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Allocation and leakage in regional cap-and-trade markets for CO₂

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ABSTRACT

The allocation or assignment of the emissions permits is one of the most contentious elements of the design of cap-and-trade systems. In this paper we develop a detailed representation of the U.S. western electricity market to assess the potential impacts of various permit allocation proposals. Several proposals involve the “updating” of allocations, where the allocation is tied to the ongoing output, or input use, of plants. These allocation proposals are designed with the goals of limiting the pass-through of carbon costs to product prices, mitigating leakage, and of mitigating the costs to high-emissions firms. However, allocation updating can also inflate permit prices, thereby limiting the benefits of such schemes to high emissions firms.

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1. Introduction

With new action at the Federal level stalled, climate policy is largely driven at the state or regional level in the United States. The Regional Greenhouse Gas Initiative, a cap-and-trade program which covers the electricity sector of the northeastern U.S., began operating in 2009. California’s Assembly Bill 32 (AB 32) requires that all sectors of its economy reduce their aggregate GHG emissions to 1990 levels by 2020. The California initiative is proceeding in advance of the broader-based Western Climate Initiative (WCI). The WCI would establish a regional cap-and-trade program that will initially

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encompass large stationary sources (primarily electricity) and then expand to include other sources, including transportation fuels in a second phase.¹

The fact that GHG policy is being driven at the local, rather than national level, has created concern over the geographic limitations of the regulations. Environmental targets can be undermined if production is able to shift away from the jurisdictional reach of the regulator through either leakage or reshuffling of production sources.² These concerns over regional U.S. policies reflect similar, more general concerns with leakage as a challenge even for international climate agreements. In the crafting of European CO₂ market, as well as the now defunct Waxman–Markey bill that would have established a national cap in the United States, much attention has been paid to the “competitiveness” question, which is fundamentally related to how vulnerable domestic producers are to leakage from imports.

In this paper, we develop a detailed model of the power sector in the western United States, and examine the impacts of alternative cap-and-trade designs. Our research is motivated by several important economic and policy questions relating to cap-and-trade design. First, there is the practical question of just how severe leakage can be in regional electricity markets where only some member states regulate CO₂. Second, we examine the general relationships between specific design elements and market outcomes such as leakage and firm profitability. Specifically, we focus on the question of the allocation of permits through “output-based updating,” a policy that links allocation to ongoing production. Last, we provide some quantitative, but necessarily qualified, estimates of the impacts of cap-and-trade on permit and power prices in the western U.S.

We find that leakage of electricity production to unregulated regions is a significant concern, even under a multi-state program. Our results show that output-based updating substantially reduces leakage, and produces relatively low electricity prices compared to an exogenous form of allocation, such as auctioning. A major question concerning updating is to what plants or industries a given plant should be benchmarked against for purposes of allocation. In our context, the benchmarking question concerns whether to apply the same emissions standard to all plants or to differentiate the benchmarks based upon fuel. This latter approach, known as “fuel-based” updating has drawn supporters because of the view that it can help ease the transition to carbon regulation by allocating disproportionately more permits to relatively high carbon producers, as well as limit the permit windfall that may be reaped by a low carbon producer under a purely output-based scheme.

However, as we demonstrate in the context of the WCI market, the more finely targeted, fuel-based, updating in fact reverses some of the effects seen under “pure” output-based updating. One implication of these results is that the more categories against which plants can be benchmarked for purposes of updating, the more the goals of output-based updating are undermined. Thus while the multiple, fuel-based, benchmarks are in part motivated by a desire to provide financial relief to carbon intensive firms, such an approach can actually prove counter-productive to those goals.

2. Design and modeling of cap-and-trade markets

Traditionally, the allocation of permits has been held to be an issue limited to economic transfers. Certainly it is the equity concerns that dominate the discussions and debates amongst policymakers and the affected industries. The impacts on efficiency can be negligible if the allocation is truly exogenous to the ongoing operations of the industries subject to the emissions cap, as is the case with the U.S. SO₂ trading program (Ellerman et al., 2000). However, in many cases the allocation of emissions permits has either been endogenous, or contingent upon market outcomes.

One approach of increasing interest is to allocate emissions permits using *output-based updating*. Under output-based updating each firm receives an allocation of emissions permits that is proportional to its total product production. In the electricity context, for example, this means each firm receives an allocation that is proportional to the MWh generated within the regulatory jurisdiction. The effects of output-based updating have been a subject of much research.³ In general, it is believed that output-based updating would help to mitigate leakage, as firms would be rewarded (in the form of permits)

¹ Western Climate Initiative (WCI) <http://www.westernclimateinitiative.org/>.

² See Bushnell et al. (2008b), Fowlie (2009), and Chen (2009).

³ see Jensen and Rasmussen (2000), Fischer (2003), and Fischer and Fox (2007).

for domestic production. Output-based updating is also widely believed to result in lower product prices than alternative forms of allocation.

While one strain of the academic literature has focused on the detrimental efficiency effects of such a price impact, it has an appeal to regulators. For example, the design recommendations of both the California Public Utilities Commission and the WCI include the minimization of the impacts of carbon regulations on consumers as a prominent objective of the allocation process. Despite the appeal of the product price effect, these “lower” prices can lead to inefficient over-consumption as the externality cost of the pollution is not adequately reflected in product prices.⁴ It is interesting to note, however, that in a general equilibrium setting, the welfare effects of minimizing the product price impacts are more ambiguous.⁵ This does not change the results of this paper, but provides a different perspective for interpreting the results with regards to electricity prices.

Further, there is a concern that output-based updating, if applied symmetrically to all producers, would exacerbate equity concerns. For example, there is a fear that low-carbon producers will experience a “windfall” under output-based allocation, while high-carbon producers will suffer most of the cost impacts of GHG regulations. This is because output-based allocation favors cleaner producers. Traditionally, allocation has been used as a tool to “soften the blow” of increased environmental compliance through allocations based upon historic emissions patterns. Under historic, or grandfathered allocation, larger polluters receive a larger share of the allocations, while also paying more for compliance due to their higher emissions levels. In this way the total costs to high-emissions producers are mitigated, while the marginal cost of compliance remains the same. The California Public Utilities Commission has recommended (CPUC, 2008) an alternative we will refer to as “fuel-based” updating in order to address this equity concern. Under fuel-based updating, the allocation of emissions permits per MWh of generation would be higher for high-carbon (e.g., coal-based) producers than it would be for low-carbon (e.g., gas-based) producers.

Fuel-based updating is part of a general class of allocation approaches now known as “benchmarking.” It is in fact more common than pure output-based allocation in practice. This is in part due to the equity concerns described above, and also due to the fact that it is not always easy to either measure or compare the “output” of some plants, particularly in C&T programs that span multiple industries. Allocations in the ETS market for CO₂ in the European Union have contained, at least implicitly, several aspects of updating (Grubb and Neuhoﬀ, 2006; Ahman et al., 2006). Benchmarked updating was also prominent in the proposed U.S. national cap-and-trade legislation.

The analysis of updating proposals, has focused on the efficiency implications of these approaches. In addition to inefficient over-consumption, updating can result in a productive inefficiency by distorting relative production decisions, as well as distort long-term investment signals.⁶ Several papers have examined the interaction of allocation policy with leakage and efficiency for specific industries, including electricity (Neuhoﬀ et al., 2006) and cement (Demailly and Quirion, 2006).

However, these papers tend not to emphasize the aspects of updating that motivate their application in practice. These are the impacts of updating on permit and product prices, as well as the equity effects for firms. Using a theoretical model, Bohringer and Lange (2005) consider a “closed” trading system where the cap is fixed and there is no opportunity for trading with other emissions markets. When allocations are exactly proportional (but not equivalent) to emissions, input-based updating recreates the “first-best” product prices and emissions of auctioning. The permit prices, however, rise in a closed system. In an “open” trading system, the effect of updating tends to push the abatement to regions or industries that are not receiving the implicit production subsidies in the form of updated permit allocations.

The western market we examine here has characteristics of both closed and open systems. The allocation rules are aimed at market shares, and therefore the industry level cap would not change

⁴ See Burtraw et al. (2005) for a discussion of the various impacts of updating.

⁵ This is because the price impacts of the environmental regulation may exacerbate the negative impacts of other existing taxes and regulations. Although there has been considerable focus on using the revenues from environmental regulations to offset these distortions (see Goulder et al. (1997), and Fullerton and Metcalf (2001)) it is possible that minimizing the price impact on the regulated products could also work in the same direction.

⁶ See Jensen and Rasmussen (2000), Ahman and Holmgren (2006), and Sterner and Muller (2008)

with allocation results. In the initial years of the WCI, when the allocated shares will be the largest, emissions will be dominated by the electric sector. As mentioned before, however, leakage is also a concern. There will therefore be opportunities for trading product, if not emissions permits with neighboring regions. The goal of this paper is to try to sort through these factors and establish the relative impacts of them on market outcomes.

2.1. Analysis of cap-and-trade design

Our focus is on the specific design of the cap-and-trade mechanism, and its impact on the operation of electricity markets. Therefore focus here is on a “short-term” time frame. We base our analysis upon actual market data drawn from the year 2007, and look at the counter-factual question of how those markets would have functioned under a cap-and-trade regime. In this sense the work follows in the spirit of Fowlie (2009), who also studies the potential for leakage from a California-only market, and also that of Bushnell et al. (2008a) who deploy similar techniques to examine competition and vertical contracting issues.

In a fashion similar to Shuliken et al. (2010), we formulate the joint equilibrium outcomes of the emissions and electricity market as a linear-complementarity problem. Unlike Shuliken et al. (2010), and Fowlie et al. (2010) we do not study the implications for updating policies on plant investment or retirements. In this sense our model, while dynamic, is focused on short-run operational decisions.

Our study differs from previous work in several important ways. While Fowlie (2009) studies portions of the western electricity market, we model the emissions credit prices as endogenous to the cap-and-trade market. This is central to our work given our focus on the endogenous impact of allocation policies on permit prices. Second, in addition to California’s CO₂ policies, we examine the broader western market proposed under the WCI. Last, we explicitly consider how allocation policies can affect firm behavior in the western U.S. Previous work examining the impacts of allocation have either taken a general equilibrium approach (Bohringer and Lange, 2005; Sterner and Muller, 2008; Fischer and Fox, 2007), or more complex formulations applied to stylized market data (Chen et al., 2011; Shuliken et al., 2010; Neuhoff et al., 2006).

3. Model

In this section, we first describe our equilibrium model and then discuss how we apply data from various sources to arrive at our calculations.

Although this simulation approach is capable of representing imperfect competition in the product market (*i.e.*, electricity) we assume here that firms act in a manner consistent with perfect competition with regards to both the electricity and emissions permit markets.⁷ We still model these markets as a series of equilibrium conditions for each of the individual firms represented, as the incentive effects on individual firms from policies such as updating are still relevant here.

The key variables and parameters of the model are grouped according to four important indices; the firm, location, technology, and time period of production. The total production of firm i from generation technology j , and location l at time t is represented by $q_{j,l,t}^i$. Total emissions by firm and technology are denoted $e_{j,l,t}^i(q_{j,l,t}^i)$. We assume that marginal emissions rates can be increasing in quantity ($e_{j,l,t}^i \geq 0$), but are unchanging over time. Production costs $C_{j,l,t}^i(q_{j,l,t}^i)$ vary by firm, technology, and location, and as described below are assumed to be quadratic in output $q_{j,l,t}^i$.

⁷ Although the California market was notorious for its high degree of market power in the early part of this decade, competitiveness has dramatically improved in the years since the California crisis, while the vast majority of supply in rest of the WECC remains regulated under traditional cost-of-service principles.

For each firm $i \in \{1, \dots, N\}$ and time period $t \in \{0, \dots, T\}$, a perfectly competitive, or cost-minimizing firm i maximizes profits for all its technologies j and locations l over periods $0, \dots, T$:

$$\pi_i(q_{j,l,t}^i) = \sum_t \sum_l \sum_j [p_{l,t} \cdot q_{j,l,t}^i - C_{i,j}^l(q_{j,l,t}^i)] \cdot r^{-t} - \sum_t \sum_{l \in REG} \sum_j \lambda_t \cdot e_{j,l}^i(q_{j,l,t}^i) \cdot r^{-t}, \quad (1)$$

where r is the discount rate and $p_{l,t}$ and λ_t are the wholesale prices of electricity and CO₂ permits in period t , respectively. Permit prices are assumed to be uniform across the regulated (capped) region. Wholesale electricity is assumed to be a homogenous commodity for purposes of setting wholesale prices, although prices are assumed to vary by location subject to transmission constraints as described below. However, electricity production falls into two categories, that within the region covered by the emissions cap and that outside the reach of the regulation. The set *REG* represents those plants located inside the cap and trade region.

In practice, the above model would be part of a larger multi-period cycle of emissions compliance and allocation. As we describe in Section 3.1, the first order conditions of (1) are explicitly related to variables in period t as well as permit prices in $t + 1$. In effect, the allocations are given out at the end of the cycle, just before permits are required to be surrendered. This suggests that a simplified two-period representation is sufficient to capture the key qualitative impacts of updating on the incentives of firms.⁸ In the following section, we therefore represent the allocation decision as part of a “closed-loop,” to a single cap-and-trade compliance cycle by applying the Hotelling’s rule, which requires permit prices to grow in commensurate with interest rate. The same approach has also been used elsewhere (see Rubin (1996)). These allocations are then linked to the actual output of producers during the compliance cycle that is about to conclude. We therefore suppress the effect of interest rates or other dynamic considerations.⁹

3.1. Cap-and-trade design

The profit function described in the previous section assumes a standard source-based cap-and-trade market, where the compliance obligation rests explicitly on the producer (in this case the electricity generator). As the focus of C&T design turned to allocation, however, much of the regulatory emphasis was devoted to mitigating consumer prices, smoothing the cost impacts to firms (at least somewhat), and mitigating the “windfall” profits that might be earned by low-carbon producers (CPUC, 2008). These goals were to be addressed primarily through allocation policies. In particular, two specific alternative implementations of output-based updating are considered here.

3.1.1. Output-based updating

As discussed above, one mechanism that can depress product market prices and at least partially combat leakage is output-based updating. In this context, the allocation of emissions permits would be tied to the electricity production of firms. Each MWh of production would earn a fraction of an emissions credit.

Following this assumption, we can rewrite the profit maximization problem for each firm to include the prospect of output-based allocation of emissions permits. Let $\delta_t \cdot q_{j,l,t}^i$ be the allocation of emissions permits earned for use in the compliance cycle $t + 1, \dots, T$ from producing $q_{j,l,t}^i$ units of electricity in regulated region l during period t . Note that we assume that the overall cap does not change from period to period, only that the distribution of (zero-cost) emissions permits across firms varies with the relative output of firms and their facilities. In other words $\delta_t = \bar{\delta}(CAP/Q_t)$, where Q_t is the aggregate

⁸ See Hagem and Westskog (2008) apply a similar two-period setting to study cost-effectiveness of intertemporal emissions trading.

⁹ In this and other ways, our analysis should be considered a view of the short-run impacts of these policies. It should also be noted that we do not consider the incentives effects on investment in new generation capacity. While these incentives may be important considerations in some context we note that current proposals for updating allocations in this context are designed to sunset relatively quickly and there are no specific provisions to include new facilities in the updating process. Because of these factors we believe that the short-run effects are likely be a larger factor than the long-run effects.

production (market demand) in period t , $\tilde{\delta}$ is the overall fraction of CO₂ permits that are allocated through updating, and $t \in 0, \dots, T$ is the cycle of the compliance period. Thus, the program of output-based updating would not take the form of a “tradable performance standard.”¹⁰ Under a performance standard, the subsidy for output is not limited by an overall cap. Even if the performance standard were a regulatory mandate, rather than an allocation of emissions permits, there is an implicit subsidy of production. Compliance with a mandate, when specified as an intensity per unit of output, can be advanced both through limiting the undesirable input *and* expanding total output.¹¹

The profit for firm i will now include consideration of the additional permits earned from additional production:

$$\pi_{i,t}(q_{j,l,t}^i) = \sum_l \sum_j [p_{l,t} \cdot q_{j,l,t}^i - C_{l,j}^i(q_{j,l,t}^i)] - \sum_{l \in \text{REG}} \sum_j \left[\lambda_t \cdot e_{j,l}^i(q_{j,l,t}^i) - \frac{\lambda_{t+1}}{r} \cdot \delta_t \cdot q_{j,l,t}^i \right]. \tag{2}$$

This profit equation highlights how the updating weakens the marginal cost impact of the cap-and-trade requirement for a given permit price, λ_{t+1} . Eq. (2) can then be simplified by $\lambda_t = \lambda_{t+1}/r$ when applying the Hotelling’s rule:

$$\pi_{i,t}(q_{j,l,t}^i) = \sum_l \sum_j [p_{l,t} \cdot q_{j,l,t}^i - C_{l,j}^i(q_{j,l,t}^i)] - \sum_{l \in \text{REG}} \sum_j \lambda_t [e_{j,l}^i(q_{j,l,t}^i) - \delta_t \cdot q_{j,l,t}^i]. \tag{3}$$

For facilities with an average emissions rate higher than the allocation rate, the cap-and-trade still effectively taxes output, although at a lower rate. For facilities with an average emissions rate that is lower than the allocation rate, $[e_{j,l}^i(q_{j,l,t}^i)]/q_{j,l,t}^i < \delta_t$, there is now a production subsidy.

3.1.2. Fuel-based updating

The other approach to updating under consideration would distinguish between the inputs of various production sources. Motivated by a desire to limit the cost impacts of cap-and-trade on utilities heavily reliant on coal-based sources of power, this proposal would allocate emissions permits to generation from differing fuel sources in a ratio roughly aligned with the average GHG emission rate from each fuel source. In the notation of our model, this approach would provide $\delta_{j,t}$ emissions permits to each MWh of generation from a source of technology type j . In other words, each technology could in theory be subject to a separate allocation ratio. The resulting equilibrium condition for production for firm i would be

$$\pi_{i,t}(q_{j,l,t}^i) = \sum_l \sum_j [p_{l,t} \cdot q_{j,l,t}^i - C_{l,j}^i(q_{j,l,t}^i)] - \sum_{l \in \text{REG}} \sum_j \left[\lambda_t \cdot e_{j,l}^i(q_{j,l,t}^i) - \frac{\lambda_{t+1}}{r} \cdot \delta_{j,t} \cdot q_{j,l,t}^i \right]. \tag{4}$$

As with the output-based allocation, the allocation component $\delta_{j,t}$ weakens the impact of permit prices on the perceived marginal cost of production. The strength of this effect is now asymmetric with respect to fuel types, and its net impact will depend upon the specific value of $\delta_{j,t}$. The general intent of the fuel-based updating is to weaken the impact on higher emission technologies and therefore soften the blow of implementing the cap. A somewhat extreme version of this allocation would arise if emissions rates within each technology class were constant and equivalent across all firms and locations (i.e., $e_{j,l}^i = \tilde{e}_j$) and the allocation factors were applied proportionately to emission rates $\delta_j = \tilde{\delta} \cdot \tilde{e}_j$. Then Eq. (4) can be rewritten as

$$\pi_{i,t}(q_{j,l,t}^i) = \sum_l \sum_j [p_{l,t} \cdot q_{j,l,t}^i - C_{l,j}^i(q_{j,l,t}^i)] - \left(\lambda_t - \frac{\lambda_{t+1}}{r} \cdot \tilde{\delta} \right) \sum_{l \in \text{REG}} \sum_j q_{j,l,t}^i \cdot \tilde{e}_j. \tag{5}$$

Note that (5) is essentially equivalent to Eq. (1), again assuming that emissions rates are constant over technologies and firms, except for the fact that the permit price has now been subtracted by

¹⁰ See Fischer (2003).

¹¹ See Fullerton and Heutel (2007). One current proposal that exhibits this characteristic is the “low carbon fuel standard” for transportation fuels (see Hughes et al. (2008)).

$(\lambda_{t+1} \cdot \bar{\delta})/r$ or scaled by $1 - \bar{\delta}$ for all firms if applying the Hotelling’s rule. The Bohringer and Lange (2005) result implies that in a closed cap-and-trading system this results in the same outcomes that would be produced by a grandfathered allocation of permits, except for the fact that permit prices are increased by $1/(1 - \bar{\delta})$. In this paper we examine the impact of this kind of updating in a much more complex production environment, with leakage, transmission, and capacity constraints. In addition, the actual updating policies proposed for the WCI do not reach the level of perfectly matching emissions rates, although some would come close. As the updating policy moves toward better correlation with emissions rates, we would expect these effects to become more pronounced. An empirical analysis such as this one is necessary to determine exactly how pronounced these impacts would be.

3.2. Transmission network management

We assume that the transmission network is managed efficiently in a manner that produces results equivalent to those reached through centralized locational marginal pricing (LMP). For our purposes this means that the transmission network is utilized to efficiently arbitrage price differences across locations, subject to the limitations of the transmission network. Such arbitrage could be achieved through either bilateral transactions or a more centralized operation of the network. For now we simply assume that this arbitrage condition is achieved.

Mathematically, we adopt an approach utilized by Metzler et al. (2003), to represent the arbitrage conditions as another set of constraints of the market equilibrium. Under the assumptions of a directed-current (DC) load-flow model, the transmission ‘flow’ induced by a marginal injection of power at location l can be represented by a power transfer distribution factor, $PTDF_{lk}$, which maps injections at locations, l , to flows over individual transmission paths k . Within this framework, the arbitrage condition will implicitly inject and consume power, $y_{l,t}$, to maximize available and feasible arbitrage profits as defined by

$$\sum_{l \neq h} (p_{h,t} - p_{l,t}) y_{l,t}$$

In the above arbitrage equation, the location h is the arbitrarily assigned “hub” location from which all relative transmission flows are defined. Thus an injection of power, $y_{l,t} \geq 0$, at location l is assumed to be withdrawn at h . This arbitrage condition is subject to the flow limits on the transmission network, particularly the line capacities, T_k :

$$-\bar{T}_k \leq PTDF_{l,k} \cdot y_{l,t} \leq \bar{T}_k$$

This combination of arbitrage pressure and physical transmission constraints are resolved in the solution to the following Lagrangian:

$$\max_{y_{l,t}} \sum_{l \neq h} [(p_{h,t} - p_{l,t}) y_{l,t} - (PTDF_{l,k} \cdot y_{l,t} - \bar{T}_k) \tau_{k,t}]$$

where $\tau_{k,t}$ is the shadow value of capacity on transmission path k at time t .

4. Data sources and assumptions

We utilize detailed hourly production data for all major fossil-fired and nuclear generation sources in the western U.S. These hourly output data are aggregated by firm and region to develop the “demand” in the simulation model. As discussed below, this is in fact a residual demand; the demand that is left after applying the output from non-CEMS (Continuous Emission Monitoring System) plants. These data are combined with cost data to produce supply cost functions for each firm.

These data are then combined to create a demand profile and supply functions for periods in the simulation. Although hourly data are available, for computational reasons we aggregate these data into representative time periods. There are 20 such periods for each of the four seasons, yielding 80 explicitly modeled time periods. As California policy was the original focus of this work, the

aggregation of hourly data was based upon a sorting of the California residual demand. California aggregate production was sorted into 20 bins based upon equal MW spreads between the minimum and maximum production levels observed in the 2007 sample year. A time period in the simulation therefore is based upon the mean of the relevant market data for all actual 2007 data that fall within the bounds of each bin. For example, every actual hour (there were 54) during Spring 2007 in which California residual demand fell between 6949 and 7446 MW were combined into a single representative hour for simulation purposes. The resulting emissions from this hour were then multiplied by 54 to generate an annualized equivalent total level of emissions.

The number of season-hour observations in each bin is therefore unbalanced, there are relatively few observations in the highest and lowest production levels, and more closer to the median levels. The demand levels used in the simulation are then based upon the mean production levels observed in each bin. In order to calculate aggregate emissions, the resulting outputs for each *simulated* demand level was multiplied by the number of *actual* market hours used to produce the input for that simulated demand level.

In the following sub-sections, we describe further the assumptions and functional forms utilized in the simulation.

4.1. Market demand

The demand for power we represent is constructed from the hourly generation of fossil-fired and nuclear power plants. In this sense, “demand” is not full end-use demand, but the portion that is provided by carbon-producing sources. In effect we are assuming that, under our CO₂ regulation counter-factual, the operations of non-modeled generation (e.g., renewable and hydro) plants would not have changed. This is equivalent to assuming that compliance with the CO₂ reduction goals of a cap-and-trade program will be achieved through the reallocation of production within the set of modeled plants. We believe that this is a reasonable assumption for two reasons. First the vast majority of the CO₂ emissions from this sector come from these modeled resources. Indeed, data availability is tied to emissions levels since the data are reported through environmental compliance to existing regulations. Second, the total production from “clean” sources is unlikely to change in the short-run. The production of low carbon electricity is driven by natural resource availability (e.g., rain, wind, solar) or, in the case of combined heat and power (CHP), to non-electricity production decisions. The economics of production are such that these sources are already producing all the power they can, even without additional CO₂ regulation. To a first-order, short-run emissions reductions will have to come either from shifting production from among conventional sources, a reduction in end-use electricity demand, or through substitution with unregulated imports, *i.e.*, leakage or reshuffling.¹²

End-use consumption, as defined above, in each location is represented by the demand function $Q_{l,t} = \alpha_{l,t} - \beta_l p_{l,t}$, yielding an inverse demand curve defined as

$$p_{l,t} = \frac{\alpha_{l,t} - \sum_{i,j} q_{i,j,t} - y_{i,t}}{\beta_l}$$

where $y_{i,t}$ is the aggregate net transmission flow into location l . The intercept of the demand function is based upon the actual production levels in each location calculated as described above. Summary statistics on demand are reported in [Appendices A and B](#). In other words, we model a linear demand curve that passes through the observed price–quantity pairs for each period. As electricity is an extremely inelastic product, we utilize an extremely low value for the slopes of this demand curve. For each region, the regional slope of the demand curve is set so that the median elasticity in each region is -0.5 .¹³

¹² It is important to recognize that our modeling approach not only assumes that existing zero-carbon sources will not change *how much* they produce but also *when* they produce it. An interesting question is whether a redistribution of hydro-electric power across time could lower CO₂ emissions by enabling a better management of fossil generation sources. Such an analysis would require a co-optimization of hydro and thermal electric production and is beyond the scope of this paper.

¹³ When the market is modeled as perfectly competitive, as it is here, the results are relatively insensitive to the elasticity assumption, as price is set at the marginal cost of system production and the range of prices is relatively modest.

Table 1
Generation by ownership and fuel type.

Firm	Coal	CCGT	Gas St	Gas CT	Oil
BRKA	6104	629	235	319	0
CPN	0	4802	0	915	0
DYN	0	2120	2875	0	0
EIX	720	1373	0	237	0
LADWP	2117	1303	1929	282	0
PW	1741	1569	430	486	0
SALTRP	1802	1537	407	0	0
SEMPRA	0	2366	0	46	0
XCEL	2593	690	107	0	0
Others	14 153	16 338	12 049	4840	629

4.2. Fossil-fired generation costs and emissions

We explicitly model the major fossil-fired thermal units in each electric system. Because of the legacy of cost-of-service regulation, relatively reliable data on the production costs of thermal generation units are available. The cost of fuel comprises the major component of the marginal cost of thermal generation. The marginal cost of a modeled generation unit is estimated to be the sum of its direct fuel, CO₂, and variable operation and maintenance (VO&M) costs. Fuel costs can be calculated by multiplying the price of fuel, which varies by region, by a unit's 'heat rate,' a measure of its fuel-efficiency.

The capacity of a generating unit is reduced to reflect the probability of a forced outage of each unit. The available capacity of generation unit i , is taken to be $(1 - fo_{fi}) * cap_i$, where cap_i is the summer rated capacity of the unit and fo_{fi} is the forced outage factor reflecting the probability of the unit being completely down at any given time.¹⁴ Unit forced outage factors are taken from the generator availability data system (GADS) data that is collected by the North American Reliability Councils. These data aggregate generator outage performance by technology, age, and region.

Generation marginal costs are derived from the costs of fuel and variable operating and maintenance costs for each unit in our sample. Platts provides a unit average heat-rate for each of these units. These heat-rates are multiplied by a regional average fuel cost for each fuel and region, also taken from Platts. Costs for each technology type are then aggregated by firm and region, and then represented with a single quadratic function for each of five technology types, further separated by firm and region. Marginal cost of technology j at location l for firm i is therefore an affine function:

$$C_{l,j}^i(q_{l,j,t}^i) = k_{l,j}^i + c_{l,j}^i q_{l,j,t}^i \cdot inhim$$

These cost functions are derived by aggregating the generation of each firm by region and technology type. The five technology categories are coal, gas combined cycle (CCGT), conventional (steam) gas, gas combustion turbine (CT), and oil.

There are ten firms consisting of the nine largest fossil generation producers and a "fringe" firm derived from the aggregation of the generation from all remaining firms. The generation capacity of each of these firms is summarized by technology type in Table 1.

4.2.1. Emissions rates

Emissions rates, measured as tons CO₂/MWh, are based upon the fuel-efficiency (heat-rate) of a plant and the CO₂ intensity of the fuel burned by that plant. They are modeled as affine functions, with rates differentiated by firm, location, and technology. This yields a functional form of

$$e_{l,j}^i(q_{l,j,t}^i) = E_{l,j}^i + \epsilon_{l,j}^i q_{l,j,t}^i.$$

¹⁴ This approach to modeling unit availability is similar to Wolfram (1999) and Bushnell et al. (2008a).

Table 2
Scope of regulation: emissions by region (mmTon).

Regulation	CA	NWPP	SW	Non-WCI	Total	Carbon price
Actual (CEMS)	40.71	87.30	63.37	149.52	340.9	NA
No cap	35.99	83.75	58.00	139.46	317.2	NA
Cal only	30.55	84.78	60.04	141.25	316.62	10.80
WCI cap	32.33	71.76	46.88	147.95	298.92	40.30
WECC cap	36.87	74.32	48.99	131.08	291.26	43.80

4.3. Transmission network

Our regional markets are highly aggregated geographically. The region we model is the electricity market contained within the U.S. portion of the Western Electricity Coordinating Council (WECC). The WECC is the organization responsible for coordinating the planning investment, and general operating procedures of electricity networks in most states west of the Mississippi. The multiple sub-networks, or control areas, contained within this region are aggregated into the four “sub-regions.” Between (and within) these regions are over 50 major transmission interfaces, or paths. Due to both computational and data considerations, we have aggregated this network into a simplified, 5 region network consisting primarily of the 4 major subregions.¹⁵ Fig. 1 illustrates the areas covered by these regions. The states in white, plus California, constitute the U.S. participants in the WCI.

Given aggregated level of the network, we model the relative impedance of each set of major pathways as roughly inverse to their voltage levels. The network connecting AZNM and the NWPP to CA is higher voltage (500 kV) than the predominantly 345 kV network connecting the other regions. For our purposes, we assume that these lower voltage paths yield 5/3 the impedance of the direct paths to CA.

There are sub-regions with both the NWPP and AZNM areas that would also not be subject to the currently organized WCI agreement. These include the states of Nevada and Idaho, as well as power plants located on tribal lands in the desert southwest. In each case these regions were considered to electrically be part of the region in which they were located, but for purposes of GHG regulation were treated as separate regions. Flow capacities over these interfaces are based upon WECC data, described in [Appendices A and B](#).

5. Results

Following the assumptions described above, we simulate the electricity production for the western electricity market under a variety of assumptions about the scope and design of cap-and-trade for CO₂. For the geographic scope of the regulation, we first simulate operations under no-cap at all to establish a reference level for the other simulation results. Then we examine CO₂ caps applied to California-only, to all (U.S.) states participating in the WCI, and finally to all states (and tribal areas) in the western market. For each of these cap-and-trade scenarios, we assume that the cap is set at 85% of the CO₂ emissions from the “no-cap” scenario. For all of the results in this section, we assume that permits are allocated exogenously and therefore do not effect the output decisions of firms. As described above, the simulation encompasses 8760 h of actual market data that were aggregated into 80 representative hours, 20 for each season. These representative hourly results were then multiplied by the number of actual hours in each of the “bins” from which these hours were based upon. The results reported below are therefore annual totals, based upon 8760 h of production.

Table 2 summarizes the aggregate annual CO₂ emissions for each of the key regulatory regions. Results are reported for each of the simulated scenarios, as well as the actual (2007) aggregate emissions, as measured by CEMS, for each of these regions. First note that simulated emissions under the

¹⁵ The final “node” in the network consists of the Intermountain power plant in Utah. This plant is connected to southern California by a high-capacity DC line, and is often considered to electrically be part of California. Because under some regulatory scenarios, it would not in fact be part of California for GHG purposes, it is represented as a separate location that connects directly to California.

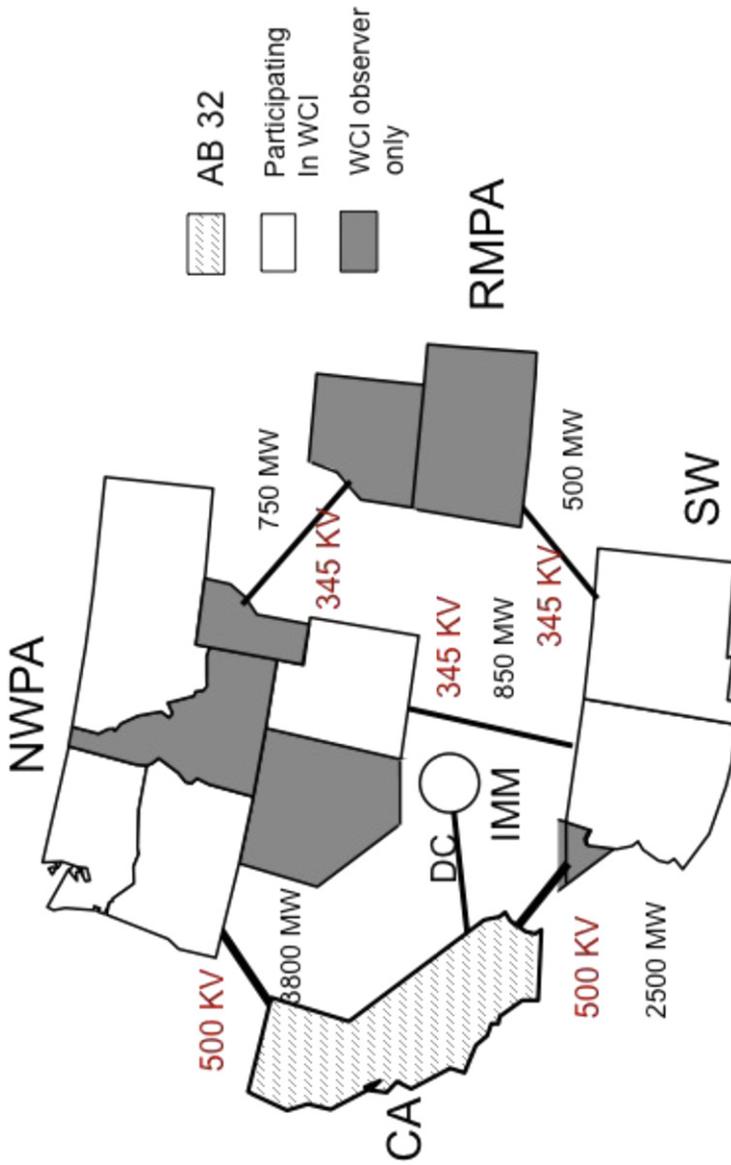


Fig. 1. Western regional network and cap-and-trade regions.

Table 3
Summary of results.

Outcome	Region	No cap	Cal cap	WCI cap	WECC cap	WCI update	WCI fuel based
Permit price (\$/ton)			10.80	40.30	43.80	45.60	67.50
	Cal	35.99	30.55	32.33	36.87	38.40	33.80
Emissions (mmTon)	WCI	141.75	144.82	118.64	123.31	112.70	117.30
	non-WCI	139.46	141.25	147.95	131.08	141.90	145.70
	Total	317.2	316.62	298.92	291.26	293.00	296.80
Elec. prices (Avg. \$/MWh)	Cal	57.22	59.88	74.78	78.54	60.36	67.41
	NW & SW	58.14	61.12	79.89	74.98	61.41	68.27
	RMPP	58.37	65.01	66.53	68.52	61.67	68.48
Export change (Avg. MWh)	Cal	122	-1405	-419	700	1293	220
	NW & SW	621	1647	-1212	54	-1046	-1002
	RMPP	-743	-241	1680	-757	-247	781

“no cap” scenario are about 6% lower than measured actual emissions. This difference is most pronounced in the California region. These differences are driven by the relative production of combined cycle (CCGT) to less efficient (CT and ST) gas plants. Production from less efficient plants is lower, and from CCGT plants higher, in our simulation than in actuality. This is most likely due to several factors. First, by aggregating actual hourly observations into representative market hours, we in effect truncate the peak demand levels of the system into a single level representing the average of a set of high demand hours. The operation of these less efficient plants is usually concentrated in these very high demand hours. Second, our simulation ignores inter-temporal operating constraints on plants, and CCGT plants are in fact less nimble than our simulation implicitly assumes them to be. Third, while we model major inter-regional transmission constraints, other more local constraints could force the operation of less efficient generation.

We now turn our focus to the impacts of cap-and-trade regulations relative to our simulated no-cap case. As would be expected, a cap applied only to California, as originally envisioned under AB 32, would result in significant leakage. Although California emissions decline by 5.5 mmTon as required by the cap, aggregate west-wide emissions decline by less than 1 mmTon. Emissions prices are correspondingly low, at only 10.80 \$/ton, due to the fact that compliance through leakage is a relatively inexpensive option. When the cap is applied to the currently configured WCI, leakage is greatly reduced, but still roughly 1/3 of the 26 mmTon reduction in WCI state emissions is picked up in the nearly 7 mmTon increase in non-WCI emissions. When the cap is applied to the entire market, permit prices rise to just below \$44/Ton. This can be interpreted as the value required to reach a true reduction of 26 mmTon over the entire region without any leakage, as opposed to a reduction of 26 mmTon under the cap that is offset by an increase outside the cap. One implication of this comprehensive CO₂ cap is that California emissions *increase*. This is because the generation capacity inside California’s borders is relatively clean, and a west-wide reduction in overall emissions is most easily accomplished by reducing output from coal generation in other states, and replacing it with gas output from California.

The rest of our results are summarized in Table 3. The first four columns of results summarizes the outcomes that vary by the scope of the cap; California, WCI, and WECC or west-wide. The first row summarizes emissions allowance prices. The rows summarize outcomes as grouped by California, the non-California members of the WCI (those in NWPP and the SW) and the non-WCI areas.

The sixth through eight rows of Table 3 summarizes the impact of the regulations on wholesale electricity prices (not retail rates) in each region. Note that the regional breakdown in these rows is slightly different than for the emissions results. These are electricity market areas, rather than CO₂ regulatory areas. The northwest (NW) and southwest (SW) includes both capped and uncapped states, while the RMPA has no WCI states in its region. The impact of the emissions cap is widespread. Prices rise substantially under the more comprehensive CO₂ caps. This is true even in regions not covered by the cap, this is due to the increased exports from these regions.

Rows 9 through 12 of Table 3 summarize the impact of the regulations on electricity flows between regions. Recall that the “demand” modeled here is based upon actual production, rather than end-use demand, so it is the *change* in flows, relative to the actual, that are summarized in this table. In the

table above, a negative figure implies a net import from the region relative to the actual period, while a positive number implies a net export. For example, California imported 347 MW/h less under our base-case simulation than was implied by the actual data for the same periods, resulting in a net increase of 347 MW of CA production. Consistent with the emissions results, one can see the sizable swing in imports into California (around 1200 MW/h) under a California-only cap, as well as the large increase in net injections from the non-WCI region (about 2200 MW/h) under the WCI cap. Note again that flows into California experience a substantial decrease under the comprehensive west-wide cap.

5.1. Impacts of allocation policies

We now turn to the question of how the various policies for allocation of permits impacts prices and operations. The last two columns of [Table 3](#) summarize the effects on several outcomes for the various permutations of an updating policy applied to the WCI. In all cases, except the no-cap case, an identical emissions cap of roughly 150 mmTon, or 85% of the uncapped level, is applied to the WCI region. Recall that column labeled ‘WCI cap’ applies to any allocation policy, such as auctioning or grandfathering, where allocations are exogenous to ongoing market outcomes. There were also two versions of allocations through updating that we considered. The column ‘WCI updating’ refers to output-based updating. Under this policy, we assumed that 80%, or 120 mmTon, of the permits are allocated under the updating policies, with the remainder either allocated in some exogenous fashion or auctioned off. Similarly, in the ‘Fuel-based’ updating scenario, we also assume that 80% of the permits were allocated, and the remainder auctioned. Under the Fuel-based updating scenario, we follow the CPUC’s (CPUC, 2008) proposed allocation ratios. This proposal would allocate twice as much to coal generation as it would to gas generation. These ratios apply only to the fraction of total permits allocated, so that the net allocation received by a coal plant was equivalent to 0.75 ton/MWh, while the allocation to gas plants would be 0.375 ton/MWh.¹⁶ We established these allocation levels so that the total number of permits assigned under both the fuel-based and output-based allocation proposals was the same. This is truly ‘fuel-based’ updating, with the distinction between updating being based upon fuel, rather than technology or explicit emissions rates. We therefore would not expect as extreme an impact from this allocation as that implied by Eq. (5). However, differentiation by fuel does capture a significant portion of the emissions rate differences between plants, so some significant differences from output-based updating would be expected.

As seen from [Table 3](#), the impacts of the allocation policies are indeed significant. CO₂ emissions in uncapped ‘non-WCI’ regions increase by roughly 7 mmTon (or 1/3 of the required reduction), under a WCI cap with no updating. When output-based updating is applied to firms within the WCI, this leakage of emissions is reduced to roughly 2 mmTon (or less than 1/10 of the required reductions). Also note that emissions within California rise substantially with the application of output-based updating. As can be seen from [Fig. 2](#), this is due to a large decrease in coal production throughout the WCI. This is due to output-based allocation, which favors gas generation relative to coal-generation. California has no coal-based utility scale generation. The output-based updating therefore had a non-trivial impact on mitigation of leakage from the WCI region. When the updating approach is changed instead to be fuel-based, however, this mitigation of leakage is largely offset. Total emissions are only 2 mmTon lower than when no updating at all is applied.

The most striking impact of the updating policies is on the prices of the emissions permits, illustrated in the first row of [Table 3](#). Permit prices rise from about \$40/ton without updating to \$45.60/ton with output-based updating. As predicted, the fuel-based updating approach has a substantial impact on permit prices, raising them to just under \$67.50/ton. Recall that this model reflects only the electricity sector, and therefore the distortions from these price impacts are contained within this industry and are largely offset by the updating policies that caused them. When one considers that this market will eventually include most major sources of CO₂ emissions within the west, and be linked with other regions through trades with other CO₂ markets, as well as offset programs, the potential distortions caused by such an inflationary impact on permit prices become a significant concern.

¹⁶ There are very few oil plants in the sample, and they received allocations in equal ratios as those of gas plants.

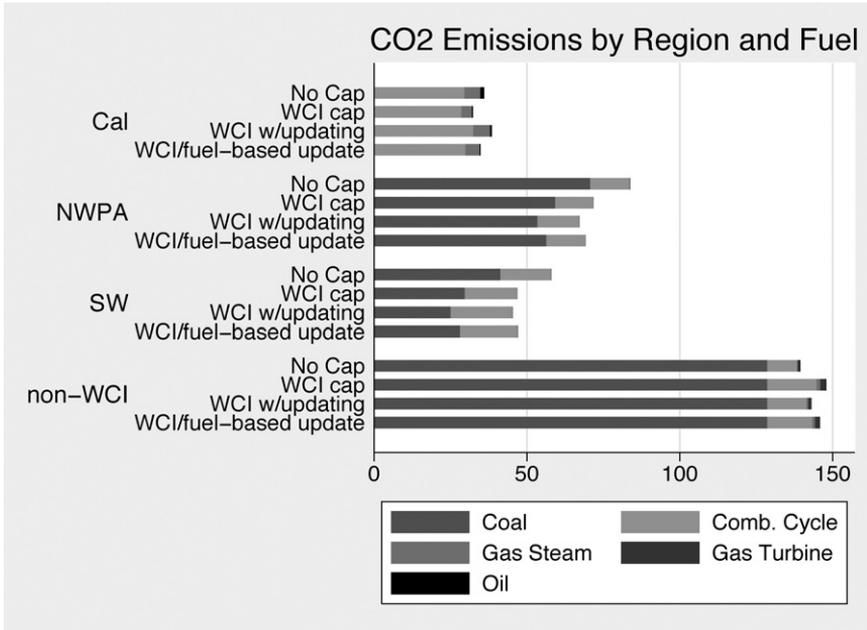


Fig. 2. Impact of updating policies.

The results summarized in the last three rows of Table 3 tell a similar story, this time in terms of energy exports rather than emissions. The application of a CO₂ cap on the WCI states results in a net increase of 2200 MW/h in net exports from the non-WCI regions, which swing from net importers to net-exporters of power. When output based updating is applied, the WCI region again becomes a net importer. As with emissions, the application of fuel-based updating reverses the effects of output-based updating, raising net-exports from the non-WCI regions by an average of about 700 MWh.

Rows six through eight of Table 3 summarize the electricity price impacts of the cap, and of the updating policies. The imposition of the cap (again requiring a 15% reduction from the no cap) raises California wholesale average prices from around \$58/MWh to around \$75/MWh. The almost \$20/MWh increase is consistent with the facts that CO₂ costs are about \$ 40/ton in this scenario, and that gas plants, which emit roughly 1/2 ton per-MWh are almost always the marginal, price-setting technology. When output-based updating is applied, most of this impact on the market-clearing price is eliminated, as prices “fall” from 75 to about \$62/MWh. Yet again the fuel-based updating policy reverses the impacts of the output-based updating. Prices under fuel-based updating average around \$70/MWh.

5.1.1. Profit impacts of allocation policies

We now examine how the allocation policies impact the emissions costs and operating profits of firms. Recall that the updating schemes are largely motivated by a desire to offset the cost impacts to high emitting firms and limit any perceived windfalls to low emissions firms. Table 4 summarizes the net costs of emissions regulations on firms. The net emissions costs is defined here as the costs of emissions permits required by the firm under the cap-and-trade regulation less the value of the emissions permits allocated under the various allocation approaches. As before the fuel-based and output-based contingent allocation schemes assume that 80% of total permits (about 120 mmTon) are allocated to producers. The last column in this table considers an exogenous grandfathered allocation of the same quantity, based upon the emissions under the “no-cap” scenario, which here serves as the proxy for historic emissions.

Table 4
Net emissions costs by firm (millions \$).

Firm	No allocation	Fuel-based	Output-based	Grand-fathering
BRKA	894.2	439.5	489.6	292.2
CPN	394.9	41.9	-96.7	126.4
DYN	261.6	6.3	-77.2	101.1
EIX	157.6	6.3	-44.1	44.3
LADWP	660.8	262.1	280.3	227.1
PW	286.4	120.5	100.4	97.8
SALTRP	341.8	135.8	123.3	110.7
SEMPRA	203.4	-0.5	-67.7	58.4
XCEL	0.0	0.0	0.0	0.0
Others	2883.3	1107.3	743.9	1261.0

Table 5
Wholesale market net revenues from fossil generation (millions \$).

Firm	No allocation	Fuel-based	Output-based	No cap	Grand-fathering
BRKA	1746	1988	1636	1587	2397
CPN	389	605	578	190	670
DYN	225	376	355	80	401
EIX	401	453	413	245	508
LADWP	442	711	535	438	899
PW	517	578	470	377	720
SALTRP	513	608	496	409	747
SEMPRA	244	338	302	91	385
XCEL	1140	1041	953	863	1140
XFRINGE	4262	4962	4168	3489	6858

Note that when a firm receives more in allocation than it must surrender due to its actual emissions, the net costs can be negative. This is in fact the case for largely gas-based producers, such as Calpine (CPN) and Dynegy (DYN) under the output-based allocation approach. In contrast, coal-heavy producers such as PacifiCorp (owned by BRKA) and Arizona Public Service (owned by PW) have significant emissions costs under any scenario. Despite the skewing of permit allocation in favor of coal producers under the fuel-based allocation approach, net emissions costs are only slightly lower for these firms under this approach. The reason is that the higher equilibrium permit prices largely offset the increased allocation quantities these firms receive under the fuel-based approach. These firms are clearly better off under grandfathering, which also skews allocations their way without impacting permit prices.

The picture becomes more complex when one considers the net effects of the allocation scheme on product (electricity) prices as well as emissions costs. Table 5 summarizes the operating profits of the firms under the assumption that each firm were selling all its output at market-clearing prices, rather than at a regulated cost-based rate. It is important to recognize that several of the firms in this table are in fact either regulated or government-owned.¹⁷ Therefore these results are more a qualitative representation of the general net revenue and cost effects than a literal assessment of each firm's bottom line impact. The profits are therefore defined as the total revenues (assuming market-based sales) less the net emissions costs from Table 4 as well as the total production costs (fuel and operating expenses).

The results in Table 5 highlight the complex interaction between the allocation policy, permit prices, and electricity prices. Recall that, based on allocation and emissions costs alone, gas-intensive firms appeared to benefit from output-based allocation. However, output-based allocation also greatly limited the pass-through of CO₂ costs to electricity prices. This results in reduced revenues for all firms. While gas intensive firms such as CPN still prefer contingent allocation to auctioning, they actually do

¹⁷ The results also reflect only revenue of sales from thermal generation sources. Firms with substantial nuclear and hydro generation would benefit disproportionately more from a higher permit price.

better under fuel-based allocation than output-based. This is despite the fact that fuel-based allocation was intended to limit their perceived windfall benefits from allocation. However, since electricity prices are higher under fuel-based, the increased revenue from this scenario more than offsets the reduced allocation in permits relative to output-based updating for these firms.

For high carbon firms, such as the coal-heavy BRKA and PW, the contingent allocation approaches look even worse. The combination of higher emissions costs due to the inflated permit prices and lower electricity revenues reduce profits under these allocation schemes to below those seen with *no* allocation at all. While fuel-based is in fact preferred to output-based allocation by such firms, neither is particularly appealing. As before, grandfathering is the clear winner from the perspective of such firms.

5.2. Interactions with new renewable energy

As elsewhere, a cap-and-trade program for the western U.S. will not be the only policy targeting CO₂ emissions in this region. In particular, many western states have renewable portfolio standards that will be escalating simultaneously with the roll out of the emissions trading system. These portfolio standards mandate a certain percentage of electricity generation come from renewable sources such as wind and solar. In this section we examine the interaction between these policies and the cap-and-trade scenarios studied above.

Note that the analysis in previous sections does not assume zero growth in renewable energy. In fact, the functional assumption in this analysis is that growth in renewable energy exactly matches the growth in overall demand. In terms of total MWh of generation and consumption through the rest of this decade, this is not an unreasonable assumption, renewable energy is in fact expected to grow about proportionally to overall energy demand.¹⁸ However, the *timing* of this renewable energy generation will almost certainly not match the growth in energy demand. Thus it is a worthwhile sensitivity to examine how our results are impacted by the change in the hourly profiles of residual demand, after accounting for renewables and hydro production growth.

To address this question, we utilize wind generation profiles taken from WECC transmission planning studies. The WECC studied several scenarios for renewable energy penetration (see Nickel, 2008), with particular focus on an assumption of 15% of total WECC energy being provided from renewable sources. This modeling effort employed a dataset from the National Renewable Energy Laboratory (NREL) that provides 10-min wind speeds with a high level of geographic resolution throughout the U.S. portion of the WECC system. The WECC study combines these wind potential data with other local sources of information to construct projections of new wind development, as well as of hourly wind production from those potential new sources.

We take the hourly load profiles of the projected wind facilities from the WECC study and aggregate these profiles according to the four WECC subregions described above. As a portion of the current residual demand, the new wind sources would account for about 15% of 2007 CEMS energy. This is equivalent to roughly 60 TWh of new wind generation. Assuming investors are free to locate at the most promising sites, these resources will not be evenly distributed across the WECC. The Rocky mountain regions, comprising much of Wyoming and Colorado, are particularly promising for wind production.

We combine the projected new wind production with the existing hourly demand as constructed in previous sections of this paper. Under the assumption that this increase would roughly offset demand growth, we also increase demand by an equivalent amount. Importantly the demand increase is assumed to be constant across all hours, while the wind generation is concentrated during high wind hours.

We first examine the impact of additional wind production independent of any other environmental policy. We then combine both policies and examine the resulting emissions and leakage consequences.

¹⁸ As of 2008, the WECC had forecast an increase of around 160 TWh of demand by 2017. This figure is now overstated as the recession has reduced growth forecast substantially. From this figure, the WECC has recently adopted projections of 60 TWh of savings by 2020, relative to the base forecast, due to a variety of energy efficiency initiatives (see WECC, 2011). According to the same report, WECC anticipates will be a total increase in renewable energy of around 90 TWh in the same time frame.

Table 6

Scope of regulation: emissions by region (mmTon).

Wind level	Regulation	Cal	WCI	Non-WCI	Total	Price
New wind	No cap	36.54	179.04	138.91	317.95	0
	Cal only	30.59	176.74	140.64	317.38	11.86
	WCI cap	34.13	151.08	146.97	298.05	40.48
High new wind	No cap	30.13	168.22	134.55	302.77	0
	Cal only	30.13	168.22	134.55	302.77	0
	WCI cap	27.72	151.08	141.50	292.58	30.27

Table 6 illustrates the results on CO₂ emissions for the relevant WECC regions. Under the assumption of 60 TWh of new wind (the amount assumed in the WECC study), the results differ little from before. The change in the load shape has relatively little effect on total emissions or leakage.

When amount of wind energy is increased to 90 TWh by scaling up the hourly supply assumed by WECC by 150%, total CO₂ emissions without any cap decline to about 302 mmTon in the WECC. This by itself constitutes a 5% reduction of the baseline WECC emissions and makes complying with a California cap trivial. The new renewable production brings California emissions below its own target of 15% below 36 mmTon. A WCI-wide cap brings in more ambitious reductions and still requires a permit price of around 30\$/ton, and leakage to non-WCI regions is reduced by about 6 mmTon.

These results illustrate two important considerations relating to the interaction of policies such as renewable mandates and an emissions cap. First, the mandates, being funded outside of the cap-and-trade market, serve to reduce emission prices by forcing reductions in emissions through a mechanism that is exogenous to the emissions market. Second, such mandates can be much more effective than an emissions cap when the cap would otherwise be applied to a relatively small market, such as California. In all of our results, a cap applied to just California resulted in very little overall emissions reductions, while the renewable mandate, which is dominated by California, produces true reductions in the overall western market.

6. Conclusions

While the establishment of cap-and-trade regulation, as opposed to command-and-control regulations, is largely motivated by a desire to provide incentives for the efficient mitigation of pollution, many other policy goals are often at play. These goals include mitigating the cost impacts of climate regulation on both consumers and on the firms to which the regulation will be applied. As climate policy continues to be controversial in the United States, these ancillary goals are playing a prominent role in the debate over emissions markets. The allocation of emissions permits is a critical element of this debate.

We have studied these issues in the context of the proposed California and Western Climate Initiative cap and trade programs, by focusing on the electricity market that spans these regions. In this context, the mitigation of leakage is a central concern. Indeed, we find that even with a western cap applied to 7 states, leakage could still be significant. Here the proposals for updated allocation of permits can have a significant impact. Output-based allocation largely achieves the stated goals of policy-makers by effectively mitigating leakage and also electricity prices when these allocations are benchmarked to an industry average emissions rate. However, when the allocation is more finely benchmarked according to the fuel used by the plant, most market outcomes closely resemble those seen under an exogenous allocation scheme. Permit prices, however, rise considerably to levels more than double that seen under an exogenous allocation. Although the primary goal of benchmarking by fuel is to insulate high-carbon firms from cost shocks and prevent “windfalls” to low-carbon producers, these goals are largely unachieved even when 80% of the permits are allocated.

While we believe these results have important practical implications for the design of the western electricity market, we need to note many caveats that limit the interpretation of these results as a forecast of WCI cap-and-trade market results. First, we limit our analysis to the electricity industry, which will dominate the WCI market for its first phase, but will then be combined with several

other sectors, including transportation fuels. Second, we model only traditional “source-based” market implementations, where the WCI is pursuing a hybrid design that will combine the source-based regulation of plants located within the WCI with attempts to account for the CO₂ content of imports into that region. Third, we do not consider the long-run incentives provided by updated allocation methods. Qualitatively, adding investment (and exit) in the presence of updating would definitely bias both decisions. This has been studied in a stylized case by Shuliken et al. (2010), who focus on entry and exit, and more specifically by Fowlie et al. (2010), who study similar allocation questions for the cement industry. For incumbent facilities, updating tends to delay retirement as the foregone permits add to the opportunity cost of exit. Updating can either reinforce or undermine investment in cleaner new facilities. The exact nature of the bias depends upon how updating is applied. For example, under a broadly applied benchmark (e.g., award permits based upon fleet average emissions rates), there would be an added incentive to invest in the cleanest technology. Under a more finely targeted benchmark (e.g., fuel-based updating), there would be an incentive to invest in more efficient coal plants over less efficient ones, but not an added incentive to invest in gas, or renewables, relative to coal.

When one considers the implications of an integration of the electricity sector with other sectors, the aspect of fuel-based updating that is most problematic is the greatly increased permit price. The concern is that the upward price pressure from the sector receiving updates will lead the mitigation to be concentrated in other sectors that do not. In those sectors, marginal emissions costs will in fact be much higher than in the sectors receiving updated allocations. For example, one would expect the utilization of unconventional “offsets,” such as permits for retrofitting inefficient facilities, to greatly increase as the result of the inflationary pressure on permit prices caused by updating.

More generally, as discussions concerning national cap-and-trade regime for CO₂ advance, these results, consistent with previous work, highlight the potential distortions that updating can introduce into a cap-and-trade market. Just as important from the point of view of policy-makers, careful attention must be paid to the equilibrium effects of any allocation proposal. The “benefits” from more complex allocation schemes may be far less than policy-makers expect, while the negative impacts remain a serious concern.

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Appendix A. Specification of complementarity problem

A.1. No updating

This appendix specifies the complementarity formulation of the optimization problem described in the text. Each firm has a limited capacity of each technology type in each location, which we denote by $\bar{q}_{j,l}^i$. Given the above framework, we can represent the resulting equilibrium as the set of quantities that simultaneously satisfy the following first order conditions. We represent as a complementarity condition, where the symbol \perp signifies that vectors $x, y \geq 0$ and $x^T y = 0$. For each firm i and period t :

$$q_{j,l,t}^i \geq 0 \perp p_t - C_{l,j}^i(q_{j,l,t}^i) - \lambda_t \cdot e_{j,l}^i(q_{j,l,t}^i) - \gamma_{j,l,t}^i \leq 0 \quad \forall i, j, t, l \in REG. \tag{6}$$

and

$$q_{j,l,t}^i \geq 0 \perp p_t - C_{l,j}^i(q_{j,l,t}^i) - \gamma_{j,l,t}^i \leq 0 \quad \forall i, j, t, l \notin REG. \tag{7}$$

Here $\gamma_{j,l,t}^i$ is the shadow value of the capacity constraint on technology $q_{j,l,t}^i$.

$$\gamma_{j,l,t}^i \geq 0 \perp \bar{q}_{j,l}^i - q_{j,l,t}^i \geq 0 \quad \forall i, j, t, l. \tag{8}$$

Each firm, taking prices as exogenous, sets its production so that marginal costs equal A.2 the price at the location of the production. This marginal cost component includes the costs of emissions permits in locations subject to the emissions cap as well as the shadow price of the limited capacity of that technology.

A.2. Output-based updating

As described above, output-based updating would allocate δ_t permits per MWh to each firm. Differentiating the profit function (2) yields the following.

$$q_{j,l,t}^i \geq 0 \perp p_t - C_{l,j}^i(q_{j,l,t}^i) - \lambda_t \cdot (e_{j,l,t}^i(q_{j,l,t}^i) - \delta_t) - \gamma_{j,l,t}^i \leq 0 \quad \forall i, j, t, l \in REG. \tag{9}$$

If the updating is instead fuel or technology specific, then the above condition is modified so that the allocation quantity, now $\delta_{j,t}$, can be unique to a technology type j .

$$q_{j,l,t}^i \geq 0 \perp p_t - C_{l,j}^i(q_{j,l,t}^i) - \lambda_t \cdot (e_{j,l,t}^i(q_{j,l,t}^i) - \delta_{j,t}) - \gamma_{j,l,t}^i \leq 0 \quad \forall i, j, t, l \in REG. \tag{10}$$

A.3. Environmental constraint

Along with equilibrium conditions (6)–(10), the equilibrium for a combined electricity and emissions market will include the following condition defining the permit price for the overall compliance period.

$$\lambda_t \geq 0 \perp \sum_i \sum_j \sum_{l \in REG} q_{j,l,t}^i \cdot e_{j,l,t}^i(q_{j,l,t}^i) - e^{MAX} \leq 0. \tag{11}$$

where, again, the symbol \perp signifies complementarity between the constraint on available emissions permits and the permit price, which is the shadow price of that constraint. If there are excess emissions permits, the price is zero; otherwise λ_t is positive.

A.4. Network constraints

Prices at individual locations will be determined by the production decisions of firms and the flows over the transmission network. The arbitrage minimization assumption described above produces the following condition:

$$p_{h,t} - p_{l,t} - \sum_k PTDF_{l,k} \cdot \tau_{l,t} = 0.$$

This reflects the general condition from an efficiently utilized network, that the prices between locations differ only by the additional costs of congestion of a shipment between those locations, as measured by the flows over lines times their shadow prices. There is a separate condition for potential congestion in each direction.

$$\tau_{k,t}^1 \geq 0 \perp PTDF_{l,k} \cdot y_{l,t} - \bar{T}_k \leq 0 \quad \forall k, t.$$

$$\tau_{k,t}^2 \geq 0 \perp \bar{T}_k - PTDF_{l,k} \cdot y_{l,t} \leq 0 \quad \forall k, t.$$

When the inverse demand, marginal cost, and emissions functions are linear, as they are described below, the equilibrium conditions for each of the possible cap-and-trade regimes, along with the respective conditions for network operations and emissions market balance, combine to form a linear complementarity problem (Cottle et al., 1992) with variables $q_{j,l,t}^i, y_{l,t}$ and dual values $\tau_{k,t}, \lambda_t$, and $\gamma_{j,l,t}^i \geq 0$. The solution to this complementarity problem constitutes a perfectly competitive equilibrium to this market, subject to the respective definitions of the cap region and allocation policy. Using

Table 7
Demand by region and season.

Season	SW	CA	NWPA	Non-WCI
Winter	10925	11 641	10 781	16 407
Spring	12 130	11 369	8394	15 604
Summer	14705	16 314	12 823	18 766
Fall	10943	13 504	12 878	16 622

Table 8
Available slack transmission capacity by region and period (MW).

Season	Period	NW-CA	SW-CA	RM-NW	RM-SW	SW-NW
Spring	Off-peak	5649	3023	731	523	709
	Peak	3692	2855	837	505	772
Summer	Off-peak	2886	3320	935	490	762
	Peak	1634	3337	957	451	922
Fall	Off-peak	5012	2604	540	369	402
	Peak	3101	2757	652	318	666
Winter	Off-peak	5473	2362	458	278	319
	Peak	3683	1921	545	231	396

the data sources and functional forms described in the following section, we calculate these equilibrium outcomes using the PATH solver algorithm (Dirkse and Ferris, 1995) implemented through the AMPL math programming language.

Appendix B. Data sources

B.1. Power supply and demand

Our primary data source is the BASECASE dataset from Platts, which is in turn derived primarily from the continuous emissions monitoring system (CEMS) utilized by the U.S. Environmental Protection Agency (EPA) to monitor the emissions of large stationary sources. Almost all large fossil-fired electricity generation sources are included in this dataset. However, hydro-electric, renewable, and some small fossil generation sources are missing. The CEMS reports hourly data on several aspects of production and emissions. Hourly data on nuclear generation plants are included with fossil generation data in the BASECASE dataset. Here we utilize the hourly generation output and CO₂ emissions for available facilities.

Plant cost, capacity, and availability characteristics and regional fuel prices are then taken from the Platts POWERDAT dataset. These data are in turn derived from mandatory industry reporting to the Energy Information Administration (EIA) and the National Electric Reliability Council (NERC).

The mean hourly demand is summarized by GHG regulatory region in Table 7.¹⁹ In each representative hour, demand is assumed to be at the levels reflected in Table 7 when market prices are equal to the levels observed in the actual market hours from which the demand numbers are taken.

B.2. Transmission network

The flow capacity over the regional interfaces are ideally based upon the amount of “slack” capacity remaining over these interfaces under actual market conditions. We have obtained data from the WECC for hourly flows and total available capacity for each hour of the first 10 months of 2007. Unfortunately data for November and December 2007 were not yet available.

¹⁹ As described below, supply and demand regions can be characterized as belonging in one of 5 electrical zones or one of the four zones distinguished by climate regulation listed in Table 7.

We characterize the available *additional* capacity over the key paths according to the average difference between available capacity (or ATC) and actual flows over each key transmission path. These differences are averaged over peak and off-peak periods for each of the four seasons represented in our model, where the winter season is based on the average of October only.²⁰ The resulting available remaining import capacity over each transmission interface is summarized in Table 8.

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²⁰ In implementing our model, “off-peak” hours are defined as falling in the lowest 6 out of 20 of demand ‘bins’ that are described above. All other hours are treated as “on-peak”.

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