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State Efforts to Cap the Commons

Regulating Sources or Consumers?

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Abstract

California's Global Warming Solutions Act (Assembly Bill 32) requires the state to reduce aggregate greenhouse gas emissions to 1990 levels by 2020. One of the challenges California faces is how the state should regulate the electricity sector. About 80 percent of the state's electricity consumption is generated in the state, but about 52 percent of the greenhouse gas emissions associated with electricity consumption comes from outside the state. The question addressed in this paper is where to locate the point of compliance in the electricity sector—that is, where in the supply chain linking fuel suppliers to generators to the transmission system to retail load-serving entities should the obligation for measurement and compliance be placed. The conclusion offered is that one particular approach to regulating the electricity sector—the "first-seller approach"—would be best for California. The alternative "load-based approach" has a running head start in the policy process but would undermine an economywide market-based emissions trading program.

Key Words: electricity, climate, state level, $CO_{2,}$ cap and trade, market-based approaches, load-based, first seller, point of regulation, California, Western Climate Initiative

JEL Classification Numbers: Q25, Q48, L94

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Introduction

In 2006 California adopted the California Global Warming Solutions Act (Assembly Bill 32), which requires the state to reduce aggregate greenhouse gas emissions to 1990 levels by 2020. The act charges the California Air Resources Board to develop a comprehensive plan for implementation by January 1, 2009; the plan will involve a number of state agencies. Whether the state will rely on prescriptive technological standards, incentive-based approaches such as cap-and-trade, or a combination is a decision that will be made in the next couple of years.

One of the challenges California faces is how the state should regulate the electricity sector. Electricity consumption accounts for 23.5 percent of the greenhouse gases in the state, including about 27.7 percent of the carbon dioxide (CO_2) emissions. This is low on a per capita basis compared with the rest of the country, where electricity consumption accounts for about 33 percent of greenhouse gases and about 40 percent of CO_2 emissions (which is about 9 percent of total CO_2 emissions worldwide).[1] The largest category of greenhouse gas emissions in California is transportation, which accounts for about 40.4 percent (California Market Advisory Committee 2007). Nonetheless, the electricity sector remains very important to the design of the California trading program. First, the electricity sector is typically identified as the source of most potential greenhouse gas reductions in the near term. Modeling at a national level indicates that the electricity sector is responsible for about 40 percent of the nation's CO_2 emissions but will account for between two-thirds and three-quarters of emissions reductions in the next two decades under national policy (EIA 2007; Pizer et al. 2006). Second, experience with cap-and-

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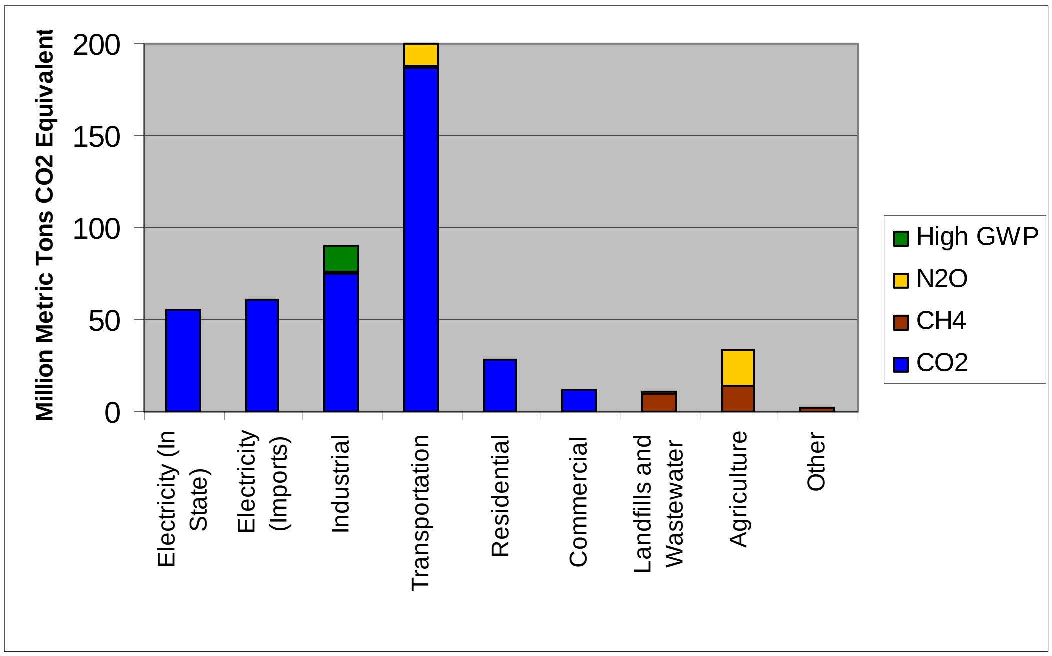
[1] The Market Advisory Committee (2007, 41) reports that the carbon intensity of electricity generation in California in 2004 was 700 pounds of CO_2 per MWh. Accounting for imported power brings the average emissions intensity of electricity consumed in the state to 930 pounds per MWh. Across the nation, the average emission intensity of electricity generation is 1,176 pounds per MWh.

trade has been largely in the electricity sector. Previous programs, including the sulfur dioxide (SO_2) and nitrogen oxide (NO_x) trading programs in the United States and the Emission Trading Scheme for CO_2 in the European Union focus exclusively on point sources, largely made up of electricity generators. The electricity sector is the demonstrated successful testing ground for this type of regulation.

Figure 1. California emissions of greenhouse gases, 2004



Source: California Market Advisory Committee, 2007

Although California's own generation resources are low emitting, its imported power is relatively high emitting. About 80 percent of the state's electricity consumption is generated in the state, but as illustrated in Figure 1, about 52 percent of the greenhouse gas emissions associated with electricity consumption comes from outside the state (CEC 2006). Attempts to regulate only in-state sources would be expensive per ton of emissions reduction compared with the opportunities to reduce emissions on a broader scale. Given the open transmission system, attempts to regulate only in-state sources also would lead to more imported power, with an associated increase in emissions out of state. The act anticipated this issue by requiring that the state's greenhouse gas reduction target include the out-of-state emissions associated with California electricity consumption.

This paper addresses options for regulation of California's electricity sector within the context of an economywide cap-and-trade program in the state, and potentially for the nation. The major decision addressed in this paper is where to locate the point of compliance in the electricity sector—that is, where in the supply chain linking fuel suppliers to generators to the transmission system to retail load-serving entities should the obligation for measurement and compliance be placed. Sections 2 sets out the different approaches that have been suggested and Section 3 addresses the debate about these approaches in detail. Section 4 provides a conclusion.

The conclusion offered is that the "first-seller approach" to regulating the electricity sector would be best for California. The alternative, the "load-based approach," has a running head start in the policy process and is more familiar to many advocates and policymakers. Most of the reasons cited to advance the load-based approach over the first-seller approach are in fact distinctions without a difference: the approaches would have the same effect. For example, the load-based approach would provide additional incentives for efficiency investments, but so would the first-seller approach. However, the approaches differ in some fundamental ways. The load-based approach would have greater complexity, and it would not provide transparent signals to electricity generators about the scarcity value of CO_2 in the economy. A load-based approach would appear substantially different from existing markets for environmental goods, and indeed, it might be more accurately described not as a market but as increasingly flexible regulation.

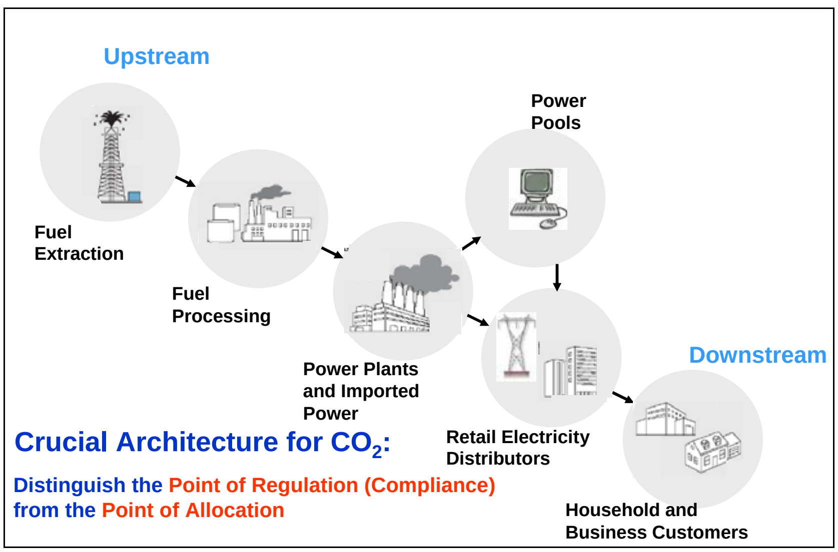
It is most important for policymakers to recognize that the future of electricity markets and allowance markets are intertwined. If the vision for the future of California's electricity markets were regulation as currently practiced, then the load-based approach would not be inconsistent. But if the goal is to increase competition—for example, through the introduction of a day-ahead market as planned, for 2008—then the load-based approach to a cap-and-trade program would pose a fundamental conflict.

Point of Compliance for CO_2 Cap-and-Trade in California's Electricity Sector

One month after passage of the California Global Warming Solutions Act, Governor Schwarzenegger issued an executive order creating the Market Advisory Committee to advise the California Air Resources Board (CARB) on developing a plan for a cap-and-trade program. One alternative identified by the committee is an "upstream" approach that would regulate emissions at the point where fossil fuels enter the economy. Implementation at this point could achieve coverage of 83 percent of the greenhouse gas emissions in the state by regulating 150 facilities.[2] Under this approach, the question of how to regulate the electricity sector would not be relevant because carbon emissions would be regulated before they entered the electricity fuel cycle.

However, the approach that received the most attention, partly based on precedent in other trading programs, is "midstream" regulation. As illustrated by Figure 2, this approach would regulate midway in the fuel cycle between the introduction of fossil fuels into the economy and their end use. This approach could achieve comparable coverage of 83 percent of the state's emissions by regulating 490 facilities, assuming that transportation fuels would be regulated at the refinery.

Figure 2. Potential points of compliance in the electricity sector



We focus on the question of how the midstream approach would be implemented in the electricity sector. Two approaches have been discussed most thoroughly. One, a *load-based approach,* would shift compliance responsibility downstream from the point of combustion and would place a legal obligation for reporting and compliance with the load-serving entities—the

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[2] This approach would require monitoring and reporting for all fossil fuels produced in or imported into California, as well as fuel exports. This includes about 100 business entities that take delivery of gas via a pipeline.

firms that sell retail electricity directly to customers. Compliance implies that these entities would be responsible for surrendering an allowance for every ton of CO_2 used by electricity generators upstream to provide electricity services to their customers. In a decision that preceded the statewide legislation, the California Public Utilities Commission (PUC) had already identified a load-based approach for regulating greenhouse gases in the electricity sector in California. PUC regulates the private investor-owned utilities (IOUs) that provide about 80 percent of the state's retail electricity. Under statewide legislation and implementing regulations to be developed by CARB, the remainder of the population served by municipal utilities and others would also participate.

The alternative approach was proposed initially by the Market Advisory Committee (2007) and is known as a *first-seller approach.* It would place a legal obligation for reporting and compliance on the first seller of power into California electricity markets. The first seller is the owner, operator, or power marketer for a generation facility located in the state, or the party bringing power onto the electricity grid for power generated out of state. Compliance would be required for power placed into the transmission system from that facility. For in-state sources, a first-seller approach would look very similar to the source-based system that characterizes previous trading programs, such as the SO_2 trading program, in which compliance is required at the point of combustion—that is, where emissions are released into the atmosphere.

Both approaches are imperfect tools for dealing with imported power, as I discuss below. It is worth emphasizing that if California's program is integrated into the efforts of the six states and two Canadian provinces participating in the Western Climate Initiative and a cap-and-trade program emerges in this broader geographic region, the issue of electricity imports will be much reduced. The other states participating in the initiative are Washington, Oregon, Arizona, New Mexico, and Utah.

The Western Electricity Coordinating Council coordinates power dispatch over the western electricity grid and encompasses portions of 14 western states (including the entirety of 11 states) along with British Columbia and Alberta. The western grid operates largely in isolation from the rest of the nation. The Western Climate Initiative would bring the vast majority of power generated in the region into the trading program. It is also worth noting that the first-seller approach would naturally evolve into a source-based program, since a growing proportion of generation sources are located within the trading region, but the load-based approach would retain the point of regulation on load-serving entities (LSEs).

Another crucial issue in the design of the program is the method of initially distributing emissions allowances. As Figure 2 illustrates, there is no reason that the point of allocation and the point of compliance should be the same. In fact, a substantial literature has advocated for the use of an auction rather than free allocation for distributing allowances.[3] This is the approach being used for 100 percent of the allowances being distributed by New York and 5 other states in the 10-state Northeast Regional Greenhouse Gas Initiative (the remaining states are still considering their plans).[4] An auction approach also was the approach highlighted as preferable, especially after a transition period, by the Market Advisory Committee.

Analysis of Point of Compliance

Several issues have surfaced in deliberation about the point of compliance as advocates for one or another viewpoint have tried to distinguish the two approaches.[5] I address these issues in three groups. The first group is where differences of opinion abound, although there is fundamentally little or no difference to be made in performance between a first-seller and a load-based approach. The second group of issues does involve fundamental distinctions. The third comprises issues where the jury is still out, especially on the legality of these approaches.

Where There Are Distinctions without Any Difference

Proponents and opponents of each approach contend that the choice would affect the regulation of imported power, procurement policies, and efficiency policies and have effects on both producers and customers of electric power. The alleged differences in the performance of the load-based and first-seller approaches do not hold up under scrutiny, however.

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[3] See, for example, Parry (1997) and Goulder et al. (1999), who demonstrate that an auction with revenue recycling aimed at reduction of other taxes dramatically lowers the social cost of the policy. Burtraw et al. (2001) demonstrate that an auction also has the property of providing more efficient pricing regulated regions of the country. CIER (2007) demonstrates that an auction can provide revenues that reinforce program goals by funding investments in energy efficiency and thereby lower the cost of the program for consumers.

[4] The initiative’s memorandum of understanding specified that all states should allocate at least 25 percent of the emissions allowances created by a cap-and-trade program to consumer benefit and strategic energy initiatives. An auction of allowances is the most likely way to implement this policy.

[5] See, for example, the proceedings and supporting documents submitted at the Joint En Banc Hearing of PUC and CEC on Point of Regulation in the Electricity Sector in San Francisco on August 21, 2007.

Regulating Imported Power

California cannot regulate or impose financial regulatory burdens directly on out-of-state sources, but it can indirectly affect the use of out-of-state generation. This is the primary motivation for looking beyond a source-based approach to regulation, and it is the reason most often cited in favor of a load-based approach. However, the load-based approach is a very imperfect way to regulate out-of-state emissions, and the first-seller approach is no better. One problem for both approaches is the imprecise assignment of emissions to generation for at least some portion of imported power. Another difficulty is "contract shuffling," which is the opportunity for wholesalers of out-of-state power to shift the assignment of existing sources with relatively low emissions rates to serve California while assigning higher-emitting sources to serve other load centers outside California. Bushnell (2007) argues that the opportunity may exist for 100 percent contract shuffling, meaning all of the imported power coming to California could be identified as zero emissions without any real change in the resource mix throughout the western electricity grid.

There is reason to believe that the opportunities for contract shuffling may be limited. Both approaches would rely on the California Climate Action Registry's Power/Utility Reporting Protocol, which assigns emissions intensity to imported power. According to a recent study by the California Energy Commission (Alvarado and Griffin 2007), this approach allows for a precise identification of the power plant and associated emissions for about 56 percent of imported power. The remainder would have to be assigned emissions intensity based on other information, such as the average emissions intensity for the control region from which the power is delivered into California. The transmission path for imported power cannot be tracked directly, but the financial path can be tracked based on the information in electronic North American Electric Reliability Council (NERC) E-tag documents.[6] Under either approach, this is the information that regulators would use to make an assignment of emissions out of state to the use of electricity in California. Under a load-based approach, information about the emissions intensity of imported power would be conveyed downstream to the LSE. Under a first-seller approach, this information would be the measure upon which to base the compliance

[6] NERC E-tags are electronic documents used to track the transmission of electricity so that sources of grid congestion can be more easily identified and mitigated. In addition to identifying the parties with financial ownership of the power, the E-tag identifies the source and destination control region. Parties identified on the E-tags are licensed to schedule power into the transmission grid.

responsibility of the party listed on the E-tag document—that is, the party that is the first seller of imported power to the electricity grid.

In sum, the basis for assessing the emissions intensity of imported power would be the same for both approaches, and the approaches are similar in their ability to account for imported power. The distinction between them stems from what happens on the California side of the boarder. The load-based approach would require an additional level of approximation in making an assignment between the contracting party identified as the first seller and the LSE that has the compliance obligation—something discussed in Section 3.2.

Procurement Policies

A second issue of little practical difference is how the choice of a point of compliance would affect PUC's portfolio-planning activities. PUC plays an important role in ensuring that dispatch meets social goals through a variety of previous orders, including most generally the procurement standard, which specifies the order in which regulated utilities should develop resources to meet demand. The order gives priority to efficiency first and renewables second, before turning to fossil-fired generation. Advocates of a load-based approach argue that this approach is necessary to support PUC's role.

Would or should PUC's supply-side procurement policies end if there is a greenhouse gas cap-and-trade program? From PUC's perspective, the answer is obviously no. PUC's policy development in this area predates events that have moved climate policy to center stage in California and reflects long-standing goals for reducing air pollution, promoting stability in the supply and price of energy resources, and promoting economic development in the state.

Would it make a difference for those policies whether a load-based or a first-seller approach was adopted? One can be equally emphatic in answering this question, although the issue is more subtle. PUC's initiative toward developing a greenhouse gas program follows on top of the other policies and is not intended to substitute for them. PUC initially declared its intent to develop a load-based cap on electricity sector emissions in February 2006, well before passage of the California Global Warming Solutions Act. The load-based approach was chosen not because it was the preferred design to complement the other goals but because it was the only option available to PUC for designing a cap on electricity sector emissions. PUC regulates investor-owned utilities, which account for roughly 80 percent of the delivered electricity supply in California. Furthermore, the generation fleet of the IOUs is predominantly nonemitting nuclear, geothermal, wind, and hydroelectric resources, and a large portion of the IOUs' load is met with system power. PUC regulates only IOUs, and not the independent power producers and others who sell power to the IOUs. A source-based emissions cap on the IOUs' own generation would have little benefit because IOU generation is already so clean and because the majority of emissions used to serve the IOU load would remain unregulated. Therefore, PUC has limited options when it comes to regulating emissions within the state.

In designing an emissions cap, PUC had only one option, to impose requirements on the load-serving function of the IOUs. This is the same regulatory handle that is exercised in other rules governing how the IOUs meet their resource requirements. For example, as mentioned above, PUC's "loading order," adopted in May 2003 as part of the state's Energy Action Plan, establishes the priorities for energy procurement for IOUs. In December 2004, PUC adopted a CO_2 cost adder of $8 to $25 per ton to be added into system dispatch, and in October 2005, it issued a policy statement on a greenhouse gas performance standard.[7] These are all load-based approaches to regulation because that is the main way that PUC can affect IOU practice, and it can affect other sources only indirectly. Furthermore, all these requirements will remain in place whether a statewide cap-and-trade program targets the LSEs or the first sellers.

Acting by itself as an independent agency, PUC did not realistically have the option of directly regulating sources or first sellers when designing its greenhouse gas policy. It was making a virtue of necessity by initially adopting a load-based approach when it began to consider cap-and-trade policy. Given the new act's mandate to cover sources statewide, PUC and its sister agencies now have the ability to design a different kind of policy.

Efficiency Policies

A related set of questions concerns the ability of PUC to implement its efficiency programs. Since the 1970s, California has been a world leader in efficiency programs. PUC has decoupled revenue from sales for California's IOUs in an effort to remove the disincentive for IOUs to invest in programs that would reduce their sales. Recently, PUC moved to provide stronger positive incentives for IOUs to invest in efficiency by rewarding the achievement of certain goals. As with the supply-side policies, the demand-side policies are intended to

[7] Senate Bill 1368 expanded this approach and directed the California Public Utilities Commission and the California Energy Commission to set a greenhouse gas performance standard to ensure that new long-term financial commitments in baseload power plants by electric load-serving entities have greenhouse gas emissions that are as low as, or lower than, emissions from a combined-cycle natural gas power plant. In May 2007 PUC adopted greenhouse gas standards for procurement.

encourage low-income assistance as well as lessen the overall environmental impact of electricity use.

Would or should PUC's demand-side efficiency programs be changed or stopped if there is a greenhouse gas cap-and-trade program? The answer clearly is no. Nonetheless, proponents of a load-based approach have suggested that this approach would do a better job of achieving emissions reductions because it would raise awareness in the firm regarding investing in efficiency and renewables and lessening reliance on fossil fuels. Since the load-serving entity is closer to the end use and typically is charged with administering efficiency programs, the argument goes, the greenhouse gas program should be placed at this point in the supply chain.[8] Further, firms are said to respond less well to a price signal than to a direct regulatory obligation, and therefore one could expect a more robust investment in efficiency if the point of compliance with the cap-and-trade program were placed on the LSE.

One could build intuition for that argument from the earliest actions by firms to implement the SO_2 trading program under the 1990 Clean Air Act Amendments, but it would be a misreading of what has been learned since. Initially, at dozens of facilities, plant managers and engineers who had not previously focused much on SO_2 emissions and who knew little about the concept of cap-and-trade began to experiment with more thorough fuel washing and expanding their use of mid- and low-sulfur coal. Vendors, meanwhile, began to experiment with the sorbent injected into desulfurization scrubbers. For the first time, all these parties had an incentive to go beyond a simple performance standard.

The SO_2 program got the attention of plant managers and engineers, but within a short time compliance responsibility was taken away from them because emissions allowances came to be viewed as a financial asset. Compliance with the cap-and-trade program was kicked upstairs and folded into fuel purchase decisions. Plant managers and engineers were given an incentive to reduce allowance use analogous to their incentive to reduce fuel use. A ton of emissions avoided was an allowance earned, as valuable as reducing fuel expense, and there were trade-offs to be made along these dimensions. This organizational learning was one of the subtle ways that

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[8] For example, testifying before the Joint En Banc Hearing of PUC and CEC on Point of Regulation in the Electricity Sector in San Francisco on August 21, 2007, Richard Cowart called LSEs "ideally positioned through portfolio management and their buy decisions. It sends signals upstream to generators and they also have relationships with customers. So, they can work with customers to reduce carbon emissions. So, they have also the potential of affecting decisions downstream."

incentives led to innovation, as firms learned to reduce their costs of compliance under the SO_2 program (Burtraw 1996). Today, firms think of the market-based SO_2 program as a financial problem managed by trading desks. They have moved beyond autarkic behavior with trading internal to the company and have become active in the external market, and the management of plants is functionally the same as if they faced an emissions tax or a change in upstream fuel prices (Ellerman et al. 2000; Swift 2001).

Siting SO_2 compliance activities at one or another level in the firm or market will not lead to any further emissions reductions because the industry operates under an emissions cap. With a CO_2 cap-and-trade program in California, the same result will obtain: it is the cap that will determine the level of emissions, not the point of compliance for the regulation. If the regulation imposes compliance at a level intended to directly affect corporate culture and organizational behavior rather than directly achieving emissions reductions, it could potentially raise costs for firms and thereby raise the social cost of the program. But it will not do anything for achieving environmental goals because emissions will be capped.[9]

Impacts on Customers and Producers

Will there be different impacts on customers and producers? Where markets determine the price of electricity, the incidence of the program (i.e., how the cost burden is shared among customers and producers) is determined by the elasticities of supply and demand in that market, not where the regulation is applied. The wholesale price of power would be different under these two approaches, but the retail price effect is expected to be identical. To the extent the wholesale electricity market is competitive and retail prices allow for a pass-through of costs, it makes no difference where the point of compliance is located with respect to the effect on consumers. To the extent that the wholesale market does not appear transparently competitive, it is foremost the result of regulatory intervention meant to protect consumers as well as achieve environmental goals.

Advocates for a load-based approach have pointed to the possibility that under a cap-and-trade program, producers could gain windfall profits at the expense of consumers. The issue of windfall profits has gained attention since evidence has emerged of billions of dollars in

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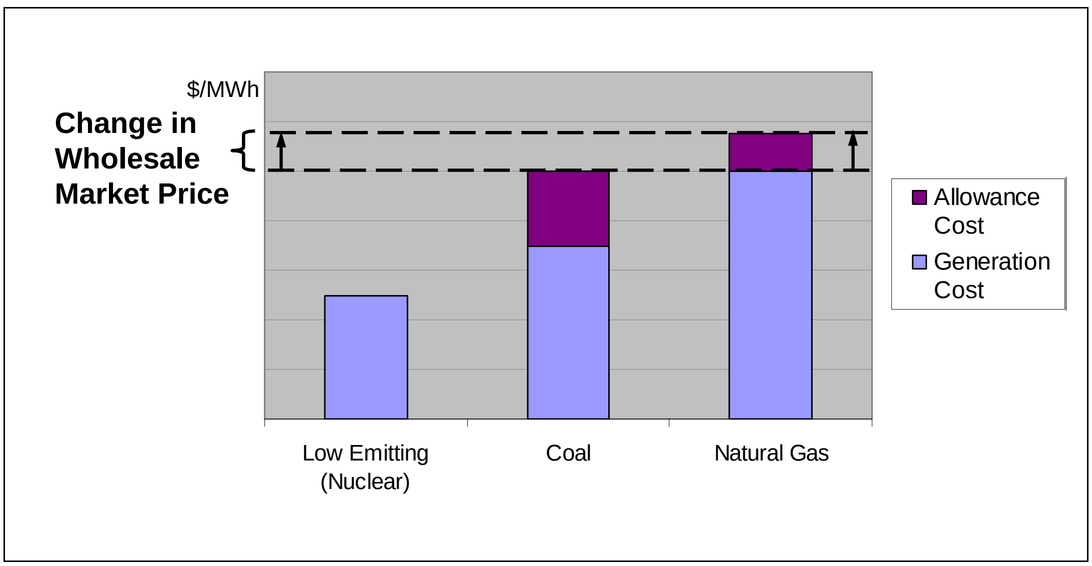
[9] Parties have made an indirect argument that changing corporate culture may make it easier to amend the cap in the future. However, the converse argument is that raising costs may erode political support for environmental goals.

unanticipated earnings due to free allocation of emissions allowances in the European Union's Emission Trading Scheme (Sijm et al. 2006).

Under a cap-and-trade program, producers receive compensation two ways. One way is the potential allocation of free allowances. The second way is through changes in the wholesale power price, where the increase in revenues is determined by the increase in the marginal cost of the marginal generator. All sources selling into the market receive the increase in revenue as determined at the margin, whether one's change in cost is greater than or less than that of the marginal generator. Typically, the marginal facility is a natural gas plant, whose CO_2 emissions, though substantial, are still less than half those from the average coal-fired plant. As illustrated in Figure 3, at low-emitting or nonemitting facilities where there is little or no change in cost associated with the program, the change in revenues is likely to represent an increase in profitability even if allowances are purchased in an auction.

Figure 3. Wholesale power price in competitive market as determined by variable costs of marginal generator



Effects in Figure 3 are illustrated for an individual facility; however, an individual facility does not really have standing. The shareholders of firms own a portfolio of facilities, and some facilities gain value and some lose value. The effect on a firm is an aggregation of effects on facilities in the firm's portfolio. Consequently, some firms win and some lose. The winners tend to be firms with relatively low compliance costs because they own a portfolio of relatively low-emitting plants. These firms will realize an increase in revenues associated with the rise in the wholesale electricity price that is greater than their own change in compliance costs. Conversely, any gain in value for one particular facility does not necessarily map into a gain in value for the portfolio of facilities owned by a firm.

Looking at the Northeast's Regional Greenhouse Gas Initiative and accounting for the portfolio of generation assets owned by companies, Burtraw et al. (2006) find that even under an auction, 11 of the 23 largest generation companies in the region would realize an increase in market value. If allowances are given away, one can expect a gain in profitability on a broad scale. These authors find that under free allocation of emissions allowances to generators, each of these companies at least breaks even, and several see substantial increases in value.

In California a large number of facilities, including nuclear, wind, geothermal, and hydroelectric plants, have zero emissions. The regulated IOUs own most of these facilities, and the increase in value of these facilities would be returned to ratepayers. Nonetheless, this does not allay the concern that free allocation of emissions allowances could lead to windfall profits for most if not all generation companies.

The key idea is that windfall profits are related to free allocation, not the point of compliance. Many people advocate a load-based approach to get away from free allocation of emissions allowances to generators and implicitly to assign allowance value to customers. This reasoning makes the mistake of lumping together point of compliance and point of allocation, but as Figure 2 illustrates, it does not have to be that way, and the Market Advisory Committee strongly recommended against it. The point of compliance would not affect how the cost of the program is distributed. Where emissions are properly accounted for, the effect on the retail power price is identical and the effect on the value of generation assets is identical.

Policymakers have a degree of freedom: they could, for example, distribute allowance value among customers and producers to achieve any distributional outcome that is desired.[10] A load-based approach with an auction would have the same effect on retail prices as the first-seller approach with an auction. Alternatively, one could have a load-based approach and freely

[10] The Market Advisory Committee suggested that assignment of value is preferable to allocation of allowances. If allowance value is assigned in the near term, that assignment could be phased out over time to allow retail price adjustments in the future. The allocation of allowances also could be phased out, but the committee reasoned that it would lead to a greater sense of entitlement to allowances.

allocate allowances to generators, who would then sell them to LSEs, and generators would earn substantial profits.[11]

In any outcome, one should guard against the parochial assignment of this allowance value to the electricity sector—that is, the notion that the allowance value is a pie that can be shared among electricity customers and producers. The economic value of allowances is not created in the electricity sector; it is created by a societal commitment to place a scarcity value on CO_2 emissions throughout the economy. The fact that electricity has incumbency as a heavy emitter of CO_2 emissions does not mean the value of carbon allowances belongs to electricity customers or electricity producers.

Given society's decision to place a value on the use of CO_2, an assignment of the value of carbon allowances to electricity customers rather than producers constitutes a windfall to electricity consumers if the value is used to subsidize the electricity price. Minimizing the politically unpopular effect on price has been an explicit objective of many advocates. The practical design of public policy success requires a transition in the changes in relative prices in the economy. This will lessen the cost of the program by lessening the economic disruptions associated with an abrupt change in policy.

However, if policymakers remain wedded indefinitely to an electricity price that does not reflect the scarcity value of CO_2 while other sectors of the economy are treated differently, then the marginal cost of emissions reductions will differ across the economy, potentially greatly increasing the cost to the economy of emissions reductions. It will also undermine consumer decisions with respect to investments in end-use efficiency because electricity will be priced below its marginal social cost. This is why the Market Advisory Committee recommended a mixed approach of auction and free allocation, with the auction growing over time, and allowance value assigned to reinforce program goals and to meet social priorities rather than to compensate producers or consumers in the long run.

[11] Both approaches preclude grandfathered free allocation to generators because of the difficulty of assigning allocation to importers. However, another type of free allocation, known as updating (in Europe this is described as benchmarking), can be used. Updating allocation is done on the basis of production and the current or very recent period. Because there is essentially an output subsidy in the form of free allowances based on output, updating provides an incentive for electricity generation. Compared with grandfathering, an updating approach tends to lessen the likelihood of windfall profits because of its effect on the product price (Burtraw et al. 2005).

Where There Are Real Differences

A second group of issues involves real differences in how load-based and first-seller programs would perform. One issue is administrative in nature, a second concerns monitoring and incentives, and a third is environmental integrity.

Administration

The virtue of a cap-and-trade program, according to economists, is that it is simple in both theory and practice. The traditional prescriptive regulatory approach (a.k.a. command-and-control) seems simple until one accounts for the endless and idiosyncratic variances that have to be reviewed for virtually every facility. The U.S. Environmental Protection Agency has found it dramatically simpler to administer cap-and-trade—nationwide, for example, only about 100 government staffers implement the SO_2 and NO_x trading programs (EPA 2003)—and this contributes to transparency and the perception of fairness associated with cap-and-trade. One of the pleasant surprises of the SO_2 trading program was the paucity of litigation, compared with what is expected when traditional rate-based or technology-based standards are implemented (Burtraw and Swift 1996).

Simplicity in theory and practice would not describe the load-based approach, however. With respect to the treatment of imported power, the load-based and first-seller approaches share complicated accounting and administration. But for in-state generation, the first-seller approach easily identifies and accounts for emissions, whereas the load-based approach introduces complexity and imprecision in making an assignment of emissions to generation that occurs in the state as well as out of state. To account for emissions associated with electricity consumption, computer software will have to link emissions to load in a manner that will lack transparency and be difficult for third parties or even market participants to verify. In California the Independent System Operator (ISO), which oversees most, but not all, of the state’s grid, manages roughly 15,000 transactions hourly. To track these transactions and their associated emissions is a tremendous project even under the best of circumstances.

Monitoring and Incentives

However, the emissions trading program is not being introduced under the best of circumstances, and consequently the load-based approach will not be able to assign emissions to load in a precise manner. One source of imprecision comes from ancillary operations providing load balancing, voltage support, and spinning and nonspinning reserve services to the electricity market, which account for five percent to seven percent of the energy procurement in the state. These services are typically applied by auction by most ISOs, and the bidding structure has no information about the emissions profile. In the context of the grid, ancillary services are a public good and their benefits cannot be uniquely assigned to one or another LSE. Therefore, emissions associated with ancillary services are assigned to LSEs arbitrarily. It follows that the LSEs would lack the ability to influence emissions associated with ancillary services in this portion of the market. In contrast, emissions associated with ancillary services would be naturally assimilated in a first-seller approach.

Under a load-based approach, imprecision of measurement in the ancillary market and the general structure of the wholesale market will erode the incentive for most generators to reduce emissions on an even broader scale. In a competitive wholesale market, the marginal generator sets the price. Imagine the market-clearing price is set by generator i and the price per megawatt-hour of electricity (p) is equal to the marginal cost (g_i) of generator i. All other facilities (j) with marginal cost (g_j) less than g_i earn p as well. These facilities have an inherent incentive to reduce their generation cost because their profit is equal to the difference between revenue and cost; that is, $p - g_j$. Under a first-seller approach, they would also have an incentive to reduce their emissions because this would reduce their requirement to surrender emissions allowances and thereby lower their cost, just like reducing generation cost.

The incentives under a load-based approach are quite different. The introduction of a load-based program would raise the cost for the LSE if generator i emits CO_2 because in addition to paying a wholesale market price, the LSE would have an allowance cost (a_i). If this facility remained the marginal generator, the effective cost of power for the LSE from this facility would rise to $p^+ = g_i + a_i$. If the LSE had the ability to send signals into the market to discriminate among bids according to their emissions, then the market would identify a new marginal generator k instead of i if $g_k + a_k < g_i + a_i$, resulting in a new wholesale power price $p' = g_k$. Facilities i and k would have incentives to reduce their emissions, but all other facilities j with $g_j + a_j < g_k + a_k$ would not have an incentive to try to reduce their emissions rate because (a) they would not have compliance responsibility under a load-based approach and (b) reducing their emissions would not change their revenue but presumably would raise their cost. Consequently, inframarginal generators would lack an incentive to achieve emissions reductions.

The differences between the two approaches come into even starker contrast in the context of the ISO’s Market Reform and Technology Upgrade initiative, already approved by the Federal Energy Regulatory Commission. One component of this will be the expected introduction of a day-ahead market in 2008 that will attract 10 to 20 percent of the power provided into the market. The reform moves away from unit-specific contracts and commitments and allows more sophisticated portfolio strategies in the power market. As such, the day-ahead market will erode the “line of sight” between generators and the LSEs because sources that supply into the market will not be identifiable by the entities purchasing from the market. The LSE would submit a schedule of bids for purchase and the ISO would clear the market among offers to sell. This is a fundamental component of the market that leads to efficiency improvements in the ISO’s scheduling of the transmission grid.

The consequence is the classic problem of the bad chasing out the good in the day-ahead market. The combination of a load-based cap-and-trade program and the day-ahead market would lead relatively dirty generators to bid into the market to hide the cost of their emissions. Generators in the day-ahead market would lack incentive to reduce emissions because they are not identified and receive no reward for doing so. The only solution would be to separate the ISO day-ahead market into a bunch of different markets, each with different emissions profiles, but this would undermine the advantages of the day-ahead market.

When LSEs buy from the day-ahead market, as opposed to making purchases outside the market, they would buy with a specific anticipated emissions rate. The actual estimation of emissions associated with generation would have to occur ex-post because the actual generation that is scheduled would depend on congestion on the transmission grid and the decisions of the system operator. What happens if sometime later the LSE finds out that a different constituency of generators was actually dispatched by the system operator and the emissions rates deviate from the rates the LSE thought it bought from the market? Litigation may have to determine whether the ISO or the LSE is responsible, and the administrative and legal issues are likely to become complex.

Meanwhile, relatively clean generators would want to avoid the day-ahead market. One would expect to see greater bilateral contracts and self-scheduling among relatively clean generators trying to capture the value of their relatively low emissions rate. The LSE would then submit instructions to the ISO for specific dispatch of facilities under a bilateral contract. This begets another issue. What happens, and which party is liable, when the LSE instructions to the ISO for self-scheduling cannot be fulfilled because of transmission constraints? Is the ISO or the LSE responsible for the unanticipated emissions?

Gillenwater and Breidenich (2007) describe an approach to load-based regulation that would help overcome the problem of imprecise monitoring and impure incentives, at least for power generated in the state, but unfortunately this approach would move the cap-and-trade program away from efficiency in other ways. The authors propose a program that would not require bilateral transactions between generators and LSEs. Generators would produce a tradable certificate for the power they sell onto the grid that would record two measures: the power put onto the grid (MWh) and the emissions (tons CO_2). LSEs would be responsible for acquiring a sufficient number of certificates to cover their sales to customers, and they would be responsible for the emissions that accompany the power sales on their portfolio of certificates. The certificates that an LSE acquires would not necessarily come from generators that provide power to the LSE; they could come from any generator in the program. The LSE would have to pay a premium for certificates with relatively a low emissions profile and would manage a portfolio of certificates such that its emissions cap was achieved.

The certificate approach is elegant in the way that it provides incentives to generators and the LSE. Unfortunately, this approach creates a bad model if the electricity sector is integrated into an economywide trading program. The way that power producers earn certificates is through power production, and therefore this is fundamentally an output-based, updating allocation of certificates (Hobbs 2007). Such a program provides an output subsidy to generators that are cleaner than the system average, which leads to expanded production from those facilities and which leads to lower electricity prices. To see this in a simple way, first imagine a program with full auction of allowances (*a*) at a price p_a, which in general moves positively with the amount of emissions and generation. A facility must buy allowances to cover emissions (*e*), and its emissions change with production at a marginal rate of $e'(q)$. The marginal generation cost is an increasing function of quantity $(c'(q) > 0)$. The marginal facility will generate where its total variable cost is equal to revenue: $p(q) = c'(q) + e'(q) * p_a$, and the allocation of emissions and generation can be expected to be efficient. Now imagine instead emission allowances were distributed for free using a certificate program. Let the average emission rate under the cap (termed the "default emission rate" by Gillenwater and Breidenich) be $\bar{e}$, such that if all generators produced this amount the cap would be met. Firms are freely allocated certificates at this emission rate times their quantity of output. At the prior level of production by all firms the price of allowances (certificates) would be unchanged. However, the price of electricity would be greater than variable cost: $p(q) > c'(q) + \left(e'(q) - \bar{e}\right) * p_a$, because of the new term on the right hand side $\bar{e} * p_a$ that constitutes a subsidy to production. Consequently, the facility would chose to produce at a level of output equal to $\hat{q} > q$.

Although there is a political virtue to lower electricity prices that would result from an output-based, updating allocation, as noted elsewhere there is a substantial efficiency cost (Burtraw et al. 2001; Fischer 2003). The output subsidy leads to increased generation, with a larger number of MWh chasing the same number of allowances under the cap, which drives up the allowance price. This has two negative consequences. The higher allowance price sends an inaccurate signal to policymakers about the minimum resource costs necessary to achieve emissions reductions. In addition, the effect would be to raise allowance prices for the economywide program while subsidizing production of electricity.

Some advocates of the load-based approach have argued that the imprecise monitoring and impure incentives problems do not matter because there is little opportunity for supply-side reductions in emissions. A similar viewpoint was prominent prior to the implementation of the SO_2 trading program as well. At that time, most observers expected that SO_2 emissions reductions would come primarily from the introduction of capital-intensive post-combustion controls (scrubbers). Some switching from high to low sulfur coal was expected. Blending of types coal types was expected to be limited to at most five percent low-sulfur coal in boilers that operated with high-sulfur fuel (Torrens et al. 1992). However, given the incentive to do so, many facilities found ways to reduce emissions without scrubbers. Ellerman et al. (2000) estimate that 63 percent of emissions reductions in the first three years of the program (1995–1997) were achieved in ways other than scrubbing; this is a careful estimate that accounts for unanticipated changes in relative fuel prices that favored switching to lower-sulfur coal even in the absence of the emissions cap. The primary method to achieve reductions was switching to lower-sulfur coal. In addition, trial and error led to the discovery that fuel blends containing up to 30 to 40 percent low-sulfur coal were possible without causing a derating of the facility (Burtraw 2000).

Today, many people look to post-combustion controls for CO_2 (carbon capture and geologic sequestration) as the prominent way to achieve large emissions reductions from the electricity sector, but unfortunately, the widespread commercial application of this technology is a ways off. But other types of measures to reduce CO_2 emissions, such as cofiring biomass at coal-fired power plants, are feasible now. Improvements in heat rate (the fuel requirement per unit of electricity generation) and associated reductions in fuel use have been achieved on a slow but ongoing basis for decades and offer continued opportunity. Moreover, fluctuation in heat rates and emissions varies significantly among facilities and depends on how a facility is dispatched, and thus the scheduling of facilities for operation provides another opportunity to harvest low-hanging fruit on a fleet-wide basis. However, under a load-based approach, the incentive to harvest these opportunities to reduce emissions would be eroded because there would be no way to pass the value of emissions reductions to many generators. More importantly, the load-based approach will fail to deliver incentives for technological innovation (Van Horn and Remedios 2007).

In sum, the load-based approach will not be able to send accurate, transparent signals to generators in a general way about the opportunity cost of emissions. This is especially true if the electricity market continues with market reform. The lesson is that it is important to recognize that the vision for the future of the electricity market and the design of a greenhouse gas cap-and-trade program are inherently linked.

Environmental Integrity

The third difference between the two approaches regards environmental integrity. If there is a CO_2 emissions cap and it is enforced, then one can presume that emissions will fall. However, the two approaches have broad-reaching—and different—implications for the integrity of the institutions that they would create.

If one is going to use a market to address environmental problems, achieving environmental integrity requires integrity in the emissions market: any emissions covered by the cap-and-trade program must be monitored, reported, and verified with a high degree of accuracy. Although both approaches have inherent inaccuracies with respect to imported power, a load-based approach has inaccuracies for all emissions in the market. This threatens to undermine public confidence in the institution of cap-and-trade for greenhouse gas policy in California.

Looking back 15 years, one can note what happened with the SO_2 trading program. At the time, emissions trading was far from popular among environmental advocates. There were cartoons asking, “What’s next, the L.A. Police Department trying to buy civil rights credits in Wisconsin?”

Yet a few years later, environmental advocates in Washington were the leading proponents for using cap-and-trade to address a new wave of environmental problems. The SO_2 program brought virtually 100 percent compliance. Interested parties could look at the web and see electronic reporting of emissions and tracking of allowance ownership. Environmental advocates could see exactly what was happening at specific plants and knew that every plant was incurring an opportunity cost associated with those emissions. That reassured the financial community. Investors knew that if they made an investment to reduce emissions at a specific plant, the value of that investment would not be hidden by averaging of emissions in the market and thereby eroded.

The key element in a market-based policy is to use changes in relative prices to pass to economic decisionmakers, both upstream and downstream, financial responsibility for the environmental consequences of the economic decisions they make. A load-based approached can be criticized in this regard for its lack of transparency and its inability to send those price signals upstream, which has the potential to undermine investor confidence and erode confidence in the emissions market.

The integrity of the emissions market is important, but not because the success of the program should be measured on the basis of the performance of a market. The point of emissions allowance trading is not to trade emissions allowances. The design of the market is important because it can lower the overall cost of achieving emissions reductions. This in turn can lead to savings for households and for business, or it can mean that society can achieve greater emissions reductions for the same cost. However, if California is to use a market to achieve its goals, then it should not want to create a market that is not going to perform as markets are expected to. That would erode confidence in the market and also in the political will to achieve environmental goals.

Where the Jury Is Still Out

In two general areas—the law and national-level environmental policy—it is difficult to tell whether there is an important difference between a load-based approach and a first-seller approach.

Legal Challenges

The legality of the approaches being considered is one issue that could trump other considerations if one or the other of the approaches was found to violate the law. Two potential legal challenges have been discussed widely. One is the Interstate Commerce Clause, which constrains the state's ability to regulate interstate trade. Specifically, the state cannot treat commerce from inside and outside the state in a different manner to the disadvantage of out-of-state entities.

One way to view the first-seller approach is that it would operate like the proposed low-carbon fuel standard (Farrell and Sperling 2007). All first sellers of electricity would be regulated according to an assumed emissions rate, and sellers would have the opportunity to introduce evidence to the contrary. In fact, for sellers of power generated in California it would be easy to introduce evidence—by reference to the monitoring of emissions from large stationary sources that will be compiled by the California Air Resources Board. For power from out of state, first sellers would have the ability to provide financial information linking power identified on the NERC e-Tag documents with specific generation sources. They could then show the path of financial obligations that is associated with power generation. Conceptually, this is a uniform application of the regulation for sources in state and out of state; whether the law views it in this manner remains to be seen. The load-based and first-seller approaches appear to be in the same boat with respect to how Interstate Commerce Clause issues are interpreted.

The second potential legal challenge has to do with the Federal Power Act, which reserves to the Federal Energy Regulatory Commission the authority to set rules governing transmission of electricity. Some have suggested that the act may render substantive “first seller” obligations unenforceable because it places the state in the position of regulating wholesale power transactions. Others disagree. Either way, some have suggested the state could seek a declaratory order that would explicitly delegate authority to the state or the ISO to regulate transactions in these ways. On this legal issue the uncertainty is greater for the first-seller approach. The load-based approach imposes obligations directly on the load-serving entities and indirectly on wholesale transactions, so it may have greater immunity against a Federal Power Act challenge.

Influencing the Federal Policy Agenda

The Market Advisory Committee articulated the view that the cap-and-trade program was not inconsistent with the state’s existing widespread technology and regulatory policies promoting efficiency in electricity end use and low-emitting sources of generation. With these policies already in place, the cap-and-trade program is intended to leave no low-cost emissions reductions behind by providing incentives for all generators in state and out of state to squeeze out the small margins of additional efficiency through heat rate improvements, biomass cofiring, small changes in the dispatch order, or whatever means they may discover.

One function of a cap-and-trade program in California is to add to the momentum for achieving climate policy at the federal level and to propose an architecture that will influence federal policymakers. The Regional Greenhouse Gas Initiative states have clearly done this already with their decision about the initial distribution of emissions allowances with an auction.

What might be the implication of a load-based cap-and-trade program in California? This approach was initially suggested as a matter of necessity, not as a useful model on a national level. If the market were to work poorly, it might impart unfortunate lessons for national policymakers. On the other hand, a powerful impetus for federal action throughout history has been to rationalize the helter-skelter of policies that spring up among the states.

A first-seller approach in California would have the advantage that as California joins with regional efforts as part of the Western Climate Initiative, the approach would segue naturally into a source-based approach on a regional basis. This option would allow California to transition naturally to a regional or national generator-based system.

Conclusion

The load-based approach and first-seller approach are two alternative designs for a cap-and-trade program in the electricity sector. They differ in their ability to account for emissions in the state, and this paper argues that a first-seller approach would be a stronger framework. This recommendation takes into account the fact that the California PUC has played a leadership role in portfolio planning, procurement, and efficiency policies. The role for cap-and-trade is simply to leave no low-cost emissions reductions behind. A first-seller approach is much better suited to this purpose.

Three points conclude this argument. First, the organization and vision for the greenhouse gas market and the electricity market are inherently linked. The load-based approach is not consistent with market reform and greater competition in the electricity sector.

Second, the load-based approach may prevail as a way to administer a cap with some flexibility, but it is not a market. It is increasingly flexible, increasingly smart regulation—one can think of it as cap-and-regulate. The reason to adopt a cap-and-trade program has to do with the virtues associated with the market, including administrative simplicity, environmental certainty, and cost reductions. If California is going to use a market-based approach, it should not design a market by compromise. It is important for good market design to keep it simple and transparent. A poorly designed market can lead to poor incentives and poor accountability that can bridge to other sectors and undermine confidence in climate policy. This raises the question whether it is worth the trouble and risk of embracing the idea as though it were a market.

Finally, from a statewide and national perspective, it is important to resist the parochial view that allowance value should be kept in the electricity sector. Keeping it in the electricity sector and subsidizing electricity consumption will cause marginal costs to differ across the economy, raise total costs across the economy, and undermine the environmental initiative. In designing its program, California has an opportunity to take a broader, longer-term view and set a progressive example that one can hope would influence national policy.

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