54.96	-$351.94	-$69.29	**-$771.18**	$843.63	**$72.45**	0.07%	-$569.68
$120,000 or More	2.8	2.5%	13.5%	3.19	-$93.89	-$277.65	-$123.27	-$453.11	-$331.29	**-$1,279.21**	$863.50	**-$415.71**	-0.35%	-$5,855.88
Midwest	25.9	22.8%	100.0%	2.49	-$89.21	-$188.43	-$19.51	-$176.00	-$30.62	**-$503.77**	$674.12	**$170.36**	0.29%	-$310.52
Less than $20,000	5.5	4.8%	21.2%	1.96	-$59.70	-$150.39	-$9.11	-$38.26	-$4.90	**-$262.36**	$529.25	**$266.89**	2.67%	$1,304.97
$20,000 to $39,999	6.5	5.7%	25.1%	2.31	-$65.25	-$147.90	-$24.10	-$120.31	-$6.78	**-$364.33**	$625.30	**$260.96**	0.87%	$1,077.38
$40,000 to $59,000	5.0	4.4%	19.3%	2.55	-$88.01	-$197.13	-$10.02	-$191.03	-$14.45	**-$500.63**	$689.70	**$189.07**	0.38%	-$104.98
$60,000 to $79,999	3.4	3.0%	13.1%	2.78	-$100.08	-$202.43	-$18.91	-$244.23	-$22.59	**-$588.24**	$751.32	**$163.08**	0.23%	-$630.47
$80,000 to $99,999	2.0	1.8%	7.7%	3.02	-$136.02	-$211.75	-$28.28	-$302.25	-$43.32	**-$721.63**	$815.91	**$94.28**	0.10%	-$2,022.48
$100,000 to $119,999	1.3	1.1%	5.0%	3.06	-$128.89	-$302.60	-$10.19	-$489.85	-$131.90	**-$1,063.42**	$828.47	**-$234.95**	-0.21%	-$5,260.31
$120,000 or More	2.1	1.8%	8.1%	2.98	-$213.79	-$340.29	-$64.48	-$441.08	-$373.37	**-$1,433.00**	$806.95	**-$626.05**	-0.52%	-$10,766.74
South	25.9	22.8%	100.0%	2.49	-$126.04	-$63.20	-$11.52	-$198.09	-$23.14	**-$421.99**	$690.91	**$268.93**	0.47%	$1,038.13
Less than $20,000	10.0	8.8%	38.6%	2.18	-$75.27	-$34.87	-$4.40	-$48.34	-$3.16	**-$166.03**	$589.64	**$423.60**	4.24%	$3,235.20
$20,000 to $39,999	10.7	9.4%	41.3%	2.35	-$96.47	-$36.94	-$7.60	-$133.12	-$3.55	**-$277.68**	$636.72	**$359.04**	1.20%	$2,316.92
$40,000 to $59,000	8.1	7.1%	31.3%	2.74	-$139.25	-$52.65	-$14.16	-$241.63	-$14.18	**-$461.87**	$741.26	**$279.38**	0.56%	$982.76
$60,000 to $79,999	4.6	4.0%	17.8%	2.69	-$150.21	-$65.67	-$14.26	-$283.93	-$14.86	**-$528.94**	$726.72	**$197.78**	0.28%	$29.89
$80,000 to $99,999	3.2	2.8%	12.4%	3.01	-$174.60	-$125.98	-$3.40	-$375.29	-$55.44	**-$734.72**	$814.96	**$80.25**	0.09%	-$1,512.53
$100,000 to $119,999	1.6	1.4%	6.2%	2.89	-$205.22	-$125.98	-$7.09	-$419.93	-$83.16	**-$841.38**	$782.28	**-$59.10**	-0.05%	-$3,237.62
$120,000 or More	3.9	3.4%	15.1%	2.99	-$266.20	-$242.08	-$14.30	-$533.83	-$306.01	**-$1,362.43**	$809.54	**-$552.89**	-0.46%	-$9,027.08
West	24.8	21.8%	100.0%	2.72	-$83.83	-$99.73	-$7.41	-$173.78	-$48.48	**-$413.23**	$735.18	**$321.95**	0.50%	$2,719.77
Less than $20,000	4.3	3.8%	17.3%	2.25	-$43.95	-$44.74	-$7.73	-$44.94	-$5.89	**-$147.26**	$608.57	**$461.31**	4.61%	$4,274.28
$20,000 to $39,999	6.0	5.3%	24.2%	2.67	-$56.99	-$69.85	-$6.06	-$108.20	-$12.15	**-$253.24**	$722.52	**$469.28**	1.56%	$4,283.66
$40,000 to $59,000	4.6	4.0%	18.5%	2.82	-$69.68	-$80.36	-$4.26	-$172.31	-$26.55	**-$353.17**	$763.86	**$410.70**	0.82%	$3,662.63
$60,000 to $79,999	3.3	2.9%	13.3%	2.74	-$95.49	-$110.04	-$6.54	-$259.33	-$26.71	**-$498.11**	$742.51	**$244.40**	0.35%	$1,941.29
$80,000 to $99,999	2.2	1.9%	8.9%	2.89	-$102.51	-$133.87	-$6.54	-$303.67	-$95.03	**-$641.61**	$780.91	**$139.30**	0.15%	$832.57
$100,000 to $119,999	1.4	1.2%	5.6%	2.96	-$124.56	-$185.95	$0.00	-$296.28	-$79.81	**-$686.60**	$799.96	**$113.36**	0.10%	$467.55
$120,000 or More	3.2	2.8%	12.9%	3.04	-$194.53	-$228.42	-$6.39	-$375.17	-$426.85	**-$1,231.35**	$822.70	**-$408.64**	-0.34%	-$5,068.09

Notes: ¹First year after tax values in 2011 chained USD (unless otherwise noted)
²Based on average income in each category, except for the highest bracket where the minimum income is used. Average incomes from CEX
³NPV for first 10 years of policy (2014-2023) using discount rate of 4.0%