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Compliance Responsibility And Allowance Allocation In A Co2 Emissions Cap-And-Trade Program For The Electricity Sector In California

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COMPLIANCE RESPONSIBILITY AND ALLOWANCE ALLOCATION IN A CO_2 EMISSIONS CAP-AND-TRADE PROGRAM FOR THE ELECTRICITY SECTOR IN CALIFORNIA

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
Karen Palmer, Dallas Burtraw and Anthony Paul
Resources for the Future,

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by binging environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

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Compliance Responsibility and Allowance Allocation in a CO_2 Emissions Cap-and Trade Program for the Electricity Sector in California is the final report for the Point of Compliance Regulation and Point of Allocation in a CO_2 Cap-and-Trade Program for the Electricity Sector in California project (contract number 500-02-004, work authorization number MR-069) conducted by Resources for the Future. The information from this project contributes to PIER's Environmental Exploratory Grant Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

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Abstract

The regulation of greenhouse gas emissions from the electricity sector within a cap-and-trade system poses significant policy questions on where to locate the point of compliance and how to allocate tradable emission allowances. The point of compliance addresses where, in the supply chain linking fuel suppliers, generators, the transmission system and retail local distribution companies, should the obligation for measurement and compliance be placed. This problem is examined in the specific context of California's legislative requirements and energy markets, and different policy options explored. The conclusion offered is that one particular approach to regulating the electricity sector—the *first-seller (first deliverer) approach*—would be best for California. How to allocate emission allowances is important because allocation conveys tremendous value and can have efficiency consequences. This research uses simulation modeling for the electricity sector to examine different approaches to allocation and how it affects prices and other aspects of the electricity sector, as well as implications for the overall cost of climate policy for the California economy. An important issue that influences both questions about point of compliance and method of allocation is the opportunity for emission reductions in California to be offset by emission increases in neighboring regions that supply electricity to the state. This study finds the amount of *emission leakage* (i.e. an increase in CO_2 emissions outside of California as a result of the program) varies with the regulatory design of the program.

Keywords: cap-and-trade, electricity generation, electricity sector, emissions, regulation, governance, allocation, California

Executive Summary

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. In June of 2008, the Air Resources Board released a draft framework for its plan that outlines important roles for both a cap-and-trade approach and a collection of regulations, voluntary measures and other policies to reduce carbon dioxide (CO_2) emissions. The details of the cap-and-trade program and exactly how it will relate to the other measures and policies is a decision that will be made in the next couple of years.

Two important challenges in designing a CO_2 allowance cap-and-trade program for implementing Assembly Bill 32 (AB32) in California are **where to assign responsibility for compliance** with the cap on emissions and **how to allocate the CO_2 emission allowances** created by the program. These two elements of policy design are distinct. Within California and beyond, debates over these two issues have focused largely on the electricity sector as one of the major large point sources of CO_2 and likely to be an important player in a future CO_2 cap-and-trade program within California. Decisions regarding both of these policy design elements will have important implications not only for the performance and effectiveness of the California program, but also for how that program helps to inform and shape a future federal economy-wide cap-and-trade program for greenhouse gases.

This research addresses the options for regulation of California's electricity sector within the context of an economy-wide cap-and-trade program in the state, and potentially for the nation. First, the issue of where to locate the point of compliance in the electricity sector is examined—that is, where in the supply chain linking fuel suppliers to generators to the transmission system to retail load-serving entities (LSEs) should the obligation for measurement and compliance be placed. Second, a simulation model of the national electricity markets is used to look at how different approaches to allocating CO_2 allowances within the electricity sector affect the performance of the regional electricity markets and of the cap-and-trade program.

The analysis of point of compliance is a systematic comparison of a compliance strategy that focuses on load serving entities and one that focuses on the entity that first delivers power to the California electricity market, what is referred to in this study as the "first seller" approach. This study identifies those areas in which the two approaches don't really differ, those areas in which they do differ, and some questions that remain about the legality of both approaches, and their relevance for influencing the design of a broader regional or national climate policy.

The effects of allowance allocation are analyzed by using an electricity sector market simulation model to quantify the likely effects of a cap-and-trade policy on state and regional electricity markets and the effects of different approaches to allowance allocation on both electricity markets and emission allowance markets. As a part of this simulation exercise, this study examines the issue of emissions leakage (i.e. an increase in CO_2 emissions outside of California as a result of the program) and considers how expanding the geographic scope of a cap-and-trade program in the region to address leakage affects the cost of controlling CO_2 emissions and the impact of a cap-and-trade program on electricity consumers both in California and beyond.

The most important findings of this study are listed below:

- Responsibility within the electricity sector for compliance with a CO_2 emissions cap-and-trade program under AB32 should rest with the first-seller of electricity in the California market.
- The first-seller approach is superior to load-based compliance in part because the latter is not consistent with market reform and greater competition in the electricity sector. A first-seller approach does not interfere with expanded competition and improved market institutions in the industry. Also, the first-seller approach promises administrative simplicity compared to the load-based approach.
- Using a first-seller approach combined with an allowance auction to cap emissions of CO_2 from the California electricity sector at 30 percent below business-as-usual levels in 2020 results in roughly an 11 percent increase in electricity price in California. Roughly half of that price increase would be mitigated if allowances are allocated to local distribution companies in California on the basis of population (load-based allocation).
- The lower electricity price effect with load-based allocation comes at a cost. This allocation approach would yield a CO_2 allowance price in 2020 that is more than 100 percent higher than the allowance price resulting under an auction. With a smaller increase in electricity price, electricity consumers would have a weaker incentive to conserve electricity, which means that there will be more demand for the fixed quantity of emission allowances, thus driving up their price.
- Under an economy-wide CO_2 cap and trade program and load-based allocation in the electricity sector, the higher allowance price effect that results compared to an auction has implications for other parts of the California economy. The relatively lower electricity price and associated higher electricity demand imply that fewer emission reductions would be achieved within the electricity sector than would occur with an allowance auction, and consistent with the higher overall allowance price, more would be required from other sectors of the California economy.
- With an allowance auction, roughly one-quarter of the emission reductions targeted for 2020 in a CO_2 cap-and-trade policy in the California electricity market would be lost through leakage. Under a load-based approach to allocation, the percentage of emissions reductions lost through leakage would rise to 45 percent. If the state were to ignore emissions associated with imported power (an approach that would not comply with AB32), leakage would approach 100 percent.

- Imposing a western regional CO_2 emissions cap on the electricity sector that delivers similarly ambitious percentage reductions in emissions throughout the region as modeled in the California-only policy would address the leakage problem. It would do so at lower cost to California electricity consumers and at a substantially lower marginal cost of CO_2 emissions reduction than a cap-and-trade policy limited to California.

In general, this analysis suggests that the most cost-effective approach to implementing a cap-and-trade program in the electricity sector would be to use a first-seller approach (first deliverer) for the point of compliance and to use an auction for the allocation of emission allowances. The possible uses of revenues raised in an auction are not addressed in this study. California's decision about the architecture of AB 32 could play an important role in helping to shape climate policy in other states and regions, and at the federal level.

1 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 (ARB) to develop a comprehensive plan for implementation by January 1, 2009; the plan will involve a number of state agencies. In June 2008, the ARB released a draft framework for its plan that outlines important roles for both a cap-and-trade approach and a collection of regulations, voluntary measures and other policies to reduce CO_2 emissions. The details of the cap-and-trade program and exactly how it will relate to the other measures and policies is a decision that will be made in the next couple of years.

One of the challenges California faces is how to regulate the electricity sector. Electricity consumption (including emissions associated with imported power) is estimated to account for 23.5 percent of the greenhouse gases in the state, including about 27.7 percent of the carbon dioxide (CO_2) emissions (California Market Advisory Committee 2007). This is a low percentage 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.[1] The largest category of greenhouse gas emissions in California is transportation, which accounts for about 40.4 percent. 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, at least at the national level, where modeling indicates that the electricity sector will account for between two-thirds and three-quarters of emissions reductions in the next two decades under national policy (U.S.EIA 2007b; Pizer et al. 2006). In California, however, there may be fewer low-cost opportunities for emission reductions in the electricity sector because little electricity is generated using coal, limiting the potential emissions reductions from fuel switching away from coal. Second, experience with cap-and-trade programs 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, have focused primarily on electricity generators and the Emission Trading Scheme for CO_2 in the European Union focuses exclusively on point sources, the majority of which are also electricity generators. The electricity sector is the demonstrated successful testing ground for this type of regulation.

<insert Figure 1-1 here>

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[1] US electricity emissions are about 9 percent of total CO2 emissions worldwide. The Market Advisory Committee (2007, p. 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.

California's own generation resources are low emitting, while its imported power is relatively high emitting. About 80 percent of the electricity consumed in the state is generated in the state, but as illustrated in Figure 1-1, about 52 percent of the greenhouse gas emissions associated with electricity consumption comes from outside the state (CEC 2006).[2] 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 out-of-state emissions. 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 research addresses options for the regulation of California's electricity sector within the context of an economy-wide cap-and-trade program in the state, and potentially for the nation. Two important design features of such a cap-and-trade program are addressed in this paper. First, this study examines the issue of 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 (LSEs) should the obligation for measurement and compliance be placed. Second, a simulation model of the national electricity markets is used to look at how different approaches to allocating CO_2 allowances within the electricity sector affect the performance of the regional electricity markets and of the cap-and-trade program. The main options for allocation that are addressed include an auction and free allocation to local distribution companies (LDCs) that are responsible for the distribution of power to retail customers. For most customers the LDC and the LSE are one in the same, but they need not be if a customer is purchasing electricity from an entity other than its local utility in which case that other entity is the LSE and the LDC is still the one that ships electricity to your door.

In considering the point of compliance, the conclusion offered is that the *first-seller approach* to regulating the electricity sector would be best for California. One alternative, the *load-based approach*, initially had 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 apply equally to the first-seller approach. 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 fundamental ways. The load-based approach would have greater complexity because of the endemic separation between the entity responsible for emissions and the entity where emissions occur. Because there are thousands of transactions every hour between these entities in the California power system, it would be challenging to construct a system that provides transparent signals to electricity generators about the scarcity value of CO_2 in the economy.

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

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[2] This measure is somewhat ambiguous because it is based on financial contracts with out-of-state generators. To some degree, if those facilities did not serve California, they would serve other customers in the west.

markets is regulation as currently practiced, then the load-based approach would be consistent. But if the goal is to increase competition—for example, through the introduction of a day-ahead market as planned for early 2009—then load-based compliance within a cap-and-trade program would pose a fundamental conflict.

<insert Figure 1-2 here>

As Figure 1-2 illustrates, the point of allocation and the point of compliance need not be the same. The term allocation implies free initial distribution of emission allowances, but in fact there may be no free allocation at all. 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 almost 100 percent of the allowances being distributed by New York and 5 other states in the 10-state Northeast Regional Greenhouse Gas Initiative that takes effect in January 2009 (the remaining states distribute a large fraction through an auction).[4] An auction approach also was the approach highlighted as preferable, especially after a transition period, by the California Market Advisory Committee. Discussions of allowance allocation in California also have included the possibility of allocating allowances for free to local distribution companies, which would transfer a substantial amount of the allowance value created by the program to electricity consumers.

In this study, the modeling analysis of a California-only cap-and-trade program for CO_2 applied to first-sellers in the California electricity market suggests that such a program would result in leakage (i.e., an increase in CO_2 emissions outside of California in response to the program) of 26 percent of the emissions reductions achieved under the program if allowances were distributed through an auction, and 45 percent if allowances were allocated for free to local distribution companies. Compared to an auction, allocating allowances to local distribution companies on the basis of population in the service territory would reduce the effect of a cap-and-trade policy on average electricity price in California by roughly half. However, the smaller price effect would come at a cost of a 100 percent increase in allowance prices in 2020. Expanding the geographic scope of the program to encompass all the western states substantially addresses the leakage concern and lowers both the marginal cost of CO_2 emission reductions, as reflected in the allowance price, and the effect of the policy on electricity

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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 the 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 in regulated regions of the country. Ruth et al. (2008) demonstrate 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.

price in California. Allocating allowances to local distribution companies in the broader western region will reduce the size of the increase in electricity price, but will increase allowance price by nearly 30 percent compared to an auction.

The next two sections of this paper set forth an analysis of the point of compliance in the electricity sector. The subsequent section addresses the issue of allocation using simulation modeling. Section 4 introduces the modeling scenarios and Section 5 presents analysis. Section 6 provides concluding observations.

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

One month after the 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 (ARB) on developing a plan for a cap-and-trade program. One alternative identified by the committee was 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.[5] 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, was midstream regulation. As illustrated by Figure 1-2, 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 a comparable coverage of 83 percent of the state's emissions by regulating 490 facilities, assuming that transportation fuels would be regulated at the refinery.

The first question addressed in this study is how the midstream regulation 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 LSEs—the 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. This approach had been previously endorsed by the California Public Utilities Commission (CPUC), which regulates the private investor-owned utilities (IOUs) that provide about 80 percent of the state's retail electricity.

In the winter of 2008, the CPUC (2008) changed course and recommended along with the California Energy Commission that ARB should pursue an alternative strategy, the *first-*

[5] 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.

deliverer approach, originally proposed as the so-called *first-seller approach* by the Market Advisory Committee (2007). 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 the same as 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 discussed below. It is worth emphasizing that if California's program is integrated into the efforts of the seven states and three Canadian provinces participating in the Western Climate Initiative and if a cap-and-trade program is implemented in this broader geographic region, the issue of electricity imports will be much reduced.

3 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.[6] These issues are addressed in three groups. The first group is where differences of opinion abound, although there is fundamentally little or no distinction 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.

3.1 Where There Are Differences but No Real Distinctions

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 consumers of electric power. The alleged differences in the performance of the load-based and first-seller approaches in these matters do not hold up under scrutiny.

3.1.1 Regulating Imported Power

California cannot legally 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 an 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

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[6] See, for example, the proceedings and supporting documents submitted at the Joint En Banc Hearing of the California Public Utilities Commission and California Energy Commission on Point of Regulation in the Electricity Sector in San Francisco on August 21, 2007. < http://docs.cpuc.ca.gov/energy/electric/climate+change/aug212007enbancagenda.htm>

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. According to Bushnell (2007) and Fowlie (2007), contract shuffling could result in no real change in the resource mix and therefore no real change in CO_2 emissions throughout the western electricity grid under AB32 even under nominal compliance with AB32 and "reductions" from baseline emissions levels.

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 (CCAR) 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), relying on the CCAR protocol allows for a precise identification of the power plant and associated emissions for about 56 percent of imported power.[7] The remainder would have to be assigned an emissions intensity based on other information, such as the average emissions intensity for the control region from which the power is delivered into California based on information from the electronic North American Electric Reliability Council E-tag documents.[8] Under either approach, this is the information that regulators would use to make an assignment of out-of-state emissions 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 used to assess the compliance 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 difference between them stems from what happens on the California side

[7] Confidence in the estimate may be undermined by the evolution of contracting relationships over time. If a financial penalty is placed on high-emission import contracts, over time as contracts expire and are renewed, they will be replaced with new contracts with cleaner sources. This turnover of contracts could erode the effectiveness of the program because the new contracts do not necessarily imply there will be any different investment or operation of the electricity system than would occur in the absence of the program. Instead, the same generation capability could be assigned differently. On the other hand, California's regulatory efforts under AB 32 and the procurement rule precluding new long-term contracts with high-emitting facilities (mentioned below) affect the investment climate in the power sector and raise the cost of capital for high-emitting projects, thereby affecting generation options over time, and these policies are expected to have a real effect on the nature of future investment. As California's efforts to facilitate an agreement with the multi-state Western Climate Initiative proceed, this effect should be more pronounced.

[8] 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.

of the border. 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.

3.1.2 Procurement Policies

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

Would or should the CPUC's supply-side procurement policies be changed if there is a greenhouse gas cap-and-trade program, and would this depend on the point of compliance? From the CPUC's perspective, the answer is obviously no. The CPUC's policy development in this area predates events that have moved climate policy to center stage in California and reflects long-standing goals for promoting stability in the supply and price of energy resources for supporting ARB efforts to reduce air pollution and for promoting economic development in the state. The CPUC's initiative toward developing a greenhouse gas program follows on top of the other policies and is not intended to substitute for them.

The CPUC 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 CPUC's other goals but because it was the only option available to the CPUC for designing a cap on electricity sector emissions. The CPUC regulates IOUs, which account for roughly 80 percent of the delivered electricity supply in California. 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. 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, the CPUC has limited options when it comes to regulating emissions from sources within the state.

In designing an emissions cap, the CPUC could impose requirements on the load-serving function of the IOUs as it has done in other rules governing how the IOUs meet their resource requirements.[9] Acting by itself as an independent agency, the CPUC did not

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[9] For example, as mentioned above, the CPUC'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, the CPUC 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. These are all load-based approaches to regulation because that is the main way that the CPUC can affect IOU practice, and it can affect other sources only indirectly.

realistically have the option of directly regulating sources or first sellers when designing its greenhouse gas policy. Given the new Act's mandate to cover sources statewide, the CPUC and its sister agencies now have the ability to design a different kind of policy.

3.1.3 Efficiency Policies

A related set of questions concerns the ability of the CPUC to implement its efficiency programs. California is a world leader in efficiency programs. The CPUC 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 and ability to recover fixed cost. Recently, the CPUC moved to provide stronger positive incentives for IOUs to invest in efficiency by rewarding the achievement of specified goals. As with the supply-side policies, the demand-side policies are intended to lessen the overall environmental impact of electricity use.

Proponents of a load-based approach have suggested this approach would do a better job of achieving emissions reductions because it would raise awareness in firms regarding investing in efficiency and renewable energy sources and lessening reliance on fossil fuels.[10] Since the LSE 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.[11] 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.

If the industry operates under an emissions cap, however, then assigning compliance activities at one or another level in the firm or market will not affect the aggregate amount of emissions. 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 or lower the costs for firms, but it will not do anything for achieving environmental goals if emissions are capped.[12]

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[10] Some have pointed to the earliest actions by firms to implement the SO_2 trading program under the 1990 Clean Air Act Amendments as evidence that learning in firms was necessary for the program's success. Indeed, learning about how to function within the new allowance market took time and was one of the subtle ways that incentives led to innovation, as firms learned to reduce their costs of compliance (Burtraw 1996). Firms moved beyond behavior focusing on self sufficiency with trading internal to the company to active trading in the external market (Ellerman et al. 2000; Swift 2001), but this did not affect the overall level of emissions because that was governed by the emissions cap.

[11] 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."

[12] 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.

3.1.4 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 (Chen et al. 2008; Wolak et al. 2007). 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 to achieve environmental goals.

A related issue has to do with 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 unanticipated earnings due to the free allocation of emissions allowances in the European Union's Emission Trading Scheme (Sijm et al. 2006; Point Carbon 2008). In competitive electricity markets in the United States, firms also can be expected to realize an increase in revenues that greatly exceed their increase in costs under the free allocation of emission allowances (Burtraw and Palmer 2008).

Advocates for a load-based approach have pointed to the possibility of windfall profits as justification for a load-based approach. Implicitly, this argument assumes a load-based approach would include allocation to LSEs, or at least no allocation to generators. Windfall profits are related to free allocation to generators. Advocates of a load-based point of regulation have implicitly assumed that it would include allocation to retail providers rather than to generators and that source-based or first-seller point of regulation would entail free allocation to generators. However, this is not necessarily the case, so point of compliance and the method of allocation are considered separately. The point of compliance, considered separately, would not affect the possibility for windfall profits or how the cost of the program is distributed. The effect on the retail power price is identical and the effect on the value of generation assets is identical under a load-based or first-seller approach.

3.2 Where There Are Real Distinctions

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.

3.2.1 Administration

The virtue of a cap-and-trade program, according to economists, is that it is relatively simple in both theory and practice. The traditional prescriptive regulatory approach (a.k.a. command-and-control) seems simple until one accounts for the many 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 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.

3.2.2 Monitoring and Incentives

The load-based approach will not be able to assign emissions to load in a precise manner. One source of imprecision comes from the provision of ancillary services, which include load balancing, voltage support, and spinning and nonspinning reserve services to the electricity market and which account for 5 percent to 7 percent of the energy procurement in the state. These services are typically acquired through an 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 would be 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 many generators to reduce emissions on an even broader scale. In a competitive wholesale market, such as the ISO's planned day-ahead market, the marginal generator sets the price. The marginal generator is the one with the highest cost among all of those deployed in a given hour. Imagine the market-clearing price, the price at which demand and supply are equal, 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 (which it could not do completely in practice), 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, generators with a lower operating and allowance cost than the marginal generator, would lack an incentive to achieve emissions reductions.[13]

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 initiative will be the expected introduction of a day-ahead market that the ISO hopes will attract 10 percent 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. The emissions of individual generators that sell into the market would not be evident to entities that buy power from the market. Generators in the day-ahead market would lack an 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 multiple 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 deviated 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.

[13] Wolak et al. (2007) provide an example where all facilities retain an incentive, but, in their example, the LSE is able to identify the source of power and associated emissions and price discriminate.

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 generation emission attribution certificate (GEAC) 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 within the market for CO_2 allowances. The GEAC 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 a relatively low emissions profile and would manage a portfolio of certificates such that its emissions cap was achieved.

A comparable approach has been proposed by Michel and Nielson (2007), which would introduce the use of CO_2 Reduction Credits (CO_2RCs). A generator would receive CO_2RC in proportion to the inverse of the emission intensity of generation. LSEs would participate in market for CO_2RCs and a price reflecting the scarcity value of CO_2 would emerge.

These certificate approaches are elegant in the way that it provides incentives to generators and the LSE. This approach has a disadvantage if the electricity sector is integrated into an economy-wide 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 (Gillenwater and Breidenich 2007; Michel and Nielson 2007; Wolak et al. 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 to lower electricity prices. 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). 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 $\left(c'(q) > 0\right)$. 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 2007) 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, at the original quantity (q), 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 $\left(-\bar{e} * p_a\right)$ that constitutes a subsidy to production. Consequently, the facility would choose to produce at a level of output equal to $\hat{q} > q$.

The output subsidy leads to increased generation and a lower electricity price than would be obtained under the first-best outcome, such as under an auction. As a consequence, consumers have less incentive to invest in efficiency in their use of energy services. Advocates of a load-based approach argue that this is offset by the greater incentive for LSEs to reduce energy consumption, and they note that LSEs are effective at reducing demand with efficiency programs and are the traditional entity responsible for such programs. But as noted elsewhere, this incentive stems from cost recovery rules and policies to promote efficiency and these policies should not be affected by the presence of an additional constraint. Secondly, the output subsidy causes a larger number of megawatt hours to chase 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 economy-wide program while subsidizing production of electricity. In addition, these approaches have the same challenges in properly accounting for emissions from out-of-state as does the first-seller approach.

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.

3.2.3 Environmental Integrity

The third distinction between the load-based and first-seller 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. Both approaches have inherent inaccuracies with respect to imported power. However, a load-based approach also introduces inaccuracies for measuring emissions for power generated within the state due to the difficulties with associating particular generating sources emissions with each kilowatt hour sold. This threatens to undermine public confidence in the institution of cap-and-trade for greenhouse gas policy in California, and it undermines the incentive to make facility-specific investments that might improve the efficiency of facilities and lower their emissions. For instance, as mentioned above, an investor cannot be sure that he or she will be able to capture the value of reduced emissions if the facility is providing ancillary services or providing power into a day-ahead market, because the performance of an individual facility cannot be distinguished from the average performance of all facilities.

Measurement of emissions at specific facilities has been key to public acceptance of the cap-and-trade approach. Nearly two decades ago, when it was first endorsed as an environmental policy, emissions trading was far from popular among environmental advocates; there were even cartoons making a comparison to tradable civil rights. 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 program had virtually 100 percent compliance. Interested parties could look to the web to 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. This level of transparency helped overcome concerns about environmental justice because observers could see that polluters were penalized financially for their specific emission behavior.

Moreover, the availability of precise information about emissions at individual plants and more importantly the confidence that reductions in emissions would be recognized reassured the financial community because investors knew that if they made an investment to reduce emissions at a specific plant, the value of that investment would not be hidden or eroded by averaging of emissions in the market. Investors could see that more efficient facilities were specifically rewarded for their performance. In the absence of such transparency and the assurance of investors that they will be able to capitalize on the value of efficiency improvements, one could expect some opportunities to be left unrealized leading to a higher marginal abatement cost and higher emissions allowance price, which in turn has ramifications for the costs that must be incurred outside the electricity sector.

The key element in a market-based policy is to use changes in relative prices to pass financial responsibility to economic decision makers, both upstream and downstream, for the environmental consequences of the economic decisions they make. A load-based approach 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.

3.3 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.

3.3.1 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 (Potts 2006). 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 North American Electric Reliability Council 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, or ruling from the Federal Energy Regulatory Commission, 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 LSEs and indirectly on wholesale transactions, so it may have greater immunity against a Federal Power Act challenge.

3.3.2 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 (deShazo and Freeman 2007). 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. Several federal proposals have an upstream point of compliance or a hybrid mixing upstream fuel sources compliance for some fuels or sectors with compliance obligations for emitters in other cases. Even a first-seller or generator-based system implemented by the states will not be the final word. Perhaps a load-based system in California and expanded to other states would introduce such complexity as to hasten federal efforts to develop a uniform and potentially pre-emptive approach to climate policy.

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

4 Simulation Analysis of CO_2 Emissions Cap and Trade for Electricity in California

In this study, the analysis of the two main proposals for how to assign compliance responsibility under a CO_2 cap-and-trade program in California suggests that compliance responsibility, the closely related question of the coverage and treatment of power imports, and the question of how allowances are allocated will have important implications for the performance of CO_2 allowance markets in California and of the California electricity market. These effects will be manifested in potential differences in allowance and electricity prices, new investments in California generators, and the mix of generation used to supply power in California. These efforts could also affect the amount of electricity imported into California and the mix of generation used in the remaining western states. In addition, policy design will affect the level of CO_2 emissions leakage into surrounding states. In this section, a simulation exercise is used to look at the effects of different approaches to a CO_2 cap-and-trade program for electricity in California on allowance markets and state and regional electricity markets.

In this analysis, a simulation model is used to analyze electricity production and consumption decisions in California and the broader western region, both with and without a cap on CO_2 emissions. The effect of the policy on fuel and technology mix, electricity consumption, and prices in the electricity and allowance markets follow from comparing results across scenarios. The model is also used to see how varying the allowance allocation and the geographic scope of the regulation affects what happens in these two related markets. The following sections discuss the simulation model and modeled scenarios.

4.1 Description of RFF's Haiku Model

The electricity supply and market analysis relies on a detailed simulation model of the electricity sector known as the Haiku Electricity Market Model (Haiku), which is maintained by

Resources for the Future. Haiku is a deterministic, highly parameterized model that calculates information similar to the National Energy Modeling System used by the Energy Information Administration (U.S. EIA 2003)., and the Integrated Planning Model developed by ICF Consulting and used by the U.S. Environmental Protection Agency (U.S. EPA 2006). As a deterministic model, Haiku does not include explicit treatment of uncertainty. It includes thousands of parameters representing costs, capacity, emissions characteristics and other features of electricity supply and demand. The data sources for the different categories of Haiku parameters are listed in Table 4.1-1. Figure 4.1-1 shows the inputs to and outputs from the Haiku model.

<insert table 4.1-1 and Figure 4.1-1 here>

The Haiku model simulates equilibrium in regional electricity markets and interregional electricity trade. The model also identifies emission control technology choices for SO_2, NOx, and mercury at different types of generators. The composition of electricity supply is calculated using a fully integrated algorithm for capacity investment and retirement, coupled with system operation in temporally and geographically linked electricity markets. The model solves for electricity price levels and production levels that equate demand and supply in 21 Haiku market regions (HMRs) for the continental United States. Each of the 21 HMRs is classified by its electricity pricing regime as having either market-based electricity pricing (i.e., electricity prices determined by the cost of producing a kilowatt hour for the marginal generator) or regulated pricing (i.e. the average cost of supplying electricity for all generators supplying the market), as shown in Figure 4.1-2. Electricity markets are assumed to maintain their current regulatory status throughout the modeling horizon; that is, regions that have already moved to market-based pricing of generation continue that practice, and those that have not made that move remain regulated. The price of electricity to consumers does not vary by time of day in any region, though all customers in competitive regions face prices that vary from season to season[14]. Electricity demand is sensitive to changes in electricity price and the nature of that responsiveness, or price-elasticity, varies by customer class and over time with less sensitivity in the short run and more sensitivity in the long-run as consumers have time to change their electricity using equipment in response to changes in electricity price. The demand elasticities assumed in the model are reported in Table 4.1-1.

[14] The structure of electricity prices in the future is the subject of a great deal of uncertainty. Research (Borenstein 2005) suggests that allowing prices to vary by time of day, even for a small subset of electricity consumers, could substantially lower the costs of supplying electricity, particularly during peak periods, by reducing demand for at least some customers. Ruth et al. (2008) find similar outcomes with respect to improvements in the efficiency in the end use of electricity. Even if these improvements occur in a subset of households and establishments, all customers benefit through a reduction in the retail electricity price.

<insert Figure 4.1-2 here>

<insert Table 4.1-2 here>

Each year is subdivided into three seasons (summer, winter, and spring-fall) and each season into four time blocks (superpeak, peak, shoulder, and base). For each time block, demand is modeled for three customer classes (residential, industrial, and commercial). Supply is represented using model plants that are aggregated according to their technology and fuel source from the complete set of commercial electricity generation plants in the country. Investment in new generation capacity and the retirement of existing facilities is determined by the model in a framework that takes into account capacity-related costs of providing service in the future ("going forward costs") and future electricity prices that are assumed to be known today. Operation of the electricity system (generator dispatch) in the model is based on the minimization of short-run variable costs of generation, including fuel costs, variable operating and maintenances cost and the costs of operating pollution control equipment plus the opportunity costs of using emissions allowances for those emissions subject to a cap-and-trade program.

Equilibrium in interregional power trading is identified as the level of trading of electricity between regions necessary to make marginal generation costs within each region net of transmission costs and power losses equal across neighboring regions. These interregional transactions are constrained by the level of the available interregional transmission capability as reported by the North American Electric Reliability Council (2003a, 2003b).[15] Factor prices, such as the cost of capital and labor, are held constant across different simulations of the model. Fuel prices for coal and natural gas vary according to the level of demand, and are benchmarked to the forecasts of the Annual Energy Outlook 2007 for both level and elasticity of supply (U.S. EIA 2007a). Coal is differentiated along several dimensions, including fuel quality and content and location of supply; and both coal and natural gas prices are differentiated by point of delivery. The price of biomass fuel also varies by region depending on the mix of biomass types available and delivery costs. Other fuel prices are specified exogenously (i.e. they do not change within the model).

Emissions caps in the Haiku model, such as the Title IV cap on national SO_2 emissions initiated under the 1990 Clean Air Act amendments, EPA's Clean Air Interstate Rule (CAIR)

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[15] Some of the HMRs are not coterminous with North American Electric Reliability Council (NERC) regions and, therefore, NERC data cannot be used to parameterize transmission constraints. Haiku assumes no transmission constraints among OHMI, KVWV, and IN. NER and NEO are also assumed to trade power without constraints. The transmission constraints among the regions ENTN, VACAR, and AMGF, as well as those among MAACR, MD, and PA, are derived from version 2.1.9 of the Integrated Planning Model (U.S. EPA 2005). Additionally, starting in 2014, the incremental transfer capability associated with two new 500-KV transmission lines into and, in one case, through Maryland, which are modeled after a line proposed by Allegheny Electric Power and one proposed by PEPCO Holdings are included (Ruth et al. 2008). The transmission capability between Long Island and PJM made possible by the Neptune line that began operation in 2007 is also included.

caps on emissions of SO_2 and NO_x [70 Fed. Reg. at 25,165]. the Clean Air Mercury Rule (CAMR) [70 Fed. Reg. at 28,606] and the Regional Greenhouse Gas Initiative (RGGI) cap on CO_2 emissions (RGGI 2005), are imposed as constraints on the sum of emissions across all covered generation sources in the relevant region.[16] Emissions of CO_2 from individual sources depend on emission rates, which vary by type of fuel and technology, and total fuel use at the facility. The sum of these emissions across all sources must be no greater than the total number of allowances available, including those issued for the current year and any unused allowances from previous years when banking, or holding of unused allowances from one year for use in future years, is permitted. To determine the rate at which the size of the allowance bank (i.e. the amount of cumulated unused emission allowances from past years) changes, the model imposes a Hotelling-type constraint that requires the rate of increase in the price of a durable asset such as emissions allowances from year to year to be no greater than the interest rate (Hotelling 1931). This constraint means that investments in emission allowances are assumed to compete with investment in other financial assets that grow in value over time at the rate of interest.

For this project, the Haiku model was upgraded such that California is disaggregated into two separate HMRs, CALN and CALS (N and S stand for north and south) – see Figure 4.1.1. Treating California as two HMRs allows for a more accurate representation of power transmission congestion for cross-state trades. The state is split by matching individual plants to local distribution companies (LDCs) using the EPA's National Electric Energy Data System (NEEDS) (U.S. EPA 2006) and to service areas using EIA forms 860 A and B. Plants are then assigned to a region based on the location of the LDC or service area. The amount of transmission capacity between the two regions is constrained to 3700 MW, which is the transfer capability reported for the EPA Base Case 2006 Integrated Planning Model.

4.2 Baseline Scenario and the AB32 CO_2 Cap

The analysis of the AB32 policy using the Haiku model is performed with reference to a baseline scenario. The baseline is designed to simulate the electricity sector in California (and beyond) in the absence of AB32 implementation. For this project, a baseline scenario is constructed that incorporates all major federal legislation governing airborne emissions from the electricity sector including the Title IV cap on national SO_2 emissions and CAIR for SO_2 emissions, the annual and ozone seasons caps on emissions of NO_x under CAIR, and CAMR for mercury emissions. Also included are some state level legislation, including RGGI, and other policies that are specific to individual states. For nuclear capacity additions, Haiku uses the regional output of the U.S. Department of Energy's (DOE) National Energy Modeling System (NEMS) model Annual Energy Outlook for 2007 (U.S. EIA 2007a) as capacity limits on new

[16] CAIR was vacated by a three-judge panel of the U.S. Court of Appeals for the D.C. Circuit on July 11, 2008 in *State of North Carolina, et al. v. EPA*, and its status is uncertain. Legislative proposals have surfaced in the U.S. Congress that would introduce CAIR in statute.

construction of nuclear plants. All of these potential capacity additions are east of the Mississippi River.

The baseline scenario assumptions that are most important for California relate to the Federal Renewable Energy Production Tax Credit (REPTC) and state level Renewable Portfolio Standards (RPS) in several western states, including California. The REPTC provides a production tax credit of $19/MWh to new wind, geothermal, and dedicated biomass generators, and a credit of $9.50/MWh is available to new landfill gas and non-dedicated biomass generators. Since the federal REPTC has repeatedly been renewed just prior to lapsing and has actually lapsed three times before being reinstituted, it is modeled in perpetuity in Haiku as a tax credit that is received with 90 percent probability, to reflect roughly the amount of time that it has been in effect since initiated in the early 1990s. The state level RPS mandates within the Western Electricity Coordinating Council (WECC) region require substantial increases in renewables generation in the coming years. The resulting capacity additions are not modeled endogenously within Haiku. Instead, new renewable capacity was added in the in order to meet these standards in the western states according to forecasts provided by Energy and Environmental Economics, Inc (E3, 2008).[17] These forecasts of renewable resource additions that E3 forecasts would be needed to meet RPS standards are built by assumption in our analysis.

In order to model the effects of the AB32 policy, this study specifies the level of the cap on CO_2 emissions from electricity generators in California that will be stipulated under the AB32 policy, or, in the case of a broader-based cap-and-trade policy, an emissions level that reflects the level of reductions expected from the electricity sector. The exact parameters for the cap-and-trade policy have not been decided yet, but the economy wide CO_2 reduction target for 2020 is about 25 percent below the anticipated 2020 business-as-usual level. Preliminary modeling and reading of research at the California agencies indicates that reductions required from the electricity sector in 2020 will be closer at least 30 percent under a cost-effective implementation of the policy, compared to the baseline level. In the ARB Scoping Plan, the assumption is that the emissions reductions under a host of measures complimentary to AB32 (including efficiency and enhanced renewables standards) will be roughly 1/3 of expected baseline emissions and that the cap and trade program will yield even greater reductions than that, bring emissions in the sector down to something between 59 and 94 million metric tons in 2020 (CARB 2008). In this analysis the assumed emissions reductions of 30% below the baseline, which includes a continued production tax credit for renewables generation and thus lower CO_2 emissions than the CEC baseline, will yield total annual emissions from the electricity sector of roughly 64 million tons in 2020.

<insert Figure 4.2-1 here>

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[17] The western states where new renewables capacity was forced include California, Arizona, Montana, Colorado, New Mexico, Utah, Nevada and Wyoming.

The cap on California electricity sector CO_2 emissions that is used in the simulation modeling is phased in over the forecast horizon based on a straight line decline from 1 percent below the 2012 baseline level of emissions to 30 percent below the 2020 baseline level in 2020. The cap is held constant starting in 2020 until the end of the modeling horizon in 2025. The cap encompasses all CO_2 emissions associated with California electricity consumption, i.e. emissions from CA generators as well as those from out-of-state generators that are derived from CA electricity demand are included under the AB32 cap. Figure 4.2-1 shows CA emissions and emissions from CA net imports in the baseline scenario. The yellow line indicates the AB32 cap levels: 156.4 million tons of CO_2 emissions in 2012 and 64.1 million tons in 2020. Note that strictly imposing this declining emissions path from 2012 through 2020 (and then flat thereafter) precludes the banking of allowances not used in early years of the program for use in the future, in order to avoid ambiguities about the compliance target; AB 32 provides that the emissions in 2020 will strictly conform to the cap. However, if the program does allow for banking of emissions allowances, then the allowance prices that result will tend to be higher than what is predicted in the early years of the program as a bank is built up, and prices will be lower in the later years as the bank is drawn down. This price differential occurs because banking increases demand for allowances of early vintages that can be used for compliance in future years and the existence of the bank reduces allowance scarcity in later years, thus lowering the value of allowances with later vintages relative to the "no-banking" case that is modeled.

<insert Table 4.2-1 here>

The model does not include the possibility of purchasing or financing greenhouse gas emissions reductions outside of the capped sector to offset emissions within this sector. Some use of offsets from other sectors likely to be allowed under the AB 32 program (CARB 2008). By not allowing for offsets this analysis is likely overstating the cost of meeting the AB 32 cap.

The CO_2 emissions imported to California are those emissions that are generated outside of California to meet electricity demand inside of California. These are projected using an incremental emissions rates approach intended to reflect the emissions associated with the incremental MWh produced in neighboring states that are generated to serve customers in California. The first step in calculating an emission rate for imported power is to perform a closed-border subbaseline simulation, which is identical to the baseline except that power trading between California and its neighbors is constrained to zero. This subbaseline scenario precludes any of California's power needs from being met by imports to the state. The difference between the regular baseline and the closed-border subbaseline provides a measure of the incremental CO_2 emissions and incremental electricity generation in the NWP and RA regions that result from power trading with California.[18] The emission rates associated with imports are calculated using seasonal and time-block specific changes in emissions and

[18] The NWP region includes the states of Oregon, Washington, Nevada, Utah, Idaho, most of Montana and Wyoming. The RA region includes Arizona, Colorado and most of New Mexico.

generation in the two neighboring regions and these time-block specific rates are used to find emissions values related to imports in subsequent policy simulations. Table 4.2-1 shows the average annual values of the import emissions rate for NWP and RA, the two regions that trade power directly with California.

An alternative methodology is contained in the California Energy Commission (CEC) report "Revised Methodology to Estimate the Generation Resource Mix of California Electricity Imports" (Alvarado and Griffin, 2007). The report presents a method described as a marginal analysis and sales assessment to assign a generation mix to imported power, and applies the method to the year 2005. When a California LSE owns an out-of-state generator or a generator is a party to a specific contract with a California LSE, the MWh of generation and its generation type are directly assigned to LSEs. The remaining portion of imported power is designated as coming from an unspecified source. Where similar commitments exist in neighboring regions, or where there are constraints on generation in order to serve local load outside of California, the authors assign power from specific out-of-state generators to out-of-state LSEs. This approach identifies the resources in the neighboring regions that are available to generate power for export from those regions to California, and they use information about what facilities are likely to be on the margin at various times of day in the Southeast to assign a resource type to the unspecified portion of imports. In 2005, under this approach, 12 percent of imports were unspecified (suggesting that the majority could be assigned to particular generating units) and that 96 percent of that small unspecified fraction came from natural gas and 4 percent from coal. In total, over 57 percent of the total imports from the Southwest to California come from coal, 28 percent from natural gas and 11 percent from nuclear. In the Northwest, a slightly different approach is used, where a generation type is attributed to unspecified imports using a sales assessment that identifies the overall resource mix of the entity selling power to California or, in some cases, the specific source identified by the entity selling power to a purchaser in California. In 2005, 88 percent of imports from the Northwest were unspecified (not assigned to a particular generating source) with 66 percent of that unspecified total coming from hydropower, 22.1 percent from natural gas, 8.8 percent from coal, 1.7 percent from nuclear, and 1.4 percent from renewables.

The results of this study's methodology are compared for calculating the CO_2 emissions intensity of imports with the findings from the CEC methodology. To do so, the aggregate CO_2 emissions rates for imported power that are calculated by Alvarado and Griffin for 2005 to the four years prior to 2005 are used, assuming the estimated 2005 resource mix holds for all the years. Table 4.2-2 shows the historical net power imports into California and the associated emissions of CO_2 estimated using this methodology. These estimates are compared with Haiku forecasts for future years developed using this study's incremental emission rate approach described above. The anticipated growth of net imports in the Haiku model estimation is roughly consistent with the historic trend. Imports grew about 36 percent between 2001 and 2005, or 5.5 billion KWh (BkWh) per year, according to CEC. The Haiku model projects a growth rate of 35 percent between 2010 and 2020, or 4 BkWh per year.

<insert Table 4.2-2 here>

The estimates for total emissions are not as consistent across the two sources and time frames. In 2010, the Haiku estimated emissions rate for power imports is 1.07 tons CO_2/ MWh, about 75 percent higher than the CEC estimated emissions rate for 2005. The difference is attributable to the differences in the techniques used to estimate emissions. CEC estimates that 26 percent of imports are generated by natural gas, a relatively low carbon emitting fuel compared to coal and 28 percent by nuclear, hydro or other renewables, which emit no carbon. The CEC's analysis assumes these suppliers would not be running if the region was not exporting power to California but in fact it is unclear which generation resources would be utilized less in the absence of demand for power from California. Because some of the resources identified by the CEC have low variable cost, such as nuclear, hydro and other renewables, it is likely that these facilities would be run to serve demand outside California and other facilities with higher fuel costs would be utilized less if California were not part of the transmission grid. The Haiku model, on the other hand, calculates equilibrium generation capacity, prices, generation, and emissions for the entire region (and country) when California is both on and off of the grid. The difference in emissions between these two baselines provides a unique way to think about out-of-state incremental generation that occurs specifically to meet electricity demand in California.

Over time the resource mix forecast in Haiku changes. Consequently, the incremental emissions rate for imported power drops almost 2/3 between 2010 and 2020 in the Haiku projections and approaches the estimate by the CEC for 2005, as illustrated in Table 4.2-2. The change in Haiku is due to growing renewable capacity throughout the West that includes an expansion in renewable generation to meet state RPS standards, and to take advantage of the federal Renewable Energy Production Tax Credit, which is assumed to be renewed with a probability of 90% in each future year (based on the experience in the past with renewal and lapses in this policy).

4.3 Policy Scenarios

Several different policy scenarios are considered and are defined by two characteristics. The first is the geographic scope of the cap-and-trade program, and the second is the approach to allocation of emissions allowances.[19] The combinations of program scopes and approaches to allocation that are modeled are illustrated in Table 4.3-1 and described in the next few paragraphs.

While AB32 is clear that emissions from imported power must be addressed by the implementing regulations, exactly how emissions from imports will be treated under a future cap-and-trade program is yet to be determined. Also, while California moves ahead with developing its approach to implementing AB 32, the Western Climate Initiative (WCI), in which California participates, is also moving ahead with developing a regional CO_2 cap-and-trade program that could be operational in a similar time frame to that proposed in AB32. In light of

[19] For a discussion of the options and staff analysis see CPUC and CEC, 2008.

these uncertainties and simultaneous developments, two different approaches to the scope of a trading program imposed on the electricity sector were considered, as shown in the column headings in Table 4.3-1. **The "California-only" approach is a first-seller regulation**, with an estimated emission intensity assigned to imported power, as described above. Under this scenario, the estimated emission rate associated with generation to serve California electricity consumption is applied. Although this rate varies with the region from which power is imported and it varies over time, it is held constant with respect to changes in the level of imported power identified in the simulation. That is, the assumed emission rate is applied equally to all imported power coming from a given region in a given year. Importers have to hold sufficient allowances to cover their estimated emissions of CO_2, as do native generators in California.

The second program scope is a western regional CO_2 cap-and-trade program that applies to all electricity generators in the Western Electric Coordinating Council (WECC) region. This program scope is a proxy for an electricity focused program under the WCI. Seven of the 11 states in the WECC, including California, are full participants in the WCI as are three Canadian provinces.[20] Under the modified WCI cap-and-trade program that is modeled, it is assumed, consistent with WCI plans, that the program will require reductions in emissions from electricity generators in the region of 30 percent from baseline levels in 2020.[21]

<insert Table 4.3-1>

The two approaches to allowance allocation are summarized in the rows in Table 4.3-1. These include an **allowance auction** and **allocation to local distribution companies (LDCs)** on the basis of the size of the population served by the LDC. Under an auction, in-state generators and power importers in the California-only scenario must purchase CO_2 emission allowances from the government and then surrender them to cover their CO_2 emissions. Under the load-based allocation, allowances are allocated for free to LDCs, and generators and importers must purchase allowances from the LDCs to whom they have been awarded. The ability to sell allowances that it received for free gives the LDCs an additional source of revenue that helps to offset the increase in the wholesale price of power associated with the new CO_2 price in the economy. This revenue lowers the portion of total costs that needs to be recovered from electricity customers. As a result, the price of electricity paid by all classes of customers is expected to be lower with load-based allocation than with an auction approach.

Allowance allocation has become an important focus of recent political debates about CO_2 cap-and-trade programs at the federal level and within Europe as well as in California.

[20] The other WECC states plus Alaska and Kansas are official observers to the WCI as are several Mexican states and two Canadian provinces.

[21] The WCI regional goal is to achieve a 15 percent reduction below 2005 levels by 2020. The target modeled in this study is a 30 percent reduction below the baseline level of emissions predicted in the model for each simulation year.

Most of the arguments in these debates are motivated by concerns about the high potential costs of these programs and who will bear them. However, how allowances are allocated can have implications for the efficiency of the cap-and-trade program as well. This is particularly true within the context of the electricity sector. In many states, including California, this sector is subject to cost-of-service regulation, and thus the opportunity cost of freely granted emissions allowances (based on some historic measure) will not be reflected in electricity prices the way they would be in regions where prices are set in the market (Burtraw et al. 2001).[22]

5 Findings from Simulation Analysis

The electricity market simulation model is used to analyze the effects of allowance allocation and geographic scope of the cap-and-trade regulation on electricity markets in California and beyond, allowance markets, greenhouse gas emissions, and emissions of pollutants that affect local air quality in California. Issues of key concern include the potential for emissions leakage and how it is affected by the method of allocation. This study also considers how a key baseline assumption regarding the future of federal policy to promote renewables affects the analysis.

<insert Table 5.1-1 here>

The results of the simulation analysis of the four scenarios are summarized and contrasted with those for the baseline scenario in Table 5.1-1. This table shows the effects on the average electricity price, the mix of fuels used to generate electricity, the amount of imports into California, and the effects on investments in new capacity for the year 2020. The table also includes projections of allowance prices and emissions of SO_2, NOx and CO_2 in California under the different scenarios.

5.1 Auction

The first approach to allocation that is considered is an auction.

5.1.1 California-Only Cap and Trade

The imposition of a cap-and-trade program on electricity sector CO_2 emissions in California-only, using the first-seller approach, and with an allowance auction, has important effects on electricity prices, electricity imports, and the mix of generators used to produce electricity in California. Under the allowance auction case, the average electricity price in

[22] Other free approaches to allocation include free allocation to generators on the basis of historic emissions or on the basis of recent generation. These approaches are not modeled here because there is no unambiguous way to calculate the historic emissions of sources outside the state that occurred historically in order to serve California. In addition, these approaches are not under active consideration as approaches for the California policy.

California in 2020 is 11 percent higher with this policy than under the baseline, and electricity demand is 3.7 percent lower. Imports into California are 24 percent lower in 2020 as a result of the policy suggesting that the first seller approach helps to stem the growing reliance on power imports in 2020 that occurs in the baseline scenario. The lower level of demand brought about by the policy means that only part of the reduction in imports needs to be made up by greater in-state generation, and the resulting increase is comprised of a combination of higher generation with natural gas and roughly 50 percent more generation from non-hydro renewables compared to the baseline. The price of an emission allowance under this policy is $47.20 per ton of CO_2 in 2020.

Imposing the California-only policy results in an average electricity price in the regions that surround California that is nearly 2 percent lower than in the baseline scenario in 2020.[23] The decline in retail prices outside of California contributes to emissions leakage (see below). The usual rationale for leakage is that generation outside the regulated region increases to meet demand in the regulated region. Hence, an increase in consumption outside the regulated region is not the usual rationale for leakage.

5.1.2 Leakage and Grid Usage

Emissions leakage is a concern for policies intended to restrict emissions of greenhouse gases. Because climate change is a global problem, the location of CO_2 emissions does not matter, and if efforts to reduce emissions in one location lead to increases in another, the effectiveness of the policy is reduced. Concerns about leakage have confounded efforts to control emissions of CO_2 within the U.S. because of the lack of such commitments on the part of trading partners including China and India, countries that could also become magnets for industries seeking to avoid regulations in the US and Europe. Concerns about leakage also plague regional programs within the U.S., the largest and most developed of which is the Regional Greenhouse Gas Initiative (RGGI) that caps emissions of CO_2 from electricity generators in 10 northeastern states beginning in 2009. Estimates of leakage under this program range substantially: Burtraw et al. (2005) reported leakage estimates of between 17 and 40 percent of emissions reductions brought about by the program over a decade of operation when allowing for investments in new capacity, while Chen and Sauma (2008) found that, in the short run, leakage from RGGI could be closer to 70 to over 90 percent of CO_2 emissions reductions in the RGGI region.

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[23] It is not obvious what expectations about the effect of this policy on prices in neighboring regions would be *ex ante*. Retail prices in the regions neighboring California are assumed to be regulated at approximate average cost, and inter-regional trade is determined by differences in the marginal generation cost between neighboring regions. Revenue from exported power is assumed to accrue to ratepayers in the exporting region thereby lowering the revenue requirement in the region that has to be recovered from native customers; therefore, an increase in exports should lower native retail price. However, if marginal generation cost in an exporting region is not increasing as the level of generation increases, then the retail (average) cost in the exporting region may rise as long as it is below marginal cost.

In a study of what the RGGI states might do about leakage, the RGGI Emissions Leakage Multi-State Staff Working Group (2008) stresses the possibility of a national plan as a way of addressing the leakage problem. They conclude that RGGI states should monitor leakage and implement leakage mitigation measures with demonstrated effectiveness and short implementation time frames. Examples of these are aggressive increases in investment in energy efficiency market transformation programs and complementary policies such as building energy codes and appliance and equipment efficiency standards that accelerate the deployment of end-use energy efficiency technologies and measures. The report recommends against using policies such as emissions portfolio standards and load-based compliance requirement at the current time, but recognizes that these and other measures are deserving of future study because they could be useful if end-use energy efficiency measures prove insufficient as a leakage mitigation approach or action toward the implementation of a federal cap-and-trade program is significantly delayed.

In the case of the California-only policy, emissions leakage was measured as the change in CO_2 emissions in the Western Electricity Coordinating Council (WECC) region that offset the reductions required under the California policy, which is equal to 26.2 million tons in CO_2 emissions reductions in 2020. Emissions leakage can come from growth in power imports into California as a result of the policy, or from changes in the generation mix or electricity consumption in the neighboring regions.

Emissions leakage from demand for imports is constrained by the capacity of the electricity transmission grid between California and it neighbors. The Haiku model imposes an exogenous growth rate for interregional transmission capability of 1.5 percent per year, which could come from new or expanded lines or software upgrades. If the transmission constraint is met in 2020, such that California maximizes its net power imports, then using the emission rate calculated from the baseline, those imports would account for 65.5 million tons of CO_2 emissions in NWP and RA. Under the state-wide cap, emissions associated with imports to California will fall to around 36.5 million tons of CO_2, or approximately 56 percent of the maximum potential. The "Grid in Use (%)" row of Table 5.2-1 shows this metric for each of the scenarios.

This study's findings with respect to total emissions leakage are summarized in Table 5.2-1 in the row labeled "Leakage (%)". This measure of leakage is calculated as the change in total emissions in the WECC relative to the baseline, divided by the emissions reduction goal of the policy (26.2 M tons of CO_2 in 2020). Any changes in CO_2 emissions beyond the WECC are ignored by this measurement of leakage. These results suggest that leakage will depend on how allowances are allocated. Under an auction, leakage would offset roughly 25 percent of the emissions reductions resulting from the program.

<insert Table 5.2-1 here>

The California-only scenarios impose an assumed emission rate on generation in NWP and RA of 0.25 tons/MWh and 0.57 tons/MWh, respectively. These emission rates are derived, as described in Section 4.2, from the difference between the baseline scenario and a subbaseline in which no power is traded between California and its neighbors. The bottom section of Table 5.2-1 shows these baseline emission rates, as well as the emissions rates associated with incremental generation in neighboring regions that obtain under each scenario.[24] When the emission rate varies from that calculated from the baseline scenarios, it indicates a change in the overall composition of the resource mix. In the model solution for the auction scenario, the imports from RA have an emission intensity that is roughly comparable to that assumed in the model. There is very little incremental generation from NWP, and the emission rate is unchanged.

In the Northeast RGGI cap-and-trade program, which will cap CO_2 emissions from power generation in 10 states beginning in January 2010, initially there will be no explicit accounting for the change in emissions that might occur out of the region in order to provide power to consumers in the region. In an exploratory analysis, the effects of this approach on California were investigated, and it was found that nearly all of the emission reductions in this case would be offset by emission increases in the neighboring regions. If the cap-and-trade program were to ignore emissions from out of state, it would clearly violate the statutory language of AB32, and it would also erode the environmental gains that would be achieved in California.

5.1.3 The Modified WCI Policy

One way to address the CO_2 emissions leakage problem would be to expand the cap-and-trade program to cover a larger geographic region. A West-wide cap-and-trade program was modeled with modified WCI scenarios, one with an auction approach to initial allocation and one with load-based allocation. The modified WCI policy imposes a 30 percent reduction in CO_2 emissions from baseline levels in 2020, with a gradual decline in the emissions cap from 2012 until 2020, and then holds the cap at the 2020 level in subsequent years.

In addition to limiting leakage, a region-wide cap would yield a substantially lower CO_2 allowance price and a smaller increase in electricity price in California than a California-only policy. When the regional policy is combined with an allowance auction, the CO_2 allowance price is $17.20 per ton in 2020, slightly more than 1/3 of the allowance price level with a California-only policy. Electricity price in California rises by 3.2 percent in 2020, again about 1/3 as much as it does with a California-only cap and an auction.

Moving from a state-specific policy to region-wide CO_2 emissions cap has important implications for power trading and what resources are used to generate power in California. Because the broader regional cap is a source-based policy, there is no compliance requirement on power importers and that results in a much smaller drop in power imports into California as

[24] This is calculated as the change in emissions for each scenario relative to the baseline, divided by the change in generation.

a result of the cap. With a modified WCI policy coupled with an allowance auction, power imports to California are only slightly lower than baseline levels. However, natural gas-fired generation within California is about 30 percent lower under the policy than in the baseline, and investment in new natural gas capacity is below baseline levels. Oil-fired generation within California, which falls dramatically under a California-only policy, only declines slightly under the WCI policy.

As expected, the region-wide policy has larger effects on California's neighbors than would a California-only policy. Average electricity price in the rest of the West increases more than 10 percent from baseline levels, and total consumption falls by 5 percent when the modified WCI policy is coupled with an auction. Total generation in the regions surrounding California falls by a comparable amount. The largest change is a reduction of 64 BkWh in coal-fired generation and a decline of 29 BkWh in gas generation, while renewable generation increases by 56 BkWh.

5.2 Load-Based Allocation

When allowances are auctioned to those entities that need them for compliance with the cap-and-trade regulation, the costs of those allowances are fully reflected in the price of electricity to consumers in California, and, under the California-only policy that is modeled, an 11 percent increase in price is seen. One way to reduce the price impact of the policy would be to allocate allowances to LDCs, the regulated companies responsible for the wires that facilitate delivery of power to final consumers. Power generators and first sellers of imported power would be required to purchase allowances from the LDCs, or alternatively allowances could be auctioned centrally with the revenues being returned to the LDCs. This approach provides another source of revenue to these regulated companies, which allows them to lower what they charge customers for electricity.[25] Allocation to LDCs may be done on the basis of several different metrics including population, electricity demand and even emissions.[26] For this

[25] An alternative approach would be to refund the allowance revenue to consumers on a per capita or per household basis. This approach, known as cap and dividend, would help to lower the impact of the greenhouse gas cap and trade policy on electricity consumers, but would do so in a way that would not affect the price they pay for electricity. As such its effects on electricity markets and allowance markets would be identical to the auction based approach discussed in section 5.1.

[26] In each of these approaches to load-based allocation, the allowances are distributed to the local distribution companies and revenue from the sale of these allowances (received at zero cost) are assumed to be used to partially offset the revenue requirement of the LDC, thus allowing it to lower its price for distributing electricity and, in the case when the LDC is also the load-serving entity, for supplying the electricity to customers. Load-based allocation could take the form of allocating allowances directly to LDCs, which would then be responsible for seeing them, or it could take the form of holding a single allowance auction and then allocating the revenues from that auction to LDCs based on one of the measures identified. An emissions-based approach to load-based allocation has been endorsed by the National Association of Regulatory Utility Commissioners (April 21, 2008). See Paul et al (2008) for a discussion of the implications of different approaches to load-based allocation of allowances under a national CO_2 cap and trade program.

analysis, a population-based approach was used. Relative to a consumption-based approach, the population-based approach rewards past investment in energy efficiency and efforts to keep consumption per person low. California may view a consumption-based approach as especially perverse, given the state's previous and ongoing efforts to reduce energy consumption. An emissions based approach would be difficult to implement in California, given the near impossibility of assigning allowances to imported power, an important source of electricity related CO_2 emissions.

The load-based approach to allocation substantially attenuates the effect of the cap-and-trade policies on average retail electricity price in California. As shown in Table 5.1-1, under the California-only policy, the electricity price increase in 2020 with load-based allocation would be only 6 percent compared to a more than 11 percent increase under the auction. The lower electricity price means electricity demand would be higher. This is partially met by more generation from natural gas plants within California, but it also has a positive effect on leakage, compared to the auction scenario. Table 5.2.1 indicates that there is little difference in the emission rate that is associated with imports from RA. However, there is a significant difference in the emission rate associated with incremental generation from NWP, where the emission rate is greater than that assumed in the model.

The lower electricity price does come at a cost. The policy would yield a more than 100 percent increase in the price of CO_2 emission allowances in 2020. With a smaller increase in electricity price, electricity consumers have a weaker incentive to conserve electricity, which means that there will be more demand for the fixed quantity of emission allowances, thus driving up their price. This has implications for other parts of the California economy as well, as discussed below.

Under the Modified WCI policy, the load-based approach to allocation actually would reduce electricity price in California to a level 2 percent below baseline price. This result reflects the fact that California is the most populous state within the Western states region and thus, under a population-based approach to load-based allocation, LDCs in California get a substantial share of the value of the emissions allowances created by the program. The lower price means that total electricity demand in California would be higher than baseline levels and more generation from renewables and natural gas fired generators would be brought on to fill the gap on the supply side. As shown in the bottom section of Table 5.1-1, the average electricity price in the rest of the West would be higher than baseline levels, but lower than the price obtained if an auction was used to implement the Modified WCI policy.

While the effect of load-based allocation on allowance price is much less pronounced with the Modified WCI than it is with the California-only policy, allowance price would still be 24 percent higher than under the auction. Thus, using this approach to compensate electricity consumers for the cost of a climate policy will come at a cost that will be felt beyond the electricity sector by all parties who must hold allowances to cover their CO_2 emissions.

5.3 Ancillary Benefits in California

Some concerns about a cap-and-trade approach in California stem from the fear that allowing firms to trade CO_2 emissions could result in increases in emissions of pollutants, such as NO_x and SO_2, that have local air quality effects and that these increases might be particularly damaging to low-income populations that tend to live in closer proximity to fossil-fueled electricity generators and other industrial facilities. This study's results suggest that a cap-and-trade program for CO_2 emissions in California will typically result in substantially lower emissions of NO_x from the electricity sector. Impacts on SO_2 emissions are mixed and vary across scenarios as shown earlier in the summary table.

<insert Table 5.3-1 here>

Table 5.3-1 shows emissions of NO_x and SO_2 under the different scenarios separately for the northern and southern regions of California. Emissions of NO_x fall in both the northern and southern parts of the state when CO_2 cap-and-trade policies are imposed. In Northern California, the drop in NO_x emissions is greater with a California-only policy than with the Modified WCI policy, assuming a common approach to initial allocation. The lowest level of NO_x emissions in both regions occurs under a California-only policy with a load-based approach to allocation. This study's model does not include the effects of local air quality restrictions on emissions of these pollutants nor does it reflect reductions required by the RECLAIM program.

Overall, the CO_2 policies have much less pronounced effects on emissions of SO_2 from California electricity generators. The one exception to this is the California-only policy with load-based allocation, which results in an over 80 percent reduction in SO_2 emissions from electricity in the northern part of the state in 2020 and a more than 50 percent reduction in the south. This is the same scenario that produced dramatic reductions in emission of NO_x, and these reductions follow from the decline in oil-fired generation resulting from this policy. With a CO_2 emission allowance price in excess of $100 per ton, generating electricity with oil becomes prohibitively expensive. In the study's model, oil generators, generally deemed necessary to meet load in load pockets, have a strong incentive to run even at high levels of costs, but the allowance cost in this scenario more than offsets that incentive. In the real world, it is unclear the extent to which the generation services provided by must-run oil generators in California may be supplied by other resources.

In general, the results indicate that CO_2 cap-and-trade policies would not lead to NO_x or SO_2 emissions increases statewide, although there are slight increases in the southern part of the state under certain policies.

5.4 Alternative Renewables Policy Assumptions in the Baseline

The assumption that the federal REPTC will remain in effect in 9 out of 10 years for the indefinite future has an important effect on the amount of renewable generation in the future predicted by the model. This effect was analyzed by running an alternative baseline that excludes the extension of the REPTC policy into the future. As shown in Table 5.4-1, at the national level including the REPTC policy results in more than double the amount of non-hydro renewables generation in 2020 as occurs without the REPTC and 5 percent lower CO_2 emissions from the electricity sector as a whole. The REPTC also results in a slightly lower average electricity price and slightly more electricity consumption nationwide, which helps to limit the reduction in CO_2 emissions brought about by the REPTC policy.[27]

The effects in the western US outside California are more pronounced than those nationwide as shown in Table 5.4-2. In the two regions that border California, the policy has a dramatic effect on the role of non-hydro renewables generation, in large part because of the abundance of wind resources located in the NWP region. Total generation by non-hydro renewables is 125 percent higher and total CO_2 emissions from the electricity sector are nearly 12 percent lower in 2020 when the REPTC policy is extended than when it is not. When the REPTC is not extended, the generation mix in the combined regions bordering California is more heavily weighted toward coal and natural gas, and the amount of power shipped into California is reduced.

Interestingly, in California eliminating the federal REPTC does not result in less non-hydro renewables generation. Instead, as a result of both the renewables that are brought on-line in California to help meet the 20 percent RPS policy and the fact that California would have to pay more for imported power without the REPTC, there would be roughly the same amount of non-hydro renewables generation within the state without the federal tax credit as with the federal tax credit for renewables. Without the REPTC, California does increase its reliance on fossil generators because importing power is more expensive. This increase in fossil generation, in turn leads to an increase in CO_2 emissions from in-state electricity generators of roughly 16.6 percent.

Figure 5.6-1 shows the time path of baseline CO_2 emissions from California generators and importers in the absence of the REPTC. Without the REPTC, baseline emissions actually rise slightly between 2010 and 2020, with all of the increase coming from emissions associated with power imports. Without the REPTC, the mix of generators that are used to produce power for export to California tend to be much higher emitting, with an average emission rate of roughly 0.8 tons per MWh. A CO_2 emissions cap in 2020 set on the basis of this baseline would be higher, but exactly how the price of allowances would be affected is difficult to predict given that having the REPTC in place lowers the cost of compliance with the cap.

[27] Palmer and Burtraw (2005) also find that a production tax credit on renewables is not a cost-effective way to reduce CO2 emissions because it results in lower electricity prices and higher electricity consumption.

6 Conclusion

Two important challenges in designing a CO_2 allowance cap-and-trade program for implementing AB32 in California are **where to assign responsibility for compliance** with the cap on emissions and **how to allocate the CO_2 emission allowances** created by the program. These two elements of policy design are distinct. Within California and beyond, debates over these two issues have focused largely on the electricity sector as one of the major point sources of CO_2 and likely to be an important player in a future CO_2 cap-and-trade program within California. Decisions regarding both of these policy design elements will have important implications not only for the performance and effectiveness of the California program, but also for how that program helps to inform and shape a future federal economy-wide cap-and-trade program for greenhouse gases.

The load-based and first-seller approaches are two alternative designs for compliance responsibility in the electricity sector. They differ in their ability to account for emissions, and this report argues that a first-seller approach would be a stronger framework. This recommendation takes into account the fact that the California CPUC has played a leadership role in portfolio planning, procurement, and efficiency policies. With this point of departure, the role for cap-and-trade is not only to provide incentives for emission reductions beyond those targeted by the CPUC, but also in part to leave no low-cost emissions reductions behind, and a first-seller approach is better suited to this purpose.

One important reason that the first-seller approach is superior has to do with the relationship between the organization and vision for the greenhouse gas market and the electricity market. The load-based approach is not consistent with market reform and greater competition in the electricity sector. A first-seller approach is a framework that does not interfere with expanded competition and improved market institutions in the industry. Also, a first-seller approach promises administrative simplicity compared to the load-based approach.

In consideration of how to allocate emission allowances, it is important to resist the parochial view that allowance value associated with historic emissions of CO_2 should be kept in the electricity sector. Keeping it in the electricity sector and subsidizing electricity consumption will cause greater marginal costs of emissions reduction in other sectors of 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.

Debates over allowance allocation in California also have focused on whether a portion of CO_2 allowances expected to be used in the electricity sector should be allocated to local distribution companies in California. An alternative viewpoint calls for allowance auctions with auction revenue available to be used for a variety of purposes including support for energy efficiency and new technology development as ways to facilitate the achievement of the goals of AB32. This study's results suggest that using a load-based approach to allocation within the electricity sector will result in higher total program costs than an allowance auction. This raises the question of whether the assignment of the property right for CO_2 allowances to electricity consumers is worth the cost. The auction alternative, which would be cheaper from an economywide perspective, represents an assignment of these property rights to the public-at-large, instead of specifically to electricity consumers. However, the alternatives for assigning revenue that might be raised in an auction are not addressed in this study.

Our simulation modeling also looked at the issue of emissions leakage. The extent of emissions leakage in a California-only cap-and-trade program depends importantly on how emissions allowances are allocated. A load-based approach to allocation, with its relatively smaller effect on electricity price, leads to nearly twice as much emissions leakage as an auction approach. Expanding the scope of the cap-and-trade program to including all the Western US states would eliminate leakage of emissions within the region and produce substantially more in CO_2 reductions at a lower allowance price. Also, contrary to the expectations of some stakeholders, a cap-and-trade policy for CO_2 would reduce emissions of NOx in the electricity sector.

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, it is transparent that an assignment of the value of carbon allowances to electricity customers constitutes a windfall to electricity consumption if the value is used to subsidize the electricity price. 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 an allowance value assigned to reinforce program goals and to meet social priorities rather than to compensate producers or consumers in the long run. The logic of that recommendation appears to be reinforced in the findings of this study.

Glossary

AB32 - Assembly Bill 32
ARB – Air Resources Board
CAIR – Clean Air Interstate Rule
CAMR – Clean Air Mercury Rule
CCAR – California Climate Action Registry
CEC – California Energy Commission
CO_2 – Carbon Dioxide
CO_2RC – CO_2 Reduction Credit
CPUC – California Public Utilities Commission
DOE – U.S. Department of Energy
E3 – Energy and Environmental Economics
EIA – U.S. Energy Information Administration
EPA – U.S. Environmental Protection Agency
GEAC – Generation emission attribution certificate
HMR – Haiku market region
ISO – Independent System Operator
IOU – Investor owned utility
LDC – Local distribution company
LSE – Load Serving Entity
NEEDS – National Electric Energy Data System
NEMS – National Energy Modeling System
NERC - North American Electric Reliability Council
NO_x - Nitrogen Oxides
NWP – the northwestern subregion of the Western Electricity Coordinating Council
PIER – Public Interest Energy Research
RA – the southwestern subregion of the Western Electricity Coordinating Council
RD&D – Research, development and demonstration
REPTC – Renewable Energy Production Tax Credit
RGGI – Regional Greenhouse Gas Initiative
RPS – Renewable Portfolio Standard
SO_2 – Sulfur Dioxide
TEPPC – Transmission Expansion Planning Policy Committee
WCI – Western Climate Initiative
WECC – Western Electricity Coordinating Council

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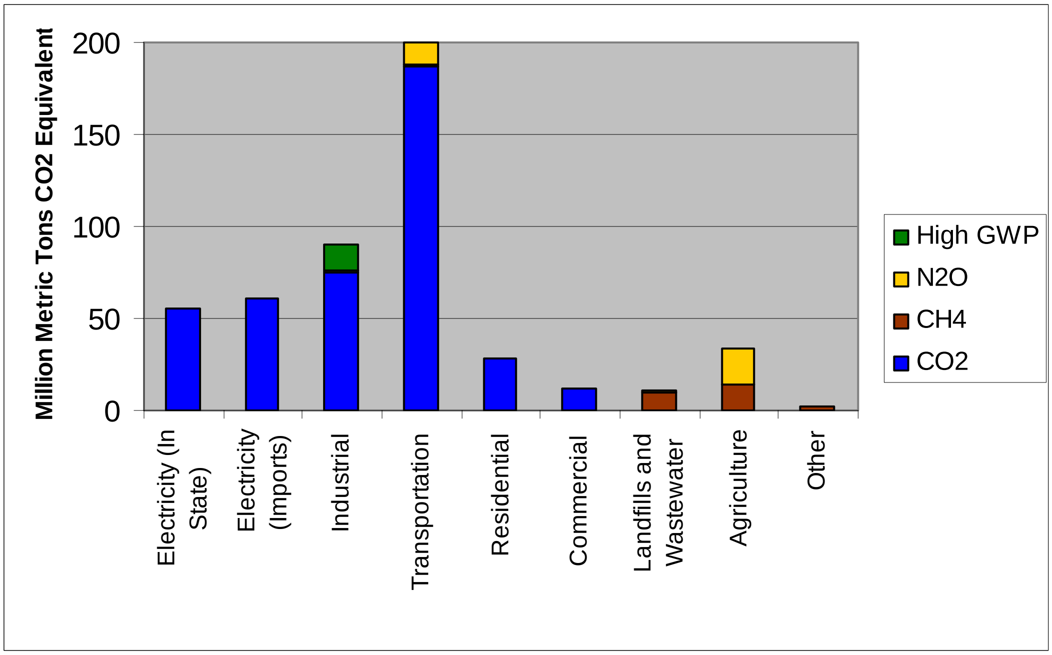
Figure 1-1. California emissions of greenhouse gases, 2004



Source: California Market Advisory Committee, 2007

Figure 1-2. Potential points of compliance in the electricity sector

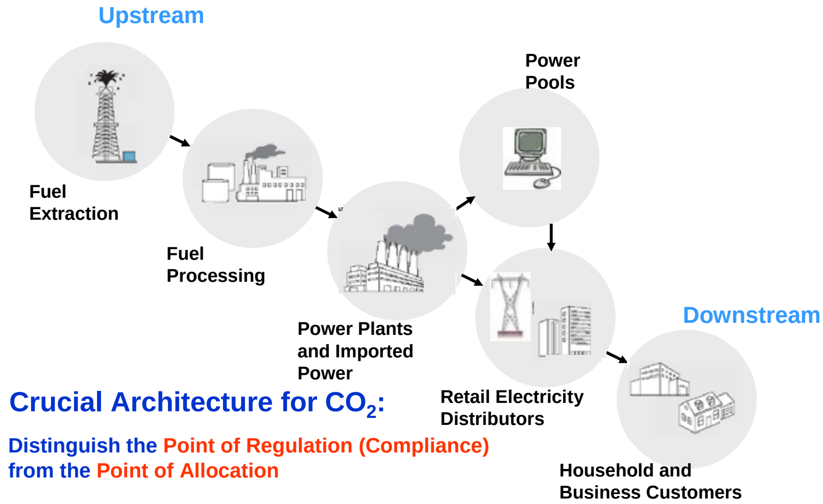


Figure 4.1-1 The Haiku Electricity Market Model: Inputs and Outputs

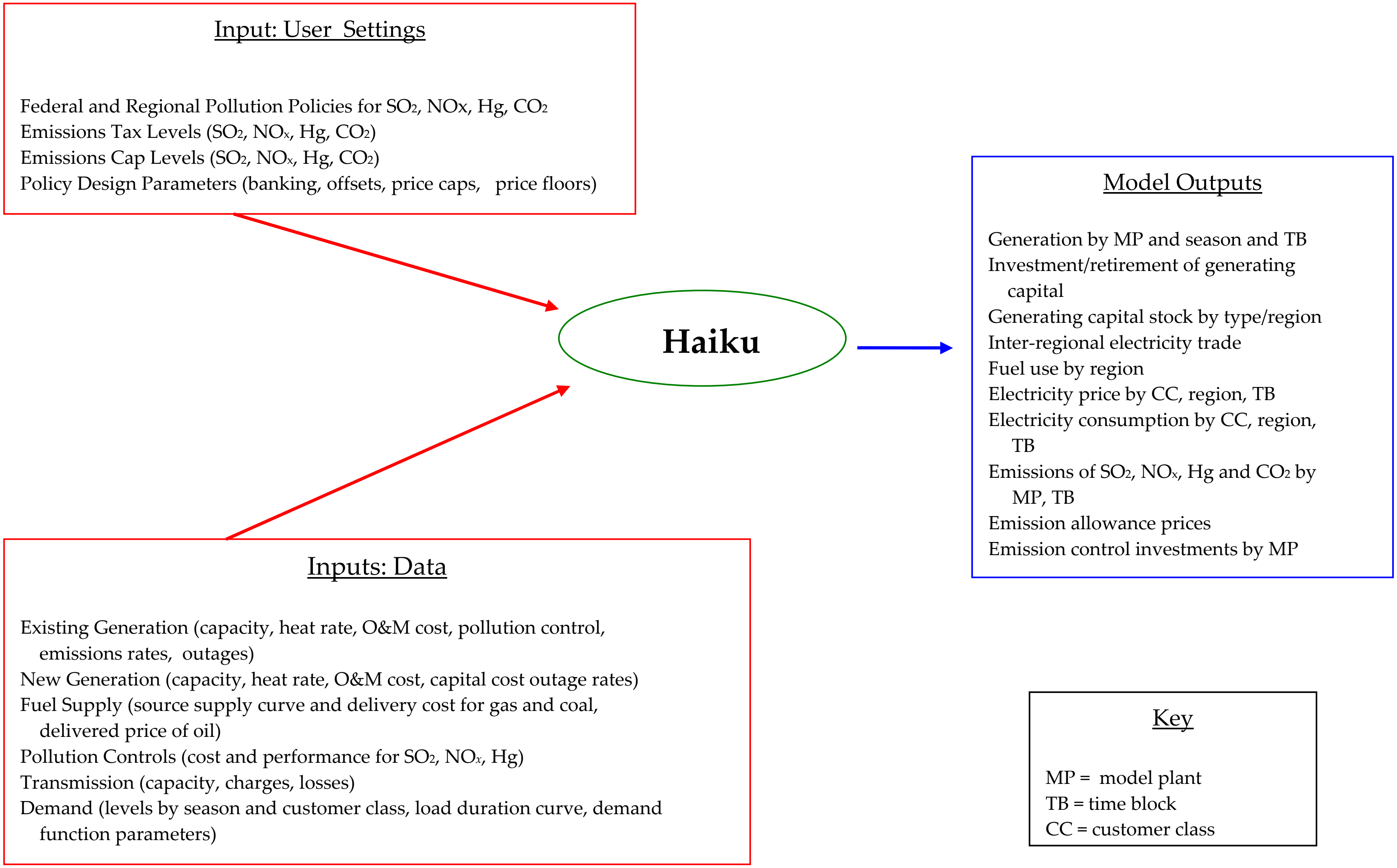


Figure 4.1-2 Haiku Market Regions and Electricity Pricing

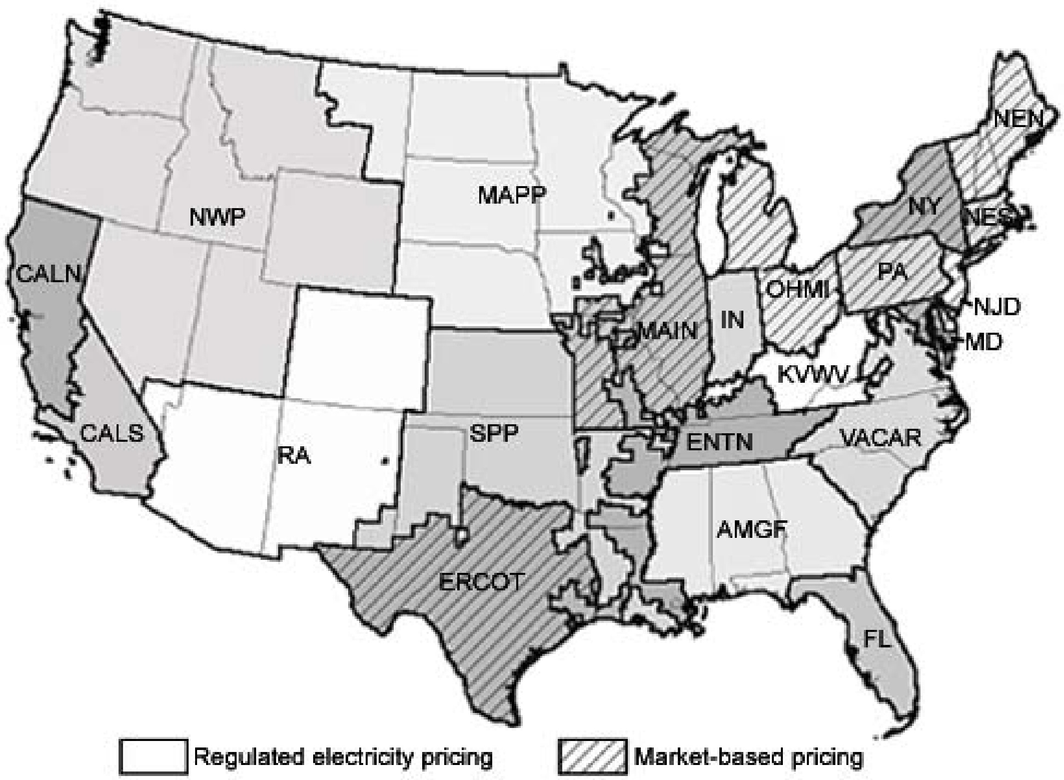


Table 4.1-1 Inputs to the Haiku Model and Data Sources

Variables	Source
Existing Generators	
Capacity	EIA
Heat Rate	EIA
Fixed and Variable O&M Cost	FERC\EIA\EPA
Existing Pollution Controls	EPA\EIA\RFF
Planned Pollution Controls	RFF
Baseline Emission Rates	EPA (CEMS/NEEDS)
Scheduled and Unscheduled Outage Rates	NERC GADS data
New Generators	
Capacity	EIA\EPA\Proprietary
Heat Rate	EIA\EPA\Proprietary
Fixed and Variable Operating Cost	EIA\EPA\Proprietary
Capital Cost	EIA\EPA\Proprietary
Outage Rates	EIA\EPA\Proprietary
Fuel Supply	
Wellhead Supply Curve for Natural Gas	Interpolated based on EIA forecasts
Delivery Cost for Natural Gas	EIA (AEO 2007)
Minemouth Supply Curve for Coal	EIA (AEO 2007)
Delivery Cost for Coal	EIA (AEO 2007)
Delivered Oil Price	EIA (AEO 2007)
Pollution Controls	
SO_2 – cost and performance	EPA
NO_x – cost and performance	EPA
Hg – cost and performance	EPA
Transmission	
Interregional Transmission Capacity	NERC
Inter and Intraregional Transmission Costs	EMF
Inter and Intraregional Transmission Losses	EMF
Demand	
Demand Level (by season and customer class)	EIA
Load Duration Curve	RFF
Demand Growth (by customer class and region)	EIA (AEO 2007)
Demand Elasticity (by customer class)	Estimated by RFF

Table 4.1-2 Demand Elasticities in the Haiku Model

	Residential	Commercial	Industrial
Short-Run	-0.167	-0.118	-0.110
Long-Run	-0.649	-0.651	-0.605

Figure 4.2-1 Baseline Emissions & the AB32 Cap

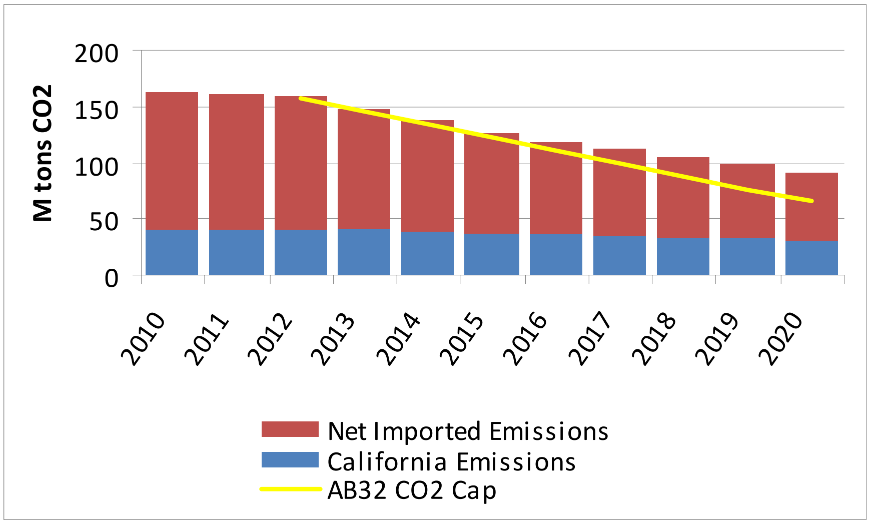


Table 4.2-1: Baseline CO_2 Emissions and Emissions Cap, 2020

Baseline CO_2 Emissions (million tons)	
Total	91.4
CA South	17.2
CA North	13.9
Net Imports	60.2
Emissions Cap	
CO_2 (million tons)	65.1
Annual Averages of Assumed Import Emissions Rates (tons/MWh)	
RA	0.57
NWP	0.25

Table 4.2-2: Emissions and Generation Comparison for Electricity Imports

Estimated from CEC "Revised Methodology to Estimate the Generation Resource Mix of California Electricity Imports"			
Year	Net Imports (BkWh)	Net Imported CO2 Emissions (Mtons CO2)	Average Emissions Rate (ton/MWh)
2001	60	41	0.68
2002	83	47	0.56
2003	81	48	0.59
2004	87	53	0.61
2005	82	50	0.61
Haiku Model Results			
Year	Net Imports (BkWh)	Net Imported CO2 Emissions (Mtons CO2)	Average Emissions Rate (Mton/BkWh)
2010	113	121	1.07
2011	114	120	1.05
2012	116	118	1.02
2013	120	108	0.90
2014	124	98	0.79
2015	128	88	0.69
2016	133	83	0.62
2017	138	77	0.56
2018	143	72	0.50
2019	148	66	0.45
2020	153	60	0.39

Table 4.3-1. Matrix of Climate Policy Scenarios

Scope: / Allocation:	California Only.	Modified WCI Region
Auction	x	x
Load-Based Allocation	x	x

Table 5.1-1. Overview of Policy Scenario Results, 2020

Scenario	*Baseline*	*California Only (Auction)*	*California Only (Load-Based))*	*Modified WCI (Auction)*	*Modified WCI (Load-Based)*
California					
Avg Elec price (2004$/MWh)	*106.7*	*118.8*	*113.0*	*110.2*	*104.6*
Generation (bill. kWh)					
Coal	2.7	2.7	2.7	2.7	2.7
Natural Gas	49.4	58.3	69.7	35.2	58.5
Nuclear	34.8	34.8	34.8	34.8	34.8
Oil	6.6	2.3	0.5	5.7	5.7
Non-hydro Renewables	*56.3*	*75.8*	*76.0*	*68.8*	*71.0*
Total	*192.3*	*216.2*	*226.0*	*189.6*	*215.1*
Imports (bill. kWh)	152.6	116.7	114.8	149.6	132.3
New Capacity[a] (GW)					
Gas	*11.1*	*12.6*	*12.6*	*8.1*	*10.6*
Wind	*7.6*	*7.6*	*7.6*	*7.6*	*7.6*
Biomass	*0.0*	*3.1*	*3.4*	*2.0*	*2.3*
Geothermal	1.7	1.7	*1.7*	*1.7*	*1.7*
Total	*21.3*	*25.8*	*26.2*	*20.3*	*23.1*
CO_2 Price (2004$/ton)	----	47.2	102.9	17.2	21.4
Emissions					
NO_x (thousand tons)	20.9	9.8	6.9	10.9	12.8
SO_2 (thousand tons)	9.8	8.9	2.2	9.7	10.0
CO_2 (million tons)	31.1	28.7	29.5	24.1	33.4
Rest of West[b]					
Avg Elec price (2004$/MWh)	*72.6*	*71.3*	*69.7*	*80.4*	*76.1*
TOTAL Gen. (bill. kWh)	*639.5*	*607.8*	*611.7*	*608.6*	*600.9*
TOTAL Cons. (bill. kWh)	460.8	464.0	466.0	439.9	452.7
Entire West					
CO_2 Reduction (mill. tons)		19.5	14.5	103.4	103.8

Table 5.2-1: Emissions Measures, 2020

Scenario	*Baseline*	*California Only (Auction)*	*California Only (LBA)*
CO_2 Emissions [M tons]			
CA	**31.1**	28.7	29.5
NWP	**125.6**	122.8	128.2
RA	**188.2**	174.0	172.9
WECC Total	***345.0***	*325.5*	*330.5*
Policy Reductions Goal [M tons]		*26.2*	*26.2*
Policy Reductions [M tons]			
CA		2.5	1.7
NWP		2.8	(2.6)
RA		14.2	15.4
WECC Total		*19.5*	*14.4*
Leakage [%]		26%	45%
Grid in Use [%]	**92%**	56%	54%
CO_2 Emissions Rate of Exports to CA [tons/MWh]			
NWP	**0.25**	------	0.45
RA	**0.57**	0.44	0.46

Table 5.3-1. Emissions of Local Air Pollutants, 2020

Scenario	*Baseline*	*California Only (Auction)*	*California Only (LBA)*	*Modified WCI (Auction)*	*Modified WCI (LBA)*
Northern California					
NO_x (thousand tons)	10.3	4.9	3.5	6.4	6.9
SO_2 (thousand tons)	7.3	6.3	1.2	7.2	7.3
Southern California					
NO_x (thousand tons)	10.6	5.0	3.4	4.5	5.9
SO_2 (thousand tons)	2.4	2.6	1.1	2.5	2.6
Total California					
NO_x (thousand tons)	20.9	9.9	6.9	10.9	12.8
SO_2 (thousand tons)	9.8	8.9	2.3	9.7	9.9

Table 5.4-1. Effect of the REPTC Nationwide, 2020

Scenario	*Baseline*	*Baseline with no REPTC*
National		
Avg Elec price (2004$/MWh)	*81.4*	*82.9*
Generation (billion kWh)		
Coal	2,221.4	2,308.1
Natural Gas	681.6	786.2
Nuclear	831.7	837.3
Oil	71.1	79.2
Non-hydro Renewables	*456.7*	*216.5*
Total	*4,575.0*	*4,539.7*
Emissions		
CO_2 (million tons)	2,805.0	2,947.9

Table 5.4-2. Effect of the REPTC in California and the Rest of West, 2020

Scenario	*Baseline*	*Baseline with no REPTC*		*Baseline*	*Baseline with no REPTC*
California			**Rest of West**		
Avg Elec price (2004$/MWh)	*106.7*	*109.4*	**Avg Elec price (2004$/MWh)**	*72.6*	*73.7*
Generation (billion kWh)			**Generation (billion kWh)**		
Coal	2.7	2.7	Coal	252.4	295.6
Natural Gas	49.4	61.1	Natural Gas	50.1	55.2
Nuclear	34.8	34.8	Nuclear	39.5	39.5
Oil	6.6	6.8	Oil	0.8	1.6
Non-hydro Renewables	*56.3*	*57.1*	Non-hydro Renewables	*122.6*	*54.2*
Total	*192.3*	*204.9*	Total	*639.5*	*620.3*
Imports (billion kWh)	152.6	134.7	**Imports (billion kWh)**	-149.9	-133.8
New Capacity[a] (GW)			**New Capacity[a] (GW)**		
Gas	*11.1*	*10.1*	Gas	*13.8*	*13.8*
Wind	*7.6*	*7.6*	Wind	*23.6*	*13.8*
Biomass	*0.0*	*0.0*	Biomass	*0.0*	0.0
Geothermal	1.7	*1.7*	Geothermal	*4.4*	3.5
Total	*21.3*	20.3	Total	*48.7*	*36.4*
Emissions			**Emissions**		
NO_x (thousand tons)	20.9	24.4	NO_x (thousand tons)	537.0	568.2
SO_2 (thousand tons)	9.8	10.5	SO_2 (thousand tons)	294.2	298.1
CO_2 (million tons)	31.1	36.1	CO_2 (million tons)	313.8	356.4

Figure 5.4-1 Baseline Emissions with no REPTC