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Compensation for Electricity Consumers under a U.S. CO_2 Emissions Cap

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RESOURCES FOR THE FUTURE

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Abstract

Policies to cap emissions of carbon dioxide (CO_2) in the U.S. economy could pose significant costs on the electricity sector, which contributes roughly 40 percent of total CO_2 emissions in the U.S. Using a detailed simulation model of the electricity sector, we evaluate alternative ways that emission allowances can be allocated. Most previous emissions trading programs have allocated the major portion of allowances for free to incumbent firms. In the electricity sector this approach would lead to changes in electricity price that vary by region primarily based primarily on whether prices are market-based or determined by cost-of-service regulation. Allocation to customers, which could be achieved by allocation to local distribution companies (retail utilities) would recover symmetry in the effect of free allocation and lead to signficiantly lower overall electricity prices. However, this form of compensation comes with an efficiency cost that will increase the overall cost of climate policy.

Key Words: emissions trading, allowance allocations, electricity, air pollution, auction, grandfathering, cost-effectiveness, greenhouse gases, climate change, global warming, carbon dioxide, asset value, compensation

JEL Classification Numbers: Q2, Q25, Q4, L94

Contents

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1 Introduction

A crucial decision in the design of a cap-and-trade program for CO_2 is the initial distribution, or allocation, of emission allowances. The creation of a market for CO_2 emissions would involve the largest distribution and enforcement of new property rights in North America in over a century, and the decision about allocation has efficiency and distributional consequences. The economics literature finds significant efficiency advantages to the use of an auction rather than free distribution of emission allowances. One reason is that an auction is administratively simple and precludes regulated parties from seeking a more generous future allocation. Another is that free allocation in competitive markets, like some markets for electricity in the United States, can move consumer prices away from the marginal cost of production and therefore distort resource allocation in the wider economy away from the efficient optimum. Compared with other approaches, an auction helps maintain transparency and the perception of fairness, and it leads to more efficient pricing of goods in the economy, which reduces the cost of the policy. These are important principles for the formation of a new market for an environmental commodity.

Most previous programs have relied on free distribution rather than an auction. Generally speaking, free allocation of allowances gives interested parties strong incentives to argue for an ever-increasing share of emissions allowances. In contrast, many authors suggest that auctions reduce rent-seeking, which occurs when regulated parties invest resources in trying to affect the outcome of an administrative process that distributes allowances freely. One particularly insidious aspect of free allocation is the adjustment to allocation rules for new emissions sources and for old sources that retire. The sulfur dioxide (SO_2) trading program in the United States has no adjustments for these sources, which is a virtue because it does not create incentives for investment

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behavior to deviate from what is otherwise efficient. However, most other trading programs have such adjustments. In the NO_x budget program in the United States, for example, individual states determine the allocation of allowances; most have set-asides for new sources, and sources that retire lose their allocations. Adjustments also are ubiquitous in the EU Emission Trading Scheme. The problem with such adjustments is that they alter the incentives for investment and retirement in a way that can lead to unintended consequences. For instance, there is evidence that as a result of adjustments to allocation rules for new sources in the EU, the value of emissions allowances can bias investment toward higher-emitting generating sources. This bias can result from the value of the subsidy embodied in free allowance allocations. Furthermore, the removal of allocations from sources that retire provides a financial incentive to continue the operation of existing facilities that are often inefficient and that otherwise would retire, except for the value of the allowances that they earn by remaining in operation. The use of an auction avoids this predicament entirely.[1]

The second, and equally forceful, reason that economists favor the use of auctions is that they generate funds that can be used to help reduce the cost of policy. For the purposes of minimizing the cost of climate policy on the economy and promoting economic growth, the economics literature has focused on dedicating the use of revenue from an auction to reduce preexisting taxes. Like any new regulation, climate policy imposes a cost on households and firms; that cost acts like a virtual tax, reducing the real wages of workers. This hidden cost can be especially large under a cap-and-trade program because the price placed on the scarcity value of carbon is reflected in the cost of goods that use carbon in their production, which are ubiquitous in the economy. However, the revenue raised through an auction (or an emissions tax), if dedicated to reducing other preexisting taxes, can reduce this cost. This so-called revenue recycling would have substantial efficiency advantages compared with free distribution.[2]

A compelling justification *for* free distribution of emission allowances is that public policy should do "no direct harm" through changes in government rules and regulations.[3] This justification has been invoked to argue for free allocation to firms, in order to soften the impact of the policy. However, consumers rather than firms or their

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[1] Åhman et al. 2007; Åhman and Holmgren 2006.

[2] Bovenberg and Goulder, 1996; Bovenberg and de Mooij, 1994; Golder et al. 1999; Parry et al. 1999. Smith et al. 2002.

[3] Schultze, 1977.

shareholders may be the most adversely affected by climate policy. Consequently, compensation for consumers has become a central element of the political dialogue about climate policy in the United States, which is made even more salient by recently increasing fuel prices. This paper looks at the effect on consumers from climate policy and approaches to compensating consumers.

We focus exclusively on the electricity sector. Although the electricity sector is responsible for about 40 percent of CO_2 emissions in the United States, most models indicate that under a cost-effective program, two-thirds to three-quarters of emission reductions in the first couple decades of climate policy are likely to come from this sector. Consequently the electricity sector is a very special case; it constitutes the heart of any proposal to implement market-based approaches to achieving CO_2 emission reductions. All of the important existing trading programs include the electricity sector, and usually they exclude other sources. In the United States, the sulfur dioxide (SO_2) trading program, which began in 1995, and the nitrogen oxide (NOx) trading program, which began in 1999, each has a pool of emission allowances with annual value of $1–3 billion and focus on the electricity sector almost exclusively. The EU Emission Trading Scheme (ETS), which began in 2005, includes major point sources, of which the electricity sector constitutes the most significant portion. In addition, the ten-state Regional Greenhouse Gas Initiative (RGGI), which will be the second mandatory cap and trade program in the world for CO_2 beginning in 2009, covers just the electricity sector.

Previous analysis of the electricity sector relying on detailed simulation modeling indicates that on an industry-wide basis only 6 percent of the allowance value created within the electricity sector (2.5 percent overall) is sufficient to hold the industry harmless because the majority of costs are recovered by changes in product prices.[4] General equilibrium models with less information about the structure of costs and production within the sector have found results that are broadly comparable. One study found that most of the economic effect of climate policy would be felt in the oil, gas, and coal industries, which could be compensated with just 19 percent of allowance value.[5] That paper found that the most important downstream industry to be compensated is the electricity sector, but that it would be much less affected than the primary fuel sectors.

[4] Burtraw and Palmer, 2008.

[5] Bovenberg and Goulder (2001) considered the effect of a constant $25 allowance value sufficient to achieve emissions reductions of 18 percent in the long run.

Another study estimated that the reduction in equity value in the electricity sector would be equivalent to 6 percent of the total allowance value.[6]

Although harm to producers may be concentrated and visible to the politicians, consumers in the electricity sector would incur a loss approximately eight times as great as that of producers (Burtraw and Palmer 2008, U.S. EIA 2005). Consequently, the political economy of climate policy in the United States invites some form of compensation for consumers, at least as a transition to full implementation of CO_2 allowance auctions.

The obvious way in which compensation for electricity consumers can be achieved is through free allocation of emission allowances. Emissions allowances represent enormous economic value—tens of billions of dollars annually under a federal carbon policy—that arises due to the value placed on emissions within a cap-and-trade system. Paltsev et al. (2007) put the possible annual auction revenue at $130–$370 billion by 2015, an amount equivalent to $1,600 to $4,900 per family of four. The initial distribution of just a portion of the valuable emissions allowances represents a significant potential source of compensation. The enormous value of the allowances makes this high-stakes issue perhaps the greatest political challenge in designing climate policy.

This paper highlights the important role that market organization and regulatory institutions in the electricity sector play in affecting the efficacy of climate policy. Specifically, the regulatory setting plays a crucial role in determining whether free allocation will effectively deliver compensation to its intended recipients. The U.S. electricity sector is split so that about one-third of the electricity consumed from the power grid is sold at market-based competitive prices and the other two-thirds are sold under cost of service regulation.[7]

As mentioned above, one virtue of an auction is the possibility to direct revenues to purposes that reduce overall cost. Another virtue applies specifically to the electricity sector. In regulated regions, compared with free allocation, an auction approach tends to reduce the difference between price and marginal production cost for electricity generation—a source of inefficiency that is endemic to the electricity industry.[8] Within a

[6] Smith et al. (2002) estimated the effects of a 14 percent decrease in emissions to be achieved by 2010, and a 32 percent decrease by 2030.

[7] As of April 2007, the following jurisdictions had deregulated electricity markets: ME, NH, MA, CT, RI, NY, NJ,PA, DE, MD, DC, OH, MI, IL, and TX (EIA 2007c). In 2006 these states and the District of Columbia consumed 36 percent of all retailed electricity in the lower 48 states (EIA 2007b).

[8] Beamon et al. 2001. Burtraw et al. 2001. Burtraw et al. 2002. Parry 2005.

partial equilibrium model, the efficiency gains from using an auction in regulated settings can be at least as great as the gains from revenue recycling in a general equilibrium context.[9]

This paper incorporates the mechanisms of electricity price formation under competitive and regulated electricity markets in a detailed simulation model to investigate the magnitude of the effects that can be anticipated from alternative methods of allowance allocation within the electricity sector. We examine the effects on consumers under an auction of allowances, and under grandfathering – free distribution to incumbent electricity-generating firms. We contrast these approaches with three allocation schemes that are primarily aimed at compensating consumers. These all involve allocation to local distribution companies, the retail companies that deliver electricity to customers. The prices that these entities charge for electricity distribution are regulated throughout the United States and local distribution companies have been identified in legislative proposals as potential trustees to act on behalf of customers with respect to the allocation of emissions allowances. Various proposals have suggested allocation to local distribution companies be done on the basis of population, emissions or consumption.

Free allocation of emissions allowances to consumers or generators diverts revenues that otherwise could be dedicated to general tax relief, which offers efficiency gains and forms broad-based compensation for the diffuse effects of the policy on households. Free allocation also diverts revenues from other purposes, such as research initiatives or energy efficiency programs linked to climate policy. In the electricity sector free allocation also moves electricity price in regulated regions further away from marginal cost. Policymakers need to be cognizant of likely impacts on all affected parties, and they may want to limit and narrowly target free distribution of emissions allowances to better address a broader set of efficiency and compensation goals.

2 Analysis of the Electricity Sector

The electricity sector deserves special attention not only because of the emission intensity of its product, but also because of the long-lived nature of capital and the idiosyncratic way in which electricity markets are organized. Regulation of generation and retail services are generally left to states. However, because electrons flow freely

[9] Burtraw et al. 2001; Parry 2005.

over the wires and across state lines, the transmission grid is regulated by the federal government. The way that most states choose to regulate generation and retail services typically differs, and the choices vary across the states.

2.1 Institutions

Economists tend to think most markets are fundamentally competitive, at least in the long run. As a general principle, in competitive markets free allocation to firms will not benefit consumers because the economic value of a commodity in a competitive market is determined by its scarcity. Emissions allowances are a valuable asset, and as long as there is a liquid allowance market, a firm can sell allowances at the market price instead of using them for its own compliance responsibilities. The firm will recognize the lost opportunity for revenue from the sale of an allowance each time it uses the allowance itself for compliance. So in most markets economists would not expect to see consumers receive the benefit from free allocation to firms. Instead the value of emission allowances would be captured by shareholders who, in turn, would recognize their opportunity cost in production decisions.

The fact that a firm in a competitive market will charge its customers for the use of an asset that the firm has received for free is often a difficult idea for people to grasp, but it is wholly consistent with economic theory and it is in general what is observed in empirical studies. Indeed, sometimes economists seek evidence of noncompetitive behavior and "market power" by looking for instances when the price of a good differs from the cost of factor inputs used in its production. An emissions allowance in a cap-and-trade program is one such factor. If a firm did not pass through the cost of an allowance in the pricing of its product, it would be *prima facie* evidence of a noncompetitive market—and of possible market manipulation.

However, a substantial portion of the electricity sold in the United States is not traded in competitive markets, but instead sold in markets that are subject to cost-of-service regulation. In these cases regulators set prices to allow firms to recover their costs, which are usually calculated on an original-cost basis. If allowances are received for free by regulated electricity generators, then the addition to the cost basis for the purpose of cost recovery is zero. Roughly speaking, this situation applies to about two-thirds of the electricity customers in the country. In these areas the benefit of free allocation to emitters or producers can be expected to be passed on to consumers.

The contrast between regions with market-based electricity prices and regulated prices could yield asymmetric changes in retail electricity prices under free allocation to firms. These asymmetric effects on electricity consumers, in which free allocation to producers benefits consumers in regulated regions of the country, but not those in regions with market-based prices, introduce a challenging dilemma to climate policy.

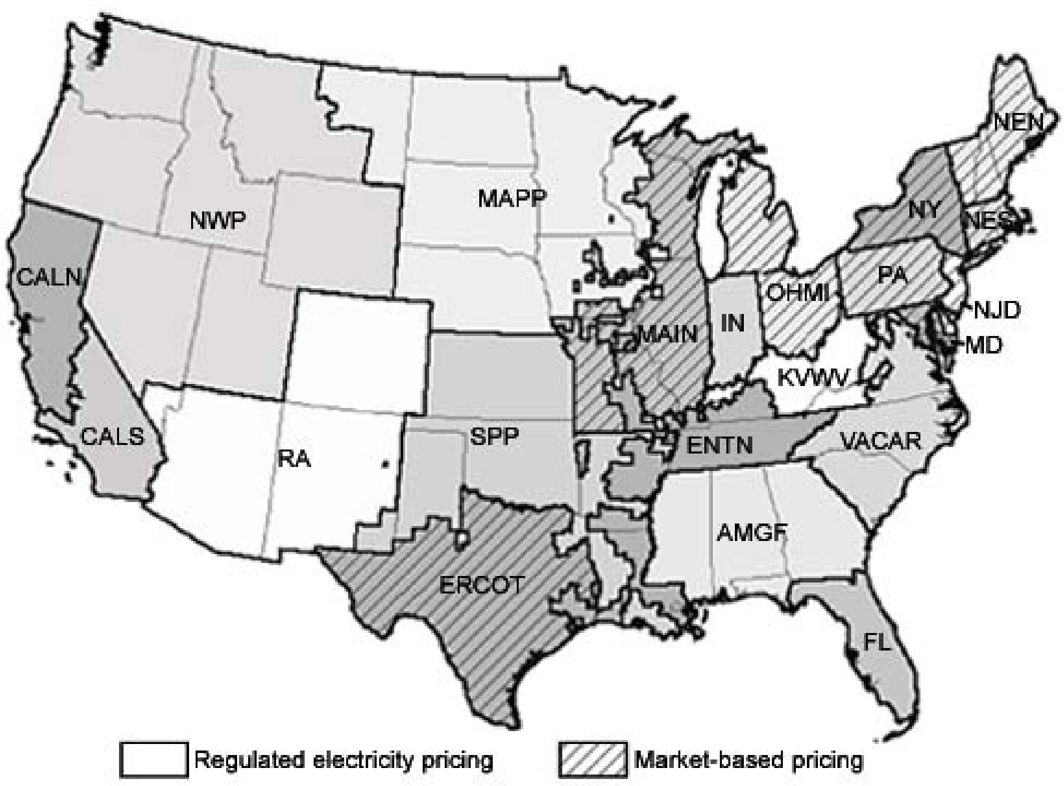
An alternative approach to compensation is allocation to local distribution companies (LDCs), the retail electricity companies that deliver electricity to customers and that could be directed to act as trustees on behalf of consumers. Although retail companies would see the cost of power in the wholesale power market increase under a cap-and-trade program, they would have substantial allowance value to rebate to consumers, and this would reduce the cost impact for their customers in competitive and regulated regions alike. Virtually the entire country is regulated in retail services, and some recent proposals, including the Lieberman–Warner climate proposal (SB 2191), would allocate some fraction of allowance value to LDCs for compensation to electricity consumers through rate reductions. This approach is expected to have the advantage of maintaining symmetry on a regional basis in the electricity sector.

2.2 Model

Several features of the market determine the relationship between CO_2 allowance price and the electricity price (Reinaud 2007). The most important are the fuel use, the portfolio of generation technologies, the nature of economic regulation and market structure, and the approach to allocation. To analyze these relationships we rely on a detailed simulation model of the electricity sector known as the Haiku Electricity Market Model, which is maintained by Resources for the Future. Haiku is a deterministic, highly parameterized model that calculates information similar to the National Energy Modeling System used by the Energy Information Administration, and the Integrated Planning Model developed by ICF Consulting and used by the U.S. Environmental Protection Agency (EPA). The Haiku model is distinguished from these models by its capacity to evaluate policy effects on consumer and producer surplus in the electricity sector and express these as a measure of economic welfare within the national and regional electricity markets.

The Haiku model simulates equilibrium in regional electricity markets and interregional electricity trade with an integrated algorithm for emission control technology choices for SO_2, NO_x, mercury and CO_2. The composition of electricity supply is calculated using a fully integrated algorithm for capacity planning and retirement coupled with system operation in temporally and geographically linked electricity markets. The model solves for electricity market equilibrium in 21 Haiku market regions (HMRs) within the continental United States. Each of the 21 HMRs is classified by its electricity pricing regime as having either competitive or regulated electricity pricing, as shown in Figure 2.2-1. Electricity markets are assumed to maintain their current regulatory status throughout the modeling horizon; that is, regions that have already moved to market-based pricing of generation continue that practice, and those that have not made that move remain regulated. The price of electricity to consumers does not vary by time of day in any region, though all customers in competitive regions face prices that vary from season to season.

Figure 2.2-1 Haiku Market Regions and Electricity Pricing



Each year is subdivided into three seasons (summer, winter, and spring-fall) and each season into four time blocks (superpeak, peak, shoulder, and base). For each time block, demand is modeled for three customer classes (residential, industrial, and commercial). Supply is represented using model plants that are aggregated according to their technology and fuel source from the complete set of commercial electricity generation plants in the country. Investment in new generation capacity and the retirement of existing facilities is determined endogenously in a dynamic framework, based on capacity-related costs of providing service in the future ("going forward costs"). Operation of the electricity system ("generator dispatch") in the model is based on the minimization of short-run variable costs of generation.

Equilibrium in interregional power trading is identified as the level of trading necessary to equilibrate regional marginal generation costs net of transmission costs and power losses. These interregional transactions are constrained by the level of the available interregional transmission capability as reported by the North American Electric Reliability Council (2003a, 2003b).[10] Factor prices, such as the cost of capital and labor, are held constant. Fuel prices are benchmarked to the forecasts of the Annual Energy Outlook 2007 for both level and elasticity (U.S. EIA 2007). Coal is differentiated along several dimensions, including fuel quality and content and location of supply; and both coal and natural gas prices are differentiated by point of delivery. The price of biomass fuel also varies by region depending on the mix of biomass types available and delivery costs. Other fuel prices are specified exogenously.

Emissions caps in the Haiku model, such as the Title IV cap on national SO_2 emissions, EPA's Clean Air Interstate Rule caps on emissions of SO_2 and NO_x, and the Regional Greenhouse Gas Initiative (RGGI) cap on CO_2 emissions, are imposed as constraints on the sum of emissions across all covered generation sources in the relevant region. Emissions of CO_2 from individual sources depend on emission rates, which vary by type of fuel and technology, and total fuel use at the facility. The sum of these emissions across all sources must be no greater than the total number of allowances available, including those issued for the current year and any unused allowances from previous years when banking is permitted. In this analysis, banking for CO_2 is not enabled. Rather, year-specific emission targets are taken from the Energy Information Administration analysis described below, to which the simulations are calibrated. This

[10] Some of the HMRs are not coterminous with North American Electric Reliability Council (NERC) regions and therefore NERC data cannot be used to parameterize transmission constraints. Haiku assumes no transmission constraints among OHMI, KVWV, and IN. NER and NEO are also assumed to trade power without constraints. The transmission constraints among the regions ENTN, VACAR, and AMGF, as well as those among MAACR, MD, and PA, are derived from version 2.1.9 of the Integrated Planning Model (EPA 2005). Additionally, starting in 2014, we include the incremental transfer capability associated with two new 500-KV transmission lines into and, in one case, through Maryland, which are modeled after a line proposed by Allegheny Electric Power and one proposed by PEPCO Holdings (CIER 2007). We also include the transmission capability between Long Island and PJM made possible by the Neptune line that began operation in 2007.

approach allows for a more transparent comparison of the effects of different approaches to allocation because the quantity of emissions in each year is held constant.

3 Scenarios

One way that electricity consumers can be compensated directly is for each citizen to receive allowance value directly. This approach has recently been described as “cap and dividend” because the allowance value would be refunded as a dividend on a per capita basis. This approach would be among the most progressive in its distributional consequences (Burtraw et al. 2008; Boyce and Riddle 2007). The Center on Budget and Policy Priorities (2007) identify another approach that would take advantage of information about household income to target the most disadvantaged households using just a portion of the allowance value.

Environmental advocates typically take a different view, however, aiming to direct auction revenue to complementary initiatives to reduce emissions. For example, the Model Rule for the 10 northeastern U.S. states in RGGI specifies that each state must allocate at least 25 percent of its budgeted allowances to a consumer benefit or strategic energy purpose. These “consumer benefit” allowances are to be sold or otherwise distributed to promote energy efficiency, to directly mitigate electricity ratepayer impacts, or to promote lower-carbon-emitting energy technologies. (Most of these ten states have indicated their intention to auction nearly 100 percent of their budgeted allowances.) Ruth et al. (2008) found the dedication of 25 percent of the allowance value to investments in end-use efficiency would offset any increase in retail electricity price from the policy. A similar plan to direct a portion of allowance value to strategic energy purposes is part of the European Commission’s proposal for moving to an auction in the EU ETS beginning in 2013. The merits of this strategy rest on the belief that there exist market barriers that prevent the realization of opportunities for improving efficiency in the end-use of energy or to bringing renewable energy sources to market. The merits rest as well on the ability to design institutions that can use allowance value effectively to overcome these barriers. Other claims for allowance value are based on the need to accelerate the adaptation to climate change. Atmospheric scientists tell us that we are already at the point where some climate warming is inevitable and that adaptation will be necessary. Adaptation will involve significant investment by the private and public sectors. An auction provides revenues that could be directed to this variety of purposes.

The scenarios we model are limited to the electricity sector, but they capture the heart of the debate regarding treatment of allocation for that sector in the United States.

The allowance distribution plan for Lieberman–Warner (S 2191) dedicates 22 percent of the allowances in the year 2012 to states in one fashion or another.[11] One major portion is directed to electricity local distribution companies (9 percent) and natural gas distribution companies (2 percent). These allocations are intended to address a variety of purposes including promotion of investment in end-use efficiency or direct rate relief for customers. Other proposals have been even more aggressive.[12] The Jeffords bill in 2002 would have allocated two-thirds of emissions allowances to the states for determination of ultimate allocation by trustees. It would be plausible for this decision to be left to the state public utility commissions, who would act as trustees on behalf of consumers.

3.1 Alternative Methods for an Initial Distribution of Emissions Allowances

The Lieberman–Warner proposal includes a cap-and-trade system for the entire economy with point of compliance at upstream fuel supply in almost every case. In general, the policy would require fuel suppliers to surrender allowances equal to the carbon content of the fuel and byproducts that they sell or consume in their refining and manufacturing processes. The exception is coal-fired power plants, which would have compliance responsibility at the point of consumption. For natural gas use in the downstream electricity sector the cost of the cap-and-trade system would be perceived as a change in the relative cost of fuel. Fuel with relatively high carbon content would be expected to have a higher price because of the opportunity cost of emissions allowances that fuel suppliers would have to surrender to bring that fuel to market. For coal-fired power plants the cost of power would depend on the method of allocation and the type of regulation in place.

In general, it is vital to recognize that the point of allocation of emissions allowances is distinct from the point of compliance. We evaluate several methods for the initial distribution of emissions allowances (Sterner and Muller 2007). One alternative is **upstream allocation**, with all emissions allowances distributed initially to fuel suppliers and with no allowances distributed to the electricity sector. Within the electricity sector, this approach is equivalent to an **auction** regardless of how the allowances are actually distributed to fuel suppliers because electricity generators purchase their emissions allowances bundled along with their fuel through an increase in the price of fuel.

[11] The remainder are allocated using a mix of free allocation to industry and an auction.

[12] The National Association of Regulatory Utility Commissioners (April 21, 2008) has called for 100 percent of the allowances to be distributed for free in the electricity sector to be given to LDCs.

As one alternative to an auction, we consider free distribution of allowances to incumbent firms in the electricity sector on the basis of historic measures of electricity generation. This approach is often called **grandfathering** because it distributes allowances without charge to incumbents in the industry. Another approach, which we do not explore here, is to regularly **update** the calculation underlying the allowance distribution based on current- or recent-year data. Like distribution based on historic data, an updating approach distributes allowances free of charge and also could distribute them according to various measures, such as the share of electricity generation or heat input (a measure related to fuel use) or a share of emissions at a facility (Burtraw et al. 2001; Fischer and Fox 2004; Rosendahl 2008). An updating approach leads to lower electricity prices than an auction or historic approach and is expected to have greater social costs because it does not provide the same incentive through higher prices for consumers to improve the efficiency of energy use (Burtraw et al. 2006).

The focus of this analysis is the modeling of allocation to local distribution companies, the retail companies that directly serve customers. This approach is described as "**allocation to load"** or **"load-based allocation**" because in one form or another it would allocate to customer demand for electricity (load). We model this at the level of 21 regions in our model, and based on three different metrics. One is the portion of electricity consumption in each region, a second is the portion of population and the third is the portion of emissions. These metrics are calculated on a one-time basis, drawing on the baseline model run for each simulation year in the model. The value of emissions allowances under allocation to load is used to offset the average cost of electricity directly, for example by offsetting the transmission and distribution charge. Although electricity prices vary by customer class because of varying time profiles of demand and different shares of transmission charges assigned to each class, we assume a uniform distribution of the value of allowances in reducing electricity price across all customers.

3.2 Baseline

The baseline scenario is constructed to incorporate all major federal legislation governing airborne emissions from the electricity sector including Title IV and CAIR for SO_2 emissions, the annual and ozone season caps on emissions of NO_x under CAIR, and CAMR for mercury emissions. Also included are some state level legislation, including RGGI, and other policies that are specific to individual states. For nuclear capacity additions, Haiku uses the regional output of the EIA National Energy Modeling System for 2007 as capacity limits on new construction of nuclear plants. All of these potential capacity additions are east of the Mississippi River (U.S. EIA 2007).

Two of the most important baseline scenario assumptions are the treatment of Federal Renewable Energy Production Tax Credit (REPTC) and of state level Renewable Portfolio Standards (RPS) in several western states, including California. The REPTC provides a production tax credit of $19/MWh to new wind, geothermal, and dedicated biomass generators, and a credit of $9.50/MWh is available to new landfill gas and non-dedicated biomass generators.[13] Since the federal REPTC has repeatedly been renewed just prior to lapsing and has actually lapsed three times for a total of 16 months (over the 15 years since it was initially instituted) before being reinstituted, it is modeled in perpetuity in Haiku as a tax credit that is received with 90 percent probability. The state level RPS mandates within the Western Electricity Coordinating Council (WECC) region require substantial increases in renewables generation in the coming years. The resulting capacity additions are not modeled endogenously within Haiku. Instead, we force new renewable capacity into our model in order to meet these standards in the western states[14] according to forecasts provided by Energy and Environmental Economics, Inc (E3).[15] These forecasts of renewable resource additions include the planned capacity additions for wind, geothermal and biomass reported by the Transmission Expansion Planning Policy Committee (TEPPC) along with additional resources that E3 forecasts would be needed to meet RPS standards. These renewable policies are significant because of their potency in reducing emissions, but also because by including them in the baseline it reduces the cost of achieving a specific emissions cap under the policy scenario.

3.3 Policy Scenario

The emissions reduction targets that we model are taken from the U.S. Energy Information Administration modeling of the Lieberman–Warner proposal (U.S. EIA 2008). From that modeling we take the CO_2 emissions determined at the national level as given, and we assume it is not affected by small changes in the electricity sector that result under the variations of policies we model. We do not allow inter-annual banking in the runs of our model, although it is implicit in the quantity targets we take from EIA.

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[13] All values are reported in 2004$ unless indicated.

[14] The western states for which we forced in new renewables capacity include California, Arizona, Montana, Colorado, New Mexico, Utah, Nevada and Wyoming.

[15] "Electricity and Natural Gas GHG Modeling: Methodology and Key Revisions," Slides 38-39, April 21, 2008; <http://www.ethree.com/GHG/E3_CPUC_GHG_21April08.pdf>.

Investment and operational decisions in our model respond to this fixed emission target. In reality (as opposed to in the model), the electricity sector decisions would play a role in the determination of the electricity sector's share of national emissions that obtain under each policy scenario, but we maintain the fixed quantity to achieve comparability across scenarios. Since the emission quantity is the same and the models are different, our model will result in a different level of allowance price and electricity price across scenarios and different from that obtained in the EIA exercise.

In addition to the no-policy baseline, five policy scenarios are modeled. These are comprised of an allowance auction, free allowances to incumbent generating firms (grandfathering), and the three allocation-to-load scenarios described above, based on consumption, population and emissions.

4 Results

The effect of climate policy on electricity consumers depends on several factors that vary by region of the country including the fuel mix and technology used for generating electricity, economic regulation and the approach to allocation. Moreover these factors interact. For example, the portfolio of generation technology determines the fuel that is used at the margin at different times of day and year, and the economic regulation in the region determines whether changes in average or marginal cost determine changes in electricity price. This analysis focuses on the role of allocation, but highlights the important interactions among all these factors, particularly how different approaches to allocation can have different effects depending whether markets are regulated.

If allowances are allocated upstream or auctioned to electricity producers, the opportunity cost of the allowances would be reflected in the price of electricity in both regions with competitive electricity markets and regions subject to cost-of-service regulation. We find that if allowances are allocated for free to generators on the basis of historic generation, the effect on electricity prices and thus on consumers would depend on whether electricity markets are regulated or not. Allocating allowances to local distribution companies would largely erase these inter-regional differences based on regulation, with remaining differences across regions being largely a function of the mix of resources used to generate electricity within a region.

This modeling exercise was performed for a horizon beginning in 2010 and ending in 2025. For expositional simplicity this paper focuses on the results obtained for the year 2020.

4.1 Allowance Allocation and Consumers

The quantitative effect of different approaches to allowance allocation on average electricity prices is shown in Table 4.1-1. The table reports price effects in each Haiku market region as well as aggregate price effects aggregated into regions defined by geography and by regulatory institutions. The auction has the biggest effect on electricity prices in both types of regions and nationwide. Prices in competitive regions increase by $8.50 per MWh with an auction, while in regulated regions the increase in average price due to the policy is closer to $6 per MWh. The difference is related to the differences in resource mix between the two types of regions and the difference in regulation. Under cost-of-service regulation, allowance costs from an auction are passed through to consumers in a way that makes the generators whole and thus these costs are averaged over all MWh sold. However, in competitive regions, the allowance cost to the marginal generator is passed through in the market-determined price that is charged for all electricity, which may be generated with an emitting technology or a non-emitting technology at any point in time. Many generators, particularly those with substantial reliance on non-emitting technologies like nuclear or hydro, will earn rents from this type of pricing (Burtraw and Palmer, 2008). Nationwide the price increase under an auction averages $7 per MWh.[16]

When allowances are grandfathered to generators based on historic generation the inevitable effect of the policy is an electricity price reduction in regulated regions relative to the auction scenario. This reduction leads to increased consumption of electricity, more power imported from neighboring competitive regions and a resultant increase in the electricity price in the competitive regions relative to the auction. Relative to the baseline, competitive regions will see an increase in electricity prices of nearly $10 per MWh under grandfathering, while regulated regions will actually experience a small decline in prices of $1 per MWh. The decline in prices is made possible by the disconnect in

[16] This price effect is difficult to compare directly with the EIA analysis. US EIA (2007) models a mixed allocation of some auction, some free allocation. Also they do not model the continuing availability of the REPTC, even on a probabilistic basis. Further, the EIA analysis of an economy-wide policy will have broader effects in primary fuel markets, especially with respect to the change in demand for natural gas and resultant price change. The demand response we capture is only that pertaining to the electricity sector. US EIA finds the change in electricity price to be $4.7/MWh (2004$).

regulated regions between marginal and average costs. Marginal costs will rise by nearly $10 per MWh, but average costs will fall as a result of the displacement of relatively carbon intensive generation resources in the baseload part of the supply curve with less carbon intensive resources, especially subsidized renewable resources. This also allows for the profitable export of grandfathered allowances. Nationwide the price increase under grandfathering will be roughly one-third of what it will be with an auction.

Table 4.1-1. Change in Electricity Price by Region and Allocation Method in 2020 (2004$/MWh)

Region	Auction	Grandfathering	Load-Based (population)
Regulated Regions	6.1	(1.0)	(0.0)
Competitive Regions	8.5	9.9	1.8
National	7.0	2.7	0.6

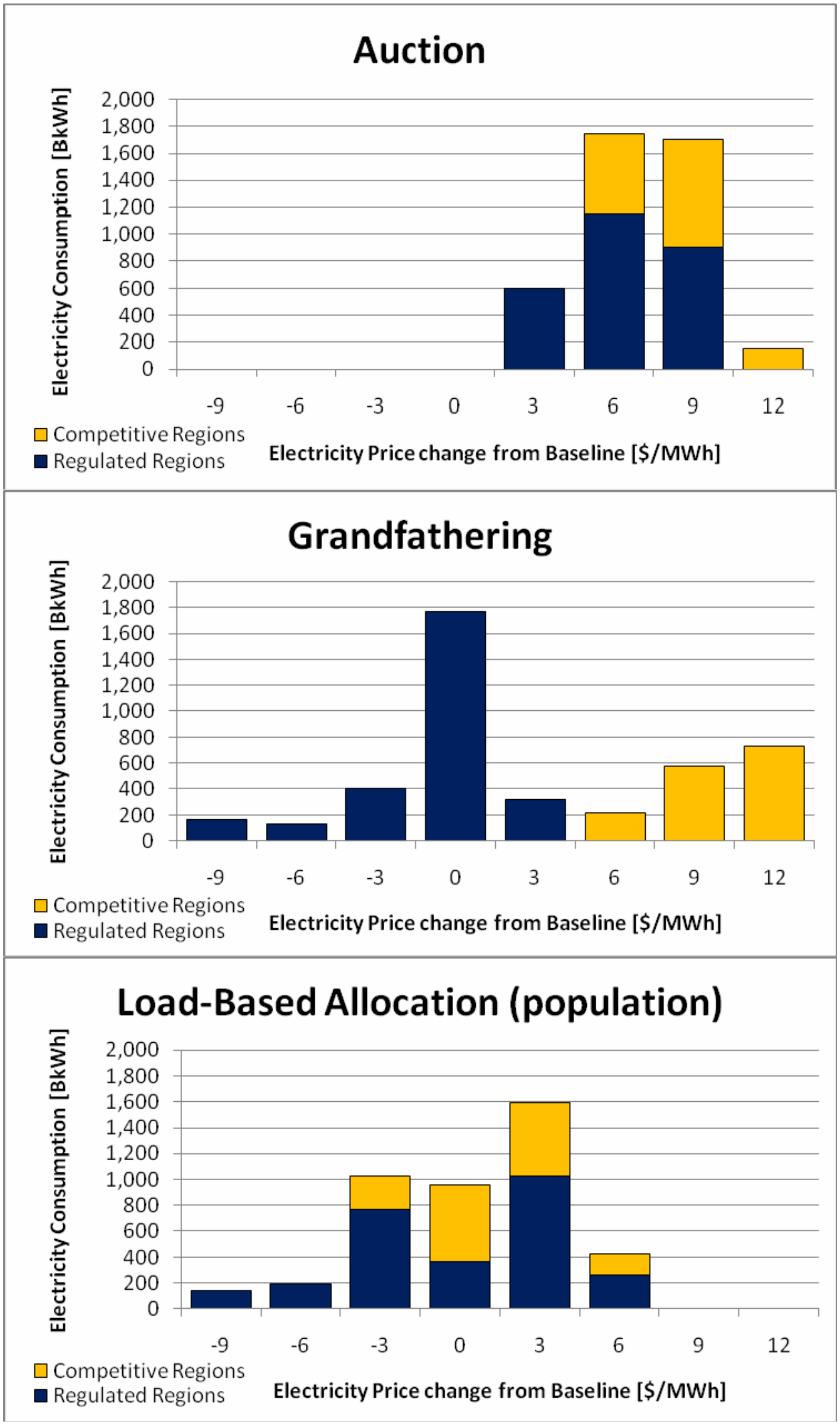
The asymmetric consequence of grandfathering emission allowances is illustrated in the first two panels of Figure 4.1-1, which illustrates the distributions of price changes across regions under different allocation approaches. The graphs in this figure provide histograms of the frequency of various levels of electricity price change resulting from the cap and trade policy under different allocation approaches. The horizontal axis in each graph indicates the size of the change in electricity price while the vertical axis indicates the number of billion kWh of electricity consumption that experience each level of price change from the policy. Changes associated with regulated and competitive regions are indicated in contrasting shading.

The top panel of the figure shows how electricity prices change in 2020 in response to a climate policy with an allowance auction. Under the auction we see that the average change in electricity price nationwide is roughly $7 per MWh with impacts in particular regions varying between $1.80 and $10.60 per MWh. This graph shows that there is much overlap between price impacts in regulated and competitive regions under this policy. The main differences in the distribution of the change in price result from the fuels and technologies used to generate electricity in each region. There remain important differences between regulated and competitive regions in the rates at which compliance costs are passed through to customers as changes in electricity prices because of the difference in average and marginal cost pricing. However, the difference among regions under an auction, and hence the explanation for the distribution of the change in costs across regions, is fundamentally driven by the change in the emission intensity of electricity generation. The middle panel of the graph shows the distribution of price effects across regions under grandfathering. This figure illustrates the dramatic difference between regulated regions and competitive regions. In regulated regions, consumers benefit from a grandfathering approach and price increases are much reduced. As shown in appendix Table 1, in two regions, Indiana and a region spanning Kentucky, West Virginia and a small part of Virginia, prices actually fall by roughly $7 and $9 per MWh, respectively, while several other regions experience price declines of between $0.20 and $1.80 per MWh. In competitive regions the distribution of price impacts actually shifts slightly to the right, reflecting the increase in generation costs associated with the increase in demand (due to the lower price) in regulated regions, compared to an auction. The biggest price increases occur in Pennsylvania (PA) and the region that includes Ohio and Michigan (OHMI).

The asymmetry in price effects under grandfathering between regions under different pricing regimes has posed one of the major political challenges to the design of climate policy in the United States. While a point of departure for policy design from the perspective of the electricity industry has been free allocation of emission allowances, analysis has informed industry members of their opposing interests, depending on what kind of region they are in, and increasingly consumer interests have taken notice. The emerging attention being given to load-based allocation is potentially one way for the industry to navigate these issues.

Compared to an auction, load-based allocation attenuates price increases from climate policy in both competitive and regulated regions. As a point of departure, we consider first LBA on the basis of population. In practice this would be implemented by initially apportioning allowances to the service territories of individual retail utilities, or more probably to states and charging state public utility commissions to complete the apportionment to service territories. In our model, this is implemented by apportioning allowances among the 21 market regions according to population. Table 4.1-1 indicates that in competitive regions the price increase from the policy falls from $8.50 per MWh with an auction to $1.80 per MWh with the load-based allocation approach. In regulated regions, the average price of electricity is unchanged under the climate policy with load-based allocation compared to the baseline. Nationwide electricity price increases by $0.60 per MWh. In general, load-based allocation dramatically reduces the effect of the policy on consumers in both competitive and regulated regions relative to the auction scenario.

Figure 4.1-1. Distribution of Electricity Price Effects in 2020



The bottom panel of Figure 4.1-1 illustrates this effect in a histogram that can be compared with the other approaches to allocation. To a rough approximation, load based allocation restores the symmetry in the price impacts on regulated and competitive regions that would be observed under an auction, albeit at much lower levels. This has made load-based allocation increasingly popular to overcome political opposition to the effect of climate policy on electricity prices.

Giving allowances away for free will help to soften the impact of the policy on consumers, but it will do so at a cost. By reducing prices, the load-based allocation approach and, for consumers in regulated regions, the grandfathering approach, mute the incentive to conserve electricity that exists with an auction. The effective subsidy to electricity consumption causes generation to be higher, leading to a higher demand for CO_2 allowances. This results in an increase in allowance price, which will spread throughout the economy under an economy-wide cap-and-trade program. Allowance prices in 2020 under the different allocation approaches are reported in Table 4.1-2. The table indicates that allowance price in 2020 rises from $14.10 per ton CO_2 under an auction to $15.30 under grandfathering and even higher, to $15.80, under a load-based approach.

Table 4.1-2. National CO_2 Allowance Price in 2020 (2004$/ton)

Auction	Grandfathering	Load-Based (population)
14.1	15.3	15.8

4.2 Different Flavors of Load Based Allocation

In a second set of simulation runs we consider three alternative bases for determining a region's load-based allocation of emission allowances. Previously we considered total population in the region, and in addition we consider total electricity consumption and total emissions from electricity generation.[17] Under load-based allocation based on population, heavily populated regions would receive a greater share of the allowance value than less populated ones. In comparison, the consumption-based approach would tend to favor consumers who reside in regions where electricity

[17] The National Association of Regulatory Utility Commissioners (April 21, 2008) call for load-based allocation on the basis of historic emissions.

consumption per capita is higher and the emissions-based approach would favor consumers in coal-intensive regions. The emissions-based approach introduces a more prominent role for the resource mix in the determination of each region's share of emission allowances, as occurs with grandfathering, except in this case the benefits of free allocation in both regulated and competitive regions accrue to consumers instead of to generators.

Varying the basis for allocation to local distribution companies from population to another measure will have different effects on electricity prices in different regions. Appendix Table 2 shows some of the factors underlying those differences. For example, both Northern (CALN) and Southern California (CALS) have low consumption per capita and conversely relatively high population per unit of consumption relative to many other regions in the model, and thus would receive a larger share of emissions allowances under a population-based allocation than a consumption-based approach. A population-based approach would produce a more substantial price reduction, especially in Northern California, which has a low rate of electricity consumption per capita.[18] An emissions-based approach also would not be favorable for California, which has a relatively clean portfolio of generators. In contrast, a coal-intensive region such as the one including much of Kentucky, part of Virginia and West Virginia (KVWV) has relatively high CO_2 emissions per capita and thus consumers in that state are expected to find an emissions-based approach to allocation to be more favorable.

To provide a summary of these different regional effects we aggregate the 21 Haiku market regions into six regions:

- Northeast states in the Regional Greenhouse Gas Initiative (RGGI)
- Southeast
- Midwest and Appalachia
- Plains
- Rocky Mountains and Northwest
- California

The composition of each region is shown in the map displayed in Figure 4.2-1.

[18] Note that the measures of electricity consumption per capital reported in the table include total consumption by all classes of customers in the state divided by total population.

Figure 4.2-1 Aggregated Regions

Table 4.2-1 reports the regional electricity price changes in 2020 under the three different approaches to load-based allocation. The last row of the table reports the average price changes for the nation as a whole and shows that varying the basis for load-based allocation does not have much impact on average electricity price nationwide. Under all three load-based scenarios national average electricity price rises by less than a dollar per MWh, which is substantially less than the price difference resulting under an auction. However, this apparent similarity masks some substantial differences across regions.

The biggest difference in price effects across the different load-based approaches occurs in California, where allocation to local distribution companies based on population yields an average electricity price that is $8.50 below baseline levels (e.g. price actually falls under the climate policy) while an allocation based on emissions yields a price that is $3.10 above baseline levels, on par with the price increase experienced under grandfathering. If allocation to local distribution companies is based on electricity consumption, the average price is also lower than in the baseline, by $3.60.

Table 4.2-1. Change in Electricity Price by Region and Approach to Load-Based Allocation in 2020 (2004$/MWh)

Region	Load-Based (population)	Load-Based (consumption)	Load-Based (emissions)
RGGI	(1.4)	2.0	5.3
Southeast	0.6	(0.8)	(0.3)
Midwest and Appalachia	4.2	3.5	0.5
Plains	2.3	1.5	0.0
California	(8.5)	(3.6)	2.9
Rockies and Northwest	(2.6)	(2.2)	(2.1)
Competitive	1.8	2.7	2.6
Regulated	(0.0)	(0.6)	(0.7)
National	0.6	0.6	0.4

The second biggest differences in price effects across the three load-based allocation scenarios are found in RGGI. Electricity consumers in the RGGI states would clearly be better off when allocation is based on population and average price is $1.40 per MWh lower than in the absence of a climate policy. Under the consumption-based allocation to local distribution companies, prices in the RGGI states increase by $2 per MWh. Consumers in this region are least well off under an emissions based approach, which produces average price increases under the policy of $5.30 per MWh. Some parts of this region experience substantially higher price increases; in northern New England, which relies heavily on hydro and nuclear power, average electricity prices will increase by $9.20 under the emissions-based approach.

The only region to experience price increases under all three load-based approaches is the Midwest and Appalachia. In this region average price rises by $4.20 in the per capita scenario, driven in large part by even bigger increases in coal-rich Kentucky and West Virginia. When emissions are used as the basis for allocation to load, the average electricity price rises by only $0.50. However, this increase masks large declines in price in the states of Kentucky, West Virginia and Indiana that are offset by price increases in the region that combines Illinois and Wisconsin, which has a fair amount of nuclear generation. Customers in the plains states also experience price increases larger than the national average under the population and consumption based approaches. However, average price remains virtually on par with baseline levels under the emissions based approach.

Our findings suggest that electricity consumers in the western region excluding California should be largely indifferent between the three approaches to load-based allocation, all of which produce price drops in 2020 of roughly $2.00. Closer examination of the results for the two Haiku market regions that comprise this larger region suggest slightly greater differences in price effects between the consumption-based and the emissions-based approaches. In particular the consumption based approach leads to slightly larger price drops in the northern part of this region, which is rich in hydro resources as well as other types of renewables. Consumers in the southern part of this region fare better under an emissions based approach as coal plays a greater role in the generation mix there.

4.3 Efficiency Consequences

The beneficial effects of load-based allocation accrue to electricity consumers through lower electricity prices; however, the downside of a load-based approach is that it yields a higher allowance price than would prevail under an auction. This effect on allowance price is essentially invariant with respect to the basis on which allowances are allocated to local distribution companies. Table 4.3-1 shows the CO_2 allowance price under all three approaches and reveals that allowance prices are little changed across the three scenarios, and they each lead to significant differences in allowance price compared to an auction.

Table 4.3-1. National CO_2 Allowance Price in 2020 (2004$/ton)

Load-Based (population)	Load-Based (consumption)	Load-Based (emissions)
15.8	16.0	16.0

From a sector-specific perspective, the difference in allowance price is not significant, but within the broader economy it signals that greater use of resources and greater cost would be required to achieve emission reduction goals. Any kind of free allocation including grandfathering will raise the allowance price, but the load-based approach does so most importantly. While grandfathering is generally intended to compensate the owners of incumbent facilities that will be regulated by climate policy, in contrast, free allocation to load is a subsidy to consumers of electricity. We find it would raise the price of allowances by about 12 percent compared to an auction. As a consequence, within a nationwide cap-and-trade program, other actors in the economy such as industries that use natural gas, or households that use fuels for home heating, or people who drive cars, would pay for this subsidy to electricity by higher prices for the use of energy elsewhere in the economy.

The subsidy to electricity consumption has the effect of reducing the incentive for consumers to make investments in end-use efficiency. Recent analyses (McKinsey 2007, Nadel et al. 2004) suggest that there are substantial opportunities to improve the efficiency with which electricity is used in the economy. While government programs and standards may contribute to the realization of these efficiency gains, another important component is the capital purchase decisions of individuals. If electricity price rises less due to free allocation to electricity consumers then those consumers will have less incentive to purchase efficient air conditioners, refrigerators, etc., causing other sectors to do more work to achieve overall emission reductions.

Electricity consumers, and the industry that supplies them with power, have a parochial interest in trying to lessen the impact of climate policy on prices and in capturing the value for the electricity sector associated with placing a scarcity value on CO_2 in the economy. However, there is no economic logic why the value of emission allowances should be reserved for a sector just because it has historically been the source of emissions. The parochial assignment of allowance value to any one sector of the economy could lead to different marginal costs for emission reductions throughout the economy, and it could lead to some sectors having to achieve greater emission reductions than would be efficient overall, which offers the prospect of raising the cost from a nationwide perspective.

5 Conclusion

It is noteworthy that precisely because the cost of climate policy is large, a good way to achieve broad-based compensation is to reduce the overall social cost of the policy. Recycling revenue raised under an allowance auction to reduce preexisting taxes, helps achieves efficiency goals and these achievements are compounded since this approach reduces the overall cost of climate policy, thereby lessening the impact on households overall. However, it would not succeed in compensating lower income households who spend a larger portion of their income on energy than wealthier households who would benefit the most from revenue recycling. Burtraw et al. (2008) find that a proportional reduction in labor income taxes would be highly regressive.

One approach to compensating households that is embodied in current legislative proposals is free allocation to electricity customers, to be achieved by free allocation to local distribution companies. This approach seems appealing because customers may have relatively little opportunity to reduce electricity use in the short term, at least until they have the opportunity to make new capital investments in appliances, home weatherization, etc.

From the national perspective, we find significant benefits for electricity consumers from free allocation to local distribution companies. In addition, this approach reconciles the important regional differences that would emerge with a grandfathering approach that distributed allowances for free to incumbent emitters. However, the benefits that emerge at the national level mask important differences across regions that depend on how the allocations are determined. Allocation to local distribution companies based on population could yield electricity prices in 2020 for populous regions with relatively clean sources of electricity generation that are actually below prices in the absence of climate policy. Consumers residing in regions that rely heavily on coal will tend to fare better under an approach that uses emissions to determine allocation.

We also find free allocation to local distribution companies comes with an important efficiency cost, not just in a general equilibrium context stemming from foregone revenue but also due to the market dynamics in the regulated industries. When electricity customers do not see the increase in retail electricity prices, they do not have an incentive to reduce electricity consumption. Across the sector, this effect would lead to more electricity consumption, and under an economy-wide program, it would lead to more emissions from the electricity sector, requiring more reductions from other sectors. This is expected to raise the overall cost of achieving climate goals. However, the political virtue of this approach is that using allocation to load provides a mechanism in the short run to avoid sudden changes in electricity prices for consumers. Because free allocation to customers has the political virtue of lessening the price effect, it may provide for a useful transition path to phasing in a full auction in the electricity sector.

Appendix

Appendix Table 1. Change in Electricity Price from by Region in 2020 (2004$/MWh)

Electricity Pricing Regime	Haiku Market Region	Auction	Grandfathering	Load-Based (population)	Load-Based (consumption)	Load-Based (emissions)
Competition	NEN	9.2	10.5	0.7	3.9	9.2
	NES	5.4	6.0	(3.6)	(0.6)	1.7
	NY	9.0	10.0	(2.0)	2.9	7.1
	NJD	6.4	7.0	(0.6)	1.6	5.3
	MD	8.4	9.9	0.8	3.3	4.7
	PA	10.6	12.1	4.6	4.6	0.8
	OHMI	10.1	11.5	3.4	3.4	1.4
	MAIN	9.7	10.6	3.6	3.6	3.5
	ERCOT	5.8	7.9	1.2	1.1	0.5
Regulation	FRCC	4.1	0.7	(2.6)	(2.5)	(1.1)
	AMGF	6.6	(0.2)	2.1	0.3	(0.2)
	VACAR	4.8	(0.4)	0.0	(1.8)	0.3
	KVWV	9.5	(9.3)	5.7	2.6	(4.1)
	IN	9.2	(7.4)	4.8	3.2	(3.3)
	ENTN	7.5	(1.1)	2.7	1.0	(0.7)
	SPP	8.0	0.2	3.6	1.5	(0.6)
	MAPP	7.9	(1.8)	2.7	1.8	(0.1)
	NWP	5.5	(0.1)	(2.3)	(2.7)	(0.6)
	RA	5.8	(1.7)	(2.9)	(1.4)	(4.2)
	CALN	1.8	2.6	(9.8)	(5.0)	2.0
	CALS	2.7	4.1	(7.5)	(2.6)	3.6
	RGGI	7.6	8.5	(1.4)	2.0	5.3
	Southeast	5.8	(0.3)	0.6	(0.8)	(0.3)
	Midwest and Appalachia	9.9	5.4	4.2	3.5	0.5
	Plains	7.1	3.1	2.3	1.5	0.0
	California	2.3	3.5	(8.5)	(3.6)	2.9
	Rockies and Northwest	5.7	(0.8)	(2.6)	(2.2)	(2.1)
	Competitive Regions	8.5	9.9	1.8	2.7	2.6
	Regulated Regions	6.1	(1.0)	(0.0)	(0.6)	(0.7)
	National	7.0	2.7	0.6	0.6	0.4

Appendix Table 2. Baseline Regional Characteristics in 2020

Electricity Pricing Regime	Haiku Market Region	Aggregate Region	Population	CO2 Emissions Rate (tons/MWh)	Electricity Consumption per Capita (MWh/person)	CO2 Emissions per Capita (tons/person)
Competition	NEN	RGGI	3,624,102	0.13	8.8	1.5
	NES	RGGI	11,685,426	0.44	9.1	3.8
	NY	RGGI	19,576,920	0.35	7.6	2.4
	NJD	RGGI	10,905,384	0.51	10.4	3.3
	MD	RGGI	6,497,626	0.68	10.3	5.1
	PA	Midwest and Appalachia	12,787,354	0.61	13.0	12.7
	OHMI	Midwest and Appalachia	21,998,225	0.85	13.2	11.1
	MAIN	Midwest and Appalachia	22,050,673	0.62	13.1	8.7
	ERCOT	Plains	25,040,400	0.63	15.0	9.7
Regulation	FRCC	Southeast	22,140,641	0.61	12.9	6.7
	AMGF	Southeast	19,883,364	0.62	17.9	12.2
	VACAR	Southeast	22,940,469	0.50	16.1	7.8
	KVWV	Midwest and Appalachia	6,976,401	1.01	21.6	27.2
	IN	Midwest and Appalachia	6,627,008	1.07	18.0	21.6
	ENTN	Southeast	15,470,035	0.68	17.0	13.5
	SPP	Plains	12,287,603	0.73	18.1	15.0
	MAPP	Plains	13,039,828	0.69	15.0	12.2
	NWP	Rockies and Northwest	18,976,707	0.34	14.2	6.6
	RA	Rockies and Northwest	18,902,845	0.67	10.7	9.8
	CALN	California	17,379,247	0.12	7.8	0.8
	CALS	California	24,827,496	0.21	7.5	0.7
		RGGI	52,289,458	0.42	8.9	3.2
		Southeast	80,434,509	0.60	15.8	9.7
		Midwest and Appalachia	70,439,660	0.79	14.4	13.2
		Plains	50,367,830	0.67	15.8	11.6
		California	42,206,743	0.16	7.6	0.7
		Rockies and Northwest	37,879,552	0.48	12.5	8.2
		Competitive Regions	134,166,109	0.61	11.8	7.5
		Regulated Regions	199,451,643	0.61	13.8	9.0
		National	333,617,752	0.61	13.0	8.4

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