# California's Greenhouse Gas Policies: How Do They Add Up?

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**Abstract**

California is implementing a broad portfolio of regulations aimed at reducing greenhouse gas emissions. However, many of these policies, if undertaken without the cooperation of neighboring states may result in far less reductions in emissions than the stated goals. This paper summarizes the initiatives likely to impact the electricity generating sector. We present calculations showing that there is a substantial risk that two of the most prominent policies could simply result in a reshuffling, on paper, of the electricity generating resources within the West that are dedicated to serving California. The problem is similar to an ineffective consumer boycott. The problem is mitigated if more western states adopt carbon limitations, but leakage and reshuffling remain serious concerns.

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## 1.0 Introduction

In the United States, climate change policies are being driven at the local, rather than national, level. Among the states pushing climate change policies, California is arguably pushing the hardest. With a series of ambitious policy initiatives focused on reducing emissions of greenhouse gases, California policy makers have drawn much attention to efforts to combat climate change. California's initiatives span the gamut of regulatory approaches. The state is pursuing market mechanisms such as cap-and-trade, and interventionist regulations, aimed, for instance, at altering electricity fuel choice, household energy use, and automotive emissions.

In this paper, we examine the mix of policies brought to bear on GHG emissions in California, focusing on the electricity industry. While some policies will affect broad sectors of the economy, we analyze how different measures vary in their impact on the electric sector. CO2 emissions from the electricity industry are considerably higher than emissions from other stationary sources, and many expect the electric sector to bear a disproportionate responsibility for carbon reductions.

The electricity industry also offers an illuminating case of environmental regulation in the context of incomplete jurisdictional control. Because California (as well as all other mainland U.S. states except Texas) operates as part of a larger regional electricity system, its policies are inherently susceptible to circumvention from firms who participate in the state's electricity system, but are located outside its political control. This is a fundamental challenge of implementing climate change policies at a local level.

Although many regulatory policies are subject to circumvention when applied at a local level, the degree to which this will happen depends upon both the specific regulation and the context in which it is applied. For example, we demonstrate how a market-based cap-and-trade policy, when applied only to California, could have very little effect on carbon emissions from the electricity sector.[1] This outcome is possible irrespective of whether the cap-and-trade metric is *producer-based* or *consumption-based*.[2]

Others have identified the *leakage* problem, where regulation of one region can cause economic activity, including the associated pollution, to move to the unregulated region (see, e.g., Fowlie 2007). Leakage is particularly problematic with a producer-based metric. Specifically, electric generators can move outside of the regulatory jurisdiction,

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[1] California Assembly Bill 32 (AB 32), in many ways the capstone piece of legislation in California, calls for an overall reduction in greenhouse gas emissions to 1990 levels by 2020. While the law does not mandate cap-and-trade, it suggests that it be used, and all of the recent policy discussions have included some form of cap-and-trade market.

[2] A producer-based cap-and-trade regulates only those electric plants within the state's regulatory jurisdiction – a significant problem for California, which imports over 20% of its electricity and 50% of its carbon from electricity. A consumption-based policy attempts to mitigate this issue by applying an emissions cap to all electricity consumption, and not merely production.

but still sell their product to the consumers in the regulated area (and, if they choose, to consumers in the unregulated area).

We show, however, that even under a consumption-based metric, California's electric utilities could still achieve their 1990 emissions levels by contracting to buy power from different sources. Essentially, there is enough existing low-carbon electricity in the West to meet all of California's projected demand in 2020 by simply reshuffling existing transactions. Unlike with leakage, with *reshuffling* of this sort, the physical plants do not relocate, indeed production patterns may not change at all, but contracts between consumers and generators do shift. Such a shift is possible as long as only some electricity customers are subject to the regulation and a sufficient amount of compliant energy is already available to meet their demand. As such, the reshuffling could be achieved, and targets met, without any change in the carbon output from electricity generation. As we demonstrate, the potential for regulatory circumvention becomes less extreme, but does not disappear, when the jurisdiction is expanded to include the multiple states and provinces currently pledged to participate in the on-going Western Climate Initiative.

While some associate these regulatory jurisdiction problems solely with market-based environmental regulations such as cap-and –trade, similar problems arise when climate policies are implemented through more traditional command and control regulations, such as plant-specific emissions rates. For example, we consider two other policies that directly impact the electricity sector in California: the renewable portfolio standard (RPS), which was articulated in senate bill 1078 and which requires electric utilities to procure a certain fraction of their power from generators using renewable fuels, and senate bill 1368 (SB 1368), which limits greenhouse gas emissions at the plant level. The important difference between these policies is that the RPS cannot be achieved with imports from pre-existing sources of renewable power from outside of California, since there is little pre-existing capacity, while it appears that the goals of AB 32 and SB 1368 can be. In other words, the goals of the RPS are binding even if sources are expanded to the entire western U.S., while the other GHG policies are not.

Comparing the emissions reduction potential of a cap-and-trade policy versus an RPS, two features of the latter emerge as salient determinants of the achievement of real reductions. First, the more flexible nature of cap-and-trade (a key feature of market-based mechanisms) offers wider opportunities for firms to engage in reshuffling. Second, the cost-imposing nature of a cap-and-trade program, as compared to the subsidy nature of an RPS, results in greater economic incentive for firms to engage in leakage-inducing shifts in production. The extent of both the *opportunities* and *motivations for* leakage and reshuffling factor into the ultimate success of a California-only climate change policy (see Bushnell, Peterman, and Wolfram 2008 for a broader discussion of leakage and reshuffling).

In other words, cost imposing and flexible, market-based mechanisms appear unlikely to reduce carbon emissions from the electricity sector when applied to California alone. On a national scale however, reshuffling and leakage are less of a concern, particularly in the case of electricity generation, so the cost-efficiency benefits of market-based mechanisms like cap-and-trade make them more attractive. Less flexible subsidy policies such as an RPS, while likely to reduce carbon emissions in California, are more costly on a national scale. Further, unlike a more flexible carbon cap, it does not reward generation from non-renewable sources of low carbon power, and rewards energy conservation only very weakly.

Our results point to the inherent policy questions a small jurisdiction like California must face: Is the goal to truly *reduce* greenhouse gas emissions, and not just cause the sources to change location? Or is the goal to stimulate innovation in technologies that could be attractive even in regions not currently active in climate change policies?

This paper proceeds by outlining the three major policy initiatives that will impact greenhouse gas output from the electricity sector in California. In section two we provide an overview of the renewable portfolio standard, and comment on its similarities to other subsidy policies designed to encourage low carbon technologies. In sections three and four we discuss and offer quantitative analysis of emissions limits (i.e. SB 1368) and the cap and trade program (likely to be implemented through AB 32), respectively. Section five ends with some concluding thoughts on the likely impacts of California's GHG policies.

## 2.0 The Renewable Portfolio Standard

Nationally, there has been a steady advance of renewable portfolio standards. More than 25 states plus the District of Columbia have some form of mandatory or voluntary renewable requirement as of this writing. California's RPS is one of the most aggressive. Specifically, California senate bill SB1078, requires all electric utilities in California to procure at least 20% of their electrical energy from renewable sources by 2010.[3] Although California has the highest near-term target, by 2020 the remaining RPS states aim to meet 8-30% of total electricity consumption with renewable resources.

As a policy instrument, the RPS stands in contrast to regulations that are directed at making emissions of GHGs more costly, such as a tax on those emissions. By requiring utilities to buy a certain amount of renewable power, even if it is more expensive than conventional power, the RPS is similar to a subsidy. Unlike more targeted programs, such as direct rebates for solar photovoltaic installations like the California Solar Initiative, an RPS forces the various renewable technologies to compete against each other. In theory, the "best" (or lowest cost) choices amongst renewable options will come to dominate the portfolios of the buyers. Thus, for example, if solar PV continues

[3] In the California RPS, "renewable" electricity is defined as energy generated from conventional renewable sources such as solar thermal, solar PV, wind, geothermal, biomass and hydro. Large hydro projects (greater than 30MW) are not considered renewable.

to be one of the most expensive renewable options, utilities are free to invest in other more economic choices.[4]

Although it is difficult to determine the direct effect RPS programs have had on renewable generation, since 2002, 60% of the non-hydro renewable capacity additions in the U.S. occurred in states with RPS programs.[5] This percentage increased to approximately 76% in 2007 and is likely to further increase as RPS targets become more binding. Of the new renewable capacity that has come on line in RPS states from 1998 through 2007, approximately 93% has come from wind power (Wiser and Barbose, 2008, p.13). The dominance of wind, one of the most economic renewable energy resources, is not surprising given buyers' flexibility to choose the lowest cost compliance under RPS programs. In this way the RPS shares some features of more market-based, flexible approaches to regulation.

The RPS also has its limitations. Because of its focus on the fuel inputs, rather than carbon output, firms do not benefit from alternative solutions to the emissions challenge, such as energy-efficiency, carbon sequestration, or nuclear power. A few U.S. states, Hawaii, Nevada, and North Carolina have designed their RPS' to allow for energy-efficiency; however this is far from the norm. Many observers believe that significant investment in some or all of these non-renewable alternatives will be necessary to achieve long-term GHG reductions goals.

Further, although there are aspects of inter-resource competition in the RPS, the playing field may not be completely level. For example, when accounting for the costs of various renewable technologies, it is not clear how the costs of new transmission, which will likely reach many billions of dollars, will be treated. California has made gains in addressing this concern with FERC approval of a financing mechanism to delay renewable generator transmission funding obligations until after generation is built.[6] The transmission problem has also been exacerbated by the focus on getting the renewable power "into" California. From a climate policy perspective, wind power is just as useful if it displaces coal generation in Canada, than if it is "imported" into California. The RPS does not allow for this kind of substitution to apply to the portfolio obligations of California utilities. Last, some renewable sources such as biomass, may have questionable GHG benefits.

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[4] See Borenstein (2008) for an analysis of the costs of solar PV.

[5] Additional factors likely responsible for new renewable capacity include: federal incentives, other state incentives, and the presence of state potential renewable resources. See Wiser and Barbose 2008 for further discussion of these factors.

[6] The California Independent System Operator (CAISO) received FERC approval of this funding concept in *Order Granting Petition for Declaratory Order* issued on April 19, 2007 in Docket No. EL07-33 (Cal. lndep. Sys. Operator Corp., 119 FERC 61,061, reh'g denied 120 FERC 61,244 (2007)).

A last issue of direct relevance to our discussion is whether an RPS would actually stimulate *new* renewable investment, rather than simply a reallocation of the cost for existing renewable energy. If enough clean resources existed outside of the state, then an RPS could in theory be subject to reshuffling. For example, if California had an RPS, but no other state in the West did, and if considerable renewable resources existed outside of California, utilities could satisfy the requirement by buying from the existing suppliers without altering the overall carbon emissions associated with electric generation in the West. In fact, the amount of renewable capacity necessary to meet California's RPS obligations does not yet exist in California or anywhere else in the western U.S. (see Table 1). Further, a number of other western states also have RPS obligations, so the option to export dirty power and import the renewable energy of other states does not exist. As a result, the RPS in California as well as those in other states have been and will continue to be a strongly binding regulation that is changing the procurement practices of electric utilities.

## 3.0 California's GHG Emissions Standard

In addition to the indirect subsidies to low-emissions technologies provided by the RPS, local jurisdictions are also applying more traditional regulations to limit emissions from conventional sources. California Senate Bill 1368 establishes an output-based emissions standard for "baseload" power plants. Specifically, it requires that all power plants that California utilities either sign long-term contracts with for non-peak power, invest in, or build themselves, meet a standard that limits their emissions to be no greater than a current combined-cycle natural gas (CCGT) plant.

By restricting the set of plants from which the utilities can procure baseload power, SB 1368, to the extent it binds, is likely to be a cost-imposing standard. As we have discussed above, cost-imposing regulations can lead to leakage, as the firms take measures to escape the regulatory jurisdiction that imposes the costs. With SB 1368, although the retail providers of electricity cannot reasonably move out of California and power plants subject to this standard cannot physically move production outside of the regulatory jurisdiction (the traditional conceptualization of leakage), utilities can move their transactions outside of the law's regulatory reach. Instead of offering long-term contracts for baseload power, at least some plants will be able to offer their output under short-term contract, on the spot market, and at capacity factors below the baseload definition. In this way the standard offers similar incentives for cost avoidance and regulatory circumvention.

On its face, SB 1368 appears quite inflexible, as it covers all types of plants from which a utility might procure power, whether through contracts or investment, and as it does not permit them to offset emissions from high carbon plants with lower carbon generation sources. This might appear to mitigate the opportunities for reshuffling, which we have argued is more prevalent with more flexible regulations. Unfortunately, as we show below, enough low carbon resources exist in the West relative to California's demand that utilities are likely to be able to comply with SB 1368 by simply rearranging from whom they buy power.

### *3.1 Analysis of SB 1368*

To evaluate the possible impacts of SB 1368, we assessed whether existing resources provided enough "clean" supply to meet California's current and expected demand. Our data and specific assumptions are described more fully in the data appendix. At a general level, our analysis involves several steps. First, we define the market from which California could potentially procure power as the area encompassed by the Western Electric Coordinating Council (WECC). This is the interconnected transmission grid roughly covering the area west of the Rockies. SB1368 implements a maximum $CO_2$ emissions level based on a CCGT plant, so we next develop a list of the universe of plants in the WECC whose emissions fall below this level. Existing plants owned by California utilities are not affected by the emissions standard, so these were also included in the list of compliant plants. Since the requirement only applies to plants meeting baseload power needs, we limit the clean set to plants to those with capacity factors greater than 60 percent. Finally, we assess whether output from these "clean" plants, if kept at historical levels, would cover California's baseload electricity demand.

Figure 1 summarizes the results of this analysis. The bar on the left of the figure depicts the energy output in 2005 from all baseload plants in the WECC by fuel type.[7] The bar on the right reflects the energy output from the subset of plants from which California firms could purchase power under SB 1368. Carbon emissions from coal plants are roughly twice as high as carbon emissions from a gas plant, so none of the coal plants are compliant (save the coal plants owned or contracted for by California utilities which were grandfathered). By contrast, nuclear and hydro output, accounting for 230.3TWh of the 2005 energy output in the WECC, have no carbon emissions.

We calculated the demand in California that would have been served by baseload plants in 2005 (i.e., demand in hours where the hourly load level was achieved in at least 60% of the hours) and have indicated this level on Figure 1 with the dashed line. As the figure depicts, California could cover its baseload power needs from clean western plants and there would still be 58 TWh of clean supply remaining in the WECC. Put another way, for every 3 TWh of clean power that California would need to contract with, it would have almost 4 TWh of supply to choose from. Note that our analysis produces a conservative estimate of the remaining clean supply because we do not automatically deem compliant plants outside of California from which California utilities are already purchasing power under long-term contracts, and we do not recalculate emission rates from cogeneration facilities to account for reduced emissions from thermal loads.[8]

[7] For purposes of this analysis we defined baseload as operating with at least a 60% capacity factor during 2005.
[8] SB1368 requires a recalculation of cogeneration emission rates to account for emissions savings from reduced gas usage. Such a recalculation may allow some cogeneration facilities in our analysis to pass SB1368 that currently do not.

Several comments give these results context. Recall that SB 1368 exempts plants owned by, or already contracted to, California utilities, so by design the policy will primarily affect from whom California imports power. California imports about one-fifth of its power, but over half of the carbon attributed to California electricity production was from the imports (see Farrell, Kammen and Ling, 2006). The carbon-intensity of the supply in the WECC outside of California is essentially bi-modal, however, with 35% of the supply coming from zero carbon sources like hydro-, nuclear- and wind-powered sources and 47% of the supply coming from carbon-intensive coal sources. Given these features of the Western electricity markets, the standard set by SB 1368 are straightforward to circumvent.

Beyond the surplus of clean power already available in neighboring states, other attributes of the policy could weaken its impact. In particular, purchases made from generation units that run less than 60% are not required to comply with the standard.[9] Also generation bought through short-term purchases, such as the daily wholesale power market, are exempted from the standard. There is a risk that these features will result in more short-term purchases and more generation that runs at 59% capacity factors, rather than cleaner power. In light of these facts, it seems unlikely that SB 1368 will meaningfully affect the carbon-intensity of the power sector in the WECC for the foreseeable future.

SB 1368 may have been designed primarily as a stop-gap measure to prevent significant investment in carbon-intensive generating plants before the overall carbon limitations associated with AB 32 are phased in. Unfortunately, since California is but one buyer from the Western electricity markets, coal plants can be built as long as the power is sold to customers outside of California. For example, Sierra Pacific Resources, a Nevada utility is proceeding with plans to build a 1,500MW coal plant called the Ely Energy Center. Reacting to SB 1368, the Sierra Pacific Resources spokesperson said, "The Ely center is needed here in Nevada just to keep up with the enormous growth that we are experiencing…. The Ely center will generate energy for the state of Nevada," (see California Energy Markets, 2007, p.12). Further expansion of coal capacity in states like Nevada could free up low-carbon sources currently consumed in these states for sale into California. Note that since electrons follow the laws of physics and not the directives of financial contracts, Californians will still be consuming some of the power from coal plants like the Ely Energy Center, even if SB 1368 forbids California utilities from contracting with them.

[9]The exemption is in place because the best technologies for meeting peak demand are natural gas fired combustion turbines. These technologies are relatively low capital cost, but have fuel efficiency and emission profiles worse than the CCGT plants upon which the standard is based. It would be impractical to operate natural gas plants to "follow load" as the more nimble, combustion turbines are designed to do.

## 4.0 Cap-and-Trade for GHG in California

The most expansive of California's GHG policies are those that could emanate from the process initiated by California Assembly Bill 32 (AB 32). The bill itself does not establish specific policies, but rather articulates an overall goal of reducing California's GHG emissions to 1990 levels by 2020. Unlike the RPS and SB 1368, the scope of AB 32 extends well beyond the electricity industry to include most major sources of GHG emissions. Market-based regulatory tools, such as a cap-and-trade program, have been widely discussed as a means of AB32 compliance, but are also somewhat controversial.

A key benefit of market-based policies is that they are the most flexible type of cost-imposing regulations. Unlike technology standards, market-based policies offer full flexibility by neither dictating the *who* nor the *how* of GHG mitigation. Instead such policies rely on the emission credit price signals to solicit the most economically efficient set of emissions reductions. In theory such policies should result in emissions reductions to the level of the cap, without requiring perfect knowledge of firms' costs by the regulator. However, the flexibility of such policies coupled with their cost imposing nature also renders them more prone to reshuffling and leakage.

It is important to note that leakage and reshuffling are usually not a concern when the damage from the pollutant is a local problem, such as urban smog. When a regulation encourages plants that contribute to smog problems to move from the LA basin to a more remote area where smog is not a problem, this can in fact be a beneficial outcome to all involved.[10]

However, when the problem is global climate change, the migration of GHG emitting plants to other states does not help Californians at all. Local concentrations of carbon are not the concern, but rather global concentrations. The earth does not care where the carbon comes from, just how much there is.

Since a specific framework for a cap-and-trade system for CO2, or perhaps all GHG, is being seriously considered, it is important to examine the likely implications of such a system when applied to California. Because no detailed program has yet emerged, we must make some assumptions about the exact nature of the program. We first consider a policy aimed at reducing California's GHG emissions attributable to electricity consumption to 1990 levels, and then turn to an analysis of a program involving more Western states.

Currently, there are several possible approaches to measuring the amount of emissions from California's electricity industry. A producer-based measure would regulate GHGs emitted only from plants physically located within California. This is a problematic approach in this context, since a substantial fraction of California's electricity and a

[10] This assumes that the new plants do not create severe smog problems in their new locations.

majority of the GHG emissions, come from plants outside of California.[11] There is significant concern that a producer-based standard could be easily circumvented by simply increasing net imports from outside of California. These imports would count as perfectly "clean" under a producer-based standard. A consumption-based approach would regulate purchases by California utilities, regardless of where the supplier is located.

The Market Advisory Committee, a panel of experts convened by the California EPA, has recommended a hybrid system known as the *first-seller* approach that would effectively act as a producer-based system for plants within California and a consumption-based system for imported power (MAC, 2007). The California Public Utilities Commission and the California Energy Commission recommend that the point of regulation be the deliverer, a variation of the first-seller (CPUC, 2008). Under such an approach the regulation would be of the entity that is responsible for the electricity either at the point of delivery on the California transmission grid or where the generator's facilities connect to the transmission grid. Under such a system, generators, retail providers, marketers, and brokers can all be regulated entities.

We focus here on consumption-based and first-seller/deliverer approaches. While these approaches may seem less likely to be circumvented through imports, even these systems are vulnerable to a reshuffling of transactions. Utilities inside California can reduce their purchases from dirty plants and increase their purchases from existing clean ones, and firms outside of California could do the reverse.

### *4.1 Analysis of AB 32*

To assess the risks of potential reshuffling, we again examine the mix of generation available in the western electricity market. Table 2 shows the amount of energy produced in 2005 from each major fuel source in each sub-region of the western market. As is evident from this table, the amount of energy from zero-carbon sources, mainly hydro and nuclear, is substantial. Also note that California has a relatively clean fuel mix (at least with regards to CO2), with large amounts of nuclear and hydro production and comparatively little coal production. To examine whether there is enough low-carbon capacity to meet California's AB 32 goals for electricity, we use a projection of California's 2020 electricity demand of about 341 TWh.[12] The CO2 emissions created to serve California demand in 1990 was approximately 82 million metric tons (MMT), so we use this as the target for 2020.

[11] The accounting of production is complicated somewhat by the fact that there is coal capacity owned by (or contracted to) California utilities that is located outside of California but connected in such a way that, electrically, it is treated as within California. The CEC attributes over 28 TWh of electricity generation to plants that fall in this category.

[12] This number is comparable to the CEC's forecast of 340 TWh. For details see the appendix.

Figure 2 plots the cumulative CO2 emissions from power plants in the West in 2005 against the cumulative TWh of electricity produced by these plants, where the TWh are assumed to come from the lowest carbon sources first. For example, the function is equal to zero for the first 279 TWh of output because zero carbon sources produced 279 TWh of output in 2005. The horizontal line in Figure 2 is drawn at the emissions level that California would need to achieve to meet the AB 32 standard (the 1990 level of 82 MMT) and the vertical line is drawn at the projected 2020 demand (341 TWh). The function crosses the vertical line before it crosses the horizontal line, suggesting that California could procure power in the western markets in 2020 from existing clean sources without exceeding 1990 carbon emissions levels. This implies that even a consumption-based standard for California is at serious risk of circumvention through a reshuffling of energy sources amongst the western states.

Our analysis reflects many important underlying assumptions about the willingness and ability of western electricity firms to trade their electricity. It is intended as an illustrative calculation to indicate the potential severity of the problem, rather than a forecast of what is likely to happen. That said, we can consider several of the most likely impediments to a complete reshuffling of energy sources in a relatively straightforward way, and they do not change the overall conclusion that California is not a large enough player in the western electricity market to cause substantive change with a cap-and-trade policy.

First, we consider the fact that the ability to import power is limited by the transmission network. These constraints stem from limits on the aggregate capacity on important transmission interfaces between California and other states and the need for a non-trivial amount of generation to be operating near load centers for voltage support and other reliability considerations. A rough approximation of these "local" needs would be to take California's 2005 generation, and assume it continues unchanged. In other words we limit the ability of firms to "swap" power generated within California for power generated outside of California. As Figure 3 demonstrates, this adjustment does little to change the overall conclusion. Since it is California's current imports that are its high-carbon sources, a rearrangement of the power that is imported into California is sufficient to meet the AB 32 target.[13]

A second observation is that institutional and contractual arrangements may limit the willingness or ability of some firms to sell their "clean" power to California. For

[13] Note that a reshuffling of imported power amongst "importing" states need not cause any additional transmission congestion. Although there are strict physical limits on how much hydro power flows south from the Pacific Northwest, these flows can be offset by flows of coal production from the Southwest up to the Northwest. If, for example, northwestern or Canadian utilities simply "swapped" the energy from their own hydro production with energy from LADWPs Intermountain coal plant, there would be a change of carbon accounting on paper, but no net change in the actual flows of electricity. Of course these utilities would likely receive some extra payments from California utilities for engaging in the transaction.

example, much of the power generated by Federal water projects and marketed by the Bonneville Power Administration (BPA) is allocated according to a Byzantine set of procedures that do not closely resemble market activity. The firms that buy power from BPA, however, are not necessarily operating under the same limitations, and so they may be able to resell that power.

Given that these limitations may exist, it is worthwhile to examine just how much reshuffling has to occur for the targets of AB 32 to be undermined. Even if we assume that California cannot buy any energy produced by BPA (even though it does purchase some today) and must use its instate generation (as we assumed above), it can stay just inside the 1990 emissions levels at 2020 demand by importing power from clean suppliers other than BPA.

It is also important to recognize several important factors that we have left out of our analysis that would make it *more* likely that AB 32 would not significantly impact the electricity industry in 2020. We are not including Canadian electricity generation, even though there is currently substantial power traded between California and British Columbia, and the majority British Columbia's electricity is generated from zero-carbon hydro sources. We have also not accounted for the additional zero-carbon capacity that is almost certain to be added as a consequence of the various RPS in western states. California's RPS alone implies that an additional 30 TWh of low carbon energy will be added to its system. Finally, we have assumed that plants will generate the same output in 2020 as they did in 2005. Older plants tend to be run less intensively, so if the supply that is added between now and 2020 is cleaner than the output it is replacing, the standards will be easier to meet.

The reshuffling in the electricity sector could impact the effectiveness of AB 32 in other sectors. If the cap-and-trade system allows trading across sectors, than electric companies could sell any excess allowances they create by reshuffling. Firms in other sectors could purchase the allowances created by reshuffling instead of actually reducing the carbon emissions from their production processes. This would limit the ability of a cap and trade system to reduce emissions in other sectors of the economy.

### *4.2 Regulatory Restrictions on Reshuffling*

While the above analysis implies that a consumption-based cap-and-trade system is highly vulnerable to a reshuffling of energy sources if it is applied only to California, it is possible that additional regulatory restrictions could limit this effect. For example, limits on the ability of firms to reshuffle their purchases can be imposed through the rules accounting for the carbon emissions of imports. Consider a rule that assigned to all imports an emissions level equal to the average emissions of all western power plants. Under this rule, there would be no benefit to switching suppliers, as the emissions from all suppliers are assumed by the regulator to be equal anyway. Such a rule would likely raise legal challenges if applied only to out-of-state resources, however, as it could be viewed as discriminatory.

A more nuanced form of this approach emerged in the CEC-CPUC recommendation (CPUC, 2008) The CEC-CPUC suggest assigning a default emissions rate of 1,100lbs CO2 MWh (similar to a CCGT) for all power purchases that are not linked contractually to a specific power plant. Firms would have the option of identifying a specific source of power, and would presumably do so only in the event the emissions of that plant were below the 1,100lbs/MWh default level. However, the proposed rule would *not* allow firms to benefit from new imports from *existing* nuclear and hydro facilities. In other words, firms can only opt-out of the default 1,100 lbs/MWh value by claiming a contract with an existing thermal plant or *new* hydro or nuclear facility.[14]

Such a rule would reduce the ability of California firms to access hydro and nuclear resources available in the rest of the WECC. We evaluate the potential impact of such a rule by excluding all hydro and nuclear energy that was not assigned to a California buyer in 2005 and repeating the analysis presented in Figures 2 and 3. Figure 4 summarizes these results. The solid line reflects the cumulative actual emissions of power plants in 2005 – again excluding hydro and nuclear sales not dedicated to California buyers. The dashed line reflects the cumulative value of emissions if one assumes that any plant with an emissions rate greater than 1,100 lbs/MWh opts to be rated at this default value. Thus no plant appears dirtier than this default value. This lower, dashed line, would reflect the emissions values used by regulators under these accounting rules. Note that actual emissions are above the accounting value for emissions (as reflected by the vertical distance between the solid and dashed lines). However, because of the exclusion of existing hydro and nuclear facilities as "clean" imports, there is insufficient production from clean plants in 2005 to completely cover California's 2020 electricity demand and stay below its 1990 emissions targets. There will still be some reshuffling of purchases – from coal to natural gas sources for example – but not enough to completely satisfy the AB 32 requirements. This suggests that the first-seller cap-and-trade regulation, with the restrictions described above, will have at least some impact on aggregate WECC-wide emissions.

It is important to note that, although additional regulations like these would limit reshuffling, they also undermine any incentive that firms outside of California would have to retire existing capacity that is particularly carbon intensive since the carbon emissions of a single plant would be small relative to the market average. In general, regulatory restrictions could undermine the market-based attributes that formed the advantages of a cap-and-trade system in the first place.

### *4.3 A Seven State Cap-and-Trade Program*

A better outcome for the fate of a cap-and-trade program would be the expansion of its jurisdiction beyond California. At the end of February 2007, California Governor Schwarzenegger together with the Governors from Arizona, New Mexico, Oregon and Washington, announced a plan to do just that. With the recent addition of Utah, Montana,

[14] Contracts with existing nuclear and hydro facilities that can be proven to predate the cap-and-trade regulation will also be allowed.

British Columbia, Manitoba, Ontario, and Quebec the Western Climate Initiative (WCI) (seven states and four Canadian provinces as of September 2008) has agreed to reduce regional emissions (across all sectors and greenhouse gases, not just electricity and CO2) to 15% below 2005 levels (WCI, 2007). The WCI regional cap-and-trade is scheduled to start January 2012 and the overall target is based on the aggregation of existing state emissions and emissions goals. California has reiterated its commitment to this initiative and plans to link its cap-and-trade program with other WCI partner programs to create a regional market system. Member states' emission reductions will need to meet their state specific targets as well as the regional goal. In view of this development, we expand our analysis to include the seven states party to the agreement.[15]

We begin with an analysis similar to the ones presented in Figures 3 and 4, which assumes that the WCI states adopt a consumer-based cap. We focus on the seven U.S. states as we do not have plant-level output or emissions data from the Canadian provinces.[16] We adjust for the new emissions target (15% below 2005) and the new energy consumption levels reflecting aggregate demand from the seven WCI states.

According to the Energy Information Administration, total CO2 emissions from all electricity producing sources within the seven states were 218 MMT in 2005. A reduction to 15% below 2005 levels to 185 MT requires eliminating 33 MT of emissions (equivalent to 9% above 1990 levels). As Figure 5 illustrates, even a seven-state program within the WECC may not bind in the electricity industry. If we add the expected renewable production required by the various RPS programs in the WECC states, aggregate 2020 demand from the seven WCI states assuming a 1% growth rate can be met from a combination of existing sources and these new renewables, while still achieving the required 15% reduction in emissions.[17] However, if we instead assume a 2% growth rate in electricity demand in the WCI states, existing sources plus the new

[15] Draft design details of the regional cap-and-trade program are available. See Western Climate Initiative. 2008. Draft Design of the Regional Cap-and-Trade Program. July 23, 2008.

[16] Leaving out the Canadian provinces most likely makes it easier to fulfill the WCI goals, as zero carbon, hydro power is the predominant generation source in these provinces (68%). Reductions to reach the target will need to come from changes to the provinces' remaining coal, natural gas, and refined petroleum generation. For example, not accounting for load growth the necessary reductions to meet the Canadian target (5.6 MMT) are reachable if half the 2005 coal generation in Ontario is replaced with natural gas plants. Calculation based on the 2005 province-level, fuel-specific greenhouse gas totals and intensities (gCO2eq/kWh) presented in "National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada, Annex 9."

[17] Again, we make no assumptions about the new capacity added in states *not* participating in the WCI. Additional demand for load in those states could be met from any source and not impact the reductions required within the WCI.

renewables could not provide all the necessary energy without exceeding the 2020 emissions cap.[18]

However, the extent of electricity trade within the seven WCI states implies that the potential for reshuffling may not be as severe as implied by Figure 5. Such an analysis is much more relevant when the regulated states are net importers of power. This is an appropriate assumption for California, which imports 22% of its power, but when we expand to the seven-state region, total generation within the states (554 TWh in 2005) is larger than total demand (513 TWh in 2005). If imports from outside the region are small, reshuffling them will likely not make a significant contribution to reducing emissions. However, a form of leakage could occur through the curtailment of exports located within the WCI states. The western states outside the WCI could replace the energy from these reduced exports with new dirty sources and not impact the accounting of WCI emissions.

Given the relative balance of supply and demand within the seven U.S. states participating in the WCI, it is worth examining conditions in these states if we assume that neither reshuffling nor leakage were possible. This is in effect assuming the opposite extreme from the analyses presented above in which we assumed no limits on potential reshuffling. If there were not any leakage or reshuffling out of these states, then the full reduction of 33 MMT of emissions must come from resources located within these states, while at the same time meeting an end-use demand that could increase by roughly 170 TWh by 2020. In fact, even assuming no leakage or reshuffling, this reduction can be met through relatively conventional measures.

We consider several different scenarios for reducing carbon production from within the seven WCI states: one in which new production has zero carbon emissions, and a scenario in which new production comes from conventional natural gas sources. If we assume reductions come from the closure of the "dirtiest," or most-carbon intensive, coal plants, this would amount to retirements of 4,478 MWs of coal capacity. This is roughly equivalent to two large plants, such as the Navajo plant in Arizona. The key question though, is what kind of capacity would replace the production of those plants, and also generate the additional energy required to meet demand growth in this region?

The seven states would need to acquire an additional 87-133 TWh of energy, while at the same time *reducing* carbon emissions by 33 MMT.[19] One way to achieve this goal would be to assume that all new demand will be met from zero-carbon sources, as will the additional TWh needed to achieve the 15% reduction from 2005 levels. The retirement of two large coal plants, (*e.g.* Navajo in Arizona and Intermountain in Utah) would displace almost 33 MMT of carbon while creating a need for an additional 31 TWh of energy. Under this "all zero-carbon" scenario, a total of about 118-164 TWh of new,

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[18] We describe our assumptions used to construct our demand estimates in the appendix. Demand growth in the range from 1 to 2% is consistent with historic patterns.

[19] The range reflects different assumptions about load growth, as discussed in the appendix. Note that we have taken 2020 forecast demand minus 2005 generation, as we are assuming that these states are atomistic and only supply their own load.

zero-carbon energy would be required. It is important to remember (see Table 1) that a large portion of this new supply, 71-79 MWh is already mandated under existing state RPS programs. One possible approach to meeting the WCI goals would therefore be to roughly double the renewable capacity called for under existing RPS programs.

However, a more conventional alternative for compliance would be an expansion of natural gas generation. Again accounting for 71-79 TWh of additional renewable energy from the state RPS programs, then the seven states would have to generate an additional 39-93 TWh of energy from CCGT plants to meet new demand.[20] It would also result in about 17-40 new MMT of CO2 emissions. The increase in emissions from new gas plants would therefore need to be offset by more closures of coal plants. If these seven states abandoned two-thirds of the coal plants from which they currently consume energy, and instead bought power from new CCGT plants, this would be sufficient to meet WCI targets if demand growth were at the high end of our estimates.[21] The implied new 198-252 TWh of natural gas energy translates into about 25,000-32,000 MW of new generation capacity operating at a 90% capacity factor. This is a significant investment, but hardly transformational.[22] Consider that a similar amount of CCGT capacity came online in the western U.S. between 1999 and 2005.

In sum, as with the California-only calculations, our analysis suggests that even if carbon limitations are expanded to cover Arizona, New Mexico, Oregon, Washington, Utah, and Montana the biggest single driver towards less carbon-intensive electricity generation is likely to be the renewable portfolio standards already in place in these states. The remaining reductions could be achieved by a shift from existing coal facilities to CCGT plants.

**5.0 Conclusions**

Our examination of California's position in the western electricity market indicates that there are significant limits to the state's ability to unilaterally impact carbon emissions

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[20] 39 TWh is the additional generation needed under a high renewables (79TWh) and low demand growth scenario. 93 TWh additional energy assumes a low renewables (71 TWh) and high demand growth scenario.

[21] Assuming an emissions rate of 850 lbs/MWh (or .425 MMT/TWh) for a CCGT plant and total RPS supply of 71-79 TWh, 39-93 TWh of new CCGT energy results in roughly an additional 17-40 MMT of carbon on top of the 33 MMT of reduction from 2005 levels. So, in addition to the CCGT generation needed to meet load growth, additional investment is necessary to reach the carbon goals. Swapping 1 TWh of CCGT gas for 1 TWh of coal results in a carbon savings of .575 MMT, and there were about 239TWh of energy from coal, consumed in these seven states in 2005. If the seven states consumed one-third the power generated from coal, and the remaining two-thirds were replaced by new CCGT plants, this would "save" about 92MMT of carbon, savings enough to reach the target even under the high population growth scenario (73 MMT).

[22] Of course, a large expansion of natural gas-fired generation could have significant impacts on the market for natural gas in the West.

from the electricity sector. Two of the main policy tools under consideration are source-specific regulations of plant emissions and a cap-and-trade system for trading carbon emission credits. Our analysis indicates that either option could lead to an outcome of "exporting" California's emissions, at least on paper. The net impact of carbon emissions from electricity generation sources would be minimal. If California were going to be the only Western state to limit GHG emissions, it appears that more direct regulatory interventions, such as directly funding power plants with low carbon emissions, would be necessary to have an impact on overall emissions.

The outlook for a cap-and-trade system brightens somewhat if it is extended in scope to include Washington, Oregon, Arizona, New Mexico, Utah and Montana. A producer or consumption-based standard applied to these seven states would require the closure of major coal-producing facilities for compliance. For the overall impact to be significant, however, these plants need to be replaced by something cleaner, instead of just by a coal plant located outside of the seven states.

Given this fact, it becomes clear that these initiatives are ineffective unless they help to induce change beyond California and the western U.S. The question therefore becomes, what attributes would make these policies most likely to have an impact beyond the state's borders? There are at least two potential answers to this question. First, the region's actions may influence the adoption of GHG regulations elsewhere, and second, these policies may influence the specific technologies used to reduce GHG emissions elsewhere.

There is already quite a bit of momentum for GHG regulations outside of California (the growth of the California led regional cap-and-trade as just one example). There is a reasonable argument to make that the specific policies adopted by California and the WCI do not matter that much in terms of influencing other jurisdictions, simply the fact that these States are trying to do something on this issue could help spur other jurisdictions to action. Under this form of the "leading by example" argument, the specifics of the example may not matter much.

Still, it is worth considering that the goal of reaching 15 percent below 2005 emissions levels by 2020, at least in the seven western states, might be achievable through relatively conventional means – widespread substitution of natural gas for coal production along with continued expansion of wind and other renewable sources. Unfortunately, these means are likely insufficient to meet the more ambitious targets necessary to achieve stability in global concentration of $CO_2$. Nor is it likely that deploying further financial resources to these conventional technologies would lead to the kind of "game-changing" innovations that may be necessary for dramatic reductions below 1990 levels. It is very possible that most of the great efficiencies to be had from wind and natural gas production have already been captured.

In light of this argument, truly expanding the impact of these local policies to a global level may require innovation in transformational technologies. Developing countries may only be persuaded to adopt clean technologies if they are demonstrated to actually be less expensive than conventional ones. This argues for focusing a GHG policy more on high-risk, high-return technologies that could truly transform the global energy picture. While the renewable portfolio standards encourage investment in new, low carbon technologies, they are input-based standards and provide no incentives for investment in other potentially important low carbon electricity generation technologies, such as geological carbon sequestration.

Returning to the question of influencing policy within the United States, it is important to remember that, while a cap-and-trade program on a local level (where "local" could even be as large as seven states) may be ineffectual, it is a much more appealing tool when applied on a national level. One could think of local policy efforts as an attempt to design a regulatory policy and infrastructure that could be readily scalable to the national level. Viewed from this perspective, the question of whether GHG policies have an immediate impact on one region, such as California, is not of central importance. After all, even if we hit California's own targets, this amounts to a relatively small withdrawal from the global carbon bucket. What is important is developing a policy that is sensible if applied to the nation and beyond.

**Table 1: Renewable Supply in the West**

| *State* | *2006 Renewable Supply* | | *Target Renewable Supply %* | *Future Renewable Supply* | |
|---|---|---|---|---|---|
| | *TWh* | *% of state load* | | *TWh 2020*[(1)] | *Date Target to be Met* |
| **AZ** | .1 | .1% | 15% | 13.5 | 2025 |
| **CA** | 23.9 | 9.1% | 10-20% | 55.1 | 2010 |
| **CO** | .9 | 1.8% | 10% | 6.1 | 2020 |
| **ID** | .7 | 3.1% | -- | -- | -- |
| **MT** | .5 | 3.8% | 15% | 2.6 | 2015 |
| **NV** | 1.3 | 3.9% | 20% | 8.5 | 2015 |
| **NM** | 1.3 | 6.0% | 10-20% | 4.3 | 2020 |
| **OR** | 1.9 | 3.9% | 5-25% | 12.0 | 2025 |
| **UT** | .2 | 0.8% | -- | -- | -- |
| **WA** | 2.5 | 2.9% | 15% | 15.7 | 2020 |
| **WY** | .8 | 5.1% | -- | -- | -- |

[(1)] Assumes targets met but not exceeded by 2020. See data appendix for 2020 state demand calculations.

Sources: 2006 renewable supply: *Electric Power Monthly,* March 2007, Table 1.14B
2006 state load: *Electric Power Annual 2006 – State Data Tables*
http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html

**Table 2: Energy Produced in 2005 by Major Fuel Source and Sub-Region (TWh)**

| | California | AZ-NM | OR-WA | Rest of WECC | Total WECC | % of Total WECC |
|---|---|---|---|---|---|---|
| Large Hydro | 34.8 | 6.5 | 100.0 | 18.9 | 160.1 | 23% |
| Nuclear | 36.2 | 25.8 | 8.2 | 0.0 | 70.2 | 10% |
| Renewables | 32.2 | 0.8 | 6.7 | 8.7 | 48.4 | 7% |
| Natural Gas | 95.7 | 30.8 | 22.2 | 36.0 | 184.7 | 26% |
| Oil | 0.6 | <.1 | 0.2 | <.1 | 0.8 | 0.1% |
| Coal | 2.9 | 70.6 | 14.2 | 151.3 | 239.0 | 34% |

Source: Platts' Powerdat database. See appendix for details.

**Figure 1**

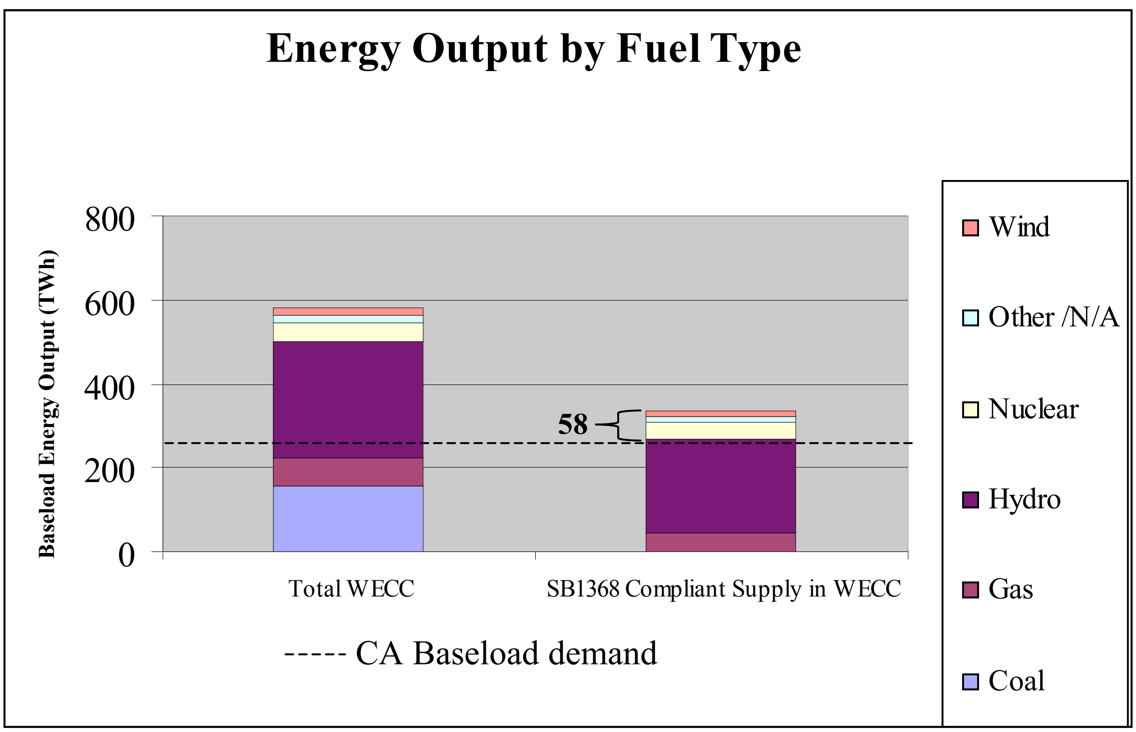


**Figure 2**

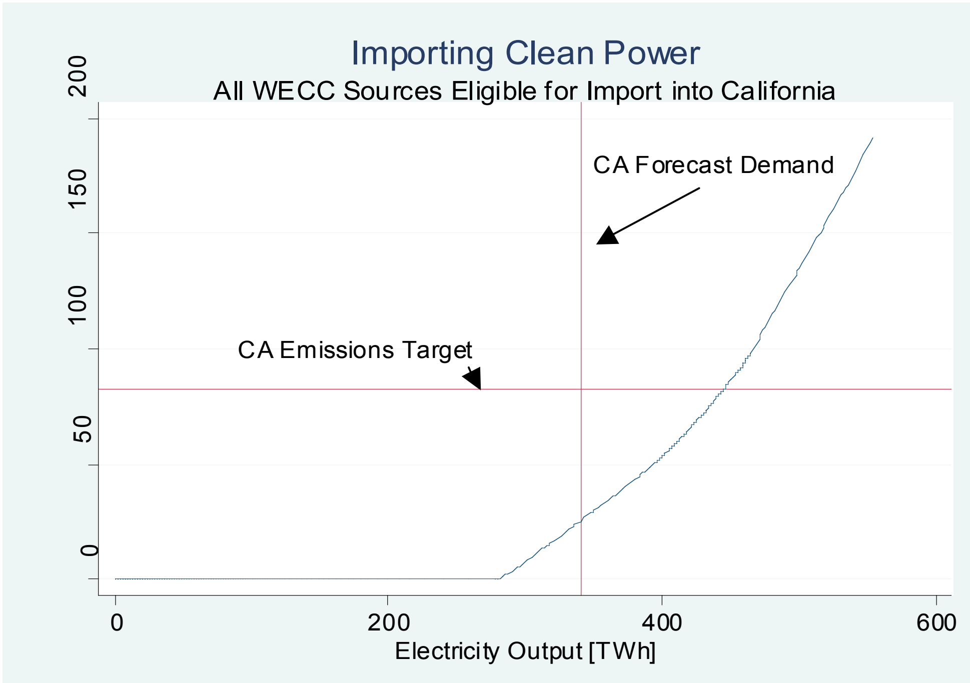



**Figure 3**

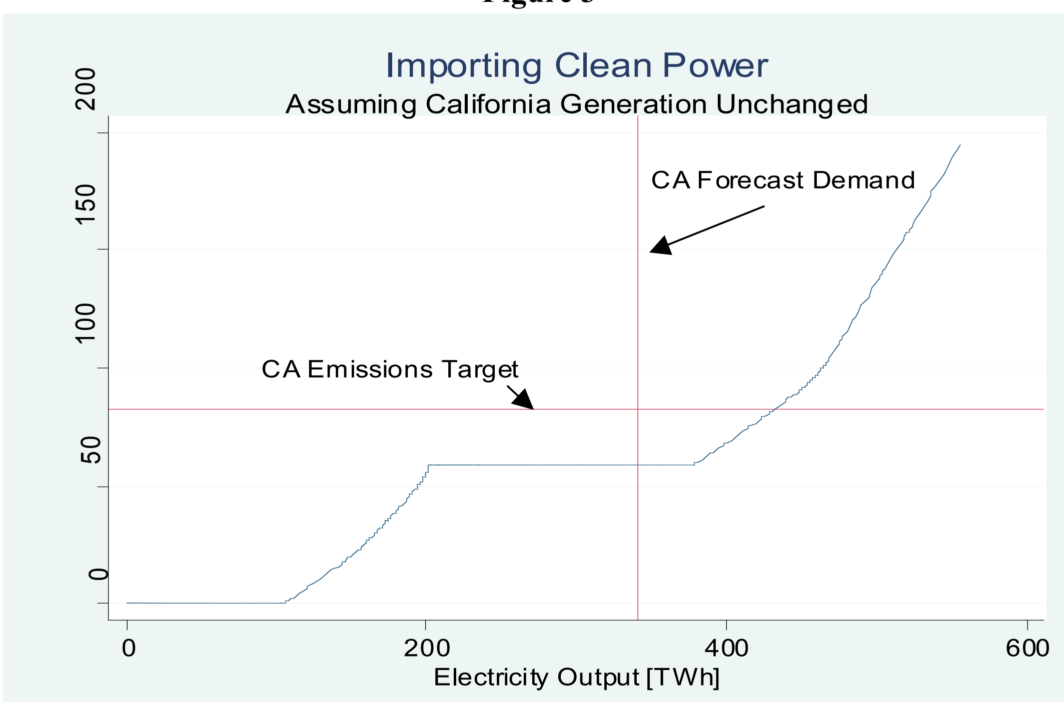


**Figure 4**

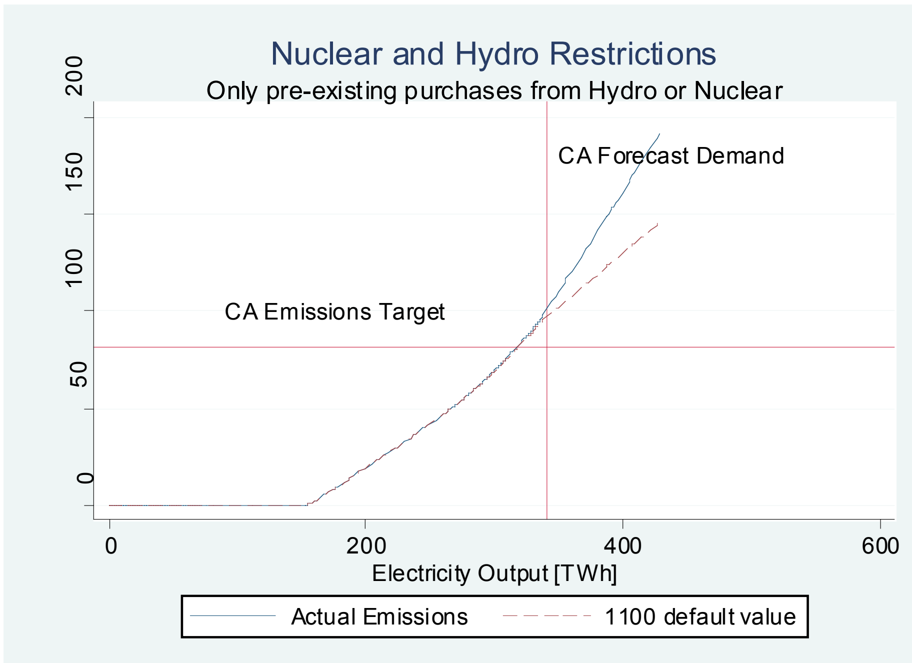
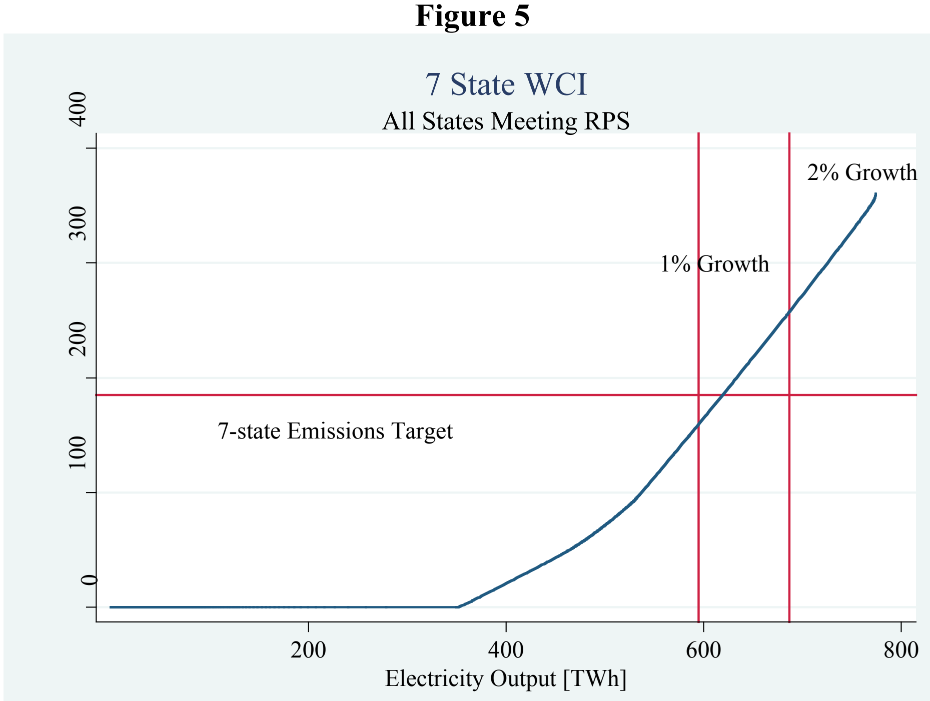



**Figure 5**



## Data Appendix

This appendix describes the data sources and underlying assumption reflected in the analyses described in the text.

### Supply

*Overview*

2005 WECC (and sub-NERC region) energy supply (in MWhs) is from the Platts Powerdat database (www.platts.com) and is supplemented with Platts Basecase database. Platts' Powerdat supply data is from the RDI modeled production costs query and information is from EIA-906 and FERC form 423. From this database the following plant level data is used: MW, net generation (MWh), capacity factor, prime mover, primary fuel, plant owner, and heat rate. This database contains a separate record for each plant by prime mover type and by ownership. Since the policies under review address the unit instead of the plant, concern was taken to make sure that the data in this form does not overlook the important unit specific factors such as fuel use and capacity factors. This query produces 1,293 plants.

Platts Basecase database (Utility/Non Utility Unit Ownership query) was used to supplement the Powerdat data with plants less than 50MW that were not captured in the main query. This database uses data from EIA forms EIA-411 and EIA-860. An additional 392 plants were added to the database with this method. Capacity factors for these plants are estimated using the average capacity factors for plants with the same fuel type already present in our database. For fuel types for which there was no know capacity factor, the average capacity factor (.4557) of the database is used.

The total WECC energy supply used here (1,685 plants) does not include Canadian or Mexican plants in WECC. The WECC includes Washington, Oregon, California, Idaho, Nevada, Wyoming, Utah, Arizona, Colorado, the bulk of Montana and New Mexico, plus western portions of Texas, and South Dakota. It also includes the Canadian provinces British Columbia and Alberta, and the northern portion of Baja California, Mexico.

Mohave generating plant is included in the database; however the units currently owned by California utilities are not considered part of their portfolio due to the December 2005 decision to indefinitely close the plant.

*SB 1368 specific*

For the SB 1368 analysis, supply with a capacity factor > 60% and hydro and wind facilities were designated as baseload. SB 1368-compliant plants are those plants that meet the baseload criteria and have a $CO_2$ emissions rate equal or less than 1,000lbs$CO_2$/MWh.

## Demand

*SB 1368 specific*
Hourly 2005 demand data for California is used to determine 60% demand. This data is from Platts Powerdat database (www.platts.com) and from its NERC Sub-Region Hourly Load query. The hourly load data is from EIA-704.

*AB32 and seven-state cap-and-trade specific*

2020 demand for the following states (AZ, CA, MT, NM, NV, OR, WA) is calculated two ways: using 2005 demand from EIA form 861 (Retail Sales of Electricity by State by Sector by Provider) and assumes an average 1.98% growth rate for each of the states and using the same data and using an average growth rate of 1.5%. 1.98% is the 10 year average demand for states in WECC region (the above states plus WY, Utah, and ID). 1.5% is used as a more conservative estimate since individual state growth largely varied over the period. Various sources were analyzed to determine state level demand forecasts. Other sources considered: 1. EIA 861 state level data average 5 year and 10 year historical growth rates (resulted in average state rates of -1% to 5%) The average for all states was 1-2%. 2. The WECC 2005 Information Summary provides a CAGR of 2.4% for the WECC region (which includes some states not considered in this analysis). 3. The California Energy Commission forecasts of 2005-2020 demand for CA have an average growth rate of 1.14% rate.

## CO2 emissions

*1990 emissions data*
1990 emissions data is from the EIA's Electric Power Annual with data for 2005 (U.S. Electric Power Industry Estimated Emissions by State (EIA-767 and EIA-906)) and is used to determine the cap targets.

*2005 emissions data*
2005 emissions data is used to determine the emissions from existing generation. It is assumed that in 2020 capacity factors and emissions rates will be the same.

Since emissions' data was not available for all plants, heat rate is used to estimate the CO2lbs/MWh emissions rate for all the plants. A regression of heat rate on CO2lbs/MWh was conducted using reported heat rate and CO2lbs/MWh data from a subset of plants for which such data was available from the EPA Continuous Emissions Monitoring Systems (CEMS) database. Plants were analyzed by fuel type and the following regressions were calculated:

| | Mean CO2lbs/MWh | Mean Heat Rate/kWh |
|---|---|---|
| Gas Plants | 1,506 | 12,510 |
| Coal Plants | 2,328 | 11,362 |

| Fuel type | Year | CO2lbs/net MWH = | constant | SE of constant | B1HR(BTU/MWH) | SE of B1 | t-test | P-value | R^2 | Correlation |
|---|---|---|---|---|---|---|---|---|---|---|
| Gas (798 units) | 2000-2005 | | 16.06 | 18.86 | 0.0001191 | 6.57E-07 | 181 | 0.000 | 0.976 | 0.988 |
| Coal (SUB and BIT) (252 units) | 2000-2005 | | 3.05 | 7.53 | 0.0002046 | 6.61E-07 | 310 | 0.000 | 0.997 | 0.999 |

The CO2 emissions rate for the following fuels, geothermal, wood, biogas, refuse, and landfill gas, were estimated due to lack of sufficient data to run a regression analysis. The records that were available for these fuel types all had CO2 emissions rates of zero, leading to the assignment of zero as the appropriate CO2 emissions rate for these fuels. Due to limited data, oil and petroleum coke emissions were estimated using the coal regression. Oil emissions are similar to coal (1.969 lbs/kWh as compared to 2.095lbs/kWh) and both fuel types have similar heat rates. These fuel sources represent 1.2% of the total MWs.

**Heat rates**

Heat rates for plants are from the previously mentioned Platts Powerdat and Basecase databases. Average heat rate calculation: Calculated by dividing the total Btu content of fuel burned for generation by the resulting net kilowatt-hour generation. Calculation is as follows: sum of [(fuel quantity X conversion factor: 42(oil)/1,000(gas)/2,000(coal/trash/wood))*fuel BTU]/net generation MWh. For example, a station that burns 45,570 tons of coal rated at 11,461 btu/lb, producing 110,700 MWH would have a heat rate calculation = ((45.570*2000)*11461) divided by 110700, = 9436 heat rate.

**RPS**

Information on the RPS programs of states in the WECC is from The Database for Incentives for Renewables and Energy Efficiency http://www.dsireusa.org/ and review of state documents. Expected RPS TWhs is calculated as: % target*2020 demand forecast. See above for more detail on state demand forecasts.

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