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Compensation Rules for Climate Policy in the Electricity Sector

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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 U.S. CO_2 emissions. Whether producers or consumers bear the cost of this regulation depends on whether generators are subject to cost-of-service regulation or sell power at market-determined prices. Using a detailed simulation model of the electricity sector, we examine one recent, relatively modest proposal that would create a pool of tradable emissions allowances with a net present value that sums to $141 billion (1999$). The limit on CO_2 emissions would cause a cumulative loss in market value of $50 billion at affected facilities; however, another group of facilities would gain $41 billion in value, and harm measured at the industry level would be just $9 billion, or 6 percent of total allowance value. Firms own a portfolio of facilities, and firms that are negatively affected would suffer a loss summing to $14 billion. Other firms would gain $5 billion in value, while consumers would incur a loss approximately 8 times as great as that of industry.

The initial distribution of a portion of the valuable emissions allowances represents a significant potential source of compensation, but it is easy for the compensation to fail to reach those who bear the burden of costs. Free allocation also has substantial efficiency costs, raising the social cost of a policy that already promises to be more expensive than prior air pollution regulations.

We look for approaches to target the initial distribution of emissions allowances to compensate producers to maximize the share of allowances available for another purpose. We find that if regions/states are apportioned emissions allowances, they can achieve a compensation target using simple rules based on public information for typically half of the allowance value that such rules would require if implemented at the federal level. Under the most optimistic scenario, we find that compensating the last $2.6 billion in harm at the federal level has an opportunity cost of about $25.4 billion in allowance value, the difference accruing as excess compensation to undeserving firms.

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

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1. Introduction

Emissions allowances represent enormous economic value—tens of billions of dollars annually under a federal carbon policy—that arise 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 burden of the cost of emissions reductions and the cost of buying emissions allowances forms the basis of stakeholder claims for compensation (Atkinson and Tietenberg 1984). The initial distribution of just a portion of the valuable emissions allowances represents a significant potential source of compensation, but compensation can easily to fail to reach those who bear the burden of costs. The enormous value of the allowances makes this high-stakes issue perhaps the greatest political challenge in designing climate policy.

Strong incentives exist for individual parties to argue for an ever-increasing share of emissions allowances through free allocation. As a result, policymakers need to identify clear policy goals and principles to guide any free initial distribution and to limit and target that distribution. Economic efficiency is one bedrock principle: if society achieves its goals in an efficient rather than inefficient manner, more resources are left for families and businesses, or even greater environmental protection could be achieved at the same cost. Many observers have turned to cap and trade or other incentive-based approaches as a strategy to reduce the cost of emissions reductions; however, the efficiency benefit of these approaches is not guaranteed. The overwhelming evidence from public finance and environmental economic research is that free distribution has a substantial hidden cost and that a revenue-raising auction is the most efficient design for

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the initial distribution of allowances.[2] Never before has such an expansive environmental policy as federal carbon legislation appeared on the horizon, and free distribution would multiply the cost of the policy.

Free allocation of emissions allowances to 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. 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. Indeed, absent a public-policy rationale, one can mount an economic case against free distribution of any emissions allowances.

One rationale for free initial distribution is that it provides compensation to parties that will bear a disproportionate cost under the trading program. A frequently cited principle of public policy is that government should "do no direct harm" (Schultz 1977)—that is, public policy needs to respond to the direct harm that may be concentrated on severely affected parties through compensation for some degree of the disproportionate cost burden they bear. Compensation can take a variety of forms, including a time delay between the announcement of a policy and its implementation, which provides for the realization of economic value from previous investments while giving investors the opportunity to realign their investment decisions going forward. The years that have transpired between the announcement of national climate policy goals and the implementation of a mandatory policy have provided such opportunity. However, the fundamental form of compensation within a cap-and-trade program is free initial distribution of emissions allowances because it conveys substantial economic value to recipients. This approach has the advantage, at least from the perspective of those affected, that it keeps value in the regulated industry and away from the vagaries of

[2] An auction approach has dramatic efficiency advantages for two reasons. Many economists and other analysts suggest that auctioning provides a source of revenue that may have economy-wide efficiency benefits if it is used to reduce taxes, with potentially dramatic efficiency advantages compared to free distribution (Bovenberg and de Mooij 1994; Parry 1995; Bovenberg and Goulder 1996; Goulder et al. 1999; Parry et al. 1999; Smith et al. 2002). Moreover, because the auction approach tends to reduce the difference between price and marginal cost in this case, an auction has a dramatic efficiency advantage in regions of the country where cost-of-service regulations causes electricity prices to differ substantially from marginal costs (Parry 2005; Burtraw et al. 2001, 2002; Beamon et al. 2001).

government appropriation. Furthermore, the magnitude of the compensation moves in direct proportion to the harm, which is evident when emissions allowances gain or lose value.

At least two other rationales exist for free distribution. First, it helps maintain the regulated sector's competitiveness in an open economy if competitors do not face comparable environmental constraints. This is especially important because little is accomplished by reducing emissions in the United States if economic activity and associated emissions move off shore. Allocation to firms based on their share of production (output) going forward into the future provides an incentive to expand output on shore (Fischer and Fox 2004) or within region or sector of the economy (Burtraw et al. 2001). Yet another rationale for the initial free distribution of emissions allowances is to use their value to explicitly promote new technology (Energy and Environmental Analysis, Inc. 2003).

We limit this paper to an investigation of the need for compensation through free allocation to generators in the electricity sector, recognizing that such a policy has various trade-offs. Not only does free allocation move society away from the most efficient design, but free allocation to one party depletes the allowance value that is available for other severely affected interest groups or other complimentary policy goals. Therefore, we pursue the design criterion that allocation should maximize the portion of emissions allowances that can be distributed in an efficient manner (e.g., through auction) by directing the free distribution of emissions allowances to mitigate the direct harm to severely affected parties. This strategy requires two pieces of information: how parties are affected under the policy and how compensation can be delivered in a way that minimizes the amount of overcompensation and maintains a preeminent consideration of efficiency in the design of the policy.

The claim to compensation depends on how the effect on producers and consumers is measured. Previous studies have analyzed the effect at the industry level, which yields a relatively low estimate of the claim for compensation, or at the facility level, which tends to provide a high estimate. Bovenberg and Goulder (2001) estimate that the effect of a 23 percent decline in emissions from 2002–2080 would cause industry-wide losses of just $28 billion in the electricity sector. They find losses about 20 times as large in the fossil-fuel supplying industries (Congressional Budget Office 2003). Smith et al. (2002) estimate the effects of a 14 percent decrease in emissions to be achieved by 2010, and a 32 percent decrease by 2030. They estimate that the reduction in equity value is equivalent to 6 percent of the total allowance value. Neither study, however, accounts for the role of regulation.[3] Taking into account the nature of regulation in the electricity sector and the organization of firms, we provide an estimate of the change in market value at the firm level. We argue that this is the primary policy-relevant metric for measuring the impact on producers. Although the majority of harm is born by consumers rather than producers, this harm is diffuse in the economy, and hence consumers may have secondary claim behind producers according to Schultz because producers bear a concentrated burden from the policy.

Upstream allocation or a full auction would cause a cumulative loss in market value at affected facilities of $50 billion; however, another group of facilities would gain $41 billion in value and harm measured at the industry level would be just $9 billion, or 6 percent of total allowance value. Firms own a portfolio of facilities, and those that are negatively affected would suffer a loss summing to $14 billion, while other firms gain $5 billion in value. In contrast, consumers would incur a loss approximately eight times as great as that of industry.

The award of free allowances to producers is a blunt instrument for compensation, especially at the federal level. It tends to reward producers in regions with market-based pricing and consumers in regions of the country with cost-of-service electricity pricing. Furthermore, unless the policy is discriminating, it tends to reward winners as well as losers, thereby eroding efficiency and the ability to compensate other affected parties. Using a detailed simulation model, we analyze a relatively modest proposal from the National Commission on Energy Policy (NCEP) and alternatives based on that proposal. As a point of departure, we find that free distribution of emissions allowances would yield a net gain in the industry of $65 billion, all in competitive regions of the country.

In this paper, we examine the role of simple decision rules in guiding the delivery of compensation to shareholders while minimizing overcompensation. Using readily available facility-specific information about fuel use and technology characteristics to calculate allocation rules at the federal level, we find that full compensation still requires 86 percent of the allowances in competitive regions (42 percent of the allowances nationally) to be allocated for free, which leaves a net gain in the industry of $51.5 billion. An alternative to federal allocation might be a compensation program

[3] Hepburn et al. (2006) provide estimates of free allocation necessary to maintain market value on an industry-wide basis in Europe.

implemented at the regional/state level after apportionment of allowance budgets to states and decentralized allocation to emitters. We find that if regions/states were apportioned emissions allowances in a manner analogous to emissions budgets under the previous nitrogen oxide (NO_x) trading programs, they could achieve compensation using facility-level information and do so more efficiently than by using similar rules at the federal level. If a strategy based on facility-specific information were implemented at a regional level, the percentage of allowances required to compensate firms in competitive regions would fall to 39 percent (19 percent of national allowances). The industry would still enjoy a net gain of $19.5 billion.

An even more efficient rule could be based on the average emissions rates for firms. If allocation remains a federal responsibility, full compensation using average emissions rate information could be achieved with 65 percent of emissions allowances in the competitive regions (31 percent of national allowances). This approach still leaves a net gain in the industry of $36.7 billion. If this approach were implemented on a regional level, the same compensation target could be achieved with just 32 percent of the emissions allowances in competitive regions (15 percent of national allowances). This approach would leave a net gain in the industry of just $14.7 billion.

These estimates illustrate the value of information. If regulators could implement a strategy to get firms to reveal their costs, then they could compensate losers directly without providing compensation to winners. Stranded-cost-recovery investigations by public utility commissions provide one example of previous experience with strategies to encourage firms to reveal their cost information. In this case, it would be sufficient to give away just 22 percent of the emissions allowances in competitive regions for free (11 percent of national allowances). This approach still leaves a net gain in the industry of $7.51 billion.

These estimates are a point of departure, calculated as if a climate policy were to take effect immediately without warning, as a surprise. We focus on 100 percent compensation for the worst-off firm to illustrate the strongest possible case for free allocation of some portion of allowances to industry. There are a variety of considerations that might move policymakers away from this goal, including the opportunity cost of diverting allowance value from other potential efforts to achieve compensation or efficiency goals. One such consideration is the delay between adoption and implementation of policy. A delay gives firms an opportunity to depreciate existing capital and adjust investment strategies, lowering the impact of the policy; however, delay also lowers the net present value of allowances and does not change the portion of allowance value that would be necessary to achieve compensation targets. Nonetheless, achieving compensation in the electricity sector is expensive. Under the best of scenarios, at the federal level we find that the incremental cost of compensating for the last $2.6 billion in harm spread across 81 firms would cost about $25.4 billion in allowance value, nearly 10 times the value of the harm. At the regional/state level, we find that the incremental cost of compensating for the last $1.35 billion in harm spread across 83 firms is $6.01 billion, about 4.5 times the harm.

2. Method of Analysis

The electricity sector represents roughly 40 percent of carbon dioxide (CO_2) emissions in the economy but is expected to yield roughly 70 percent of emissions reductions under future carbon policy (U.S. Energy Information Administration 2005b). Several features of the market determine the relationship between CO_2 allowance price and the electricity price (Reinaud 2007). We conducted our analysis using a detailed simulation model of the electricity sector maintained by Resources for the Future (Paul et al. 2007). The model accounts for temporal detail with three seasons and four time blocks and solves for investment and operational decisions over a twenty-five-year horizon.

2.1. Baseline Assumptions

The baseline model simulation in this exercise uses fuel price and electricity demand calibrated to the *Annual Energy Outlook 2005* (U.S. Energy Information Administration 2005a) levels. Fuel prices and electricity price vary in response to changes in the quantity supplied. The level of demand for both electricity and fuels responds to price changes, including those associated with a carbon policy. Demand is represented by a constant elasticity function $Q_i\left(P_i\right) = A_i \cdot P_i^{\varepsilon_i}$, where *P* is electricity price in a given time block; Q_j is quantity demanded by an individual customer class in each time block, season, and region; *A* is a constant used in calibration; and ε_i is the own price elasticity of demand. The quantity demanded is summed across three customer classes in each market. In principle, ε_i varies by region, customer class, and time block; in practice data is scarce, and elasticity values are common across many of these distinctions. Aggregate weighted elasticity of demand is approximately -0.25.

The baseline includes the national restrictions on sulfur dioxide (SO_2), NO_x, and mercury emissions from electricity generators under Title IV as well as additional emissions restrictions found in the Clean Air Interstate Rule and Clean Air Mercury Rule.

It does not include the Regional Greenhouse Gas Initiative (RGGI) to be implemented in northeastern states beginning in 2009 because we anticipate that the results would be most useful if they reflect the total cost of climate policy, rather than just the incremental cost of the national policy given the regional policy.

A critical assumption is the status of regulation in the electricity sector. Roughly speaking, half the consumers in the nation buy electricity at competitive market-based prices, and half buy electricity at prices determined by the cost of service of regulated firms. The model represents the nation as thirteen sub-regions. In competitive regions, generation cost is determined by the variable cost of the marginal facility at every point in time.[4] In the absence of time-of-use pricing for residential and commercial customers, the marginal generation cost is averaged over the hours of the day to achieve an average marginal generation cost. We assume industrial customers in competitive regions see time-of-use pricing. Since the price is set by marginal rather than average cost, characteristics of the marginal generation facility determine the change in electricity price due to the program and, ultimately, contribute to the ability of the industry to pass on costs to consumers through higher prices.

In the standard regulatory case, we assume six of the sub-regions have market-based prices and seven have cost-of-service regulation.[5] We model cost of service regulation in a textbook manner: in each sub-region, the total annual cost of production is aggregated and divided by the quantity of electricity sold to achieve an average generation price that is added to transmission and distribution costs. The electricity price varies for different customer classes reflecting empirical practice that shares transmission and distribution costs in different ways for different classes of electricity customers.

The key aspect of cost-of-service regulation is that all costs are included at original cost and the firm is reimbursed for them. In the short term, there are numerous variations from this rule in practice, as regulators disallow some types of costs and encourage others. The time lag in administrative proceedings that come before many types of adjustments to the rate base provides regulated firms with an opportunity to gain

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[4] Payment for reserve is determined by the going-forward cost of marginal capacity.

[5] We characterize six sub-regions of the North American Electric Reliability Council (NERC) as competitive, including New York, New England, Mid-Atlantic (MAAC), Illinois area (MAIN), the Ohio Valley (ECAR), and Texas (ERCOT)—and we assume that there is time-of-day pricing of electricity for industrial customers in these regions.

or lose earnings. If firms can cut costs while price remains unchanged, they can profit. If costs rise, they lose. Often regulators will consider ex post adjustments to account for changes in costs, and usually changes in fuel cost are automatically passed through as changes in price. In many cases, however, the unexpected changes in costs are not recovered fully by the firm (Braine 2003). In addition, many regulators appear willing to leave prices stable as costs fall, but they are less willing to increase prices when costs rise because any increase in price triggers a political reaction (Joskow 1974; Joskow and Schmalensee 1986). Consumer advocates argue that such increases should have been anticipated and avoided. When price does increase, it can lead to reductions in demand, thereby lowering sales revenue to the firm. And finally, it is important to note that managers of the firm are under increasing pressure from capital markets to maintain short run profitability. All these factors together suggest that regulated firms are likely to be opposed to new costs.

In the long run, however, firms must recover their cost of providing service; otherwise they would experience a change in their cost of capital. The long run would bring would be excess profits, implying regulators are not applying a test of prudence on cost recovery, or firms would lose money and go out of business. We take a long-run perspective and assume that because producers in regulated regions are reimbursed for all costs, they are fully compensated for the cost of climate policy through changes in electricity price. We recognize that the assumption about the nature of regulation in the electricity industry has an important bearing on the expected cost of the policy and who bears that cost.

2.2. Alternative Methods for an Initial Distribution of Emissions Allowances

The policy we model based on the NCEP proposal is a cap-and-trade system for the entire economy with point of compliance at upstream fuel supply. 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. In the downstream electricity sector, the cost of such a 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.

We evaluate alternative methods for the initial distribution of emissions allowances (Sterner and Muller 2007). In general, the point of allocation of emissions allowances is distinct from the point of compliance. 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 would be perceived as 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. As an alternative, we consider free distribution of some allowances to 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 and CO_2 emissions) or a share of emissions at a facility (Burtraw et al. 2001; Fischer and Fox 2004; Rosendahl 2007). 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.

2.3. Policy Scenario

The emissions reduction targets that we model are taken from the U.S. Energy Information Administration (EIA) modeling of the NCEP CO_2 cap-and-trade proposal with an upstream allocation policy and with the safety valve (U.S. Energy Information Administration 2005b).[6] From that modeling we take the CO_2 allowance price 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. The EIA forecast includes a safety valve price that is binding after 2016. Investment and operational decisions in our model respond to this fixed price. In reality (as opposed to in the model), the electricity sector decisions would play a role in the determination of the national price, but we maintain the fixed price to achieve comparability with EIA results. Since price is the same and the models are different, our model will result in a different level of

[6] A safety valve is a price range that bounds the variability in the allowance price. NCEP proposes a one-sided safety valve that places a ceiling the price.

emissions than that obtained in the EIA exercise. The EIA emissions and price targets and our modeled policy are compared in Table A.

Table A. Comparison of EIA (2005b) and RFF Modeling Scenarios (1999$)

	2010	2015	2020	2025
EIA (2005b)				
Baseline				
Emissions (tons CO_2)	2.88	3.07	3.31	3.65
NCEP Policy				
Emissions (tons CO_2)	2.85	3.01	3.20	3.41
Allowance Price ($/ton)	8.38	12.62	15.00	16.50
RFF				
Baseline				
Emissions (tons CO_2)	2.76	2.92	3.10	3.37
Moderate Policy				
Emissions (tons CO_2)	2.67	2.83	3.01	3.19
Allowance Price ($/ton)	3.91	5.89	7.00	7.70
More Stringent Policy				
Emissions (tons CO_2)	2.52	2.60	2.71	2.89
Allowance Price ($/ton)	8.38	12.62	15.00	16.50

The results of this exercise for the year 2020 are reported in Table B. We find baseline generation for the nation of about 4,777 billion kilowatt hours (kWh) decreases by about 1.5 percent. The upstream allocation policy leads to a reduction of about 94 million short tons of CO_2 associated with electricity generation. (For comparison, we report that the EIA modeling finds this policy would yield a reduction of about 112 million short tons.) Slightly more than half of the reductions occur in competitive regions, and the rest occur in regulated regions.

Table B. Moderate Policy: General Results for the Upstream Allocation (No Allocation to the Electricity Sector) with the Standard Mix of Regulation and Competition

Year 2020 unless stated otherwise Values in 1999 dollars	**Competitive Regions**	**Regulated Regions**	**Nation**
Change in Electricity Price ($/MWh)	3.75	4.28	4.05
Annual Consumer Cost (billion $)	7.47	11.10	18.57
Baseline Generation (bill. kWh) and	2,141	2,636	4,777
(Change from Baseline as %)	(-2.0%)	(-1.2%)	(-1.5%)
Coal	1,244	1,222	2,466
	(-3.5%)	(-4.0%)	(-3.8%)
Gas	422	595	1,017
	(-1.2%)	(+1.0%)	(+0.1%)
Oil	~0	0.2	0.2
	(-44.2%)	(-53.4%)	(-52.8%)
Nonemitting	474	819	1,294
	(+1.4%)	(+1.5%)	(+1.5%)
Annual Producer Cost (billion $)			
Industry Level	2.97	-	2.97
Firm Level*	3.43	-	3.43
Facility Level*	4.74	4.07	8.82
Total Producer Cost			
Loss in Market Value			
(NPV in 2006, billion $)			
Industry Level	9.00	-	9.00
Firm Level*	14.95	-	14.95
Facility Level*	23.41	26.57	49.98
CO_2 Tax Price ($)	7.00	7.00	7.00
Modeled CO_2 Emissions			
Baseline (bill. short tons)	1.506	1.596	3.102
Reductions from Baseline	(0.049)	(0.045)	(0.094)
EIA forecast of CO_2 Emissions			
Baseline (bill. short tons)			3.309
Reductions from Baseline			(0.112)
Annual Value of Emissions Allowances	10.19	10.86	21.05
Total Value of Emissions Allowances (NPV in 2006, billion $)	68.27	72.84	141.11

* Aggregation of losses excluding gains to winners.

3. Producer Claims for Compensation Depend on the Length of the Yardstick

Simulation modeling accounts for the equilibration of electricity markets on a sub-regional basis, by season and time of day, and for changes in new investment and retirement. The level of detail has a significant effect on calculation of changes in the market value of existing generation assets. The basic element of the cost to investors is the change in market value of an individual electricity generating facility, which we calculate using a discounted cash flow model of activity through 2030, discounted back to 2006. Table B reports the loss in market value of facilities under upstream allocation (auction) sums to almost $50 billion.[7]

However, investors do not own stock in facilities. Rather, they own stock in firms that own a portfolio of facilities. At the firm level, the loss in value at one facility may be offset by the gain in value at another. To calculate the change in value at the firm level, we aggregate individual facilities to portfolios owned by firms as of January 2004. The value of new facilities that the model predicts will be built after 2005 is not included in these calculations (except for some units already under construction). In addition, we assume that in regulated regions the vast majority of federally mandated environmental costs would be included in the rate base, as has been historic practice, and that the regulated rate of return on invested capital is maintained, so the cost at the firm level in these regions is zero. Therefore, we assume that only firms in competitive regions are directly affected in the long run. The loss in market value among losing firms under upstream allocation (auction) totals to $14.95 billion. Many firms that gain value are excluded from this calculation.

The third potential level of aggregation is the industry level, at which the increase in market value at one firm may offset the loss in market value at another. If one believes that most investment occurs not in the form of stock or bond holdings in individual firms but in a portfolio of firms captured in various industry indices held by mutual funds or large pension funds, then the industry level measure might be the preferred measure of damage. For example, a growing portion of the stocks on Wall Street are held by mutual funds or institutional investors, suggesting that for many investors, the effect on the

[7] All values are reported in 1999$.

industry is more relevant than the effect on individual firms.[8] At the industry level, the total drop in market value under upstream allocation (auction) is $9 billion.

Figure 1 illustrates the way in which the level of aggregation—at the facility, firm, or industry level—determines the claim for compensation in the electricity industry, causing the estimate of direct harm to producers to vary by a factor of five. Also noted is the $141 billion net present value of the stream of emissions allowances for the policy. Were it feasible to compensate for the $9 billion loss at the industry level—effectively leaving shareholders financially unaffected by the policy—it would be sufficient to allocate just 6.4 percent of the allowances at no cost. Full compensation for the loss of $14 billion at the firm level could be achieved for 10.6 percent of the total allowance value for the nation while creating an increase of $6 billion in the net value of the industry (almost all in competitive regions).

If one considers just the pool of allowances in competitive regions, the loss in market value represents 13.2 percent of the allowance value. Full compensation for the loss of $14 billion at the firm level could be achieved for 22 percent of the total allowance value in competitive regions, while creating an increase of $6 billion in the net value of the industry.[9]

In principle, this information suggests that free allocation of emissions allowances not only has the potential to compensate the shareholders for changes in the market value, but potentially to substantially overcompensate for the cost of the policy (Burtraw et al. 2002; and Bovenberg and Goulder 2001). Researchers analyzing the CO_2 emissions trading system in Europe that began in 2005 have reached a similar conclusion (Sijm et al. 2005; UK House of Commons 2005). In RGGI, Burtraw et al. (2005, 2006) find that giving away 100 percent of the allowances to emitting generators based on historic output (or other measures) will more than compensate generators for the costs of the program. Using a simple model with fixed capacity and fixed demand in the RGGI program, the Center for Energy, Economic and Environmental Policy (2005) finds that all three approaches to allocation—historic, updating, and auction—would lead to increased

[8] Individual and institutional mutual fund accounts manage nearly $9 trillion dollars of value in 2005 (Investment Company Institute 2006).

[9] 48.4 percent of permit value is in competitive regions and 51.6 percent of permit value is in regulated regions.

profitability for the electricity sector as a whole in RGGI relative to no policy, with the historic approach resulting in the greatest increase in profits.

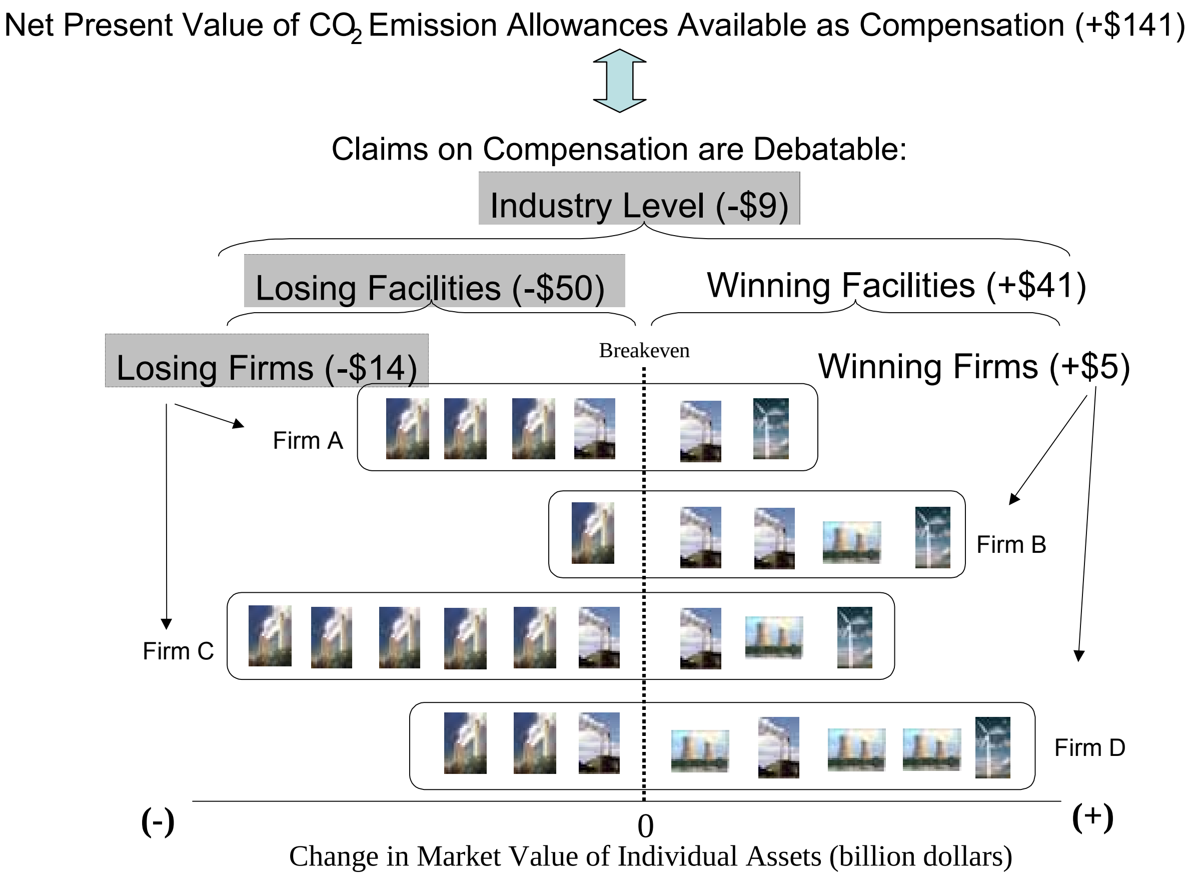


Figure 1. Firms Own a Portfolio of Facilities That Lose and Gain Value

Note: The level of aggregation in the electricity industry determines the claim for compensation as a share of emissions allowances (billion 1999 dollars, net present value in 2006).

4. Consumer Claims for Compensation Are Diffuse

The case for consumer compensation depends on the change in electricity prices, which increase by $4.05 per megawatt hour (MWh), or 6 percent, at the national level in 2020 under upstream allocation (auction). This leads to an overall increase in expenditures by consumers of $18.6 billion in that year.[10] The impact of the policy on consumers can also be measured by the partial equilibrium change in consumer surplus, which is measured as the area under the demand curve for each customer class in each linked electricity market. In 2020, the loss in consumer surplus is $18.2 billion, which is less than the change in expenditures because of the curvature of the demand curve. The net present value of change in consumer surplus over the entire forecast horizon is $135.6 billion.

The impact of the policy on consumers is not uniform across the country. Consumers in regions with a greater dependence on fossil generation tend to experience greater losses than those in regions with more mixed generation portfolios. We adjust for size of the regions by dividing the net present value of change in consumer surplus by the level of electricity demand in the region to yield a measure of surplus change per kWh of demand. Ranking the 13 regions by this measure shows where consumers are most affected per unit of electricity consumed. We also rank regions according to the fossil fuel intensity of their generation mix in 2020. A Spearman rank correlation test indicates that these two rankings have a correlation coefficient of .797, which is statistically significant at the 99 percent level. The effect of the climate policy on consumers across different regions, then, is highly dependent on the fossil intensity of a region's generation.[11]

Typically the price impact of the policy tends to be bigger in regulated regions than in competitive regions because consumers bear both the higher fuel cost due to the embedded cost of allowances and the cost associated with fuel switching and other steps taken by generators to reduce CO_2 emissions. This is true in particular for those regions with a majority of coal-fired generation. Several regulated regions have more than the national average share of coal-fired generation. The biggest price increases happen in regions with a large amount of coal and a small fraction of non-emitting generation. The highest price increase happens in the sub-region consisting largely of Oklahoma, Kansas,

[10] This cost is estimated as the change in national average retail price multiplied by the quantity of electricity consumed. The quantity of electricity consumption varies between the baseline and policy scenario due to the change in retail price. We use the average of baseline and policy scenario quantities.

[11] It is unclear whether this correlation would persist at higher allowance price levels. Preliminary results with a doubling of the allowance price cap suggest that the effect on consumer prices will be much larger in competitive regions than in regulated regions, despite the fact that many of these regions tend to be lower ranked in terms of fossil intensity than are the regulated regions.

and parts of Louisiana and Texas, a regulated region with only 6.5 percent non-emitting generation in 2020 in the baseline. A separate Spearman rank correlation test between net present value of consumer surplus change per kWh demand and fossil intensity of generation within just the set of seven regulated regions reveals a rank correlation coefficient of .786, which is significant at the 95 percent level.

In competitive regions, the electricity price does not necessarily fully reflect compliance cost. The determination of electricity price depends on the fuel that is at the margin and most often that fuel is natural gas. When this is the case, the change in electricity price will be less than if coal were at the margin, and the change in electricity price may not be sufficient to compensate the firm for its increase in cost. On the other hand, if a firm had no coal generation but substantial non-emitting generation, the change in electricity price when natural gas is at the margin could overstate the change in the firm's cost of generation. Thus, the change in electricity price may understate or overstate the average cost per MWh of electricity generation, depending on the relationship between the marginal and average carbon intensity of electricity generation. The more indirect link between effects of the policy on cost and electricity price in competitive regions can be illustrated by another Spearman rank correlation test on just the subset of restructured regions. In this case, the correlation coefficient between the rank of fossil intensity of generation and change in consumer surplus per kWh is .743, which is not statistically significant given the small sample size.

The competitive region with the largest price impact is the region consisting of the central Ohio Valley, which has 84 percent coal generation and more than 90 percent fossil generation, and is where coal is more likely to be at the margin than in any other region. The price impact in ECAR is second-highest of all regions for the nation.

5. How Well Does Free Allocation Compensate Producers and Consumers?

As an alternative to upstream allocation or distribution through an auction, we consider free initial distribution to producers of all emissions allowances used by the electricity industry. We model the initial distribution of 100 percent of allowances to electricity generators based on a facility's share of total heat input at emitting facilities in 1999.[12] This approach is similar to the one used in Title IV of the 1990 Clean Air Act

[12] This is comparable to their share of emissions.

Amendments that gives SO_2 emissions allowances away to facilities based on a measure of performance in the 1985–1987 base period, an allocation formula carried forward in the Clean Air Interstate Rule for SO_2.

5.1. Generators in Competitive Regions and Consumers in Regulated Regions Benefit from Free Allocation

The effect of free allocation on electricity prices and, therefore, consumers, is markedly different in competitive and regulated regions. Generators in regulated regions should be indifferent in the long run between free allocation to generators and an auction. In these regions free allocation will benefit electricity consumers by reducing the revenue requirement that determines the electricity price. In competitive regions, consumers are approximately indifferent to the type of allocation because electricity prices reflect the opportunity cost (market value) of emission allowances under free allocation and an auction.

The differing effects on consumers between competitive and regulated regions are, as illustrated in Figure 2. This figure displays the distribution of the change in average retail electricity price in 2020 aggregated at the level of the 13 sub-regions in the model. Panel (A) in the figure corresponds to the upstream allocation policy, which is equivalent to an auction from the perspective of the electricity industry. Competitive regions and regulated regions are distinguished by different shading in the figure. The average change in price for the nation is \$4.05/MWh. The price increase is about \$0.53/MWh (14 percent) greater in regulated regions.

Panel (B) in the figure represents results of allocating allowances for free to generators in the electricity industry. Comparing the panels, we see that free allocation has only small effects on the distribution of cost for customers in competitive regions because the electricity price is set by the cost of the marginal generator, and that cost does not change substantially with free allocation in competitive regions. In the aggregate, consumers in competitive regions are slightly worse off than under an auction by \$630 million and would bear a total cost of \$8.1 billion.[13] However, free allocation has a dramatic effect in regulated regions, where the change in electricity price is reduced by 90 percent on average to about \$0.40/MWh. In regulated regions, free allocation offsets the cost of

[13] In competitive regions, the increase in price in 2020 is larger than under an auction because of the relatively greater level of demand in regulated regions and its effect on the wholesale power market.

allowances embedded in the cost of fuel and removes that cost from the rate base, thereby lowering average cost and electricity price. Free allocation benefits consumers significantly in regulated regions, but it does not benefit consumers in competitive regions unless consumers receive the allowances directly.

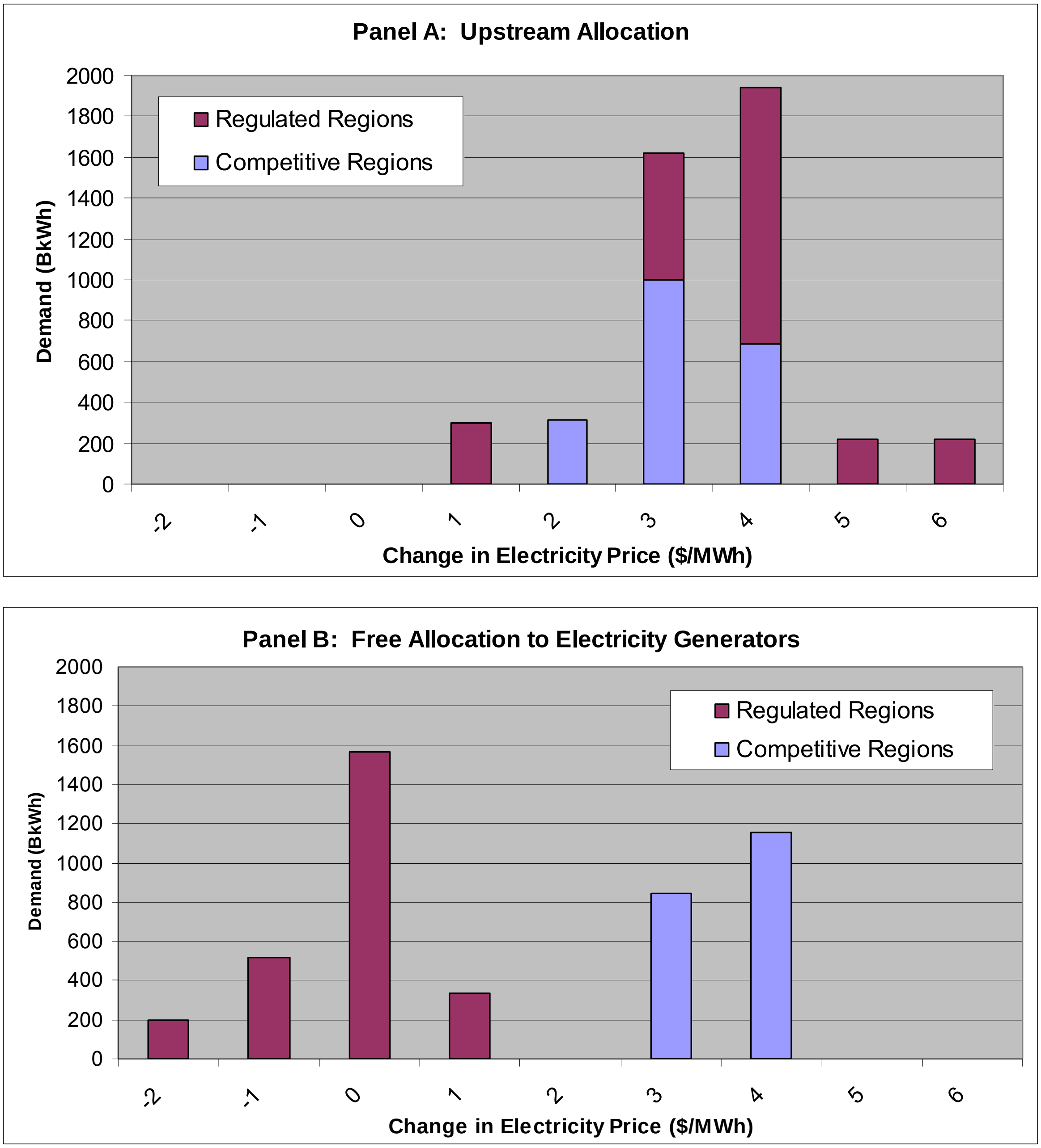


Figure 2. Distribution of Change in Electricity Price Sorted by Regulated and Competitive Regions under Two Approaches to Allocation

Note: Panel A represents upstream allocation (no allocation to electricity sector) and Panel B represents free allocation to electricity sector. Only customers in regulated regions benefit from free allocation.

Table D summarizes the effects of free allocation on consumers and producers separately in regulated and competitive regions in the year 2020. As shown in the table, with free allocation to the electricity sector, electricity consumers in regulated regions are compensated for 91 percent of the losses they incur under the upstream allocation (auction) approach. In contrast, in competitive regions, generators realize $11.14 billion gain relative to upstream allocation (auction), resulting in substantial overcompensation of generators totaling $8.26 billion.

Table D. Annual Compensation and Percent of Annual Losses Compensated with 100% Free Allocation: Effect on Electricity Producers and Consumers of 100% Free allocation to Electricity Generators Relative to Upstream Allocation

Year 2020 (Billion $)	**Producers**	**Consumers**
Competitive Regions	$11.14* (375%)	$-0.63 (-8%)
Regulated Regions	----	$10.09 (91%)

*The estimate includes both producers who would be losers and those who would be winners under upstream allocation.

Over the entire planning horizon, the present discounted value of the gain in asset values for the industry under free allocation is more than $68 billion, while the few firms that lose incur a loss that totals just $110 million. The majority of firms in competitive regions gain significant value.

Figure 3 illustrates that upstream allocation (auction) and free allocation affect firms quite differently. The figure characterizes approximately 150 firms that account for 93 percent of the electricity generation identified in the model to exist in 2010. The model indicates the largest 20 firms would account for 51 percent. The distribution of the change in market values under the upstream allocation policy is displayed in the left-hand side distribution in Figure 3. The horizontal axis represents the change in market value of a firm averaged over the kilowatts of generating capacity it owned in 2005. The heights of the bars represent the total amount of generation capacity that falls into each category of change in value. Under upstream allocation (auction), about 33 percent of the firms lose market value, while 21 percent gain value. The remaining 46 percent of firms only have holdings in regulated regions and experience no change in market value due to cost of service regulation.

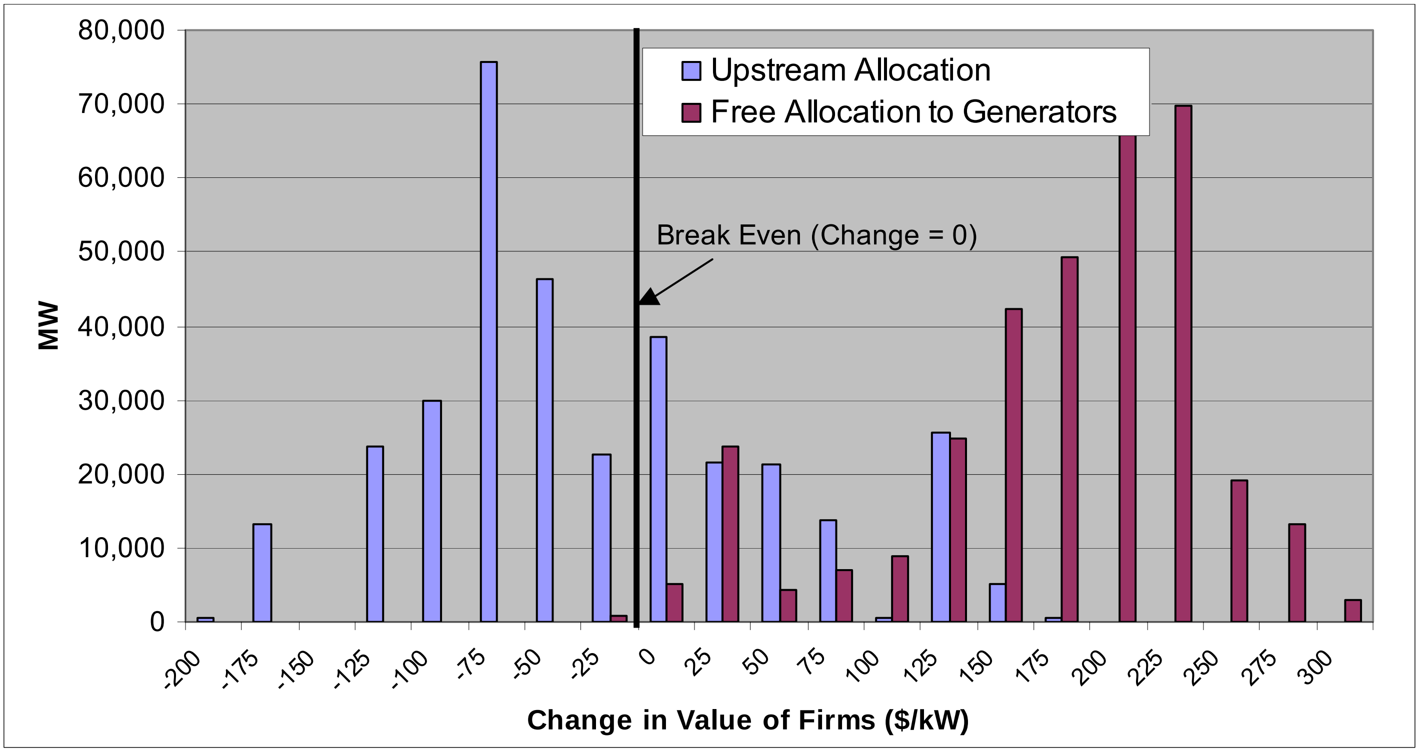


Figure 3. Distribution of Costs among Generators under Upstream Allocation (No Allocation to Electricity Sector) and Free Allocation to Electricity Sector

Note: The data include the holdings in competitive regions of 81 firms.

The distribution on the right of Figure 3 represents changes in asset value under a policy with free allocation to generators. In this case, we see that virtually every firm gains value under the climate policy. The average firm gains about $165 per kW of generation capacity.[14]

In sum, free allocation primarily benefits two groups: consumers in regulated regions where electricity price is the average cost of service, and producers in competitive regions, where free allocation of 100 percent of emissions allowances would provide compensation far in excess of damage to most firms. Consumers in competitive

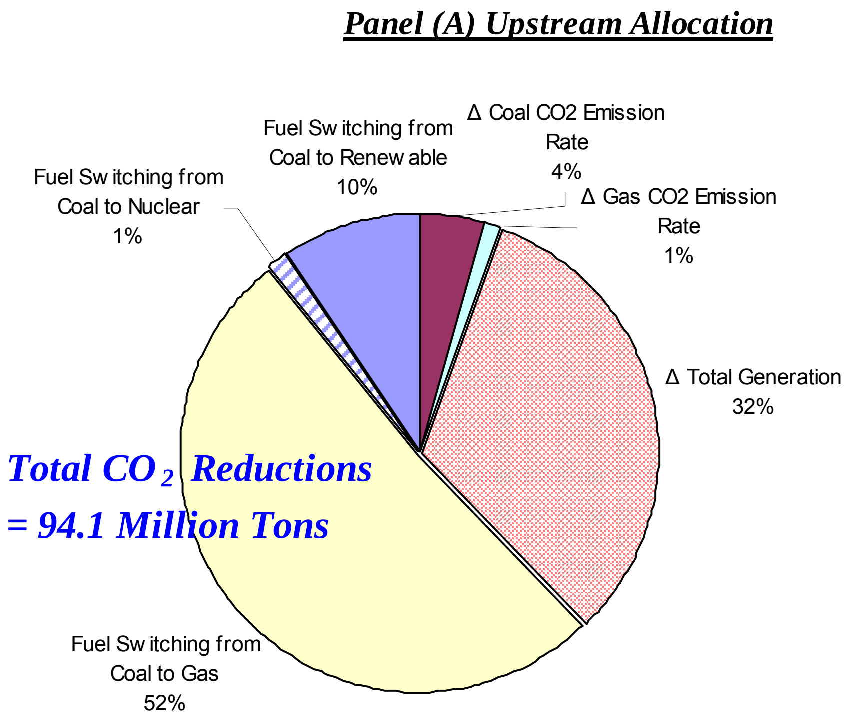
[14] When weighted by the size of the firm, the average firm gains about $187 per kW, indicating that the largest firms have the most to gain from free allocation. By way of comparison, EIA estimates the cost of a new scrubbed coal-fired power plant today is about $1,102 per kW (1999$). The electricity industry had about 950 million kW of installed generation capacity in 2006.

regions do not benefit directly from free allocation to producers because free allocation has no direct effect on the determination of electricity price. And to a first order approximation, producers in regulated regions are not expected to benefit from one form of allocation versus another because cost of service regulation is expected to assure recovery of costs. We presume the policy goal is to compensate severely affected parties while at the same time minimizing the amount of compensation overall. Consequently, the challenge is how to provide compensation to the electricity industry without transferring wealth to the industry or to individual firms in excess of their harm.

5.2. Efficiency Cost of Free Allocation

Free allocation mutes the effect of the cap-and-trade policy on prices paid by consumers in regulated regions, which reduces consumers' response and raises the social cost of the program. Since we model the allowance price achieved in EIA analysis and allow emissions reductions to vary, this effect leads to lower overall emissions reductions from the electricity sector. With upstream allocation (auction), electricity prices in both regulated and competitive regions reflect in some direct manner the opportunity cost of using allowances and thus there is a greater incentive to conserve electricity to reduce emissions. In 2020, CO_2 emissions associated with electricity generation fall by 94.1 million tons when allowances are distributed to upstream fuel suppliers. However, with free allocation the opportunity cost of using allowances is not reflected in electricity prices in regulated regions thereby muting incentives for conservation, resulting in 75.8 million tons of reductions when all of the allowances associated with electricity generation are distributed for free to generators.

The changing relative importance of reductions in generation as a means of achieving emissions reductions is reflected in Figure 4. The two panels of this graph show the relative sources of emissions reductions in 2020 under the two allocation approaches and the relative total areas of the two pie charts illustrate the relative size of the total emissions reductions from electricity generators associated with each allocation approach.



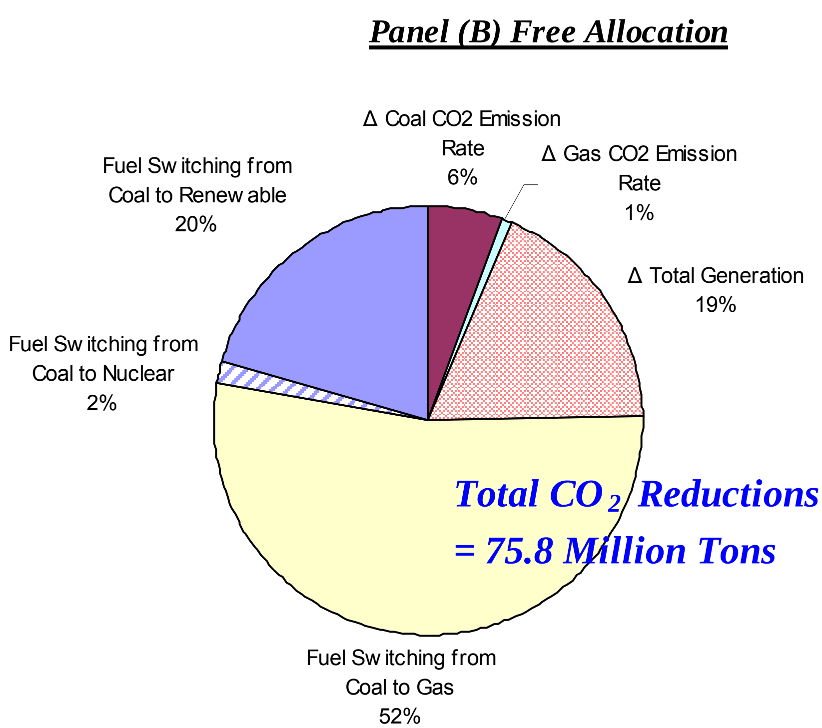


Figure 4. Sources of CO_2 Emissions Reductions from Electricity Vary with Allocation Approach (Results for 2020)

In panel (A) we see that fuel switching from coal to gas is the largest source of CO_2 emissions reductions from electricity generators achieved with upstream allocation (auction), responsible for 52 percent of the 94.1 million tons. To a large extent marginal gas generation has replaced infra-marginal coal generation. The second-most important source is reduction in electricity generation, which accounts for 32 percent of CO_2 emissions reduction. The drop in electricity generation subsumes investments in end-use efficiency and conservation measures, which are accounted for in our model by the own-price elasticity of demand. Fuel switching from coal to renewables plays a lesser role, accounting for 10 percent of emissions reductions. Approximately 4 percent of the emissions reductions come from improvements in efficiency by switching among coal-fired generators. Switching from coal to nuclear accounts for only about 1 percent of total emissions reductions.

In panel (B), we see that under 100 percent free allocation to electricity generators, the role for efficiency or energy conservation leading to reductions in electricity generation is much reduced to only 19 percent of the 75.8 million ton total emissions reduction. Under this scenario, fuel switching from coal to renewables becomes much more important, accounting for 20 percent. Fuel switching from coal to gas remains the biggest source of reductions at 52% percent and fuel switching from coal to nuclear is still relatively unimportant, as is switching among gas-fired facilities. The relative importance of shifting toward relatively more efficient coal facilities is slightly increased compared to what it was under the upstream approach (auction).

5.3. Limited Free Allocation to Generators

The middle ground between an upstream allocation (auction) and free allocation to generators could provide limited compensation. We model free allocation of 20 percent of the allowances, the level at which the market value of firms in aggregate is approximately unaffected by the policy. This percent is the ratio of losses in value at the firm level (roughly $14 billion), which are all in competitive regions, to the total present discounted value of allowances in competitive regions ($68.27 billion). The remaining allowances in this scenario are allocated upstream (or auctioned).

Table E. The Effect of Different Levels of Free Allocation on the Cost for Producers and Consumers for a Single Year

	Producers Cost*			Producer Gain**	Consumers Costs			Total
Year 2020 (Billion $)	Competitive Regions	Regulated Regions	Nation	Nation	Competitive Regions	Regulated Regions	Nation	Nation
Upstream Allocation	3.43	-	3.43	(+) 0.46	7.47	11.10	18.57	21.54
Mix of Allocation (20% given to electricity sector)	1.50	-	1.50	(+) 1.32	8.10	9.04	17.12	17.30
Free Downstream Allocation	0.01	-	0.01	(+) 8.26	8.10	1.01	8.98	0.73

*Producer cost measures losses in 2020 among firms the suffer loss in market value.

**Producer gain measures gain in 2020 among firms that increase market value. Note that the sign on gain is the opposite of cost.

In competitive regions, allocation of 20 percent of the allowances for free to generators reduces the cost of the policy to producers in 2020 by $1.93 billion, from $3.43 billion under upstream allocation (auction) to $1.5 billion (Table E). It also increases the gain among firms that profit from the policy by $972 million, from $0.46 billion to $1.32 billion. Net losses and gains in competitive regions and for the nation approximately break even with a 20 percent share of allowances given away for free. However, the policy still creates separate classes of losing and winning firms. Consumers in competitive regions actually see a small increase in their cost because of the expansion in demand in regulated regions and its effect in the wholesale power market.

In regulated regions, producers are assumed to be indifferent, but consumers benefit from the mixed policy relative to upstream allocation (auction). Their cost falls in 2020 from $11.1 billion to $9.04 billion if 20 percent of the allowances were given away for free. On net for all producers and consumers, the cost to the electricity sector falls from $21.54 billion to $17.3 billion. Under 100 percent auction there would be $21.18 billion in auction revenue available, which would fall to approximately $17 billion.

6. Generator Claims for Compensation Vary Inversely over a Range of Moderate Policies

The size of claims for compensation among electricity generators depends on the stringency of the climate policy. Under stricter policies, the differences in producer costs among the different metrics—industry-level or firm-level—become even more pronounced than they are in the $7-price-cap case.

The results for a case with a $15 price cap are presented in Table F. When viewed at the industry level, producers *profit* from the climate policy, with industry-wide assets increasing in value by $9 billion under the policy. Thus, if the disparate producers in the electricity sector could find a way to share the winnings from the climate policy among themselves, electricity producers as a whole would be better off with a CO_2 policy that caps allowance prices at $15 than without a CO_2 policy. At both the firm and facility level, however, the size of losses to the losers actually increases under the higher allowance safety valve price of $15 (relative to the $7 level reported in Table B). Losses to losing firms nationwide total almost $40 billion, while at the facility level, losses to losing facilities total slightly more than $90 billion. These findings indicate that the spread between winning and losing firms and winning and losing facilities grows bigger as the price of CO_2 emissions allowances increases. We also evaluated an intermediate CO_2 allowance price cap level of $11, which yields an intermediate result with a small increase in asset values at the industry level of $1.5 billion, and total losses to losers at the firm and facilities levels in between the other two cases.

On the consumer side, Table F shows that consumer losses between regulated and competitive regions are evenly split (about $23–24 billion each) for a total of about $47 billion across the nation. This compares to a less even split in the $7 safety valve case, with 60 percent of the $18.6 billion in losses coming in regulated regions. Note that for an allowance price increase of slightly more than 100 percent from $7 to $15, consumer costs in 2020 increase by about 150 percent. The higher allowance price hits consumers in competitive regions particularly hard, which is what one would expect given that all the winning generators are located in competitive regions.

Table F. More Stringent Policy: General Results for the Upstream Allocation (No Allocation to the Electricity Sector) with the Standard Mix of Regulation and Competition

Year 2020 unless stated otherwise Values in 1999 dollars	**Competitive Regions**	**Regulated Regions**	**Nation**
Change in Electricity Price ($/MWh)	11.88	9.38	10.45
Annual Consumer Cost (billion $)	23.36	24.12	47.43
Baseline Generation (bill. kWh) and	2,141	2,636	4,777
(Change from Baseline as %)	(-7.8%)	(-0.2%)	(-3.6%)
Coal	1,244	1,222	2,466
	(-21.5%)	(-15.1%)	(-18.3%)
Gas	422	595	1,017
	(+8.9%)	(+12.7%)	(+11.1%)
Oil	~0	0.2	0.2
	(+97.7%)	(-18.1%)	(-10.4%)
Nonemitting	474	819	1,294
	(+13.5%)	(+12.6%)	(+12.9%)
Annual Producer Cost (billion $)			
Industry Level	-0.96	-	-0.96
Firm Level*	7.87	-	7.87
Facility Level*	5.31	8.83	14.14
Total Producer Cost			
Loss in Market Value			
(NPV in 2006, billion $)			
Industry Level	-8.95	-	-8.95
Firm Level*	39.76	-	39.76
Facility Level*	32.25	59.59	91.84
CO_2 Tax Price ($)	15.00	15.00	15.00
Modeled CO_2 Emissions			
Baseline (billion short tons)	1.506	1.596	3.102
Reductions from Baseline	(0.252)	(0.137)	(0.390)
EIA forecast of CO_2 Emissions			
Baseline (billion short tons)			3.309
Reductions from Baseline			(0.112)
Annual Value of Emissions Allowances	18.80	21.88	40.68
Total Value of Emissions Allowances (NPV in 2006, billion $)	128.58	147.60	276.18

* Aggregation of losses excluding gains to winners.

7. Designs for Delivering Compensation to Firms

We have seen that upstream allocation or an auction of emissions allowances imposes costs on some electricity producers in competitive regions and on consumers in competitive and regulated regions. The revenue generated by an auction in 2020 would be $21.05 billion, which potentially could be used to offset most of the $21.54 billion in costs.[15] Most of this cost falls on consumers, but the concentrated effects fall on producers. The obvious place to compensate producers is the level of the firm. Workers and local communities also will be affected by the policy and some legislative proposals provide for compensation to these entities. In any case, the competing claims for compensation and the alternative potential uses for allowance value from auction make the case for avoiding overcompensation to industry or any other one group.

Free allocation using a historic measure of emissions is a blunt instrument for compensation because it distributes value to many firms who do not need compensation, while other firms may receive insufficient allocation to maintain the firm's market value. Therefore we seek to find simple decision rules that could govern the provision of compensation by guiding the distribution of allowances. We calculate compensation based on a policy that has upstream allocation (auction). Only firms in competitive regions are the recipients of compensation; we assume compensation through free allocation of allowances is delivered to consumers in regulated regions.[16]

7.1. Complete Information: Targeting Compensation to Firms

We noted that compensating the electricity industry would require 6.4 percent of the allowance value, but political economy leads us to consider compensation at the level of a firm. Free allocation, on the other hand, would distribute 100 percent. Table G summarizes detailed results for the 182 largest firms operating in competitive regions of the country. The first column of the table indicates that free allocation would cause all but two of these firms to be winners, sharing a gain of $65.08.

[15] This is the sum of annual consumer cost ($18.57 billion) and producer cost at the industry level ($2.97 billion) reported in Table B.

[16] We do not consider the inclusion of these allowances in the rate base, which would lead to a different equilibrium of emissions for the nation as illustrated in Table C. Instead, we implicitly assume a different method of compensating consumers, such as lump-sum redistribution (of annual rebates) that does not influence electricity consumption directly.

Table G. Summary of Federal and Regional/State Approaches to Compensation for 182 Firms Operating in Competitive Regions

Information:	n/a	Complete		Incomplete									
Approach:	n/a	**Federal**	**Regional**	**Federal**					**Regional**				
Compensation Metric:	Free	Firm Value		Facility-Level Fuel / Technology:			Emissions Rate -Firm:		Facility-Level Fuel / Technology:			Emissions Rate -Firm:	
				Fuel	**Fuel +Gas**	**Fuel +Clean +Gas**	**Fit**	**Full**	**Fuel**	**Fuel +Gas**	**Fuel +Clean +Gas**	**Fit**	**Full**
# Winners	180	182	182	182	182	180	101	177				99	178
Gain (billion $)	65.08	7.51	8.51	60.72	59.99	51.52	13.85	36.67	Gains and losses are not measured at the national level.			10.02	14.69
# Losers	2	0	0	0	0	2	81	5				83	4
Loss (billion $)	0.005	0	0	0	0	0.011	2.59	0.012				1.35	0.013
Industry Net (billion $)	65.07	7.51	8.51	60.72	59.99	51.51	11.26	36.66	41.04	23.32	19.45	8.67	14.68
(%) Free Allowances in competitive regions**	100*	22	23	100*	99	86	27	65	71	45	39	23	32

Note: Estimates are measured against a backdrop of upstream allocation (auction).

*The first column represents free allocation of 100% of allowances nationally as described in Table C and leads to a different equilibrium than free allocation of allowances in competitive regions coupled with upstream allocation (auction) in regulated regions.

**68.27% of national allowances is apportioned to competitive regions.

If a mechanism existed to allocate only to those firms that suffer a negative effect on market value, the net present value compensation target would be just $14.95 billion, equivalent to 10 percent of the net present value of emissions allowances. If one were to restrict attention to the pool of allowances to be used in competitive regions, 22 percent of these allowances would offer value sufficient to offset the losses. The result is presented in the second column in Table G. Complete information reduces overcompensation for the industry to $7.5 billion and all firms in this sample at least break even.

In all these cases the overall market value of the industry would increase relative to the baseline because many firms that are winners would retain their gain in value and the allocation ensures that no firms would lose value. Table G reports that the net increase in the market value of the industry when compensation is delivered federally is $7.5 billion.[17]

One can imagine the regulator might seek to compensate firms through an individualized allocation of emissions allowances so to achieve a precise compensation goal. The regulator may obtain such detailed information by solving a simulation model or establishing a rebuttable presumption against compensation and inviting firms to appeal through the demonstration of harm, again presumably through the use of simulation modeling. These approaches would resemble the stranded-cost-recovery proceedings that accompanied the restructuring of the electricity sector in many states in the late 1990s, when regulators relied on simulation models to estimate the potential change in the value of generating assets due to restructuring.[18]

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[17] This differs slightly from the results in Table B and Figure 1 because Table G includes just 182 firms.

[18] Regulators and utilities used three methods to estimate the potential change in value of generating assets due to restructuring (Kahal 2006). One was the measure of the change in the discounted value of revenues due to anticipated changes in prices. A second conceptually similar method calculated the year-by-year revenues and costs of the generating assets in a deregulated market over the assumed remaining lives of the assets. The net present value (discounted cash flow) of this stream of profits was assumed to be the market valuation. The difference between the market valuation and the net book value of the assets (i.e., the value under regulation) measured the gain or loss from deregulation.

In the later stages of restructuring, the comparable transaction approach became widely used. This method involved compiling a database on generation plant sales (usually associated with utility divestitures). Expert judgment was used to identify comparable generation assets that had been sold and sales prices announced. In many cases, this method produced much higher post-restructuring asset valuations than those produced by simulation models, perhaps because asset buyers were willing to pay premium prices to enter newly deregulated markets quickly.

In the restructuring process, the modeling exercise led to contentious disputes between utilities and regulatory staffs (and consumer representatives) concerning the validity of simulation models, including key data input assumptions and calculation procedures. In the absence of case settlements, state commissions were required to adjudicate these very technical modeling issues. In the present case, similar disagreements could be expected.

In any event, we imagine that any credible appeal for compensation would likely involve simulation modeling. We assume the results of modeling are available to the regulator who seeks to target the allocation of emissions allowances in order to compensate only losing firms. Were this possible, the first column of Table H indicates that among the six competitive regions, the portion of allowance value necessary to compensate the losers varies from 12 percent in the Ohio Valley region) to 40 percent in the region centered around Illinois and in New York. The ECAR region has the largest amount of coal in the nation, which paradoxically means that producers need a smaller share of allowance value for compensation because coal-fired generation sets the wholesale marginal electricity price more often in this region. Consequently, consumers are more likely to see an increase in electricity price than in other regions where less energy is generated from coal.

The effect for the nation as a whole, when using a regional approach, is reported in the third column of Table G. We would expect that if compensation were delivered on a regional basis, the net gain in market value would be greater, because some portions of a firm's portfolio would lose value in one region even when other portions of the firm's portfolio gained value in another region. The table indicates that the net effect of this decentralized approach to compensation requires 23 percent of the allowances in competitive regions for compensation. The industry gains value in every region, and in the aggregate, the net increase in the value of the industry would be $8.5 billion—slightly more than that under a federal approach.

Table H. Allocation Using Simple Rules at the Regional/State Level to Achieve 100% Compensation for the Worst-off Firm

	Complete Information		Incomplete Information Using Simple Rules					
			Fuel Type		*Fuel + Gas Technology*		*Fuel + Gas Tech.+ Clean*	
Units are percent and billion 1999$	Percent Free Allocation	Net Gain in Market Value	Percent Free Allocation	Net Gain in Market Value	Percent Free Allocation	Net Gain in Market Value	Percent Free Allocation	Net Gain in Market Value
ECAR	12%	1.74	27%	6.29	27%	6.29	24%	5.63
ERCOT	25%	0.385	45%	2.56	45%	2.50	37%	1.65
MAAC	34%	1.09	220%	15.61	71%	3.97	54%	2.69
MAIN	40%	3.00	76%	7.44	53%	4.64	48%	4.00
NY	40%	1.47	209%	5.96	143%	4.20	130%	3.85
NE	21%	0.832	125%	3.18	60%	1.72	56%	1.63
Aggregate Regions*	23%	8.52	71%	41.04	45%	23.32	39%	19.45

Note: Results and percentages as share of allowances in competitive regions only.

* For convenience this row repeats information in Table G.

7.2. Incomplete Information: Compensation Based on Facility Fuel Use

In practice, the regulator may not have information about the financial performance of firms and may not be able or willing to gain this information through the regulatory process. In this case, the regulator does have information based on readily observable characteristics of firm portfolios of generating capacity and historic generation that can be used to differentiate among firms. For instance, the most obvious distinction is the type of fuel used by various facilities. By targeting free allocation to individual facilities at rates that vary based on fuel use, the regulator can compensate firms at different rates.

The mathematical problem is to find allocation rules that minimize the free allocation of allowances necessary to compensate every firm for loss incurred under an allowance auction. Formally, the problem is to identify allocation rates—r_j , defined as allowances per MWh of 1999 generation, by fuel type j, where j refers to coal, gas, oil—that minimize the value of the allowances allocated for free:

$$\min_{r_C, r_G, r_O} P^*\left[\sum_{f=1}^{F} r_C C_f + r_G G_f + r_O O_f\right] \text{ such that } \forall f \in F:\ P^*\left[r_C C_f + r_G G_f + r_O O_f\right] \geq \theta(V_f^{BL} - V_f^{A}),$$

where P^* is the discounted weighted average CO_2 allowance price (1999$/ton CO_2), F is the set of firms $\{f\}$; C_f, G_f *and* O_f stand for 1999 generation (MWh) with coal, gas, and oil, respectively, for firm f; V^A_f is the net present value of firm f under an auction (1999$); and V^{BL}_f is the net present value of firm f in the baseline (1999$). The parameter θ is a policy target that can vary between zero and one ($0 < \theta < 1$) and represents the portion of market value in the absence of the program that must be maintained for all firms. For instance, if $\theta = 1$, the solution will provide full compensation to the most disadvantaged firm, implying of course that other firms gain in market value under the program.

Using this approach, one firm usually just breaks even in each fuel category and thereby determines the allocation rule. These break-even firms are typically small and have idiosyncratic, unbalanced portfolios of assets. Often, to achieve full compensation these firms require a very high rate of allowances per MWh of generation in 1999, which leads to massive overcompensation of the other firms that also receive allowances at the same rate. Thus, in some cases these firms (a maximum of one firm in each region for each fuel) were deemed outliers and removed from the analysis and the allocation rules by fuel type are recalculated. The recalculated number of allowances required for compensation is divided by the total number of allowances under the cap over the period 2010–2030 to obtain the percentage of the allowance pool that must be given away.

It is not obvious ex ante whether facility-specific information will enable the attainment of compensation targets with few allowances when implemented at the federal or regional level. A federal perspective may help overcome an adverse selection problem. At the federal level, losses in one region may be offset by gains in another region, so that overall the firm may deserve less compensation than if viewed on a region-by-region basis. On the other hand, there is more heterogeneity among facilities and their characteristics at this level. At the regional level, regulators can apply rules based on facility-specific information with greater precision, taking advantage of greater homogeneity in the region. In the following experiments we seek to identify the compensation strategy that requires the smallest free allocation to achieve a compensation target.

7.2.1. Accounting for Fuel Characteristics

The allocation rules that we identify are differentiated by fuel type so that, for example, gas and coal fired generators receive a different amount of allowances per MWh of historical generation. There is regulatory precedent for differentiating allowance allocation by fuel type in order to compensate firms differentially. Under the U.S. Environmental Protection Agency's (EPA) Clean Air Interstate Rule, NO_x allowances are allocated to coal-fired generators at the rate of the total number of NO_x allowances divided by the fuel-adjusted total average annual heat input between 1999 and 2002. Under this rule, gas-fired generators receive allowances at 40 percent of the coal-fired rate (per BTUs of total historic heat input), and oil-fired generators receive allowances at 60 percent of the coal-fired rate.

The second set of columns in Table G reports results with incomplete information when the policy is implemented at the federal level. Differentiation by fuel type requires 100 percent of allowances to be given away for free. To achieve the compensation goal requires coal generation to be compensated at a rate of 45.06 allowances per MWh of generation in 1999, oil generation receives none, and natural gas generation is compensated at 50.35 allowances per MWh. To put these numbers in perspective, firms would be compensated at a rate of 21.4 allowances per MWh of 2010 baseline generation under the historic allocation if all fossil generation were treated the same. This fuel-specific approach leaves the industry with a net gain in market value of $61 billion. Even though the use of fuel for the compensation metric requires that 100 percent of the allowances be given away, the net gain to the industry is less than under free allocation through direct grandfathering of allowances.[19] This $4 billion difference arises because free allocation to firms based on historic heat input (grandfathering) leads to a different level of consumption overall, compared to upstream allocation or an auction, which is assumed for regulated regions in Table G. As a result, firms in competitive regions gain value if consumption increases in regulated regions.

A different approach to allocation of emissions allowances would be to apportion the allowances to the states or regions—much as it is done under the NO_x State Implementation Plan Call trading program or to Member States in the EU Emissions Trading Scheme (EU ETS)—and then let states determine the allocation in order to achieve compensation goals and other policy objectives. Were the strategy of basing compensation on fuel type of individual facilities implemented at the regional level, a different solution could be obtained. We assume that at the state or regional level the regulator has information about the performance of generation facilities within that region only and therefore develops allocation rules based on fuel to compensate the worst-off firm in that region, based on that firm's portfolio of generation assets in that region.[20]

In Table H, we report that the portion of allowances that would need to be distributed would range from 27 percent in ECAR to 220 in the mid-Atlantic region, 209 percent in New York and 125 percent in New England. In the three regions receiving more than 100 percent, it would not be possible to achieve compensation through free allocation based on fuel type if the states apportionment were equal to what facilities in the region would receive under historic (grandfathering) allocation. Therefore we assume there is a reduction in the apportionment to other regions that is sufficient to achieve full compensation for every region. This is somewhat analogous to the universal service charge for long-distance telephone service or rural free delivery for the postal service, in which regional cross-subsidies were implemented to achieve network externalities.

The third set of columns in Table G provides results with incomplete information using a regional approach. The table indicates that in the aggregate, the decentralized

[19] For the 182 firms included in Table G, the net gain to the industry from free allocation is $65 billion. Table C indicates that for the full universe of firms, the gain in value for the entire industry is $68 billion.

[20] The rates at which incumbent facilities are compensated in each region for this and the subsequent cases that are discussed are reported in Appendix Table A.

approach requires 71 percent of the allowance value in the competitive regions to be given away for free to achieve compensation. In this case, the industry gains $41 billion in value. We find compensation can be more efficiently delivered at the regional level when using a simple rule that differentiates fuel type. This approach reduces the amount of overcompensation to the industry by $19.7 billion and frees up about 29 percent of the allowances for distribution through auction.

7.2.2. Accounting for Fuel and Technology Characteristics

In addition to differentiating by fuel type, we explore other variations on the compensation rule by incrementally adding more information. Another piece of incremental information that we consider is the type of natural gas technology at a facility. The columns labeled “Fuel + Gas” in Table G reflect our assumption that the regulator can differentiate among natural gas technologies, treating combustion turbines, steam, and combined cycle as classes of facilities deserving different allocation rules—and that the regulator combines this information with information about fuel. At the federal level this information by itself provides almost no value. The percent of allowances required for compensation is 99 percent, comparable to 100 percent in the absence of information about gas technology. At the regional level, however, this information provides considerable value. The percent of allowances required for compensation falls to 45 percent, and the net gain in market value for the industry falls to $23 billion.

The final columns in Table G add information about the percent of nonemitting generation that is part of the portfolio of each firm. One might expect that firms owning nonemitting generation will realize an increase in value from those assets and hence are unlikely to need as much compensation as firms that have a less balanced portfolio. By adjusting the allocation based on the nonemitting portion of the firm’s generation portfolio, we find we reduce the overcompensation that accrues to many firms. Using all this information at the federal level, this approach still requires that 86 percent of the allowances be given away for free.

Across the regions, however, the combination of fuel and technology information reduces that percentage to 39 percent, and it reduces the gain in market value for the industry to under $20 billion. Table H indicates that one region, New York, remains where full compensation of the worst-off firm cannot be achieved. But for the nation as a whole, this approach leaves 61 percent of the allowance value available for other purposes.

In summary, we find that making use of information about facility-specific fuel and technology in constructing a compensation strategy with the goal of compensating the worst-off firm provides only modest value at the federal level. If implemented at the regional level, however, a policy based on facility-specific information can achieve significantly greater efficiency in the design of compensation.

7.3. Incomplete Information: Compensation Based on a Firm's Emissions Rate

Another type of information that can be used to develop targeted compensation rules is the CO_2 emissions rate, which is closely related to a firm's fuel use and directly affects the cost of compliance with the policy. Emissions rate information is readily available or for all emitting fossil-fired facilities greater than 25 MW through the EPA's continuous emissions monitoring database. Since the firm represents a portfolio of facilities, we examine how well the change in the market value of the firm correlates with the firm-level emissions rates, and we find a strong correlation.

Figure 5 displays the relationship of the estimated change in market value ($/MWh) with upstream allocation to the average emissions rate (tons CO_2/MWh) for the largest 182 firms operating in competitive regions. The changes in market value for the firms that are estimated in the model simulation are divided by total generation across the facilities operated by each firm in 2010 in the baseline scenario. The average CO_2 emissions rate for firms is calculated from the baseline emissions and generation of the facilities in the firm's portfolio in 2010. Systematically, we find the loss in market value per MWh of generation increases with the baseline emissions rate. With upstream allocation, 57 of the firms gain value and 125 lose value. An ordinary least squares regression indicates the average emissions rate contributes importantly to the change in market value (R^2=0.62). The estimated threshold emissions rate at which firms are expected to break even is 0.52 tons/MWh. The estimated change in market value per change in emissions—in other words, the slope of the solid line in Figure 5—is $37.47 per ton (1999$). This coefficient is significant at the 99 percent level.

We use this information to calculate a formula to guide free allocation. We assume firms receive allowance value equivalent to $37.47 per ton of emissions from their portfolio of incumbent facilities (including facilities owned by these firms under construction up to the present), but only firms with an average emissions rate in excess of the threshold receive compensation, and they receive compensation only for the difference between their emissions rate and the threshold. For those firms with an emissions rate in excess of the threshold, we use the regression equation and the firm's emissions rate in 2010 under the baseline scenario to predict the compensation rate per MWh of generation in the baseline in 2010. In Table G, we report for the "Fit" case at the federal level; the amount of free allocation necessary to compensate all eligible firms using this formula is 27 percent of the allowances, leaving 73 percent available for auction. The result leaves 101 firms as winners, with a gain in value of $13.85 billion, and 81 firms as losers, with a loss of $2.59 billion.

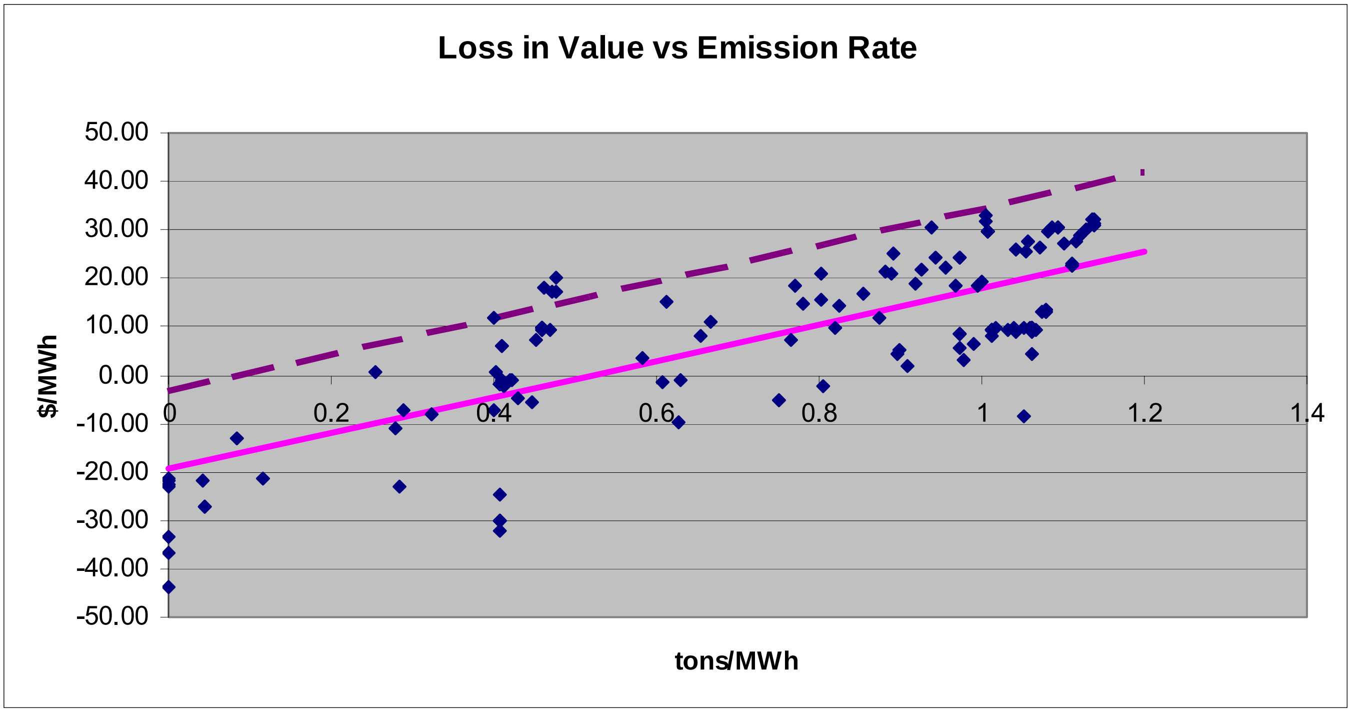

Figure 5. Change in the Market Value of 182 Firms Operating in Competitive Regions under Upstream Allocation/Auction per MWh of Operation as Forecast in the Baseline in 2010, Compared to the Firms' Average Emissions Rate for Existing Facilities as Forecast for 2010

Note: Also indicated are average emissions rates in competitive regions for four classes of technology.

The number of firms losing value can be reduced through more generous allocation so that virtually every firm is compensated, as reported in the "Full" case in Table G. Using an arbitrary decision rule at the federal level, we accomplish full compensation for all but five firms, including one outlier firm, by reducing the threshold to 0.09 tons/MWh. The upper dashed line in Figure 5 shows this example. We find that 65 percent of the allowances must be given away, leaving 35 percent available for auction. This leaves five firms with losses of $120 million, while the industry as a whole gains value of $36.7 billion.

The percent of allowances that must be given away for free to compensate the worst-off firm is reduced further if compensation on the basis of emissions rates is calculated and implemented at the regional/state level. In this case, we calculate thresholds and coefficients for compensation for each firm separately in each region. Although some firms receive compensation in some regions but not others and may be overcompensated overall, the coefficients relating compensation to emissions rates can be tailored to each region. In Table G, we report that at the regional level, full compensation based on emissions rates requires 32 percent of the allowances in competitive regions (15 percent nationally) and yields industry a net gain of $14.7 in value. Figures illustrating the expected distribution of loss as a function of emissions rates differ for each region.

7.4. Overview of Compensation Strategies

If regulators lack complete information about the performance of firms, they can use readily available information to design rules as a way to compensate losing firms. How well this proxy is achieved depends whether a federal or regional approach is adopted. If regions/states are assigned emissions budgets and apportioned emissions allowances, we find the regions can achieve compensation goals much more efficiently than can be achieved from the federal level.

At the regional level, facility-specific information can enable full compensation using 39 percent of the emissions allowances in competitive regions (19 percent of national allowances). This approach leaves a net gain in the industry of $19.5 billion. At the national level, this approach requires free allocation using 86 percent of the emissions allowances in competitive regions (42 percent nationally), yielding the industry a net gain of $52 billion. Compensation can be delivered even more efficiently on the basis of emissions rates. At the federal level, full compensation could be achieved using 65 percent of emissions allowances in competitive regions (31 percent of national allowances), leaving a net gain in the industry of $36.7 billion. At the regional level, full compensation based on emissions rates requires 32 percent of the allowances in competitive regions (15 percent nationally) and yields industry a net gain of $14.7 in value. Incomplete information raises the cost of providing compensation, but careful design of compensation rules can dramatically lower that cost.

On the other hand, if regulators can obtain and act on information about the expected performance of firms, they could compensate losers directly without providing compensation to winners. In this case, it would be sufficient to give away just 22 percent of the emissions allowances in competitive regions (11 percent nationally), leaving 78 percent of the allowances available for auction (89 percent nationally). This would still leave a net gain in the industry of $7.51 billion.

8. The Compensation Goal

We have maintained a 100 percent compensation goal for the most disadvantaged firms as a yardstick for comparing the different approaches to the distribution of allowances. In reality, the regulator may decide on a goal that differs from 100 percent compensation. Let us denote the share of the value of allowances that must be given away for free to achieve this goal as *S*. For a compensation target less than 100 percent—that is for $\theta < 1$—the value of allowances necessary to achieve that goal is $\theta \cdot S$.

Several factors influence the compensation goal (θ). Hochman (1974) argues that individual behavior presumes the permanence of preexisting rules, and dealing equitably with those who suffer windfall losses may be crucial to preserving a belief in the fairness of social rules and institutions. On the other hand, investors in a competitive market are expected to anticipate uncertainties and factor them into account, and some observers argue that society is better off in the absence of compensation.[21]

Some policy changes have a positive effect and some have a negative effect on investments. For the most part, investors retain the payoff when gains exceed expectations. However, sometimes regulators or legislators intervene to prevent profit making, as in recent decisions in Maryland and Illinois that allow consumers to phase in adjustments in electricity rates when rate caps that survive from industry restructuring will be lifted. Fairness and efficiency may be served by a symmetric process in which the regulator relieves the firm of some, but perhaps not all, responsibility for changes in policy that impose large loss in value. Inevitably, the final outcome will be shaped as

[21] For example, Polinsky (1972) suggests that a single policy should be viewed as part of a larger social agenda in which government pursues many policies to improve the welfare of society generally.

much by political necessity as by compensation principles, but information about those principles can help inform the policy dialogue.[22]

Timing also affects the need for compensation. The emergence of climate policy may have been anticipated years ago—perhaps with the signing of the Kyoto Protocol—which may be said to remove the element of surprise for subsequent events. The time between announcement and implementation of a policy gives firms that are to be regulated time to adjust their investment plans so as to avoid new investments that would be particularly disadvantaged under the forthcoming policy and to make investments that will perform better under the policy. To the extent that the loss in economic value stems from investments made between the announcement and implementation of the policy, this advance warning diminishes the claim for harm. Most investments since the early 1990s were in natural-gas-generation technologies, some of which gain value and some of which lose value due to climate policy.

A second aspect to delay is that it may allow for the continued realization of economic value from investments that predate the policy. As a consequence, the lost economic value will be less than if the policy were implemented in the same year it is announced because for the intervening years the owner will continue to incur revenues and costs equivalent to those in the baseline. Therefore, the need for compensation will be less if implementation occurs sometime after the adoption of the policy. But although delay reduces the harm, it does not directly affect the compensation target (as a share of harm that is to be compensated) or the share of allowance value necessary to achieve the target.

To illustrate these points, we assume that the annual value of existing assets going forward is constant in every year t in the baseline (v^{BL}) and also constant at a reduced value under the auction policy (v^{A}). If the policy were adopted and implemented in the same year, the loss in value (L) would be

$$L = \sum_{t=0}^{\infty} \partial^t \left(v^{\mathrm{BL}} - v^{\mathrm{A}} \right) = \left(\frac{1}{1-\partial} \right) \left(v^{\mathrm{BL}} - v^{\mathrm{A}} \right).$$

[22] A "public choice" view is that appropriate compensation is discovered in a political market place, with bartering commencing in the form of political negotiations (Buchanan 1973). Compensation serves a practical purpose by this rationale, affecting a political buy-out of groups opposing changes in social policy (Tullock 1978).

Assume the discount factor is $\partial = 0.92$, corresponding to a discount rate 0.08. The instantaneous loss in the value of existing assets from the implementation of the policy is $L = (12.5)\left(v^{\mathrm{BL}} - v^{\mathrm{A}}\right)$. If implementation were to be delayed by five years after the adoption of the policy, the loss in value due to the policy would be

$$L = \sum_{t=5}^{\infty} \partial^t \left(v^{\mathrm{BL}} - v^{\mathrm{A}}\right) = (8.24)\left(v^{\mathrm{BL}} - v^{\mathrm{A}}\right).$$

The delay in implementation reduces the financial magnitude of harm by more than one-third. However, delay between adoption and implementation also reduces the present value of allowances measured at the time when the policy is adopted. Consequently, the portion of allowance value (*S*) required for full compensation is unchanged.

9. Conclusion

A CO_2 regulation implemented upstream can be viewed as an auction from the perspective of the electricity sector. Whether producers or consumers of electricity bear the cost of such a policy depends on whether generators are subject to cost-of-service regulation or sell power at market-determined prices. In regulated regions, the utility regulator is assumed to compensate generators for federally mandated environmental policy, at least in the long run, and consumers bear the costs of the policy. In regions with market-based prices producers may bear a large share of the cost of an auction.

The measurement of the impact on producers depends on how one measures the harm. Financial losses at facilities that lose value under the policy we examine total to one-third the total present discounted value of the allowances created under the policy. However, many other facilities gain significant value under the policy. When viewed at the industry level on a national basis, which has been the focus of previous studies, the gains by one facility offset losses at other facilities, and net losses total just one-sixteenth (6 percent) of the value of allowances created.

This paper focuses on losses measured at the level of a firm and borne by shareholders. Cumulating the losses of firms that lose value, we find that total claims on compensation are roughly 11 percent of total allowance value nationally. Since we assume these losses all occur in competitive regions, we can compare the loss to the total allowance value in those regions to estimate that the claims of losing firms are about 22 percent of allowances in these regions. At the same time, many other firms are winners.

Consumer claims for compensation across regions depend on the fossil fuel intensity of the generating sector in the region, particularly in regulated regions. In the aggregate, consumer claims for compensation dwarf producer claims by a factor of 8 to 1. However, consumer claims for compensation are diffuse, and consequently they are less potent in the political context of carbon policy.

In previous programs in the electricity sector, the most common approach to the initial distribution of emissions allowances was to distribute allowances for free to firms according to a uniform formula based on historic emissions or heat input. This approach raises both distributional and efficiency issues. Uniform historic-based allocation will dramatically overcompensate firms in the aggregate, providing a net gain of $65 billion in the policy we analyze, and it is not well targeted to the firms with the largest losses. In particular, this approach will compensate firms but not consumers in competitive regions and only consumers in regulated regions. Historic-based allocation also diminishes the environmental effectiveness of the price-capped emissions trading policy in reducing CO_2 emissions because it dampens the price effect in regulated regions.

We search for decision rules based on publicly available data that can be used to distribute free emissions allowances in order to minimize the amount of overcompensation, and we ask whether this can be more efficiently achieved at the federal or regional/state level. Even under a national cap-and-trade program, states could determine allocation if state jurisdictions were assigned emissions budgets and apportioned emissions allowances, as occurred in the NO_x trading program and the EU ETS.

Regulators at the regional/state level can achieve full compensation using facility-level information or average emissions rates of a firm and do so more efficiently than when using similar rules at the federal level because at the state level, regulators can take advantage of the heterogeneity in costs and technology that disappears from the federal viewpoint. At the regional level, facility-specific information can enable full compensation using 39 percent of the emissions allowances in competitive regions (19 percent of national allowances) and 61 percent of the value of emissions allowances in those regions to be dedicated to purposes other than compensating electricity producers. This approach still leaves a net gain in the industry of $19.5 billion. At the federal level, achieving this compensation goal requires free allocation of 86 percent of the emissions allowances in competitive regions (42 percent nationally), resulting in $51 billion in net gain in the industry. It is less costly to achieve this compensation target based on average emissions rates calculated for each firm. At the regional/state level, firm-level emissions rates would require 32 percent of the allowances in competitive regions (15 percent nationally) to be given away, yielding $14.7 billion in gain across the industry. If allocation remains the purview of federal policy, full compensation using average emissions rate information would require 65 percent of emissions allowances in competitive regions (31 percent nationally) to be given away, and would leave a net gain in the industry of $36.7 billion.

This research also highlights the value of improved information. If regulators can obtain and act on information about the expected performance of firms, they can compensate losers directly without providing compensation to winners. In this case, it would be sufficient to give away just 22 percent of the emissions allowances in competitive regions, preserving 78 percent of the allowance value. This approach still leaves a net gain in the industry of $7.51 billion.

This research indicates that compensation of the worst-off firm can be achieved for much less than 100 percent of the value of emissions allowances, and to do so still leaves dramatic net gain in value for the industry. But this information begs the question of the appropriate level of compensation. All our analyses assume that the compensation goal is to fully compensate the worst-off firm, but less than 100 percent compensation may be desirable for a variety of reasons. For instance, one factor that can lower the level of harm is a delay between when a policy is announced and when it is implemented. A second factor may be the desire to limit compensation overall, especially since compensating firms has dramatic cost. Under even the most efficient policy, with incomplete information the cost of eradicating the last $2.6 billion is about $25.4 billion in allowance value, nearly 10 times the value of the harm. At the regional/state level, we find the incremental cost of compensating for the last $1.35 billion in harm spread across is $6.01 billion, about 4.5 times the harm. These opportunity costs may suggest practical limits on the amount of compensation that should be incorporated in climate policy.

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Appendix

Appendix Table A1. Regional Approach by Reported by Regions

	ECAR				
Information:	Complete	Incomplete			
Compensation Metric:		Generation Fuel / Technology:			
	Firm Value	**Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation rate (tons per MWh)					
Coal		13.50	13.50	13.50	13.50
Oil		0	0	0	0
Gas (all)		0	0	--	--
Gas (steam)		--	--	0	0
Gas CC		--	--	0	0
Gas CT		--	--	0	0
# Winners	70	70	70	70	70
Gain (billion $)	1.74	6.29	5.63	6.29	5.63
# Losers	0	0	0	0	0
Loss (billion $)	0	0	0	0	0
Industry Net (billion $)	1.74	6.29	5.63	6.29	5.63
Free Allowances (%)	12%	27%	24%	27%	24%

	ERCOT				
Information:	Complete	Incomplete			
Compensation Metric:		Generation Fuel / Technology:			
	Firm Value	**Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation rate (tons per MWh)					
Coal		32.29	32.29	28.80	28.80
Oil		0	0	0	0
Gas (all)		5.24	5.24	--	--
Gas (steam)		--	--	55.72	55.72
Gas CC		--	--	5.24	5.24
Gas CT		--	--	0	0
# Winners	49	49	47	49	48
Gain (billion $)	0.385	2.56	1.70	2.50	1.65
# Losers	0	0	2	0	1
Loss (billion $)	0	0	0.01	0	0
Industry Net (billion $)	0.385	2.56	1.69	2.50	1.65
Free Allowances (%)	25%	45%	37%	45%	37%

Information:	MAAC				
	Complete	Incomplete			
Compensation Metric:	Firm Value	Generation Fuel / Technology: **Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation rate (tons per MWh)					
Coal		36.87	36.87	36.87	36.87
Oil		0	0	0	0
Gas (all)		571.3	571.3	--	--
Gas (steam)		--	--	0	0
Gas CC		--	--	7.34	7.34
Gas CT		--	--	1,528	1,528
# Winners	35	35	34	35	33
Gain (billion $)	1.09	15.61	13.56	3.97	2.69
# Losers	0	0	1	0	2
Loss (billion $)	0	0	0.004	0	0.004
Industry Net (billion $)	1.09	15.61	13.56	3.97	2.69
Free Allowances (%)	34%	220%	193%	71%	54%

Information:	MAIN				
	Complete	Incomplete			
Compensation Metric:	Firm Value	Generation Fuel / Technology: **Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation rate (tons per MWh)					
Coal		31.97	31.97	31.97	31.97
Oil		0	0	0	0
Gas (all)		360.8	360.8	--	--
Gas (steam)		--	--	0	0
Gas CC		--	--	0	0
Gas CT		--	--	360.8	360.8
# Winners	35	35	35	35	35
Gain (billion $)	3.00	7.44	6.65	4.64	4.00
# Losers	0	0	0	0	0
Loss (billion $)	0	0	0	0	0
Industry Net (billion $)	3.00	7.44	6.65	4.64	4.00
Free Allowances (%)	40%	76%	70%	53%	48%

Information:	Complete	Incomplete			
	NY				
Compensation Metric:	Firm Value	Generation Fuel / Technology: **Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation rate (tons per MWh)					
Coal		27.55	27.55	27.55	27.55
Oil		640.1	640.1	640.1	640.1
Gas (all)		132.6	132.6	--	--
Gas (steam)		--	--	132.6	132.6
Gas CC		--	--	70.72	70.72
Gas CT		--	--	85.90	85.90
# Winners	53	53	51	53	51
Gain (billion $)	1.47	5.96	5.36	4.20	3.85
# Losers	0	0	2	0	2
Loss (billion $)	0	0	0	0	0.001
Industry Net (billion $)	1.47	5.96	5.36	4.20	3.85
Free Allowances (%)	40%	209%	187%	143%	130%

Information:	Complete	Incomplete			
	NE				
Compensation Metric:	Firm Value	Generation Fuel / Technology: **Fuel**	**Fuel +Clean**	**Fuel +Gas**	**Fuel +Clean +Gas**
Allocation rate (tons per MWh)					
Coal		36.03	36.03	26.03	26.03
Oil		0	0	0	0
Gas (all)		53.34	53.34	--	--
Gas (steam)		--	--	0	0
Gas CC		--	--	19.95	19.95
Gas CT		--	--	53.34	53.34
# Winners	29	29	26	29	26
Gain (billion $)	0.832	3.18	3.02	1.72	1.65
# Losers	0	0	3	0	3
Loss (billion $)	0	0	0.011	0	0.018
Industry Net (billion $)	0.832	3.18	3.01	1.72	1.63
Free Allowances (%)	21%	71%	63%	45%	39%