INTERIM DECISION ON BASIC GREENHOUSE GAS REGULATORY FRAMEWORK FOR ELECTRICITY AND NATURAL GAS SECTORS

California Energy Commission Docket # 07-OIIP-1

California Public Utilities Commission Rulemaking 06-04-009

JOINT AGENCY DECISION

March 2008
CEC-100-2008-002-F

Arnold
Schwarzenegger,
Governor

TABLE OF CONTENTS

TABLE OF CONTENTS
(Cont'd)

Title **Page**

INTERIM OPINION ON GREENHOUSE GAS REGULATORY STRATEGIES

1. Summary

The California Public Utilities Commission (Public Utilities Commission) and the California Energy Commission (Energy Commission) recommend that the California Air Resources Board (ARB) adopt a number of policies and requirements for greenhouse gas (GHG) emissions reductions from the electricity and natural gas sectors in California. These recommendations should be adopted as part of ARB's scoping plan for its further work in implementing Assembly Bill (AB) 32, which requires that statewide GHG emissions be reduced to 1990 levels by 2020.[1]

In particular, we recommend that ARB adopt a mix of direct mandatory/regulatory requirements for the electricity and natural gas sectors and a cap-and-trade system that includes the electricity sector. We recognize that, under AB 32, ARB has the ultimate responsibility to determine the appropriate design and mix of mandatory and market-based programs to reduce GHG emissions, as prescribed in the law. We also recognize that, prior to adopting any market mechanisms, ARB must find that such mechanisms meet the tests outlined in Parts 4 and 5 of AB 32.[2] Our task in this decision is to give

---

[1] California Health and Safety Code Section 38530(a), added by AB 32.

[2] Part 5 of AB 32 reads as follows:

> 38570. (a) The state board may include in the regulations adopted pursuant to Section 38562 the use of market-based compliance mechanisms to comply with the regulations.
>
> (b) Prior to the inclusion of any market-based compliance mechanism in the regulations, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

Footnote continued on next page

ARB our best formulation of approaches to the electricity and natural gas sectors so that they may be evaluated along with other options for regulating California GHG emissions. We expect that ARB will fulfill the requirements of Part 5 of AB 32 with our advice and recommendations in mind.

Our recommendations are summarized in more detail below. We also recommend that implementation of all aspects of our recommendations to ARB regarding mechanisms to ensure real GHG reductions in the electricity and natural gas sectors should be regularly monitored and enforced, with mechanisms built in for monitoring, rapid identification of problems, and tools to react to, correct, or penalize non-compliance.

---

(1) Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution.

(2) Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants.

(3) Maximize additional environmental and economic benefits for California, as appropriate.

(c) The state board shall adopt regulations governing how market-based compliance mechanisms may be used by regulated entities subject to greenhouse gas emission limits and mandatory emission reporting requirements to achieve compliance with their greenhouse gas emissions limits.

38571. The state board shall adopt methodologies for the quantification of voluntary greenhouse gas emission reductions. The state board shall adopt regulations to verify and enforce any voluntary greenhouse gas emission reductions that are authorized by the state board for use to comply with greenhouse gas emission limits established by the state board. The adoption of methodologies is exempt from the rulemaking provisions of the Administrative Procedure Act (Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code).

38574. Nothing in this part of Part 4 (commencing with Section 38560) confers any authority on the state board to alter any programs administered by other state agencies for the reduction of greenhouse gas emissions.

In addition, we continue our commitment to work in collaboration with other states and provinces in the Western Climate Initiative to design a cap-and-trade system for the West. The timeframe set for the Western Climate Initiative to agree on a design framework and principles is quite similar to ARB's AB 32 timeframe. Thus, we are confident that we can develop our California policies to be compatible with a regional cap-and-trade system and in cooperation with our partners in the Western Climate Initiative.

1.1. Electricity Sector

For the electricity sector, we recommend that all retail providers in California be required to provide a minimum level of cost-effective energy efficiency programs and renewable energy delivery to their customers. The Energy Action Plan includes a "loading order" for investment in electricity resources that puts energy efficiency as the top priority, followed by renewable energy investment. These are also the priorities and best available approaches to drive GHG reductions in California's electricity sector.

Therefore, we recommend that all retail providers in California, regardless of regulatory structure or status, be required to deliver these resources to consumers. For energy efficiency, we recommend that requirements include a minimum level of cost-effective energy efficiency and be consistent for all retail providers. In addition, energy efficiency should be defined broadly to include any programmatic approach that reduces on-site usage of electricity. For electricity from renewable energy, we recommend that the requirements go beyond the current 20% requirement, consistent with State policy, but leave open consideration of exact percentage requirements or deadlines, pending further analysis. We recognize that the agencies may need to seek Legislative authority to achieve some of these objectives. Fundamentally, the energy efficiency and renewable energy programs provide a base of GHG reductions that are permanent and continuous through 2020. We expect these regulations to continue to be enhanced over the AB 32 period.

Beyond this, we recommend that a multi-sector cap-and-trade program be developed for California that includes the electricity sector, provided that ARB finds that the tests outlined in Parts 4 and 5 of AB 32 are met. In order to have the AB 32 program in place by 2012, design of all mechanisms should begin now; we recommend against any delay or a wait-and-see approach. A number of policy reasons underlie our recommendation to design a cap-and-trade program now:

- A cap-and-trade program is likely to produce additional real GHG emissions reductions beyond the mandatory programs described above, from a wider variety of sources and at a lower cost than requiring reductions only from additional mandatory measures.
- It would achieve reductions in the least-cost manner by allowing for flexibility in achieving emissions targets through allowing obligated entities to rely on the least-cost abatement options across the entire economy.
- It would encourage investment in research and innovation in technologies that lower GHG emissions by providing a larger market in which new technologies could be introduced.
- It would allow market participants to manage risk.
- It would efficiently distribute the cost of GHG reductions across all capped entities, so that total costs of achieving emission targets are minimized.
- AB 32 establishes an aggressive timetable for implementing reductions in California that persuades us to proceed now to design how the electricity sector could participate in a multi-sector cap-and-trade program, which ARB may choose to pursue if it finds that the tests outlined in Parts 4 and 5 of AB 32 are met.

In order to obtain real GHG emissions reductions, the design of an effective cap-and-trade program in the electricity sector must address the emissions associated with California's imported power. This is because, while California imports approximately 20% of its electricity from neighboring states, those imports represent more than 50% of the GHG emissions from the sector. Therefore, we conclude that any cap-and-trade program design for California must include an import component.

For the point of regulation in the electricity sector, we recommend that ARB designate deliverers of electricity to the California grid, regardless of where the electricity is generated, as the entities responsible for compliance with the AB 32 requirements. This is a variation of the first seller approach recommended by the Market Advisory Committee. In arriving at this conclusion, we evaluated four options against a set of criteria. The four options are:

- Deliverers (a variation of first sellers),
- Retail providers (also referred to as load-based),
- In-state generators, with no inclusion of imports in the cap-and-trade system, and
- In-state generators, with retail providers as the point of regulation for imports (often referred to as a hybrid option).

We assume that as a threshold matter, all options would have to be consistent with other federal, State, and local environmental requirements, such as those pertaining to criteria pollutants and toxic waste. The four options identified above were evaluated using the following criteria:

- Environmental integrity (i.e., ability to produce real GHG emissions reductions),
- Compatibility with/expandability to potential regional and/or national GHG emissions cap-and-trade markets,
- Accuracy and ease of reporting, tracking, and verifying GHG emissions reductions,

- Compatibility with ongoing reforms in wholesale and retail energy markets, and
- Legal issues.

After evaluating the point of regulation options, we find that the deliverer option best meets the first four criteria listed above. Each of the other options has serious shortcomings regarding one or more of our priorities. The deliverer system provides for obtaining real GHG emissions reductions by covering imported power as well as in-state generation. It also shares a number of common characteristics with a pure generation-based point of regulation, making it likely to be compatible with the eventual design of a cap-and-trade system that is broader in geographic scope (regional and/or national). The deliverer point of regulation also improves the ability to report and track emissions in the sector, which in turn helps provide real GHG reductions. It also minimizes the impact of AB 32 GHG regulations on California's wholesale electricity markets. In addition, it is consistent with the existing methods for regulating criteria pollutants and toxic waste.

Finally, the deliverer method can be supported on legal grounds. For all of these reasons, we recommend deliverers as the point of regulation for a GHG cap-and-trade program as it applies to the electricity sector.

We also address certain policy questions regarding the allocation of GHG emission allowances in a deliverer-based point of regulation system. Fundamentally, determining the point of regulation is independent from determining the method of obtaining allowances or the method of distributing any benefits which might come from allocation. Allocation issues will be addressed in more detail in the next portion of this proceeding.

In addressing allocation issues, we keep in mind that some deliverers of electricity to the California grid are also retail providers of electricity for consumers. We also recognize that allocation policy will have an impact on consumer costs. Our intent in developing additional allocation policy recommendations is to ensure that GHG emissions reductions are accomplished equitably and effectively, at the lowest cost to consumers. While we may wish to reward early actions to reduce GHG emissions in advance of 2012 when the AB 32 compliance period begins, it is not our intent to treat any market participants unfairly based on their past investments or decisions made prior to the passage of AB 32.

We have determined that the next portion of this proceeding can be most focused and productive if a few major design principles are adopted in this decision. As a starting principle, it is important that any policy for distribution of allowances provide that revenues from the sale of allowances be used primarily to benefit consumers in the energy sectors directly. This is because energy sources such as electricity and natural gas are vital commodities. Thus, we believe special focus is warranted for allowance allocation policy in the energy sectors.

The method by which GHG emission allowances are distributed will affect liquidity in the emission allowance market; incentives to invest in low-GHG technologies and fuels, including energy efficiency; the potential for windfall profits; and costs to various groups of stakeholders.

With these impacts in mind, we recommend that some portion of the emission allowances available to the electricity sector should be auctioned. Among the options under consideration would be to phase in auctioning beginning with a small percentage in the first year and transitioning to greater percentages over time as the State and market participants gain experience with auctions. We make the recommendation for some auctioning in order to promote least-cost solutions throughout the California economy, promote liquidity in the emission allowance market, improve the accuracy of emission allowance prices as a reflection of marginal emission reduction costs, improve investment incentives, avoid windfall profits at consumer expense, and allow new market entrants easy access to allowances.

An integral part of this auction recommendation is that the majority of the proceeds from the auctioning of allowances for the electricity sector should be used in ways that benefit electricity consumers in California, such as to augment investments in energy efficiency and renewable energy or to provide customer bill relief. There are multiple ways to accomplish allocation of benefits to consumers.

As we discuss in this decision, additional record development is needed to allow us to make more complete recommendations on allowance distribution issues, including the proper mix between auctions and administrative allocations of emission allowances for the electricity sector, the manner in which auction proceeds should be used for the benefit of electricity consumers, and the manner in which any administrative allocations should be made. We will consider various options for the allocation of allowances, including to retail providers and/or deliverers. The concerns of all parties, along with potential solutions, will be considered carefully.

A cap-and-trade market structure must address the potential for volatility in the price of GHG emission allowances. In order to avoid short-term allowance availability problems and send appropriate long-term investment signals, a certain degree of stability in allowance prices is needed. Mechanisms that could be used to help ensure stability of allowance prices include, but may not be limited to, banking or borrowing of allowances, allowance price floors or ceilings, and GHG offsets. We will continue to explore these options and plan to address them in a later decision in this proceeding.

In addition, the modeling work being conducted in coordination with this proceeding is likely to help us answer more analytical questions about the impact of possible allowance distribution policies and other flexible compliance mechanisms on consumers and companies in the electricity sector.

Finally, in response to comments on the proposed decision, we plan to consider further the treatment of combined heat and power (CHP) facilities under this policy framework. We want to avoid unintended negative consequences for CHP, which may be a valuable source of additional GHG emissions reductions in California. Therefore, we intend to consider further the treatment of emissions from CHP facilities in the next portion of this proceeding, and plan to include recommendations on this issue to ARB in our next decision.

1.2. Natural Gas Sector

For purposes of this decision, we include in the natural gas sector combustion of natural gas that is not otherwise likely to be regulated by ARB as a point source. Natural gas combustion for electricity generation is covered under the electricity sector and combustion at large industrial facilities will be covered as industrial emissions. Therefore, for purposes of this decision, the natural gas sector is defined to include end-user combustion at facilities below ARB's reporting threshold for GHG emissions, as well as emissions from natural gas infrastructure, including fugitive emissions from pipelines and compressor stations.

For this portion of emissions associated with the use of natural gas, we recommend that all entities that provide transportation, distribution, and/or retail sales of natural gas to end-users (natural gas providers) in California be required to provide a minimum level of energy efficiency or other demand reduction programs to their customers. Energy efficiency is the best available approach to drive GHG reductions in California's natural gas sector. Therefore, we recommend that all natural gas providers in California, regardless of regulatory structure or status, be required to deliver energy efficiency to consumers. Fundamentally, energy efficiency provides a base of GHG reductions that are permanent and continuous through 2020. We expect these regulations to continue to be enhanced over the AB 32 period. We also expect to consider other programmatic options for reducing demand for natural gas including the use of solar hot water heating equipment.

We recommend that the natural gas sector not be included in a cap-and-trade system at this time. There are several reasons for this recommendation. Key differences between the electricity and natural gas sectors persuade us that it would be premature to include the natural gas sector in a cap-and-trade system:

- Significantly fewer options exist to reduce GHG emissions in the natural gas sector compared to the electricity sector.
- There is currently very limited availability of low-carbon alternative sources of natural gas.
- Energy efficiency and other natural gas demand reduction programs are the best options for reducing GHG emissions in the natural gas sector.
- The incremental benefits from including the natural gas sector in a multi-sector cap-and-trade program are likely to be smaller than those for the electricity sector.
- Reporting protocols for GHG emissions are still under development.
- Relying on programmatic measures to achieve emission allows additional time to develop reporting protocols.

As California gains greater experience with a cap-and-trade system, regional and national frameworks are established, reporting protocols are adopted, and alternative lower-carbon sources of natural gas are developed, we expect that it will become appropriate to add the natural gas sector to the multi-sector GHG emissions allowance cap-and-trade system, and we expect to recommend inclusion of the natural gas end-use sector at that time. Taking direct programmatic actions in the meantime is also compatible with the potential inclusion of the natural gas sector in an upstream form of regulation in the future.

2. Background

In the Order Instituting Rulemaking (OIR) initiating Rulemaking (R.) 06-04-009, the Public Utilities Commission provided that Phase 2 would be used to implement a load-based GHG emissions cap for electricity utilities, as adopted in Decision (D.) 06-02-032 as part of the procurement incentive framework, and also would be used to take steps to incorporate GHG emissions associated with customers' direct use of natural gas into the procurement incentive framework.[3]

On September 27, 2006, Governor Schwarzenegger signed into law AB 32, "The California Global Warming Solutions Act of 2006." This legislation requires ARB to adopt a GHG emissions cap on all major sources in California, including the electricity and natural gas sectors, to reduce statewide emissions of GHGs to 1990 levels.

We held a prehearing conference (PHC) in Phase 2 on November 28, 2006. The Phase 2 scoping memo, which was issued on February 2, 2007, determined that, with enactment of AB 32, the emphasis in Phase 2 should shift to support

[3] In D.07-01-039 in Phase 1 of this proceeding, the Public Utilities Commission adopted a GHG emissions performance standard for new long-term financial commitments to baseload electricity generation. D.07-05-063 denied applications for rehearing of D.07-01-039. D.07-08-009 denied a petition for modification, but clarified how the adopted cogeneration thermal credit methodology will be applied to bottoming-cycle cogeneration. On February 12, 2008, SCE filed an amended Petition to Modify D.07-01-039, which is pending.

implementation of the new statute. Because of the need for "a single, unified set of rules for a GHG cap and a single market for GHG emissions credits in California," the Phase 2 scoping memo provided that "Phase 2 should focus on development of general guidelines for a load-based emissions cap that could be applied … to all electricity sector entities that serve end-use customers in California,"[4] including both investor-owned utilities (IOUs) that the Public Utilities Commission regulates and publicly owned utilities (POUs).

As detailed in the Phase 2 scoping memo, the Public Utilities Commission and Energy Commission are undertaking Phase 2 on a collaborative basis, through R.06-04-009 and Docket 07-OIIP-01, respectively, to develop joint recommendations to ARB regarding GHG regulatory policies as it implements AB 32.

The Phase 2 scoping memo noted that the policies in D.06-02-032 were adopted prior to passage of AB 32. It placed parties on notice that, in the course of Phase 2, the Public Utilities Commission might adopt policies that would modify portions of D.06-02-032 as a result of AB 32, subsequent actions by ARB, or the record developed in the course of this proceeding.[5]

In D.06-02-032, the Public Utilities Commission stated an intent to apply a load-based GHG emissions cap to the three major IOUs, and also to Community Choice Aggregators (CCAs) and Electric Service Providers (ESPs) operating within the service territory of the three major IOUs. In D.06-10-020 amending the OIR, the Public Utilities Commission specified that, with the passage of Senate Bill (SB) 1368, all ESPs, all CCAs, and all electrical corporations, including

---

[4] Phase 2 scoping memo, *mimeo.* at 8.

[5] *Id., mimeo.* at 10-11.

all IOUs, multi-jurisdictional utilities, and electric cooperatives, are respondents to this rulemaking. The Phase 2 scoping memo specified that Phase 2 would address whether the load-based GHG emissions cap should apply to the additional respondents added by D.06-10-020.

On April 19, 2007, the Public Utilities Commission and the Energy Commission held a symposium which addressed linking GHG cap-and-trade systems. Reporting issues were also discussed.

As Phase 2 has progressed, the Public Utilities Commission has modified the scope of Phase 2 through D.07-05-059 and D.07-07-018 amending the OIR.[6] D.07-05-059 specified that Phase 2 should be used to develop guidelines for a load-based GHG emissions cap for the entire electricity sector and recommendations to ARB regarding a statewide GHG emissions limit as it pertains to the electricity and natural gas sectors. To that end, D.07-05-059 also expanded the natural gas inquiry in Phase 2 to address GHG emissions associated with the transmission, storage, and distribution of natural gas in California, in addition to the use of natural gas by non-electricity generator end-use customers as originally contemplated in the OIR. The list of respondents to this proceeding was amended to include all investor-owned gas utilities, including those that provide wholesale or retail sales, distribution, transmission, and/or storage of natural gas.

D.07-07-018 amended the OIR further to provide for consideration in Phase 2 of issues raised by and alternatives considered in the June 30, 2007

---

[6] On December 20, 2007, the Assigned Commissioner issued a ruling modifying the Phase 2 scoping memo to specify the manner in which natural gas issues raised in the OIR and the issues added by D.07-05-059 and D.07-07-018 would be considered in Phase 2.

Market Advisory Committee report entitled, "Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California," to the extent that they were not already within the scope of Phase 2. Thus, D.07-07-018 provided for consideration of alternatives to a load-based cap for the electricity sector, a deviation from the policies adopted in D.06-02-032. In that report to ARB, the Market Advisory Committee considered design of a market-based program to reduce GHG emissions, and described various options for the scope of a cap-and-trade program. For the electricity sector, the Market Advisory Committee recommended a "first seller" approach, with the entity that first sells electricity in the state responsible for meeting the compliance obligation. As discussed in this decision, we are now focusing on a variation on this approach, the "deliverer" approach.

By Administrative Law Judge's (ALJ) rulings, parties were asked to submit comments and legal briefs on issues raised by the Market Advisory Committee report. On August 21, 2007, the Public Utilities Commission and the Energy Commission held a joint en banc hearing addressing the type and point of GHG regulation in the electricity sector, including deliverer/first seller and load-based cap-and-trade approaches. In an ALJ ruling issued on November 9, 2007, parties were provided an opportunity to file additional comments on issues regarding the type and point of regulation for the electricity sector.

By ALJ ruling dated July 12, 2007, parties were asked to file comments on preliminary recommendations of the Public Utilities Commission staff regarding the regulatory treatment of GHG emissions in the natural gas sector. The staff paper attached to the ALJ ruling identified and discussed various policy issues associated with developing regulations to control GHG emissions in the natural gas sector. A prehearing conference was held on August 2, 2007 to address the manner in which regulation of GHG emissions in the natural gas sector should be considered in this proceeding. By ALJ ruling dated November 28, 2007, parties were asked to file comments on the approach to GHG regulation that would be appropriate for the natural gas sector.

ARB is taking the lead on developing reporting protocols and requirements for all entities covered by AB 32, including the electricity and natural gas sectors. In D.07-09-017 and a companion Energy Commission decision, the Public Utilities Commission and the Energy Commission recommended that ARB adopt proposed regulations contained in that decision as reporting and verification requirements applicable to retail providers and marketers in the electricity sector. The reporting requirements for the electricity sector approved by ARB on December 6, 2007 are consistent with the proposed regulations recommended by the two Commissions. ARB has indicated that protocols for some sectors, including the natural gas sector, will be issued later. While staff will continue to coordinate closely with ARB on development of reporting requirements, we do not plan to develop recommendations on reporting requirements for the natural gas sector unless reporting issues arise that are unique to the sector.

The scoping memo specified that Phase 2 would address the appropriate 1990 emissions baseline for the entire electricity sector. ARB adopted statewide 1990 GHG emissions levels on December 6, 2007. No concerns related to 1990 emissions in the electricity and natural gas sectors have been identified in this proceeding to warrant development of recommendations by the two Commissions to ARB. As a result, we have not developed recommendations regarding the 1990 GHG emissions baseline.

Phase 2 is also addressing how to distribute annual emissions allowances under a cap-and-trade mechanism to individual entities, to the extent appropriate, and how such a process should be administered. An October 15, 2007 ALJ ruling requested comments on allowance allocation issues, and a workshop was held on this topic on November 5, 2007.

As part of our Phase 2 analysis, the Public Utilities Commission hired a consultant to conduct detailed modeling of the electricity sector impacts of potential GHG emissions cap scenarios. The modeling analysis is to take into account the policy options developed in other portions of the proceeding in order to analyze various options for cap design and implementation for the electricity sector. The consultants are also considering the natural gas sector in their modeling process. However, separate, detailed modeling of the natural gas sector is not being undertaken. The modeling effort is examining the level and costs of emission reductions that can be achieved by the electricity and natural gas sectors before the 2020 deadline set by AB 32. It is also addressing the rate at which these types of reductions can be achieved, which will inform our recommendations for annual emissions goals for the electricity and natural gas sectors. A November 9, 2007 ALJ ruling requested comments on modeling-related issues and on a staff paper on emission reduction measures. A workshop on input assumptions and initial model results was held on November 14, 2007.

3. GHG Policies for the Electricity Sector

In this section, we consider policies for the regulation of GHG emissions in the electricity sector. As we explained in D.07-09-017, AB 32 governs statewide GHG emissions including electricity consumed in California (including imports) and in-state generation that is exported out of California. Thus, as a starting point, we consider all such electricity to be within the electricity sector. Because power that is wheeled through California does not fall within the purview of

AB 32,[7] we do not include power wheeled through California in the electricity sector for purposes of establishing GHG regulations.

The proposed decision suggested that power delivered to the California grid from CHP facilities be regulated as part of the electricity sector. In Section 4.2.2, we defer a determination of the proper treatment of GHG emissions from CHP facilities pending further analysis. Thus, we have not decided yet whether the recommendations developed in this decision for the electricity sector should apply, in whole or part, to electricity generated by CHP facilities.

3.1. Overview of Approaches Considered

In Phase 2, we have considered a variety of approaches to GHG regulation in the electricity sector. All approaches are based on a foundation of mandatory GHG emission reduction programs, including cost-effective energy efficiency and investment in renewable resources. Before describing the positions of the parties, it is useful to provide a brief overview of the major alternatives that have been examined.

First, the type of regulation appropriate to the sector has been considered. By this we mean whether the regulation is of the direct/mandatory type or whether it is market-based. Second, for the market-based options, the point of regulation has been considered. By this we mean the entity with responsibility for compliance with the regulation.

---

[7] This is consistent with our determination in D.07-09-017 that AB 32 would not regulate emissions associated with power wheeled through California. We did, however, recommend in that decision that marketers be required to report imports that are wheeled through California. (D.07-09-017, *mimeo*., pp. 7, 49, 59 (Conclusion of Law 2), and Attachment A, p. A-14.)

The type of regulation options considered (some in more detail than others) include a carbon tax, upstream regulation of emissions from fossil fuel combustion, a downstream cap (with or without trading), and additional direct mandatory requirements.

The point of regulation options considered include retail providers of electricity, in-state generators (with no direct provision for imported power in the cap-and-trade program), deliverers of electricity to the California grid, and a hybrid in which the point of regulation would be generators for in-state power and retail providers for imports.

In addition, we consider options for the distribution of GHG emissions allowances, should a cap-and-trade system be adopted for California that includes the electricity sector.

3.2. Types of GHG Regulation

In this section, we address various types of GHG regulation for the electricity sector in California.

As described in an Assigned Commissioner ruling revising the scoping memo for this proceeding, we have examined options for further direct programmatic regulations for the electricity sector:

> "Regardless of whether a market-based system for GHG regulation is adopted,… regulatory and other strategies will continue to be employed to reduce GHG emissions in the electricity and natural gas sectors in California. In particular,…currently mandated programs such as energy efficiency programs, renewable portfolio standards, and building and appliance efficiency standards will continue. Such programs also may be expanded if such expansion is found to be desirable relative to other emission reduction strategies. Additional emission-reducing mandates could also be imposed. For example, efforts could be undertaken to expand the emission performance standard to apply to short-term contracts and/or non-

baseload power. In addition, ARB could impose other emission reduction measures, e.g., on generators in California."[8]

In particular, we evaluate the requirement that all retail providers of electricity in California be required to provide a minimum level of cost-effective energy efficiency programs and renewable energy delivery.

We also consider the alternative of capping GHG emissions from retail providers, without introducing an emissions trading component. In this approach, California would rely only on strategies not involving emissions trading to reduce emissions toward AB 32 goals, pending implementation of a regional and/or national GHG program. Such a strategy could involve setting entity-specific caps to ensure and track progress toward AB 32 goals in the absence of an emissions trading program.

We also consider the adoption of various forms of a cap-and-trade system that includes California's electricity sector. Options include upstream regulation of fossil fuel combustion, inclusion in a regional and/or a national cap-and-trade system, or inclusion in a multi-sector cap-and-trade system in California.

The Market Advisory Committee, in its recommendations to ARB, presented an option for upstream regulation of fossil fuel combustion in California.[9] This model is also currently under consideration in the United States Congress.

---

[8] Assigned Commissioner's Ruling Modifying the Phase 2 Scoping Memo and Updating the Phase 2 Schedule, December 20, 2007, p. 6.

[9] "Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California, Recommendations of the Market Advisory Committee to the California Air Resources Board," (Market Advisory Committee report) June 30, 2007, pp. 27-32.

As mentioned above, we also consider deferring consideration of a California cap-and-trade system pending implementation of a regional and/or national program. We also consider options for a California cap-and-trade system to coexist with or transition to a regional and/or national system.

3.2.1. Positions of the Parties

In this section, we summarize the input received from parties on the subject of the type of regulation appropriate for the electricity sector in California.

3.2.1.1. Cap-and-Trade System

Most parties support a market-based cap-and-trade system for the electricity sector, including PG&E, SDG&E/SoCalGas, Calpine, IEP, EPUC/CAC, Powerex, Constellation, SMUD, SCPPA, NRDC/UCS, Environmental Defense, Morgan Stanley, WPTF, and AREM.[10] They have differing opinions, however, regarding the possible need to wait until a regional and/or national trading system can be implemented. Other parties including LADWP assert that additional information is needed before the desirability of a cap-and-trade system can be determined.

Supporters of a market-based compliance program for the electricity sector in California assert that a well-designed cap-and-trade program would yield numerous benefits.

Supporters submit that, by establishing a market price for carbon (PG&E), providing price visibility and access to the global marginal price of abatement (SDG&E/SoCalGas), and giving the right price signals (DRA, IEP, and

---

[10] Attachment A contains a list of parties that have filed comments in Phase 2, and associated acronyms used in this decision.

EPUC/CAC), a cap-and-trade system would provide the least-cost method of obtaining emission reductions.

Parties submit the following additional reasons for supporting a cap-and-trade program for the electricity sector:

- Emissions trading would maximize flexibility in achieving emissions targets (Calpine).
- The compliance flexibility would direct capital investment to the lowest cost opportunities (PG&E and Morgan Stanley) and allow entities to make the most cost-effective choices (SDG&E/SoCalGas).
- Cap-and-trade would harness the ingenuity of the market to identify the best ways to meet the goal (Morgan Stanley).
- Emissions trading would reward innovation (Calpine) and efficiencies (Powerex).
- Entities would be likely to reduce emissions more (SDG&E/SoCalGas) and sooner (Calpine, IEP) than they would under regulatory mandates. SCPPA views the purpose, however, as achievement of mandated GHG reductions at a reduced cost, not additional emissions reductions.
- Cap-and-trade would advance abatement technology research and accelerate the introduction of leading-edge carbon reduction technologies (PG&E and IEP), and would lead to operational improvements (IEP).
- Cap-and-trade would internalize externalities and consumers would face the proper incentive to curtail electricity use (IEP).
- Cap-and-trade would allow market participants to manage the risks associated with GHG emissions reduction compliance (Constellation).
- It would give options to meet targets given operational and demand fluctuations and would help manage the "blocky" nature of emission reduction measures (SMUD).
- Cap-and-trade would efficiently distribute the cost of greenhouse gas reductions across capped entities (WPTF) and would provide allocative and productive efficiencies (AREM).

PG&E and Morgan Stanley stress that a cap-and-trade approach would help ensure environmental integrity. They assert that a cap-and-trade approach with a specific reduction target would provide a high degree of certainty that the AB 32 reduction goals will be met.

According to Morgan Stanley, a market-based approach may be less complex to administer than command-and-control.

Several parties argue that California should put its primary efforts into collaborating at the regional and national levels in order to develop an effective program. The CAISO submits that a fully-effective GHG policy for the electricity sector must cover the bulk of the electricity sector in the western United States. The CAISO submits that a major goal of California policy should be to facilitate the establishment and implementation of federal or other West-wide policies. Environmental Defense asserts that California needs to take a leadership role in designing an effective cap-and-trade system to shape future federal regulation. Constellation argues that California's development of a well-designed framework for a market-based cap-and-trade program can serve as a model for the development of regional and national systems. Finally, PG&E points out that momentum is building to pass federal cap-and-trade legislation and State actions will help to build this momentum.

Amount of Reductions due to Cap-and-Trade

Several parties recognize that a cap-and-trade system is likely to provide only a relatively small portion of the overall emissions reductions needs. NRDC/UCS stress, however, that it would reduce emissions lower than could be achieved through existing regulatory programs alone. The CAISO comments that most of the GHG reductions that would be achieved in the electricity sector in the short term likely would result from existing renewable energy and energy efficiency programs. WPTF states similarly that, in the short term, emissions reductions from a market-based approach are not likely to be much larger than those deriving from committed regulatory programs, citing the potential for leakage as one reason. WPTF asserts, however, that a cap-and-trade program has greater potential for greater emission reductions in the long term.

Sectors and Geographic Scope

Several parties see a need for a cap-and-trade program to include multiple sectors, not just the electricity sector, and/or be regional or national in scope. SDG&E/SoCalGas state that a diversity of emissions reduction opportunities would provide the least-cost approach and reduce market power concerns. GPI submits that only a regional approach can prevent abuses to California consumers, and that it favors a delay, if needed for development of a regional approach and a tracking system. The CAISO states that California's dependency on imported power raises doubts about the environmental integrity of a California-only trading system.

DRA states that a liquid market with broad participation is needed to minimize opportunities for market power activities and collusion. LADWP argues similarly that a cap-and-trade program must be robust and economy-wide in order to be successful. LADWP submits that it remains to be determined which sectors, other than electricity, can implement a market-based mechanism effectively. LADWP states that further evaluations are needed to determine if a California-only market-based system can be robust enough to resist market power and/or manipulation, gaming, credit hoarding, and other potentially negative impacts that could affect system reliability and price volatility. Absent such assurances, LADWP recommends that ARB postpone a market-based cap-and-trade program.

Timing

Several parties, including Calpine, IEP, EPUC/CAC, WPTF, DRA, Environmental Defense, and NRDC/UCS, urge California to move forward without waiting for a resolution of GHG issues at the regional or federal level. These parties urge California to act as a leader in creating a cap-and-trade program for a 2012 implementation date. WPTF argues that deferral of a market-based system would hinder the development of the most efficient emission reduction tool, delay the development of tracking infrastructure necessary for a trading system, and miss an important opportunity to gain experience with GHG trading. NRDC/UCS state that the longer a cap-and-trade system is in operation, the longer it has to reap benefits. It submits that California has an opportunity for leadership to influence regional and federal systems, whereas waiting would relegate California to being "one voice among many at the table." NRDC/UCS stress that, if California adopts a cap-and-trade program with an allowance distribution scheme that does not reward dirty polluters, it would advantage California, as a relatively clean state, if a similar system were adopted nationally.

These parties urge that California should continue working toward a regional or federal system and, to the extent possible, should design its cap-and-trade program so it can transition smoothly into a regional or federal system (IEP, Calpine, Constellation, WPTF, and Environmental Defense).

Other parties that support an eventual cap-and-trade program, including PG&E and SDG&E/SoCalGas, suggest that deferral of a cap-and-trade market structure until it can be implemented on a regional and/or national basis may be desirable. While recognizing that California must proceed with implementing a compliance program regardless of broader action, PG&E states that deferral of a cap-and-trade program may facilitate integration with a subsequent regional or federal program and could yield significant advantages and efficiencies. In PG&E's view, a key integration issue is the transferability of allowances, and an inability to transfer such allowances could cause significant integration issues and be very costly to complying entities and retail providers' customers.

SDG&E/SoCalGas state similarly that deferral is reasonable given the regional/national nature of GHGs. It is concerned that a California-only program could strand investments, particularly if California implements a retail provider-based program but a later regional or national program is source-based.

The CAISO states that it does not necessarily favor immediate implementation of a cap-and-trade system in California. The CAISO states that it is difficult to justify the cost of establishing a sophisticated trading system that might be abandoned soon in the face of federal preemption. It sees advantages to deferring implementation of trading until the form of federal regulation becomes clear. NCPA takes a similar position, stating that it is not important that a cap-and-trade program be adopted in the near term, but that any system adopted in California should allow for a transition to a regional or federal program that does not affect California investments adversely.

Other parties are more cautious about a cap-and-trade approach to GHG emission reductions. TURN recommends that a cap-and trade program not be implemented for the electricity sector in 2012. It states that California would be better served by promoting existing policies that result in real GHG reductions, by developing a comprehensive regional tracking system for GHGs, and by deferring implementation of a cap-and-trade system, pending further regional or national developments.

DRA states that while, on its face, it seems that the electricity sector should be included in a California cap-and-trade program, that is true only if such a program reduces emissions. It views the on-going modeling effort as being critical to answering whether a market-based system is likely to provide additional reductions. DRA submits that deferral of a cap-and-trade program until there is a broader coverage would avoid contract shuffling and leakage issues.

LADWP supports direct regulation as the least-cost approach, with a cap-and-trade program as a secondary method of compliance. LADWP recommends that a California-only cap-and-trade program be implemented only if it can be determined to cost-effectively provide emission reductions equal to those that can be achieved through direct regulation within the same time period, and if further evaluations determine that the market would be robust enough to avoid market power problems.

3.2.1.2. Other Emission Reduction Approaches

Parties are divided into three distinct groups regarding how emissions from the electricity sector can be reduced most cost-effectively.

Supporters of a cap-and-trade system believe that alternatives would be less effective. Powerex argues that trading should be a key component because "a cap alone unfairly assumes all emitters have the same cost of compliance, penalizes those that have a higher cost of compliance, and does not reward those that may be able to reduce emissions greater than what is required by compliance through being rewarded by the market for such action." Similarly, SCE suggests that, "Given the significant actions of the electric sector in California to reduce GHG emissions to date, it is unlikely that the most cost-effective reductions will come from this sector. Instead, they are likely to come from trading with other sectors and through offsets. Increased programmatic goals are likely to cost more and raise rates more than a market-based approach."

Constellation suggests that, "while there is likely more that can be done with energy efficiency and renewables, these mechanisms will have their limitations, as is evidenced by the increased attention to the real costs of wind power with respect to the need for services that can shape the wind power deliveries and ancillary services necessary to provide contingent power supply." SMUD expresses concern that strict command and control goals in areas such as Renewables Portfolio Standard (RPS), energy efficiency, and solar installations would lead to excessive costs and that, "the compliance costs will not be the most cost effective as required by AB 32. Morgan Stanley adds that, "Command and control mechanisms tend to be more complex to administer than market-based approaches and lead to less than optimal investment in GHG reduction technologies."

A second group echoes TURN's sentiment that, "the state would be better served by promoting existing policies that result in real GHG reductions, by developing a comprehensive regional tracking system for greenhouse gases and by deferring the implementation of a cap-and-trade system for the electric sector pending further regional or national developments." LADWP supports "direct regulation through changes in the generation resource mix and avoidance of emissions through energy and water conservation and demand-side management as the least cost approach to reducing emissions for the electricity sector." DRA asserts that "increased programmatic goals likely would increase cost of electricity but not necessarily more so than a cap-and-trade program."

A third group expresses an interest in a dual approach, whereby a cap-and-trade system would be implemented at the same time that the stringency of existing programs such as RPS, energy efficiency, and the Emissions Performance Standard would be increased. SCPPA contends that, "The continuation and expansion of targeted energy efficiency, renewable portfolio, technology development, and similar programs aimed at retail providers as the GHG point of regulation would be compatible with instituting a cap-and-trade." NRDC/UCS assert that, "a cap-and-trade system provides only a generic innovation signal, and targeted policies are more useful for spurring innovation for specific technologies, and overcoming market barriers." NRDC/UCS argue further that both a cap-and-trade system and increased regulatory measures are necessary because, "regulatory policies in the absence of a cap on absolute emissions would not guarantee that the electric sector will meet the GHG reductions goals of the state for this sector."

Parties generally support the incorporation of flexible compliance mechanisms regardless of whether they prefer a cap-and-trade or command and control approach to emissions reductions. Constellation asserts that, "The use of offsets and other flexible compliance tools will help to achieve emission reductions in a cost effective manner and should be incorporated into any emission reduction strategy, whether those strategies are market-based or not." SMUD asks that retail providers have general flexibility in meeting their targets through existing energy efficiency and renewable programs.

3.2.2. Discussion

In determining our recommendation for how to regulate the electricity sector in California under AB 32, there are essentially four options that could be adopted individually or in combination: 1) a carbon tax, 2) upstream regulation of emissions from fossil fuel combustion, 3) a downstream emissions cap (with or without trading), and 4) additional direct mandatory/regulatory requirements.

We did not seriously consider the carbon tax option in the course of this proceeding, due to the fact that, if a carbon tax were implemented, it would most likely be imposed on the economy as a whole by the Legislature after recommendations by ARB. Since our focus is on energy sectors only, we did not examine this idea in any detail in this proceeding, nor do we plan to do so.

Similarly, the Market Advisory Committee presented an option for upstream regulation of fossil fuel combustion in California. As the Market Advisory Committee points out, "there is no precedent for using this approach in a cap-and-trade program run by a single agency." However, if this were to be done, ARB may impose it on an economywide basis. While there may be policy reasons for further examination of this approach, which is also under consideration in the United States Congress, we have not undertaken a detailed review of this option for the energy sectors in California. This proposal is not well defined and seems more aimed at a national regulatory regime. Instead, we have focused attention on additional direct mandatory/regulatory requirements and an electricity sector cap or cap-and-trade program.

We begin by examining the direct mandatory/regulatory policies and requirements that California already has in place that contribute to GHG reductions. The State's Energy Action Plan lays out a "loading order" for investment in electricity resources in California that puts energy efficiency as the top priority, with renewable resources second, and clean fossil-fired generation to the extent that other options are not available. To address each of these resource areas, California has three primary policy tools already in place:

- Energy efficiency programs, including building codes and appliance standards,
- The RPS program, and
- The Emissions Performance Standard.

In the case of energy efficiency building codes and appliance standards, the Energy Commission updates these approximately every three years and is continuously including more requirements that reduce electricity use and therefore GHG emissions. These regulations provide a base of electricity and GHG reductions that are permanent and continuous through 2020. We expect these regulations to continue to be enhanced over the entire AB 32 period.

In addition, the Public Utilities Commission sets requirements for the amount of energy savings each investor owned utility (IOU) is required to achieve on an annual and cumulative basis. Current requirements are set through 2013 and are being updated this year in R.06-04-010 to include goals through 2020. The goals are generally set according to the availability of cost-effective energy savings in the utilities' service territories. In D.07-09-043, the Public Utilities Commission also set up a risk/reward mechanism for the IOUs, which allows them to earn financial incentives as they approach meeting their energy savings goals and assesses penalties if they fail to meet at least 65% of their goals.

AB 2021 (Levine, Chapter 734, statutes of 2006) required the Energy Commission, in collaboration with the Public Utilities Commission and the publicly owned utilities (POUs), to set statewide energy efficiency targets for 2017 for all utilities in the state. The legislation requires, among other mandates, that the POUs identify all potentially achievable cost-effective electricity energy savings, establish annual targets for achieving feasible and reliable energy efficiency savings and demand reduction for the next 10-year period, and report these targets to the Energy Commission.

Based upon an assessment of energy efficiency potential available, and considering the need for aggressive energy efficiency savings to help meet climate change goals, the Energy Commission has established a statewide target to achieve 100% of the economic potential identified for energy efficiency. This target is significantly higher than the combined goals proposed by the POUs, the IOUs, or other parties. The Energy Commission expects this statewide target to be achieved through a combination of utility and non-utility programs coordinated at the state level by the Energy Commission and the Public Utilities Commission.

No statutory requirements currently exist for Energy Service Providers (ESPs) or Community Choice Aggregators (CCAs) to invest in energy efficiency for their customers, though their customers fund a portion of the IOU energy efficiency programs through their distribution charges and are currently eligible to participate in IOU-administered energy efficiency programs.

The RPS statutes (Senate Bill (SB) 1078 enacted in 2002, as amended by SB 107 in 2006) require IOUs, CCAs, and ESPs to provide a minimum of 20% of delivered energy from renewable sources by 2010. In addition, SB 1078 as amended by SB 107 requires POUs to set RPS targets, but does not specify minimum delivery requirements or the types of renewables that should qualify.

SB 1, enacted in 2006, requires the development of a solar photovoltaic program for California, including both IOUs and the POUs. Production of solar energy at customer sites is another option for reducing GHG emissions from the electricity sector. This program is a direct programmatic measure that will reduce emissions in the sector from customers of several types of retail electricity providers.

SB 1368 enacted in 2006 directed the Public Utilities Commission and the Energy Commission to develop an emissions performance standard for non-renewable, generally fossil-fueled generation resources, for all retail providers of electricity. The Public Utilities Commission adopted regulations for IOUs, ESPs, and CCAs in January 2007 (D.07-01-039), while the Energy Commission adopted regulations for POUs in August 2007; the two sets of requirements are nearly identical. The regulations require all new long-term investments in baseload generation by retail providers to be in power plants that emit no more than 1,100 pounds of carbon dioxide (CO_2) per megawatt hour (MWh) produced.

Of the State statutes we have just described, the emissions performance standard statute is the most recent, and it applies its environmental requirements uniformly to all electricity retail providers in California. We agree with the underlying logic of this statutory approach. The goals of AB 32 would be best achieved if all retail providers of electricity, including IOUs, POUs, ESPs, and CCAs, are subject to minimum requirements in the areas of cost-effective energy efficiency and renewables. Such requirements would benefit California customers by ensuring that they receive the GHG emission reductions of cost-effective energy efficiency and renewables. Therefore, we recommend that ARB, as part of its AB 32 regulations, adopt mandatory minimum levels of cost-effective energy efficiency savings required from POUs, at levels recommended by the Energy Commission. Likewise, ARB should adopt mandatory minimum levels of cost-effective energy efficiency consistent with the programs and goals adopted by the Public Utilities Commission for IOUs, CCAs and ESPs.

The POU governing boards have already set 20% renewables goals. Some of the largest POUs plan to achieve that level by 2010, a few have already obtained it, and the rest plan to do so by 2017. We recommend that ARB require that the POUs deliver at least 20% renewable electricity to their customers by no later than 2017 and incorporate this assumption into its scoping plan. ARB should include enforcement mechanisms in its plan, so that it can be assured that the related GHG reductions will be achieved.

In making these recommendations, we have not analyzed whether ARB has the authority to implement these regulations as part of AB 32. Our preliminary analysis suggests that they do. However, if ARB believes that such authority does not exist, we recommend that it seek such authority from the Legislature.

In addition, we also recognize that existing RPS requirements are limited to 20% renewables by 2010. The Public Utilities Commission is prohibited by statute (SB 107 enacted in 2006[11]) from requiring that IOUs obtain more than 20% of their power from renewables. In order to meet the AB 32 goals, the IOUs and POUs should be required to go beyond a 20% level of renewable electricity delivered. Therefore, we recommend that the Energy Commission, Public Utilities Commission, and ARB jointly seek legislation that requires retail electricity providers to obtain a greater proportion of their power from renewables by a date certain, with flexibility to allow the Public Utilities Commission and/or ARB to require exceeding that level under certain conditions (subject to a cost-effectiveness evaluation, for example). The Energy Action Plans jointly adopted by the Public Utilities Commission and the Energy Commission commit us to "evaluate and develop implementation plans for achieving 33 percent renewables by 2020, in light of cost-benefit and risk analysis." While achieving renewable energy deliveries at this level would contribute significantly to attainment of the emissions reductions required by AB 32, we leave open consideration of the appropriate statutory percentage requirements and deadlines, pending further analysis.

We do not adopt the policy, as suggested by some parties, that we should eliminate mandatory targets for energy efficiency and/or renewables, and allow

[11] Public Utilities Code Section 399.15(b)(1) states that "A retail seller with 20 percent of retail sales procured from eligible renewable energy resources in any year shall not be required to increase its procurement of renewable energy resources in the following year."

an AB 32 cap to govern instead. As recognized in D.07-12-052, long-term integrated resource planning is now, and will continue to be, an essential component of achieving sustained GHG emissions reductions within the electricity and natural gas sectors. We firmly believe that our existing energy efficiency, renewables, and emissions performance standard policies are the foundation upon which other AB 32 policies should be built. We intend to work with ARB to determine appropriate levels of requirements for each of these types of resources and programs.

With this basis, we turn our attention to the question of whether a cap-and-trade system should be implemented in California for the electricity sector, in addition to the programmatic measures identified above. Before examining in detail the cap-and-trade option, we note that it would be possible to cap emissions from the electricity sector, most likely at the retail provider level, without a provision for trading of allowances among entities in the sector. In D.06-02-032, which was adopted prior to the passage of AB 32, the Public Utilities Commission concluded that GHG emissions should be capped in the electricity sector, but deferred the question of whether emission allowance trading should be implemented. At that time, the Public Utilities Commission contemplated that the GHG cap would apply to the electricity sector only. Now that AB 32 requires an economy-wide cap in California, we see little advantage to a cap system without a trading component, compared to the direct programmatic approaches described above. In addition, a cap without a trading component would offer many fewer advantages than those we describe below for a cap-and-trade program. Therefore, we decline to recommend a cap-only system for the electricity sector in California.

As summarized in Section 3.2.1.1 above, most parties support the inclusion of the electricity sector in a market-based, multi-sector, cap-and-trade program for GHG emission allowances. However, some parties, including TURN, CAISO, CMUA, DRA, PG&E, and SDG&E/SoCalGas, would prefer that California wait to establish a cap-and-trade program until there is either a regional or national system in place.

Our recommendation to ARB is to proceed now to design a multi-sector cap-and-trade system for California that includes the electricity sector. We have a number of reasons for this recommendation. First and foremost, we are cognizant that ARB must develop comprehensive plans by the end of this year for the major sectors of the California economy to meet the 2020 goal. All of the major mechanisms will need to be included in ARB's scoping plan, as required by AB 32, by January 1, 2009. ARB should not simply include a placeholder for cap-and-trade and develop its key provisions later. We believe that the scoping plan should be a blueprint for what California will do if the mechanism is to be in place by 2012, the first year for compliance with AB 32. If ARB determines that market measures are an appropriate means of achieving ARB's and AB 32's goals and ARB further determines that cap-and-trade is the preferred market mechanism, then in order to meet this goal, initial development of a cap-and-trade program should be undertaken now. Detail on how a cap-and-trade program could be implemented in the electricity sector will aid ARB in its assessment of the feasibility and net benefits of a multi-sector program. Our purpose in adopting this recommendation is to provide detail to ARB for its evaluation of a cap-and-trade program design for the electricity sector. We fully recognize that ARB may decide not to adopt a cap-and-trade program for California.

However, we favor inclusion of the electricity sector in a cap-and-trade program for a number of policy reasons. While we fundamentally favor a certain minimum level of mandatory reductions from existing programs as described above, a cap-and-trade system in combination with these mandatory reductions should be able to produce the GHG emissions reductions required by AB 32 at a lower cost than sole reliance on additional mandatory reductions. This is because emission allowance trading would maximize flexibility in achieving emissions targets by allowing obligated entities to rely on the least-cost abatement options throughout the economy. This, in turn, would provide strong incentives for investment in research and innovation in technologies that lower GHG emissions. A trading system also would allow market participants to manage risk associated with compliance obligations. Finally, it would internalize GHG externalities and should distribute the cost of GHG reductions efficiently across all capped entities. This is valuable because the impacts of GHG emissions are felt by all Californians.

We agree with several parties, including NRDC/UCS, that the cap-and-trade system need only produce a relatively small portion of the overall emissions reductions in the short term. We recommend that ARB design it as a complement to existing policies and their expansions as noted above. As described above, a large portion of the emissions reductions in the electricity sector will come from mandated investments in energy efficiency and other demand reduction programs, as well as renewable energy goals. The additional reductions due to a cap-and-trade system from the electricity sector will likely be small beginning in 2012, but may expand as experience with the mechanism and compliance obligations increase over the AB 32 time period. Furthermore, one of the advantages of a cap-and-trade system is that it facilitates cost-effective GHG reductions from other sectors within the multi-sector cap. This opportunity to gain experience with the cap-and-trade mechanism, in addition to finding real least-cost reductions, is a major reason for our recommendation to proceed now with cap-and-trade for the electricity sector.

In addition, AB 32 requires that ARB design any cap-and-trade program to ensure that there be no increase in the emissions of toxic air contaminants or criteria air pollutants and that localized impacts in communities already adversely impacted by air pollution be minimized. Our recommendation is consistent with other federal, State, and local environmental requirements pertaining to criteria pollutants, and we are confident that these tests can be met.

Finally, we are confident that California can design its cap-and-trade program in collaboration with the other states in the Western Climate Initiative. The timeframe set for the Western Climate Initiative to agree on a design framework and principles is similar to ARB's AB 32 timeframe. Therefore, we intend to continue to work with the other states to develop a coordinated approach. While the approach recommended by the Western Climate Initiative might not be identical to the system we propose for California, we believe that there will be adequate time prior to 2012 to ensure consistency among the cap-and-trade designs.

3.3. Point of GHG Regulation in a Cap-and-Trade System

In this section, we consider the point of regulation or entity in the electricity sector with responsibility for compliance in a multi-sector cap-and-trade system in California. There are four primary options under consideration for point of regulation in the electricity sector:

Retail Providers. In what has been called a "load-based" or "retail provider-based" approach, the regulated entities would be the retail providers of electricity to California customers. Retail providers would be required to obtain and surrender emission allowances for the GHG emissions associated with all power (including both in-state generation and imported electricity) sold to end users in California. Generators would not have a compliance obligation under this approach, except possibly for exported power. We agree with CMUA that "retail provider" is a more accurate and descriptive terminology, and use that term herein.

In-State Generators. In what has been called a "pure source-based" approach, the regulated entities would be generators (owners or operators of power plants) located in California. Emissions attributed to all in-state generation, whether used to serve California load or exported, would be included in a cap-and-trade system. Under such a system, electricity use associated with imports would not be directly regulated under the cap-and-trade system, but could be included in determining whether California economy-wide emission reduction goals are reached consistent with AB 32.

Deliverer. The structure of what has been called the "first seller" approach was a matter of some discussion in this proceeding. The Market Advisory Committee suggested that the point of regulation should be the "first seller" of power into California electricity markets.[12] As explained in Section 3.3.2.6, we recommend a variation of the first seller approach, in which the point of regulation would be specified as the entity that owns the electricity as it is delivered to the grid in California. We use the term "deliverer" to describe this regulatory approach.

In-State Generators/Retail Providers for Imports. A fourth point of regulation approach that has received consideration is a hybrid system in which the point of regulation would be the generators (owner or operators of power plants) for in-state generation with the retail providers responsible for imported electricity.

---

12 Market Advisory Committee report, at 42.

3.3.1. Positions of the Parties

In this section, we summarize the positions of the parties on the appropriate point of regulation in the electricity sector for a cap-and-trade program in California.

3.3.1.1. Retail Providers as the Point of Regulation

The retail provider (or load-based) point of regulation imposes the obligation on retail providers to retire allowances corresponding to the emissions associated with the electricity generated or procured to serve customer loads. Parties' positions are divided about the desirability of this approach to regulating GHGs. Generally, the retail provider approach is supported by POUs and opposed by IOUs, ESPs, marketers, and generators.

LADWP believes that the retail provider-based approach "remains the superior and only feasible approach," if applied to a California-only GHG emission reduction program. According to LADWP, its advantages include consistency with energy efficiency and renewable initiatives, minimized costs of retail providers instead of relying on high market prices to change generation dispatch, and that it is least susceptible to legal challenge.

SCPPA states that "the number of regulated entities would be minimized in contrast to either the first seller or the hybrid approach, leading to administrative simplicity."

SMUD also supports the retail provider approach, expressing its view that, "Assumptions about the carbon content of market purchases would have to be made but these assumptions would be required under the first seller concept as well. The retail service provider would be in the best position to balance the level of energy efficiency, renewable energy or other low carbon strategies needed to meet its GHG goals."

While TURN's overall recommendation is to delay implementation of a cap-and-trade program, TURN recommends further analysis of the feasibility and relative benefits of a retail provider-based regulatory system using tradable emission attribute certificates (TEACs), an option described in more detail below.

PG&E and SCE are strongly opposed to a retail provider-based approach for a number of reasons, most of which stem from their concerns regarding inaccuracies that may arise in reporting and tracking emissions and may result in gaming opportunities and market distortions. Furthermore, PG&E argues that, "because a national system is likely to be source-based, California would have to invest a large amount of money and effort to create a system that would quickly become obsolete…"

The CAISO Market Surveillance Committee asserts that a retail provider-based system is inferior to the other options. It states that load-based and source-based systems are essentially the same on the issues of determining the GHG content of power imports and incentives for investments in energy efficiency and renewable energy. However, it contends that a retail provider-based system has serious disadvantages in other respects: administrative complexity, adverse impacts on the efficiency and costs of dispatching generation units, and incompatibility with likely federal GHG legislation.

The CAISO Market Surveillance Committee contends that a retail provider-based system in which retail providers signed contracts with individual generators to minimize the cost of serving load results in the same cost to load as a source-based system in which generators maximize profit and emission allowances are allocated to retail providers for subsequent auction to generators.[13] It asserts, however, that due to the effects of a retail provider-based system on wholesale markets, particularly the CAISO markets, it would lead to the deployment of a less-efficient generation mix, thereby resulting in higher, not lower, energy costs for consumers. The CAISO Market Surveillance Committee concludes that the resulting cost of energy to consumers would likely be higher under a load-based cap.

Although NRDC/UCS would support any of three point of regulation options (retail provider, deliverer, or hybrid), they state that each has different strengths. NRDC/UCS support LADWP's and SCPPA's comments that a retail provider-based cap will produce stronger incentives for retail providers to invest in low-GHG emitting technologies.

Tracking, including TEACs and CO2RCs

Several parties argue that difficulties in tracking the contractual responsibility for the electricity used to serve a retail provider's load back to the ultimate sources constitutes a serious weakness to the retail provider approach.

---

[13] The CAISO Market Surveillance Committee describes two sources of rents that, in its view, producers can capture with the implementation of a GHG cap-and-trade system: "allowance rents" and "rents of clean generation." "[I]f allowances are given to load, and then sold to generators (perhaps via an auction) for use in a source-based system, with the proceeds returned to consumers, then these rents will, to some extent, offset the price increases resulting from the cap-and-trade mechanism. These rents are also retained by consumers under a load-based system."

It states that generation units with low emissions would also benefit from higher energy prices because price increases will exceed their allowance expenses, that these "rents to clean generation" would be retained by independently owned generators, and, for generation owned by utilities, any such additional profits could be returned to consumers. It concludes that consumers could, under either a retail provider or first seller point of regulation, retain the allowance rents as well as the portion of rents to clean generation that accrue to utility owned and new renewable generation.

Powerex argues that the use of "broadly estimated regional intensity factors" would decrease not only accuracy but also the likelihood of real reductions. SCE states that the inability to accurately match load to sources is the fundamental and unavoidable flaw in a load-based approach. Morgan Stanley believes that, largely due to issues associated with unspecified power, a retail provider approach would be more administratively complex than the deliverer approach.

In contrast, other parties believe that issues regarding accurately tracking retail provider responsibility for GHG emissions can be overcome. SCPPA states that the retail provider approach may actually be superior to the deliverer approach and less costly due to the ability to use contracts and settlements data of a retail provider to identify the sources of energy derived from a third party.

GPI argues that a comprehensive regional tracking system is needed to improve the accuracy of GHG attribution to retail providers, and that this effort could piggy-back on multi-attribute tracking systems that have already been developed in other parts of the country. SMUD prefers a tracking system that uses existing settlements and reporting data as much as possible, stating that accuracy for unspecified sources would improve as more parties opt in to the tracking system. However, SCPPA believes that developing, and requiring the use of, a universal source-to-sink accounting would have the potential to impede energy market trading and to reduce market liquidity.

An alternative form of retail provider point of regulation that would use TEACs for compliance was proposed by WPTF. As proposed, this system would work by giving a certificate to generators for every MWh of output that represents the GHG emissions associated with that output. Similar to the use of tradable renewable energy certificates (RECs), retail providers would be required to obtain certificates to match each MWh of load served. A punitive high default rate would be assigned for every MWh of a retail provider's load that is not covered by a certificate. WPTF explained its view that using TEACs could improve accuracy by reducing the need for default emission rates for unspecified purchases, and that improved accuracy in attribution of emissions also would send the right economic signals to all generators. WRA submitted a similar proposal that would assign CO2 reduction credits (CO2RCs) to generators based on the difference between generators' emission rates and a high default rate.

Some parties believe that the TEAC/CO2RC approach deserves serious consideration. IEP likes the CO2RC or TEAC approach should a retail provider-based point of regulation be chosen. DRA supports WRA's CO2RC proposal, arguing that favorable aspects of this approach include administrative simplicity, likelihood of achieving real reductions by mitigating contract shuffling, compatibility with source-based systems, and low legal risk.

Several parties, including WPTF, Calpine, Constellation, and AREM, state that, while they prefer a source-based system, the TEAC approach would offer significant advantages if California adopts a retail provider point of regulation. Calpine states that, since "TEACs would provide a carbon signal directly to generators, it would provide a strong incentive for both investment in, and dispatch of, low-emission generation."

By contrast, the CAISO Market Surveillance Committee states that a TEAC approach would be functionally and economically equivalent to a source-based approach with output-based allocation of allowances, and argues that the additional administrative complexity of a TEAC system is unnecessary. PG&E and SCE similarly assert that the costs of creating and administering a TEAC system would outweigh any possible advantages that it might offer. SCPPA contends that, rather than being simple, this approach itself would need to track all power that is generated and delivered to retail providers in California.

Compatibility with CAISO Markets

Some parties argue that, because a retail provider-based system would depend on default emission rates for unspecified power purchases, it may have deleterious effects on CAISO's pooled markets with the averaging of emissions in the pool reducing the incentive for generators in the pool to reduce emissions. They assert that clean generators with emission rates lower than the default rate would negotiate bilateral contracts that enable them to capture some of the value of their lower emissions and that this increased reliance on specified contracts and self-scheduling would dampen the efficiencies in dispatch and transmission that the Market Redesign and Technology Upgrade (MRTU) is designed to provide.

The CAISO Market Surveillance Committee states its additional view that, "Another reason why more self-scheduling is likely to occur is because each [retail provider] will be trying to self-manage its supply portfolio to stay within [its] emissions limitation." The CAISO Market Surveillance Committee expresses concern that, "The [CAISO] markets for energy and ancillary services will become significantly thinner… Furthermore, thinner markets would likely also be less competitive markets. Ultimately, all of these increased costs would be passed on to consumers." PG&E, SCE, and SDG&E/SoCalGas express similar positions.

Contract Shuffling

The CAISO Market Surveillance Committee expresses concern that the ability to regulate the GHG content of imported electricity may be grossly overstated because of contract shuffling concerns. It submits that there is enough "clean" generation available in the West-wide market, "such that there is likely to be more than enough clean generation that can be assigned, on paper, to California imports, without actually changing system operations, or investment, in the West." Several parties argue that there is no way to entirely combat contract shuffling, except through a national or at least region-wide source-based system.

PG&E, SCE, and WPTF express the view that, while the potential magnitude of contract shuffling for imported electricity is likely to be similar for all points of regulation, it may be of greater concern under a retail provider point of regulation since in-state sources could be shuffled as well. PG&E contends that there would be the possibility of "greenwashing through exports," in which a high-GHG in-state generator could export power from California and import cleaner power to sell to a California retail provider.

NRDC/UCS contend that contract shuffling concerns would be approximately the same under a retail provider-based, first seller or hybrid system. They contend, however, that contract shuffling would become less of a concern over time because of the Western Climate Initiative or, potentially, a federal system and, moreover, that new infrastructure investments will require long-term financial commitments that would lend themselves to easier emissions tracking and therefore be less prone to contract shuffling.

Some parties, including SCPPA, CMUA, and SMUD, believe that the threat of contract shuffling does not warrant much concern. CMUA states that, "…there is little threat of *actual* contract shuffling within a California-only retail provider-based program. Robust verification procedures will serve as an adequate deterrent to virtually eliminate *actual* contract shuffling by retail providers." SMUD contends that other Western states' RPS requirements limit the potential for contract shuffling.

3.3.1.2. In-State Generators as the Point of Regulation, Imports not in Cap-and-Trade

PacifiCorp is the only party to support an in-state generator-only point of regulation. DRA supports the CO2RC method described by WRA, but DRA suggests a source-based point of regulation as a second choice, stating that it would be simpler and easier to track, and would minimize legal risk.

Morgan Stanley states that, "a source-based approach for in-state resources is necessary to ensure that dispatch decisions reflect the price signal for GHG emissions. This in turn, will provide market participants with incentives to alter behavior." However, it concludes that the deliverer approach would be superior to other alternatives for dealing with imports.

<u>Compatibility with AB 32</u>

Parties were asked whether a pure source-based program would be compliant with AB 32, which requires that ARB adopt GHG reporting requirements that account for the GHG emissions associated with electricity imported into and consumed in California. Several parties, including SDG&E/SoCalGas, Calpine, IEP, LADWP, SCPPA, GPI, and AREM, assert that the exclusion of import-related emissions from a tradable cap would violate the requirements of AB 32.

DRA counters with an alternative view that, while AB 32 requires ARB to adopt regulations that account for imports, it does not require direct regulation of emissions associated with imported electricity as long as the overall emissions goal is achieved.

Leakage

NRDC/UCS argue that a pure source-based point of regulation likely would fail AB 32 requirements to minimize leakage. Several other parties express similar concern about leakage under a pure source-based program. WPTF states that a system that solely covers in-state generation would impose a cost differential between in-state and imported power and contribute to leakage, at least in the short term. SCE and Calpine express similar views. SMUD asserts that a source-based system has to be West-wide or national, and that an in-state-only system would drive generation out-of-state.

Other parties are less concerned about leakage under a pure source-based system. These parties cite four principal factors that, in their view, would limit leakage. First, DRA submits that the existing surplus transmission capacity for importing additional power is limited. Second, several parties, including PG&E, PacifiCorp, SDG&E/SoCalGas, SCE, IEP, and Constellation, view the implementation of the Emissions Performance Standard as an important factor limiting leakage. Third, some parties argue that the current Western Electricity Coordinating Council generation mix and capacity factors of coal-fired resources limit the potential for leakage. PG&E and PacifiCorp state that marginal generators are often gas combined cycle units, so that leakage would merely cause in-state combined cycle usage to be shifted to out-of-state combined cycle. Parties argue that out-of-state coal plants have such low running costs that they will run at high capacity factors regardless of programs California imposes. Fourth, Constellation, PacifiCorp, PG&E, and WPTF consider the likelihood of a regional or national GHG emission reduction program as largely mitigating the threat of a long-term shift of production to regions outside the state.

Other Requirements in Conjunction with Generator Cap-and-Trade

Parties were asked to comment on whether expanding programmatic approaches to mitigate GHG emissions would be needed to meet AB 32 goals if an in-state source-based point of regulation were adopted.

Many parties express concern about the costs and effectiveness of expanding "command and control" approaches. Calpine states that, "Because out-of-state generators would not be subject to the emissions cap, a variety of indirect actions would need to be taken to…ensure emissions reductions…and would likely place additional burdens on in-state resources, …increasing the costs to reduce emissions. Such an approach to ensuring compliance with AB 32 is clearly less efficient than a system that simply makes emissions from imported power subject to a cap."

Constellation urges that policies that create more incentives for offsets should be given special attention in the event imports are excluded.

DRA and NRDC/UCS believe that some additional programs are desirable in any event, as described in Section 3.2.1.2. NRDC/UCS argue that, if emissions from imports are excluded, it will be all the more critical for the State to expand energy efficiency and renewable energy programs. WPTF suggests that the current suite of policies be applied uniformly across retail providers if imports are not included in the cap-and-trade program. AREM strongly opposes extension of energy efficiency programs to ESPs as "inappropriate and unnecessary."

Several parties submit that strengthening the Emissions Performance Standard would not be an effective means of mitigating additional leakage that could occur from a California-only source-based cap-and- trade regime. They contend that the Emissions Performance Standard is not a suitable mechanism for reducing emissions from imports that fall below the 1,100 pounds (lbs)/MWh threshold, and that such imports, if they are not included in a California cap, could displace a substantial portion of cleaner in-state generation.

3.3.1.3. Deliverers as the Point of Regulation

A threshold issue is the best formulation of a "deliverer" approach. This approach evolved out of the "first seller" approach recommended by the Market Advisory Committee. The Market Advisory Committee recommended that the point of regulation be either the owner or operator of the California power plant, or the importing contractual party, depending on whether the electricity is generated in-state or out-of-state. In comments, parties take differing positions regarding the proper formulation of a first seller approach, or a variation thereof.

PG&E suggests that, for in-state power, the owner or operator of the generating unit would be the point of regulation, since it is usually the first to deliver the power to the busbar, which is usually the first delivery point on the transmission grid in California. PG&E suggests that, for imports, the entity with ownership of or title to the power at the first point of delivery in California would be the point of regulation. In this view, for those imports that have E-tags, the deliverer would be the Purchasing/Selling Entity listed on the E-tag[14] at the first point of delivery in California. Because intra-balancing authority[15] imports would not have E-tags when they are delivered to the California grid,

---

[14] North American Electric Reliability Corporation E-tags identify the Purchasing/ Selling Entity responsible for the power at a particular point or portion of the physical scheduling path, power quantities, and the balancing authorities where the power originates and sinks.

[15] The balancing authorities in California are the CAISO; Imperial Irrigation District; LADWP; PacifiCorp-West; SMUD; Sierra Pacific Power Company; Turlock Irrigation District; and Western Area Power Administration, Lower Colorado Region.

PG&E suggests a technical working group to address information sources for such imports.

SCPPA asserts that, in a deliverer approach, entities that control plants through tolling agreements should be the point of regulation rather than the generator. While such entities are neither owners nor operators, SCPPA states that they "are tantamount to being owners or operators" by virtue of their tolling agreements.

SCE takes the position that, rather than identifying the deliverer of imports based on the point of delivery within California, the deliverer should be identified based on the first delivery point for which the balancing authority is a California entity. SCE explains that this would include delivery points outside the State that are controlled by a California balancing authority.

Parties take differing positions regarding whether marketers and brokers should have compliance obligations under a deliverer approach. SCE submits that marketers and brokers should be treated as any other Purchasing/Selling Entity, except that generators would be responsible for all in-state transactions. Several parties take the position that marketers would be first sellers, but not brokers since they do not own or schedule the power (LADWP, SCPPA, WPTF/AREM, and DRA). Morgan Stanley states that, for imported power, the party responsible for scheduling the energy into California should be the point of regulation.

Several parties support a deliverer approach, including PG&E (if multi-sector California only), SDG&E/SoCalGas, SCE, Calpine, Powerex, Constellation (until a regional source-based system is implemented), Environmental Defense, Morgan Stanley, WPTF, and AREM.

Contract Shuffling and Leakage

Several parties that comment on the risks of contract shuffling and leakage submit that any system that includes imports in the cap faces the same contract shuffling and leakage concerns for the imports. For example, Morgan Stanley states that each approach for dealing with imports "is only an administrative approximation and is vulnerable to leakage and contract shuffling. The challenges for dealing with imports are essentially the same for each … and the flaws for each approach are roughly equal."

Several parties assert that a deliverer system would reduce contract shuffling for in-state resources. WPTF submits that, under a retail provider-based system that uses contracts and settlement data to assign emissions to retail providers, there would be on-going potential for contract shuffling but that contract shuffling would be reduced under a deliverer approach since the portion of load for which it would be necessary to assign emissions, i.e., some imports, would be smaller than under a retail provider-based system.

EPUC/CAC cite the Market Advisory Committee report as observing that linkage with other regional GHG programs is required to eliminate the leakage problem. EPUC/CAC state that contract shuffling issues result similarly where regulation does not address all potential sources of emissions. While they see the adopted Emissions Performance Standard as a good step toward reducing leakage and contract shuffling for long-term import contracts, they argue that inclusion of imports in California's GHG regulatory scheme is important to mitigate the potential for short-term leakage and shuffling.

Consistency with Potential Federal Programs

Morgan Stanley asserts that the deliverer approach is superior to other alternatives for dealing with imports because it "is the most consistent with a source-based approach for in-state resources, and is therefore superior to the others." WPTF believes similarly that a deliverer-based approach should be pursued on the grounds that it could be most easily adapted to the source-based approaches being considered at the federal level. Calpine states that both a source-based system and a deliverer approach likely would be consistent with expected regional and federal source-based systems. Powerex asserts that the deliverer approach is suitable as a model for a national or regional program and, if adopted by California, can be easily scaled and integrated with broader regional or national programs.

Incorporation of Price of Carbon into Energy Market Prices

Several parties, including SCE, PG&E and Powerex, assert that, because electricity deliverers would be responsible for obtaining allowances, the deliverer approach would incorporate GHG compliance costs within electricity costs, thereby providing the correct price signal to the market to place generation in the appropriate dispatch order. SDG&E/SoCalGas describe that some deliverers may not have adequate information to include carbon costs into their offers in the day ahead or real-time auctions, specifically sellers making intraday trades. SDG&E/SoCalGas submit however that, if that information became valuable, it is likely that the needed information would become available.

PG&E argues that this approach would provide stronger price signals for development of low-emitting or zero-emitting renewable energy supplies. It contends, in particular, that the profitability and competitiveness of renewable energy producers bidding into wholesale power markets would be increased under this approach, compared to a retail provider-based approach which would not directly internalize the cost of GHG emissions.

Morgan Stanley states that "a source-based approach for in-state resources is necessary to ensure that dispatch decisions reflect the price signal for GHG emissions. This in turn will provide market participants with incentives to alter behavior."

TURN is concerned that adoption of a source-based or deliverer-based regulatory framework could increase the cost of electricity for California ratepayers.

Interaction with MRTU and Wholesale Markets

SCPPA views the impact of a deliverer approach on the real-time or forward markets as a "direct interference" that would increase the cost of the GHG reduction program. However, the CAISO Market Surveillance Committee strongly favors a deliverer approach due to what it sees as reduced interference in the efficient operation of its markets. SCE asserts a related advantage with respect to imported energy, that an entity that delivers power to California must take responsibility for that energy before it is bid into the CAISO market. In SCE's view, this addresses the attribution challenge of market bids from imports.

SCPPA is concerned that this approach may discourage importers from selling into the California market, "thereby reducing California electricity market liquidity, increasing wholesale electricity prices, and decreasing reliability."

Administrative Issues

SCPPA and GPI submit that a deliverer approach would involve a larger number of regulated entities, and that this would complicate administration of the program. SDG&E/SoCalGas and Environmental Defense state that, while there would be more points of regulation for imports, the number would not be overly burdensome. As a potential benefit, Calpine suggests that having more actors in the market may help to increase liquidity and reduce the risk of market power.

SCPPA contends that no GHG emissions tracking device is available to permit identification of GHG emissions associated with imported electricity.

SDG&E/SoCalGas submit that the same type of contract information would be used to assign emissions to imported energy under either a retail provider-based approach or a deliverer-based approach, and that there is nothing that makes this undertaking more challenging under the deliverer approach, as long as the required parties report the information.

Other parties (SCE, Calpine, and Morgan Stanley) assert that a deliverer approach would be less complex administratively than a retail-provider approach because only imports would have to be tracked under a deliverer approach while under the retail provider-based model all wholesale power transactions must be tracked in order to assign emissions to retail providers.

SDG&E/SoCalGas view emissions tracking and verification associated with the deliverer approach as being relatively transparent, because most of the participants in such a program would have close ties to the generation that they are selling. It states that the use of generator data would be a significant advantage for the deliverer approach compared to the retail provider approach, which would use default emissions values for all purchases of unspecified power, including power generated in California. However, GPI points to the dependence on default factors for many imports.

3.3.1.4. In-State Generators, Retail Providers for Imports as Point of Regulation

The only party in the proceeding that advocated for this model is EPUC/CAC, which later changed its position to support the deliverer approach. EPUC/CAC cited several possible advantages to a hybrid approach. According to EPUC/CAC, a hybrid approach: 1) "best aligns the incentives to reduce emissions with the source of those emissions," 2) "allows for greater accuracy in the tracking of emissions," 3) facilitates expandability, 4) "offers administrative simplicity," and 5) "can overcome legal challenge." While EPUC/CAC acknowledged that a hybrid approach would treat out-of-state sources differently, it asserted that the program could be designed to not disadvantage them and thus mitigate susceptibility to Commerce Clause challenge. It contends that, since the hybrid approach also would not directly regulate wholesale transactions, it should also overcome Federal Power Act (FPA) challenges.

EPUC/CAC asserted that, with an in-state generator/retail provider for imports hybrid, roughly 75-80% of California's load would be captured at the source. It argued that using a retail provider approach for imports could give California greater leverage in dealing with imported emissions, and that discovery of out-of-state sources could be incentivized by attributing a high default GHG emission rate to unspecified purchases.

Several parties contend a hybrid design would have significant disadvantages. SDG&E/SoCalGas, SCE, WPTF, and Calpine submit that a major problem with the hybrid approach would be its impacts on the CAISO markets. Calpine contends that such an approach would bestow a competitive advantage on out-of-state sources since they would not have to include a carbon price in their bids into the CAISO markets. SCE argues that carbon costs would not be imposed on imports bidding into the CAISO markets, and thus that importers would receive higher prices from the CAISO market with no emissions obligation. EPUC/CAC cited such concerns in reply comments and abandoned its support of a hybrid approach in favor of a deliverer approach.

Several parties contend that a hybrid approach would be at least as administratively complex as a deliverer approach. They submit that all load would need to be tracked to sources for the system to work. SMUD, Constellation, and PG&E are also concerned that a hybrid system would require extensive accounting to avoid double counting. DRA similarly states that such a system would require all of the reporting and tracking protocols associated with a retail provider-based system to account for imports, and would require the regulatory enforcement and compliance standards for generators associated with a source-based approach.

SDG&E/SoCalGas and SCE express concern that this option is vulnerable to challenges under the FPA and the Commerce Clause.

3.3.2. Discussion

As described in Section 3.2.2, we recommend that ARB adopt a cap-and-trade program that includes the electricity sector in California provided that ARB finds that the tests outlined in Parts 4 and 5 of AB 32 are met. An integral component of a cap-and-trade program is the point of regulation. That is: which entities should have the compliance obligation within a cap-and-trade system for delivering GHG emissions reductions within the electricity sector?

To answer this question, we focus on what we believe are the five most important criteria. Those criteria are:

1. **Environmental integrity.** Here we focus on how each option deals with the problems of unspecified system purchases and imports in order to minimize the potential for leakage and/or contract shuffling, leading to real GHG emissions reductions from the electricity sector.
2. **Compatibility with/expandability to potential regional and/or national GHG emissions cap-and-trade markets.**
3. **Accuracy and ease of reporting, tracking, and verifying GHG emissions reductions.** Without accurate tracking, we cannot ensure that reductions are real, quantifiable, verifiable, and valid.
4. **Compatibility with ongoing reforms of wholesale and retail energy markets.** We focus, in particular, on potential interactions with the CAISO's new market design and the MRTU, while keeping in mind that some California entities are less involved with CAISO markets.

5. **Legal issues.**

We assume that, as a threshold matter, all options would have to be consistent with other federal, State, and local environmental requirements, such as those pertaining to criteria pollutants and toxic waste.

Below, we address each of the first four criteria in turn and discuss how each option for point of regulation does or does not meet the criteria. We stress at the outset, however, that none of the options meets all criteria fully. With any one-state cap-and-trade design in the electricity sector, there are inherent pros, cons, and tradeoffs. Our job is to weigh the pros and cons against our most important criteria. We note that there are other criteria that could be applied to this choice, as discussed in several ALJ rulings that have helped us reach this decision point and upon which parties have commented extensively. However, in this decision, we focus on those criteria that have led us to our recommendation for point of regulation in the electricity sector. We also discuss some other secondary criteria as they relate to the options under consideration.

As explained below, we conclude that the deliverer point of regulation best meets these four criteria. We then address some details regarding formulation and application of the deliverer point of regulation and consider legal issues (the fifth criterion listed above) related to the deliverer approach.

3.3.2.1. Environmental Integrity and Real GHG Emissions Reductions

In assessing the viability of the four options for point of regulation, obtaining real GHG emission reductions is our most important consideration. With any design, we must ensure that the system will deliver real reductions in GHG emissions into the atmosphere as required by AB 32. The two chief concerns here for California's electricity sector are that, while California imports approximately 20% of its electricity from neighboring states, those imports represent more than 50% of the GHG emissions from the sector and that, within California, unspecified system purchases are a substantial portion of purchases. Thus, to be effective, any system we design must address imported power and unspecified system purchases in some way. Since in Section 3.2.2 we recommend design of a cap-and-trade system for California that includes the electricity sector, we now examine how well options for cap-and-trade design address both in-state generation and imported power.

First we consider the option where in-state generators would be the point of regulation, without imports included in the cap-and-trade system. By not covering imports directly in the system, it is likely that there would be incentives for the electricity sector in California to reduce its GHG emissions by importing more power from out-of-state, without necessarily reducing emissions into the atmosphere at all. This is certainly true in the long term and likely true in the short term as well. As environmental costs begin to make in-state generation more expensive, the economic incentive to begin importing more power from uncapped out-of-state power plants would be strong. Therefore, this option appears to be the least desirable from the standpoint of environmental integrity.

The other three options (retail providers; deliverers; and a hybrid in which the point of regulation includes in-state generators and, for imports, retail providers) address imported power and unspecified in-state purchases in different ways.

With retail providers as the point of regulation, integrity of the system would be addressed by holding retail providers responsible for all of the power they deliver to consumers. In the hybrid option, retail providers would be responsible only for imported power. In order to make either of these retail provider-based systems function more accurately, it is likely that a tracking system and/or an emission attribute certificate system would need to operate parallel to the cap-and-trade system to ensure that contract shuffling is minimized under the model. It is impossible to track accurately all generation from each power plant to the retail provider that delivers it to a consumer. One option to deal with this problem is the development of default factors, but those factors are inherently inaccurate and create unintended and negative incentives for market participants. To reduce inaccuracies in retail provider-based systems, development of a mandatory emissions attribute tracking system which included imports likely would be needed.

For the deliverer point of regulation, the entity that first delivers the power to the electricity grid in California would be held responsible for its emissions. This would capture emissions from electricity generated within California and electricity imported into California from out-of-state. The problem of in-state unspecified purchases would disappear, and this would be a major advantage. The carbon attributes of imports would be determined by the entity most likely to know what has been purchased and in the best position to provide verification documentation. Because of the increased accuracies of the deliverer approach in identifying the generating source of electricity, reported GHG emission reductions would also be more accurate and reliable. As a result, we conclude that the deliverer approach is the preferable alternative regarding the ability to ensure that reported GHG emission reductions are real.

3.3.2.2. Compatibility With/Expandability to Potential Regional and/or National Cap-and-Trade Markets

We want to design a system that is likely to be compatible with any regional and/or federal cap-and-trade system that may be established within the next few years. Negotiations are underway to design a Western region cap-and-trade system through the Western Climate Initiative, and a number of proposals are currently pending in the United States Congress. Thus, it appears likely that a regional and/or federal cap-and-trade system could be established within the next few years. It also appears likely that initiation of the compliance period for a regional and/or federal system could follow California's 2012 compliance initiation by at least a few years. Thus, at some point in the near future, a California cap-and-trade system will likely need to be linked to, or adapted to be compatible with a regional or national system.

Some parties have argued that it is not necessary to worry about compatibility of the design of the cap-and-trade system with a regional or federal system, because a regional or national program would render the California system obsolete. Others have argued that certain designs of a cap-and-trade system for California could co-exist with or link to a parallel federal or regional program. Both of these things could be true; it likely depends upon the ultimate design of each system. In the face of this uncertainty, we think it would be beneficial to design a system that is most likely to be similar to a federal or regional system.

As most parties have noted, all cap-and-trade systems operating to date have been source-based systems. These include not only the European Union Emissions Trading System, but also a number of cap-and-trade systems for controlling criteria pollutants within the United States. Therefore, this is the type of cap-and-trade system with which entities in the electricity sector in California, and the rest of the country, are familiar.

In addition, if the geographic scope and coverage of the cap-and-trade system is large enough, we need not worry so much about the potential for leakage and/or contract shuffling with entities outside of the capped area. If all, or at least most, of the emissions are covered under the cap-and-trade system, accounting for imports becomes fundamentally less of a concern. Thus, the point of regulation should be designed such that tracking of imports can be reduced or eliminated as the necessity of accounting for imports diminishes.

Under this criterion, we conclude that the retail provider point of regulation would perform least well in terms of compatibility with a national or regional system. This is because, as discussed above, most existing and proposed cap-and-trade systems are source-based in nature. While it may be possible, as some parties argue, that a retail provider system for California's electricity sector could be compatible with a national or regional source-based system, it is also likely that the retail provider point of regulation would produce a need for certain contractual and operational changes to the way electricity transactions currently take place. We prefer not to introduce this kind of shift into the electricity sector for what may be a period of only a few years (if a national or regional system supersedes our efforts here). We believe that it would be less complex and more effective to be able to integrate the cap-and-trade method chosen for the California electricity sector into an eventual regional or national system, rather than having it structured such that it could operate only in parallel to, rather than as an integrated component of, a broader system. Therefore, the retail provider point of regulation is the least preferred under this criterion.

All of the other three options (in-state generators with no imports under cap-and-trade, deliverer, and in-state generators/retail providers for imports) share a common component where, for most electricity sold in the state, the point of regulation would be at the generator level. Therefore, any of these three options could be integrated more easily into a regional or national system.

The in-state generator option for point of regulation with no inclusion of imports under cap-and-trade is likely the most forward-compatible of the options. This approach would transition more easily into a larger geographic cap-and-trade system. But, as we mentioned above, it is the least favorable alternative for environmental integrity.

The option of in-state generators with retail providers as the point of regulation for imports is likely second-best, since the retail provider portion likely could be easily abandoned at such time as the states from which California imports become covered under a regional or national cap-and-trade system. However, the deliverer point of regulation could be modified to eliminate its coverage of imports, though the process may not be as simple, as some regulations or designs may need to be modified once imports are captured under a regional or national system.

3.3.2.3. Accuracy and Ease of Reporting, Tracking, and Verifying Emissions Reductions

We want to design a system where emissions can be accurately and reliably reported, tracked, and verified. Using this criterion, the option of in-state generators only, with imports not covered under cap-and-trade, is the simplest among the choices. But, as we have discussed, this option has serious flaws under our most important criterion of environmental integrity.

The retail provider point of regulation is a less preferable alternative under this criterion. In order to make the retail provider option function accurately, it is necessary to track all electricity generated to serve California customers from the point where it is generated to the point where it is delivered to a retail provider's customers. While this may be relatively easy in the case of in-state generation owned by a utility company that uses the power for its customers, it becomes most difficult in the case of purchases from unspecified power plants. The best way to make such a system work would be to undertake a West-wide tracking system for emissions attributes, perhaps with tradable aspects similar to

RECs for renewable energy, where the attributes are tradable separately from the commodity electricity. While such an option would be theoretically workable, in our judgment the administrative complexity and time required to set up such a system render this among the less preferable alternatives.

Similarly, the in-state generator/retail provider for imports option is also administratively complex. In order to make such a system work and hold retail providers responsible only for their imported power, their entire electricity portfolio would need to be tracked, with the in-state generation portion netted out to determine the portion of the portfolio attributable to imports. Thus, all of the tracking or attribution necessary under the retail provider point of regulation would also be necessary under this alternative, with an added layer of complexity to conduct the proper accounting to subtract out in-state generation. Thus, we also find the in-state generator/retail provider for imports point of regulation option to be less preferred under this criterion.

We conclude that the deliverer point of regulation is the most workable. This is because each deliverer is responsible for reporting and tracking the GHG attributes of its power as it is delivered onto the California grid. For in-state generation, generators (or other entities that own the power when it is delivered to the grid) are tracked, similar to a system in which only in-state generation is capped. Similarly for imports, the party that owns the power as it is delivered to the California grid is held accountable. This removes the need for complete tracking from generation source to delivery to customers, as under the retail provider system, and also removes the need for complex netting of in-state generation from the retail provider portfolios, as under the in-state generator/retail provider for imports system. Making the deliverer the point of regulation moves the compliance obligation as close as possible to the generation source, which increases the accuracy of knowledge of GHG emissions attributes of the generation sources. Therefore, we find the deliverer point of regulation to be the preferred option for accurate reporting, tracking, and verification of emissions in the sector.

3.3.2.4. Compatibility with Wholesale and Retail Energy Market Reforms

In discussing this criterion, we begin by noting that our purpose in designing a cap-and-trade system for the electricity sector in California is fundamentally to reduce GHG emissions from the sector, including all electricity consumed in California as well as all electricity produced in the State regardless of where it is used. In doing so, we do not wish to interfere with the functioning of the wholesale market for electricity in the State. Instead, we aim to produce the environmental result required under AB 32 with the least impact possible on wholesale electricity markets. We recognize, however, that the cap-and-trade market is likely to cause the price of some electricity sold through the wholesale market to rise. To the extent that happens, our goal is to have that price effect be transparent to and consistent for all participants, without any distortionary impact.

In addition, in order to meet not only the 2020 goals under AB 32, but also the more aggressive 2050 goal of reducing GHG emissions 80% below 1990 levels, as established by Governor Schwarzenegger,[16] we will need to focus much more on the kind of electricity infrastructure built to serve California consumers, and not simply the type of generation dispatched in the wholesale markets.

In California, the main centralized wholesale electricity market is operated by the CAISO. The CAISO has undertaken a multi-year effort to redesign its

[16] See Governor Schwarzenegger, Executive Order S-3-05, June 2005.

electricity markets under the MRTU process. Its new market design is due to go into operation this year. This market redesign comes under the jurisdiction of the Federal Energy Regulatory Commission (FERC). The MRTU process will lead to both a day-ahead and a real-time energy market, and one goal of the market redesign is to encourage the scheduling of more power through these markets, which will enhance efficiency of dispatch, increase market liquidity, and provide more operational flexibility to the CAISO to balance the system.

With these facts in mind, we have evaluated the point of regulation options against their likely impacts not only on the CAISO's MRTU markets, but also on California's energy markets in general.

We first examine the in-state generator option with no imports in the cap-and-trade system. Under this system, we expect that in-state generators would reflect the increased cost of compliance with the AB 32 regulations in their wholesale bid prices. However, because out-of-state resources would not face any cap-and-trade compliance costs, their costs would not change. They could nevertheless raise their bid prices by an amount slightly less than the allowance price, capturing a rent from California consumers while still being dispatched ahead of in-state resources. The result would be a less efficient use of both generation and transmission infrastructure coupled with a wealth transfer from California consumers to out-of-state generators for no environmental gain.

This situation is a major disadvantage of this option for point of regulation, because it would cause the price of in-state electricity generation to rise in California, while imports on which California relies would see a smaller impact, if any. This is true regardless of emission allowance allocation policy, because the in-state generation price would reflect either the actual cost of the emissions allowances or their opportunity cost. Out-of-state generators, which would not face the compliance cost of the GHG regulation, would be able to sell their power at a relatively lower price than in-state generators. Thus, the system would produce leakage, violating the environmental integrity principle outlined above. For that reason, as we state above, we do not prefer this alternative.

The deliverer and the in-state generator/retail provider for imports point of regulation options are similar in terms of their impacts on wholesale markets. In either case, a compliance obligation would be placed on some entity for all power that has emissions associated with it. All power generated in California or consumed by California customers would reflect the cost of compliance with the cap-and-trade program.

There is still some risk of distortion in the MRTU markets with the in-state generator/retail provider for imports hybrid option, because some low-emissions imported power may face incentives to self-schedule in order to identify its low-emission characteristics to the entity responsible for the emissions for this imported power. This is because low-emissions power offers additional value to retail providers by reducing the number of allowances that need to be retired. This is value that low-emissions out-of-state generators can partially capture when their power is sold on a specified basis. Moreover, this approach may also induce leakage through the CAISO markets as out-of-state generators, with no compliance obligation, could bid into the markets at a lower price than in-state generators. California retail providers who purchase from the CAISO markets could only be held responsible for allowances for imports after bids have cleared.

The magnitude of potential MRTU market distortion may be relatively small under this option, however, because imports represent only about 20% of the power sold in California, and low-emissions imports represent an even smaller percentage. Under either of these point of regulation options, the approximately 80% of generation produced and sold in California through the markets would have no incentive to self-schedule to identify their emissions characteristics, because they would be responsible for their own compliance with the program. The deliverer approach avoids these perverse impacts on the CAISO markets since out-of-state entities delivering power to CAISO would also have to factor allowance costs into their bids.

Finally, we consider the potential for a retail provider point of regulation system to interfere with the functioning of the wholesale electricity markets in California. It is likely that the risk of interference with markets is the greatest with this option. This is because the incentive that would induce clean imports to sell to California on a specified basis under the in-state generator/retail provider hybrid approach would apply to in-state sources as well under a retail provider point of regulation. This would reduce the flexibility of the CAISO to schedule resources based on economic and/or operational considerations, instead forcing it to dispatch units that are self-scheduled due to relatively low GHG emissions characteristics. Thus, wholesale prices from low-emission generation would rise, and further costs would likely result from the higher transaction costs of negotiating specified purchases and the foregone efficiencies of the pooled CAISO markets.

Therefore, we conclude that the retail provider point of regulation has the most potential to interfere with the functioning of the wholesale markets.

In addition to the wholesale market reforms being undertaken by the CAISO, the Public Utilities Commission is currently exploring the possibility of restoring retail competition in R.07-05-025. In this decision, we take no position on whether, when, or how direct access should be reopened in California. We note, however, that reopening direct access could result in increased market share for retail providers that rely heavily on market purchases of energy to meet their customers' needs. Decreases in long-term contracts, which are chiefly entered into by vertically integrated utilities, would likely increase the amount of unspecified energy flowing through California's markets. The deliverer point of regulation can best accommodate such a development as it does not require source-to-sink tracking of all transactions.

3.3.2.5. Conclusions Regarding Compatibility with the First Four Criteria

In evaluating the point of regulation options against our key criteria above, we conclude that the deliverer point of regulation best meets the four criteria evaluated above. Each of the other options has serious shortcomings regarding one or more of our priorities.

A deliverer point of regulation would provide for the environmental integrity of the cap-and-trade system by covering imported power as well as in-state generation. The deliverer point of regulation shares a number of common characteristics with a source-based point of regulation, making it likely to be compatible with the eventual design of a cap-and-trade system that is broader in geographic scope (regional and/or national). The deliverer point of regulation also would improve the ability to report and track emissions in the sector and would minimize the impact of AB 32 GHG regulations on California's wholesale electricity markets.

3.3.2.6. Formulation of the Deliverer Point of Regulation

Having determined that the deliverer point of regulation best meets the four criteria examined above, we turn to certain details regarding the manner in which compliance requirements should be determined in a cap-and-trade system with a deliverer point of regulation for the electricity sector.[17]

We conclude that the most useful formulation of the deliverer point of regulation approach is that the point of regulation would be the entity that owns electricity as it is delivered to the grid in California. In most situations, this would be the entity that owns the electricity on the portion of the physical path just before the point where it is delivered to the California transmission grid, which would be the busbar for in-state generation or the first Point of Delivery in California for imported power.[18] Where electricity is first delivered to the California grid at the distribution level, the deliverer definition results in the following: (i) for generation facilities that are connected to a retail provider's distribution network, the deliverer would be the entity that owns the electricity as it is delivered to the distribution network, and (ii) for electricity delivered directly to California retail customers of a multi-jurisdictional utility from out-of-state sources, the deliverer would be the multi-jurisdictional utility.[19] Recognizing that electricity is an instantaneous commodity, we call the entity that owns the electricity as it is delivered to the California grid the "deliverer" of the electricity for purposes of establishing GHG responsibility. We recommend

---

[17] As explained in Section 3, electricity that is wheeled through California is not included in the electricity sector for purposes of establishing GHG regulations pursuant to AB 32. As explained in Section 4.2.2, we defer the issue of whether electricity generated by CHP facilities should be included in the electricity sector.

[18] In this situation, the deliverer would be the owner that delivers the electricity to the first Point of Delivery in California, not an entity that accepts ownership of the electricity for the first time at that Point of Delivery.

[19] We understand that the multi-jurisdictional utilities generate or purchase electricity out-of-state and that the electricity is delivered at the distribution level directly from out-of-state to their California retail customers.

that deliverers be required to surrender allowances associated with the electricity's GHG emissions.

Deliverers would include generators, operators, retail providers, marketers, and any other types of entities that own electricity as it is delivered to the California grid. While the deliverer often may be the owner or operator of the generating unit, it could also be any entity that purchases or otherwise has a contractual arrangement such that it owns the electricity as it is delivered to the California grid.

The proposed decision and parties' comments on the proposed decision addressed several possible exceptions to our determination of the manner in which deliverers should be identified for the purpose of GHG compliance obligations. We address these proposed exceptions in turn.

California Balancing Authority with Out-of-State Transmission

At least one California balancing authority (LADWP) controls transmission from sources located outside of the State that are considered part of its balancing authority territory. Thus, E-tags are not generated for this power when it is delivered to California. SCE suggests that the regulated imports be identified based on their first delivery to "a point of delivery within a California balancing authority" rather than their delivery to "a point of delivery within California." If that approach were taken, E-tags associated with deliveries to the balancing authority at an out-of-state Point of Delivery could be used to determine the deliverer at that delivery point.

However, the Point of Delivery at which ownership is used for AB 32 compliance purposes should be physically within the State. As PG&E suggests, alternative documentation may need to be used to identify the owner of imports that do not have E-tags at the Point of Delivery to the California grid.

Multi-jurisdictional Utilities

Multi-jurisdictional utilities serve retail customers in a service territory that overlaps the State border, e.g., PacifiCorp and Sierra Pacific. The proposed decision suggested that multi-jurisdictional utilities should be regulated using a retail provider-based approach, rather than a deliverer approach. The proposed decision reached this conclusion based on measurement and tracking concerns arising because the balancing authorities of these retail providers encompass service territory both inside and outside of California and, thus, no E-tags are generated for imports into California. For the multi-jurisdictional utilities, the initial measurable deliveries of electricity to the California grid occur at the distribution level to their retail customers. Moreover, the sources of electricity used to serve the California customers currently cannot be distinguished from the sources used to provide electricity for the entire balancing authority. For these reasons, the measurement protocols that apply to other deliverers are not workable for the multi-jurisdictional utilities at this time.

In comments, Sierra Pacific takes issue with the proposed decision's conclusion that a retail provider point of regulation should be used for multi-jurisdictional utilities, while PacifiCorp supports the proposed decision in this regard. In its comments on the proposed decision, Sierra Pacific implies that a retail provider point of regulation for the multi-jurisdictional utilities might have the effect of requiring them to reduce the carbon footprint for all of their customers, most of whom are located in other states. It is not our intent to require multi-jurisdictional utilities to change how they provide electricity to customers in other states. For this reason, we find that GHG emissions associated with multi-jurisdictional utilities' deliveries of electricity to California should be regulated using the deliverer approach. Nevertheless, the methodology for tracking and accounting for the GHG attributes of the electricity these utilities deliver to California may not be identical to that of other entities not similarly situated.

As we stated in our reporting recommendations to ARB in D.07-09-017, "Multi-jurisdictional utilities would be required to report information for their operations that provide electricity to service territories that include end use customers in California. ARB would attribute GHG emissions to their California operations based on the proportional share of their electricity sales in California." This is the approach that ARB approved in its mandatory reporting protocols.

PacifiCorp supports a retail provider-based approach for multi-jurisdictional utilities, stating that,

> The combination of utility-owned generating resources and resources providing contracted for power located throughout the western United States, coupled with load-serving responsibilities and multi-state cost structures, puts [multi-jurisdictional utilities] in the complicated position of having to equitably assign the costs of system energy, including emissions, to each state's retail load. Alternative rules should be developed for [multi-jurisdictional utilities] to address their complicated position in the western energy market. Given these unique circumstances and peculiarities of [multi-jurisdictional utilities], it is not disputed that under either the deliverer/first seller or the hybrid approach, PacifiCorp should be regulated according to the [retail provider]-based approach.

Regulating the emissions associated with the multi-jurisdictional utilities' deliveries of electricity to the California grid, with GHG emissions attributed based on a proportional share of their electricity sales in California, appears to be the only reasonable approach at this time. We anticipate making future recommendations to ARB, perhaps in 2009, concerning its mandatory reporting protocol in order to refine the recommendations provided in D.07-09-017 on reporting of GHG emissions in the electricity sector. We will consider revisions that would give multi-jurisdictional utilities greater flexibility to differentiate the power used for their California customers from the power used for their other customers. In any event, we will strive to ensure that the tracking and accounting methodology for the multi-jurisdictional utilities does not disadvantage them, or make it impossible for them to comply with the requirements of other jurisdictions in which they operate. If it should turn out that the unique circumstances of a particular multi-jurisdictional utility prevent application of a deliverer point of regulation to it, we will develop an alternative approach.

Power Whose Deliverer is a Federal Entity

Another situation relates to power whose deliverer, as generically defined above, would be a federal entity not subject to California regulation. In that situation, we agree with the proposed decision that the deliverer for AB 32 compliance purposes should be the first non-federal entity that owns the electricity thereafter on the physical scheduling path in California.

Independent Power and Renewable Power

In comments on the proposed decision, various independent power producers, including renewable generators, argue that they should not be regulated under a deliverer point of regulation. Among the issues raised are contractual language required by the Public Utilities Commission under which renewable generators assign "environmental attributes" to the IOUs, and contracts that allegedly do not permit inclusion of GHG emission allowance costs in prices received for the power. However, we see no reason why the existence of such contractual language would warrant an exception to our general recommendation that deliverers be legally responsible for GHG compliance under AB 32.

We note, however, that the deliverer's compliance obligation would not prevent parties from entering into contractual arrangements under which an entity other than the deliverer would shoulder the financial burden of compliance. For example, contractual arrangements could provide that the entity purchasing power from a deliverer pay for and obtain allowances which the deliverer would then surrender to meet its compliance obligation. Nor do we decide, in adopting a uniform deliverer approach, which entity would be required under Public Utilities Commission-mandated, or other, contractual language, to shoulder the financial costs of GHG compliance obligations.

We recognize that ARB may determine that certain kinds of renewable technologies do not produce any GHG emissions that should be subject to regulation under AB 32. Thus, although such generators may meet the criteria we establish for deliverers, they may not have any obligation to surrender allowances. However, renewable generation that ARB determines has GHG emissions subject to regulation under AB 32 should be treated like any other generation, in that the deliverer would have a GHG emissions compliance obligation.

In R.06-02-012, the Public Utilities Commission is considering whether to create a tradable REC program as a compliance mechanism for the RPS in California.[20] In addition, while RECs may be defined in R.06-02-012 for RPS compliance in California, other jurisdictions may define RECs differently for use

---

[20] Currently, contracts for bundled RPS-eligible power purchases (where both the generation and its renewable attributes are sold to one purchaser in one transaction) define the REC to be separate from the GHG emission attributes (see D.07-02-011, as modified by D.07-05-057. See also Administrative Law Judge's Ruling Requesting Post-Workshop Comments on Tradeable Renewable Energy Credits, October 16, 2007, Attachment F-2, setting out the current RPS contract requirements in this regard.)

in other markets, including compliance with renewable generation requirements, compliance with GHG emissions requirements, or compatibility with voluntary markets. We do not prejudge the question of how a deliverer of renewable generation that may unbundle and sell RECs separately should be treated for purposes of GHG compliance.

M-S-R Proposal

M-S-R is a joint powers authority among the Modesto Irrigation District, City of Santa Clara (dba Silicon Valley Power), and the City of Redding. In its comments on the proposed decision, M-S-R describes a situation in which certain power owned by M-S-R is delivered to a Point of Delivery just north of the California-Oregon border, at which point its member agencies take delivery.

In its comments, M-S-R suggests that "the point of delivery should be clarified to mean delivery to the WECC-recognized California grid whether within or without the physical boundaries of the State of California." Such a determination would result in using ownership at a Point of Delivery physically located in Oregon to determine the deliverer. As M-S-R's comments do not point to any real problems that will arise from our recommended definition, we decline to adopt its suggestion.

SMUD Proposal

SMUD describes in comments on the proposed decision that much of SMUD's in-state generation is held by joint powers authorities, with such plants dispatched by SMUD and with "all the energy delivered to the bus bar … owned by SMUD." SMUD asserts that, in reading the proposed decision, it is not clear who would be considered the deliverer in this situation. SMUD recommends that "the definition of deliverer be delved into in much more detail in light of the wide spectrum of ownership arrangements that exist for plants in the state."

As described above, we have clarified our recommended definition of deliverer, with what we believe is sufficient detail for ARB to be able to resolve disputes that may arise. In making recommendations to ARB, it would not be fruitful for us to try to evaluate every existing contractual arrangement or try to anticipate possible future contractual arrangements to pass judgment on which entity owns the power as it is delivered to the California grid.

Small Generating Facilities

We recognize that ARB's reporting thresholds are such that a GHG compliance obligation under the deliverer approach would not apply to certain small facilities.

Reporting and Measurement under the Deliverer Approach

Several parties raise concerns about documentation that may be needed to establish the entity that is the deliverer, particularly for imported power that does not have E-tags. They also submit that E-tags are not sufficiently accurate to establish the source, and thus, emissions related to imported power. We agree that additional work will be needed on these reporting and measurement issues.

3.3.2.7. Legal Issues Related to Deliverer Point of Regulation

Federal Power Act

Several parties contend that a deliverer point of regulation would likely be preempted by the FPA. We have reviewed these, and the opposing, arguments, and conclude that a deliverer point of regulation is not preempted by the FPA.

LADWP argues that a GHG regulatory structure using a deliverer point of regulation may be struck down by the courts on the grounds that it regulates wholesale sales of electricity and therefore is preempted by the FPA, which applies, *inter alia*, to "the sale of electric energy at wholesale in interstate commerce" (16 U.S.C. § 824(b)(1)). We believe, however, that the use of a deliverer point of regulation should be upheld by the courts on the grounds that it is an environmental regulation whose purpose is to decrease the impact of global warming on California insofar as that impact is caused by electricity used or generated in California. The deliverer point of regulation does not single out wholesale sales of electricity, but rather applies uniformly to electricity consumed in California and electricity generated in California. As Morgan Stanley points out, the deliverer approach does not regulate wholesale generators, marketers, or transmission as such.

There is no "field preemption" here because in enacting the FPA, Congress did not intend, either explicitly or implicitly, to occupy the field of environmental regulation of the power sector. California will be regulating in a field (GHG emissions and their reduction) that Congress has not even addressed in the FPA, nor is there any suggestion in the FPA or in its administration that Congress intended to forbid states from enacting GHG regulations on their own. The regulations we are recommending to ARB are not directed at wholesale rates or service or the other terms and conditions of wholesale sales that *are* the focus of the FPA. Rather, they are directed at reducing GHG emissions associated with the generation of electricity in California and with ultimate electric service within California, matters left to the discretion of the states. Nothing in the part of the FPA at issue here[21] or its legislative history suggests that Congress intended to occupy the field of environmental regulation, which is the sole purpose of the California law and proposed regulations at issue here.

---

[21] Parties arguing that there is FPA preemption rely on the portion of the FPA dealing with the Regulation of Electric Utility Companies Engaged in Interstate Commerce, 16 USC § 824, et seq.

Indeed, 16 U.S.C. § 824(a) states: "Federal regulation . . . [under the FPA extends] only to those matters which are not subject to regulation by the States." This broad savings clause supports the conclusion that because air pollution is subject to regulation by the States, and not by the FPA or FERC, state regulation of GHG emissions caused by the generation and consumption of electricity is not preempted by the FPA, but may be regulated by the States. While such GHG regulation may have some impact on the wholesale prices paid for electricity, it is no more preempted by the FPA than state regulations limiting the amount of other pollutants that may be emitted by electric power plants -- that may affect the cost of generating electricity and therefore indirectly affect the price of wholesale electricity.[22]

We are recommending that allowances be surrendered based on the delivery of electricity to the grid. This does not mean that California would be regulating the grid. By choosing a deliverer *point of regulation* we are simply choosing a trigger that determines which entities have to comply, but what is being regulated is the amount of GHGs being produced in California or in order to supply electricity to customers located in California.

Even though our recommended point of regulation is the point of delivery to the grid, these GHG regulations are still essentially environmental regulations, and not a regulation of wholesale rates or other terms and conditions of wholesale power sales or electric transmission that the FPA and FERC do exclusively regulate, nor a requirement to obtain a license to engage in those

---

[22] The inclusion of any such costs in FERC-jurisdictional rates would be subject to FERC review under § 205 of the FPA (16 U.S.C. § 824d). We are not suggesting that any wholesale sales subject to FERC jurisdiction would occur at anything other than the FERC-authorized rate.

activities.[23] Therefore our choice of this point of regulation does not mean that these GHG regulations are preempted by the FPA.

The regulations we are recommending to ARB are not directed at matters subject to FERC regulation[24] (nor are they directed at matters that the FPA has determined should be exempt from either state or federal regulation). They are directed at reducing GHG emissions and are intended to change the way that electricity is generated and consumed. For example, the GHG regulations are expected to increase the use of (i) renewable resources to generate electricity, (ii) low-emitting sources of generation, and (iii) more efficient methods of using electricity. To the extent such actions are not a cost-effective means of reducing GHG emissions associated with the use of electricity, these regulations are expected to result in investments outside of the electricity sector that will cost-effectively reduce GHG emissions from other activities.

The arguments that a deliverer point of regulation is preempted by the FPA do not take into consideration the subject-matter scope of the FPA and FERC's regulations. Here, we are proposing to regulate the environmental impacts of electric generation and consumption, whereas the FPA's regulation of wholesale sales does not cover the environmental impacts associated with electric generation, wholesale sales of electricity, or the consumption of

---

23 As explained in greater detail below, the proposed structure for regulating GHG emissions does not prevent anyone from selling electricity into the California market, rather it requires that, at a later date, sufficient allowances be surrendered or other compliance shown.

24 Indeed, AB 32 addresses GHG emissions generally, and ARB's regulations therefore will address other industries and activities outside the electricity and natural gas sectors.

electricity.[25] Because the FPA expressly leaves room for state regulations dealing with electricity and because there is nothing in the FPA that deals with the regulation of emissions (either generally, or GHG emissions specifically), the deliverer approach is not preempted by the FPA. The deliverer regulations we are recommending to ARB do not have as their central purpose the regulation of matters that Congress intended FERC to regulate. Even though ARB's regulations will wind up requiring some sellers of wholesale electricity to surrender allowances that fact does not establish preemption just because FERC regulates wholesale transactions *for other purposes*. The FPA does not address GHG emissions and therefore the recommended regulations do not fall within the limits of the comprehensive regulatory scheme enacted by Congress.

In short, there is no FPA field preemption here because, under AB 32, California will not be regulating the same subject matter as the FPA, nor will its regulations be for the same intended purpose. The objectives sought by AB 32 and the use of a deliverer point of regulation for the electricity sector are not the same as those sought by the FPA.

PacifiCorp argues that the FPA would preempt a deliverer point of regulation, because (i) under that approach the state of California would unilaterally determine which parties are allowed to participate in the wholesale energy market and (ii) the cost of buying allocations will affect the costs of wholesale energy. The deliverer point of regulation does not determine which parties are allowed to participate in the wholesale energy market. Any party that wishes may participate in the market, subject to a requirement that GHG

---

25 Under a different portion of the FPA, dealing with the Regulation of the Development of Water Power and Resources (16 U.S.C. § 791, et. seq.), and not at issue here, FERC does regulate the environmental impact of hydroelectric projects on fish and wildlife.

allowances are surrendered after the end of the compliance period (or compliance is shown by another method). While this may impose costs on some participants in the wholesale energy markets, that does not mean that such regulation is preempted by the FPA. Pollution control requirements normally impose costs on participants in wholesale energy markets (such as generators), but that fact does not preempt states from imposing pollution control requirements.

CMUA suggests that there is a potential conflict between a deliverer point of regulation and the "electric reliability" section of the FPA, 16 USC § 824o. CMUA poses a hypothetical under which a high-GHG emitting facility would be unable to sell power into California that is needed for reliability purposes because there are insufficient allowances available. However, under the regulatory framework that we are proposing, allowances would *not* need to be surrendered at the time the power is delivered into California.[26] Rather, those entities with compliance obligations would only be required to surrender allowances, or otherwise comply with the regulations, after the end of a compliance period. Thus, an entity with compliance obligations (including an out-of-state generator) would have an opportunity, if it did not already possess enough allowances, to acquire allowances on the market or to show compliance using flexible compliance mechanisms such as offsets (to the extent they are

---

[26] In any event, FERC previously concluded that a generator with a FERC-required must-run obligation would be excused from that obligation where a pollution control requirement prevented the generating plant from operating. ("Order Granting Emergency Motion Clarification," *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange*, Docket No. EL00-95-039 96 FERC ¶ 61, 117 at 61, 446- 8, July 25, 2001.)

allowed). In short, the GHG regulatory program we are proposing would not prevent even high-GHG sources from providing reliability services when needed. Thus, there will be no conflict with the FPA's electric reliability provisions.

In its comments on the proposed decision, SCPPA appears to argue that emissions reductions can only be achieved by directly affecting the wholesale price of imported electricity. That is not the case. Under a cap-and-trade system with a declining cap, the impending scarcity of GHG allowances is expected to drive investment in technological innovation, energy efficiency, and other measures to reduce GHG emissions, regardless of whether there is any impact on wholesale electricity prices.

Commerce Clause

Parties also briefed the issue of whether a deliverer point of regulation is permissible under the "dormant" Commerce Clause. Under the dormant Commerce Clause, a state's laws or regulations may be unconstitutional if there is a differential treatment of in-state and out-of state economic interests that benefits the former and burdens the latter. We have considered the parties' filings and conclude that a deliverer point of regulation does not violate the Commerce Clause.

The regulations we are proposing are facially neutral and do not have a discriminatory purpose or effect. In other words, a deliverer point of regulation does not on its face, or in effect, discriminate against interstate commerce in favor of intrastate commerce, nor is there any purpose to favor intrastate commerce over interstate commerce. A deliverer point of regulation treats all electricity delivered to the California grid the same, whether that electricity is generated in California or elsewhere. In either case, the deliverer will have to surrender GHG allowances based on the amount of GHG emissions associated with that electricity.

When a state law or regulation is not facially discriminatory and does not have a discriminatory purpose or effect, the courts apply the *Pike* balancing test. Under *Pike*, a state enactment "will be upheld unless the burden imposed on [interstate] commerce is clearly excessive in relation to the putative local benefits." (*Pike v. Bruce Church, Inc.* (1970) 397 U.S. 137, 142.) Here, the burden on interstate commerce is purely incidental and the local benefits[27] to California of reducing GHG emissions, and therefore the impact of global warming, are most significant. In AB 32, the Legislature made the following findings:

> (a) Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems.
>
> (b) Global warming will have detrimental effects on some of California's largest industries, including agriculture, wine, tourism, skiing, recreational and commercial fishing, and forestry. It will also increase the strain on electricity supplies necessary to meet the demand for summer air-conditioning in the hottest parts of the state. (Health & Safety Code § 38501(a), (b).)

The local benefits of reducing GHG emissions are further elaborated in the Final Climate Action Team Report to the Governor and the Legislature (presented to

[27] In the context of *Pike* analysis, the term "local benefits" refers to the benefits to the jurisdiction imposing the regulation at issue, in this case, California.

the Legislature in March 2006).[28] As noted in D.07-01-039, there are other local benefits of a program to reduce GHG emissions from electricity used in California. The program we are recommending encourages a wide range of clean energy sources, which protects the reliability of the grid serving California. Furthermore, if California were to wait until the federal government begins regulating GHG emissions, California would have less time to adjust to a low-GHG emission regime for meeting electricity needs, which could be costly and inefficient. For example, by taking early action to meet the environmental challenge of GHG emissions, California will reduce the costs its ratepayers would have to pay if there were continued investment in high-GHG emitting sources in the interim.

Accordingly, we conclude that any burdens on interstate commerce that may result from the implementation of AB 32 under the regulations that we will be proposing to the ARB (including a deliverer point of regulation) are incidental in relationship to the local benefits to California.[29]

Finally, we conclude that using a deliverer point of regulation for the electricity sector does not regulate extraterritorially in violation of the Commerce Clause. A state statute or regulation may be struck down as impermissibly extraterritorial if it regulates commerce that occurs wholly outside the state. The

---

[28] See also the impacts on California identified in the Environmental Council's opening comments on the Market Advisory Committee report, at p. 23.

[29] In its comments on the proposed decision, LADWP questions the extent to which the regulations proposed in this decision will affect global GHG emissions. However, these regulations are only a part of California's overall efforts to reduce GHGs, and states are not required to resolve massive problems in one fell regulatory swoop, but may take reform one step at a time. For the reasons explained in this decision, the regulations we are proposing will help slow the pace of global emissions increases.

deliverer point of regulation only regulates electricity that is generated in, or delivered for consumption in, California. Thus, it does not regulate any commerce that occurs totally outside of California, and therefore does not regulate extraterritorially in violation of the Commerce Clause.[30]

<u>Other Legal Issues</u>

SCPPA argues that the deliverer approach is inconsistent with the legislative intent expressed in AB 32. More specifically SCPPA refers to Health & Safety Code § 38530, contained in Part 2 of AB 32 dealing with GHG reporting and provides in pertinent part:

> 38530. (a) On or before January 1, 2008, the state board [ARB] shall adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program.
>
> (b) The regulations shall do all of the following:
>
> . . .
>
> (2) Account for greenhouse gas emissions from all electricity consumed in the state, including transmission and distribution line losses from electricity generated within the state or imported from outside the state. This requirement applies to all retail sellers of electricity, including load-serving entities as defined in subdivision (j)

---

[30] In its comments on the proposed decision, LADWP argues that there may be extraterritorial regulation under the reporting regulations relating to contract shuffling. Neither the purpose nor the effect of these anti-contract shuffling rules is to regulate how power is sold, or accounted for, in other states. Indeed, in our reporting decision, we emphasized that these rules would not prohibit parties from entering into contracts for the supply of electricity that they are otherwise permitted to enter into. (D.07-09-017, *mimeo*. at p. 19.) Rather, the purpose of these rules is to prevent entities from claiming to have reduced GHG emissions caused by the consumption of power in California when in fact there has been no real reduction in those emissions. In short, the effect of these rules is simply to provide an accurate accounting of the GHG emissions caused by the consumption of electricity in California.

of Section 380 of the Public Utilities Code and local publicly owned electric utilities as defined in Section 9604 of the Public Utilities Code.

ARB has already adopted these regulations, and they do provide for reporting by all load-serving entities and local publicly owned utilities. We are now in the process of recommending to ARB how it ought to implement a different portion of AB 32, Part 4 of AB 32 dealing with GHG reductions. The fact that the Legislature required reporting by retail providers does not mean that retail providers must be the point of regulation for achieving the required reductions in GHG emissions.[31]

3.3.2.8. Conclusion

As described in the preceding subsections, the deliverer point of regulation best meets the first four criteria that we find to be most important. We also find that the deliverer method can be supported on legal grounds. For these reasons, we choose the deliverer point of regulation as the recommended approach for a GHG cap-and-trade program as it applies to the electricity sector.

3.4. Allowance Distribution in a Cap-and-Trade System with Deliverer Point of Regulation

Because we recommend a deliverer-based point of regulation, in this section we limit our consideration of methods for distributing GHG emission allowances to those that are appropriate for a deliverer system.

---

[31] SCPPA also expresses concern that this point of regulation will result in the regulation of transactions where power is merely wheeled through California, but generated and consumed in other states or countries. However, as discussed in Section 3, our recommended deliverer point of regulation would not cover power that is merely wheeled through California.

Under a cap-and-trade system, two basic options exist for distribution of emission allowances: they may be auctioned or they may be allocated administratively. A third option is some combination of the two, whereby some emission allowances are auctioned and the rest allocated administratively. There may also be a transition from predominantly administrative allocations to greater reliance on auctions.

In addition to considering the method for distributing emission allowances, we also address the manner in which auction proceeds should be used and the manner in which any free allowances should be allocated.

3.4.1. Positions of the Parties

3.4.1.1. Auctions

Parties that favor auctions submit that, because auctions should create a least-cost, multi-sector clearing price, they should reduce the societal cost of avoiding environmental damage while rewarding early action. These parties assert variously that auctions would allow new suppliers to enter the market (AES); avoid the windfall profits to historical emitters seen in the European Union (CPC, DRA); promote allowance market liquidity (Morgan Stanley); provide revenues to invest in further carbon reductions or to compensate consumers (CPC, DRA, TURN, NRDC/UCS); set a precedent for a national auction policy that would benefit California with its lower carbon footprint (NRDC/UCS); and change the relative prices among higher- and lower-GHG emitting power plants and technologies, thus advantaging cleaner plants and technologies (TURN). Other arguments include that auctions would be simpler than an administrative allocation scheme; that auctions would reward early adoption through the market mechanism while avoiding the need to determine administrative credits for early adopters; and that auctioning emissions allowances would follow the basic environmental principle of "polluter pays" (TURN).

Most parties that support auctions recommend some form of transition from predominantly administrative allocations to greater reliance on auctions as California gains experience with an auction methodology. In their view, such a transition over a period of time would better allow entities to deal with legacy contracts, recover existing investments, and determine their best emission reduction options (AES, IEP, DRA, WPTF, AREM).

Among parties that oppose auctions, some claim that they or their customers would suffer from facing the full and uncertain cost of auctioned allowances or that system reliability would suffer if producers fail to invest in generation for California (Calpine, EPUC/CAC, LADWP). Other parties are concerned that sole or heavy reliance on auctions is untested and that the State lacks experience to administer auctions (Calpine, El Paso, EPUC/CAC). Dynegy opposes auctions due to the mixed nature of the California market and argues that, if auctions are chosen, they should be used only for regulated entities. Calpine argues that auctions would increase volatility in the short term because there are few options to lower carbon through retrofit investments and generators would have no basis on which to set bids. Some parties are concerned that auction proceeds might be used for some purpose other than benefiting electricity ratepayers. NCPA submits that, without return of revenues, customers would have to pay both for the allocations and for the future emission reductions required to avoid buying additional allowances. While most parties appear to believe that ARB has the legal authority to require auctions, some contest ARB's ability to auction emission allowances without new State law (LADWP, SCPPA, EPUC, El Paso, PG&E).

An important issue regarding auctions is what to do with the proceeds. SDG&E/SoCalGas recommend that, if auctions are used, proceeds should benefit customers by being used for cost-effective contributions to climate change mitigation, or should be used to offset price impacts to price-regulated entities and their customers and to entities subject to competition from uncapped entities. NRDC/UCS state that auction proceeds should be returned to the electricity sector and used in the public interest and to further the goals of AB 32. NCPA recommends that revenues be returned to electric retail providers that will bear the costs of emissions reduction programs.

All parties, including those that support auctions, are in agreement that there are many difficult issues in designing an effective, transparent, and enforceable auction process. Several recommend that the State hire experts on auction design for assistance in developing the best auction mechanism for California.

3.4.1.2. Administrative Distribution Options

The alternative to selling emission allowances through auction is administrative allocation, either to deliverers or potentially to other entities such as retail providers. Emission allowances could be allocated free of charge, or rights to purchase allowances at a set fee could be distributed. Some parties believe that deliverer-based systems should rely exclusively on auctions and, therefore, limit their recommendations regarding administrative distributions to their use in retail provider-based systems.

EPUC/CAC support administrative distribution and strongly oppose full auction. Caithness and Dynegy favor administrative distribution of allowances to those who will need them based on historical emissions. They argue that this approach is appropriate because it would take years to recover current investment costs. Calpine favors an administrative, output-based, updated method of allocation regardless of the point of regulation. WPTF favors initial administrative allocations with a gradual transition to an auction, in order to give entities time to plan their emission reduction strategies.

POUs generally prefer administrative allocation (LADWP, MID, SCPPA, NCPA). They believe that the chances of auction revenues not being returned to their customers would be high. These entities fear that, if they do not receive auction revenues, they would have to pay both for current emissions and for the new investments needed in low carbon infrastructure and energy efficiency. LADWP prefers that it spend its dollars directly on investments in its own infrastructure and community rather than participate in a statewide program.

Some parties are concerned that, should regulators over-estimate the number of allowances needed, the administrative distribution of allowances would inadvertently provide windfall profits to those entities whose allocations exceed their needs, as happened to many generators in Europe (Calpine, LADWP, SCE).

3.4.2. Discussion

The parties make important points regarding both auctions and administrative allocations of emission allowances for the cap-and-trade market.

Regardless of the initial emission allowance distribution methodology, we expect that there would be active secondary trading of emission allowances. Even with initial administrative allocations, a secondary market would develop because administrative allocations would not perfectly meet the entities' actual needs. Entities with insufficient allowances to cover their needs would need to purchase allowances, and those with excess allowances would either hold them or sell them. Additionally, to the extent allowed by ARB rules, entities without compliance obligations themselves may also want to participate in the market.

As Morgan Stanley points out, auctioning rather than initial administrative allocation of allowances would promote allowance market liquidity. The increased trading opportunities would assist in finding least-cost emission reduction investments and improve incentives for investing in energy efficiency and low-GHG technologies and fuels. Because of the increased pursuit of lower-cost emission reductions, open, transparent, fair, and enforceable auctioning would promote the accurate reflection in allowance prices of the true cost of marginal emission reduction measures. These benefits due to allowing more parties to seek the least-cost reductions from whichever sector of the economy can produce them would tend to reduce allowance prices and the cost of GHG emission reductions across all participating sectors.

Regardless of the initial allowance distribution mechanism, entities that retire allowances rather than pursue low-cost emission reduction opportunities would lose the opportunity cost of selling the allowances. As a result, we expect that the power market would tend to reflect the value of allowances, regardless of whether allowances are distributed via auctions or administrative allocations.

However, many parties point out that auction design is a new field for the State and an auction would take several years to develop. Careful design, a learning period, and effective enforcement would be needed. In addition, there are lessons to be learned from the experiences of others with auction design.

Many parties concerned about auctions are most concerned that the proceeds from auctions could be used for purposes other than benefitting the customers who will pay the costs. In addition, some entities who are both deliverers and retail providers are concerned that there may be an added impact on their customers, who may have to pay both for the purchase of emissions allowances and the costs of direct programs to reduce emissions such as renewables and energy efficiency. Impacts on entities with compliance obligations and on customers will depend in large part on the use that is made of auction proceeds.

Auction proceeds could be used to benefit consumers directly by rate mitigation or indirectly by providing funds for investments that would reduce GHG emissions and avoid the need for future allowances. By contrast, free or below-market value administrative allocations could result in windfall profits to deliverers in cases where those deliverers are not also retail providers of electricity to consumers. For these reasons, and in light of the potential benefits of increased market liquidity on allowance prices, we conclude that initially auctioning of a portion of the allowances is superior to relying solely on administrative allocations in terms of reducing costs to consumers of achieving GHG emission reductions. We also conclude that California may need a development and learning period before a full multi-sector auction would be viable.

Entities with potential compliance obligations are concerned that auctioning could make them more vulnerable to volatility in allowance prices, since they would have to purchase needed allowances. This is a valid concern and one that can be addressed by having flexible compliance mechanisms in place. Our final recommendations to ARB will include more information on the potential role of flexible compliance.

One issue of particular concern is how new entities with compliance obligations would obtain allowances.[32] A beneficial aspect of auctions is that

---

[32] In its comments on the proposed decision, LADWP argues that the auctioning of allowances would violate its right of home rule. While, LADWP claims that an auction structure would financially undermine its renewable procurement program, it has not substantiated this claim. We are not convinced that a conflict exists between the use of

Footnote continued on next page

new entrants would have the same access to allowances as other market participants, with no need for administrators to anticipate new entrants' need for administrative allocations. On a broader scale, auctions would avoid the complex and imprecise task of establishing and maintaining an administrative allocation scheme. Instead, purchasers would determine how many allowances to buy and how to minimize their costs of buying allowances. Finally, auctioning rewards early action automatically, because entities who have reduced their emissions will not need to purchase as many allowances.

Because of the benefits, we conclude that some portion of the allowances available to the electricity sector should be auctioned. As an integral part of this recommendation, we conclude that the proceeds from the auction of allowances for the electricity sector should be used primarily to benefit electricity consumers in California in some manner, in order to minimize costs of GHG emission reductions to consumers and assist with emissions reduction opportunities. Possibilities include use to augment investments in energy efficiency and renewable power or to maintain affordable electricity rates. Allocating the value

---

auctions under AB 32 and LADWP's home-rule authority to operate its municipal utility. The courts have stated that "[t]o the extent difficult choices between competing claims of municipal and state governments can be forestalled in this sensitive area of constitutional law, they ought to be; courts can avoid making such unnecessary choices by carefully insuring that the purported conflict is in fact a genuine one, unresolvable short of choosing between one enactment and the other." (California Fed. Sav. & Loan Assn. v. City of Los Angeles (1991) 54 Cal.3d 1, 16-17.) LADWP has not shown that any purported conflict is unresolvable short of choosing between one enactment and the other.

LADWP also argues that in a pure auction system it would be required to purchase allowances for coal-fired generation it was forced to purchase decades ago due to a now repealed federal law. We note that this decision does not recommend a pure auction system.

of allowances and/or auction revenues primarily to benefit consumers recognizes the importance of electricity as a vital commodity. Thus, we believe that reservation of allowances or allowance value for consumers in this sector is warranted regardless of what may be done for other sectors.

Another option available for distributing the value of allowances to consumers, even under an auction scenario, is to allocate auction revenue rights to consumer purposes and/or to allocate allowances to retail providers directly, with the provision that they must offer up those allowances in a centralized auction and receive the proceeds. We will examine these and other available options for the treatment of any available auction proceeds in more detail in the remainder of this proceeding and may make further recommendations to ARB in this regard in a later decision.

Parties disagree as to whether ARB has authority under current statutes to conduct auctions of allowances.[33] This is not an issue that we should, or need to, resolve. If ARB concludes that it needs additional authority in order to conduct auctions and distribute auction proceeds consistent with our recommendations, we recommend that ARB seek additional legislation. We would support ARB in this endeavor.

Based on the current record, we are not able to determine the proper relative roles of auctions and administrative allocation of allowances in a deliverer-based system. Several parties recommend that there be a gradual transition over several years from relatively more administrative allocations initially to relatively greater reliance on allowance distribution via auctions.

---

[33] LADWP argues that AB 32 does not authorize auctions and that auctions would be an illegal tax if it did.

Distributing some amount of allocations administratively in the early years of the program could reduce the immediate impact on entities that would bear the costs of obtaining allowances, and would give them more time to develop emission reduction strategies. Based on the current record, it may be reasonable to provide a transition from small amounts of auctioning in the early years to greater amounts in later years. However, we require more analysis before making a determination on this issue.

Other parties raise concerns with any administrative allowance allocations to deliverers, including the potential for windfall profits in cases where the deliverer is not also a retail provider, and uncertainties regarding how the value of the allowances would be returned to consumers or other affected entities. If auctions are to be phased in, the transition period should be specified well in advance so that parties can plan their investment strategies. We plan to seek additional comments on this issue in the context of the deliverer-based cap-and-trade system which we recommend to ARB.

If any allowances are to be distributed administratively, the manner of the administrative allocation must be determined. Options recommended by parties for determining allowance allocations range from use of historical emissions to output-based metrics. In addition, as mentioned above, some parties recommend direct distribution of allowances to retail providers, which would then be required to sell the allowances at auction and would receive the proceeds. Many of the parties' comments on this issue were couched in terms of a retail provider-based approach rather than the deliverer-based approach that we recommend to ARB. There has been little development of the record on the relative impacts of the various administrative allocation approaches in the context of a deliverer point of regulation. Nor have complications in estimating needed allowances due to fluctuations in emissions due to temperature, hydro conditions, and business cycles been explored adequately.

Now that we have determined that a cap-and-trade system should be implemented, with deliverers bearing the compliance responsibility and with some allowances auctioned for the electricity sector, parties should be given the opportunity for further comment and recommendations on these and any other remaining allowance distribution issues. We reiterate our openness to considering all reasonable options for allocation policy that take into account the circumstances of differently-situated entities in the electricity sector, to ensure that all obligated entities have a path for compliance at reasonable cost, consistent with the general principles outlined here. The modeling analysis that is being undertaken by staff and consultants should also provide additional insight on some of these issues.

We plan to address further in this proceeding the allowance-related issues that we identify but do not resolve in this decision. The ALJs may request comments and/or schedule additional workshops or other follow-up activities as appropriate. We plan to address these additional issues related to the distribution of emission allowances in a subsequent decision.

4. GHG Policies for the Natural Gas Sector

4.1. Overview of Approaches Considered

In its July 2007 report, staff identifies two regulatory approaches that could be used to reduce GHG emissions in the natural gas sector, which could be adopted individually or in combination: reliance on direct emission reduction measures to achieve AB 32 goals and/or reliance on a market-based system.

With sole reliance on direct emission reduction measures, individual entities would not be capped. GHG emission reductions would be achieved through a combination of currently mandated programs, expansions of those programs, and any additional mandatory programs that may be imposed. For the natural gas sector, currently mandated programs that affect GHG emissions include energy efficiency programs and the Energy Commission's building and appliance efficiency standards. The Legislature recently approved incentives to encourage residential and commercial customers to install solar hot water heaters which will reduce the demand for natural gas. These programs could be expanded if such expansion is found to be desirable relative to other emission reduction strategies in the natural gas sector or in other sectors.

In considering market-based approaches, staff and parties focus on options that would utilize a cap-and-trade mechanism. One approach would be to cap emission at an "upstream" point, which could be the wellhead, where natural gas enters either an interstate pipeline or a gas utility's transmission system, and/or where the gas enters the State on interstate pipelines. Another approach would be to cap GHG emissions of large industrial end users at the source, with smaller end users capped at the California utility that provides the final portion of transportation and/or sales service.

4.2. Scope of the Natural Gas Sector

Before we analyze the various approaches for regulating GHG emissions in the natural gas sector, it is necessary to determine the types of natural gas uses that should be included in the sector for the purpose of GHG regulations.

In addition to aiding us in making a recommendation to ARB, determining the scope of emissions in the natural gas sector will aid parties in considering expansion of current programmatic measures and proposing new programs to reduce GHG emissions. In its July 2007 report, staff identifies seven primary uses of natural gas: combustion by large industrial end users, combustion by small end users, infrastructure operations, fugitive releases, natural gas vehicles, CHP operations, and distributed generation. Parties also identified natural gas for industrial processes that is not combusted as another use of natural gas. GHG emissions from natural gas used for electricity production are addressed through our recommendations on the regulation of GHG emissions in the electricity sector.

4.2.1. Position of the Parties

In their comments, parties address the regulatory approach best suited for GHG emissions from each of the eight uses of natural gas. Summaries of parties' position are organized by use of natural gas.

Large Industrial End Users

All of the parties agree with staff's conclusion that the largest industrial end users should be regulated by ARB as industrial point sources, with the emissions not attributed to the natural gas sector. Parties disagree, however, regarding the size demarcation above which industrial end users should be regulated as point sources. Several parties, including PG&E, Wild Goose, El Paso/Mojave, SCE, and SDG&E/SoCalGas, support regulating industrial end users as point sources if they meet or exceed ARB's reporting threshold of 25,000 metric tons of CO2e (expressed by PG&E as 4.5 million therms) per year, which they argue would cost-effectively capture the bulk of the emissions. PG&E and Wild Goose assert that treating smaller industrial end users as point sources would not significantly increase the proportion of emissions regulated on that basis. Wild Goose points out that, as determined by ARB, lowering the threshold to include industrial end users with CO2e emissions that meet or exceed 10,000 tons per year would only include an additional 2% of GHG emissions in ARB's point source regulatory approach.

NRDC/UCS support lowering the threshold for regulating industrial end users as point sources to 10,000 metric tons of CO2e per year, which they assert would cover more end users that are capable of making reductions and would not place an undue burden on these users or on regulators. These parties point out that California's three largest local distribution companies have only 127 customers that consume more than 2 million therms (which is roughly equivalent to 10,000 tons of CO2e) per year. They suggest that this level may be a better fit with the "expandability" criterion, since a United States Senate Committee has approved the Lieberman-Warner Climate Security Act (S.2191), including a reporting threshold of 10,000 tons of CO2e per year for stationary sources. SMUD supports a threshold equivalent to 1 MW, in order to be consistent with the electricity sector and to avoid creating incentives for fuel switching.

Small End Users

As described in greater detail below, parties differ on the appropriate regulatory approach for reducing GHG emissions from combustion of natural gas by end users that are too small for ARB to regulate as a point source. However, none of the parties dispute staff's assertion that combustion-related GHG emissions from small end users account for a significant proportion of all GHG emissions associated with natural gas usage.

Natural Gas Infrastructure

In delivering natural gas to end users, utilities and other entities operate compressors and other equipment that directly combusts or releases natural gas. In its report, staff refers to these sources of GHG emissions as "infrastructure." Some parties, including NRDC/UCS, PG&E, Environmental Council, and SCE, support including infrastructure emissions within the natural gas sector for purposes of GHG emissions regulation. NRDC/UCS assert that extending regulation to this type of emissions would only cover an additional 8 entities, each of which emits close to 10,000 tons of CO2e per year. PG&E believes that natural gas infrastructure is essentially an industrial process that can be regulated in the same way as other industrial processes. PG&E recommends that the infrastructure providers be considered as a single fuel-consuming entity since they can manage overall emissions by increasing the efficiency of the total system.

IP asserts that the emissions from local distribution utilities' infrastructure should be directly addressed by regulating natural gas utilities, while emissions from proprietary pipelines should be addressed by ARB directly by including those emissions into a multi-sector cap-and-trade system.

Other parties, including Kern, Lodi, Wild Goose, SDG&E/SoCalGas, and Southwest, oppose including natural gas infrastructure in the natural gas sector, stating that the incremental benefits of regulation would be relatively small. SDG&E/SoCalGas report that, other than the facilities that would be regulated as large point sources by ARB, these sources represent less than 0.03% of statewide CO2e emissions. SDG&E/SoCalGas also assert that these kinds of emissions are not easily subject to measurement or verification. Kern and Wild Goose submit that natural gas pipelines already have incentives to operate efficiently, and that further regulation could lead to restrictions in supply, which could result in the use of higher carbon alternatives. Wild Goose argues that, if these sources are capped, they should be part of a cap-and-trade system because an approach that relies on direct emission reduction measures could result in reduced natural gas availability.

Fugitive Releases

In addition to using natural gas to provide end users with service, entities may also release natural gas directly, primarily through leaks and emergency maintenance operations. Staff refers to these as fugitive emissions and estimates that fugitive emissions account for less than 1% of GHG emissions in the sector.

NRDC/UCS, SMUD, and SCE support including fugitive emissions from sources such as transmission and storage within the natural gas sector. SMUD argues that covering these emissions would be equitable relative to the electricity sector, which is responsible for its "transport" emissions in the form of line loss. NRDC/UCS support programmatic measures to address fugitive emissions, and also urge that fugitive emissions be considered for inclusion in a cap-and-trade program at a later date if the reported data is accurate enough.

Other parties, including Environmental Council, Kern, SDG&E/SoCalGas, El Paso/Mojave, and Southwest, oppose including fugitive emissions in the sector on the basis that they are relatively small and difficult to measure. SDG&E/SoCalGas believe that fugitive emissions are better addressed through programs aimed at best practices in managing leaks. El Paso/Mojave and Kern recommend that corrections to fugitive emissions be eligible for offset credits.

Lodi asserts that a reasonable threshold level should be established to allow for smaller amounts of fugitive emissions to be exempt from any GHG regulatory program, stating that the burden of regulation would outweigh any benefit from a reduction in emissions.

Two parties comment on measurement and reporting issues. IP, while not recommending that fugitive emissions be regulated, points out that the tracking of fugitive emissions could be feasible using existing data that are reported to State and federal air pollution and transportation authorities. PG&E states that fugitive emissions could be regulated like a point source if measurements are based on sound estimates. However, PG&E opposes regulation based on use of existing protocols for calculating fugitive emissions, such as miles of pipe or number of compression stations, because limiting supply would then be the only way to achieve reductions.

<u>Natural Gas Vehicles</u>

Several parties, including Clean Energy, NRDC/UCS, SDG&E/SoCalGas, SCE, and PG&E, support regulating natural gas vehicles as part of the transportation sector, rather than the natural gas sector. SDG&E/SoCalGas believe that natural gas vehicles should be viewed as sources of conservation-based efforts, not GHG sources that should be capped. Clean Energy states that California utilities should "not be penalized for the increased use of natural gas that results from their successful efforts to accelerate the market penetration of natural gas vehicles…" PG&E recommends that distributors of natural gas for combustion by natural gas vehicles should receive credit for any GHG-related fuel-substitution value.

NRDC/UCS argue that, if petroleum-based transportation fuels were excluded from a cap, it would be important to take further steps not to disadvantage natural gas used for transportation. In their view, this could be done either by excluding natural gas used for transportation from the cap or by adopting other policies to compensate.

Kern does not address the appropriate sector for regulation, but comments that natural gas vehicles should not be subject to a cap.

IP believes that natural gas vehicles should be included in the State's GHG plan, but that it is not clear yet whether natural gas vehicle fuel is best addressed within the natural gas sector or directly by ARB.

Combined Heat and Power (CHP)

Parties advocate several different approaches to attributing the emissions from CHP facilities to the electricity and natural gas sectors. These facilities, which include cogeneration facilities, are typically used by large industrial end users to serve on-site power needs and to provide thermal output for industrial process. Some smaller end users have installed CHP facilities where the thermal output is used for on-site heating and cooling.

El Paso/Mojave believe that larger CHP facilities should be placed in a downstream electricity cap, and smaller CHP facilities should be regulated with efficiency programs, like other small users.

EPUC/CAC advocate that emissions from CHP facilities be attributed to neither the electricity nor the natural gas sector. These parties assert that emissions from CHP facilities are best regulated in a separate sector. IP supports the EPUC/CAC position that a separate sector should be created for CHP facilities, to avoid discouraging the development and operation of these resources. SDG&E/SoCalGas support designating CHP facilities as point sources, arguing that this approach would make attributing GHG emissions between industrial and electric generation unnecessary.

NRDC/UCS argue, as a preliminary position, that large CHP facilities should be regulated as point sources, while smaller CHP facilities should be regulated within the natural gas sector, with the local distribution companies as the point of regulation. NRDC/UCS also say that this issue may require further evaluation once the design of an overall GHG regulatory system has been developed.

Other parties, including PG&E, SMUD, and SCE, favor attributing the emissions from CHP facilities to both the electricity and the industrial sectors. SMUD believes that CHP emissions should be split between the sectors according to the proportion of electricity and thermal energy production. SCE urges that the electricity portion of cogeneration, CHP, and distributed generation should be regulated as part of the electricity sector. SCE also argues that, if these sources are not included in the electricity sector due to their size, they should be included in the natural gas sector, either as a point source or through the local distribution company. PG&E argues that, under a deliverer point of regulation for electricity (its preferred approach), emissions from CHP facilities would be regulated as electricity generation while natural gas combustion for industrial processes should be regulated as industrial stationary sources.

Distributed Generation

Another source of GHG emissions related to natural gas combustion is distributed generation facilities where end users combust natural gas for the purpose of meeting on-site electricity needs. Unlike CHP, these facilities do not serve an accompanying thermal load. NRDC/UCS and SCE support including emissions from distributed generation facilities that generate electricity within the electricity sector. SCE supports including within the natural gas sector any of these facilities that, due to their size, would not be included in the electricity sector. NRDC/UCS state that this issue may need further investigation once the design of the overall GHG regulatory system has been determined.

Use of Natural Gas in Industrial Processes

In some industrial processes, natural gas is used but not combusted or released into the atmosphere. As an example, natural gas is used as a feedstock in fertilizer manufacturing and natural gas is also used in pharmaceutical production. In these applications, natural gas is used without combustion or release, and the natural gas does not contribute to GHG emissions. No parties support including non-combustion uses which do not lead to GHG emissions within the natural gas sector. SDG&E/SoCalGas and IP believe the vast majority of the sources in this category would qualify as large point sources subject to regulation by ARB. IP also believes there are limitations in the availability of data for these sources. El Paso/Mojave believe that a voluntary reduction program should be implemented to address non-combustion uses.

4.2.2. Discussion

Before we determine a recommendation for regulating GHG emissions in the natural gas sector, it is useful to define the scope of the sector to which the regulations would apply. We note that ARB did not identify natural gas as a separate sector in its inventory of GHG emissions for California. Instead, the inventory includes natural gas-related emissions in the electricity, residential, commercial, industrial, and transportation categories, depending on the type of entity that uses the natural gas.

Our inquiry began by considering all potential sources of natural gas GHG emissions, whether from combustion or from direct release of methane into the atmosphere. However, certain portions of these natural gas emissions will be regulated based on ARB's definition of other sectors of the economy with GHG emissions. Therefore, for purposes of today's decision, we define the natural gas sector as the remainder of natural gas combustion emissions and direct emissions, excluding those sources that we anticipate ARB will address through regulations for other sectors.

ARB proposes to regulate emissions from large end users of natural gas (with emissions of 25,000 or more metric tons of CO2e per year) as individual industrial sources. Therefore, we propose that they not be included in the natural gas sector. Should ARB lower the threshold for reporting and/or regulation of industrial point sources, the additional entities captured under that regulation would not be considered part of the natural gas sector for purposes of regulating GHG emissions from the natural gas sector.

In addition, natural gas that is used to generate electricity that is delivered to the California grid should not be considered part of the natural gas sector, because it would be regulated under the deliverer approach that we recommend for the electricity sector.

The proposed decision recommended that natural gas used by CHP facilities to generate electricity delivered to California grid be regulated as part of the electricity sector, with other natural gas used by CHP facilities considered either as point sources or within the natural gas sector, depending on the size of CHP operations. However, comments on the proposed decision (chiefly from EPUC/CAC) cause us to question whether all natural gas used by CHP facilities should be treated instead as a separate sector, because of concerns about potential negative unintended consequences of splitting CHP natural gas usage between electricity, natural gas, and industrial sectors. We defer this issue at this time, in order to conduct further analysis of CHP options and potential in the next portion of this proceeding. We plan to make comprehensive recommendations to ARB at a later date regarding the regulation of GHG emissions from CHP facilities. In the case of distributed generation fueled by natural gas, to the extent that the electricity is used on site and not delivered to the electricity grid, natural gas used for that purpose would be considered part of the natural gas sector.

Some parties argue that emissions from natural gas vehicles should be excluded from the natural gas sector, by instead including them in the transportation sector. We do not make a recommendation at this time, but will work with ARB as it determines the appropriate regulatory treatment for GHG emissions from natural gas and other alternative-fuel vehicles.

Finally, some natural gas is used for non-combustion purposes in industrial processes. The record is very limited regarding the extent of such uses. Because non-combustion uses of natural gas generate no emissions, it would be appropriate to exclude them from the natural gas sector for purposes of GHG regulations. However, since the natural gas utilities currently do not collect information on non-combustion uses and quantities, further analysis may be needed to determine whether it would be feasible to exclude these non-combustion uses from GHG regulations, for example, if emission caps were applied to the natural gas utilities.

With exclusion of CHP at this time, and of natural gas uses that do not produce GHG emissions or are likely to be regulated separately by ARB, there are four main sources of emissions in the natural gas sector:

1) End-user combustion sites with annual emissions below the ARB threshold for separate industrial point-source regulation,
2) Natural gas infrastructure used in the provision of storage, transportation, and distribution of natural gas to end users,
3) Fugitive emissions, and
4) Emissions from distributed generation facilities for the portion of electricity that is used on site.

For purposes of assessing GHG regulatory options, we include these four uses of natural gas in the definition of the natural gas sector.

4.3. Types of GHG Regulation

As in the electricity sector, we consider two main options for reducing GHG emissions from the natural gas sector under the AB 32 framework. These are direct/mandatory emission reduction measures or programs and a market-based cap-and-trade system.

4.3.1. Position of the Parties

4.3.1.1. Increased Reliance on Direct Emission Reduction Measures

Many parties favor increased reliance on direct emission reduction measures to achieve GHG reductions for smaller end-users including PG&E, SDG&E/SoCalGas, DRA, NRDC/UCS Kern, Southwest, El Paso, GPI, Wild Goose, and CMTA. In general, these parties support increased building and appliance standards and expansion of energy efficiency programs mandated by the Public Utilities Commission. They have differing opinions, however, regarding the use of direct emission reduction measures to reduce GHG emissions from infrastructure and fugitive sources.

Supporters of increased reliance on direct emission reduction measures assert that this approach is a better GHG reduction strategy than cap-and-trade for small end users of natural gas.

AGA believes that energy efficiency programs can be expanded to achieve additional GHG emission reductions from residential and small commercial customers. Among other reasons that it gives for not adopting a cap-and-trade system for the natural gas sector, AGA asserts that, unlike electricity retail service providers, gas utilities have virtually no availability to substitute low carbon alternatives for natural gas other than some limited potential for biogas.

Many supporters of reliance on direct measures assert that there would be little incremental benefit to a market-based system for the natural gas sector, beyond the benefits of existing programs to improve end-user efficiency. Southwest Gas and PG&E believe that a cap-and-trade system would be more costly than direct emission reduction measures. Supporters submit that including large numbers of individuals and small end users of natural gas in a cap-and-trade system would be administratively burdensome and too costly.

PG&E and SDG&E/SoCalGas assert that they have limited control over end-user efficiency, and question the effectiveness of a cap-and-trade system that relies on gas utilities as the point of regulation for small end users. El Paso, Mojave, and SDG&E/SoCalGas argue that price signals would be difficult to pass through to customers if gas utilities act as the point of regulation in a cap-and-trade system.

DRA argues that smaller end-use customers should not be included in a cap-and-trade system until the price of emission allowances is stabilized and the overall price impacts to consumers of a cap-and-trade program are better understood.

While generally supporting market-based solutions, GPI and CMTA support direct emission reduction measures, stating that a market-based approach would be impractical due to the limited substitutes for natural gas in its principal end uses. CMTA, in particular, is concerned that a cap-and-trade system imposed on the natural gas sector would adversely affect California industrial and manufacturing end users because these entities may face higher prices for fuel and/or would have to limit their production to comply with a cap-and-trade system. Several supporters assert that a programmatic approach would avoid creating incentives for fuel switching from natural gas to electricity. CMTA notes that many thermal processes in manufacturing use natural gas directly because of efficiencies, and concludes that any regulations that discourage the use of natural gas would likely result in greater GHG emissions. Several parties acknowledge that biogas holds some potential, but submit that there are technological and environmental obstacles to be overcome before this resource can be commercialized.

Some parties argue that a cap on sources that use natural gas could cause economic dislocations. Several infrastructure providers (interstate pipelines and storage utilities) assert that a cap on emissions could reduce the availability of natural gas supplies. CMTA believes that a cap applied at the local distribution company level could result in a utility allocating or curtailing natural gas supplies among its customers. CMTA and Wild Goose also argue that a cap could result in leakage if manufacturers move their operations to other jurisdictions.

CALSEIA/SRCC recommend that in addition to energy efficiency programs, solar hot water heaters be considered as a GHG emission reduction measure. They recommend using both market-based and programmatic approaches to promote installation of solar hot water heating equipment by residential and commercial customers. CALSEIA/SRCC recommend mandating the use of solar hot water heaters for new residential and commercial construction and renovations, and using incentives to induce customers with existing natural gas fired hot water heaters to convert to solar hot water heaters.

Finally, many parties argue that the natural gas sector does not need to be regulated in the same manner as the electricity sector, including NRDC/UCS, PG&E, SCE, and SDG&E/SoCalGas.

4.3.1.2. Cap-and-Trade System

Some parties, including Environmental Council, IP, SMUD, SCE, NRDC/UCS, and GPI, support a cap-and-trade system as the approach most likely to identify cost-effective emissions reduction options for the natural gas sector, or between this and other sectors. IP agrees with the Market Advisory Committee report that a cap-and-trade program would, as a general matter, allow California to reach emissions targets at lower cost. El Paso and Mojave argue that market-based programs would achieve environmental goals with less cost to society, would provide greater flexibility and equity for the regulated sectors, and would be easier to regulate. SMUD recommends a cap-and-trade approach on the basis that it would be more likely to encourage innovation in the covered sectors.

Several parties argue that including natural gas within a broader cap-and-trade system would lead to a more-liquid emissions trading market and better price signals. SCE, SMUD, and IP argue that a broad-based, multi-sector cap-and-trade system would allow entities responsible for compliance in individual sectors to optimize their emissions reductions across all available emissions reduction options, not just from within their own sectors. NRDC/UCS point out that excluding a single sector from an economy wide cap-and-trade system would make it more difficult to account for consumption shifts between sectors. IP also argues that if emissions from other sectors are included in an economy wide cap-and-trade system, it would be equitable to include emissions from the natural gas sector as well.

Some parties argue for trading of emissions allowances between natural gas and other sectors with the potential for competition for certain end uses. SMUD believes that a cap-and-trade system would allow for cost-effective adjustments between sectors to allow such activities as electrifying ports or the use of heat pumps for residential heating and cooling. GPI argues that competition among fuel sources is likely to become more complicated in the future with the introduction of plug-in hybrid and electric vehicles. They advocate that all fuels be included in a multi-sector GHG emissions cap-and-trade system.

Wild Goose argues that cap-and-trade is preferable to programmatic measures that could place restrictions on the way that storage facilities operate their businesses. It fears that restrictions could control “how many hours compressors could run or what type of equipment can be used,” and would limit the availability of natural gas supplies in California.

Amount of Reductions Due to Cap-and-Trade

Several parties suggest that, while cap-and-trade is likely to provide only a relatively small portion of the needed emission reductions in the natural gas sector, this approach could still lead to greater reductions overall than would occur with reliance only on direct emission reduction measures. NRDC/UCS argue that, while they expect the majority or reductions to be achieved through energy efficiency programs and performance standards, a cap-and-trade program could provide a "backstop" for intensity-based programs to ensure that emission reductions are achieved. NRDC/UCS urge that both regulatory policies and performance standards be expanded, and that a cap-and-trade program be utilized to reduce emissions. Environmental Council believes that "much of the expected emissions reductions from a natural gas sector cap and trade system probably could be (and probably will be) realized through existing state and federal policies to increase natural gas efficiency and to promote alternatives to natural gas."

Timing

Several parties, including Environmental Council, NRDC/UCS, and SCE, urge California to move forward with a cap-and-trade program for natural gas without waiting for such a program to be adopted at the regional or the national level. NRDC/UCS argue that deferral of a cap-and-trade program would leave California in a position of having to accept other jurisdictions' program designs, which might ultimately disadvantage the state. They point out that California has the opportunity to design and develop a system that would help serve as a model for broader systems and help serve California's interests. Environmental Council asserts that there is no guarantee that any regional or federal system will be in operation even a decade from now, and California should act now because emission reductions are needed over the next ten years to avoid the worst impacts of climate change.

Other parties, including PG&E, Kern, CMTA, El Paso, and Mojave, argue that a California program would be more efficient if deferred until such time that it can be integrated into a regional or national system. CMTA asserts that a robust cap–and-trade system is best achieved through a regional or national system. PG&E, El Paso, and Mojave believe that deferral of a cap-and-trade program would facilitate integration into a broader program and reduce the need to revisit California's program once a broader program is in place. As an additional benefit of deferring a California cap-and-trade program, Kern argues that new technologies that become available later might reduce the cost of the program. Kern believes that such a program should be deferred until these technologies are available at a reasonable cost.

4.3.2. Discussion

Comparable to the electricity sector, there essentially are four options for how to regulate GHG emissions in the natural gas sector: 1) a carbon tax, 2) upstream regulation of emissions from fossil fuel combustion, 3) a downstream emissions cap (with or without trading), and 4) additional direct mandatory/regulatory requirements.

As we discuss in Section 3.2.2 for electricity, we did not seriously consider the carbon tax option in this proceeding. Similarly, we have not undertaken a detailed review of upstream regulation of fossil fuel consumption in California. We have instead focused on options for additional direct mandatory/regulatory requirements and a cap or cap-and-trade program that includes the natural gas sector.

As for electricity, we assess first the direct mandatory/regulatory policies and requirements that California already has in place that contribute to GHG reductions. Since the natural gas sector has limited ability to substitute different fuel types for natural gas, there is really only one major direct programmatic approach to reducing emissions from the sector currently in effect. That primary tool is energy efficiency, including both building codes and appliance standards, as well as energy efficiency programs currently administered by the Public Utilities Commission. The Legislature recently adopted a program to provide financial incentives to residential and commercial customers to use solar hot water heaters in new construction and to replace existing hot water heaters. Like energy efficiency, this program will lower natural gas usage and GHG emissions.

As we describe in Section 3.2.2, the Energy Commission updates its energy efficiency building codes and appliance standards approximately every three years, and includes other requirements on an on-going basis. The Public Utilities Commission sets requirements for the amount of energy savings that each natural gas IOU is required to achieve on an annual basis, just as it does for the electricity IOUs, based on the availability of cost-effective energy savings in the utilities' territories. The risk/reward mechanism adopted in D.07-09-043 applies to both natural gas and electricity utilities. Although these programs are primarily directed at end users, opportunities exist for GHG emission reductions in natural gas infrastructure, including storage. It may be cost effective to mandate improvements that enhance operational efficiencies and decrease fugitive emissions. As we refine programmatic measures in the natural gas sector, either as modifications to existing programs or as recommendations to ARB, we intend to examine emission reduction measures for natural gas infrastructure.

AB 2021 requires that the Energy Commission set statewide energy efficiency targets for 2017, and the Energy Commission's determination that the goal for the State should be to achieve all cost-effective energy efficiency apply for both natural gas and electricity utilities in the state.

Consistent with our discussion in Section 3.2.2, we believe that the goals of AB 32 would be best achieved if all entities that provide transportation, distribution, and/or retail sales of natural gas to end users, including IOUs, POUs, and interstate pipelines, are subject to minimum requirements in the areas of cost-effective energy efficiency or other demand reduction programs. We expect to consider other programmatic options for reducing demand for natural gas including the use of solar hot water heating equipment. Such requirements would benefit California customers by ensuring that they receive the GHG emission reductions of cost-effective energy efficiency and solar water heating. Therefore, our recommendation that ARB adopt mandatory minimum levels of cost-effective energy efficiency savings applies to both natural gas and electricity for IOUs and POUs. We reiterate our suggestion that, if ARB believes that it lacks authority to implement this suggestion, it seek such authority as soon as possible from the Legislature. Also as described in Section 3.2.2, we reject the suggestion made by some parties that we should eliminate mandatory targets for energy efficiency and allow an AB 32 cap to govern instead.

We see little advantage of implementing a cap system in the natural gas sector, compared to reliance on the direct programmatic approaches described above. Under either a cap or direct programmatic approach, ARB will need to measure the GHG emissions from the sector as part of its obligations under AB 32 of ensuring that statewide GHG emissions are reduced to 1990 levels by 2020. If the anticipated level of reductions from programmatic approaches is not achieved in the natural gas sector, ARB will likely modify and/or add new programmatic approaches. Therefore, any advantage of a cap only would be achieved under the programmatic approach we recommend. In addition, similar to the electricity sector, a cap without a trading component would offer fewer advantages than a cap-and-trade program. Therefore, we do not recommend a cap-only system for the natural gas sector in California.

As summarized in Section 4.4.1 above, parties disagree regarding whether the natural gas sector should be included in a multi-sector cap-and-trade system. Some parties, including PG&E, SDG&E/SoCalGas, and Southwest Gas, prefer that California rely only on programmatic measures to achieve GHG reductions in the natural gas sector. Other parties, including NRDC/UCS, Environmental Council, and SCE, advocate including the natural gas sector in a multi-sector cap-and-trade system.

In Section 3.2.2, we recommend that ARB design a multi-sector cap-and-trade system that includes the electricity sector. However, we recommend that the natural gas sector not be included in a cap-and-trade system at this time. There are several reasons for this recommendation. Key differences between the electricity and natural gas sectors persuade us that it would be premature to include the natural gas sector in a cap-and-trade system. First and foremost, there are significantly fewer options at this time to reduce GHG emissions in the natural gas sector. Unlike the electricity sector, there is no commercially available low-carbon alternative source of natural gas. While bio-gas holds potential, its development is still in the early stages. Thus, in the near-term, natural gas utilities and end-users cannot substantially reduce GHG emissions by choosing an alternative source of natural gas. As a result, energy efficiency and solar water heating programs are the only reliable near-term options available for reducing GHG emissions in the natural gas sector.

Second, because energy efficiency and solar water heating programs are the primary means to reduce GHG emissions in the sector, the incremental benefits from including the natural gas sector in a multi-sector cap-and-trade program are likely to be smaller than those for the electricity sector. Third, unlike the electricity sector, reporting protocols for GHG emissions associated with the transportation, storage, and delivery of natural gas are still under development and do not yet include provisions for reporting end user-related combustion emissions. Relying on programmatic measures to achieve emission reductions would allow additional time to develop protocols for all sources of GHG emissions in the natural gas sector. Finally, we agree with DRA that including the natural gas sector in a cap-and-trade system now could expose small end users in the natural gas sector to greater price risk than small end users in the electricity sector because their utilities have fewer options to mitigate variations in allowance prices.

As mentioned in our discussion of electricity sector cap-and-trade options, we are aware that there is consideration, at both the regional and national levels, of upstream regulation for natural gas use. Should such a system be put in place, the programmatic approach we endorse today would still be compatible with an upstream system with minimal adjustments necessary.

While we recommend that the natural gas sector not now be included in a multi-sector GHG emissions cap-and-trade system at this time, we do not reject GPI's and NRDC/UCS's argument that eventual inclusion of all fossil fuels in a multi-sector cap-and-trade system could maximize its benefits. Taking a programmatic approach for the natural gas sector now would not preclude its future inclusion in a multi-sector GHG emissions cap-and-trade system. As California gains greater experience with a cap-and-trade system, regional and national frameworks are established, reporting protocols are adopted, and alternative lower-carbon sources of natural gas are developed, we expect that it will become appropriate to add the natural gas sector to the multi-sector GHG emissions allowance cap-and-trade system, and we expect to recommend inclusion of the natural gas end-use sector at that time.

4.4. Distribution of Allowances in a Cap-and-Trade System

El Paso/Mojave, IP, Lodi, SDG&E/SoCalGas, SMUD, and Southwest Gas filed comments that address the distribution of allowances in the natural gas sector if it is included in a GHG emissions cap-and-trade system. However, we need not address this issue since we recommend a programmatic approach that relies on direct emission reduction measures. In this approach, no distribution of allowances would be necessary.

5. Comments on Proposed Decision

The proposed decision of President Peevey in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Public Utilities Commission's Rules of Practice and Procedure. Comments were filed on February 28, 2008, and reply comments were filed on March 4, 2008. We have made corrections and clarifications in the proposed decision in response to comments, as well as substantive changes on selected issues, as we describe in today's decision.

6. Assignment of Proceeding

President Michael R. Peevey is the assigned Commissioner in this proceeding, and Charlotte F. TerKeurst and Jonathan Lakritz are the assigned Administrative Law Judges in Phase 2 of this proceeding.

Findings of Fact

1. The state Energy Action Plan lays out a "loading order" for investment in electricity resources in California that puts energy efficiency as the top priority, with renewable resources second, and clean fossil-fired generation to the extent other options are not available.

2. Energy efficiency building codes and appliance efficiency standards promulgated by the Energy Commission provide a base for energy and GHG emissions reductions.

3. Consistent with AB 2021, the Energy Commission has recommended statewide energy efficiency goals at the level of all cost-effective investment in energy efficiency, to be met through a combination of utility and non-utility programs, including building codes and appliance standards.

4. The Public Utilities Commission sets requirements and energy savings goals for energy efficiency programs for the IOUs, and has set up a risk/reward mechanism for the IOUs that allows them to earn financial incentives as they approach meeting the adopted energy savings goals and assesses penalties if they fail to meet at least 65% of their goals. In addition, during 2008 the Public Utilities Commission will adopt IOU energy efficiency goals for the years 2014 to 2020.

5. It is reasonable for the State of California to apply minimum requirements in the areas of cost-effective energy efficiency and renewables to all retail providers of electricity.

6. It is reasonable that existing California policies regarding energy efficiency building codes and appliance efficiency standards, retail provider energy efficiency programs, the renewables portfolio standard program, solar photovoltaic and solar water heating programs, and the emissions performance standard be maintained and strengthened as recommended in this decision.

7. For the electricity sector, a cap-and-trade system, in conjunction with the continuation and strengthening of existing policies regarding energy efficiency building codes and appliance efficiency standards, retail provider energy efficiency programs, the renewables portfolio standard program, solar photovoltaic, and the emissions performance standard as recommended in this

decision, is likely to be a less expensive means of complying with AB 32 GHG emission reduction requirements than sole reliance on existing and increased mandatory programmatic requirements.

8. For the electricity sector, GHG emissions trading would maximize flexibility in achieving emissions targets by allowing obligated entities to rely on least-cost options across the entire economy.

9. For the electricity sector, a GHG emissions cap-and-trade program would encourage investment in research and innovation in technologies that lower GHG emissions.

10. For the electricity sector, a GHG emissions cap-and-trade program would allow market participants to manage risk associated with compliance obligations.

11. For the electricity sector, a GHG emissions cap-and-trade program would internalize GHG externalities and should distribute the cost of GHG reductions most efficiently across all capped entities.

12. Implementing a GHG emissions cap-and-trade system in 2012 for the electricity sector would allow entities to gain experience with finding real least-cost GHG emission reduction opportunities.

13. It is reasonable for ARB to proceed to design a multi-sector GHG emissions cap-and-trade system for California that includes the electricity sector, for implementation in 2012, as described in this decision provided that ARB finds that the tests outlined in Part 5 of AB 32 are met.

14. For the electricity sector, placing the compliance obligation in a GHG emissions cap-and-trade system on the entities that deliver power to the electricity grid in California, which we call "deliverers," is reasonable because this point of regulation best meets, on balance, the most important criteria, as described in this decision.

15. The "deliverer" is the entity that owns electricity as it is delivered to the grid in California.

16. For electricity whose deliverer would otherwise be a federal entity not subject to California regulation, it is reasonable for the deliverer for AB 32 compliance purposes to be the first non-federal entity that owns the electricity thereafter on the physical path in California.

17. By choosing a deliverer *point of regulation* we are simply choosing a trigger that determines which entities have to comply, but what is being regulated is the amount of GHGs being produced in California or to supply electricity to customers located in California.

18. The deliverer point of regulation does not single out wholesale sales of electricity, but rather applies uniformly to electricity consumed in California and electricity generated in California.

19. An entity with compliance obligations under a deliverer form of regulation, if it does not already possess enough allowances, would have an opportunity after delivery of the energy to acquire allowances on the market or to show compliance using flexible compliance mechanisms such as offsets (to the extent they are allowed).

20. The GHG regulatory program we are proposing would not prevent even high-GHG sources from providing reliability services when needed.

21. A deliverer point of regulation would treat all electricity delivered to the California grid the same, whether that electricity is generated in California or elsewhere. In either case, the deliverer would later have to surrender GHG allowances (or secure adequate offsets to the extent they are allowed) based on the amount of GHG emissions associated with that electricity.

22. "Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential

adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems." (Health & Safety Code § 38501(a).)

23. "Global warming will have detrimental effects on some of California's largest industries, including agriculture, wine, tourism, skiing, recreational and commercial fishing, and forestry. It will also increase the strain on electricity supplies necessary to meet the demand for summer air-conditioning in the hottest parts of the state." (Health & Safety Code § 38501(b).)

24. The local benefits to California of reducing GHG emissions are further elaborated in the Final Climate Action Team Report to the Governor and the Legislature (presented to the Legislature in March 2006) and other sources.

25. Additional local benefits of the GHG program we are recommending include its encouragement of a wide range of clean energy sources, which protects the reliability of the grid, and the avoidance of unnecessary costs and inefficiencies that would result if California were to wait until the federal government begins regulating GHG emissions.

26. Any burdens on interstate commerce that may result from the implementation of AB 32 under the regulations that we recommend to ARB (including a deliverer point of regulation) would be purely incidental, while the local benefits to California of reducing GHG emissions, and therefore the impact of global warming, would be most significant.

27. The proposed GHG regulations are intended to change the way that electricity is generated and consumed and are expected to increase the use of (i) renewable resources to generate electricity, (ii) low-emitting sources of

generation, and (iii) more efficient methods of using electricity. To the extent such actions are unable to sufficiently reduce GHG emissions associated with the use of electricity, these regulations are expected to result in investments outside of the electricity sector that will cost-effectively reduce GHG emissions from other activities.

28. The emissions associated with multi-jurisdictional utilities' deliveries of electricity to the California grid should be regulated using a deliverer point of regulation. Nevertheless, the methodology for tracking and accounting for the GHG attributes of the electricity these utilities deliver to California may not be identical to that of other entities not similarly situated.

29. The auctioning of some portion of the emission allowances available to the electricity sector would promote least-cost GHG emission reductions throughout the California economy, promote liquidity in the emission allowance market, improve incentives for investing in energy efficiency and low-GHG technologies and fuels, improve the accuracy of emission allowance prices as a reflection of marginal emission reduction costs, and allow new market entrants access to allowances on an equal basis with other parties.

30. It is reasonable to require that some portion of the GHG emissions allowances for the electricity sector be auctioned in a GHG emissions cap-and-trade system in which deliverers are the point of regulation for the electricity sector. As part of this approach, the majority of proceeds from the auctioning of allowances for the electricity sector would be used in ways that benefit electricity consumers in California.

31. The record in R.06-04-009 is not sufficient, at this time, to determine a reasonable mixture of auctioning and the administrative allocation of GHG emissions allowances for the electricity sector, nor the extent to which there

should be a transition from a small amount of auctioning to a greater reliance on auctions.

32. The record in R.06-04-009 is not sufficient, at this time, to determine a reasonable approach for the administrative allocations of GHG emissions allowances, if such distributions are undertaken.

33. It is reasonable for the State of California to apply the same minimum requirements in the areas of energy efficiency and energy conservation to all entities that provide retail sales, transportation, and/or distribution of natural gas to end-users in California.

34. Key differences between the electricity and natural gas sectors make it reasonable to recommend that ARB proceed to design a multi-sector GHG emissions cap-and-trade system for California but not include the natural gas sector at this time.

35. Entities in the natural gas sector have fewer options to reduce GHG emissions than entities in the electricity sector.

36. There are limited commercially available lower carbon alternative sources of natural gas.

37. The only options in effect for reducing GHG emissions in the natural gas sector are energy efficiency programs.

38. The Legislature has recently approved financial incentives for residential and commercial customers to install solar water heating equipment which will reduce GHG emissions when implemented.

39. It is reasonable for the State of California to apply minimum requirements in the areas of energy efficiency or other demand reduction programs to all entities that provide transportation, distribution, and/or retail sales of natural gas to end-users, including IOUs, POUs, and interstate pipelines.

40. The incremental benefits from including the natural gas sector in a multi-sector GHG emissions cap-and-trade system are likely to be less than those from including the electricity sector.

41. Reporting protocols for GHG emission arising from the storage, transportation and distribution of natural gas to end-users are under development and do not yet include provisions for reporting end-user combustion related GHG emissions.

42. Implementing a multi-sector GHG emissions cap-and-trade system that includes small end-users of natural gas now may expose those customers to greater price risk than small end-users in the electricity sector.

43. Including all fuels in a multi-sector cap-and-trade system could maximize the benefits of a market-based system.

44. Taking a programmatic approach to the natural gas sector now does not preclude future inclusion of the natural gas sector in a multi-sector GHG emissions cap-and-trade system.

45. It is reasonable for ARB to not include the natural gas sector when designing a multi-sector GHG emissions cap-and-trade system for California, for implementation in 2012, as described in this decision.

Conclusions of Law

1. AB 2021 requires the Energy Commission, in consultation with POUs and the Public Utilities Commission, to set statewide energy efficiency goals. The statute requires POUs to establish 10-year energy efficiency goals on a triennial basis.

2. SB 1078 as amended by SB 107 requires that IOUs, CCAs, and ESPs obtain at least 20% of delivered electricity from renewable sources by 2010.

3. SB 1078 as amended by SB 107 requires POUs to set RPS targets, but does not specify minimum delivery requirements or the types of renewables that should qualify.

4. SB 1 requires the development of a solar photovoltaic program for California, including both the IOUs and the POUs.

5. SB 1368 directed the Public Utilities Commission and the Energy Commission to develop an emissions performance standard for non-renewable, generally fossil-fueled generation resources, for all retail providers of electricity.

6. The Federal Power Act (FPA) does not address GHG emissions, nor is there any suggestion in the FPA or in its administration that Congress intended to forbid states from enacting GHG regulations on their own.

7. 16 U.S.C. § 824(a) states: "Federal regulation . . . [under the FPA extends] only to those matters which are not subject to regulation by the States." This broad savings clause supports the conclusion that because air pollution is subject to regulation by the States, and not by the FPA or the FERC, state regulation of GHG emissions caused by the generation and consumption of electricity is not preempted by the FPA, but may be regulated by the States.

8. Because the FPA expressly leaves room for state regulations dealing with electricity and because there is nothing in the FPA that deals with the regulation of emissions (either generally, or GHG emissions specifically) the deliverer approach is not preempted by the FPA.

9. A GHG regulation that incorporates a deliverer point of regulation is an environmental regulation whose purpose is to decrease the impact of global warming on California insofar as that impact is caused by electricity used or generated in California. Such a GHG regulation is not a regulation of wholesale rates or other terms and conditions of wholesale power sales or electric transmission that the FPA and FERC exclusively regulate.

10. There is no field preemption here because, in enacting the FPA, Congress did not intend, either explicitly or implicitly, to occupy the field of environmental regulation of the power sector.

11. There is no FPA field preemption here because, under AB 32, California will not be regulating the same subject matter as the FPA, nor will its regulations be for the same intended purpose. California will be regulating GHG emissions for the purpose of reducing them and lessening the impacts of global warming on California.

12. While GHG regulation may have some impact on the wholesale prices paid for electricity, such regulation is no more preempted by the FPA than state regulations limiting the amount of other pollutants that may be emitted by electric power plants -- that may affect the cost of generating electricity and therefore indirectly affect the price of wholesale electricity.

13. The inclusion, in FERC-jurisdictional rates, of any costs of compliance with California's GHG regulations would be subject to FERC review under § 205 of the FPA (16 U.S.C. § 824d). All wholesale sales subject to FERC jurisdiction would occur at the FERC-authorized rate.

14. The proposed structure for regulating GHG emissions would not prevent anyone from selling wholesale electricity into the California market, nor would it require a license to do so.

15. The proposed deliverer point of regulation would not conflict with the FPA's electric reliability provisions.

16. A deliverer point of regulation is not preempted by the FPA.

17. The regulations we are proposing are facially neutral, as between interstate and intrastate commerce, and do not have a discriminatory purpose or effect.

18. Under *Pike v. Bruce Church, Inc.* (1970) 397 U.S. 137, 142, a state enactment "will be upheld unless the burden imposed on [interstate] commerce is clearly excessive in relation to the putative local benefits."

19. The use of a deliverer point of regulation would not violate the dormant Commerce Clause.

20. The deliverer point of regulation would only regulate electricity that is generated in, or delivered for consumption in, California. Thus, it would not regulate any commerce that occurs totally outside of California, and therefore would not regulate extraterritorially in violation of the Commerce Clause.

21. The fact that the Legislature required reporting by retail providers does not mean that retail providers must be the point of regulation for achieving the required reductions in GHG emissions.

22. Power that is merely wheeled through California is not part of the electricity sector and is not subject to the emissions reduction requirements of AB 32.

INTERIM ORDER

IT IS ORDERED that:

1. We recommend that the California Air Resources Board (ARB) adopt mandatory minimum levels of cost-effective energy efficiency savings for publicly owned utilities (POUs), at levels recommended by the California Energy Commission (Energy Commission).

2. We recommend that ARB adopt mandatory minimum levels of cost-effective energy efficiency for IOUs, CCAs, and ESPs consistent with the programs and goals adopted by the Public Utilities Commission.

3. We recommend that ARB require POUs to deliver at least 20 percent renewable electricity to their customers by 2017.

4. We recommend that ARB work with the Public Utilities Commission and the Energy Commission to seek legislation that requires retail providers of electricity to deliver more than 20 percent of their power from renewable sources in the future, at levels and dates to be determined.

5. We recommend that, if ARB concludes that it does not have authority to adopt regulations consistent with Ordering Paragraphs 1, 2, and 3, ARB seek such authority from the Legislature.

6. We recommend that ARB design a multi-sector cap-and-trade system for greenhouse gas (GHG) emissions in California, to be implemented in 2012, provided that ARB finds that the tests outlined in Parts 4 and 5 of AB 32 are met. This GHG emissions cap-and-trade system should include the electricity sector.

7. We recommend that, for the electricity sector, ARB establish the compliance obligation in the GHG emissions cap-and-trade system on the entities that own electricity as it is delivered to the California electricity grid, as described in this decision.

8. We recommend that some portion of the GHG emission allowances available to the electricity sector be auctioned, with the majority of the proceeds from the auctioning of allowances for the electricity sector being used in ways that benefit electricity consumers in California.

9. We recommend that, for the natural gas sector, ARB rely on programmatic measures to achieve emission reductions and not include the natural gas sector in a multi-sector GHG emissions cap-and-trade system at this time. We recommend consideration of the inclusion of the natural gas sector in a cap-and-trade program at a later date.

This order is effective today.

Dated _____________________________, at San Francisco, California.

ATTACHMENT A
Page 1

PARTIES THAT HAVE FILED COMMENTS IN PHASE 2 OF RULEMAKING 06-04-009

Party	
AES Southland L.L.C.	AES
Alliance for Retail Energy Markets	AREM
American Gas Association	AGA
CalEnergy Operating Corporation	CalEnergy
California Manufacturers and Technology Association	CMTA
California Independent System Operator	CAISO
California Municipal Utilities Association	CMUA
California Solar Energy Industries Association and the Solar Rating Certification Corp.	CALSEIA/SRCC
California Wind Energy Association, Bright Source Energy, Inc., ASURA Inc., and Abengoa Solar Inc.	CalWEA et al.
Caithness Energy, LLC	Caithness
Calpine Corporation	Calpine
Carson Hydrogen Power Project	Carson
Center for Energy Efficiency and Renewable Technologies	CEERT
Center for Resource Solutions	CRS
Clean Energy Fuels Corp.	Clean Energy
Climate Protection Campaign	CPC
Coalition of California Utility Employees	CUE
Community Environmental Council	Environmental Council

ATTACHMENT A
Page 2

Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc.	Constellation
Covanta Energy Corporation	Covanta
Division of Ratepayer Advocates	DRA
Dynegy Morro Bay LLC, Dynegy Moss Landing, And Dynegy South Bay LLC	Dynegy
El Paso Natural Gas Company and Mojave Pipeline Company	El Paso
Energy Producers and Users Coalition and Cogeneration Association of California	EPUC/CAC
Environmental Defense	Environmental Defense
FPL Energy Project Management, Inc	FPL
Green Power Institute	GPI
Independent Energy Producers Association	IEP
Indicated Producers	IP
International Emissions Trading Association	IETA
Kenneth C. Johnson	Johnson
Lodi Gas Storage, LLC	Lodi
Los Angeles Department of Water and Power	LADWP
M-S-R Public Power Agency	M-S-R
Modesto Irrigation District	MID
Morgan Stanley Capital Group Inc.	Morgan Stanley
Natural Resources Defense Council	NRDC
Northern California Power Agency	NCPA
Pacific Gas and Electric Company	PG&E
PacifiCorp	PacifiCorp
Powerex Corp.	Powerex

ATTACHMENT A
Page 3

Redefining Progress	Redefining Progress
Sacramento Municipal Utility District	SMUD
Salt River Project Agricultural Improvement And Power District	Salt River
San Francisco Community Power	SF Community Power
San Diego Gas & Electric Company and Southern California Gas Company	SDG&E/SoCalGas
Sempra Global and Sempra Energy Solutions	Sempra
Sierra Pacific Power Company	Sierra Pacific
Silicon Valley Leadership Group [6/22]	SVLC
Southern California Edison Company	SCE
Southern California Public Power Authority	SCPPA
Southwest Gas Corporation	Southwest Gas
Sustainable Conservation	Sustainable Conservation
Terra-Gen Power, LLC	Terra-Gen
The Redding Electric Utility	Redding
The Utility Reform Network	TURN
Union of Concerned Scientists	UCS
Western Power Trading Forum	WPTF
Western Resource Advocates	WRA
Wild Goose Storage, LLC	Wild Goose

(END OF ATTACHMENT A)