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(Executive Summary)

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**Abstract**

Flexibility in environmental regulations can lead to reduced costs if it allows additional abatement from lower cost sources or if policy tailoring and experimentation across states increases regulatory efficiency. The EPA's 2014 Clean Power Plan, which implements greenhouse gas regulation of power plants under the Clean Air Act, allows substantial regulatory flexibility. The Clean Power Plan sets state-level 2030 goals for emissions rates (in lbs $CO_2$ per MWh) with substantial variation in the goals across states. The Clean Power Plan allows states considerable flexibility in attaining these goals. In particular, states can choose whether to implement the rate-based goals or equivalent mass-based goals (i.e., emissions caps). Moreover, states can choose whether or not to join with other states in implementing their goals. Using a model of electricity generation across states, we analyze incentives to adopt inefficient rate-based standards versus efficient mass-based standards. We show that adoption of inefficient rate-based standards is a dominant strategy for states from both a consumer's and a generator's perspective. We calibrate the model for electricity markets in the Western United States and calculate significant inefficiencies from a failure to coordinate. In particular, state-by-state rate-based standards result in a substantial loss of welfare relative to business as usual. Even a harmonized West-wide rate-based standard dissipates a substantial proportion of the potential gains from regulation. Despite these large inefficiencies, the incentives for adoption of the inefficient policies are substantial particularly for generators.

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# 1 Introduction

Within the United States, state-by-state variation in regulatory approaches has been more of the norm than an exception. Within the utility industries, individual state regulatory commissions have applied substantially different variations on the rate-of-return regulatory framework, for example, while some states have chosen to rely on wholesale power markets instead of vertically integrated utilities. In the environmental realm, the Federal Environmental Protection Agency (EPAs) has often deferred to state or local air quality regulators to develop specific implementation plans to achieve the EPA's environmental mandates. The Clean Air Act, one of the dominant environmental regulatory instruments, requires the EPA to leave regulatory decisions up to individual states.

In electricity markets, the regulatory actions of states, or even local communities, often affect the market outcomes in surrounding areas because electricity flows throughout regional networks. The most extreme form of this interaction is manifested when one state adopts a policy or regulation and its neighbors do nothing. In the climate change arena, California and states in the northeastern U.S. have faced this issue with their unilateral adoption of cap-and-trade programs limiting carbon emissions from their local sources. In both instances, there have been concerns that such actions could spur "leakage" of both emissions and of beneficial economic activity to the neighboring uncapped regions; specifically, while emissions may decrease within the regulatory jurisdictions, emissions may *increase* elsewhere as output increases from unregulated power plants.[1]

A more subtle but still powerful form of economic spillovers from regulatory choices can arise when individual states respond to regulatory requirements with different methods. The choice of regulatory instrument affects power plants' opportunity cost of selling electricity. Therefore, certain policies may provide a competitive advantage to power plants within a particular state, and this advantage will depend on the policies adopted in other states. In the face of these incentives, it is not clear that the efficient mix of policies will be the equilibrium outcome.

Recent actions by the EPA to address greenhouse gas emissions appear likely to create a similar dynamic, but on a greater scale given the prominence of the environmental challenge and costs of greenhouse gas mitigation. The EPA's "Clean Power Plan" (CPP) proposes major reductions in carbon emissions from electricity generators in the United States (US). By focusing on the electricity sector, the CPP uses existing provisions of the Clean Air Act Amendments to regulate a substantial share of carbon emissions. Due in part to inaction

[1] See Fowlie (2009) and Chen (2009).

at the federal level, recent US climate policy has been driven almost exclusively by state and regional initiatives. A national framework may decrease inefficiencies created by the patchwork of state and regional policies and could improve US standing in international climate negotiations.

The regulatory approach taken by the EPA is, in many ways, unprecedented. The CPP establishes state-level targets for carbon emissions rates in lbs of carbon dioxide per megawatt hour of electricity generated (lbs per MWh). States have a great deal of flexibility in how to achieve these goals. For example, they may adopt the default "rate-based" standard or they could adopt an equivalent "mass-based" regulation such as a carbon cap and trade system. Under a rate-based standard, the state must decrease its carbon emissions rate, whereas under a mass-based standard the state must decrease its aggregate emissions (e.g., create an emissions cap). Because these systems create different incentives, effects on consumers and producers within a state could be quite different depending on the type of regulation adopted both in that particular state as well as in other states because electricity is traded regionally across state lines. Furthermore, the states' private incentives may be at odds with those of a national social planner.

We analyze the potential effects of the CPP in terms of electricity market outcomes and state adoption incentives. We first analyze a general theoretical model and then calibrate a simulation model to analyze electricity markets in the Western United States. We then use these simulations to investigate likely outcomes under the CPP.

The theoretical model has a market supply curve which is a step function ordering the generation technologies by their marginal cost. This ordering is called the "merit order". Under mass-based carbon regulation, generators must purchase carbon credits to cover all their carbon emissions. This increases each generator's marginal costs in proportion to its carbon emissions and may change the merit order of the generation technologies so that generation is higher from less carbon intensive technologies. Under a tradable rate-based regulation, generators sell or purchase carbon credits based on whether their emissions rate is better or worse than the target emissions rate. This can increase or decrease a generator's marginal costs in proportion to its carbon emissions and may change the merit order.

Our first theoretical result compares the efficiency of supply, i.e., the merit order, under the different regulatory outcomes and shows increasingly stringent necessary conditions for supply efficiency as regulations depart from the efficient regulation. Under mass-based regulations, supply is efficient if the carbon price in each state is sufficiently close to the social cost of carbon. Supply can also be efficient under rate-based standards since costs increase or decrease in proportion to carbon emissions. However, now the carbon price must equal the social cost of carbon *and* the rate standard must be equal across all the states. Importantly, if carbon prices are equal across states but rate standards are not equal, carbon costs would be different for identical generators in the different states and thus the merit order could be inefficient. Surprisingly, supply can be efficient when regulation is a mixture of mass- and rate-based standards across states. In this case efficiency additionally requires that full marginal costs (which include carbon costs) must be sufficiently different. Thus it may be impossible to attain supply efficiency with mixed regulations.

Efficiency of supply is a necessary but not sufficient condition for efficiency. In fact, if demand is not perfectly inelastic, we show that only a mass-based standard can be efficient. This result echoes earlier results in the literature, e.g., Helfand (1991), Holland, Hughes, and Knittel (2009).

The theoretical model then turns to the incentives for adoption of mass- or rate-based standards from different perspectives. To minimize inefficiencies in the theoretical analyses, we assume that carbon prices equal the social cost of carbon. We first examine the incentives of a coalition of states and then the incentives of a single state. For the coalition of states, adoption of mass-based standards is best from an efficiency perspective. However, from the perspective of an individual state, adoption of a rate-based standard (instead of a mass-based standard) results in lower electricity prices. This benefits consumers (both in this state and in other states) so consumers have an incentive to lobby for adoption of rate-based standards.

From a generator's perspective, the lower electricity prices from adoption of a rate-based standard could lead to lower profits. However, regulated generators' costs fall by more than the electricity prices fall. This leads to a split in incentives for generators. Generators whose operations are not covered by the regulation, e.g., distributed generation, renewables, nuclear, small fossil plants, prefer the high electricity prices associated with mass-based standards. On the other hand, regulated generators (e.g., existing fossil plants) benefit from lower costs and prefer rate-based regulation. Holding carbon prices fixed we show that adoption of a rate-based standard is a "dominant strategy" from the perspective of "covered" generators, but adoption of a mass-based standard is a dominant strategy from the perspective of "uncovered" generators.

Although consumers and covered generators prefer rate-based standards, mass-based standards result in carbon market revenue which could be used to compensate consumers and covered generators for their losses under mass-based standards. This compensation could occur, for example, through the allocation of the carbon credits. However, theory cannot provide clear guidance on whether or not carbon market revenues would be sufficient to compensate consumer and covered generators. Thus, whether or not potential compensation is possible is an empirical question.

We next calibrate the model for the eleven states which make up the western interconnection of the U.S. electricity grid. There are two main differences between our theoretical model and our simulation model. First, the simulation model recognizes that electricity cannot flow freely throughout the West. Thus our simulation model has four demand regions with potentially different electricity prices in each region and limited transmission capacity between regions.

Second, our simulation model does not hold carbon prices fixed, but rather tries to imitate the regulations (i.e., the caps and rate standards) which would result under the CPP. In particular, the simulations attempt to implement the reductions in the emissions rates required from redispatch of existing generation resources under the second building block of the CPP. These emissions reductions range from 0% in Montana and Idaho to 40% in Arizona. Thus we model significant heterogeneity in the regulations.

The model calibration is based on 2007 supply and demand conditions. We update the model with current natural gas prices and test the sensitivity of our results to this assumption. The model simulates a variety of regulation scenarios including: no regulation (business as usual), a single West-wide mass-based standard, a single West-wide rate-based standard, state-by-state mass-based standards, and state-by-state rate-based standards. We also simulate mixed mass- and rate-based regulations across two coalitions: the Coastal states (CA, OR, and WA) and the Inland states (AZ, CO, ID, MT, NM, NV, UT, and WY).

We first illustrate the effects of the different regulations on the market supply curve (the merit order) for electricity. Compared to the business as usual supply curve, a west-wide mass-based standard increases the full marginal costs for all generators in proportion to their carbon emissions. A west-wide rate-based standard raises the full marginal costs of coal-fired generation, but *lowers* the full marginal costs of most gas-fired generation. The full marginal costs from a west-wide mass- or rate-based standard are remarkably similar across units (the relative prices are correct) but the full marginal costs under a rate-based standard are lower.

When states fail to coordinate on a policy, the merit order can be "scrambled" quite dramatically. In particular, state-by-state mass- or rate-based standards result in full-marginal costs (and a merit order) which are substantially different than would result under a west-wide policy. We also illustrate the scrambling of the merit order when the Coastal states adopt a mass-based standard and Inland states adopt a rate based standard.

To estimate the welfare effects of the different policies, we first calculate the short-run equilibria under the different scenarios. Based on the equilibrium electricity prices we can analyze the changes in consumer surplus, generator profits, and carbon market revenue. In addition, we can calculate the deadweight loss of each scenario based on an estimate of the social cost of carbon.

Our short-run analysis shows substantial deadweight loss from a failure to coordinate policies. In particular, state-by-state rate standards result in a deadweight loss which is twice that of business as usual, i.e., which is twice as bad as doing nothing. In contrast, the deadweight loss from failures to coordinate on mass-based standards is only 30% of the BAU deadweight loss.

The deadweight loss from adopting a west-wide rate-based standard is about 30% of the BAU deadweight loss. This DWL results from electricity prices that are too low relative to the first best and hence too much consumption of electricity. This lower electricity price implies higher consumer surplus under a rate-based standard. Our calculations show that carbon market revenues (e.g., from auctioning carbon permits) could only partially compensate consumers even if they received all the carbon market revenue from a mass-based standard.

The lower electricity prices under a west-wide rate-based standard have different effects on generator profits depending on whether the generators are covered by the Clean Power Plan (e.g., most fossil-fired plants) or are not covered (e.g. renewables, nuclear, and distributed generation). Under rate-based standard, covered generator profits are higher (by about \$1 billion per year) but uncovered generator profits are lower (by about \$6 billion per year) relative to a mass-based standard.

Our simulations suggest that efficiency is enhanced when states form regional trading markets. A natural question, then, is whether states will have the incentive to form such coalitions? We consider the incentives of the two blocks of states defined above: coastal and inland states. Our calculations show that from an abatement cost perspective (the sum of consumer surplus, generator surplus, and any carbon market revenue) the strategic interaction between the regions would result in west-wide adoption of a mass-based standard, i.e., Cap/Cap is the "Nash equilibrium".

When we look at the individual sets of stakeholders, Cap/Cap is no longer an equilibrium. From a consumer's perspective the Nash equilibrium would be Rate/Rate, i.e., would result in west-wide adoption of a rate-based standard. The incentives of firms depend on the mix of covered and uncovered generators. From the generator's perspective We find that there is a strong incentive to have different regulatory mechanisms; Cap/Rate and Rate/Cap are both Nash equilibria.

Another important dimension over which states and EPA will need to evaluate their compliance plans is the treatment of newly constructed fossil-fired power plants. Technically, Section 111d of the Clean Air Act covers only existing sources. New sources are covered under a different Section and will have to comply with a source-specific $CO_2$ emissions rate standard. At the time of this writing, the extent to which state-level plans may or may not include new plants under their Clean Power Plan compliance strategies has not been resolved.

We analyze investment in new combined cycle gas turbines under an assumption of 10% demand growth relative to 2007. Under a mass-based system, abatement levels are dramatically lower when new investments are excluded. Under a rate-based system, abatement levels are higher when new investments are excluded. Average abatement costs are generally higher when new plants are excluded and a mass-based standard is applied. The location of new investment will also depend on the regulatory mix. In general new investment will occur in the rate-based regions if it is included under the CPP. Our calculations show that investment swings can be quite dramatic for different changes in the regulatory mix.

This work is closely related to, but addresses a new chapter in, the literature on environmental and economic spillovers from local climate policies. The fact that GHG policy has been driven at the local, rather than national level, has long created concern over the geographic limitations of the regulations. Three concerns exist. First, as noted 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] Second, the existence of many local regulatory programs is unlikely to lead to the efficient amount of abatement across the regions as marginal abatement costs will not equalize. Third, regulatory action in one area may put firms in that region at a competitive disadvantage relative to firms in unregulated regions. These concerns have been a challenge for regional climate initiatives in the US. More generally, concerns over leakage have been a challenge for international climate agreements. In the crafting of European $CO_2$ 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.

Finally, our work contributes to the literature on rate-based environmental regulation. Holland, Hughes, and Knittel (2009) show that rate-based policies cannot, in general, achieve the efficient allocation of emissions and energy production.[3] In the case of a national low

[2]See Bushnell, Peterman, and Wolfram (2008), Fowlie (2009), and Chen (2009).

[3]This inefficiency does not arise when rates are calculated using an exogenous base such as historical

carbon fuel standard (LCFS) for transportation fuels, Holland, Hughes, and Knittel (2009) and Holland et al. (Forthcoming) find the inefficiency is quite large. Average abatement costs are several times greater under an LCFS compared with a mass-based cap and trade (CAT) policy that achieves the same emissions. We make three main contributions to this literature. First, prior work assumes demand for energy is essentially static. Since electricity demand can vary substantially hour to hour, our work explicitly captures time varying demand. Importantly, because different generators are dispatched in different periods depending on demand, mixed regulation may introduce inefficiencies by distorting the merit order. Second, we quantify the efficiency cost of rate-base policies compared to mass-based policies in the electricity sector. While prior theory results imply rate-based policies are inefficient, we use our calibrated simulation model to estimate the magnitude of these effects. Third, we investigate states' unilateral incentives to adopt rate-based or mass-based regulations. Since the EPA rule allows states to choose which system to adopt, understanding these incentives has important policy implications.[4]

Our theoretical model is most closely related to Fischer (2003). Fischer analyzes carbon trading between mass- and rate-based standards and finds that such trade raises carbon emissions. Our theoretical work extends the work of Fischer by analyzing two components which are crucial for understanding the CPP. First, we explicitly model trading in the product market (electricity) which crucially affects the interactions of the states' policy choices. Second, we analyze the states' adoption incentives for mass- and rate-based standards.

Section 2 discusses the Clean Power Plan in more detail and provides policy background. Section 3 develops the theoretical model and derives the theoretical results. Section 4 presents the simulation model and Section 5 describes the results. Section 6 concludes.

# 2 The Clean Power Plan: GHG Regulation under the Clean Air Act

Air pollution in the United States is primarily regulated under the Clean Air Act (CAA). The Clean Air Act Amendments of 1990 introduced the landmark emissions trading program known as the Acid Rain Program and established a system of permitting for both new and existing sources of criteria pollutants. The National Ambient Air Quality Standards (NAAQS) establish threshold measures of ambient pollution for criteria pollutants. If

emissions (Holland, Hughes, and Knittel, 2009) or GDP (Pizer, 2005).

[4]See also Holland (2012), Huang et al. (2013), Pizer (2005) and Zilberman et al. (2013).

pollution in a region exceeds these standards, the region is designated non-attainment and permitting requires additional stringency. Since the enactment of the CAA, there has been a substantial decline in many air pollutants despite significant economic growth.

Greenhouse gas emissions are fundamentally different than the criteria air pollutants regulated under the CAA. First, greenhouse gases are a global pollutant. Thus while there may be regional variation in damages from global climate change, there is no regional variation in damages from *emissions* of greenhouse gases. Therefore, the system of regional attainment and non-attainment designations makes little sense. Second, greenhouse gases are a stock pollutant, i.e., they accumulate in the atmosphere over time. Regulations must be based not just on current ambient concentrations and current damages but also on expected future concentrations and future damages.

Despite the poor fit of the CAA for regulating greenhouse gases, the US EPA is nonetheless compelled to regulate greenhouse gases under the CAA. The 2007 decision by the U.S. Supreme Court in *Massachusetts v. EPA* found that "greenhouse gases fit well within the Act's capacious definition of 'air pollutant'." Moreover the court found that the CAA "conditions EPA action on its formation of a 'judgment,' [based on] whether an air pollutant 'cause[s], or contribute[s] to, air pollution which may reasonably be anticipated to endanger public health or welfare'." In December 2009, the EPA issued its "Endangerment Finding" which found that "six greenhouse gases taken in combination endanger both the public health and the public welfare of current and future generations." This finding compels the EPA to regulate GHGs under the CAA.

The looming regulation of GHGs under the CAA likely spurred efforts to develop new legislation regulating GHGs outside the CAA framework. However, since the failure in 2009 of H.R. 2454 (also known as the Waxman-Markey Bill) to gain passage in the U.S. Senate, new legislation has been blocked in the U.S. Congress. In the absence of new legislation, EPA has no option but to proceed with GHG regulations under the CAA.

Since *Massachusetts v. EPA*, the EPA has taken several steps to limit GHG emissions under the CAA. In May 2007, Executive Order 13432 implemented a process for regulation of GHG emissions from motor vehicles and off-road vehicles. In May 2010, the EPA issued its "Tailoring Rule" establishing air permitting requirements for large stationary sources of GHG emissions. In November 2010, EPA issued guidelines for permitting of GHG emissions for new sources. But none of these guidelines addressed GHG emissions from existing power plants, which account for approximately a quarter of GHG emissions in the United States.

On June 2, 2014, the Obama administration released the Clean Power Plan (CPP) which proposes using the CAA to regulate power plant GHG emissions. Rather than following the familiar permitting process for existing power plants, the CPP uses instead provisions in Section 111 of the CAA. Section 111 gives the EPA jurisdiction over pollutants other than those identified as criteria pollutants "which may reasonably be anticipated to endanger public health or welfare." The Section provides a flexible framework for regulation, but also imposes constraints on the types of policies that may be implemented under the CPP.

Regulation under Section 111 requires that the EPA establish "standards of performance" for new sources and then within a year to establish standards of performance for existing sources. The text defines a standard of performance as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction." The text also requires state-level implementation of the standards.

The Clean Power Plan implements Section 111 by establishing emissions rate goals (in lbs $CO_2$ per MWh) for each state.[5] These goals are constructed based on the estimated best system of emissions reductions for each state. The states then develop plans for achieving those goals, and the EPA approves the plans.

To estimate the best system of emissions reductions goals for each state, the Clean Power Plan uses four "building blocks" each of which contributes to emissions reductions. The first building block focuses on emissions from coal-fired generation. It requires reductions in emissions rates through efficiency improvements, co-firing, retirements, or retrofitted carbon capture and sequestration. The second building block focuses on shifting generation from relatively dirty coal-fired plants to relatively cleaner gas-fired plants. The third building block requires increased generation from low emissions or zero-emissions generation (e.g., nuclear and renewables). The final (fourth) building block focuses on energy efficiency improvements. Efficiency improvements are treated as equivalent to zero-emissions generation, thus both the third and fourth building blocks reduce the goal's emissions rate by increasing the denominator of the "lbs $CO_2$ per MWh" goal.

Each state's emissions reductions goal from the four building blocks was published by the EPA for 2030 with an interim goal for 2020. The goals range across states from less than a 20% reduction in the emissions rate for North Dakota to over a 70% reduction in the emissions rate for Washington (see NRDC Summary of EPA's Clean Power Plan). It is hard to compare the stringency of these different goals across states since both the numerator and

[5]It is unclear why the CPP specifies rate-based goals (i.e., in lbs $CO_2$ per MWh) instead of mass-based goals (i.e., in lbs $CO_2$). The rationale is likely that rate-based goals are synonymous with performance standards as required in Section 111. Comments to the EPA recommend that the CPP publish equivalent mass-based goals for each state.

denominators vary. Nonetheless, it is clear that there is substantial variation in goals across states.

The CPP then requires that the states develop plans for implementing these goals. The CPP allows states to meet their goals by adopting either a rate-based standard or a mass-based standard, i.e., "capped" policy. The CPP also allows states to join a regional multi-state plan.[6] However, the CPP neither compels states to adopt a capped policy nor compels states to adopt a regional approach. This flexibility could allow states to tailor their regulations to better fit their unique circumstances. Alternatively, the flexibility could lead states to adopt inefficient regulations which benefit some stakeholders at the expense of others.

# 3 The Model

Consider a model of electricity generation and consumption in multiple states (regions).[7] Let $s$ index the states. Since electricity cannot be stored, demand and prices vary across time. Let $t$ index hours and assume electricity flows freely across the states so that the electricity price in hour $t$ is $p_t$ and is common across all the states.[8] Total demand at time $t$ is given by $D_t(p_t)$, and (net) consumer surplus, $CS$, is found by integrating under the demand curve and summing over $t$. To analyze the distribution of consumer surplus, $CS_s$, across the states, we assume that each state's share of demand is a constant fraction of total demand.

Supply in the model comes from a variety of generating units each with a constant marginal cost of generation and a limited capacity. Since the generating units may be regulated differently across states, we differentiate generating units by their location. Let $i$ index the technologies (e.g., coal-fired, combustion turbine, etc.) and $s$ index the states. Assume $c_i$ is the marginal cost of generating from technology $i$; $\bar{q}_{si}$ is the installed capacity in state $s$ of technology $i$; and $\beta_i$ is the carbon emissions rate of technology $i$.

Under a market-based carbon regulation, costs also include carbon costs. Let $\tau$ be the social cost of carbon, and let $r \in \{BAU, MB, RB\}$ index the carbon regulations: "business as usual", "mass-based standards", and "rate-based standards".[9] Define the *full marginal*

[6] The CPP states: "A state could adopt the rate-based form of the goal established by the EPA or an equivalent mass-based form of the goal. A multi-state approach incorporating either a rate- or mass-based goal would also be approvable based upon a demonstration that the state's plan would achieve the equivalent in stringency, including compliance timing, to the state-specific rate-based goal set by the EPA."

[7] The model obviously applies to other industries with similar characteristics. We discuss extensions of the model to other industries in Section 6.

[8] In the simulations, we extend the model to include transmission constraints.

[9] Below we define additional regulatory environments, e.g., $MBx$ refers to a state with a mass-based standard when other states may have rate-based standards.

*cost*, $FMC_{si}^{r}$, as the sum of the marginal generation plus (private) carbon costs. Below we define the full marginal cost for mass- and rate-based standards. In the absence of carbon regulation, i.e.., in $BAU$, private carbon costs are zero and $FMC_{si}^{BAU} = c_i$. We also define the *full marginal social cost* as the marginal generation plus social carbon costs, i.e., $c_i + \beta_i \tau$.[10] Welfare, $W^r$, under regulation $r$ is the gross consumer surplus less full social costs, or, equivalently, the sum of net consumer surplus, generator profit, and any carbon market revenue minus carbon damages.

The supply from each technology is determined by comparing the electricity price with the full marginal cost. Generators supply at capacity if the electricity price exceeds their full marginal cost, supply nothing if the price is below their full marginal cost, and supply any amount up to capacity if the price equals their full marginal cost.

The market supply is determined by aggregating the supply from each generation technology. The resulting market supply is a non-decreasing step function which orders the technologies by their full marginal cost. The order of the technologies along the supply curve determines the order in which generation units would be called into service as demand increases and is called the *merit order.*

The market supply in the absence of carbon regulation ($BAU$) is illustrated in Fig. 1. This figure shows the full marginal costs of four technologies: nuclear ($c_N$), coal ($c_C$), gas ($c_G$), and oil ($c_O$). As illustrated, the unregulated merit order would be first nuclear, then coal, gas, and finally oil because $c_N < c_C < c_G < c_O$.

The equilibrium electricity price in hour $t$ is found from the intersection of hour $t$ demand and market supply. Specifically, under carbon regulation $r$, the price in hour $t$ is given by

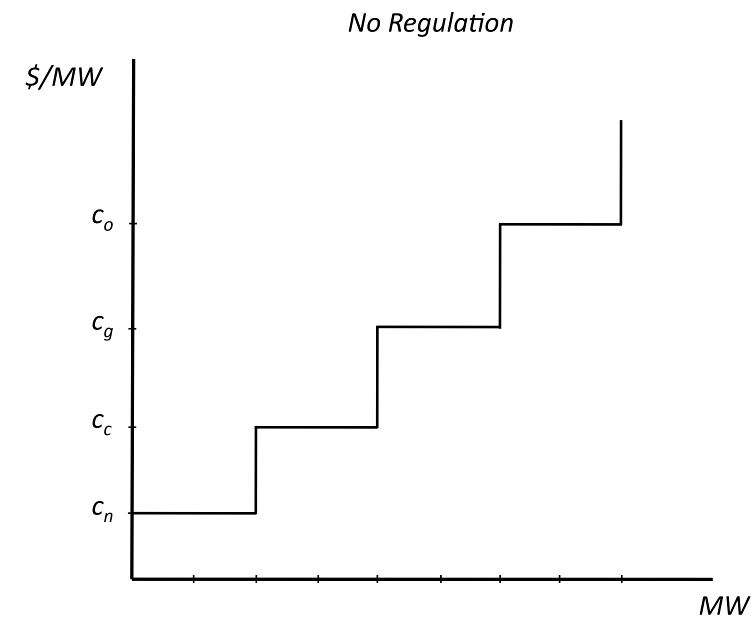
$$p_t^r = min\{p : D_t(p) \leq \sum_s \sum_i \Phi(FMC_{si}^r \leq p)\bar{q}_{si}\} \tag{1}$$

where $\Phi$ is an indicator function which takes the value one if the argument is true and zero otherwise. Thus $\Phi(FMC_{si}^r \leq p)$ is one if $FMC_{si}^r \leq p$, i.e., if technology $i$ is willing to supply at price $p$ and is zero otherwise. The set defined in [1] is the set of prices for which there is excess supply. The minimum of this set will either be a price at which demand exactly equals market supply when all inframarginal generators supply at capacity (i.e., on a vertical portion of the supply curve) or will be a price at which any smaller price would have excess demand (i.e., on a horizontal portion of the supply curve).

Fig. 2 illustrates the equilibrium electricity prices under $BAU$ for five demand hours.

[10] The full marginal social cost does not depend on the state or the carbon regulation.

**Figure 1:** Aggregate supply curve in the absence of carbon regulation ($BAU$).




The equilibrium prices are determined by the intersection of the aggregate supply and the demands. In the low demand hour, only nuclear is used, whereas in higher demand hours coal-fired generation is also used and then gas- and oil-fired generation in the highest demand hours. The electricity prices equal the full marginal costs of the marginal generator in all hours except hour four in which the price is determined to ration the available capacity.

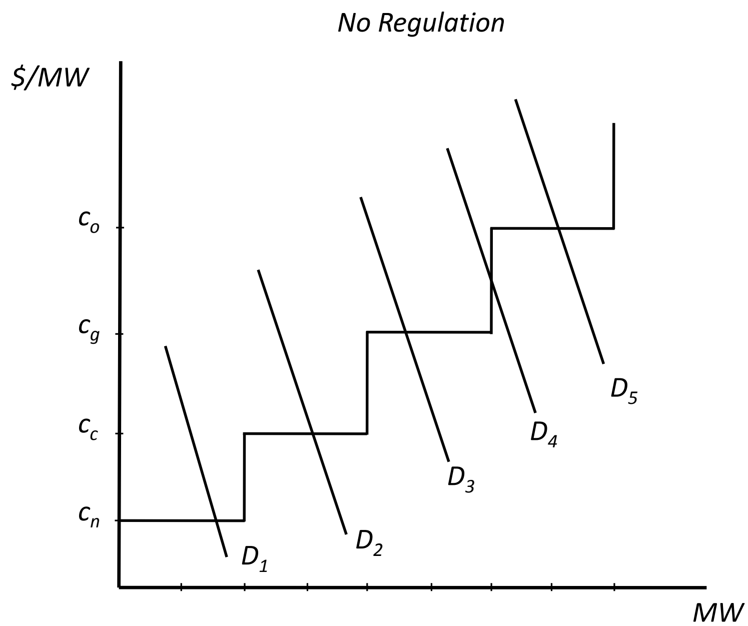
Based on these equilibrium prices, we can now characterize the equilibrium generation and profits of each technology. If $q^r_{sit}$ is equilibrium generation in state $s$ from technology $i$ in hour $t$ under regulation $r$, then profits are $\pi^r_{si} \equiv \sum_t (p^r_t - FMC^r_{si}) q^r_{sit}$ for technology $i$ in state $s$ under carbon regulation $r$.[11] Finally, we define equilibrium carbon emissions as $Carbon^r = \sum_s \sum_i \sum_t \beta_i q^r_{sit}$.

[11]Technically, we define

$$q^R_{sit} = \begin{cases} \bar{q}_{si}, & \text{if } FMC^r_{si} < p^r_t \\ \bar{q}_{si}\alpha^r_{sit} & \text{if } FMC^r_{si} = p^r_t \\ 0 & \text{if } FMC^r_{si} > p^r_t \end{cases}$$

The equilibrium supply has three cases. If price is above marginal cost, then generation is at capacity. If price is below marginal cost, then generation is zero. If price is equal to marginal cost, we assume that each generator supplies the same fraction of their capacity $\alpha^r_{sit}$, where $0 < \alpha^R_{sit} < 1$. We define $\alpha^r_{sit} = \frac{D(p^R_t) - \sum\sum \Phi(FMC^r_{si} < p^r_t - \epsilon)\bar{q}_{si}}{\sum\sum(\Phi(FMC^r_{si} < p^r_t + \epsilon) - \Phi(FMC^r_{si} < p^r_t - \epsilon))\bar{q}_{si}}$, where $\epsilon$ is small. Note that $\sum_s \sum_i (\Phi(FMC^r_{si} < p^r_t + \epsilon) - \Phi(FMC^r_{si} < p^r_t - \epsilon))\bar{q}_{si}$ is the additional capacity which becomes inframarginal when the price increases from $p^r_t - \epsilon$ to $p^r_t + \epsilon$. Only the portion $D(p^r_t) - \sum_s \sum_i \Phi(FMC^r_{si} < p^r_t - \epsilon)\bar{q}_{si}$ of this additional capacity is required. So we assume that each technology on the margin supplies the same proportion of this additional generation. With a carbon policy $\alpha^r_{sit}$ may need to be redefined such that the carbon market clears.

**Figure 2:** Market demands and aggregate supply in the absence of carbon regulation ($BAU$).



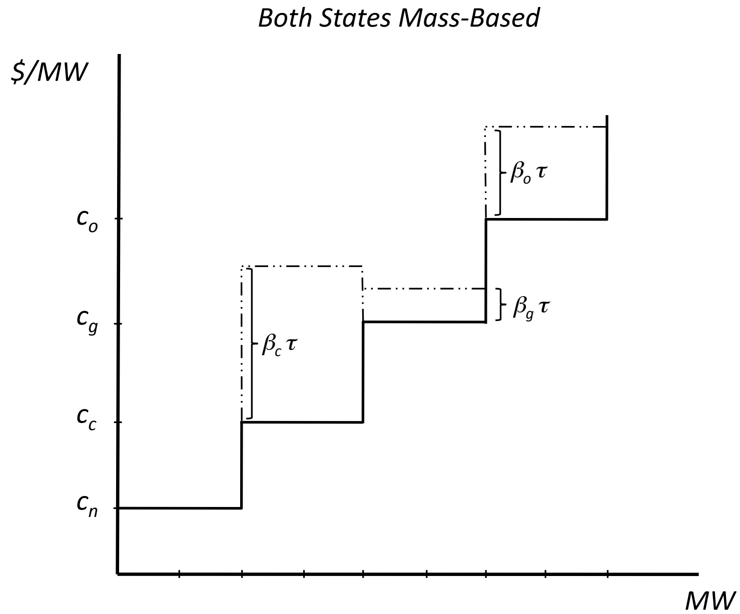

## 3.1 Mass-Based Regulation

We now turn to equilibrium under mass-based standards, or equivalently caps. A mass-based standard limits total carbon emissions. A limit on total emissions can be implemented through a cap-and-trade program where the state issues tradeable certificates. Let $E_s$ be allowable emissions in state $s$ and $p_{cs}$ be the price of tradeable certificates for one unit of carbon emissions in state $s$. It is well known that such a cap-and-trade program raises costs of generators in proportion to their carbon emissions thus the full marginal cost of technology $i$ is $FMC_{si}^{MB} = c_i + \beta_i p_{cs}$ in state $s$.

This full marginal cost is illustrated in Fig. 3 for four technologies where $\beta_O > \beta_C > \beta_G > \beta_N = 0$. Note that the carbon regulation increases the full marginal costs of coal-fired generation more than of gas-fired generation due to coal's higher carbon emissions. Thus as illustrated mass-based standards switch the merit order of coal- and gas-fired generation. Market supply would be found from Fig. 3 by re-ordering the technologies according to their full marginal costs.

If all states adopt mass-based standards, the equilibrium electricity price in hour $t$ is characterized by [1] with this full marginal cost. Generator profits are given by $\pi_{si}^{MB} \equiv$

**Figure 3:** Full marginal costs under mass-based standards.




$\sum_t (p_t^{MB} - FMC_{si}^{MB}) q_{sit}^{MB} = \sum_t (p_t^{MB} - c_i - \beta_i p_{cs}) q_{sit}^{MB}$. Thus generator profits do not include carbon market revenue, e.g., permits are auctioned not grandfathered, and welfare calculations must account for the carbon market revenue separately.

To complete the characterization of the mass-based equilibrium, we describe equilibrium in the market for carbon certificates. Since the supply of permits is fixed at $E_s$, demand equals supply in state $s$ when $\sum_i \sum_t \beta_i q_{sit}^{MB} = E_s$. Note that a higher carbon price $p_{cs}$ decreases carbon emissions, so there exists a carbon price which clears the carbon market.

The above characterization of the market equilibrium under cap and trade assumes each state has its own independent regulation. The model is readily extended to allow carbon trading between states. If states $s$ and $s'$ allow carbon trading, then the price of carbon certificates is equal across both states, i.e., $p_{cs} = p_{cs'}$, and the market equilibrium is characterized by $\sum_i \sum_t \beta_i q_{sit}^{MB} + \sum_i \sum_t \beta_i q_{s'it}^{MB} = E_s + E_{s'}$. It is well known that allowing trading across cap-and-trade programs reduces the cost of achieving the aggregate emissions target.

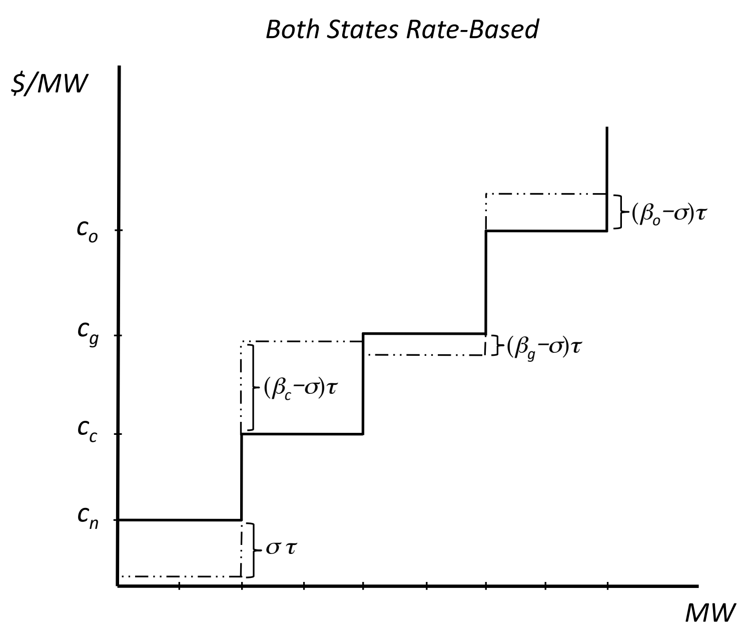
## 3.2 Rate-Based Regulation

Next we characterize equilibrium under a rate-based standard. A rate-based standard limits the aggregate carbon emissions per MWh of electricity. Such intensity regulations can be implemented as a tradeable intensity standard (see Holland, Hughes, and Knittel (2009)). Let $\sigma_s$ be allowed emissions per MWh in state $s$. Any technology whose emissions rate,

$\beta_i$, exceeds the standard would be required to purchase certificates per MWh based on the amount by which its emissions rate exceeds the standard. Conversely, any technology whose emissions rate is below the standard could sell certificates based on the difference between their emissions rate and the standard. Let $p_{cs}$ be the price of tradeable certificates for one unit of carbon emissions. Thus the intensity standard changes the full marginal cost of generators based on whether they are buying or selling permits. In particular, the rate-based standard changes the full marginal cost of technology $i$ in state $s$ from $c_i$ to $c_i + (\beta_i - \sigma_s)p_{cs}$. Note that full marginal costs may be higher or lower than $BAU$ depending on whether $\beta_i - \sigma_s$ is positive or negative, i.e., depending on whether a technology buys or sells certificates.

These full marginal costs are illustrated in Fig. 4 for the four technologies. As illustrated, the rate-based standards reduce the full marginal costs of (i.e., subsidize) nuclear- and gas-fired generation, but increase the full marginal costs of coal- and oil-fired generation. As with the mass-based standards, the merit order under rate-based standards as illustrated switches gas and coal, i.e., gas-fired generation is used before coal-fired generation as demand increases.

**Figure 4:** Full marginal costs under rate-based standards.




If all states adopt rate-based standards, the equilibrium electricity price in hour $t$ is characterized by [1] with these full marginal costs. This equilibrium price characterizes the equilibrium supply and profits. Profits are $\pi_{si}^{RB} \equiv \sum_t (p_t^{RB} - FMC_{si}^{RB})q_{sit}^{RB} = \sum_t (p_t^{RB} - c_i - (\beta_i - \sigma_s)p_{cs})q_{sit}^{MB}$. As above we assume that generators are not given permits. However some generators create permits by generating electricity, namely, those relatively clean technologies for which $\beta_i < \sigma_s$. In this case, the term $-(\beta_i - \sigma_s)$ is positive and captures the revenue which would arise from selling carbon credits. Thus the profits capture all revenue streams and there is no carbon market revenue to be accounted for separately.

To complete the characterization of the equilibrium, we describe equilibrium in the market for carbon certificates. The demand for carbon certificates is determined by the amount each technology exceeds the standard and by how much electricity is generated from each technology. For example, demand for certificates in state $s$ from technology $i$ is $\sum_t(\beta_i - \sigma_s)q_{sit}^{RB}$ if $\beta_i > \sigma_s$. Similarly, supply in state $s$ from technology $i$ is $\sum_t(\sigma_s - \beta_i)q_{sit}^{RB}$ if $\beta_i < \sigma_s$. Because demand less supply equals zero in equilibrium, the carbon market equilibrium is characterized by $\sum_i \sum_t(\beta_i - \sigma_s)q_{sit}^{RB} = 0$. Note that a higher carbon price $p_{cs}$ decreases demand and increases supply for carbon certificates, so there exists a carbon price which clears the carbon market. Note also that the equilibrium condition can be written

$$\frac{\sum_i \sum_t \beta_i q_{sit}^{RB}}{\sum_i \sum_t q_{sit}^{RB}} = \sigma_s,$$

which implies that the aggregate carbon emissions rate exactly equals the standard in equilibrium, i.e., the tradeable intensity standard implements the rate-based standard.

The model can be readily extended to analyze two states who combine their rate-based standards through carbon trading. Suppose the states $s$ and $s'$ allow carbon certificates to be freely traded between the states. Then the prices of the certificates will be equal, i.e., $p_{cs} = p_{cs'}$. The equilibrium condition is now that demand across both states equals supply across both states. Setting demand less supply equal to zero, we can characterize the carbon market equilibrium by $\sum_i \sum_t(\beta_i - \sigma_s)q_{sit}^{RB} + \sum_i \sum_t(\beta_i - \sigma_{s'})q_{s'it}^{RB} = 0$. This equilibrium condition can be written:

$$\frac{\sum_i \sum_t \beta_i(q_{sit}^{RB} + q_{s'it}^{RB})}{\sum_i \sum_t(q_{sit}^{RB} + q_{s'it}^{RB})} = \frac{\sum_i \sum_t q_{sit}^{RB}}{\sum_i \sum_t(q_{sit}^{RB} + q_{s'it}^{RB})}\sigma_s + \frac{\sum_i \sum_t q_{s'it}^{RB}}{\sum_i \sum_t(q_{sit}^{RB} + q_{s'it}^{RB})}\sigma_{s'}, \tag{2}$$

which implies that the aggregate carbon emissions rate equals a weighted average of the allowed emissions rates across the states where the weights depend on generation.

In addition to trading carbon, which equates the carbon prices, states may also wish to harmonize their rate-based standards, i.e., to set $\sigma_s = \sigma_{s'}$. Note that if states do *not* harmonize their rate-based standards, then the full marginal costs of identical generators can be different across states even if carbon prices are the same. In order to avoid this additional inefficiency, states would need to harmonize their rate-based standards as well as to allow carbon trading.

Combining rate-based standards across states does not have the efficiency justification of combining mass-based standards. Combining mass-based standards across states allows the same aggregate emissions target to be attained at lower cost. Combining rate-based standards across states does reduce costs, but it also means that the emissions target changes: both the aggregate emissions and the aggregate emissions rate are changed by combining rate-based standards in two states.

## 3.3 Mixed Mass- and Rate-Based Regulation

Finally, we consider the case of *mixed regulation* in which some states adopt mass-based standards and other states adopt rate-based standards. Under the Clean Power Plan proposals, states can choose whether to adopt mass-based or a rate-based standards and a mixture of mass- and rate-based standards could result. The model is readily extended to mixed regulation. In particular, the equilibrium electricity price is found from the set defined in [1] where the full marginal costs are $c_i + \beta_i p_{cs}$ in a mass-based state and $c_i + (\beta_i - \sigma_s)p_{cs}$ in a rate-based state.

States could allow carbon trading across mass- and rate-based standards. If state $s$ has a mass-based standard and state $s'$ has a rate-based standard, then trading carbon certificates would equate the price of certificates in each state, i.e., would set $p_{cs} = p_{cs'}$. Setting the difference between aggregate certificate demand and supply equal to zero implies that the equilibrium certificate price is characterized by $\sum_i \sum_t \beta_i q_{sit}^{RB} - E_s + \sum_i \sum_t (\beta_i - \sigma_{s'}) q_{s'it}^{RB} = 0$. This condition does not have a clear interpretation either as a mass-based or rate-based constraint.

## 3.4 Results

We next compare the outcomes and adoption incentives under certain conditions for the general model. The proofs of all the results are in the appendix. Section 4 then quantifies the effects and makes additional comparisons with a simulation model in the context of the emissions reductions required under the CPP.

The first result describes conditions under which *supply* is efficient under the different regulations. We then address efficiency in a corollary.

**Result 1. Efficient Supply:** *The merit order is efficient (full social costs are minimized):*

*(i): if all states adopt mass-based standards and $p_{cs}$ is sufficiently close to $\tau$ for all s;*

*(ii): if all states adopt rate-based standards, $p_{cs}$ is sufficiently close to $\tau$ for all $s$, and $\sigma_s$ is sufficiently close to $\sigma$ for all $s$; or*

*(iii): if there is mixed regulation, $p_{cs}$ is sufficiently close to $\tau$ for all $s$, $\sigma_s$ is sufficiently close to $\sigma$ for all $s$, and $|c_i + \beta_i\tau - c_j - \beta_j\tau| > \sigma\tau$ for all $i$ and $j$.*

This result shows sufficient conditions for the efficiency of supply. Importantly, the sufficient conditions become increasingly stringent across the regulations. For mass-based standards, supply is efficient if the carbon price equals (or is close to) the social cost of carbon.

For rate-based standards, supply can also be efficient. Intuitively, the rate-based standard can induce the correct relative prices across the technologies because it shifts the full marginal costs down by a constant. However, here supply efficiency requires that carbon prices equal the social cost of carbon *and* that the rate-standards be equal across states. Note that this sufficient condition will not be ensured by carbon trading but would require explicit harmonization of the rate-standards across states. Thus the sufficient conditions are more strict for rate-based standards than for mass-based standards.

Surprisingly, Result 1 (*iii*) shows that mixed regulation can also attain the efficient supply but only under more stringent conditions. This result is illustrated in Fig. 5 for four technologies where some of each technology is subject to a mass-based standard and some is subject to a rate-based standard of $\sigma$ and the carbon price is $\tau$. Note that within each technology, the implicit subsidy of the rate-based standard lowers the full marginal cost by $\sigma\tau$, so the rate-based technology is dispatched first, e.g., gas under the rate-base standard is dispatched before coal under the mass-based standard. As illustrated, the merit order is efficient, because all the gas-fired generation is used before the coal-fired generation as demand increases.

However, the efficiency of supply only occurs because the full marginal costs are sufficiently different. If the full marginal costs are close, i.e., if $|c_C + \beta_C\tau - c_G - \beta_G\tau| < \sigma\tau$, then the merit order is not efficient. As illustrated in Fig. 6 the full marginal costs are sufficiently close that the merit order is rate-base gas, followed by rate-base coal, then mass-base gas, and then mass-base coal. This merit order is inefficient since the full marginal social cost of gas-fired generation is less than the full marginal social cost of coal.[12]

Result 1 also highlights the importance of coordination across states. For mass-based standards, all carbon prices need to be sufficiently close to $\tau$, which can be ensured by

[12]This inefficiency from mixed regulation is limited, because it only arises if full marginal costs are sufficiently close, i.e., if costs are small from the wrong merit order.

**Figure 5:** Full marginal costs when one state adopts a mass-based standard and the other state adopts a rate-based standard: Efficient dispatch.

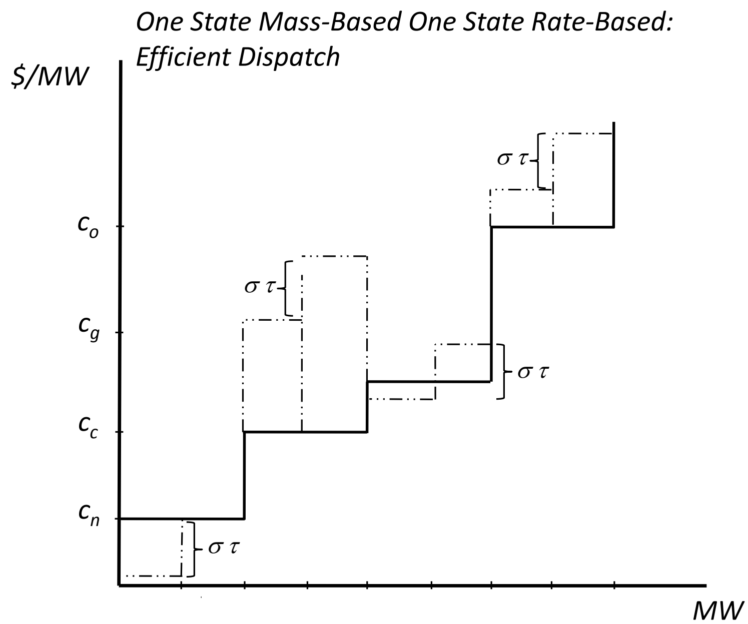
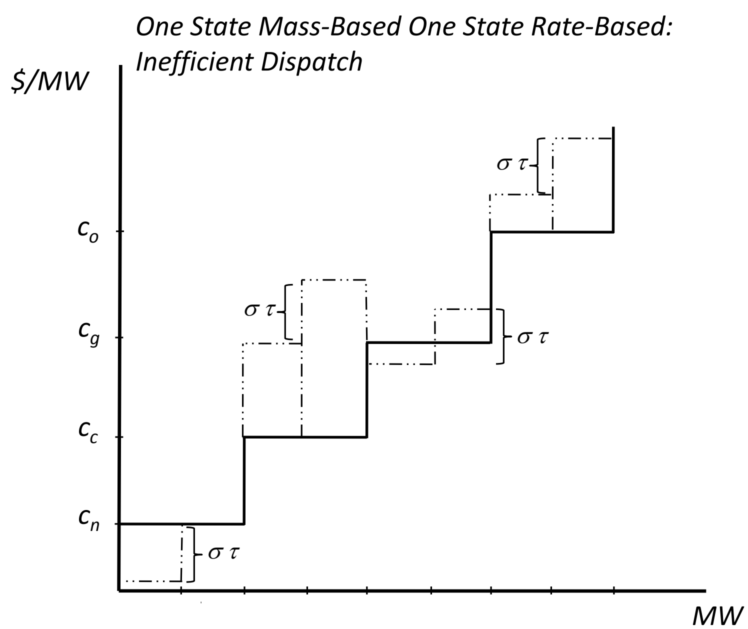



**Figure 6:** Full marginal costs when one state adopts a mass-based standard and the other state adopts rate-based standard: Inefficient dispatch.



carbon trading and a correct overall cap. Note that with carbon trading the distribution of the cap across states is irrelevant. With rate-based standards, trading can again ensure that carbon prices are equal across states. However, now the standards must be set equally across states in order for the merit order to be efficient, i.e., the distribution of the rate standards across the states is crucial. The result also shows an additional inefficiency if states fail to coordinate on mass- or rate-based standards.

Result 1 shows the increasingly stringent conditions under which the different regulations can lead to an efficient supply, i.e., an efficient merit order. However, efficiency of supply is necessary but not sufficient for overall efficiency of a regulation, as the following corollary makes clear:

**Corollary 1. Efficiency:** *If demand is perfectly inelastic, then mass- or rate-based standards or mixed regulation achieve efficiency if the merit order is efficient.*

*If demand is not perfectly inelastic, then mass-based standards achieve efficiency if* $p_{cs} = \tau$ *for all* $s$*. Rate-based standards and mixed regulation do not achieve efficiency.*

This corollary echoes earlier results in the literature (e.g., see Helfand (1991), Kwoka (1983), Holland, Hughes, and Knittel (2009)). If demand is perfectly inelastic, then there is no consumption inefficiency and efficiency only requires efficient supply. However, if demand is not perfectly inelastic, then only mass-based standards with a carbon price of $\tau$ can attain the first best.[13]

Given the importance of equal carbon prices in Result 1, the next result addresses the benefits from carbon trading, which equates carbon prices across regions.

**Result 2. Carbon Trading:** *Trading carbon between states reduces costs. Trading between states with mass-based standards holds aggregate emissions constant. Trading between states with rate-based standards may cause aggregate emissions to increase or decrease.*

This result shows that although carbon trading does reduce costs, it may not have clear efficiency benefits. Under mass-based standards, aggregate emissions are held constant and thus a reduction in costs leads to a clear efficiency gain. Under rate-based standards, aggregate emissions could increase or decrease, and thus the welfare effects are indeterminate.

We next compare the equilibrium outcomes across policies in which all states adopt the same policy. We analyze electricity prices, consumer surplus, and profits to "uncovered generators", which are not covered by the regulation, e.g., renewables or distributed generation.

[13] Holland (2012) shows that rate-based standards can attain the first best if they are coupled with an electricity tax of $\sigma\tau$.

**Result 3. Prices, Consumer Surplus, and Uncovered Generator Profits:** *For a given carbon price* $p_{cs} > 0$*,*

*(i) electricity prices are higher under mass-based standards than under either rate-based standards or no regulation, i.e.,* $p_t^{MB} \geq p_t^{RB}$ *and* $p_t^{MB} \geq p_t^{BAU}$*, and electricity prices under rate-based standards or under mixed regulation can be either higher or lower than under no regulation;*

*(ii) consumer surplus is lower under mass-based standards than under either rate-based standards or no regulation, i.e.,* $CS^{MB} \leq CS^{RB}$ *and* $CS^{MB} \leq CS^{BAU}$*, and consumer surplus under rate-based standards or under mixed regulation can be either higher or lower than under no regulation; and*

*(iii) profits for uncovered generation are higher under mass-based standards than under either rate-based standards or no regulation, and profits for uncovered generation under rate-based standards or under mixed regulation can be either higher or lower than under no regulation.*

This result shows that electricity prices are higher under mass-based standards but can be higher or lower than BAU prices under rate-based standards. These price comparisons follow from a comparison of the full marginal costs under the policies. Since full marginal costs are higher under mass-based standards than under rate-based standards or $BAU$, the electricity price is higher. Similarly, since the full marginal costs under rate-based standards can be higher or lower than under $BAU$, the electricity prices are similarly higher or lower. The results on consumer surplus and profits of uncovered generation follow directly from the result on prices.

The result on uncovered generation is important since significant generation may not be covered by the Clean Power Plan, e.g., hydro, nuclear, and some combined heat and power. The result shows that these uncovered generators will prefer mass-based standards because they will benefit from the higher electricity prices. The effect is somewhat different for "dirty" and "clean" uncovered generators. For dirty uncovered generators, the benefit arises from the higher electricity prices and because the lack of carbon regulation does not increase their costs. For clean uncovered generators, the difference arises from the higher electricity prices and because the lack of carbon regulation does not *decrease* their costs under rate-based standards. The inability to sell carbon credits under a rate-based standard implies that uncovered clean generation prefers mass-based standards. Note that this result also implies that incentives are strongest under mass-based standards for new clean generation and for efficiency improvements both of which might be uncovered by the Clean Power Plan.

The result also has important implications for investment incentives. Investment will occur in the most profitable locations. Fossil-fuel fired generation is likely to be "uncovered" since it is subject to other regulations, e.g., Section 111 (b), and is not subject to the Clean Power Plan. Renewables and small combined heat and power will also likely not be covered by the Clean Power Plan. The result implies that there would be more investment in uncovered generation under mass-based standards.

We next analyze the incentives for states to adopt either mass-based or rate-based standards. We begin by analyzing the outcomes if states coordinate on either mass- or rate-based standards. To focus the analysis, we assume additionally that carbon prices equal $\tau$ and rate standards are equal across states, i.e., we assume that supply is efficient.

**Result 4. Adoption Incentives of a Coalition:** *Suppose that all states adopt the same regulation, i.e., all states have mass-based standards or all states have rate-based standards. Suppose further that mass-based standards or rate-based standards result in a carbon price equal to the social cost of carbon across both regimes and across all states, i.e.,* $p_{cs} = \tau$ *for all* $s$*, and that rate-based standards are equal across states, i.e.,* $\sigma_s = \sigma$ *for every* $s$*.*

*(i):* $p_t^{MB} \leq p_t^{RB} + \sigma\tau$ *for all* $t$*;*

*(ii):* $\sum_s \sum_i \sum_t q_{sit}^{MB} \leq \sum_s \sum_i \sum_t q_{sit}^{RB}$

*(iii):* $\pi_{si}^{MB} \leq \pi_{si}^{RB}$ *for all* $s$ *and* $i$*;*

*(iv):* $\sum_s \sum_i \sum_t (c_i + \beta_i\tau) q_{sit}^{MB} \leq \sum_s \sum_i \sum_t (c_i + \beta_i\tau) q_{sit}^{RB}$*;*

*(v):* $Carbon^{MB} \leq Carbon^{RB}$*;*

*(vi):* $W^{MB} \geq W^{RB}$*; and*

*(vii):* $TR^{MB} + \tau(Carbon^{RB} - Carbon^{MB}) \geq (CS^{RB} - CS^{MB}) + (\pi^{RB} - \pi^{MB})$.

*If additionally we assume that demand is perfectly inelastic, then each of the weak inequalities above is an equality.*

This result compares the outcomes when states coordinate on mass- or rate-based standards. Much of the intuition of the result comes from the comparison of the electricity prices in Result 4 ($i$). This result shows that although electricity prices are lower under rate-based standards, the drop in prices is bounded by $\sigma\tau$. Because full marginal costs are lower by $\sigma\tau$ under rate-based standards, prices are also lower by exactly this amount if demand is perfectly inelastic. If demand is not perfectly inelastic, then a price which is lower by $\sigma\tau$ could result in excess demand. Thus the price difference is at most $\sigma\tau$.

Because electricity prices are lower under rate-based standards, generation, costs, and carbon emissions are higher. Generator profits are also higher under rate-based standards, despite the lower electricity prices because full marginal costs are lower. Because full marginal costs are lower by $\sigma\tau$ and prices are lower by at most $\sigma\tau$, generator profits increase.

The inefficiency of rate-based standards, described in Corollary 1, implies the result on welfare in Result 4 $(vi)$. Rewriting this in Result 4 $(vii)$ shows that the sum of carbon market revenue and the increase in carbon market damages exceeds the sum of the increases in consumer surplus and profit under rate-based standards.

With perfectly inelastic demand this equality becomes $CS^{MB} + TR^{MB} = CS^{RB}$, which shows that the gain in consumer surplus from rate-base standards is exactly the foregone carbon market revenue $TR^{MB}$. In this case, the carbon market revenue is exactly sufficient to compensate consumers for the lost consumer surplus under mass-based standards.

If demand is not perfectly inelastic, the inequality in $(vii)$ is much less informative about the ability of carbon market revenue to compensate consumers and producers for their losses under mass-based standards. In particular, it shows that carbon market revenue plus the additional carbon damages would be sufficient to compensate both producers and consumers for their losses under rate-based standards. However, the result suggests that it is an empirical question whether or not carbon market revenue by itself will be sufficient to compensate both producers and consumers for their losses under mass-based standards.

We now turn to the adoption incentives of individual states. In particular the question of how a state's choice interacts with other states' choices to influences economic outcomes.

**Result 5. Adoption Incentives of a State:** *Consider two scenarios of mixed regulation. In one scenario, $RBx$, state $s$ has a rate-based standard, and in the other scenario, $MBx$, state $s$ has a mass-based standard. Regulation of each other state is unchanged across the scenarios, and carbon prices equal $\tau$ in all scenarios.*

*(i)* $p_t^{MBx} \geq p_t^{RBx} \geq p_t^{MBx} - \sigma_s\tau$ *for every* $t$

*(ii)* $\pi_{is}^{MBx} \leq \pi_{is}^{RBx}$ *for every* $i$

*(iii)* $CS^{MBx} \leq CS^{RBx}$.

*(iv)* $TR_s^{MBx} > TR_s^{RBx} = 0$.

*(v)* $CS_s^{MBx} + TR_s^{MBx} + \sum_i \pi_{is}^{MBx}$ *can be greater or less than* $CS_s^{RBx} + \sum_i \pi_{is}^{RBx}$

This result shows the strong incentives for a state to adopt inefficient rate-based standards. Under these assumptions, a rate-based standard is a dominant strategy from the perspective of both consumers and generators' profits. In other words, both consumers and generators are better off if their state adopts a rate-based standard no matter what other states are doing.

Intuitively, adoption of a rate-based standard causes electricity prices to fall, which benefits consumers. However, prices fall by at most $\sigma_s \tau$ as shown in Result 5 (*i*). But since costs fall by $\sigma_s \tau$, generator profits increase.

This result implies that adopting a rate-based standard is a dominant strategy from the perspective of profit to the regulated generators, because profits are higher no matter what policies the other states adopt. Importantly, if the coalition of states were to adopt mass-based standards, generators in any single state would have an incentive to lobby for adoption of a rate-based standard in their own state. Moreover, there remains an incentive for generators to lobby for adoption of a rate-based standard in their own state no matter how many other states adopt rate-based standards. In fact, the only outcome, which is stable from the perspective of generator profits, is the coalition in which all states adopt rate-based standards.

Result 5 (*i*) also implies that adoption of a rate-based standard in state $s$ decreases generator profits in other states. This follows since the electricity price falls, which decreases margins. Since the merit order can also change, generators in other states may also generate less, so profits decrease. This implies that defection by state $s$ from the coalition in which all states adopt mass-based standards *increases* the incentive for other states to also defect from the coalition.

Result 5 (*iii*) shows that consumers are better off under rate-based standards . Our assumption that each state accounts for a constant share of consumer surplus implies that consumers in each state have an incentive to lobby for adoption of rate-based standards in their state and in other states as well. In fact, becasue we assume that carbon market revenue benefits consumers within a state, this result implies that consumers have a stronger incentive to lobby for *other* states to adopt rate-based standards.

Despite the strong incentive to adopt rate-based standards from the perspective of both consumers and generators, there is an efficiency cost to rate-based standards. Result 5 (*iv*) and (*v*) show that states may or may not have sufficient carbon market revenue to compensate consumers and generators such that everyone prefers more efficient mass-based standards. The result is weaker than Result 4 (*vii*) which showed that compensation might require monetizing carbon damages. Here since welfare may increase when a single state adopts rate-based standards, it may not be efficient (or desirable!) to compensate consumers and generators so that they would be willing to support mass-based standards.[14]

Result 5 ($v$) shows that there may or may not be sufficient carbon market revenue to compensate consumers and generators so that adoption of an efficient mass-based standard is preferred. Since theory is indeterminate, we will return to this question in our simulations analysis.

## 3.5 Analytical Solution for Four Technologies

To illustrate the results further, consider a simple version of the model with four technologies, two symmetric states, and perfectly inelastic demand. Additional details of the four-technology model are presented in the appendix. To illustrate the adoption incentives of the two states, we present the normal form of the policy adoption "game" with payoffs from the perspective of both social welfare and generator profit. The normal forms of the "game" are presented in Tables 1-4.

Tables 1 and 2 show the normal form from a social welfare perspective. Since demand is perfectly inelastic, there is no inefficiency if both states coordinate on policies. Thus both states are indifferent between coordinating on mass- or rate-based standards (the main diagonals). In Table 1, dispatch is efficient even with mixed regulation (full marginal social costs are sufficiently different). Thus there is no inefficiency, and the game is zero sum. However, states still have an incentive to adopt rate-based standards since they gain more in generator profit and consumer surplus than they give up in carbon market revenue.

With inefficient dispatch as in Table 2, the normal form is similar except now there is an efficiency penalty from inefficient dispatch when the two states fail to coordinate (the game is not zero sum). Nonetheless, adoption of a rate-based standard is still a dominant strategy from the perspective of social welfare.

Tables 3 and 4 show the normal form from the perspective of generator profits. Due to the perfectly inelastic demand, generator profits are equal whenever both states coordinate. However, as above, adoption of a rate-based standard is a dominant strategy since adoption of the rate-based standard causes more generation from that state and increases its profit at the expense of profits in the other state.

[14]To illustrate, suppose there are two states and perfectly inelastic demand and the full marginal social costs are sufficiently close. Then adoption of a rate-based standard will decrease efficiency (since the merit order will be inefficient) but adoption by the second state will increase inefficiency (since the merit order will be efficient.

Tables 3 also shows that the interaction is not zero-sum. This adds an interesting twist. Because total generator profit is highest under mixed regulation, if a firm derived profit from generation in both states it might have an incentive to lobby for a mass-based standard in one state and a rate-based standard in the other state. Alternatively, a firm in one state might offer side payments to a firm in another state. Since this effect is not zero sum, profits are sufficient that one generator could sufficiently compensate the other for any lost profits.

# 4 Numerical Simulations

As described above, for a good such as electricity, a homogenous product that is freely traded throughout multi-state markets, the choice of a specific regulatory instrument by a given state influences (and is influenced by) the outcomes and choices of other states. We quantify the effects of our analysis in the context of the electricity market in the western U.S. with a model similar to that used in Bushnell and Chen (BC 2010) and Bushnell, Chen, and Zaragoza-Watkins (BCZ 2011). In this section, we briefly present the formulation of the simulation model and then discuss how we apply data from various sources to arrive at our calculations. In the following section we will describe the assumptions applied to the specific scenarios that are simulated.

## 4.1 Model

As in the model in Section 3, we assume here that firms act in a manner consistent with perfect competition in both the electricity and emissions permit markets.[15] As such, equilibrium of a perfectly competitive market is equivalent to the solution of a social planner's problem. Our social planner's problem maximizes gross consumer surplus less generation costs subject to two sets of constraints. Using the notation developed above, the planner's objective is thus

$$Max_{q_{sit}} CS + \sum_s \sum_i \sum_t (p_t - c_i) q_{sit} \tag{3}$$

Note that objective does not consider carbon damages, which are addressed through the constraints.

[15]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 the rest of the WECC remains regulated under traditional cost-of-service principles.

*Emissions Constraints*

The first set of constraints capture the environmental policy choices. If a state adopts a mass-based standard, then total emissions from production sources in the state must be less than allowed emissions.

$$\sum_i \sum_t \beta_i q_{sit} \leq E_s. \tag{4}$$

Similarly, if a state adopts a rate-based standard, then the emissions rate in the state must be less than the allowed emissions rate: $\sum_i \sum_t \beta_i q_{sit} / \sum_i \sum_t q_{sit} \leq \sigma_s$. The shadow values of these constraints are the carbon prices that would result from a market mechanism implementing the policy.[16]

The second set of constraints models transmission constraints, which are ignored in Section 3. We assume that the transmission network is managed 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 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.

*Investment in New Capacity*

In some scenarios we consider a medium-term time horizon where there is some new generation entry that supplements existing capacity. This new entry is market driven, and in equilibrium requires sufficient market revenues to cover the (annualized) capital costs of new generation. Formally, hourly production from generation plant $i$ is constrained to not exceed the installed capacity of that plant.

$$q_{sit} \leq CAP_{si} \forall i, t.$$

For some technologies we consider new investment, which in equilibrium equates annual operating profits to annualized capital costs. In those scenarios the annualized capital cost of each new MW of capacity is an additional cost that is present in the objective function that maximizes social welfare.

[16] In the simulations we write this constraint as $\sum_i \sum_t \beta_i q_{sit} \leq \sigma_s \sum_i \sum_t q_{sit}$ so that the shadow value of the constraint is in dollars per ton of carbon.

## 4.2 Market Demand

We model electricity demand in each of four regions for each of 80 representative time periods (20 periods for each of four seasons).[17] To create the 80 representative time periods, we sort California aggregate generation into 20 bins based upon equal MW spreads between the minimum and maximum generation levels observed in the 2007 sample year.[18] Demand in the representative time period is based on the mean of the relevant market data for all 2007 data within each bin. To aggregate, we then weight each representative time period by the number of season-hour observations in each bin.[19]

To construct our demand functions, we assume linear demand that passes through the mean price and quantity for each representative time period and region. End-use consumption, as defined above, in each region is represented by the demand function $Q_{r,t} = \alpha_{r,t} - \beta_r p_{r,t}$, yielding an inverse demand curve defined as

$$p_{rt} = \frac{\alpha_{r,t} - \sum_i q_{rit} - y_{i,t}}{\beta_r}$$

where $y_{r,t}$ is the aggregate net imports into region $r$.

The parameter $\alpha_{rt}$ is calibrated so that, for a given $\beta_r$, $Q_{r,t}^{actual} = \alpha_{r,t} - \beta_r p_{r,t}^{actual}$. In other words, the demand curve is shifted so that it passes through the average of the observed price quantity pairs for that collection of hours. To derive actual demand, FERC form 714 provides hourly total end-use consumption by control-area which we aggregate to the North American Electric Reliability Commission (NERC) sub-region level.[20]

For electricity prices, we use hourly market prices in California and monthly average prices taken from the Intercontinental Exchange (ICE) for the non-market regions.[21]

Because electricity demand is extremely inelastic, we utilize an extremely low value for the slopes of this demand curve. For example, in an early review article Taylor (1975) finds short-run price elasticities of electricity demand for residential consumers on the order of

[17] Although hourly data are available, for computational reasons we aggregate these data into representative time periods.

[18] California was the original focus of this work so aggregation is based only on California generation.

[19] For example, in Spring 2007 there were 54 hours in which California (residual) demand fell in the bin between 6949 and 7446 MW. To aggregate, resulting emissions from our representative time period are multiplied by 54 to generate an annualized equivalent total level of emissions.

[20] Average values for demand by sub-region are given in Table ??.

[21] To obtain hourly prices in regions outside of California, we calculate the mean difference by season between the California prices and prices in other regions. This mean difference is then applied to the hourly California price to obtain an hourly regional price for states outside of California. Because demand in the model is very inelastic, the results are not very sensitive to this benchmark price method.

0.15 with some estimates as high as 0.90. Commercial and industrial demand elasticities are estimated at 0.17 and 0.22 in the short-run. More recently, Kamerschen and Porter (2004) estimate total electricity demand elasticities in the range of 0.13 to 0.15 using US annual data from 1978 to 2008. Reiss and White (2005) estimate a mean elasticity of 0.39 for households in California while Ito (2014) estimates values consistently less than 0.10. Because the CPP affects the price of energy and approximately half of consumers' rate is related to non-energy charges, such as transmission, the response of consumers to changes in wholesale energy prices is likely even smaller. Therefore, the slope of the demand curve is set so that the median elasticity in each region is -.05.[22]

## 4.3 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, $CO_2$, 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 $(1 - fof_i) * cap_i$, where $cap_i$ is the summer-rated capacity of the unit and $fof_i$ is the forced outage factor reflecting the probability of the unit being completely down at any given time.[23] Unit forced outage factors are taken from the generator availability data system (GADS) data that are collected by the North American Reliability Councils. These data aggregate generator outage performance by technology, age, and region. State-level derated fossil generation capacity is shown in Table 5.

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. Marginal cost of each plant $p$ is therefore constant.

[22] Because the market is modeled as perfectly competitive, 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.

[23] This approach to modeling unit availability is similar to Wolfram (1999) and Bushnell, Mansur and Saravia (2008).

As described below, we consider only investment in new combined cycle gas turbines (CCGT). Based upon information from the EIA, we assume that the annualized capital cost $F_{si}$ of a standard new CCGT would be \$100 KW-yr. Operating costs $mc_{st}$ depend upon our natural gas price assumption and are assumed to be \$48/MWh under 2007 gas prices and \$32/MWh under current gas prices.

Emissions rates, measured as tons $CO_2$/MWh, are based upon the fuel-efficiency (heat-rate) of a plant and the $CO_2$ intensity of the fuel burned by that plant.

Figure 9 illustrates the merit order, including carbon costs, for all simulated (large fossil) plants included in the simulation. The location of a specific plant on the horizontal axis corresponds to its social marginal cost based upon a carbon cost of \$35/ton. Coal generation is represented by red + symbols while gas generation is represented by green $x$ symbols. The lower solid line displays the private marginal costs of the same units. One can see how the \$35 carbon price shifts some low-cost gas generation to the base of the supply order, displacing low cost coal, which after applying carbon costs shift to the middle of the supply order.

## 4.4 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 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.[24] Figure 7 illustrates the areas covered by these regions. The states in white, plus California, constitute the U.S. participants in the WECC.

Mathematically, we adopt an approach utilized by Metzler, et al. (2003), to represent the transmission arbitrage conditions as another set of constraints. Under the assumptions of a direct-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, $PTDF_{lk}$,

[24]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 be electrically part of California. However 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.

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

Transmission models such as these utilize a "swing hub" from which other marginal changes in the network are measured relative to. We use the California region as this hub. In other words, an injection of power, $y_{l,t} \geq 0$, at location $l$ is assumed to be withdrawn in California. The welfare maximization objective function is therefore subject to the flow limits on the transmission network, particularly the line capacities, $T_k$:

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

Given the 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. Flow capacities over these interfaces are based upon WECC data, and aggregate the available capacities of aggregate transmission paths between regions. The resulting PTDFs for our aggregated network is summarized in the appendix.

## 4.5 Hydro, Renewable and Other Generation

Generation capacity and annual energy production for each of our regions is reported by technology type in Tables 5 and 6. We lack data on the hourly production quantities for the production from renewable resources, hydro-electric resources, combined heat and power, and small thermal resources that comprise the "non-CEMS" category. By construction, the aggregate production from these resources will be the difference between market demand in a given hour, and the amount of generation from large thermal (CEMS) units in that hour. In effect we are assuming that, under our $CO_2$ 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 $CO_2$ reduction goals of a cap-and-trade program will be achieved through the reallocation of production within the set of modeled plants. [25]

[25] We believe that this is a reasonable assumption for two reasons. First the vast majority of the $CO_2$ emissions from this sector come from these modeled resources. Indeed, data availability is tied to emissions

Non-CEMS production is derived by aggregating CEMS production by NERC sub-region, and calculating the difference for each region between hourly demand, hourly net-imports, and hourly CEMS production for that sub-region. Since the hourly demand data, which come from FERC 714, is aggregated to the sub-regional level, both those data and non-CEMS production, which is derived in part from the load data must be allocated to individual states for purposes of calculating the state-level impacts of different policies. This is done by calculating a state's share of total electricity consumption, and of non CHP fossil production, for allocating load and production, respectively. We take these data from the Energy Information Administration Detailed State Data section (http://www.eia.gov/electricity/data/state/). The original source of the load data is EIA form 861 and of the generation data is EIA form 860. Most states are assigned completely to on NERC sub-region, with the exception of Nevada, where 75% of the load and of the non-CEMS production is allocated to the AZNMNV sub-region, with the remaining 25% being allocated to the NWPP sub-region.

## 4.6 Decomposition of Benefits and Costs

The choice of regulatory instrument carries very different implications for different stakeholders in each state. One key division is between electricity consumers and producers. Another is the distinction between sources that will be covered (regulated) under the clean power plan and those that are not (unregulated). All generation sources are assumed to earn the market clearing wholesale electricity price for their region. Only the covered sources are exposed to the costs and incentives created by the $CO_2$ regulation.

For this analysis we make the assumption that all regulated sources are included in our dataset and that the difference between hourly measured output from CEMS and measured demand is comprised of generation from non-regulated sources such as large hydro electric, renewable, and renewable generation. Current EPA proposals apply a more complex formula to renewable and nuclear generation, so this assumption is an approximation.

From our data we can calculate an estimate of hourly regional non-CEMS (e.g. "uncovered") generation. Recall that our measure of non-CEMS generation was derived by taking the difference between regional demand less CEMS generation less net imports into a region. Data on imports are taken from WECC data aggregated to the regional level. We therefore do not observe imports into an individual state for a given hour, for example. Our data

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.

of demand are aggregated by utility control area, which in several cases overlaps individual states and NERC sub-regions. Because our hourly data sources are aggregated to differing levels of both time and geography, we must make additional assumptions about how the regional impacts from our simulation are disaggregated to state level.

For uncovered generation, we use data from EIA that provides annual aggregate production by fuel type and state. From these data we can calculate the fraction of a region's uncovered generation that originates from uncovered sources. We apply that fraction to the hourly regional data and simulation results to dis-aggregate those results to the state level. Similarly we apply EIA data on annual consumption by state to calculate the fraction of a region's demand that is attributable to a given state. Both of these approximations assume that the hourly distribution of regional supply and demand amongst states is the same as the annual average of those distributions.

Table 6 summarizes the generation totals and emissions for each of the states coming from covered and uncovered sources based upon EIA data and compares those data to the results of our simulation. These simulation results assume no $CO_2$ regulation and therefore constitute the "business as usual" case.

# 5 Results

In this section we present simulation results under a variety of possible policy scenarios. We examine the western market under two different sets of conditions. We first utilize actual reported natural gas prices from 2007 in order to calibrate the model and establish if the simulation reasonably captures production and emissions totals over western states. However, natural gas prices have declined sharply since 2007 and this carries important implications for estimates of the costs of compliance with the CPP. Therefore, after establishing that the model accurately depicts market equilibrium outcomes using 2007 fuel prices, we re-simulate the market using natural gas prices that are, on average \$2.00/mcf lower, in order to better capture current conditions. The results we report here therefore utilize the lower natural gas prices representative of current prices.

We first establish a baseline level of costs and emissions by simulating the western market without any GHG regulations. The first case, Scenario 0, represents no regulation, *i.e.* "business as usual." Scenarios 1 through 8 vary which states operate under mass- and rate-based regulations. In each case, the reductions required by each state are based upon the EPA's targeted reductions for the second "building block" of their abatement estimates.

These are the EPA's expected carbon savings from re-ordering the supply order so that low carbon sources run more frequently and at least partially displace higher carbon (e.g. coal) sources. We focus on this building block for two reasons: it requires the largest reductions, and it is the only mitigation activity captured by our simulation model.[26] The requirements vary widely by state, ranging from the 40% reduction in emissions intensity for Arizona to no reductions at all from Montana and Idaho. These emissions reductions are illustrated in Figure 8.

The odd numbered scenarios assume the states operate under the same mass- or rate-based constraints, and can therefore trade across state lines to achieve the required reductions. The even numbered scenarios assume that each individual state has their own mass- or rate-based constraint. In Scenario 1 western states operate under a single emissions cap. In Scenario 2 each state has a state-specific emissions cap. Scenarios 3 and 4 assume all states instead use rate-based regulation. Scenario 3 assumes a single rate-based standard for all states and Scenario 4 assumes state-specific standards. Scenario 5 models a single emissions cap for coastal states and a single rate-based standard for inland states.[27] Scenario 6 assumes inland states have state-specific standards. Finally, Scenarios 7 and 8 assumes inland states face an emissions cap, while coastal states have rate standards.

There are many metrics one could use to evaluate the impacts of these regulations. We focus on the standard economic metrics of consumer surplus, producer profits, abatement, abatement costs, and deadweight loss. To establish a baseline upon which to judge these proposals, we assume that the reductions required by EPA accurately reflect the social cost of carbon. In other words, we assume the social costs of carbon are equal to the marginal abatement costs under the most efficient form of abatement, a west-wide cap-and-trade system.[28] Therefore Scenario 1, a west-wide cap-and-trade program, produces zero deadweight loss, by definition.[29] The other scenarios, including no regulation, produce some deadweight loss either due to inefficient levels of emissions or excessive abatement costs.

[26] In the west, the CPP requires an average reduction of 36% in the emissions rate. Of this, the four building blocks contribute 4%, 15%, 9%, and 9% respectively.

[27] Coastal states are California, Oregon and Washington. Inland states are Arizona, Colorado, Idaho, Montana, New Mexico, Nevada, Wyoming and Utah.

[28] In other words, we assume the emissions cap is optimally set.

[29] The implied cost of carbon is \$35.10 which is well within the range of estimates of the social cost of carbon and similar to the EPA's assumed SCC of \$37/MT of $CO_{2e}$.

## 5.1 Supply-side/Merit order effects

We first illustrate the effects of the regulation on the market supply functions. Instead of comparing the market supply curves for different regulations, we illustrate the market supply curve for one regulation and then show the full marginal costs for each generation unit under different regulations. The market supply (or merit order) under the different regulations could be determined by "re-sorting" the generating plants along the x-axis.

Figures 9 and 10 compare the full marginal costs of fossil-fuel generation units under west-wide mass- and rate-based standards to the market supply under BAU (i.e., the generating units are sorted along the x-axis by BAU marginal costs). The generating units to the left of 23 GW are coal-fired and the generating units to the right of 23 GW are gas-fired. The mass-based standard (West-wide Cap) increases the full marginal costs of the units in proportion to their carbon emissions. Thus the mass-based standard changes the merit order so that gas-fired generation is cheaper than coal-fired generation, i.e., the gas-fired generation would be used first as demand increases.

The rate-based standard (West-wide Rate Standard), increases the full marginal costs of the coal-fired generation because these plants have emissions rates which are worse than the standard. However, the rate-based standard *decreases* the full marginal costs of most of the gas-fired generation because these plants have emissions rates which are better than the standard.

These figures show the high correlation between the merit orders under west-wide mass- and rate-based standards. This correlation illustrates the theoretical result that both mass- and rate-based standards can eliminate the supply-side inefficiency by correcting the merit order. However, although the relative costs of the technologies can be correct, these figures illustrate that the level of the full marginal costs is too low under the rate-based standard.

Figure 11 illustrates the merit order that arises if states fail to harmonize their mass-based standards. The figure illustrates the supply curve for a mass-based standard (West-wide Cap) and compares it with state-by-state mass-based standards (State Caps). The state-by-state caps lead to full marginal costs which are too high in some states—those with tight caps—and too low in other states—those with loose caps. This heterogeneity "scrambles" the merit order and is an additional source of inefficiency.

Similarly, Figure 12 illustrates the merit order that arises if states fail to harmonize their *rate-based* standards. The figure plots the supply curve for a rate-based standard (West-wide Rate) and compares it with state-by-state rate-based standards (State Rates). As above, the state-by-state rates "scramble" the merit order and are an additional source of inefficiency. An additional complication arises with state-level rate-based standards compared to state-level mass-based standards. If states adopt, state-level mass-based standards, but allow for trading across states, then the inefficiency will no longer exist; trading equalizes the shadow value of the mass-based constraints across the states. Allowing for trading within state-specific rate-based standards does not eliminate the inefficiency. Trading across states will equate the shadow value of the state-specific constraints, but as long as the rate targets vary across states, this merit order will be scrambled.

Figure 13 illustrates the merit order when regional coalitions fail to coordinate policies. This figure compares a west-wide mass-based standard (West-wide Cap) with mixed regulation in which Coastal states adopt a mass-based standard and Inland states adopt a rate-based standard. The merit order is scrambled so effectively with mixed regulation that almost all the Inland plants have lower full marginal costs than any of the Coastal plants! Of course, transmission constraints would prevent such an extremely inefficient dispatch, so estimating the inefficiency of these scrambled merit orders requires calculating the equilibria under the various regulations.

## 5.2 Short-run Equilibria

We next analyze short-run equilibria.[30] Table 7 reports equilibrium prices, profits, and changes in welfare across the different scenarios. Prices increase by roughly \$20 per MWh, relative to business-as-usual, under a single western-states emissions cap. The quantity of electricity consumed falls by 3 percent, while emissions fall by 17 percent, implying that changes in the merit order are largely driving emission reductions.[31] The equilibrium permit price, reflecting the price of carbon, is roughly \$35 per metric ton of $CO_2$. We note that this closely matches the social cost of carbon used by the EPA in regulatory filings.

We next calculate the change in consumer and producer surplus prior to any redistribution of carbon permit revenue. We compute the change in consumer surplus and the producer surplus of power plants regulated under the CPP—"covered" plants—and plants that are not regulated under the CPP—"uncovered" plants. Consumer surplus falls by \$14 billion under a single western emissions cap. The producer surplus of plants regulated under the CPP falls

[30] Below we allow investment in new generation capacity.

[31] We note that this is in contrast to Holland, Hughes, and Knittel (2009) and Holland et al. (Forthcoming) which find that, within transportation, the majority of emission reductions come from lowering fuel consumption as opposed to shifting to lower greenhouse gas emitting fuels (ethanol). This is due, in part, to our demand elasticity of 0.05 compared to 0.50 in their baseline simulations.

by \$2.5 billion, while profits of uncovered plants increase by roughly \$6 billion. Producer surplus rises for these plants because equilibrium prices increase and uncovered plants are not required to pay additional carbon costs. The net impact, therefore, on producer surplus is an increase of approximately \$4 billion. Profits from transmission decrease slightly relative to business as usual. Despite the reduction in generation, production costs increase slightly due to changes in the merit order. The implied carbon market revenue for permit sales exceeds \$9 billion.

The abatement cost of emission reductions is roughly \$1 billion, resulting in an average abatement cost of \$21.95 per ton of $CO_2$.[32] The drop in carbon damages necessarily exceeds abatement costs by \$0.69 billion—the deadweight loss under no regulation.

This scenario serves as a baseline to compare alternative regulation regimes. The next regulatory regime, scenario 2, assumes that each state operates under their own emissions cap. Therefore, this scenario will not take advantage of differences in marginal abatement costs across the states. Electricity prices increase slightly compared to a single cap, from \$59.80 to \$68.17/MWh.[33] By definition, emission reductions are the same, but the permit prices increase by roughly \$9/MT.

Consumers are harmed by state-level caps, given the higher prices, but firms are better off. Profits of covered plants fall by \$0.7 compared to \$2.5 under a single cap and producer surplus of uncovered plants increases by an extra \$3 billion. The increase in production cost is slightly less under the multiple caps, while abatement costs are slightly higher. The average abatement cost is roughly \$4 per metric ton greater compared to a single cap. While less efficient than a single cap, multiple state caps reduce the amount of deadweight loss by approximately 75 percent compared to no regulation.

We next analyze rate-based regulation. Scenario 3 imposes a single rate standard for the western states. Under a single rate standard electricity prices rise slightly compared to no regulation. Abatement is slightly greater than under an emissions cap. The shadow value of emission reductions exceeds \$48 per metric ton. The higher electricity prices decreases consumer surplus slightly, producer surplus decreases for covered but increases for uncovered plants. The average abatement costs increase by 16 percent compared to a single cap. Finally, deadweight loss decreases by 75 percent compared to no regulation.

Large inefficiencies exist under state-specific rate standards. Average electricity prices increase to nearly \$85/MWh. This leads to much larger emission reductions compared to

[32]Abatement cost is defined as sum of changes in consumer surplus, producer surplus and carbon market revenues.

[33]We report the weighted-average electricity price, weighted by state-level consumption.

first best, a drop of 75.16 million metric tons versus a drop of 52.45 million metric tons. The shadow value of emission reductions increases to approximately $288 per metric ton. The higher prices lead to lower consumer surplus and higher profits compared to either no regulation or a single cap. Average abatement costs are more than double those of a single cap. More importantly, social welfare falls under multiple rate standards by $1.24 billion compared to first best and by $0.55 billion compared to no regulation ($1.24B-$0.69B).

Our next set of scenarios model either the coastal or inland states forming a cap-and-trade coalition while the remaining states adopt state-level or a single rate standard. These simulations will in turn help us understand the incentives these two coalitions might have to join a western-wide cap-and-trade program. Scenario 5 assumes a coastal-state-wide emissions cap and a single rate-standard for inland states. Under this scenario average electricity prices are $53.65/MWh, falling between the Western-wide cap and Western-wide rate scenarios. Emissions fall by 49.04 MMT of $CO_2$, compared to 52.45 MMT under the Western-wide cap scenarios and 75.16 MMT under the state-specific rate standards. Permit prices are $33.23/MT in the capped market, lower than the west-wide cap, while the shadow value of the rate constraint is $89.40/MT, considerably higher than under a west-wide rate. Both consumer surplus falls while producer surplus increases for both covered and uncovered generation. There is little carbon market revenue ($1.78B) consistent with fewer coastal emissions covered by the cap.

Most importantly average abatement costs are higher than a Western-wide cap despite the fact that abatement is lower. Furthermore, a considerable amount of deadweight loss remains; deadweight loss falls by only 50 percent relative to the unregulated case.

Scenario 6 replaces the single inland-rate standard with state-specific standards. Not surprisingly average prices increase considerably, as does abatement. We find that such a scenario *increases* deadweight loss by 13 percent, relative to the unregulated case though average abatement costs are not as high as scenario 4 (state-specific rate standards for every state).

Our final two scenarios assume that coastal states adopt either a single rate standard or state-specific standards, while inland states adopt a single emissions. Given that California currently has a cap-and-trade system in place, we do not believe our last two scenarios are realistic, but they provide the basis for understanding the complete set of incentives. Interestingly, we find that an inland cap-and-trade system with rate standards in the west dominates the coastal cap-and-trade system combined with inland rate standards. That is, welfare improves more under these scenarios than under scenarios 5 and 6.

We next turn to state-specific welfare changes. Table 8 calculates the welfare changes for each state, as well as the two blocks of states discussed above, under each of the scenarios. We assume that carbon-market revenues are returned to consumers and producers in a lump-sum fashion. This table makes clear the divergent incentives of coastal and inland states. The coastal states prefer a single rate standard, while inland states are most harmed by such a standard. The intuition for this result is that coastal generation sources are, on average, cleaner than inland generators. Therefore under a single rate standard, more coastal generators are implicitly subsidized, while more inland generators are taxed, giving coastal power plants a competitive advantage when the market operates under a single rate standard. Notice that state-specific rate standards (Scenarios 4 and 6) do not lead to such a competitive advantage.

Table 8 focuses on aggregate welfare changes; we turn to changes in producer surplus in Table 9. Here the incentives across states are more aligned, since producer surplus depends heavily on equilibrium electricity prices. Producers in both coastal and inland states prefer state-specific rate standards, which as we have shown leads to large increases in the price of electricity. Across Scenarios 5 through 8, each block of states prefers to face state-specific rate standards, but we find that coastal generators benefits, relative to business-as-usual in each of these scenarios.

## 5.3 Incentives to form coalitions

Our simulations suggest that efficiency is enhanced when states form regional trading markets. A natural question, then, is whether states will have the incentive to form such coalitions? We analyze a slightly more aggregated than state-level question that is somewhat reflective of current policy discussions. That is, we consider the incentives of the two blocks of states defined above: coastal and inland states. We can pose the question for different stakeholders. Table 10 is the normal form representation of the change in abatement cost or private surplus (ignoring transmission revenues and carbon damages) across the two coalitions. As shown, from a social-surplus perspective, the inland region gains from adopting a cap, regardless of the regulation in the coast. The best regulation for the coast depends on the regulation in the inland region. Thus the "Nash equilibrium" is the efficient regulatory mechanism: Cap/Cap (i.e., Coastal Cap/Inland Cap).

This normal form is also illustrated in Figure 16 which shows the state-by-state distribution of the abatement costs. This shows that although the inland states as a group always gain from adopting a cap, not all states gain. For example, ID would be harmed more by adopting a cap if the coastal states also adopt a cap than if the inland states adopted a rate.

This figure illustrates that incentives even within these coalitions may not be consistent.

When we look at the individual sets of stakeholders, Cap/Cap is no longer an equilibrium. Table 11 represents the game among consumers. If consumers chose the regulatory mix, the Nash equilibrium would be Rate/Rate. These first two results imply that if left to the social planner, or consumers, the regulatory mechanism would be the same across the two coalitions: Cap/Cap if the planner and Rate/Rate if consumers. As we have seen from Table 7, this has important implications for economic efficiency.

The consumer's perspective is also illustrated in Figure 17 for the individual states. This figure shows the dominance of Rate/Rate from the consumer's perspective. In particular, it illustrates the losses for California consumers under a cap.

The incentives of firms differ drastically. Table 12 and Figure 18 represent the change in profits across both covered and uncovered generators. We see that there is a strong incentive to have different regulatory mechanisms; Cap/Rate and Rate/Cap are both Nash equilibria. Furthermore, we find, consistent with the theoretical results, that the coalition benefits from choosing Rate under each of these equilibria. This would imply the potential for a first-mover advantage if either one of these coalitions could commit to choosing rate-based regulation.

Table 13 and Figure 19 focus on the profits of covered generators. Once again we find that only disparate regulation is a Nash equilibrium, but we can narrow the equilibrium to Rate/Cap, which curiously is an unlikely outcome given that California has already established a cap-and-trade program. We find the same unique Nash equilibrium (in pure strategies) when we look at the profits of uncovered generation.

Combined, these results imply that there is very little incentive for adoption of a Western-wide mass-based system. While the Nash equilibrium from the social planner's perspective is a Western-wide mass-based system, consumers prefer a Western-wide rate-based system, while generators prefer a mixture of regulatory mechanisms.

## 5.4 Entry incentives

Another important dimension over which states and the EPA will need to evaluate their compliance plans is the treatment of newly constructed fossil-fired power plants. Technically, Section 111d of the Clean Air Act covers only existing sources. New sources are covered under a different Section and will have to comply with a source-specific $CO_2$ emissions rate standard. At the time of this writing, the extent to which state-level plans may or may not include new plants under their Clean Power Plan compliance strategies has not been resolved.

We examine this question by adjusting our baseline simulations in two ways. First we anticipate demand growth by escalating hourly demand for every state by 10% over 2007 levels. Second, we allow firms in each state the option of constructing new combined cycle gas turbines (CCGT). As described previously, these plants are assumed to cost \$100 kw-yr, with a marginal cost of \$32/MWh at current gas prices. They have an assumed emissions rate of .428 tons/MWh. We assume these costs do not differ across states.

The specification of the investment decision was described in section 4. Essentially, new MW of CCGT capacity are added when the sum of the net revenues (net of MC) exceed the \$100 KW-yr threshold. Capacity is continued to be added until such investments just break even. Last we assume that under every environmental regulation scenario, the emissions goal is set equivalent to those established in our baseline simulations without new entry.

The efficiency effects of the different scenarios with investment are shown in Table 15 where new investment is included under the CPP and in Table 16 where it is excluded. In general we see that the average abatement cost is much lower if new investment is included in the CPP. If new investment is included in the CPP, average abatement costs are \$24.90 per MT of $CO_2$ under a mass-based standard and \$26.44 per MT of $CO_2$ under a rate-based standard. If new investment is *not* included in the CPP, average abatement costs are \$36.87 per MT of $CO_2$ and \$31.24 per MT of $CO_2$ under mass- and rate-based standards. This shows that under either regulation, average abatement costs are lower if new investment is included under the CPP.

Of course the net revenues of such investments will depend upon the regulatory treatment of not just new sources but also of existing sources. Table 17 summarizes the total additional new CCGT capacity that would be added in each region (coastal or inland), under different combinations of regulatory policies and policies toward new generation. Because of demand growth, there is new investment under every scenario. If we assume that the EPA targets are optimal, then the scenario with all states and new units under a cap would produce the first-best outcome. Relative to this, excluding new plants from the mass-based regulation almost doubles the amount of new CCGT capacity from about 3800 MW to 6500 MW. Conversely, new investment is 5600 MW when new gas capacity is included under a rate-based scheme, and this declines to 4500 MW when the new capacity is excluded. In all cases there is more demand for new capacity in the coastal states when all states adopt a consistent approach.

When we examine the mix of regulations, the contrary incentives provided by the two regulations are highlighted. In general, excluding new plants encourages investment under a mass-based system and discourages it under rate-based approaches. When new plants are included, investment is favored under rate-based regimes relative to mass-based. When the coastal states adopt mass-based and the inland states adopt rates, this influence is magnified. Despite an underlying economic benefit of coastal investment, when new plants are included under the regulations *all* new investment occurs in the inland states, which are operating under a rate-based regulation. When new plants are excluded, this influence reverses and much of the new investment migrates back to the coastal states. However over 3000 MW of new capacity is also built in the rate-based states, essentially for export back to the coastal states. Overall under this scenario almost 9500 MW of new gas capacity are constructed, almost triple that of what could be considered the first-best level.

# 6 Conclusion

There are many contexts in which environmental regulation and trade can interact to undermine the efficiency of both. The EPA's Clean Power Plan is a clear and timely example of these interactions. The CPP proposes major reductions in carbon emissions from generators of electricity, a good that is perfectly substitutable across neighboring states. The CPP establishes state-level targets for carbon emissions rates in lbs of carbon dioxide per megawatt hour of electricity generated. States have a great deal of flexibility in how to achieve these goals. Because this flexibility creates different incentives, effects on consumers and producers within a state could be quite different depending on the type of regulation adopted both in that particular state as well as in other states because electricity is traded regionally across state lines. Furthermore, the states' private incentives may be at odds with those of a social planner.

In this paper we have focused on the two likely market-based regulatory approaches that could be adopted by states, a mass-based (e.g. cap-and-trade) approach, and a rate-based (e.g. intensity standard) approach. Our theoretical findings imply that efficiency is most likely achieved under a mass-based approach, and that a mix of mass and rate based approaches is likely to create an inefficient "ordering" of generation resources. Further we find that, while consumers in each state may prefer to coordinate on rate-based approaches, producers can prefer to coordinate on inconsistent regulations, where different states adopt different approaches.

We investigate the importance of our theoretical findings using numerical simulations of the electricity market in the western United States. We find lack of coordination, when states independently pursue their own emissions targets without regard to electricity trading partners, leads to large inefficiencies. For example under state-specific caps, average abatement costs are nearly 25% higher than under a uniform mass-based standard. Under state-specific rate based targets, average abatement costs can nearly double relative to a uniform mass-based standard. Regional cooperation does little to mitigate these concerns. When two regions of the west coordinate internally, but adopt different instruments, average abatement costs remain 20-30% higher than costs under a uniform mass-based standard. Unfortunately, we find generator incentives do not favor coordination and may lead to adoption of less efficient mixed policies.

One unresolved aspect of the CPP is whether new natural gas generation is included in state emission rates. We examine the implications of the CPP on the construction of new natural gas generation under a medium-term outlook where demand grows by 10% relative to 2007 levels. We find that when new plants are not covered under the CPP, average abatement costs can increase by 50% relative to when they are included. Under mixed regulation, whether new plants are covered by the CPP can dramatically change where new plants are built. When new plants are included in CPP compliance new generation shifts out of mass-based regions toward rate-based regions.

Overall, our findings indicate that despite the *opportunities* the CPP provides for states to coordinate and implement compliance plans that can efficiently achieve their joint targets, the incentives of individual states to participate in those plans are conflicted. Indeed, there can easily be circumstances when states find it in their own interest to adopt a regulatory approach that is contrary to those of its neighbors.

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# Tables

**Table 1:** Comparison of welfare in each state across the policies: efficient dispatch.

| | Mass-based | Rate-based |
|---|---|---|
| Mass-based | $W_s$<br>$W_s$ | .<br>. |
| Rate-based | $W_s + (\frac{4}{5}Carbon_B^{Mix} - Carbon_A^{Mix})\tau/2$<br>$W_s - (\frac{4}{5}Carbon_B^{Mix} - Carbon_A^{Mix})\tau/2$ | $W_s$<br>$W_s$ |

**Table 2:** Comparison of welfare in each state across the policies: inefficient dispatch.

| | Mass-based | Rate-based |
|---|---|---|
| Mass-based | $W_s$<br>$W_s$ | .<br>. |
| Rate-based | $W_s + (\frac{16}{21}Carbon_B^{Mix} - Carbon_A^{Mix})\tau/2 - (c_C + \beta_C\tau - c_G - \beta_G\tau)/2$<br>$W_s - (\frac{16}{21}Carbon_B^{Mix} - Carbon_A^{Mix})\tau/2 - (c_C + \beta_C\tau - c_G - \beta_G\tau)/2$ | $W_s$<br>$W_s$ |

**Table 3:** Comparison of each state's profit across the policies: efficient dispatch.

| | Mass-based | Rate-based |
|---|---|---|
| Mass-based | $\pi$<br>$\pi$ | .<br>. |
| Rate-based | $\pi + 10\sigma_B\tau$<br>$\pi - 6\sigma_B\tau$ | $\pi$<br>$\pi$ |

**Table 4:** Comparison of each state's profit across the policies: inefficient dispatch.

| | Mass-based | Rate-based |
|---|---|---|
| Mass-based | $\pi$<br>$\pi$ | .<br>. |
| Rate-based | $\pi + 11\sigma_{B'}\tau - (c_C + \beta_C\tau - c_G - \beta_G\tau)$<br>$\pi - 5\sigma_{B'}\tau - (c_C + \beta_C\tau - c_G - \beta_G\tau)$ | $\pi$<br>$\pi$ |

**Table 5:** Derated CEMS (Fossil) Generation Capacity (MW) by State and Fuel Type

| State | Coal | CCGT | Gas St | Gas CT | Oil | Total |
|---|---|---|---|---|---|---|
| AZ | 4833 | 7875 | 1009 | 528 | 0 | 14244 |
| CA | 0 | 11015 | 12534 | 2728 | 496 | 26773 |
| CO | 4049 | 1476 | 96 | 1569 | 0 | 7190 |
| ID | 222 | 335 | 0 | 0 | 0 | 556 |
| MT | 1984 | 0 | 0 | 0 | 0 | 1984 |
| NM | 3312 | 496 | 337 | 383 | 0 | 4528 |
| NV | 950 | 2943 | 476 | 517 | 0 | 4887 |
| OR | 484 | 1967 | 88 | 0 | 0 | 2539 |
| UT | 3762 | 884 | 206 | 319 | 0 | 5171 |
| WA | 1184 | 1358 | 107 | 0 | 0 | 2649 |
| WY | 4810 | 60 | 0 | 0 | 0 | 4870 |
| Total | 25591 | 28409 | 14853 | 6044 | 496 | 75392 |

**Table 6:** Actual and Simulated Output and Emissions by State

| | Actual (EIA) | | | Simulated Baseline | | |
|---|---|---|---|---|---|---|
| State | Uncovered Gen (GWh) | Covered Gen (GWh) | Emissions MMTon | Uncovered Gen (GWh) | Covered Gen (GWh) | Emissions MMTon |
| AZ | 35.85 | 77.49 | 54.90 | 54.81 | 75.60 | 55.71 |
| CA | 127.68 | 83.16 | 37.20 | 123.03 | 86.99 | 35.23 |
| CO | 4.73 | 49.18 | 42.10 | 13.63 | 44.09 | 41.94 |
| ID | 9.97 | 1.52 | 0.62 | 7.75 | 1.34 | 0.66 |
| MT | 10.46 | 18.47 | 19.60 | 8.14 | 17.38 | 19.78 |
| NM | 2.21 | 33.78 | 31.60 | 3.38 | 31.27 | 33.10 |
| NV | 5.97 | 26.70 | 15.60 | 8.01 | 26.36 | 15.74 |
| OR | 42.48 | 12.60 | 7.42 | 33.03 | 18.71 | 10.43 |
| UT | 1.66 | 43.71 | 37.70 | 1.29 | 39.18 | 36.57 |
| WA | 92.83 | 14.16 | 11.40 | 72.19 | 18.83 | 14.73 |
| WY | 2.51 | 43.13 | 44.80 | 7.23 | 42.14 | 45.55 |
| Totals | 336.35 | 403.90 | 302.93 | 332.48 | 401.90 | 309.45 |

**Table 7:** Equilibrium outcomes for business as usual and eight policy scenarios.

| | 0<br>No Reg | 1<br>CAT | 2<br>CATs | 3<br>Rate | 4<br>Rates | 5<br>CAT Rate | 6<br>CAT Rates | 7<br>Rate CAT | 8<br>Rates CAT |
|---|---|---|---|---|---|---|---|---|---|
| Electricity Price ($/MWh) | $ 40.38 | $ 59.80 | $ 68.17 | $ 41.02 | $ 84.68 | $ 53.65 | $ 72.78 | $ 61.38 | $ 74.96 |
| Electricity Quantity (GWh) | 411,362 | -13,133 | -18,863 | -405 | -30,050 | -9,141 | -22,304 | -14,283 | -23,310 |
| Emissions (MMT) | 313.81 | -52.45 | -52.45 | -52.70 | -75.16 | -49.04 | -69.70 | -54.07 | -59.79 |
| CAT Permit Price ($/MT) | | $ 35.10 | $ 44.36 | | | $ 33.23 | $ 63.48 | $ 30.19 | $ 41.30 |
| Rate Permit Price ($/MT) | | | | $ 47.91 | $ 287.64 | $ 89.40 | $ 187.48 | $ 190.91 | $ 331.18 |
| Consumer Surplus ($ bn.) | $ 417.36 | -$14.14 | -$20.36 | -$0.33 | -$33.09 | -$10.00 | -$24.06 | -$15.70 | -$25.66 |
| Covered Generator Profit ($ bn.) | $ 6.47 | -$2.48 | -$0.72 | -$1.10 | +$14.48 | +$2.24 | +$7.04 | +$0.85 | +$3.57 |
| Uncovered Generator Profit ($ bn.) | $ 13.48 | +$6.36 | +$9.21 | +$0.14 | +$15.06 | +$4.55 | +$10.97 | +$7.09 | +$11.61 |
| Transmission Profit ($ bn.) | $ 0.14 | -$0.07 | -$0.01 | -$0.06 | +$0.36 | +$0.04 | +$0.10 | +$0.10 | +$0.18 |
| Production Costs ($ bn.) | $ 12.69 | +$1.19 | +$0.91 | +$2.42 | +$2.42 | +$1.80 | +$2.45 | +$1.39 | +$0.99 |
| Carbon Market Rev. ($ bn.) | | +$9.17 | +$10.54 | | | +$1.78 | +$3.40 | +$6.27 | +$8.58 |
| Abatement Cost ($ bn.) | | -$1.15 | -$1.33 | -$1.34 | -$3.19 | -$1.39 | -$2.53 | -$1.39 | -$1.72 |
| Avg. Abatement Cost ($/MT) | | +$21.95 | +$25.41 | +$25.46 | +$42.46 | +$28.25 | +$36.34 | +$25.72 | +$28.74 |
| $\Delta$ Carbon Damages ($ bn.) | | -$1.84 | -$1.84 | -$1.85 | -$2.64 | -$1.72 | -$2.45 | -$1.90 | -$2.10 |
| Deadweight Loss ($ bn.) | -$0.69 | +$0.00 | -$0.18 | -$0.18 | -$1.24 | -$0.35 | -$0.78 | -$0.18 | -$0.31 |

Notes: Results from Scenarios 1-8 are reported as changes relative to Scenario 0. "+" indicates an increase and "-" indicates a decrease. "Abatement Cost" is the sum of consumer surplus, profits (covered, uncovered, and transmission), and carbon market revenue. Carbon damages assume a social cost of carbon equal to $35.10.

**Table 8:** Social welfare gains across regions relative to business as usual under eight policy scenarios.

| | 0<br>No Reg | 1<br>CAT | 2<br>CATs | 3<br>Rate | 4<br>Rates | 5<br>CAT Rate | 6<br>CAT Rates | 7<br>Rate CAT | 8<br>Rates CAT |
|---|---|---|---|---|---|---|---|---|---|
| Social Welfare ($ bn.) | | | | | | | | | |
| CA | $176.20 | -$0.43 | -$1.19 | +$2.06 | -$2.44 | -$0.25 | -$1.13 | -$0.44 | -$1.93 |
| OR | $30.55 | +$0.13 | +$0.09 | +$0.22 | +$0.13 | +$0.08 | +$0.07 | -$0.01 | +$0.09 |
| WA | $54.30 | +$0.33 | +$0.08 | +$0.11 | -$0.13 | +$0.16 | +$0.13 | -$0.29 | -$0.14 |
| Coastal Total | $261.05 | +$0.03 | -$1.01 | +$2.38 | -$2.45 | -$0.01 | -$0.92 | -$0.74 | -$1.98 |
| AZ | $50.56 | +$0.71 | +$0.53 | +$0.38 | +$0.94 | +$2.11 | +$0.63 | +$0.59 | +$1.25 |
| CO | $27.00 | +$0.06 | -$0.00 | -$0.47 | -$0.30 | -$0.44 | -$0.36 | +$0.18 | +$0.23 |
| ID | $14.39 | -$0.24 | -$0.41 | +$0.07 | -$0.71 | -$0.13 | -$0.49 | -$0.33 | -$0.50 |
| MT | $10.02 | -$0.04 | +$0.28 | -$0.36 | +$0.49 | -$0.42 | +$0.36 | +$0.12 | +$0.18 |
| NM | $14.40 | -$0.36 | +$0.18 | -$0.34 | +$0.06 | -$0.38 | +$0.01 | -$0.30 | -$0.35 |
| NV | $22.43 | -$0.06 | -$0.14 | +$0.23 | +$0.00 | +$0.72 | -$0.00 | -$0.04 | -$0.04 |
| UT | $17.21 | +$0.21 | +$0.18 | -$0.45 | -$0.33 | -$0.40 | -$0.39 | +$0.25 | +$0.41 |
| WY | $9.24 | +$0.45 | +$0.90 | -$0.87 | +$1.39 | -$0.75 | +$0.98 | +$0.68 | +$1.01 |
| Inland Total | $165.24 | +$0.72 | +$1.52 | -$1.82 | +$1.54 | +$0.31 | +$0.73 | +$1.15 | +$2.18 |
| Transmission Profits | $0.14 | -$0.07 | -$0.01 | -$0.06 | +$0.36 | +$0.04 | +$0.10 | +$0.10 | +$0.18 |
| Total | $426.43 | +$0.69 | +$0.51 | +$0.51 | -$0.55 | +$0.34 | -$0.09 | +$0.51 | +$0.38 |

Notes: Results from Scenarios 1-8 are reported as changes relative to Scenario 0. "+" indicates an increase and "-" indicates a decrease. Carbon damages assume a social cost of carbon equal to $35.10. Carbon damages are allocated across states based on population.

**Table 9:** Generator profits across regions for all generation (covered and uncovered) under business as usual and eight policy scenarios.

| | 0 No Reg | 1 CAT | 2 CATs | 3 Rate | 4 Rates | 5 CAT Rate | 6 CAT Rates | 7 Rate CAT | 8 Rates CAT |
|---|---|---|---|---|---|---|---|---|---|
| CA | $5.64 | +$2.85 | +$3.84 | +$1.22 | +$9.16 | +$1.62 | +$4.53 | +$4.66 | +$7.19 |
| OR | $1.97 | +$0.67 | +$1.07 | +$0.07 | +$2.76 | +$0.51 | +$1.43 | +$1.20 | +$2.02 |
| WA | $3.98 | +$1.35 | +$2.09 | -$0.16 | +$4.51 | +$1.05 | +$2.79 | +$1.84 | +$3.25 |
| Coastal Total | $11.59 | +$4.88 | +$7.00 | +$1.12 | +$16.42 | +$3.18 | +$8.75 | +$7.71 | +$12.46 |
| AZ | $2.47 | +$0.77 | +$1.14 | +$0.38 | +$3.85 | +$2.95 | +$2.85 | +$0.63 | +$1.86 |
| CO | $1.26 | -$0.37 | -$0.22 | -$0.50 | +$1.75 | +$0.14 | +$1.17 | -$0.12 | +$0.13 |
| ID | $0.40 | +$0.16 | +$0.25 | +$0.01 | +$0.59 | +$0.23 | +$0.42 | +$0.23 | +$0.37 |
| MT | $0.87 | -$0.19 | +$0.75 | -$0.41 | +$1.34 | -$0.18 | +$0.96 | +$0.04 | +$0.18 |
| NM | $0.56 | -$0.31 | -$0.04 | -$0.35 | +$0.89 | -$0.14 | +$0.64 | -$0.28 | -$0.16 |
| NV | $0.51 | +$0.17 | +$0.26 | +$0.20 | +$1.50 | +$1.15 | +$1.11 | +$0.21 | +$0.54 |
| UT | $0.99 | -$0.53 | -$0.42 | -$0.55 | +$1.15 | +$0.01 | +$0.64 | -$0.16 | -$0.01 |
| WY | $1.29 | -$0.69 | -$0.24 | -$0.85 | +$2.05 | -$0.55 | +$1.48 | -$0.31 | -$0.19 |
| Inland Total | $8.36 | -$1.00 | +$1.49 | -$2.08 | +$13.12 | +$3.61 | +$9.27 | +$0.23 | +$2.72 |
| Total | $19.95 | +$3.88 | +$8.49 | -$0.96 | +$29.54 | +$6.79 | +$18.01 | +$7.94 | +$15.18 |

Notes: Results from Scenarios 1-8 are reported as changes relative to Scenario 0. "+" indicates an increase and "-" indicates a decrease. Profits in $ billion.

**Table 10:** Abatement cost incentives in the coastal and inland west.

| | | Inland | |
|---|---|---|---|
| | | Cap | Rate |
| Coastal | Cap | - $1.23 , + $0.14 | - $1.19 , - $0.23 |
| | Rate | - $2.04 , + $0.55 | + $1.12 , - $2.40 |

Notes: "Abatement Cost" is the sum of consumer surplus, generator profits (covered and uncovered), and carbon market revenue and is measured relative to business as usual (Scenario 0) in $ billion. "+" indicates an increase (i.e., a gain) and "-" indicates a decrease (i.e., a loss).

**Table 11:** Consumer surplus incentives in the coastal and inland west.

| | | Inland | |
|---|---|---|---|
| | | Cap | Rate |
| Coastal | Cap | - $8.38 , - $5.75 | - $6.15 , - $3.84 |
| | Rate | - $9.74 , - $5.96 | - $0.00 , - $0.32 |

Notes: Consumer surplus is measured relative to business as usual (Scenario 0) in $ billion. "+" indicates an increase and "-" indicates a decrease.

**Table 12:** Profit incentives for all generation (covered and uncovered) in the coastal and inland west.

| | | Inland | |
|---|---|---|---|
| | | Cap | Rate |
| Coastal | Cap | + $4.88 , - $1.00 | + $3.18 , + $3.61 |
| | Rate | + $7.71 , + $0.23 | + $1.12 , - $2.08 |

Notes: Profit is measured relative to business as usual (Scenario 0) in $ billion. "+" indicates an increase and "-" indicates a decrease.

**Table 13:** Profit incentives for covered generation in the coastal and inland west.

| | | Inland | |
|---|---|---|---|
| | | Cap | Rate |
| Coastal | Cap | + \$0.26 , - \$2.74 | - \$0.26 , + \$2.50 |
| | Rate | + \$2.35 , - \$1.50 | + \$1.09 , - \$2.19 |

Notes: Profit is measured relative to business as usual (Scenario 0) in \$ billion. "+" indicates an increase and "-" indicates a decrease.

**Table 14:** Profit incentives for uncovered generation in the coastal and inland west.

| | | Inland | |
|---|---|---|---|
| | | Cap | Rate |
| Coastal | Cap | + \$4.62 , + \$1.74 | + \$3.43 , + \$1.11 |
| | Rate | + \$5.36 , + \$1.73 | + \$0.03 , + \$0.11 |

Notes: Profit is measured relative to business as usual (Scenario 0) in \$ billion. "+" indicates an increase and "-" indicates a decrease.

**Table 15:** Future equilibrium outcomes with investment for business as usual and eight policy scenarios where new NGCC investment is included under the CPP.

| | 0<br>No Reg | 1<br>CAT | 2<br>CATs | 3<br>Rate | 4<br>Rates | 5<br>CAT Rate | 6<br>CAT Rates | 7<br>Rate CAT | 8<br>Rates CAT |
|---|---|---|---|---|---|---|---|---|---|
| Electricity Price ($/MWh) | $ 43.10 | $ 59.57 | $ 59.31 | $ 38.05 | $ 45.33 | $ 36.59 | $ 42.43 | $ 50.66 | $ 51.20 |
| Electricity Quantity (GWh) | 483,169 | -11,278 | -11,135 | +3,365 | -2,200 | +4,178 | +97 | -4,966 | -6,604 |
| Emissions (MMT) | 345.10 | -51.21 | -51.21 | -49.17 | -36.35 | -29.61 | -26.38 | -32.12 | -28.60 |
| CAT Permit Price ($/MT) | | $ 35.01 | $ 34.88 | | | $ 0.00 | $ 9.62 | $ 19.34 | $ 18.81 |
| Rate Permit Price ($/MT) | | | | $ 35.80 | $ 92.67 | $ 32.70 | $ 23.91 | $ 236.75 | $ 215.62 |
| Consumer Surplus ($ bn.) | $ 501.42 | - $13.03 | - $12.89 | + $4.41 | - $3.71 | + $5.18 | + $0.22 | - $6.06 | - $8.45 |
| Covered Generator Profits ($ bn.) | $ 7.70 | - $3.72 | - $3.79 | - $3.83 | - $0.25 | - $4.03 | - $1.76 | - $2.04 | - $1.69 |
| Uncovered Generator Profits ($ bn.) | $ 14.23 | + $5.38 | + $5.31 | - $1.75 | + $1.23 | - $2.15 | - $0.04 | + $2.54 | + $3.25 |
| Transmission Profits ($ bn.) | $ 0.22 | - $0.18 | - $0.12 | - $0.18 | + $1.31 | + $0.14 | + $0.16 | - $0.12 | + $1.24 |
| Production Costs ($ bn.) | $ 16.18 | + $0.89 | + $0.88 | + $1.70 | + $0.91 | + $0.79 | + $0.74 | + $0.23 | + $0.12 |
| Carbon Market Rev. ($ bn.) | | + $10.29 | + $10.21 | | | + $0.00 | + $0.56 | + $4.55 | + $4.42 |
| Abatement Cost ($ bn.) | | - $1.26 | - $1.29 | - $1.35 | - $1.42 | - $0.86 | - $0.87 | - $1.13 | - $1.23 |
| Avg. Abatement Cost ($/MT) | | + $24.62 | + $25.13 | + $27.42 | + $39.16 | + $29.00 | + $32.87 | + $35.25 | + $42.87 |
| New Capacity (MW) | +4,517 | +3,716 | +4,108 | +5,977 | +9,046 | +6,081 | +5,087 | +9,095 | +10,333 |

Notes: Results from Scenarios 1-8 are reported as changes relative to Scenario 0. “+” indicates an increase and “-” indicates a decrease. “Abatement Cost” is the sum of consumer surplus, profits (covered, uncovered, and transmission), and carbon market revenue.

**Table 16:** Future equilibrium outcomes with investment for business as usual and eight policy scenarios where new NGCC investment is *not* included under the CPP.

| | 0<br>No Reg | 1<br>CAT | 2<br>CATs | 3<br>Rate | 4<br>Rates | 5<br>CAT Rate | 6<br>CAT Rates | 7<br>Rate CAT | 8<br>Rates CAT |
|---|---|---|---|---|---|---|---|---|---|
| Electricity Price ($/MWh) | $ 43.10 | $ 44.66 | $ 44.40 | $ 44.33 | $ 44.81 | $ 44.31 | $ 44.49 | $ 44.74 | $ 45.04 |
| Electricity Quantity (GWh) | 483,169 | -1,039 | -1,034 | -1,024 | -1,040 | -1,044 | -1,045 | -1,043 | -1,034 |
| Emissions (MMT) | 345.10 | -10.46 | -16.20 | -66.08 | -68.44 | -69.60 | -59.22 | -20.85 | -19.47 |
| CAT Permit Price ($/MT) | | $ 16.20 | $ 13.83 | | | $ 11.52 | $ 10.99 | $ 16.24 | $ 14.57 |
| Rate Permit Price ($/MT) | | | | $ 54.79 | $ 86.80 | $ 69.60 | $ 84.46 | $ 63.95 | $ 111.48 |
| Consumer Surplus ($ bn.) | $ 501.42 | - $0.97 | - $0.79 | - $0.74 | - $1.04 | - $0.70 | - $0.81 | - $1.03 | - $1.27 |
| Covered Generator Profits ($ bn.) | $ 7.70 | - $5.07 | - $4.83 | - $0.72 | - $1.26 | - $1.22 | - $1.69 | - $4.18 | - $3.88 |
| Uncovered Generator Profits ($ bn.) | $ 14.23 | + $0.40 | + $0.36 | + $0.35 | + $0.40 | + $0.34 | + $0.36 | + $0.42 | + $0.49 |
| Transmission Profits ($ bn.) | $ 0.22 | - $0.16 | - $0.17 | - $0.95 | - $0.41 | - $1.50 | - $0.66 | - $0.08 | + $0.18 |
| Production Costs ($ bn.) | $ 16.18 | - $0.42 | + $0.05 | + $2.82 | + $2.34 | + $2.23 | + $1.97 | + $0.08 | - $0.03 |
| Carbon Market Rev. ($ bn.) | | + $5.42 | + $4.94 | | | + $0.93 | + $0.87 | + $4.16 | + $3.71 |
| Abatement Cost ($ bn.) | | - $0.37 | - $0.49 | - $2.05 | - $2.30 | - $2.15 | - $1.93 | - $0.72 | - $0.77 |
| Avg. Abatement Cost ($/MT) | | + $35.60 | + $30.12 | + $31.07 | + $33.67 | + $30.91 | + $32.59 | + $34.33 | + $39.74 |
| New Capacity (MW) | +4,517 | +6,353 | +4,822 | +4,520 | +10,600 | +9,471 | +8,671 | +6,979 | +8,229 |

Notes: Results from Scenarios 1-8 are reported as changes relative to Scenario 0. "+" indicates an increase and "-" indicates a decrease. "Abatement Cost" is the sum of consumer surplus, profits (covered, uncovered, and transmission), and carbon market revenue.

**Table 17:** New capacity under four policy scenarios when new NGCC investment is included and *not* included under the CPP.

| New Capacity (MW) | Mass-Based (CAP) | | | Rate-Based | | | Coast Mass & Inland Rate | | | Coast Rate & Inland Mass | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Coast | Inland | Total | Coast | Inland | Total | Coast | Inland | Total | Coast | Inland | Total |
| Included | +3,355 | +361 | +3,716 | +4,931 | +1,046 | +5,977 | +0 | +6,081 | +6,081 | +10,273 | -1,177 | +9,095 |
| Excluded | +5,922 | +431 | +6,353 | +2,402 | +2,118 | +4,520 | +5,928 | +3,543 | +9,471 | +5,937 | +1,042 | +6,979 |

Note: Results are reported as changes relative to new capacity built under business as usual. ``+" indicates an increase and ``-" indicates a decrease.
Scenarios assume 10% load growth from 2006 levels.

# Figures

**Figure 7:** Western regional electricity network and transmission contraints.

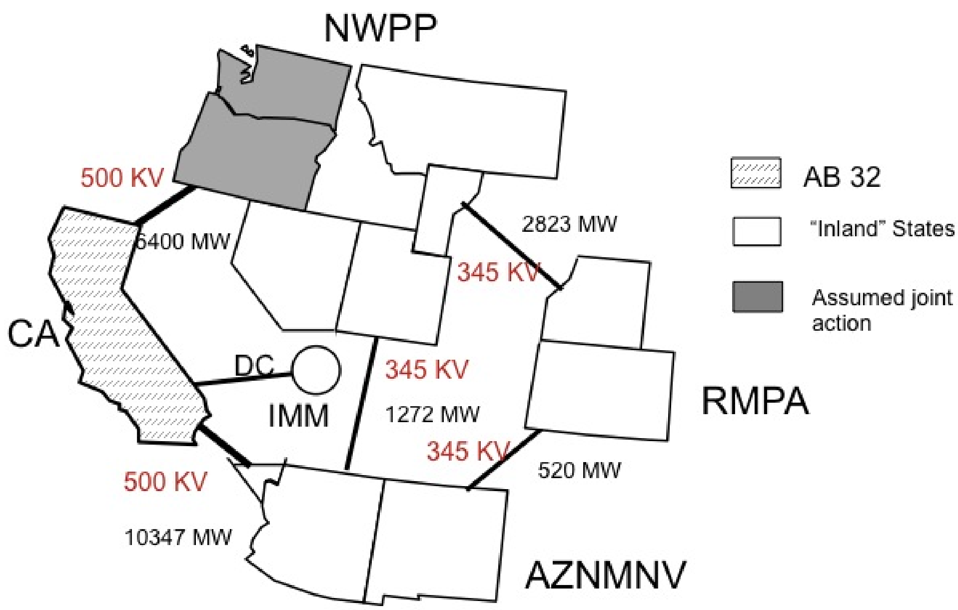
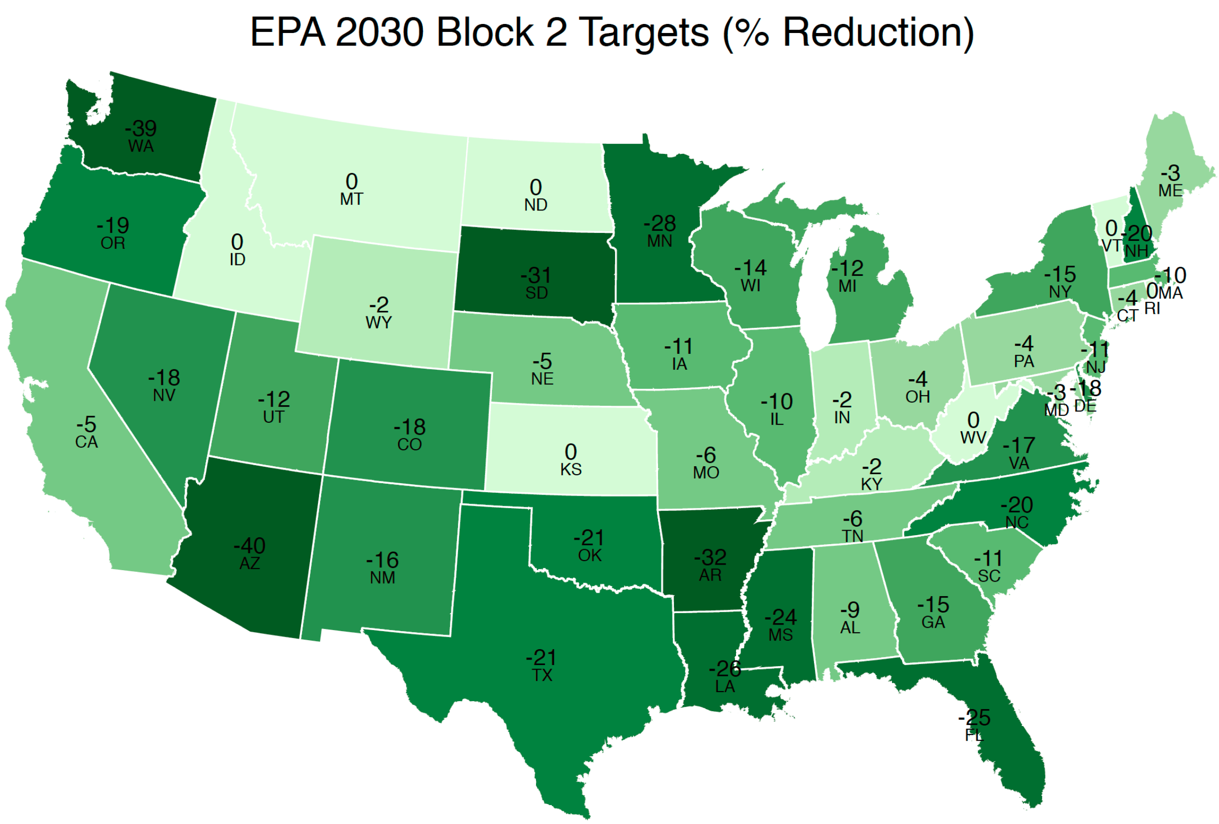
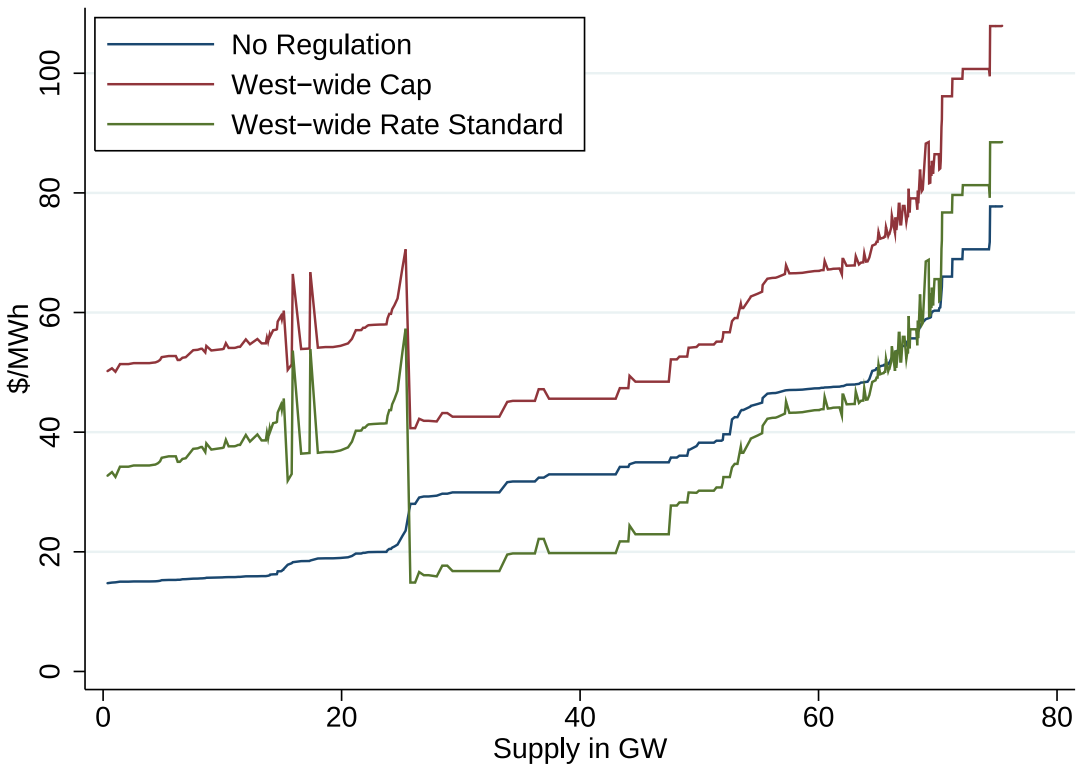


**Figure 8:** EPA Clean Power Plan target reductions for 2030 from Building Block 2.



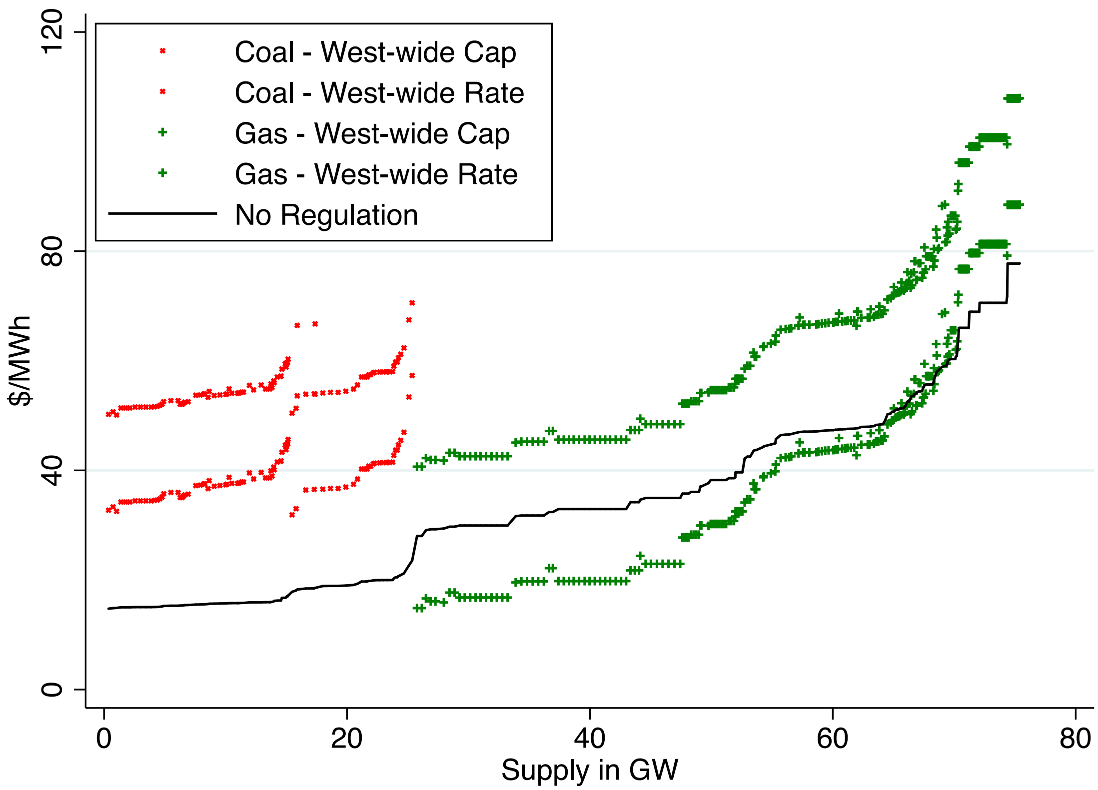

Note: Percentage reduction in lbs per MWh.

**Figure 9:** Merit order under different regulations: BAU and west-wide mass- and rate-based standards.



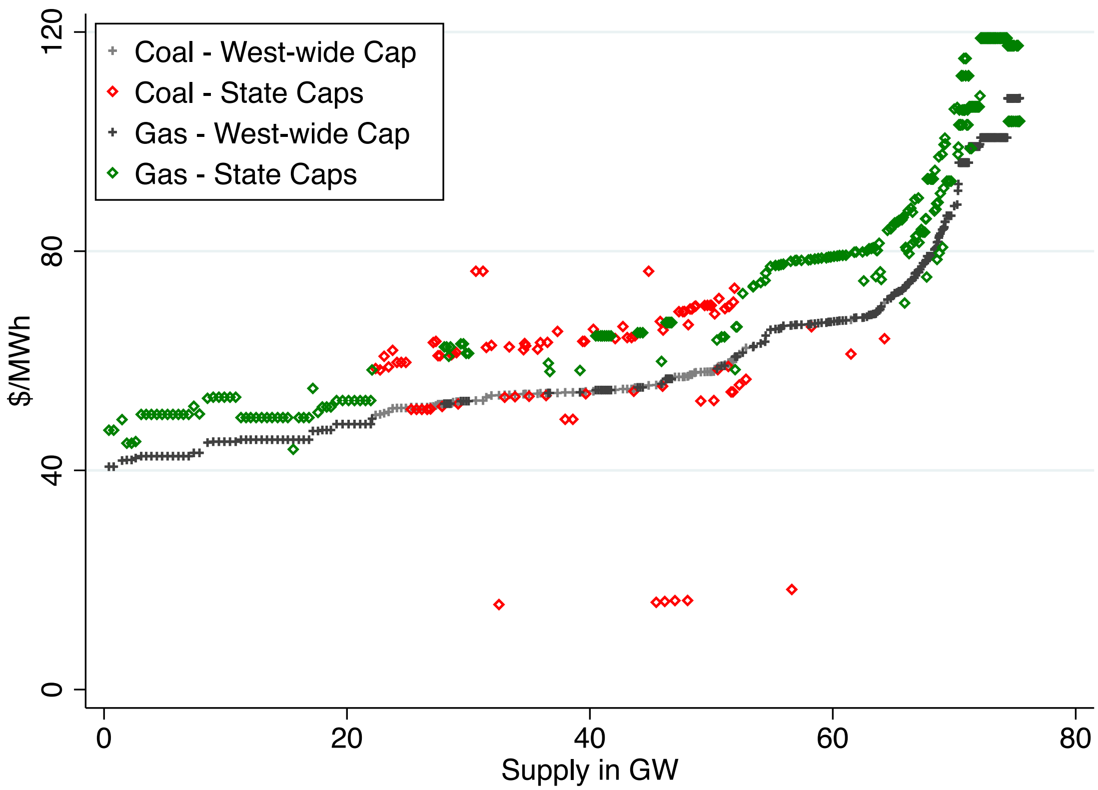

Note: Generating units sorted on x-axis by marginal costs under BAU (Scenario 0).

**Figure 10:** Merit order under different regulations: BAU and west-wide mass- and rate-based standards.



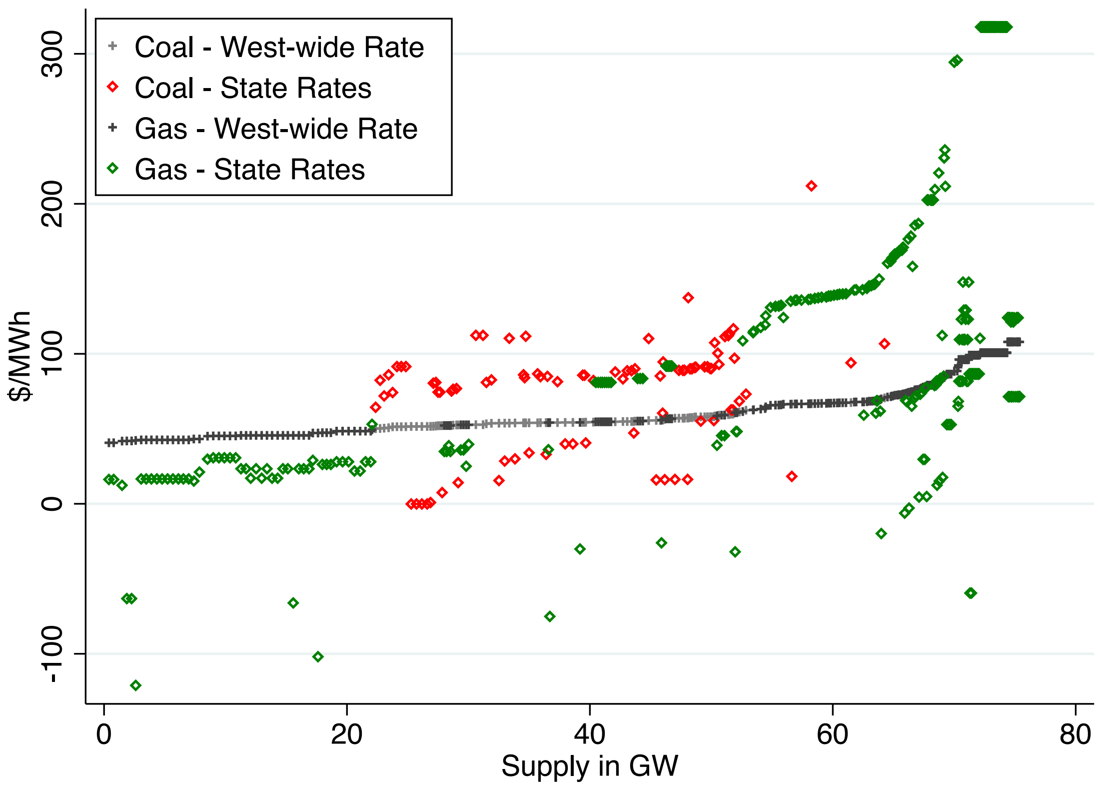

Note: Generating units sorted on x-axis by marginal costs under BAU (Scenario 0). Upper scatter is mass-based standard and lower scatter is rate-based standard.

**Figure 11:** Merit order under different regulations: west-wide mass-based standards and state-by-state mass-based standards.



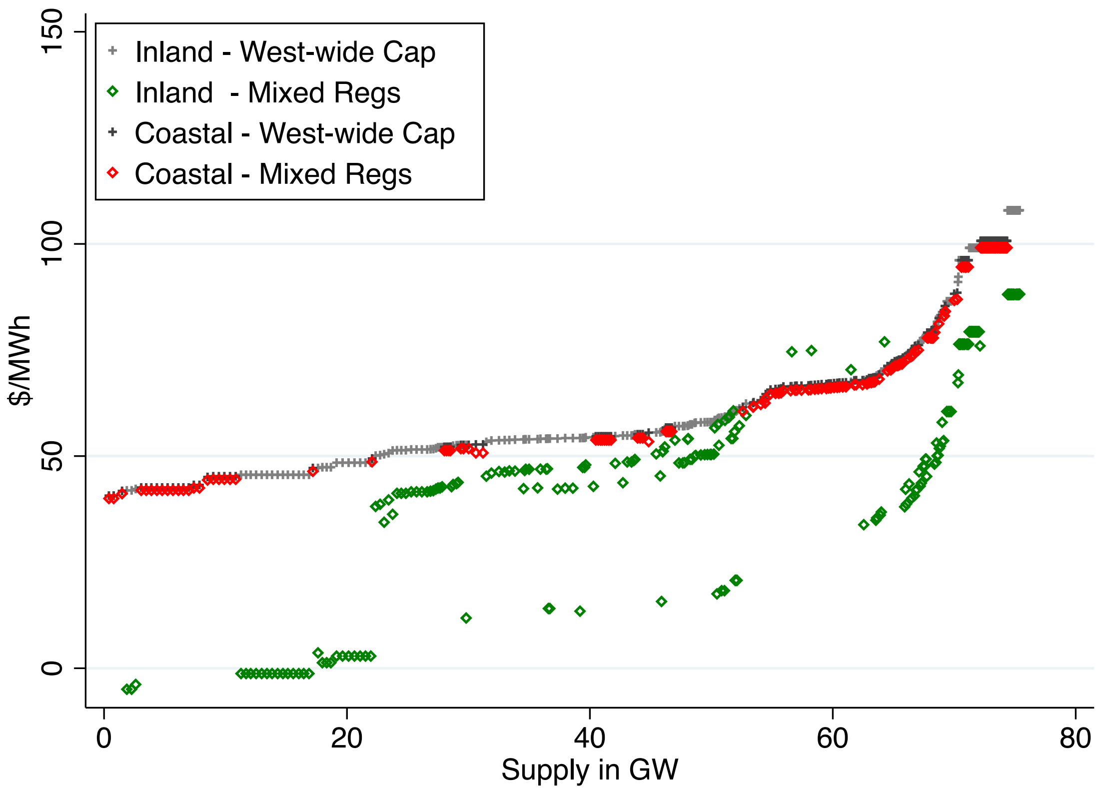

Note: Generating units sorted on x-axis by full-marginal costs under west-wide mass-based standards (Scenario 1).

**Figure 12:** Merit order under different regulations: west-wide rate-based standard and state-by-state rate-based standards.



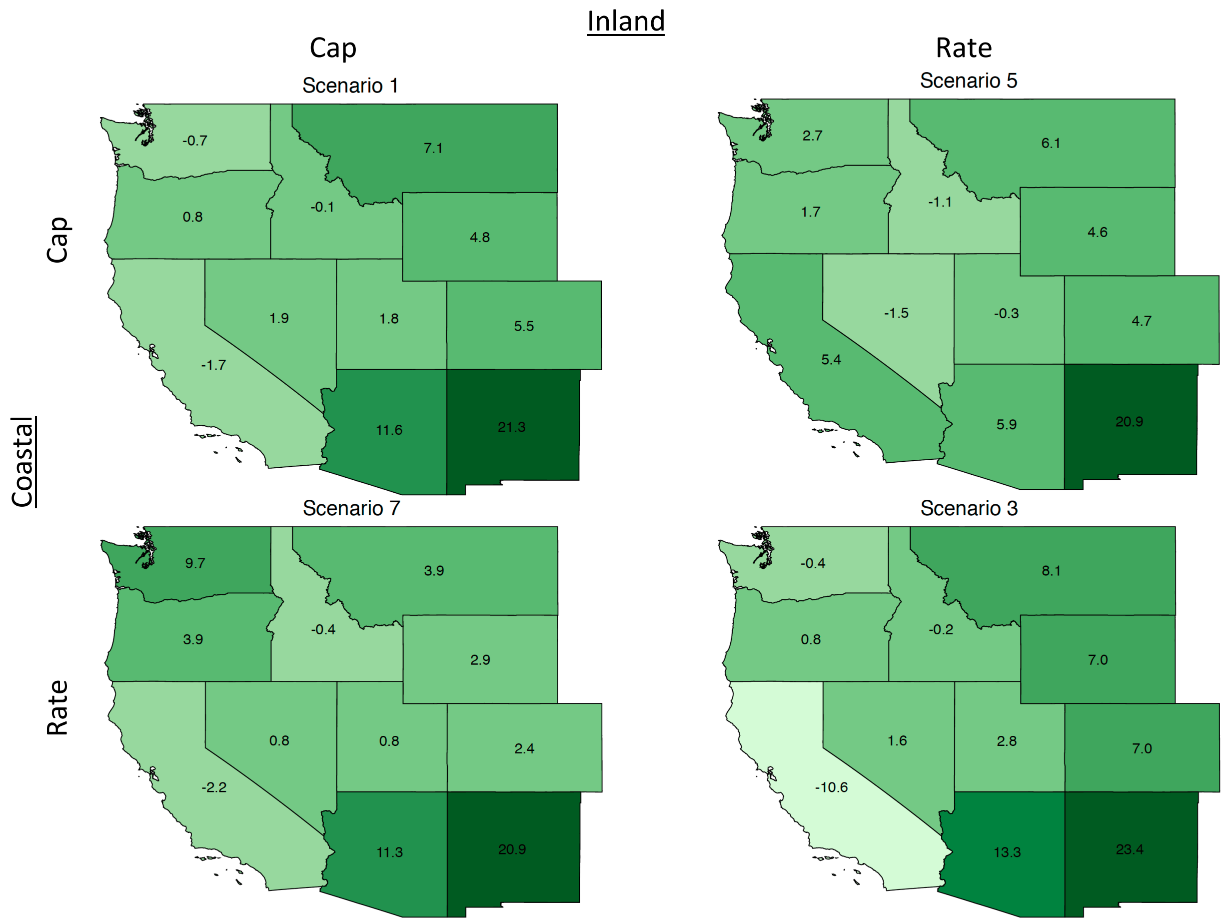

Note: Generating units sorted on x-axis by full-marginal costs under west-wide rate-based standard (Scenario 3).

**Figure 13:** Merit order under different regulations: west-wide mass-based standards and mixed regulation.



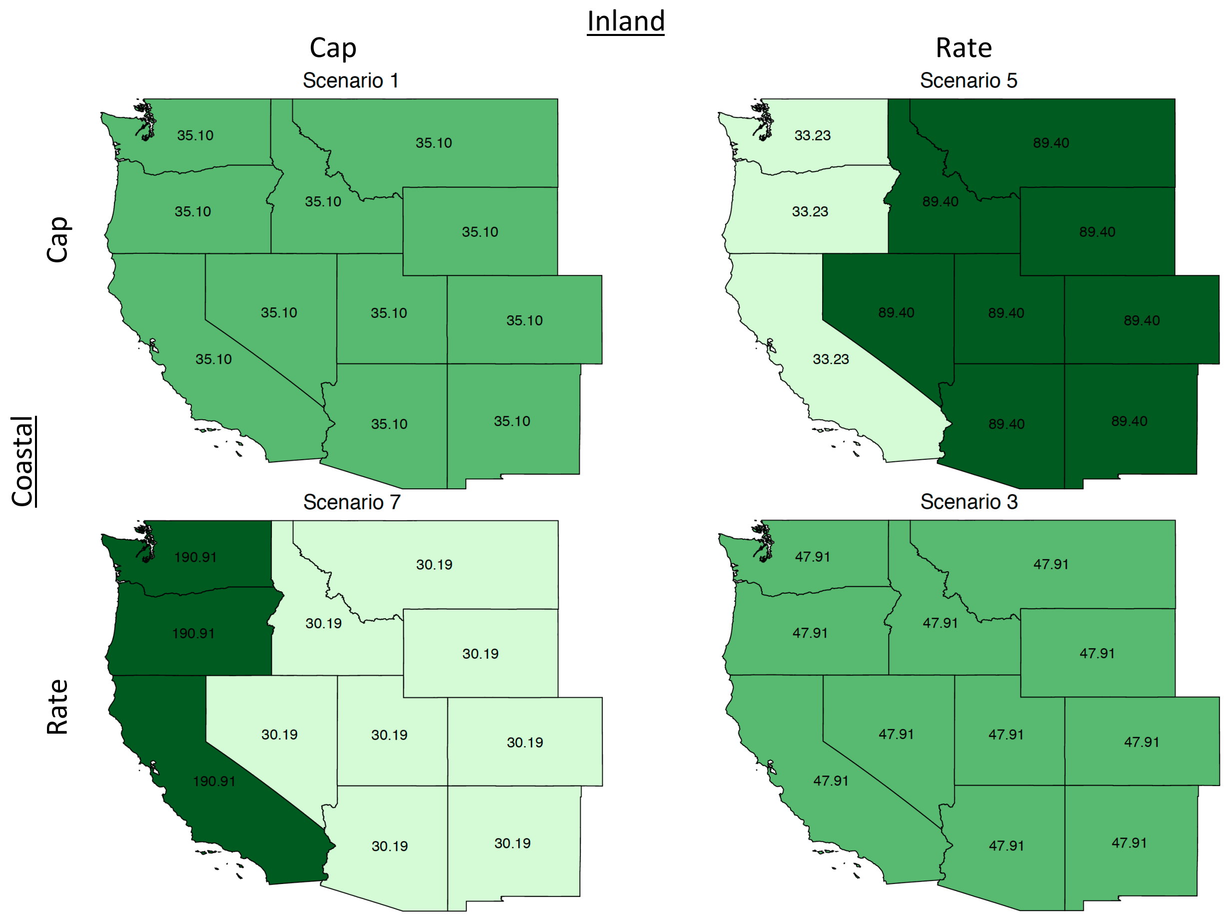

Note: Generating units sorted on x-axis by full-marginal costs under west-wide mass-based standards (Scenario 1). Mixed regulation has Coastal mass-based standard and Inland rate-based standard.

**Figure 14:** Carbon abatement under uniform and mixed regulation.



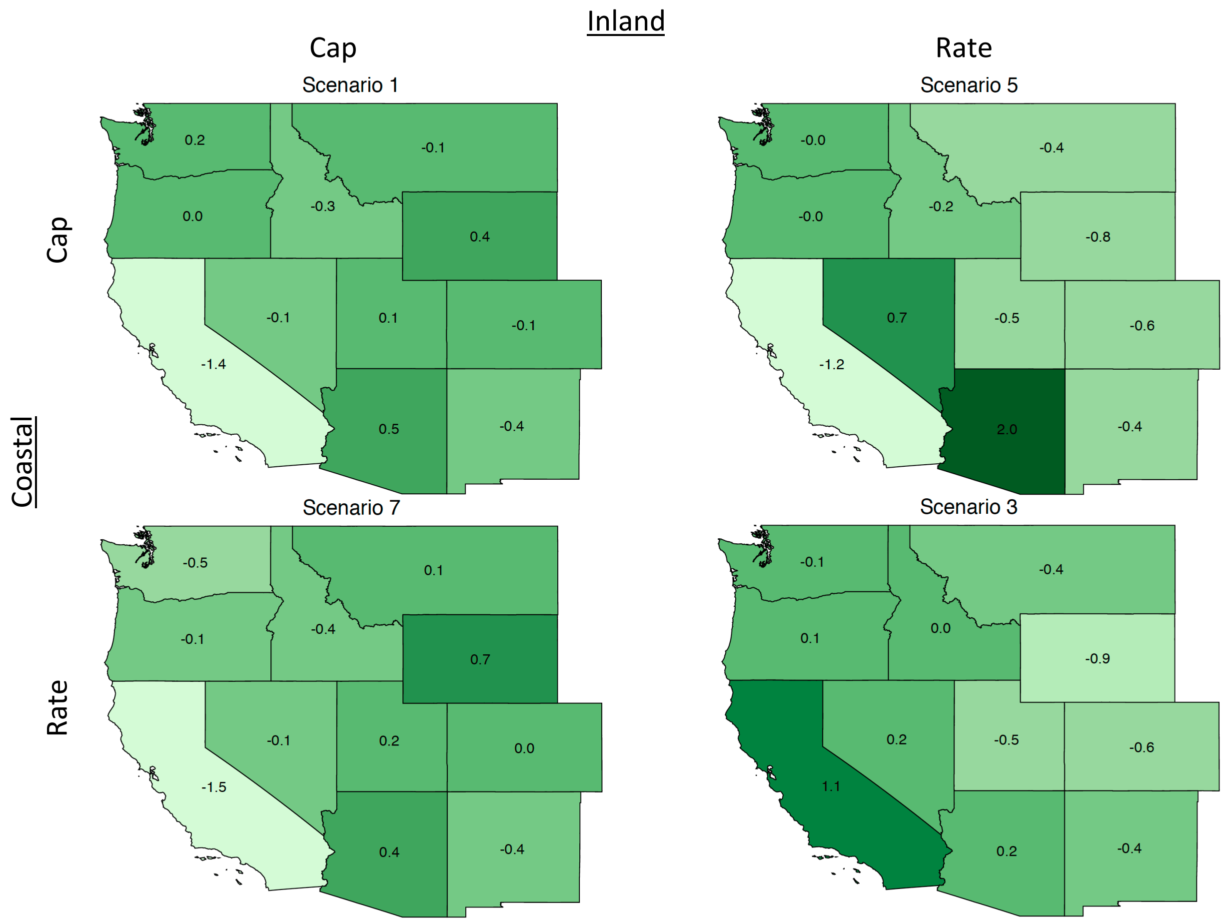

Note: Carbon abatement in million metric tons.

**Figure 15:** Carbon prices under uniform and mixed regulation.



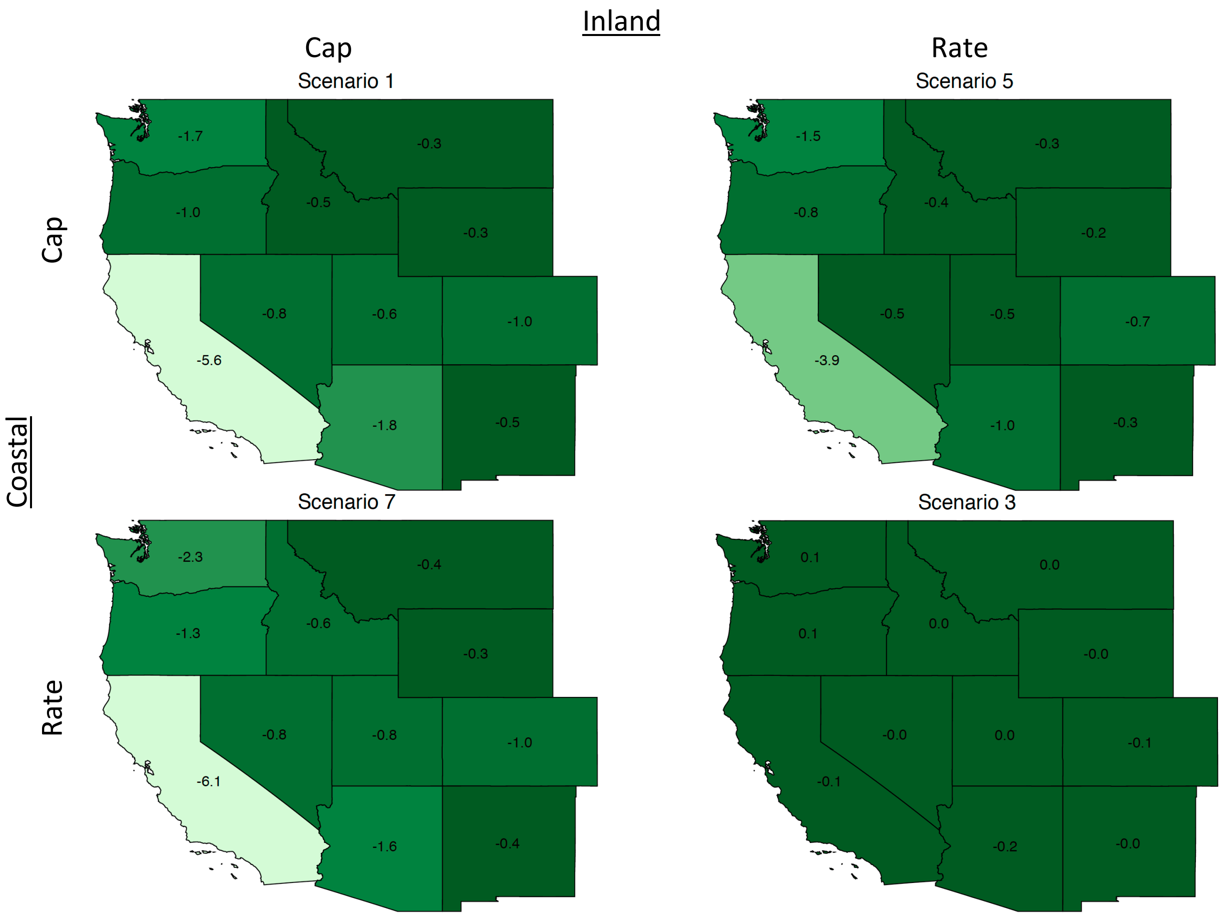

Note: Carbon prices in $ per ton.

**Figure 16:** Abatement cost under uniform and mixed regulation.



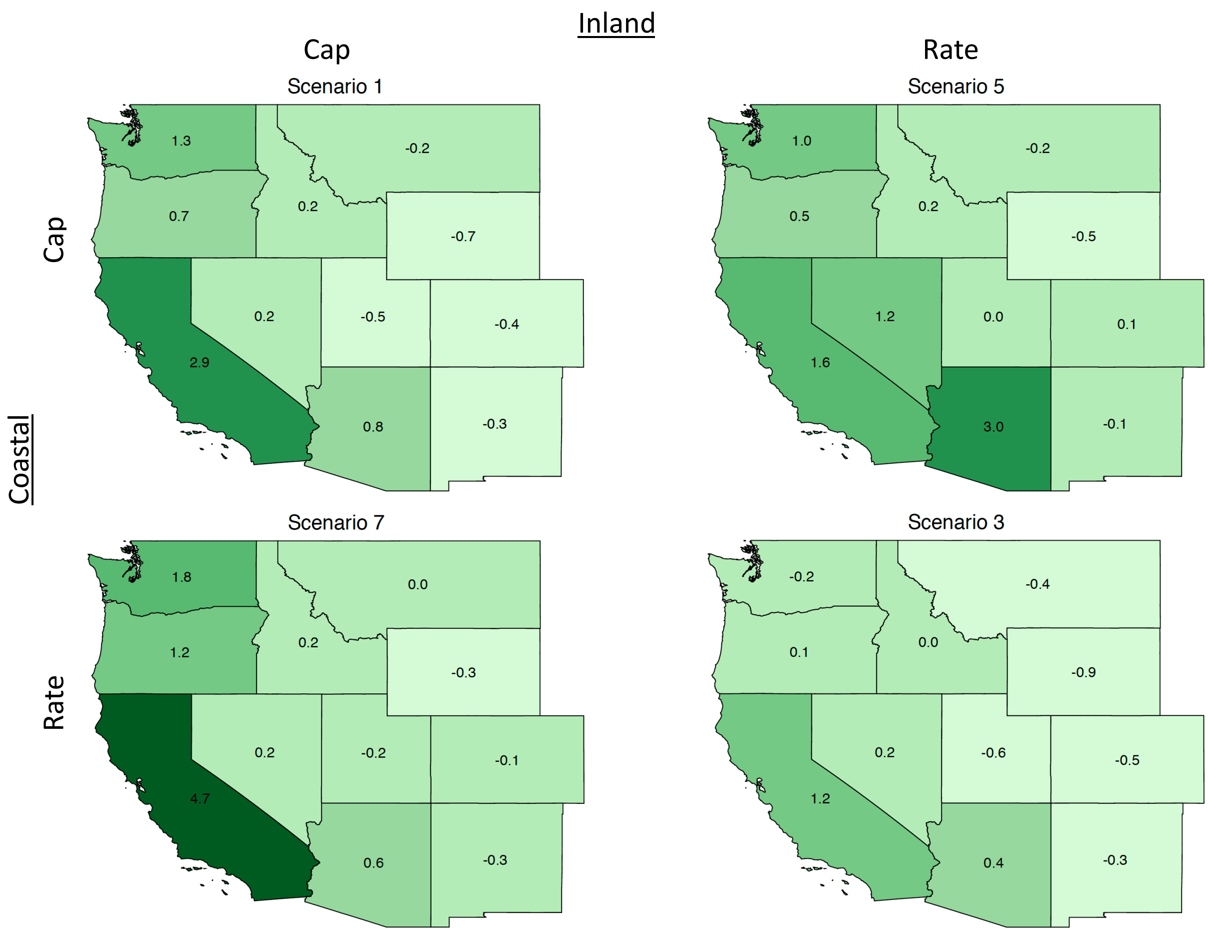

Note: Abatement cost in $ billion relative to BAU.

**Figure 17:** Consumer surplus incentives under uniform and mixed regulation.



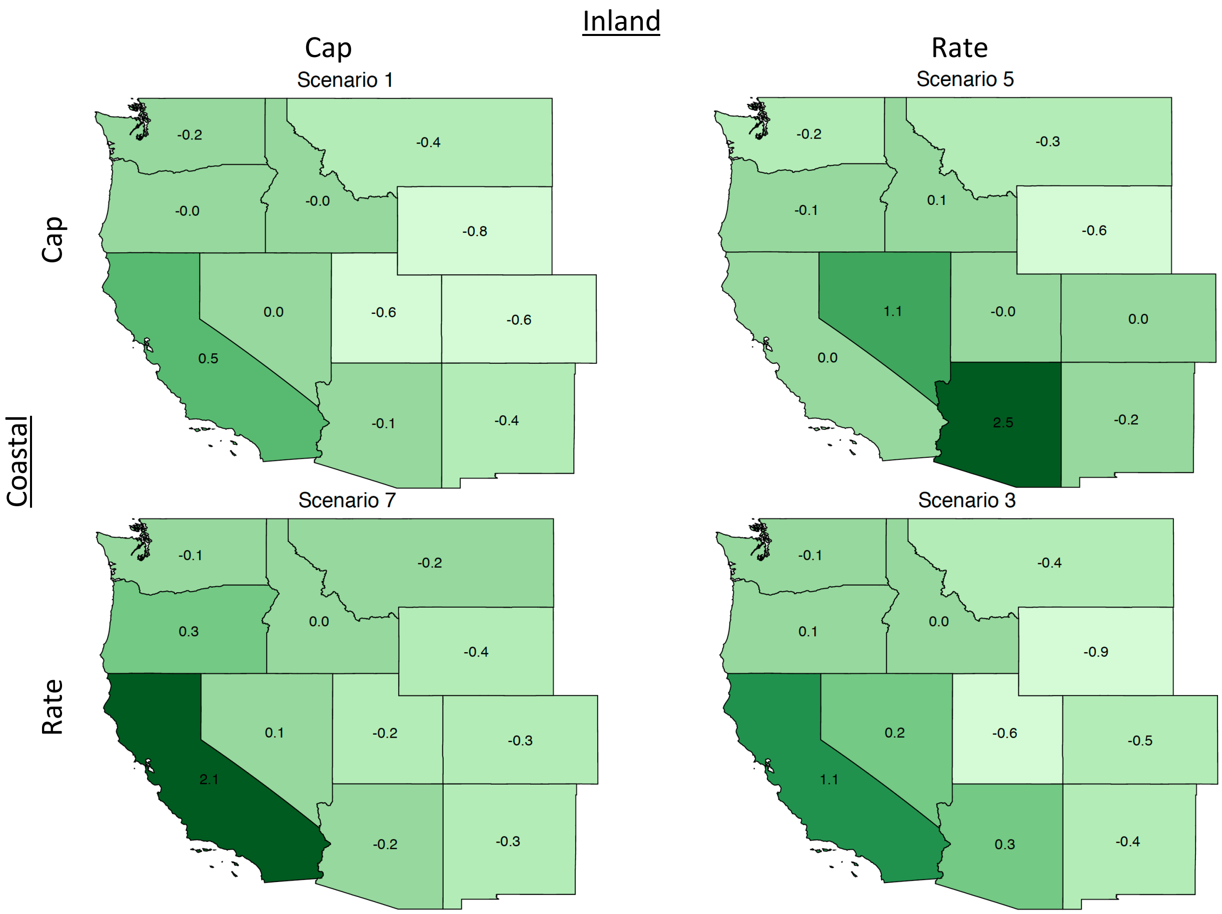

Note: Consumer surplus changes in $ billion relative to BAU.

**Figure 18:** Profit incentives for all generation (covered and uncovered) under uniform and mixed regulation.



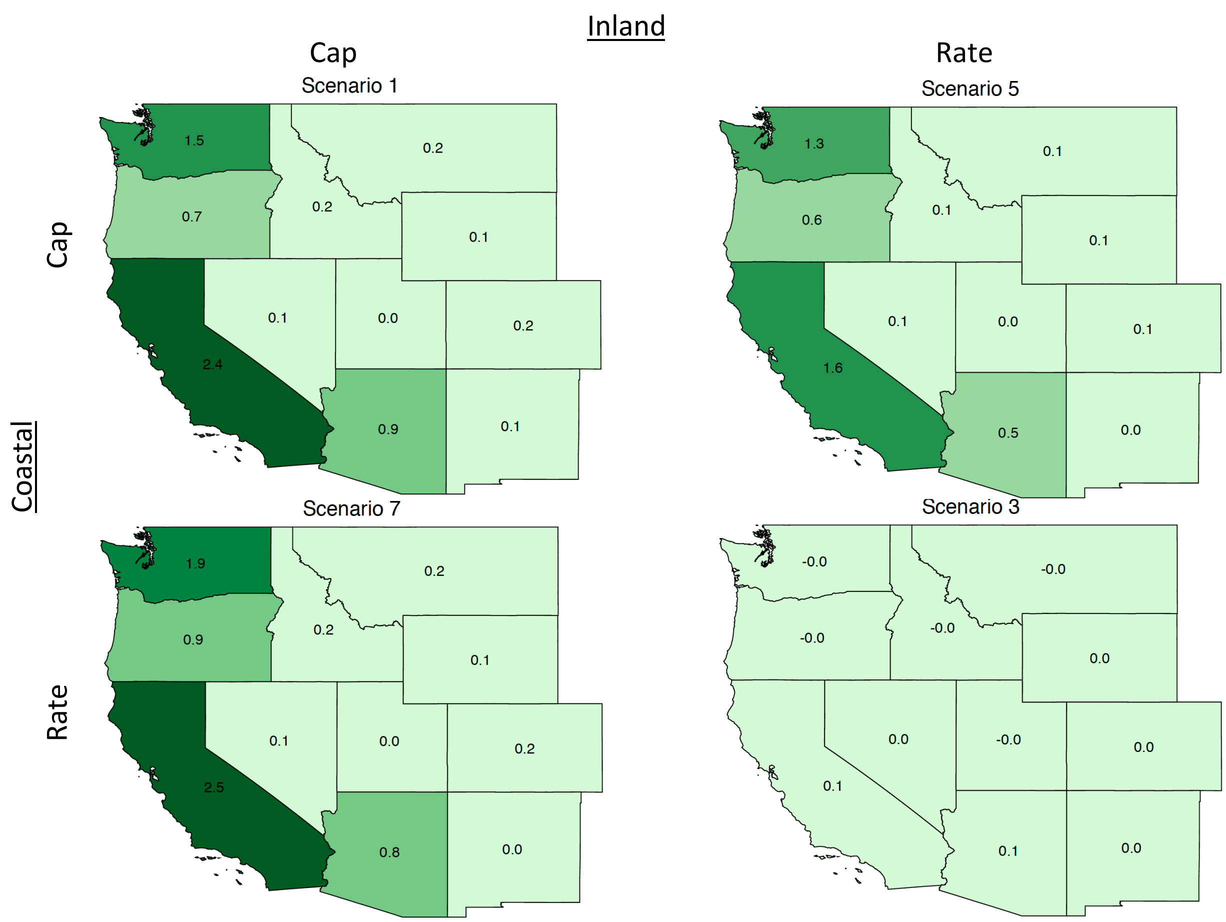

Note: Profit changes in $ billion relative to BAU.

**Figure 19:** Profit incentives for covered generation under uniform and mixed regulation.



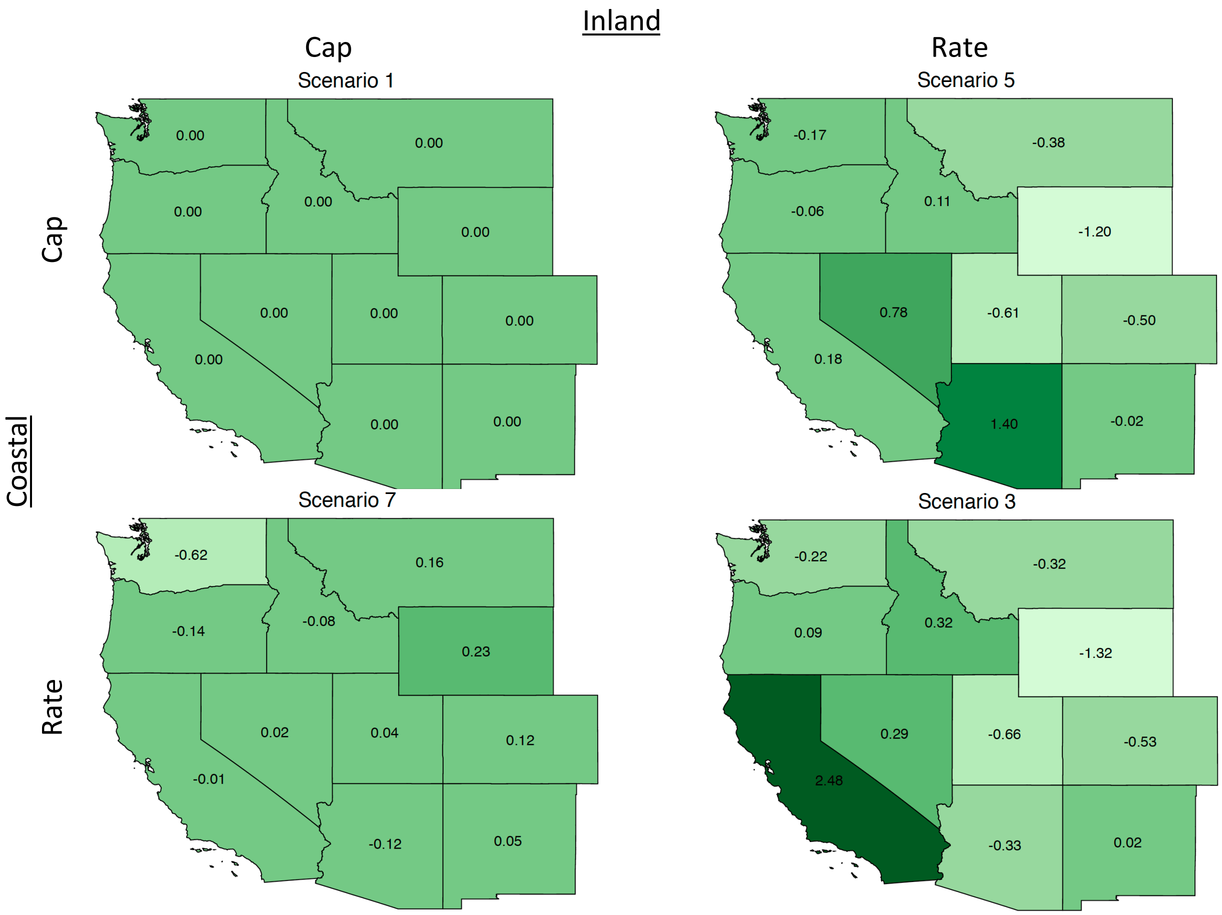

Note: Profit changes in \$ billion relative to BAU.

**Figure 20:** Profit incentives for uncovered generation under uniform and mixed regulation.




Note: Profit changes in $ billion relative to BAU.

**Figure 21:** Deadweight loss under uniform and mixed regulation.




Note: Deadweight loss in \$ billion relative to uniform mass-based with carbon permit price and social cost of carbon equal to \$35 per ton.

# Appendices

## A Proofs

### A.1 Proof of Result 1

The merit order is efficient for regulation $r$ if $FMC^r_{si} < FMC^r_{s'i'}$ iff $c_i + \beta_i\tau < c_{i'} + \beta_{i'}\tau$.

Result 1 $(i)$ follows because for mass-based standards $FMC^{MB}_{si} = c_i + \beta_i p_{cs}$. Clearly this merit order is efficient if $p_{cs} = \tau$ for every $s$. The result also holds if $p_{cs} \neq \tau$ and $|p_{cs} - \tau| \leq \min_{i,j} |\frac{c_i - c_j}{\beta_j - \beta_i} - \tau|$, i.e., if $p_{cs}$ is sufficiently close to $\tau$.

To see this, assume, without loss of generality, that $\beta_j > \beta_i$. First consider the case in which $c_i + \beta_i\tau < c_j + \beta_j\tau$, i.e., in which $\tau - \frac{c_i - c_j}{\beta_j - \beta_i} > 0$. Then $c_i + \beta_i p_{cs} < c_j + \beta_j p_{cs}$ iff $\frac{c_i - c_j}{\beta_j - \beta_i} < p_{cs}$ iff $\tau - \frac{c_i - c_j}{\beta_j - \beta_i} > \tau - p_{cs}$. But this last condition clearly holds because $p_{cs}$ is sufficiently close to $\tau$.

Next consider the case in which $c_i + \beta_i\tau > c_j + \beta_j\tau$, i.e., in which $\frac{c_i - c_j}{\beta_j - \beta_i} - \tau > 0$. Then $c_i + \beta_i p_{cs} > c_j + \beta_j p_{cs}$ iff $\frac{c_i - c_j}{\beta_j - \beta_i} > p_{cs}$ iff $\frac{c_i - c_j}{\beta_j - \beta_i} - \tau > p_{cs} - \tau$. But this last condition clearly holds because $p_{cs}$ is sufficiently close to $\tau$.

Result 1 $(ii)$ follows because for rate-based standards $FMC^{RB}_{si} = c_i + (\beta_i - \sigma_s)p_{cs}$. If the carbon price is $\tau$ and rate standard is $\sigma$ in all states, $FMC^{RB}_{si} < FMC^{RB}_{s'i'}$ iff $c_i + (\beta_i - \sigma)\tau < c_{i'} + (\beta_{i'} - \sigma)\tau$ iff $c_i + \beta_i\tau < c_{i'} + \beta_{i'}\tau$. Clearly, this result can still hold if $p_{cs}$ is sufficiently close to $\tau$ and $\sigma_s$ is sufficiently close to $\sigma$ for every $s$.

To demonstrate Result 1 $(iii)$, assume without loss of generality that $c_i + \beta_i\tau < c_{i'} + \beta_{i'}\tau$ so that the sufficient condition is $c_{i'} + \beta_{i'}\tau - c_i + \beta_i\tau > \sigma\tau$. First, let state $s$ have a rate-based based standard and state $s'$ have a mass-based standard. Then $FMC^{RB}_{si} = c_i + (\beta_i - \sigma)\tau < c_i + \beta_i\tau < c_{i'} + \beta_{i'}\tau = FMC^{MB}_{s'i'}$, i.e., the merit order is efficient. Next, let state $s$ have a rate-based based standard and state $s'$ have a mass-based standard. Then $FMC^{MB}_{si} = c_i + \beta_i\tau < c_{i'} + (\beta_{i'} - \sigma_{s'})\tau = FMC^{RB}_{s'i'}$ where the inequality follows from the sufficient condition.

### A.2 Proof of Corollary 1

If demand is perfectly inelastic, then consumption cannot be inefficient, and efficiency of the regulation merely requires efficiency of supply.

If demand is not perfectly inelastic, then consumption is only efficient if the electriciy price reflects the full marginal social cost. The only regulation in which the electricity price equals the full marginal social cost is a mass-based standard with carbon price $\tau$.

## A.3 Proof of Result 2

Carbon trading reduces costs since firms would only undertake mutually beneficial trades if costs are reduced.

Trading between states with mass-based standards holds aggregate emissions constant because the equilibrium in the carbon market is determined by $\sum_t \sum_i \beta_i q_{sit}^{MB} + \sum_t \sum_i \beta_i q_{s'it}^{MB} = E_s + E_{s'}$. which holds aggregate emissions constant at $E_s + E_{s'}$.

Trading between states with rate-based standards may cause aggregate emissions to increase or decrease. As shown in [2], carbon trading across states with rate-based standards results in a carbon intensity which is a weighted average of the intensity standards of the two states. Rewriting [2], shows that

$$\sum_i \sum_t \beta_i (q_{sit}^{RB} + q_{s'it}^{RB}) = \sum_i \sum_t q_{sit}^{RB} \sigma_s + \sum_i \sum_t q_{s'it}^{RB} \sigma_{s'}.$$

Defining policies $RBT$ and $RBNT$ as "trading" and "no trading" and defining $Q_s^r \equiv \sum_i \sum_t q_{sit}^r$, this equation implies:

$$Carbon_s^{RBT} + Carbon_{s'}^{RBT} = Q_s^{RBT} \sigma_s + Q_{s'}^{RBT} \sigma_{s'}$$

which can be rewritten as

$$Carbon_s^{RBT} + Carbon_{s'}^{RBT} = \frac{Q_s^{RBT}}{Q_s^{RBNT}} Carbon_s^{RBNT} + \frac{Q_{s'}^{RBT}}{Q_{s'}^{RBNT}} Carbon_{s'}^{RBNT}.$$

This equation relates carbon emissions with trading to carbon emissions without trading and shows that carbon trading has an ambiguous affect on aggregate carbon emissions.

## A.4 Proof of Result 3

Result 3 $(i)$ follows from a comparison of the full marginal costs. Under mass-based standards, $FMC_{si}^{MB} = c_i + \beta_i p_{cs}$. Since $FMC_{si}^{MB} \geq c_i = FMC_{si}^{BAU}$ for every $s$ and $i$ the electriciy price is higher under mass-based standards than under no regulation.

Since $FMC_{si}^{RB} = c_i + (\beta_i - \sigma_s)p_{cs}$, it follows that $FMC_{si}^{RB} \leq FMC_{si}^{MB}$ for every $s$ and $i$ and thus the electricity price is lower under rate-based standards than under mass-based standards.

Moreover, since $(\beta_i - \sigma_s)$ can be positive or negative, it follows that the electricity price under rate-based standards can be higher or lower than under no regulation.

Result 3 $(ii)$ follows directly from the comparison of electricity prices in Result 3 $(i)$ because higher electricity prices result in lower consumer surplus from electricity consumption.

Result 3 $(iii)$ also follows directly from the comparison of electricity prices in Result 3 $(i)$. For an uncovered generator, their costs are unaffected by the regulations. Thus regulations only affect their profit through the electricity prices and higher electricity prices imply higher profit.

## A.5 Proof of Result 4

Result 4 $(i)$ follows by comparing full marginal costs under mass- and rate-base standards. Since the merit order is the same across the two scenarios, Because full marginal costs are lower by $\sigma\tau$ under rate-based standards, prices are also lower by exactly this amount if demand is perfectly inelastic. If demand is not perfectly inelastic, then a price which is lower by $\sigma\tau$ could result in excess demand. Thus the price difference is at most $\sigma\tau$.

Result 4 $(ii)$ follows readily by noting that prices are lower under rate-based standards and hence equilibrium electricity generation is higher. If demand is prefectly inelastic, equilibrium electricity generation is unchanged.

Result 4 $(iii)$ follows by noting that in the case of perfectly inelastic demand, prices and full marginal costs both differ in the two scenarios by exactly $\sigma\tau$; i.e., margins are equal. Because quantities are fixed and margins are identical across the scenarios, profits are equal across the scenarios for each technology. If demand is not perfectly inelastic, costs are lower by $\sigma\tau$ but prices are lower by at most $\sigma\tau$ under rate-based standards. Thus margins are higher under rate-based standards. Because quantities are also greater, profits cannot fall.

Result 4 $(iv)$, $(v)$, and $(vi)$ follow because equal carbon prices and equal rate standards across the scenarios ensure that the merit order is identical across the scenarios. Fixed quantities under perfectly inelastic demand, then ensure that costs, carbon emissions, and welfare are identical across the scenarios. If demand is not perfectly inelastic, the higher quantities imply that quantities and costs are higher. The inefficiency of rate-based standards when demand is not perfectly inelastic, described in Corollary 1, implies that welfare is weakly greater under mass-based standards.

Result 4 ($vii$) follows directly from Result 4 ($vi$) since $W^{MB} = CS^{MB} + \pi^{MB} + TR^{MB} - \tau Carbon^{MB}$ and $W^{RB} = CS^{RB} + \pi^{RB} - \tau Carbon^{RB}$ .

## A.6 Proof of Result 5

Result 5 ($i$) follows from noting that if state $s$ adopts a rate-based standard, the full marginal costs of all generators in state $s$ decrease by $\sigma_s \tau$, but the full marginal costs of generators in other states are unchanged. Thus the electricity price in hour $t$ falls by $\sigma_s \tau$ if a generator in state $s$ is marginal in that hour under both a mass- and a rate-based standard, i.e., $p_t^{RBx} = p_t^{MBx} - \sigma_s \tau$. Alternatively if a generator from state $s$ is not on the margin in hour $t$, the price is unchanged, i.e., $p_t^{MBx} = p_t^{RBx}$. Finally, for all other situations (e.g., if a generator in state $s$ goes from being marginal to non-marginal) the electricity price falls by at most $\sigma_s \tau$.

Result 5 ($ii$) follows directly from ($i$). If state $s$ switches to a rate-based standard, the full marginal costs of generators in state $s$ fall by $\sigma\tau$, but the price falls by at most $\sigma\tau$, so margins increase. Since generation does not decrease profits increase.

Result 5 ($iii$) follows directly from ($i$), because electriciy prices are lower if state $s$ switches to a rate-based standard.

Result 5 ($iv$) follows since carbon market revenue is positive under a mass-based standard but is zero under a rate-based standard.

Result 5 ($v$) follows because welfare can increase or decrease with one state switching from a mass- to a rate-based standard. The results in Table 1 show that welfare can increase with adoption of a rate-based standard, which implies that $CS_s^{MBx} + TR_s^{MBx} + \sum_i \pi_{is}^{MBx} < CS_s^{RBx} + \sum_i \pi_{is}^{RBx}$. The other inequality holds if welfare decreases.[34]

[34] This result could be stated more precisely.