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Cap-and-Trade Climate Policy, Free Allowances, and Price-Regulated Firms

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Cap-and-Trade Climate Policy, Free Allowances, and Price-Regulated Firms*

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Abstract

Firms subject to cost-of-service regulation cannot withhold windfall profits associated with free emissions allowances. This paper examines the efficiency and distributional impacts of two approaches to transfer free allowances to consumers: output subsidies and lump-sum payments. We employ an empirically calibrated model of the U.S. economy that features regulated monopolies in the electricity sector and many heterogeneous households. Under a carbon dioxide cap-and-trade policy, we find that using free allowances to subsidize regulated electricity prices increases aggregate welfare costs by 40-80 percent relative to lump-sum transfers. These inefficiencies are disproportionately borne by households in the tails of the income distribution.

Keywords: Climate policy, Cap-and-trade, Allowance allocation, Cost-of-service regulation, Electricity Generation.

JEL classification: C61, C68, D58, Q43, Q54

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1 Introduction

Over the past three decades, market-based "cap-and-trade" (CAT) regulations have become a centerpiece of environmental policy in the U.S. and in Europe. In a competitive setting with full information, the creation of a market for emission allowances will equalize marginal abatement costs across sources, thereby minimizing aggregate compliance costs (Montgomery, 1972). The efficiency property of CAT regulations hinges upon the emissions price signal, so that the initial distribution of allowances can be used to target specific distributional outcomes or promote political support for the policy (Stavins, 2008). In particular, freely allocating allowances to emissions sources preserves the implicit property rights prevailing before the regulation, and it can relieve participating firms from the compliance costs (Hepburn et al., 2012). Allocating allowances for free has been used for sulfur dioxide regulation in the U.S. and in Europe's carbon dioxide (CO_2) market, and projections for a U.S. CO_2 CAT policy suggest that free allowance allocation would more than offset firms' compliance costs (Goulder et al., 2010).

This paper examines how the presence of price-regulated firms affects the outcome of CAT regulations when allowances are initially free. Under traditional cost-of-service price-regulation, output prices are set to cover operation costs, and capital gains in the form of free allowances have to be transmitted to consumers. If the price-setting authority requires regulated firms to adjust output prices with the value of free allowances, so that free allowances implicitly subsidize the price paid by consumers, the opportunity cost of allowances will not be fully reflected in output prices. In turn, a failure of output prices to fully reflect the value of emissions will distort consumer choices, decreasing conservation incentives, and thereby imply inefficiently high emissions by regulated firms. Given that aggregate emissions are capped, the redistribution of abatement across the economy will affect the allocative efficiency property of CAT policies. As an alternative, the regulator could require any profits from allowance trading, including freely received allowances, to be transferred lump-sum to households, thereby preserving the price signal associated with emissions.[1]

The treatment of free allowances by the price-setting authority is of practical importance for the design of U.S. climate policies. The U.S. electricity sector features a large number of regional monopolies that generate nearly 60% of total electric power and emit around 30% of economy-wide CO_2. These firms are subject to cost-of-service regulation and electricity rates

[1] A CAT policy where allowances are auctioned would avoid this issue altogether, although it is politically contentious and brings up the wider question of revenue recycling (see e.g. Goulder et al., 1999).

are set by Public Utility Commissions (PUCs), which aim to protect the interests of consumers (Joskow, 2006). In this setting, a Federal CAT policy where allowances are freely allocated to emissions sources could interact with the objectives of regional PUCs. In particular, using free allowances to subsidize output prices would mitigate the impact of the policy on electricity rates, and thus reduce the burden accruing to households. This could represent an attempt to alter the distributional incidence of the policy by alleviating the regressive element of CO_2 pricing associated with the fact that low income households spend a larger fraction of their income on utility bills.[2]

In order to quantify *ex-ante* the efficiency costs and assess the distributional incidence of alternative treatments of free allowances, we employ an empirically calibrated model for the U.S. economy. The behavioral assumptions of the model are simple and based on cost minimization of firms and utility maximization of households. However, the underlying data, representation of electricity markets and household heterogeneity, as well as computational methods are uniquely well-suited for our purposes and novel in several dimensions. First, to characterize abatement opportunities in the electricity sector, we use data on all 16,891 electricity generators active in 2006 (Energy Information Agency (EIA), 2007a). Generators are owned by a set of operators, and we identify 319 operators subject to cost-of-service regulation (EIA, 2007b). Regulated operators are treated as cost-minimizers charging average costs, whereas generators owned by non-regulated operators trade on imperfectly competitive regional wholesale markets.[3] This framework provides a "bottom-up" structural representation of abatement options in the electricity sector, in that substitution among electricity technologies is driven by generator-level data on generation costs, taking into account fuel switching possibilities, time-varying demand for electricity, and limited trade opportunities among electricity operators.

Second, we embed the operator-level representation of electricity generation into a general equilibrium representation of the U.S. economy. The model is calibrated to rationalize an input-output representation of regional economic accounts for 2006, which allows us to characterize economy-wide effects of the policy, including fuel markets interactions and abatement opportunities outside the electricity sector. Moreover, working in general equilibrium where households

[2] In Europe's CO_2 CAT regulation, the distribution of free allowances to participating firms induced several governments to put pressure on electricity providers in order to mitigate electricity price increases (Radov and Klevnas, 2007; Sijm et al., 2008; Shuttleworth and Antstey, 2012).

[3] Although the degree of competition on wholesale markets is not the primary focus of this paper, it is an important determinant of the outcome of market-based environmental policy (e.g. Malueg, 1990). We thus follow Bushnell et al. (2008) and Fowlie (2009) and model wholesale markets as a set of large Cournot players interacting with a competitive fringe.

own productive assets enables us to quantify both income-use and income-source side effects (Musgrave, 1964).

Third, our framework recognizes the considerable heterogeneity among households. We integrate "real" households as individual agents in the model with data on all 15,588 respondents from the Consumer Expenditure Survey (CEX), a representative sample of the U.S. population (Bureau of Labor Statistics (BLS), 2006). Disaggregating theoretically sound welfare indexes at the household level enables us to quantify the distributional impacts of the policies studied here.[4]

Fourth, given the dimensionality and highly non-linear nature of the problem, with a large number of electricity operators and many heterogeneous households, we employ numerical decomposition methods by Rutherford and Tarr (2008) and Böhringer and Rutherford (2009). This allows us to obtain mutually consistent solutions for each sub-problem that together represent a general equilibrium.

We employ the model to study a setting where allowances are freely allocated to emission sources and where regulated electricity producers have to transfer the value of free allowances to consumers. More specifically, we investigate two design features of economy-wide CAT regulations. First, we compare a case where electricity rates are adjusted in proportion to the value of free allowances, which is equivalent to a subsidy for a subset of electricity consumers, against direct transfers to households through lump-sum payments. In our setting, the latter case can also be interpreted as an auction whose revenues are distributed back to households through per-household lump-sum transfers.[5] The second design dimension of interest is the basis to determine the amount of allowances received for free, i.e. benchmark emissions or benchmark output. If free allowances are used to subsidize electricity rates, allocating allowances based on benchmark emissions mitigates electricity price increases of the most CO_2-intensive operators. This can smooth price differentials across operators, but magnifies economic distortions. Using benchmark output as a basis for allowance allocation provides an intermediate case, as it would equalize the subsidy rate across regulated operators, thus partially preserving the link between emissions intensity and output prices.

While this paper provides the first comprehensive assessment of free CO_2 allowances in the

[4] See, for example, Fullerton and Heutel (2007) for a discussion of general equilibrium-based incidence measures of environmental taxation.

[5] In the case of an auction, however, the government could use revenues to reduce pre-existing distortionary taxes, thereby affecting the overall regulatory burden (Bovenberg and Goulder, 1996). We rather focus on PUC behavior and consider only the case of per-household lump-sum transfers.

presence of price-regulated electricity producers, our results complement a number of existing studies. Paul et al. (2010) study the allocation of allowances in CAT policies for the U.S. electricity sector alone in a numerical partial equilibrium model, where 12 out of 21 regions are subject to cost-of-service regulation. Burtraw et al. (2009) and Rausch et al. (2010) provide evidence on the allocation of free allowances to electricity distribution companies, which would implicitly subsidize electricity prices for *all* electricity consumers.[6] Focusing on the interactions between PUCs and market-based environmental regulation, theoretical work by Bohi and Burtraw (1992), Coggins and Smith (1993) and Fullerton et al. (1997) show that cost-of-service regulation and PUCs can induce inefficient abatement behavior, potentially increasing the welfare costs of a CAT policy. Evidence from empirical studies confirms this view. In the context of the Clean Air Act, Arimura (2002) finds that uncertain PUCs rulings mitigated incentives for allowance trading. In the NO_x Budget Program, Fowlie (2010) shows that regulated operators were more likely to invest in capital-intensive abatement technologies due to guaranteed rates of return. While we make the simplifying assumption that PUCs are successful in inducing cost minimization, so that regulated monopolies efficiently abate given the prevailing allowance price, our results further support the view that the discretionary power of PUCs is a key factor in the outcome of CAT regulations.

The paper proceeds as follows. Section 2 offers a graphical illustration of the central issue of this paper. Section 3 provides some background about U.S. electricity markets. Section 4 describes our modeling framework. Section 5 lays out the policy scenarios, reports simulation results, and discusses our findings and assumptions. Section 6 concludes.

2 Allowance Allocation and Price Regulation: A Graphical Illustration

In the presence of price-regulated firms, the initial allocation of emissions allowances can impact the outcome of a CAT policy. To convey the intuition about the incidence of alternative policy designs, Figure 1 provides a partial equilibrium representation of CAT equilibrium outcome for a monopolist subject to cost of service regulation. In the initial equilibrium without environmental regulation, the output price and level are $\overline{P}$ and $\overline{Q}$, respectively. These are determined by

[6] This work is inspired by the American Clean Energy and Security Act of 2009 which planned to allocate around 30% of allowances directly to local electricity distribution companies (see Holt and Whitney (2009) for an overview).

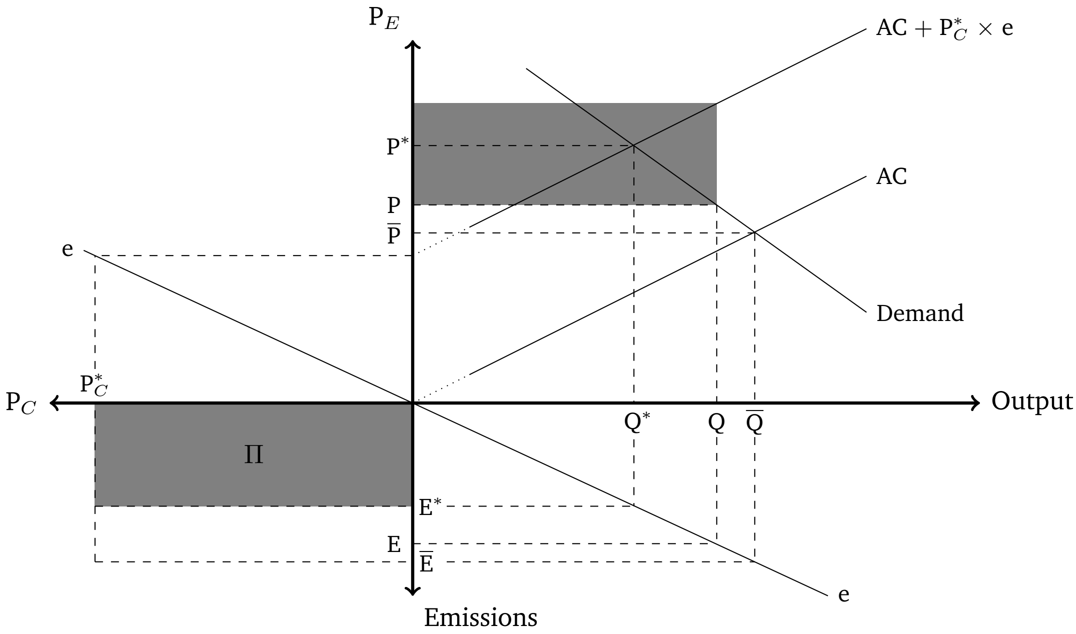

Figure 1: Market equilibrium, allowance allocation, and price regulation.

the intersection of the market demand with the average cost schedule (AC) of the regulated monopolist (the marginal cost is assumed to be linearly increasing in output). Given a constant emission rate e, benchmark emissions are given by $\overline{E}$.

Under a CAT policy with associated allowance price P_C^*, the monopolist must surrender allowances to cover its emissions. If allowances are auctioned, buying allowances at price P_C^* increases production costs and shifts the supply curve upwards ($AC + P_C^* \times e$). The new equilibrium (P^*, Q^*), associated with emissions E^*, fully reflects emissions price P_C^*.

If allowances to cover emissions E^* are initially free, firms make a "windfall" capital gain represented by the shaded area Π in the bottom-left quadrant. For regulated monopolies, these profits are not allowed, and the value of free allowances needs to be passed forward to consumers. If Π is transferred to consumers through output prices, so that the shaded area is used to subsidize the price of output, the price signal associated with emissions is distorted ($P \leq P^*$). In turn, output and emissions are higher than in the efficient equilibrium ($Q \geq Q^*$, $E \geq E^*$). If Π is instead transferred to consumers as a lump-sum payment, relative prices are not affected and equilibrium (P^*, Q^*, E^*) prevails.

In the context of regulated electricity monopolies in the U.S. electricity sector, free allowances have two policy-relevant effects. First, subsidizing electricity rates with free allowances increases emissions by regulated firms. Since aggregate emissions are constrained by the cap, higher emissions by regulated firms will increase the price of allowances and redistribute emission reductions towards non-regulated firms, increasing aggregate compliance costs. Second, a subsidy mitigates electricity price increases, thereby sheltering a subset of consumers from potentially large increases in electricity rates, suggesting that consumers could be better off by subsidizing electricity prices. This view however does not consider income-side welfare effects of the policy.

On deregulated wholesale markets, electricity prices are a function of the marginal generation cost of the most expensive technology used to cover the demand. As the opportunity cost of trading allowances will be included in firms' bidding behavior, the wholesale price will reflect the value of emissions regardless of the allocation method. Hence the magnitude of efficiency costs depends on the share of emissions from regulated firms, in addition to the price-responsiveness of electricity consumers, and on the marginal abatement cost in other economic sectors.

3 Electricity Markets and CO_2 Emissions in the U.S.

Historically, the U.S. electricity sector has developed through regional monopolies, where generation, transmission and distribution are vertically integrated. On each market, electricity rates are regulated by a PUC to protect customers from monopoly pricing. The "rate of return" regulation allows utilities to recover prudently incurred operating costs, so that consumers pay a price comparable to the average accounting cost of service. In the 1970s, a movement of deregulation took place across numerous regulated industries (Winston, 1993), and the 1978 Public Utilities Regulatory Policies Act provided initial legal support for a separation of generation from transmission. In addition, limited economies of scale in modern generation technologies and advances in high-voltage transmission technologies increased opportunities for mutually beneficial trades to take place in a highly balkanized system (Joskow and Schmalensee, 1983).

Through regulatory and technological evolution, traditional regional monopolies were progressively complemented by investor-owned independent power producers that had no network ownership and directly supplied large industrial activities. This situation created a demand from other industrial consumers to be able to purchase electric power from alternative suppliers, particularly in areas with high electricity prices (Joskow, 2005). Through the Energy Policy Act of 1992, the Federal Energy Regulatory Commission (FERC) could order electric utilities to let current transit on their network, implicitly inviting market transactions to take place on the network for a fee. In 1999, the FERC called for the creation of Regional Transmission Organizations in order to provide independent supervision of transmission grids.

The trend towards competitive wholesale markets slowed down significantly after the 2000-

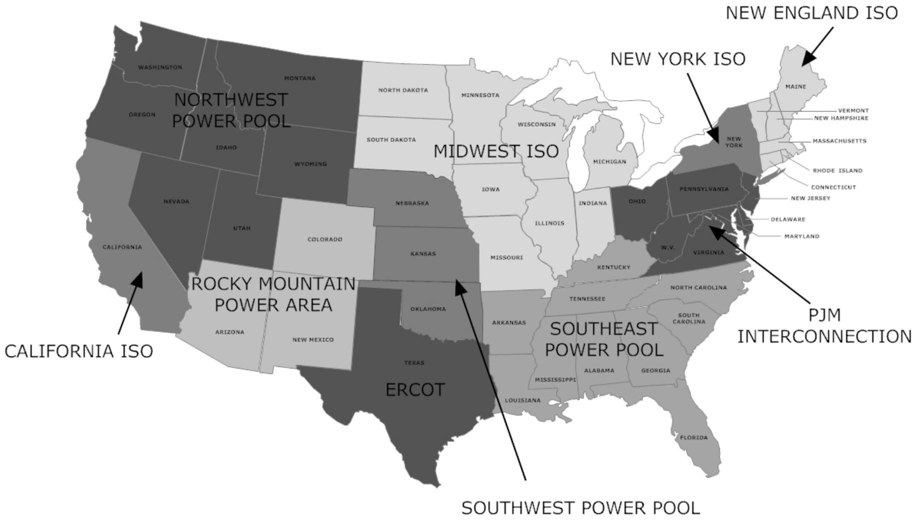

Figure 2: State-level aggregation of national electric power market regions.

01 electricity crisis in California. As of 2006, the base year for our analysis, around 60% of electric power is generated by regulated utilities. The electricity sector in continental U.S. can can be divided in 10 regions, which we approximate by state-level borders in Figure 2. While in most of these regions the administration of transmission networks has been transferred to an Independent System Operator, in all regions there remains a number of regulated utilities (Table 1). For example, in the state of Texas, where most electricity producers have joined the ERCOT wholesale market, some 20 regulated monopolies are active within state borders. In regions such as NY and CA, a small number of regulated operators hold with large, mainly hydroelectric capacity, while in SEAST, SPP and MOUNT, electric power is almost entirely generated by regulated operators.[7] Note that given the existence of regulated producers in each regions, wholesale electricity markets cover a smaller area than regions reported in Figure 2. But for simplicity we refer to geographical areas by the name of associated regional wholesale electricity market.

Empirical evidence suggests that regional wholesale electricity markets are best described as oligopolies (see for example, Wolak, 2003; Mansur, 2007; Puller, 2007; Bushnell et al., 2008). While conventional market concentration indexes have drawbacks as a measure of imperfect competition for non-storable goods (Borenstein et al., 1999), the Herfindahl-Hirschman Indexes shows that regions with a low share of non-regulated production (MISO, MOUNT, NWWP, and SPP) exhibit the highest concentration. Conversely, in regions with a high share of generation

[7] Regulated operators also sell and buy power through wholesale transactions. For our purposes, the key feature of regulated operators is that their rates reflect generation costs as these are still subject to approval by PUCs.

Table 1: Regional electricity generation, market structure and CO_2 intensity in 2006.

Region	Generation (TWh)	Regulated generation %	Regulated N[a]	Regulated tCO_2/MWh	Non-regulated %	Non-regulated N[b]	Non-regulated HHI[c]	Non-regulated tCO_2/MWh
SEAST	1,126.6	87.0	87	0.61	13.0	287	310	0.60
SPP	142.4	86.2	133	0.78	13.8	30	1,570	0.42
MOUNT	214.1	85.7	38	0.73	14.3	57	1,160	0.38
NWPP	317.4	79.5	64	0.38	20.5	154	1,130	0.63
MISO	724.4	67.7	305	0.85	32.3	315	1,680	0.47
CA	231.3	49.8	39	0.19	50.2	317	220	0.42
PJM	665.0	35.5	51	0.79	64.5	259	580	0.58
NY	142.9	29.6	14	0.30	70.4	148	550	0.37
ERCOT	348.9	13.2	20	0.84	86.8	157	820	0.52
NENGL	132.8	4.8	28	0.79	95.2	214	510	0.40
US-wide	4045.7	61.2	731	0.65	38.8	1938	–	0.51

Notes: [a] Number of traditional vertically integrated electric utilities. [b] Number of independent electric power producers. [c] Herfindahl-Hirschman index. *Sources*: Authors' own calculations. Data on generation and operator's regulatory status is from EIA Form 906-920 (2007b). CO_2 emissions are based on fuel consumption for each operator (EIA Form 906-920, 2007b) and fuel-specific CO_2 emissions factors (EIA, 2009a).

from non-regulated operators, capacity on wholesale markets is less concentrated.

The fragmentation of the U.S. electricity sector and differences in generation technologies available on each market implies that the impact of CO_2 pricing policies will be highly heterogeneous. The CO_2 content of electricity from regulated operators is on average about one third higher as compared to non-regulated operators, with large variations at the regional level. Electricity produced by regulated operators in NENGL and ERCOT emits almost twice as much CO_2 per MWh as compared to non-regulated operators in these regions, as the latter hold large natural gas capacity. In CA, NWPP, and NY, regulated operators mainly hold hydroelectric resources, and the CO_2 intensity of non-regulated operators is higher.

4 Data, Modeling Framework and Computational Strategy

To quantify the impacts of alternative treatments of free allowances received by price-regulated firms, we develop a numerical representation the U.S. economy that features (i) a "bottom-up" generator-level model of electricity generation, (ii) a detailed representation of regional electricity markets' structure, including regulated markets and imperfectly competitive regional wholesale markets, (iii) a general equilibrium model of economy-wide interactions, and (iv) a model of final consumer demand that integrates the utility-maximizing behavior of many heterogeneous households based on micro-data from the CEX.

The model is formulated as a mixed complementarity problem (Rutherford, 1995) distinguishing two classes of equilibrium conditions: zero economic profits and market clearance. The former condition determines a vector of activity levels and the latter determines a vector of prices.[8] Given the large number of electricity markets and households, however, it is computationally not feasible to operate directly on the system of equations defining the vector of equilibrium prices and quantities. We therefore make use of recent advances in decomposition methods pertaining to the computation of equilibria in numerical general equilibrium models with bottom-up technology representation Böhringer and Rutherford (2009) and many heterogeneous households Rutherford and Tarr (2008). This involves formulating electricity markets and households optimization problems as partial equilibrium problems, and consistently integrate the solution to these problems into an economy-wide framework. We stress that the numerical techniques applied here solve for a general equilibrium, i.e. simultaneous equilibria on all markets taking into account optimizing behavior of all firms and households.

We now turn to the description of the economy-wide interactions, electricity markets, household behavior, and numerical techniques employed to integrate multiple electricity markets and the many heterogeneous households within a consistent general equilibrium framework.

4.1 Economy-wide Aggregate Economic Activities

4.1.1 Data

We use 2006 state-level economy-energy data where each state is described by a social accounting matrix from the 2006. The IMPLAN data set (Minnesota IMPLAN Group, 2008) provides an input-output representation of social accounts for production, consumption and trade for 509 commodities, existing taxes, government revenues and transfers. To expand the characterization of energy markets in the IMPLAN data, we supplement it with data on energy quantities and prices for 2006 (EIA, 2009c). Energy commodities identified in our study include coal (COL), natural gas (GAS), crude oil (CRU), refined oil (OIL), and electricity (ELE); this allows us to account for the substitutability between different energy sources in industrial production and final

[8] The mixed complementarity format embodies weak inequalities and complementary slackness, relevant features for problems with corner solutions and bounds on specific variables. Moreover, as it essentially solves the system of Karush-Kuhn-Tucker conditions of the associated optimization problem, the mixed complementarity formulation can accommodate multiple decision-makers engaged in strategic interaction, whose objective are not integrable. Formally, given a function $F\colon \mathbb{R}^n \longrightarrow \mathbb{R}^n$, we search for a vector $z \in \mathbb{R}^n$ such that $F(z) \geq 0$, $z \geq 0$, and $z^T F(z) = 0$. A complementary-based approach has been shown to be convenient, robust, and efficient (Rutherford, 1995). We formulate the numerical model in the GAMS software and solve it using the PATH solver (Dirkse and Ferris, 1995).

Table 2: Sectoral CO_2 emissions and regional emission intensity.

Region	Total emissions ($MtCO_2$)	Sectoral share of emissions (%)							Emission intensity (tCO_2/\$)
		Electricity sector		Non-electricity sectors					
		Wholesale	Regulated	AGR	EIS	SRV	TRN	MAN	
ERCOT	639.9	27.8	6.5	1.0	26.5	2.6	32.2	3.4	0.71
SPP	204.1	5.3	45.1	3.2	8.9	3.1	30.1	4.3	0.65
SEAST	1335.3	5.9	43.0	0.8	10.6	1.3	36.4	2.0	0.52
MISO	1056.5	11.2	38.7	1.7	10.1	4.0	29.7	4.5	0.51
MOUNT	251.6	1.2	48.9	0.7	4.5	2.3	39.9	2.5	0.47
PJM	908.7	27.0	20.5	0.2	11.2	3.7	35.5	1.8	0.44
NWPP	313.0	13.8	30.0	1.9	5.5	2.2	44.8	1.8	0.43
NENGL	143.0	31.8	3.7	0.5	4.1	3.9	55.1	0.9	0.24
CA	359.0	9.6	5.6	0.7	6.9	3.9	67.7	5.7	0.23
NY	163.9	21.8	13.6	0.4	5.3	14.1	43.3	1.6	0.22
US-wide	5374.9	14.8	29.2	1.0	11.3	3.2	37.6	2.9	0.44

Sources: CO_2 emissions from the electricity sector are based on simulated fuel consumption in the benchmark and fuel-specific CO_2 emission factors (EIA, 2009a). Emissions calculations for non-electricity sectors are based on EIA's State Energy Data System (EIA, 2009c), witch also underlies the calculation of emissions intensity together with economic value flows for industrial output from IMPLAN data 2008.

demand. Our commodity aggregation further comprises five non-energy composites: energy-intensive products (EIS), other manufacturing products (MAN), agriculture (AGR), transportation (TRN), and Services (SRV). Primary production factors included are labor, capital, land, and fossil-fuel resources.[9]

We aggregate state-level data into 10 U.S. regions as identified in Figure 2 in order to approximate wholesale transmission regions by state-level border. Table 2 reports benchmark CO_2 emissions, sectoral shares of total emissions, and emission intensity by region. CO_2 emissions from regulated electricity generation represent about 30% of total national emissions, transportation (industrial and private) being the other main contributor besides electricity. There is significant variation among regions in terms of emissions intensity of industrial output. For example, ERCOT, as the most CO_2 intensive region[10], shows an emissions intensity that is three times as large as those of CA, NENGL, and NY.

[9] The aggregation and reconciliation of IMPLAN state-level economic accounts needed to generate a micro-consistent benchmark data set which can be used for model calibration is documented in Rausch and Rutherford (2009).

[10] This can be traced back to large-scale activities in oil refining and energy-intensive industries in Texas.

4.1.2 Model Overview

Economy-wide interactions are represented by a numerical Arrow-Debreu general equilibrium model of the U.S. economy.[11] We here provide a brief description of the model structure, and presents the equilibrium conditions of the model in Appendix A. The integration of electricity supply and household behavior are discussed subsequently.

For each industry ($i = 1, \ldots, I$), gross output X_i is produced using inputs of labor (L_i), capital (K_i), natural resources (R_{zi}, $z = 1, \ldots, Z$) including coal, natural gas, crude oil, and land, and produced intermediate inputs (x_{ji}, $j = 1, \ldots, I$) including electricity.[12] All industries are characterized by constant returns to scale, except for fossil fuels and agriculture, which are produced subject to decreasing returns. Apart from electricity, all commodities are traded in perfectly competitive markets, where firms maximize profits given technology and prices. Labor is assumed to be fully mobile across sectors within a given region, but immobile across regions. Capital is mobile across sectors and regions.

For all activities but electricity generation, we characterize production technology by distinguishing three types of production activities: primary energy sectors (indexed by $pe = \{coal, gas, oil\}$), non-resource based industries (indexed by *nr*), and agriculture (indexed by *agr*):

$$X_i = \begin{cases} f_i[KLM_i(g_i, M_i), R_{zi}; \sigma_f] & \text{if } i \in \{pe\} \\ f_i[KLE_i(g_i, E_i), M_i(x_{1i}, \ldots, x_{Ii}); \sigma_f] & \text{if } i \in \{nr\} \\ f_i[REM_i(R_i, EM_i), g_i(K_i, L_i); \sigma_f] & \text{if } i \in \{agr\}\,. \end{cases} \tag{1}$$

where σ_f is the elasticity of substitution among composite inputs. We employ nested constant-elasticity-of-substitution (CES) functions with nesting structures reported in Table 3. Elasticity parameters for each nest are taken from Paltsev et al. (2005).

Elements in the E and M nests are Armington (1969) composites of local and traded products (σ_{xjr}), where traded products are themselves a composite of intra-and inter-national imports (σ_{Tjr}). We distinguish three different representations of *intra*-national trade which depends on the type of commodity and associated regional integration. First, non-energy goods are treated as regionally heterogeneous and the price transmitted to producers and consumers is a CES index of varieties from U.S. regions. Second, domestically traded energy goods (excluding

[11] This paper builds on the model employed in Rausch et al. (2010) where electricity generation choices are represented at the operator-level (Section 4.2) and where final demand derives from many heterogeneous households (Section 4.3).

[12] For ease of notation, we omit the region index when no ambiguity can result.

Table 3: Nested production structure and elasticity parameters.

Function	Description	Elasticity (by sector[a])		
		pe	nr	agr
σ_f	Output	0.6	0	0.7
$KLE = KLE(g, E; \sigma_{gE})$	Capital/labor-energy composite	-	0.5	-
$KLM = KLM(g, M; \sigma_{gM})$	Capital/labor-materials composite	0	-	-
$REM = REM(R, EM; \sigma_{REM})$	Resource-Energy/materials composite	-	-	0.6
$EM = EM(E, M; \sigma_{EM})$	Energy-materials composite	-	-	0.3
$M = M(x_1, \ldots, x_I; \sigma_{xM})$	Materials composite	0	0	0
$g = g(K, L; \sigma_{KL})$	Capital-labor composite	1	1	1
$E = E(x_{ELE}, h; \sigma_{ELEh})$	Energy composite	-	0.5	0.5
$h = h(x_{COL}, x_{GAS}, x_{OIL}; \sigma_{xE})$	Coal-gas-oil composite	-	1	1
$x_i = x_i(xD_i, xT_i; \sigma_{xjr})$	Domestic-imported inputs composite	5	5	5
$xT_i = x_i(xDT_i, xFT_i; \sigma_{Tjr})$	Imported inputs composite	5	5	5

Notes: All functions are CES in form. [a] Primary energy (pe): COL, GAS, CRU; Non-resource using (nr): OIL, EIS, MAN, TRN, SRV; Agricultural (agr): AGR.

electricity) are assumed to be homogeneous products, so that each region trades with a national pool where all regions supply and demand goods. This reflects the high degree of integration of U.S. market for natural gas, crude and refined oil, and coal. Third, for electricity we approximate the three asynchronous interconnects in the U.S. by defining three regional electricity pools: the Eastern Interconnection, Western Electricity Coordinating Council (WECC), and the Electric Reliability Council of Texas (ERCOT).[13] Each region thus trades directly with its regional pool, within which electricity is homogeneous, and there is no electricity trade between regional pools.

The U.S. economy as a whole is modeled as a large open economy, so that the U.S. can affect world market prices. The international trade closure of the model is determined through a national balance-of-payments constraint. Hence the total value of U.S. exports equals the total value of U.S. imports accounting for an initial balance-of-payments deficit given by 2006 statistics.

In each region, a single government entity approximates government activities at all levels – federal, state, and local. The government raises revenues through taxes, purchases goods and services, and provides lumpsum transfers to households (i.e., social security). Government consumption is represented by a Leontief composite of goods $x_i, \ldots, x_I$ where benchmark value shares are based on social accounting matrix data. Revenues are based on observed ad-valorem output taxes, corporate capital income taxes, and payroll taxes (employers' and employees'

[13] In terms of the regional aggregation described in Figure 2, the Eastern Interconnection thus comprises SPP, MISO, SEAST, PJM, NY, and NENGL, and the WECC comprises CA, NWPP, and MOUNT.

Table 4: Generation Technologies and Fuels.

Technologies	
	Combined cycle, combustion turbine, hydraulic turbine, internal combustion engine, photovoltaic, steam turbine, wind turbine.
Fuels	
Coal:	
	Anthracite and bituminous coal, lignite coal, coal-based synfuel, sub-bituminous coal, waste and other coal.
Natural gas:	
	Blast furnace gas, natural gas, other gas, gaseous propane.
Oil:	
	Distillate fuel oil, jet fuel, kerosene, residual fuel oil.
Other:	
	Agricultural crop, other biomass (gas, liquids, solids), black liquor, geothermal, landfill gas, municipal solid waste, nuclear fission, petroleum coke, other wastes, solar, wood and wood waste, wind, hydroelectric.

contribution).

4.2 Electricity Generation

4.2.1 Data

We use 2006 data on all 16,891 generators active in continental U.S., with information on generation technology, capacity (i.e. maximum output), and up to three fuels that can be used (EIA Form 860, 2007a).[14] Table 4 shows the details of technology and fuels included. Each generator is matched to plant level data reported in EIA Form 906-920 (2007b), where a plant can include multiple generators. EIA Form 906-920 provides plant-level monthly output per technology and fuel type, fuel consumption, as well as the operator of each plant, its regulatory status (i.e. whether it is a traditional vertically integrated electric utility or an independent operator), and its region of operation. Our data set therefore comprises information on the portfolio of generation technologies of each operator and its regulatory status.

The marginal cost of generation (in \$/MWh) comprises fuel costs and operation and maintenance (O&M) costs. Fuel costs are based on plant-specific efficiency (in MBTU/MWh), calculated using fuel consumption and electricity output reported in EIA Form 906-920 (2007b) and state-level fuel prices for 2006 (in \$/MBTU) from EIA (2009d).[15] Second, as we do not

[14] We obtain the dependable capacity by scaling installed capacity figures from EIA Form 860 (2007a) with technology-specific availability data reported by the North American Electric Reliability Council (2007).

[15] Since information on output and fuel consumption at the generator level is not available, generators that belong to the same plant and share the same technology and fuels are assumed to have the same efficiency.

observe O&M costs at the generator level, we use technology-specific data from EIA (2009b). This includes labor, capital, material and waste disposition costs per MWh.

CO_2 emissions depend on the CO_2 content of the fuel used to generate electricity (in tCO_2/MBTU), as reported by EIA (2008). Implicitly, the CO_2 intensity of each operator also depends on the efficiency of the plant, as it determines the fuel requirement to generate electricity.

The benchmark demand for electricity (i.e. in the absence of a CO_2 policy) at each regulated operator is given by observed monthly output (EIA Form 906-920, 2007b). We consider only the 319 regulated operators with annual output greater than 10 GWh.[16] To determine the demand on regional wholesale markets, we first map all non-regulated operators to their wholesale market region, and then determine the monthly benchmark demand by summing monthly electricity output for all non-regulated operators within each region. For regulated and wholesale markets, we capture variations in electricity demand over the year by dividing the year into nine load segments. Specifically, monthly demand on each 329 market is aggregated into three seasons (summer, winter and fall/spring), and then seasonal demand is divided into three load blocks (peak, intermediate, and base load) based on region- and season-specific load distribution data (EIA, 2009b).

4.2.2 Regulated Electricity Markets

Regulated operators $f = 1, \ldots, 319$ are assumed to minimize generation costs to meet the demand, and thus implicitly construct a piece-wise linear supply function by ranking available technologies by increasing marginal cost (the "merit order"). In equilibrium, generator g is thus active in load segment $t = 1, \ldots, 9$ if its marginal cost c^g is lower than the marginal cost of the generator used to cover the last unit of demand, denoted C_t^f. This is summarized by the following complementarity condition:

$$c^g + \nu^g \tau + \mu_t^g \geq C_t^f \quad \perp \quad Y_t^g \geq 0 \tag{2}$$

where Y_t^g is the output level, ν^g is the CO_2 intensity, τ denotes the price of emissions and $\perp$ indicates a complementary relationship. μ_t^g represents the shadow value of installed capacity,

[16] This roughly corresponds to the yearly consumption of 1,000 households. Generation from the 412 regulated operators that are not included in the model represents less than 0.1% of electricity generated in each region.

and it is the complementarity variable of the capacity constraint of each generator:

$$Y_t^g \leq \kappa_t^g \quad \perp \quad \mu_t^g \geq 0\,, \tag{3}$$

where κ_t^g is the dependable capacity of generator g in load segment t. Generators listed with multiple fuel options endogenously select the least-cost fuel based prevailing fuel prices.

The equilibrium marginal generation cost C_t^f is determined by a market clearing condition for each load segment:

$$\sum_{g \in G_f} Y_t^g \geq d_t^f \quad \perp \quad C_t^f \geq 0\,, \tag{4}$$

where G_f denotes the set of generators owned by regulated operators f and d_t^f is electricity demand in t.

The price of electricity at operator f, P^f, is given by the average generation costs:

$$P^f = \frac{\sum_{g \in G_f} \sum_t Y_t^g c^g + \nu_t^g \tau}{D^f} - s^f\,. \tag{5}$$

where $D^f = \sum_t d_t^f$ is the total demand for generation at operators f over the year. If PUCs requires the value of free allowances V_f to be transferred to customers through electricity rates, s^f is a firm-specific subsidy rate that reflects the value of free allowances received:

$$s^f = \frac{V_f}{D^f}\,. \tag{6}$$

While this pricing rule is an important simplification of reality, notably because of regional idiosyncrasies in the application of cost of service regulation and the existence of other rules such as block-pricing, it mainly reflects the fact that the price signal for many consumers is close to constant throughout the year. Note that capacity rents μ_t^g are not included in the price.

Under a CAT policy, generation costs increase proportionally to the emissions coefficient ν_t^g. Since we assume that regulated operators are minimizing costs, the fact that they must surrender allowances induces fuel switching and a reordering of generators along the supply schedule (merit order effect). The demand response at operator f is a linear approximation of the non-linear economy-wide demand calibrated at benchmark price $\overline{P}^f$ and demand $\overline{D}^f$:

$$D^f = \overline{D}^f \left(1 + \epsilon \left(\frac{P^f}{\overline{P}^f} - 1\right)\right)\,, \tag{7}$$

where $\epsilon < 0$ is the *local* price elasticity of demand. The demand in load segment t is then given by: $d_t^f = D^f\, \overline{d}_t^f / \overline{D}^f$.

4.2.3 Wholesale Electricity Markets

Each region $r = 1, \ldots, 10$ is associated with a wholesale market which brings together generators owned by non-regulated operators. Following Bushnell et al. (2008) and Fowlie (2009), we assume that operators holding more than 3% of wholesale generation capacity behave as Cournot players. Smaller operators act as a price-taking competitive fringe. The Cournot-Nash equilibrium unit profit function for strategic players (denoted by the set G_r^{cournot}) and non-strategic players (denoted by the set G_r^{fringe}) are respectively:

$$\pi_t^g = \begin{cases} p_t^r + \frac{\partial D^r(p_t^r)^{-1}}{\partial Y_t^g} - c^g - \mu_t^g - \nu_t^g \tau & \text{if } g \in G_r^{\text{cournot}} \\ p_t^r - c^g - \mu_t^g - \nu_t^g \tau & \text{if } g \in G_r^{\text{fringe}}\,. \end{cases} \tag{8}$$

Here p_t^r is the wholesale price and $D_t^r(p_t^r)^{-1}$ denotes the inverse demand function. Equilibrium electricity output by each generator is determined by the following zero profit condition:

$$-\,\pi_t^g \geq 0 \quad \perp \quad Y_t^g \geq 0\,. \tag{9}$$

Non-regulated operators who own generators with marginal cost below the market clearing price earn capacity rents μ_t^g according to:

$$Y_t^g \leq \kappa_t^g \quad \perp \quad \mu_t^g \geq 0\,. \tag{10}$$

The wholesale equilibrium price p_t^r is the complementary variable associated with the following market clearing conditions:

$$\sum_{g \in G_r} Y_t^g \geq d_t^r \quad \perp \quad p_t^r \geq 0\,, \tag{11}$$

where G_r denotes the set of generators in wholesale market r.

As for regulated markets, we assume that the wholesale price signal transmitted to consumers is constant over the year and given by an output-weighted average of the prices in each load segment:

$$P^r = \frac{1}{D^r} \sum_t p_t^r d_t^r\,. \tag{12}$$

The annual demand response for wholesale power is locally approximated by a linear demand function:

$$D^r = \overline{D}^r \left(1 + \epsilon \left(\frac{P^r}{\overline{P}^r} - 1\right)\right) , \tag{13}$$

so that demand in load segment t is given by: $d_t^r = D^r \, \overline{d}_t^r / \overline{D}^r$.

4.2.4 Market Integration in the Electricity Sector

The demand for electricity by households and firms is based on a regional "retail" price, P^r_{retail}, and this for two reasons. First, social accounts that are used to calibrate the economy-wide model only report annual electricity consumption by region. Thus P^r_{retail} links electricity generation to the rest of the economy by aggregating information from multiple electricity markets within each region and across time (load segments). Second, it allows us to incorporate assumptions about the degree of electricity markets' integration within a region without an explicit representation of a transmission network.[17]

In the benchmark, we thus define $\overline{P}^r_{\text{retail}} = \overline{P}^r_{\text{ele}} + TD^r$, where $\overline{P}^r_{\text{ele}}$ is an output-weighted average of generation costs across electricity markets in each region, and TD^r are regional transmission and distribution costs.[18] Away from the benchmark, we represent barriers to market integration by monopolistic competition between regulated and non-regulated operators (with a fixed number of firms), i.e. each market produces a variety of electricity with a distinct price:

$$P^r_{\text{ele}} = \left[\theta^r \left(\frac{P^r}{\overline{P}^r}\right)^{(1-\sigma)} + \sum_{f \in r} \theta^f \left(\frac{P^f}{\overline{P}^f}\right)^{(1-\sigma)}\right]^{\frac{1}{1-\sigma}} , \tag{14}$$

where θ^r and θ^f denote the observed market shares for wholesale market r and for regulated operator f in region r, respectively. σ capture the degree of market integration, including regulatory and network constraints.[19]

[17] Observed differences in prices across markets (and operators) suggest that trade opportunities among operators are limited, in turn reflecting both the existing regulatory structure and transmission constraints. It is, however, far from clear how such barriers to market integration will evolve in the future and, in particular, under a CO_2 emissions control policy. For example, given differences in the technology portfolios of operators, establishing a uniform price on CO_2 will generate heterogeneity in generation cost increase, favoring opportunities for mutually beneficial trades. PUCs may thus require regulated operators to shut down highly CO_2-intensive plants and purchase power from other sources, weakening monopoly power of regulated operators.

[18] Formally, $\overline{P}^r_{\text{ele}} = (\overline{D}^r + \sum_{f \in r} \overline{D}^f)^{-1} (\overline{D}^r \overline{P}^r + \sum_{f \in r} \overline{D}^f \overline{P}^f)$. As benchmark prices $\overline{P}^r$ and $\overline{P}^f$ only include generation costs, we impute transmission and distribution costs as $\overline{TD}^r = \overline{P}^r_{\text{retail}} - \overline{P}^r_{\text{ele}}$, where $\overline{P}^r_{\text{retail}}$ denotes observed retail prices in the IMPLAN data (2008). For all counterfactual simulations, we assume that these costs remain constant at their benchmark level.

[19] This structure assumes that trade opportunities among regulated operators and between each regulated operator and the wholesale market are symmetric. We have experimented with more complicated substitution patterns but have found them to yield similar results.

By calibrating equation (14) to observed market shares and prices, this model "rationalizes" existing and observable price differentials in the benchmark. Thus our approach can be thought of as implicitly representing *existing* barriers to price equalization across markets that are independent of σ. Away from the benchmark, the model response is governed by the second- and higher-order properties of equation (14), as represented by the elasticity of substitution σ. Our base case assumption is "low integration" ($\sigma = 1$), and our analysis explores the implications of independents markets ($\sigma = 0$) and a "high integration" case ($\sigma = 10$).

4.3 Household Behavior

4.3.1 Data

We use data on 15,588 households from the 2006 CEX survey (BLS, 2006), which provides consumption expenditures and income sources for a representative sample of the U.S. population.[20] Since the CEX focuses primarily on recoding households' spending, a well-known issue with this survey is quality of income-side data. First, households with income above a certain level are "top-coded" and their income is replaced with the national average. We observe see a substantial amount of top-coding for the top 4% of the income distribution (with pre-tax income above $250k), and our analysis cannot break out the top 4% of the income distribution.

Second, capital income is low as compared to data reported in official National Accounts (e.g. Deaton, 2005; Rutherford and Tarr, 2008). Metcalf et al. (2010) also suggest that capital income may misrepresent capital holdings across income groups. Indeed, if financial assets are disproportionately held by higher income groups then the CEX capital income measure will be biased towards more capital holdings in lower income groups. To supplement capital income data, we use data from the 2007 Survey of Consumer Finances (SCF Federal Reserve Board, 2007), which provides detailed information on different components of wealth holdings. The SCF combines a core representative sample with a high income supplement, which is drawn from the Internal Revenue Service's Statistics of Income data file. This data thus captures both the wealth at the top of the distribution and wealth portfolio of other households. Following Metcalf et al. (2010), we replace capital income reported in the CEX by imputed capital income based on capital income shares by income decile from SCF and total household income from

[20] Each household is interviewed every three months over five calendar quarters, and in every quarter 20% of the sample is replaced by new households. We include all households that report expenditures and income for 2006 even if they have only been interviewed for a subset of quarters in this year by following the procedure outlined in BLS (2006, p. 271).

Table 5: Selected expenditure and income shares (%) and median household income (2006$).

Income decile	Electricity	Natural Gas	Capital	Labor	Transfers	Capital-labor ratio	Median income
1	4.7	1.8	27.4	23.5	49.1	1.17	13,090
2	3.7	1.3	26.1	43.1	30.8	0.61	22,366
3	3.2	1.1	23.4	55.7	21.0	0.42	31,398
4	2.8	1.0	19.2	67.5	13.3	0.28	40,026
5	2.4	0.9	18.3	71.0	10.7	0.26	49,169
6	2.5	0.8	16.8	75.6	7.6	0.22	59,941
7	2.2	0.8	15.5	79.1	5.4	0.20	72,433
8	1.9	0.7	14.7	80.9	4.4	0.18	87,987
9	1.8	0.7	19.7	77.7	2.6	0.25	114,628
10	1.5	0.6	28.7	69.7	1.6	0.41	187,365
All	2.6	1.0	20.9	64.7	14.4	0.32	55,140

Notes: Population-weighted within-income group averages based on benchmark data.

CEX.

An other issue with the CEX data pertains to the implied tax rates reported by households. In particular, imputing personal income tax rates from tax payments in the CEX sample results in tax rates that are significantly lower than observed tax rates. For each households, we thus use data on 2006 average and marginal personal income tax rates by income decile from the *National Bureau of Economic Research*'s tax simulator (Feenberg and Coutts, 1993).

Finally, to obtain expenditure data that are consistent with the definition of consumption goods in our macroeconomic data, we aggregate expenditures into *Personal Consumption Expenditure* accounts, and mapped these to *North American Industry Classification System* accounts with a bridge matrix from the Bureau of Economic Analysis (2007). As savings are not reported directly in the CEX data, they are imputed as pre-tax household income minus the sum of consumption expenditures and tax payments. This ensures that pre-tax household income is equal to the sum of consumption expenditures, tax payments, and savings.

Table 5 reports expenditure shares for electricity and natural gas, and income shares for capital and labor by annual income decile.

4.3.2 Utility Maximization Problem

Each household is incorporated as a separate agent within the general equilibrium framework, so that aggregate consumption, labor supply, and savings result from the decisions of $h = 1, \dots, 15,588$ households, each maximizing its utility subject to an income constraint. The preferences of each household is represented by a nested CES function that combines material consumption, savings, and leisure thus making consumption-investment and labor supply de-

Table 6: Nested Utility Structure and elasticity parameters.

Function	Description	Elasticities
$U = U(CI, l)$	Household utility	$\sigma_c{}^a$
$CI = CI(C, q)$	Consumption-savings composite	0
$C = C(E, NE)$	Composite material consumption	0.25
$E = E(x_1, \ldots, x_I)\ , i \in \{e\}$	Energy consumption	0.4
$NE = NE(x_1, \ldots, x_I)\ , i \in \{ne\}$	Non-energy consumption	0.65

Notes: All functions are CES in form. [a] Calibrated to match an uncompensated (compensated) labor supply elasticity of 0.1 (0.3).

cisions endogenous. The nested utility structure is summarized in Table 6. The structure of material consumption is specified to reflect estimates of substitution elasticities among energy and non-energy goods (Paltsev et al., 2005). Household income is derived from government transfers and from supplying regional markets with capital, labor, and natural resources.

4.4 Computational Strategy

The key challenge for solving the model is to obtain consistency between the economy-wide general equilibrium framework and partial equilibrium representations of electricity generation and household behavior. Consistency has to be achieved both in the no-policy benchmark and when using the model for counterfactual analysis. This section outlines our strategy to address these computational challenges.

4.4.1 Benchmark Calibration and Model Fit

We first construct a consistent benchmark equilibrium across data sets (i.e. the benchmark data on electricity generation, the social accounting matrices, and household consumption and income data). This requires the benchmark data to be mutually consistent across sources. For example, cost-minimizing labor demand by electricity operators needs to be consistent with economy-wide equilibrium on the labor market, which in turn depends on labor supply decisions by the set of heterogeneous households. This procedure is described in Appendix B and C for electricity generation and households' demand respectively.

Prices and quantities from the consistent benchmark social accounting matrix are used to calibrate the value share and level parameters in CES functions portraying production and consumption technologies. By this procedure, the benchmark data represents the solution to the optimization problem in the absence of a policy (see e.g. Robinson, 1991). However, the benchmark outcome on each wholesale and regulated electricity market is simulated based on gener-

Table 7: Wholesale electricity markets: Prices and emissions intensity.

Region	Regional wholesale price ($/MWh)		CO_2 intensity (tCO_2/MWh)	
	Observed[a]	Simulated[b]	Observed[c]	Simulated[b]
NWPP	50.2	48.6	0.63	0.62
SEAST	58.1	53.5	0.60	0.61
PJM	55.1	52.2	0.58	0.58
ERCOT	52.9	57.5	0.52	0.50
MISO	44.0	47.7	0.47	0.50
SPP	55.4	63.6	0.42	0.43
CA	48.9	48.7	0.42	0.34
NENGL	60.8	61.5	0.40	0.36
MOUNT	57.4	44.9	0.38	0.35
NY	70.2	71.2	0.37	0.36

Notes: [a]Load-weighted average reported by FERC (2006); [b]Simulated from the electricity sector model; [c]Computed based on fuel consumption (EIA Form 906-920, 2007b) and fuel-specific CO_2 emission factors (EIA, 2009a).

ation costs and benchmark demand (see Appendix A). We now provide evidence on how well the electricity model fits observed data.

We first compare operator-level data on electricity generation for each combination of fuel-type and technology simulated with the model with observed values for 2006 are reported in EIA Form 906-920 (2007b). For regulated operators, the R^2 of the model is 90.2%, and 84.1% for wholesale markets.[21] Second, we compare observed average wholesale prices and emissions-intensity with those simulated from the model. Figures reported in Table 7 suggest that our model provides a good representation of generation costs, and also accurately predicts CO_2 intensity for wholesale producers.

Finally, while price data is not available for regulated operators, Figure 3 provides evidence that the model also provides a good representation of CO_2 emissions intensity for regulated operators.

4.4.2 Decomposition Algorithms

The electricity sector and economy-wide general equilibrium components are consistently solved based on the iterative algorithm by Böhringer and Rutherford (2009). This involves sequentially solving the electricity and economy-wide components under the same policy shock. Changes in general equilibrium prices are transmitted to the electricity generation model, and changes in the quantity of electricity produced and associated demand of inputs determined in the electric-

[21] Formally, we compute: $R^2 = 1 - \frac{\sum_{\text{tech,fuel}}(y_{\text{tech,fuel}} - \hat{y}_{\text{tech,fuel}})^2}{\sum_{\text{tech,fuel}}(y_{\text{tech,fuel}} - \bar{y})^2}$ where $y_{\text{tech,fuel}}$ is observed output for each technology-fuel combination, $\hat{y}_{\text{tech,fuel}}$ is the model prediction, and $\bar{y}$ is the average observed outcome.

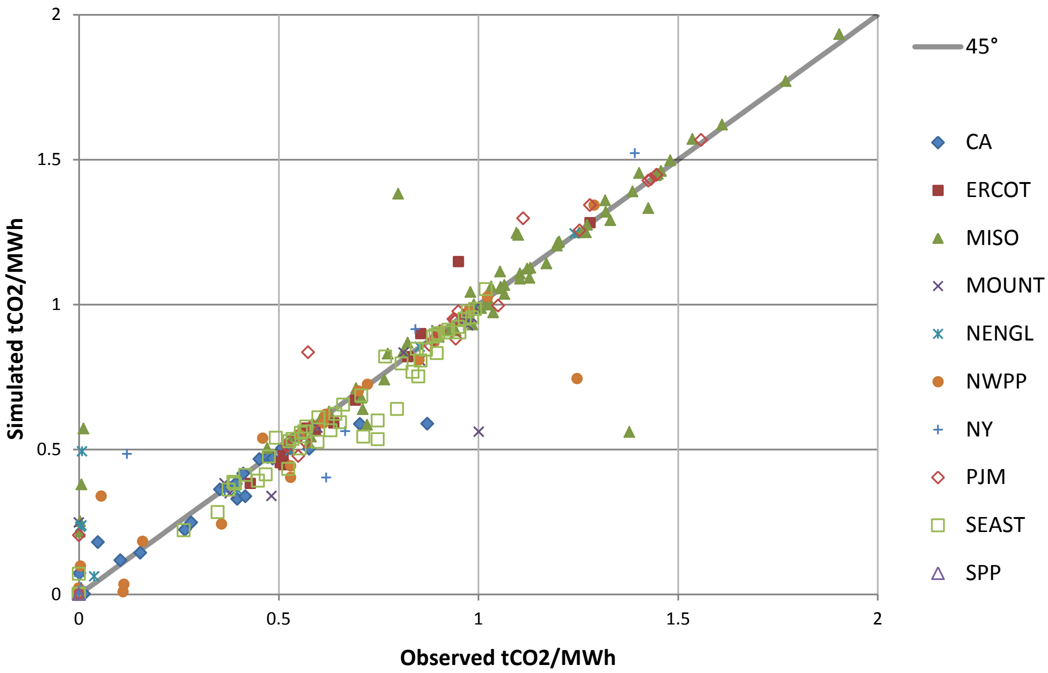

Figure 3: Regulated electricity markets: Emission intensity. *Notes*: Observed emissions intensity estimates are based on fuel consumption (EIA Form 906-920, 2007b) and fuel-specific CO_2 emission factors (EIA, 2009a).

ity generation model are transmitted back to the economy-wide model. The link between the two models is achieved by the linear demand functions for electricity (Eq. (7) and (13)) which are sequentially updated using candidate general equilibrium solutions for electricity price and demand.[22] Consistency is also achieved in terms of prices and demands for fuels, capital, labor, and other commodities and services used to produce electricity.

Endogenous decisions by all households are integrated in the economy-wide framework through a decomposition algorithm based on Rutherford and Tarr (2008). The key idea is to compute a sequence of artificial agent equilibria which replicate choices of the many "real" households. The algorithm also employs an iterative procedure which is undertaken after each solution of the electricity sector model. First, a candidate equilibrium is computed in the economy-wide model where households in each region are replaced by a single artificial agent. Second, we solve a partial equilibrium relaxation of the utility maximization problem for each 15,588 households given candidate general equilibrium prices from the artificial agent problem. Iterating between both sub-problems involves re-calibrating preferences of the artificial agent in

[22] As Böhringer and Rutherford (2009) point out, the choice of the local elasticity value in the linear demand approximation does not influence the equilibrium solution, although it determines the convergence speed.

each region based on partial equilibrium quantity choices by "real" households.

This procedure ensures that the general equilibrium prices derived from the economy-wide model with a single representative consumer are consistent with partial equilibrium demands by individual households. In particular, note that this procedure does not alter preferences of the "real" households nor does it rely on any form of aggregation of preferences; the single representative agent is simply used as a computational device to incorporate general equilibrium effects. Appendix C provides further details on this procedure.

5 Results from Policy Simulations

5.1 Scenario Setup

In a general equilibrium setting, any allowance allocation scheme translates into a statement about how the CO_2 revenue is distributed among households. Formally, let T_0 denote economy-wide CO_2 emissions in the benchmark, τ the equilibrium allowance price, ξ the emissions reduction target of the CAT regulation (expressed as a fraction of benchmark emissions), and ϑ the fraction of allowances retained by the government to achieve budget neutrality.[23] We can decompose the CO_2 revenue received by consumer h according to:

$$A_h = \tau \xi T_0 (1 - \vartheta) \cdot (a_h + b_h + c_h) , \tag{15}$$

where a_h, b_h, and c_h denotes a household's share of CO_2 revenue from allowances allocated to regulated electricity producers, non-regulated electricity producers, and non-electricity sectors respectively. Further define λ_m, the share of allowances allocated to electricity market m, as a linear combination of the share of benchmark electricity emissions ($\overline{E}_m$) and benchmark electricity output ($\overline{O}_m$):

$$\lambda_m = \alpha_E \frac{\overline{E}_m}{\overline{E}} + (1 - \alpha_E) \frac{\overline{O}_m}{\overline{O}} , \tag{16}$$

where $\alpha_E \in [0, 1]$, $\overline{E}$ represents benchmark emissions from the electricity sector, and $\overline{O}$ is total electricity generation in the benchmark.

We now formulate alternative CAT policy designs in terms of a_h, b_h, c_h, α_E, and the value of allowances used to subsidize firm-level electricity rates, V_f. First, for regulated electricity

[23] In each scenario, ϑ is determined endogenously as the the equilibrium amount of allowances required to compensate for changes in non-CO_2 tax revenue. This corresponds to a (non-distortionary) lump-sum tax and ensures that the aggregate budget of the government remains constant across all counterfactual equilibria.

producers we consider the following three scenarios:

- LUMPSUM: $a_h = \upsilon_h w \sum_m \lambda_m I_{m,h},\ V_f = 0,\ \alpha_E = 1;$
- SUB_E: $a_h = 0,\ V_f = \tau\xi T_0(1-\vartheta)w\lambda_f,\ \alpha_E = 1;$
- SUB_O: $a_h = 0,\ V_f = \tau\xi T_0(1-\vartheta)w\lambda_f,\ \alpha_E = 0;$

where υ_h denotes the weight of household h in total population, $w = \overline{E}/T_0$ is the benchmark share of emissions from electricity sector and $I_{m,h}$ is an indicator variable which is equal to one if household h is a consumer in market m, zero otherwise.[24]

The LUMPSUM scenario represents a CAT policy where allowances are allocated for free based on benchmark emissions and where the PUCs require the value of free allowances to be transferred to households through lump-sum transfers. Alternatively, LUMPSUM can be viewed as a CAT policy where allowances are auctioned to regulated electricity monopolies and revenues are distributed as per capita lump-sum transfers. While other lump-sum transfer schemes that are independent of electricity consumption are conceivable, per household transfers are most plausible if PUCs are responsible for the decision to redistribute the value of free allowances.

The SUB_E and SUB_O cases represent policies where free allowances are allocated based on benchmark emissions or output, respectively, and regulated firms transfer the value of free allowances through electricity rates. This reflects a situation where the distribution of allowances aims at sheltering some electricity consumers from adverse price impacts, either by intent of the Federal regulation or because of the PUC rate setting. The value of allowances allocated to regulated producer f, V_f, determines firm-specific subsidies s_f according to Eq. (6).

To identify the incidence of alternative allowance allocations in the presence of regulated electricity producers, we keep the treatment of other sources constant across policy scenarios. In particular, non-regulated electricity operators and non-electricity sectors receive free allowances based on benchmark emissions in all scenarios. For these firms, free allowances represent windfall profits, and we assume that these are distributed among equity owners in proportion to benchmark capital income:

$$b_h = \kappa_h w \sum_r \lambda_r \tag{17}$$

$$c_h = \kappa_h (1-w)\,, \tag{18}$$

[24] Note that we do not consider the LUMPSUM scenario with $\alpha_E = 0$ as the results are virtually identical to the case where $\alpha_E = 1$.

Table 8: Welfare costs, CO_2 prices, and sectoral CO_2 abatement.

	LUMPSUM			SUB_E			SUB_O		
Reduction target[a] (%)	10	20	30	10	20	30	10	20	30
Welfare cost[b]									
Total ($billion)	34.4	83.0	155.3	60.4	129.9	213.0	57.4	124.7	206.5
Per avoided ton of CO_2 ($)	58.8	70.9	88.4	103.8	111.4	121.6	98.4	106.8	117.8
CO_2 price ($ per ton)	14.1	31.2	51.3	18.9	40.5	63.2	17.3	37.4	60.0
Electricity price changes[c] (%)	20.8	38.7	68.1	13.9	29.7	52.8	15.3	34.1	56.4
Regulated operators (%)	28.8	67.7	115.5	15.7	38.0	66.6	18.8	46.3	78.5
Non-regulated operators (%)	8.2	20.2	38.0	11.1	24.5	44.0	9.8	26.4	42.4
Sectoral abatement									
Economy-wide (million tons)	585	1,170	1,756	585	1,170	1,756	585	1,170	1,756
Sectoral contribution (%)									
Regulated electricity (%)	38.1	38.9	38.8	19.3	23.7	28.8	25.3	27.9	31.4
Wholesale electricity (%)	11.0	14.0	16.5	17.8	20.5	20.8	15.8	19.1	19.7
Non-electricity sectors (%)	50.9	47.1	44.7	63.0	55.8	50.4	58.9	53.0	48.9

Notes: [a]Emissions reductions relative to benchmark $(100(1-\xi))$. [b]Negative of the weighted sum of equivalent variations of each household. [c]Weighted average across electricity markets, net of transmission and distribution costs.

where κ_h is the share of capital income of household h in aggregate capital income. While this is an imperfect approximation of capital ownership, this part of the scenario remains constant across the policy treatments of interest, and does not affect conclusions on the incidence of SUB_E and SUB_O scenarios relative to the LUMPSUM scenario.

5.2 Aggregate Efficiency Costs

Figure 4 and Table 8 summarize the impacts of allowance allocation schemes on national welfare.[25] If the value of freely allocated allowances is passed on to consumers through electricity rates, the welfare costs of the policy are between 40% and 80% higher relative to lump-sum transfers. For a 20% reduction target, the economy-wide efficiency cost is equivalent to an additional burden of around US$50 billion. The efficiency costs become smaller as the stringency of the policy increases, so that for higher targets inefficiencies of the SUB scenarios represent a smaller share of total welfare costs. Inefficiencies introduced by SUB scenarios are also reflected in the CO_2 price reported in Table 8, which is between 15% and 35% higher as compared to LUMPSUM.

If electricity rates of regulated operators do not fully reflect the CO_2 price signal, electricity

[25] Aggregate welfare costs are the weighted average of each household's equivalent variation as a percentage of full income, where a household's weight is proportional to its share of the total population. Focusing on a emissions cap avoids the need to explicitly value benefits from reducing CO_2 emissions.

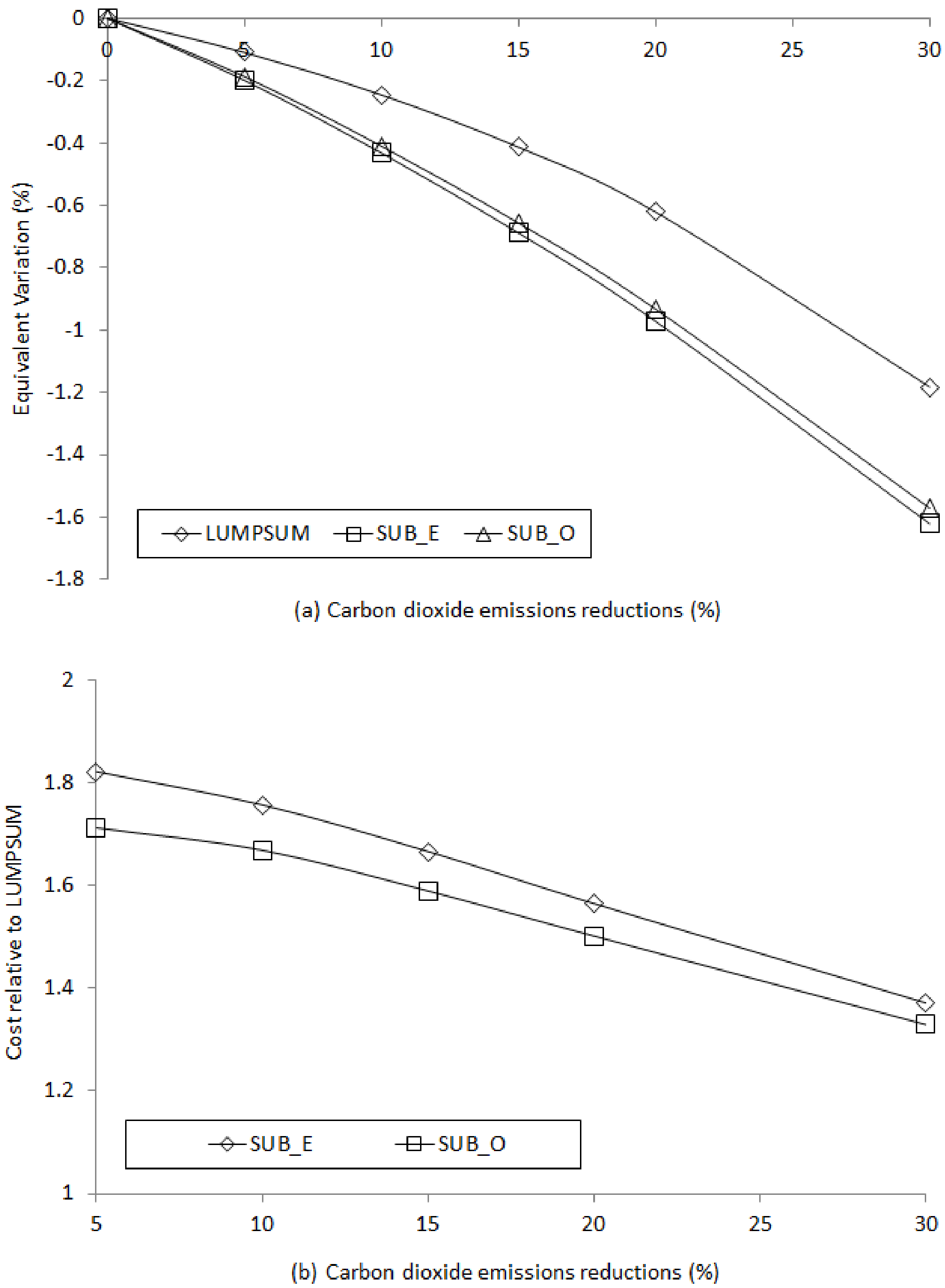

Figure 4: National-level mean welfare impacts and CO_2 abatement (a). Excess welfare costs relative to LUMPSUM (b).

consumption and in turn CO_2 emissions from electricity production are sub-optimally high. The magnitude of efficiency costs is therefore closely related to the size of electricity price changes. As reported in Table 8, a 20% target under the LUMPSUM scenario induces average electricity price increases of about 70% for regulated operators.[26] This induces a 12% US-wide decline in electricity output by regulated operators. Subsidizing electricity prices with free allowances substantially reduces the average increase of electricity prices. Under an emissions-based allocation, a 20% target raises electricity prices at regulated operators by 38% on average, and by around 45% under an output-based allowance allocation. As compared to the LUMPSUM scenario, the associated change in output for regulated operators is substantially dampened (-4.5% and -5.3% for SUB_E and SUB_O respectively). However, The CO_2 price signal transmitted to electricity consumers is higher under an output-based subsidy, which incentives abatement. In turn, economy-wide efficiency costs are lower under an output-based allocation, although differences are small and decline as the stringency of the policy increases.

Figure 5 summarizes the distribution of operator-level electricity price changes for a 20% reduction in emissions. For the LUMPSUM scenario, where electricity prices fully reflect CO_2 emissions, price increases range from about zero for producers with low CO_2 intensity to around 250% for operators holding a portfolio composed mainly of coal-fired plants. When free allowances subsidize regulated electricity rates, both the mean and the dispersion of price changes decline. The maximum price increase under an emissions-based subsidy is about 100%, and 181.5% under an output-based subsidy. Under an output-based subsidy, regulated operators with low CO_2 emissions can be overcompensated by the subsidy, which can induce a reduction in prices.

Efficiency costs do not only stem from electricity sector characteristics but also depend on how costly it is to abate in non-electricity sectors relative to the electricity sector. As shown in Table 8, our model suggests that abatement at regulated operators is overall relatively cheap. For the LUMPSUM scenario, about 40% of total abatement comes from regulated electricity producers, amounting to a 29% emissions reduction in this sector. Under SUB_E and SUB_O, regulated operators are still required to surrender allowances, and cost minimizing behavior

[26] Similarly, wholesale electricity prices increase on average by about 20%. Differences between regulated and non-regulated markets reflect the higher CO_2 intensity of regulated producers, but also the lower substitution possibilities among fuels and technologies, as regulated operators typically hold a much smaller set of generators compared to the set of generators active on regional wholesale markets. Moreover, regulated operators set prices according to the average cost of generation, so that electricity rate reflect the average CO_2 content of electricity. On wholesale markets, the price reflects (a function of) the generation costs of the marginal producer, and hence the CO_2 price is reflected in wholesale electricity prices only through the CO_2 content of the marginal producer.

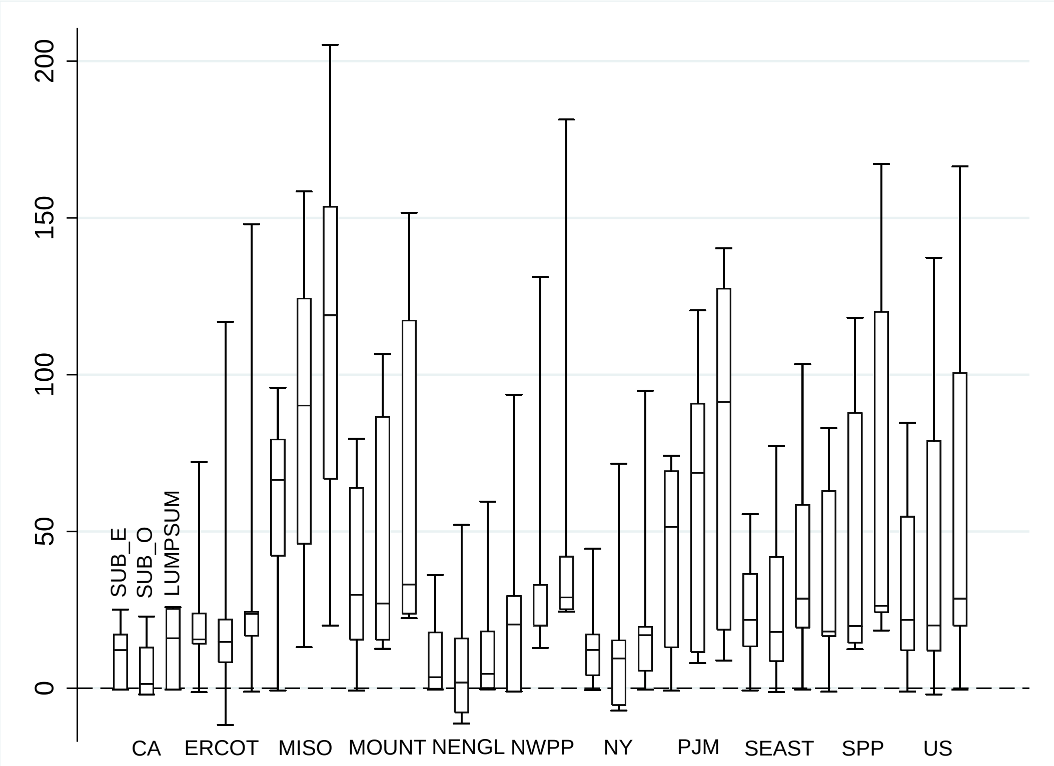

Figure 5: Distribution of electricity price changes by region ($\xi = 0.8$). *Notes:* Electricity prices are net of transmission and distribution costs. For each region, the box-whisker plots from left to right refer to the LUMPSUM, SUB_O, and SUB_E cases, respectively. The whiskers show outlier values at the 5^{th} and 95^{th} percentile, respectively.

will induce fuel switching and a merit order effect, but consumers do not fully see the CO_2 price signal. In turn, the share of total abatement by regulated operators drops from 40% to 23% under SUB_E and 28% under SUB_O.

Higher emissions by regulated operators increase their demand for allowances, which raises the equilibrium CO_2 price, and incentivizes sub-optimally large levels of abatement in the wholesale electricity and non-electricity sectors. For a 20% target, the contribution of non-regulated electricity producers increases from 14% for LUMPSUM to about 20% under both subsidy cases. Similarly, non-electricity sectors contribute about 47% of total abatement in the LUMPSUM case while the corresponding share increases to 56% and 53% under SUB_E and SUB_O, respectively.

5.3 Regional and Sectoral Distributional Impacts

Table 9 summarizes regional welfare changes relative to the LUMPSUM scenario and provides information on the average level of the electricity subsidy rate for a 20% emissions reductions target. First, note that all regions are worse off when subsidizing regulated electricity rates. Sec-

Table 9: Efficiency cost, subsidy rate, and CO_2 emissions by region ($\xi = 0.8$).

	Δ Welfare rel. to LUMPSUM (%)[a]		Subsidy rate (cents/kWh)[b]		Δ CO_2 emissions rel. to LUMPSUM (%)[a]	
	SUB_E	SUB_O	SUB_E	SUB_O	SUB_E	SUB_O
MOUNT	-0.99	-0.90	1.2	1.0	3.2	2.2
SPP	-0.90	-0.82	1.3	0.9	4.8	2.7
SEAST	-0.65	-0.63	1.0	0.9	1.0	1.7
MISO	-0.41	-0.37	1.2	0.8	3.7	1.9
NWPP	-0.31	-0.28	0.5	0.8	-0.2	-1.0
PJM	-0.23	-0.21	0.6	0.4	-1.4	-1.4
ERCOT	-0.13	-0.11	0.2	0.1	-4.5	-3.5
NY	-0.11	-0.09	0.3	0.3	-2.9	-1.8
CA	-0.09	-0.07	0.2	0.5	-2.8	-1.2
NENGL	-0.07	-0.05	0.1	0.1	-2.5	-1.8

Notes: [a]Difference in percentage points of percentage mean welfare changes under LUMPSUM relative to SUB_E/SUB_O. [b]Output-weighted average across regulated electricity producers in each region.

ond, regions with high shares of electricity produced under cost-of-service regulation (SEAST, SPP, MOUNT) suffer relatively large adverse welfare impacts from subsidizing electricity prices. Conversely, regions with a low degree of regulation (NENGL, ERCOT, NY, PJM) experience the smallest welfare losses. The pattern of regional welfare losses correlates closely with the magnitude of subsidy rates, suggesting that the value of allowances allocated to regulated firms in a given region, expressed per unit of electricity output, is a strong driver of regional welfare costs.

Another driver of regional efficiency costs is the benchmark CO_2 intensity of regulated electricity generation. For example, CA experiences the second smallest efficiency costs despite the fact that almost half of electricity is produced under regulation. However, regulated operators in this region mostly hold hydroelectric resources and have the lowest CO_2 intensity among all regional regulated operators (see Table 1). Similarly, SEAST has the largest share of output from regulated operators, but CO_2 intensity is lower than other highly regulated regions (SPP and MOUNT), leading to significantly lower efficiency costs. Under SUB_O, subsidy rates are smaller, and welfare gains are largest in regions with CO_2-intensive generation.

Table 9 also reports changes in regional abatement relative to LUMPSUM. Under a subsidy, regions where regulated operators have a large market share and hold CO_2 intensive technologies, reduce their abatement effort, i.e. emit more CO_2. Because aggregate emissions are capped, other regions have to abate more. An output-based subsidy generally leads to smaller changes in abatement, which mitigates redistribution of abatement. In only two regions emissions are higher under the SUB_O as compared to SUB_E: SEAST, which hosts a small number of regulated operators with large output and low emissions intensity, and NWPP, where a few

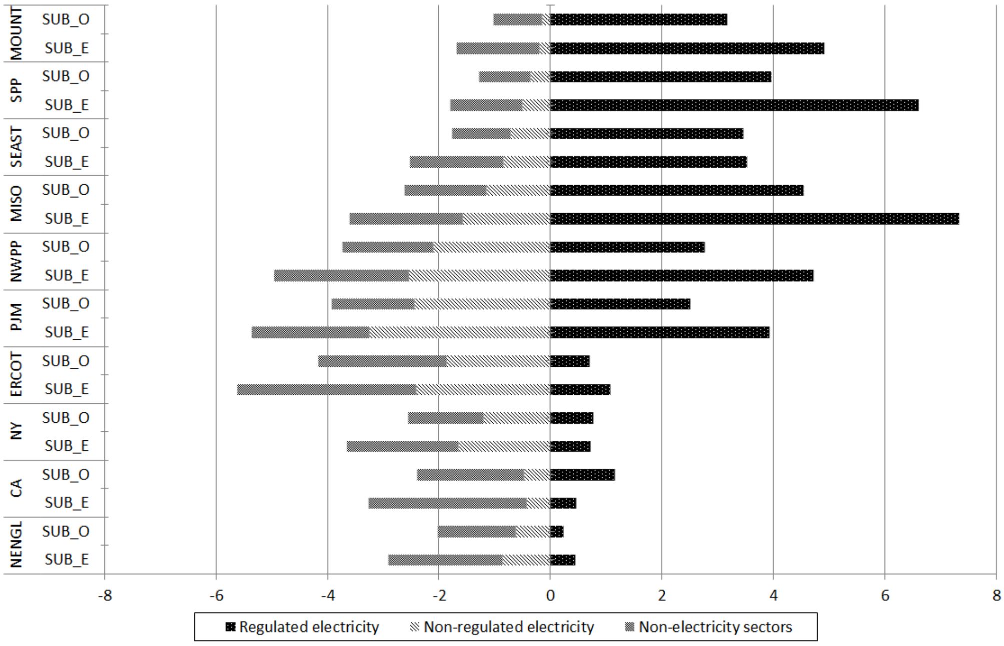

Figure 6: Sectoral decomposition of absolute percentage change in CO_2 emissions by region relative to LUMPSUM, $\xi = 0.8$. *Notes:* For a given region, sum of changes across sectors corresponds to percentage change in total CO_2 emissions reported in Table 9.

regulated operators hold very large hydro resources.

Figure 6 further disaggregates changes in regional emissions (relative to LUMPSUM) by sector. This shows how an increase of emissions from regulated electricity operators is compensated by more abatement in non-electricity sectors. For regions where emissions by regulated operators increase significantly, those with a large wholesale electricity market generally abate significantly more, as electric power from non-regulated electric power is a better substitute than abatement from non-electricity sectors. In regions with a low share of regulated electricity output, other sectors abate proportionally more, thus absorbing some of the efficiency costs. Figure 6 also support the view that for any analysis aimed at quantifying the efficiency costs from failing to pass through the carbon price signal in the electricity sector, it is of crucial importance to incorporate abatement opportunities in non-electricity sectors.

5.4 Household Distributional Impacts

An important aspect for policy-makers is how the economic costs (and benefits) of a policy affect equity considerations among households that are placed at different levels of the income distribution. Properly assessing the distributional incidence requires capturing both uses- and sources-side of income effects, i.e. how do consumers spend and earn their income. In addition,

Table 10: Distribution of household welfare impacts across income groups (SUB_E relative to LUMPSUM, $\xi = 0.8$).

	SUB_E					SUB_O				
Income deciles	Mean[a]	$ per hh[b]	25%	50%	75%	Mean[a]	$ per hh[b]	25%	50%	75%
1	-0.50	-76	-0.77	-0.38	-0.11	-0.50	-77	-0.74	-0.38	-0.13
2	-0.34	-91	-0.53	-0.26	-0.07	-0.34	-90	-0.50	-0.25	-0.10
3	-0.32	-111	-0.52	-0.27	-0.06	-0.31	-108	-0.48	-0.25	-0.08
4	-0.32	-136	-0.50	-0.27	-0.11	-0.29	-127	-0.44	-0.24	-0.11
5	-0.29	-151	-0.43	-0.27	-0.10	-0.26	-139	-0.39	-0.23	-0.10
6	-0.29	-182	-0.42	-0.27	-0.13	-0.26	-163	-0.37	-0.22	-0.12
7	-0.30	-220	-0.41	-0.28	-0.14	-0.26	-194	-0.34	-0.23	-0.12
8	-0.29	-253	-0.39	-0.27	-0.15	-0.25	-220	-0.32	-0.22	-0.12
9	-0.34	-362	-0.40	-0.25	-0.11	-0.29	-308	-0.31	-0.19	-0.09
10	-0.46	-676	-0.48	-0.20	-0.06	-0.38	-564	-0.35	-0.15	-0. 05
Weighted average	-0.34	-227	-0.46	-0.27	-0.10	-0.31	-200	-0.41	-0.23	-0.09

Notes: [a]Difference in percentage points of population-weighted within-income group percentage welfare changes under SUB_E relative to LUMPSUM. [b]Population-weighted within-income group average of equivalent variation expressed in 2006$ relative to LUMPSUM (absolute difference).

to be empirically relevant, it is important to base the analysis on observed expenditure and income patterns of real households rather than on highly aggregated, stylized representative consumers. Our model is set-up to perform reasonably well in terms of these two dimensions.

Table 10 summarizes the within and across income decile distribution of efficiency costs of the SUB scenarios relative to the LUMPSUM scenario for a 20% emissions reduction target. Specifically, we report the difference in equivalent variation between SUB_E and LUMPSUM, and SUB_O and LUMPSUM, respectively. First, the additional efficiency cost born by an average household expressed in 2006$ is 227 for an emission-based allocation and 200 for an output based allocation. Second, looking at the mean welfare impacts by income decile suggest that the efficiency costs from subsidizing electricity rates are regressive. Third, within the three lowest income deciles, there is a substantial number of households that experience large negative welfare impacts, so that regressivity is more pronounced at the mean of the distribution. For the top 20% of the distribution, however, some households also experience significant losses, making average policy impacts slightly progressive in this part of the income distribution. Fourth, as a more general point, Table 10 shows that focusing on aggregate welfare impacts, even when looking at representative households by income class, masks important variations across individual households. In particular, the variation in impacts across households within a given income decile swamps the variation in means across income deciles.

What explains the inverted U-shaped profile of the mean impacts by income decile? First, low-income household spend a larger fraction of their budget on electricity and hence benefit relatively more from lower electricity price under SUB_E and SUB_O. However, low-income households also benefit more from the per-capita lump-sum transfer they receive under LUMPSUM. Hence, for low-income households, the value of reduced electricity rates in the subsidy cases is overcompensated by the loss of transfer income in the SUB cases. Second, the effect of CO_2 pricing on welfare strongly depends on changes in factor prices. As in our model capital is assumed to be more mobile than labor, capital is a better substitute for CO_2 abatement. It follows that a CO_2 policy increases the relative price of capital to labor. Under a subsidy, inefficiencies in economy-wide abatement further depress the demand for capital relative to that for labor, so that the relative price of capital to labor is lower under the SUB cases as compared to the LUMPSUM case. As households in the tails of the income distribution rely more heavily on capital income relative to labor income, they are more adversely impacted relative to middle income households.

Besides variations in income and expenditure shares, heterogeneity in households' impacts is also explained by regional differences in the electricity market structure. In regions where electricity is mainly produced by non-regulated operators, the welfare difference between LUMPSUM and SUB_E/SUB_O are negative but remain small. In contrast, households located in highly regulated regions that are also highly CO_2 intensive, namely SPP and MOUNT, are significantly worse off under a subsidy as compared to lump sum transfers. Households in the tails of the income distribution of these regions are among the most adversely affected.

5.5 Sensitivity Analysis and Caveats

The work reported in this paper should be interpreted as an attempt to put a theory in an empirical perspective in order to quantify the policy-relevance of distortions. By design, exante policy projections face a number challenges. For our purposes, the main determinant of welfare costs is the marginal cost of CO_2 abatement, and it is mainly determined by two sets of parameters. First, in the electricity sector, substitution among generation technologies is based on changes in relative generation costs. Second, for households and non-electricity sectors, the behavior response is described by means of CES functions, so that abatement costs are mainly determined by elasticity parameters.

Elasticity estimates for all regions and sectors that are represented in our model are fraught with uncertainties. However, by focusing on the relative magnitude of alternative policy scenarios, our results are robust to changes in elasticity parameters. In particular, varying the key drivers of abatement costs, σ_{KLE}, affects the absolute value of the welfare costs of each scenario,

Table 11: Impacts of different cap-and-trade designs under alternative parameter assumptions.

Parametrization *Scenario*	Mean EV[a]	Standard deviation of EV[b]	Mean EV by region[c]	Electricity price change[d]	Mean electricity price change by region[e]
Central case ($\sigma = 1$, $\sigma_{xELE} = 0.5$)					
SUB_E	-0.34	0.47	0.34	0.29	0.12
SUB_O	-0.31	0.42	0.31	0.46	0.15
Low market integration ($\sigma = 0$)					
SUB_E	-0.35	0.46	0.33	0.29	0.13
SUB_O	-0.32	0.42	0.32	0.47	0.16
High market integration ($\sigma = 10$)					
SUB_E	-0.31	0.50	0.37	0.27	0.10
SUB_O	-0.28	0.46	0.35	0.44	0.12
High market integration ($\sigma = 10$) and high electricity trade elasticity ($\sigma_{xELE} = 5$)					
SUB_E	-0.30	0.51	0.38	0.25	0.09
SUB_O	-0.26	0.49	0.37	0.36	0.11

Notes: Results shown for $\xi = 0.8$. [a]Percentage point difference relative to LUMPSUM, weighted average across households. [b]Percentage change of welfare by household relative to LUMPSUM. [c]Percentage change of mean welfare by region relative to LUMPSUM. [d]Percentage change of price change by market relative to LUMPSUM. [e]Percentage change of mean price change by region relative to LUMPSUM.

but does not affect the relative difference across scenarios. One exception to this are elasticities that measure market integration in the electricity sector (σ and σ_{xELEr}). Indeed different policy scenario induce drastically different electricity price impacts, so that market integration can potentially affect the size and regional distribution of efficiency costs differently across scenarios.

Table 11 reports results for alternative assumptions about electricity market integration. In the first panel, we summarize the impacts of the SUB_E and SUB_O scenarios relative to LUMPSUM for our central assumptions. The second and third panels show results for low and high market integration cases, respectively. For the low σ case, efficiency costs of both subsidy scenarios increase slightly, but it has almost no impacts on the dispersion of welfare measures and electricity prices. For the high σ case, efficiency costs decline, as abatement is cheaper in the electricity sector. Moreover, the dispersion in electricity price impacts declines. CO_2 prices are lower compared to the central case, translating into lower subsidy rates, and this induces a modest increase of the dispersion of welfare measures. Finally, increasing both σ and σ_{xELEr} further reduces inefficiency costs and the dispersion of price changes, but increase the dispersion of welfare impacts.

These results suggest that different assumptions about market integration do not affect our results substantially. Changing trade opportunities mostly affects the tails of the price change distribution, but leave the average price impacts almost unaffected. As households in our model do not directly observe electricity prices on each market – but rather trade-off an aggregate electricity commodity with the consumption of other aggregate goods – changes in the dispersion of electricity price are not directly reflected in the distribution of welfare impacts.

A final limitation in the representation of abatement costs is the absence of investment in low-CO_2 electric technologies. While higher capacity in low-CO_2 technologies would decrease aggregate welfare costs under all scenarios, thereby not affecting the main insights of our analysis, a subsidy would lower incentives to invest in clean technologies relative to lump-sum transfers. Therefore, in the mid- to long-run, efficiency costs associated with a subsidy are likely to grow larger. We note however that investment behavior will differ between regulated and non-regulated operators, as the former are typically granted a predetermined rate of return on investments. This issue thus remains as an important research question.

6 Conclusions

This paper has quantified the efficiency and distributional implications of alternative treatment of free CO_2 allowances by price-regulated electricity operators. We have employed a numerically solved general equilibrium model of the U.S. economy with a detailed characterization of the electricity sector, economy-wide CO_2 abatement potential, and household heterogeneity.

If free allowances come as a subsidy to regulated electricity rates, so that prices do not fully reflect the value of emissions, the welfare costs of the CAT policy increase substantially. For an emission reduction target of 20%, our analysis suggests that efficiency cost are about 60% higher relative to a case where the CO_2 price signal is fully passed through to consumers. Subsidizing electricity rates with the value of allowances drastically reduces abatement in the electricity sector, shifting the burden to other sectors of the economy. Since electricity generation is the largest contributor to CO_2 emissions, and abatement in this sector is relatively cheap, this leads to higher welfare costs.

When electricity rates fully reflect the value of allowances, however, electricity prices increase can be substantial, ranging up to 250% for a 20% emissions reductions target. For consumers located near operators with highly CO2-intensive technologies, subsidizing electricity prices may thus be perceived as being beneficial for low-income households, as these spend a larger fraction of their income on electricity. However, our analysis shows that this is not the case: low-income households bear a disproportionately large fraction of the efficiency costs. This results can be traced back to the finding that income-source side effects dominate income-use side effects.

The main policy message of our analysis is thus that CAT climate proposals in the U.S. need to factor in PUC rate setting rules to ensure that all electricity consumers perceive the CO_2 price signal. In our analysis, we took the extreme stance that all regulated operators apply the same pricing rule. In reality, regional PUCs hold discretionary power as to the treatment of allowances, and if such considerations are left out of the policy design process we showed that the efficiency property of carbon trading markets can be hampered, with potentially unintended distributional consequences.

Appendix A: Equilibrium conditions for economy-wide model

This section lays out the equilibrium conditions for the economy-wide model. Our complementarity-based formulation of the economy-wide model distinguishes two classes of conditions that characterize the competitive equilibrium: zero-profit conditions and market clearance conditions.[27] The zero-profit conditions determine a vector of activity levels (X) and the market clearance conditions determine a vector of prices (P).

Zero profit. Let $\Pi_{ir}^X(p)$ denote the unit profit function of industry i in region r which is calculated as the difference between unit revenue (R_{ir}) and unit costs (C_{ir}) where:

$$C_{ir}(p) = \mathit{min}\{p_r^l L_i + p^k K_i + p_r^z R_{zi} + \sum_j p_{jr} x_{ji} \mid F_{ir}(L_{ir}, K_{ir}, R_{zir}; x_{1ir}, \ldots, x_{10ir}) = 1\} \quad (19)$$

$$R_{ir}(p) = \mathit{max}\{\sum_j p_{ir}^X X_{ir} \mid X_{ir} = 1\}\,. \quad (20)$$

where p_{ir}^X is the price of X_{ir}. Zero profits implies that no production activity makes positive profits, i.e.:

$$-\Pi_{ir}^X(p) = C_{ir} - R_{ir} \geq 0 \qquad \perp \qquad X_{ir}\,. \quad (21)$$

Similar conditions hold for Armington aggregation ($\Pi_i^x r$).

Market clearance. The second class of equilibrium conditions is that at equilibrium prices and activity levels, the supply of any commodity must balance or exceed demand. For regional output markets we can express this condition as:

$$X_{ir} \geq \sum_j x_{jr} \frac{\partial \Pi_{jr}^x(p)}{\partial p_{ir}^X} \qquad \perp \qquad p_{ir}^X \quad (22)$$

The market for Armington good i is in balance if:

$$x_{ir} \geq \sum_j X_{jr} \frac{\partial \Pi_{jr}^X(p)}{\partial p_{ir}^x} + \frac{\partial p_r^I}{\partial p_{ir}^x} I_r + \frac{\partial p_{GP}^x}{\partial p_{ir}^x} GP + d_{ir}(p, M_r) \qquad \perp \qquad p_{ir}^x \quad (23)$$

where by Shephard's Lemma the first three summands on the right-hand side represent the

[27] An income balance accounting condition is usually specified to simplify the implementation of the problem, but can be substituted out of the model without altering the basic logic. In the present context, this condition is given by aggregating equation (24) across households.

demand of good i by the constant returns to scale production, investment, and government sectors, respectively. Household income is given by:

$$M_h = p^k \omega_h^k + p_r^l \omega_h^l + \sum_z p_r^z \omega_h^z + T_h \tag{24}$$

where p^k, p_r^l, and p_r^z are prices for capital, labor, and resources, ω's denote the initial endowment of capital, labor (including leisure time), and resources, and T_h is benchmark transfer income. Final demands $d_{ir}(p, M_r)$ are derived from the budget-constrained maximization:

$$d_{ir}(p, M_r) = \mathit{argmax}\{U(x_{1r}, \ldots, x_{10r}, q, w, l) \mid \sum_i p_{ir}^x x_{ir} + p_r^q q + p_r^w w + p_r^l l = M_r\} \tag{25}$$

where $U(\cdot)$ is a CES utility index. Market clearance conditions for labor, capital, and natural resources are given by:

$$\sum_j Y_j \frac{\partial \Pi_{jr}^Y(p)}{\partial p_r^f} + d_{fr}(p, M_r) \geq \sum \omega_r^f \qquad \perp \qquad p_r^f \tag{26}$$

where $f = \{k, l; 1, \ldots, Z\}$ denotes the set for primary production factors (labor, capital, and natural resources). Market clearance conditions requiring balanced intra-national trade for non-energy goods that are traded on a bilateral basis are omitted here for simplicity.

Foreign closure of the model is warranted through a national balance-of-payments constraint which determines the price of foreign exchange:

$$\sum_i \mathit{EX}_i + B = \sum_i \mathit{IM}_i \frac{\partial \mathit{pdfm}_i}{\partial \mathit{pfx}} \qquad \perp \qquad \mathit{pfx} \tag{27}$$

where *EX* and *IM* denote the level of foreign exports and imports, respectively.

Appendix B: Integration of electricity generation into economy-wide transactions

The electricity sector and economy-wide models are consistently solved based on an algorithm by Böhringer and Rutherford (2009). As a first step, we generate a consistent benchmark data set where electricity sector outputs and inputs are consistent with the aggregate representation of the economy. For each regulated and wholesale electricity markets, we simulate utilization of technologies, fuel use, and hence benchmark CO_2 emissions by calibrated the electricity generation model to observed demand for output on each market and fuel/input prices. Formally, for regulated markets, given the benchmark demand at each operator $\overline{d}_t^f$, we simulate benchmark output of each generator $\overline{Y}_t^g$, input and fuel demand, as well as benchmark price $\overline{P}^f$, by solving expressions (2) to (4) as a mixed complementarity problem. Similarly, for wholesale markets, we solve Eq. (10) to (11).

To integrate the resulting input demand into markets represented in the economy-wide model, we map fuel categories and input from the electricity sector to commodities in the economy-wide model, and adjust the input-output data with least-square optimization techniques in order to minimize the required adjustments.[28] Second, we calibrate the value share and level parameters of the CES functions in the economy-wide model using benchmark prices and quantities of the integrated electricity-economy data set.[29]

We now provide an algebraic description of the integrated electricity-economy model. Let $n = 1, \ldots, N$ denote an iteration index and consider first the economy-wide component. The least-cost input requirements obtained from solving the electricity generation model in iteration $(n-1)$ are used to parametrize the general equilibrium model in (n). This is accomplished by defining the market clearing condition for electricity (22) as:

$$\sum_{g,t} Y_t^{g^{(n-1)}} \geq \sum_j x_{jr}^{(n)} \frac{\partial \Pi_{jr}^{x^{(n)}}(p)}{\partial p_{ir}^{Y^{(n)}}} \qquad \perp \qquad p_{ir}^{Y^{(n)}} \qquad i = ele \tag{28}$$

[28] Given our operator-level representation of electricity markets, we are able to precisely match each regulator to its region. Operators that hold generators across regional borders defined in the model lead to small discrepancies in the benchmark data. For non-regulated operators, all the generators are mapped to their appropriate region of operation, so that discrepancies between state-level borders and wholesale markets geography do not affect our analysis.

[29] Nested CES function that characterize technology are formulated in calibrated share form (Rutherford, 2002), which considerably eases anchoring of a CES functions to the calibration point.

where the left-hand side represents electricity supply as defined in (35). Demand for input i comprising fuels and other materials by the electricity sector is accommodated through:

$$Y_{ir}^{(n)} \geq \sum_j x_{jr}^{(n)} \frac{\partial \Pi_{jr}^{x^{(n)}}(p)}{\partial p_{ir}^{Y^{(n)}}} + \sum_{g,t} \phi_i^c \, c^g \, Y_t^{g^{(n-1)}} \qquad \perp \qquad p_{ir}^{Y^{(n)}} \tag{29}$$

where ϕ_i^f and ϕ_i^c represent the benchmark value share of good i in variable generation costs. Factor market Eq. (26) for capital and labor are modified according to:

$$\sum_j Y_j^{(n)} \frac{\partial \Pi_{jr}^{(n)}(p)}{\partial p_r^{f^{(n)}}} + d_{fr}^{(n)}(p, M_r) + \sum_{g,t} \phi_f^c \, c^g \, Y_t^{g^{(n-1)}} \geq \sum \omega_r^f \qquad \perp \qquad p_r^f \tag{30}$$

A consistent solution also requires capturing profits earned by non-regulated electricity operators. There are two types of profits. First, generators with marginal costs below the equilibrium price for electricity earn sub-marginal profits that reflect the shadow value of installed capacity (μ^g). Second, profits for Cournot players are due to markups on marginal generation costs. Total profits are implicitly given by the difference between the wholesale market price in each load segment and total generation costs. We assume that profits generated in a given region are distributed nationally in proportion to capital income.[30]

To account for these profits, we modify the income balance (24) to account for technology-specific rents and profits (Π_r^{ELE}):

$$M_r^{(n)} = p^{k^{(n)}} \omega_r^k + p_r^{l^{(n)}} \omega_r^l + \sum_z p_r^{z^{(n)}} \omega_r^z + T_r^{(n)} + \Pi_r^{ELE^{(n)}} \,. \tag{31}$$

Electricity-sector output and inputs are valued implicitly at market prices, and hence we do not need to include capacity rents and profits explicitly in the economy-wide model:

$$\Pi_r^{ELE^{(n)}} = \sum_{g \in r} \sum_t Y_t^{g^{(n-1)}} \left(p_{ele,r}^{Y^{(n)}} \, P^{r^{(n-1)}} - P_r^{\mathrm{c}^{(n)}} c^g \right) \tag{32}$$

where the price indexes for variable generation costs are updated according to:

$$P_r^{\mathrm{f}^{(n)}} = \sum_f \phi_f^f \, p_r^{f^{(n)}} \,,$$

[30] Due to data constraints on the ownership patterns of electric-sector capital, we use base-year capital income as a proxy. We find that alternative assumptions regarding the distribution of electric-sector capital do not materially affect our conclusions.

$$P_r^{c^{(n)}} = \sum_i \phi_i^c \, p_{ir}^{Y^{(n)}} + \sum_f \phi_f^c \, p_r^{f^{(n)}} \, ,$$

respectively.

In the electricity generation model, the demand schedules are parameterized to locally approximate the response of the top-down model. In each iteration step, the linear function is re-calibrated to price and quantities derived from the top-down solution. Hence the demand function for a regulated operator f in iteration n (compare with Eq. (7)) is updated according to:

$$D^{f^{(n)}} = \overline{D}^{f^{(n)}} \, \zeta^{f^{(n)}} \left(1 + \epsilon \left(\frac{P^{f^{(n)}}}{\overline{P}^{f^{(n)}} \, \xi^{f^{(n)}}} - 1 \right) \right) \tag{33}$$

where

$$\zeta^{f^{(n)}} = \sum_j x_{jr}^{(n)} \frac{\partial \Pi_{jr}^{x^{(n)}}(p)}{\partial p_{ir}^{Y^{(n)}}} \, \overline{D}^{f^{(0)}} \qquad , \, f \in r$$

$$\xi^{f^{(n)}} = p_{ele,r}^{Y^{(n)}} \, \overline{P}^{f^{(0)}} \qquad , \, f \in r$$

are scale factors that are based on the n^{th} solution of the economy-wide model, and reference demand ($D^{f^{(0)}}$) and price ($\overline{P}^{f^{(0)}}$). A similar updating rule applies to wholesale electricity demand in Eq. (13).

Finally, using the updated variable cost indexes, the revised unit profit functions for Cournot players and for price takers in iteration (n) are given by:

$$\pi_t^{g^{(n)}} = \begin{cases} p_t^{r^{(n)}} + \frac{\partial D^{r^{(n)}}(p_t^r)}{\partial Y_t^{g^{(n)}}}^{-1} - P_r^{c^{(n)}} \, c^g - \mu_t^{g^{(n)}} & \text{if } g \in r \text{ is a Cournot player} \\ p_t^{r^{(n)}} - P_r^{c^{(n)}} \, c^g - \mu_t^{g^{(n)}} & \text{if } g \in r \text{ is a price taker} \, . \end{cases} \tag{34}$$

Non-negative profits and average cost pricing conditions for regulated operators in iteration (n) are given by:

$$P^{c^{(n)}} c^g \geq \overline{C}_t^{f^{(n)}} \quad \perp \quad Y_t^{g^{(n)}} \geq 0 \, , \tag{35}$$

$$P^{f^{(n)}} = \frac{\sum_{g \in G_f} \sum_t P^{c^{(n)}} \, Y_t^{g^{(n)}} c^g}{D^{f^{(n)}}} \, . \tag{36}$$

Appendix C: Integration of heterogeneous households into economy-wide transactions

To illustrate the key idea of the algorithm, we develop the following notation for nested utility functions. Let the quantity choices be denoted by q_i, for $i = 1, \ldots, I$, corresponding to commodities with prices p_i, respectively. The utility tree consists of $N+1$ levels, $n = 0, 1, \ldots, N$; on each level we distinguish several utility components. At the highest level (indicated by $n = N$) of the utility tree there is only one component, which corresponds to overall utility; this component is a function of utility components at the next-lower level $n = N - 1$. These utility components at $N - 1$ are in turn each a function of disjoint groups of utility components at the next lower level $N - 2$, and so on. Finally, the utility components at level $n = 1$ are functions of the the elementary utility components.

We specify the utility function for household h by assuming that all the utility components are linear homogeneous CES-type functions of the associated components at the next lower level:

$$q^h_{n,i} = \left[\sum_{j \in i} \theta^h_{n-1,j} \left(\frac{q^h_{n-1,j}}{\bar{q}^h_{n-1,j}} \right)^{\rho^h_{n,i}} \right]^{\frac{1}{\rho^h_{n,i}}} \quad , \quad \rho^h_{n,i} = \frac{\sigma^h_{n,i} - 1}{\sigma^h_{n,i}} \, , \tag{37}$$

where $j \in i$ is used to indicate the set of components $q^h_{n-1,j}$ associated with $q^h_{n,i}$, and where $\sigma^h_{n,i}$ denotes the elasticity of substitution between commodities $j \in i$. Note that we write the nested utility function in calibrated share form (Rutherford, 2002); θ and $\bar{q}$ denote the value share and consumption in the benchmark equilibrium, respectively.

The decomposition algorithm is implemented by replacing in each region the household side with an artificial agent whose utility function exhibits the identical structure as household utility in Eq. (37):

$$Q_{n,i} = \left[\sum_{j \in i} \Theta_{n-1,j} \left(\frac{Q_{n-1,j}}{\bar{Q}_{n-1,j}} \right)^{\tilde{\rho}_{n,i}} \right]^{\frac{1}{\tilde{\rho}_{n,i}}} \quad , \quad \tilde{\rho}_{n,i} = \frac{\tilde{\sigma}_{n,i} - 1}{\tilde{\sigma}_{n,i}} \tag{38}$$

where $\Theta_{n,j}$ and $Q_{n,j}$ denote the respective counterparts for the artificial agent to individual households as defined in Eq. (37). A key insight from Rutherford and Tarr (2008) is that the choice of $\tilde{\sigma}_{n,i}$ is entirely innocuous as this parameter bears no economic significance for the behavior of “real” households in the underlying economic model (it can, however, affect the convergence speed of the iterative solution procedure).

Given benchmark data on observable household demand $\bar{q}_i^h$ and prices $\bar{p}_i$, we initialize the artificial agent general equilibrium model such that commodity demands are consistent with the aggregate of benchmark household demands. This is achieved by calibrating consumption ($\bar{Q}$) and value share (Θ) parameters as:

$$\bar{Q}_{n,j} = \sum_{h=1}^{H} \bar{q}_{n,j}^h \, , \tag{39}$$

$$\Theta_{n,j} = \frac{\bar{p}_{n,j}\bar{Q}_{n,j}}{\sum_{j' \in i} \bar{p}_{n,j'}\bar{Q}_{n,j'}} \, . \tag{40}$$

Solving for a CO_2 policy shock involves first solving the artificial agent model to obtain a candidate vector of general equilibrium prices $\mathbf{p}^k$. k denotes an iteration index. The second step solves a partial equilibrium relaxation of the underlying economy by evaluating household demand functions $q_{n,i}^{h,k}(\mathbf{p}^k, y^k)$, where household income y^k is updated sequentially at prices in iteration k. The key step in each iteration involves "re-calibrating" preferences of the artificial agent based on partial equilibrium households' quantity choices:

$$\bar{Q}_{n,i}^{k+1} = \sum_{h=1}^{H} q_{n,i}^{h,k}(\mathbf{p}^k, y^k) \, , \tag{41}$$

$$\Theta_{n,j}^{k+1} = \frac{\bar{p}_{n,j}^k \sum_{h=1}^{H} q_{n,j}^{h,k}(\mathbf{p}^k, y^k)}{\sum_{j' \in i} \bar{p}_{n,j'}^k \sum_{h=1}^{H} q_{n,j'}^{h,k}(\mathbf{p}^k, y^k)} \, . \tag{42}$$

Note that this iterative procedure never alters preferences of the "real" households; it simply "re-benchmarks" successively the utility function of the artificial household to be consistent with the aggregated choices of individual households in each iteration.

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