STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
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TO PARTIES OF RECORD IN RULEMAKING 06-04-009

This is the proposed decision of President Michael R. Peevey. It will not appear on the Commission's agenda for at least 30 days after the date it is mailed. The Commission may act then, or it may postpone action until later.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, opening comments shall not exceed 15 pages.

Comments must be filed either electronically pursuant to Resolution ALJ-188 or with the Commission's Docket Office. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJs TerKeurst and Lakritz at cft@cpuc.ca.gov and jol@cpuc.ca.gov and Commissioner Peevey's advisor Nancy Ryan at ner@cpuc.ca.gov. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

ANG:tcg

Attachment

Decision **PROPOSED DECISION OF PRESIDENT PEEVEY** (Mailed 2/8/2008)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies.	Rulemaking 06-04-009 (Filed April 13, 2006)

INTERIM OPINION ON GREENHOUSE GAS REGULATORY STRATEGIES

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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 and a cap-and-trade system for the electricity and natural gas sectors. 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 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.

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

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

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 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 be set at the level of all cost-effective energy efficiency. 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. 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 can produce additional GHG emissions reductions beyond the mandatory programs described above at a lower cost than requiring additional mandatory reductions.
- It would allow for flexibility in achieving emissions targets by 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.
- 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 the cap-and-trade program.

In order to design an effective cap-and-trade program in the electricity sector, we conclude that we 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 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).

These options were evaluated against the following criteria:

- Environmental integrity,
- 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 against these key criteria, we find that the deliverer option best meets the criteria. Each of the other options has serious shortcomings regarding one or more of our priorities. The deliverer system provides for the environmental integrity of the system 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 and minimizes the impact of AB 32 GHG regulations on California's wholesale electricity markets. 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 distribution of GHG emission allowances in a deliverer-based point of regulation system. The method in 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 at least some portion of the emission allowances available to the electricity sector should be auctioned. We make this recommendation in order to 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 at least a portion 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.

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 free 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 free allocations should be made. Based on further analysis, we may recommend, for example, that allowances should be distributed entirely by auctions, or alternatively using a mix of auctions and free allocations which may transition over time to a system of greater reliance on auctions.

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 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 consumer and companies in the electricity sector.

1.2. Natural Gas Sector

For the natural gas sector, 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 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 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 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, it may become appropriate to add the natural gas sector to the multi-sector GHG emissions cap-and-trade system. Taking direct programmatic actions now 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.[2]

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 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

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[2] 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.

applied … to all electricity sector entities that serve end-use customers in California,"[3] 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 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.[4]

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 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.

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

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

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.[5] 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 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

[5] 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.

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 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

3.1. Overview of Approaches Considered

In Phase 2, we have considered a variety of approaches to GHG regulation in the electricity sector. 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.

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."[6]

In particular, we evaluate the possibility of creating a level playing field for all retail providers of electricity in California by extending the same requirements for energy efficiency programs and renewable energy delivery to IOUs, POUs, ESPs, and CCAs.

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

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

California.[7] This model is also currently under consideration in the United States Congress.

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.

Finally, we consider the inclusion of the electricity sector in California in a multi-sector cap-and-trade system for the state.

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, Calpine, IEP, EPUC/CAC, Powerex, Constellation, SMUD, SCPPA, NRDC, Environmental Defense, Morgan Stanley, WPTF, and AREM.[8] 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 DRA and LADWP assert that additional

[7] "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.

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

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), and giving the right price signals (DRA, IEP, and 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).
- 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) 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 stresses, 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 one reason as 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 states 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, 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 states 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 stresses 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, 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 states 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 asserts 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 argues 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: 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 such a policy were implemented, it would most likely be imposed on the economy as a whole 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 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 usually 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 enacted in 2007 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 Energy Commission, in its Integrated Energy Policy Report process, concluded that the goal for the State should be to achieve all cost-effective energy efficiency. However, this target is not binding on the POUs the way the Public Utilities Commission's regulations are on the IOUs. The governing board of a POU may set targets that may be lower than what the Energy Commission has recommended or may choose not to establish targets at all. In addition, no statutory requirements currently exist for Energy Service Providers (ESPs) or Community Choice Aggregators (CCAs) to invest in energy efficiency for their customers.

The RPS statutes (Senate Bill (SB) 1068 enacted in 2001, as amended by SB 107 in 2006) require IOUs, CCAs, ESPs, and POUs to provide a minimum of 20% of delivered energy from renewable sources by 2010. In addition, SB 107 requires POUs to set RPS targets, but does not specify minimum delivery requirements or the types of renewables that should qualify. As with energy efficiency, POUs may set RPS goals that are different than IOU requirements.

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 (CO2) 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 statute. The goals of AB 32 would be best achieved if all retail providers of electricity, including IOUs, POUs, ESPs, and CCAs, are subject to the same minimum requirements in the areas of energy efficiency and renewables. Such equal requirements would create a level playing field among different types of electricity retail providers and not systematically disadvantage some relative to others.

Therefore, we recommend that ARB, as part of its AB 32 regulations, adopt mandatory levels of energy efficiency savings required from POUs, similar to those required of the IOUs by the Public Utilities Commission and at the levels recommended by the Energy Commission. Similarly, we recommend that ARB require the POUs to deliver at least 20% renewable electricity to their customers by a date certain. We recognize that 2010 would not be realistic but ARB should consider 2015 or 2017.

In making this recommendation, 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[9]) from requiring that IOUs obtain more than 20% of their power from renewables. In order to meet the AB 32 goals, not only must the POUs be part of the equation, but also 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 contain a target of 33% energy delivered from renewable sources. 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 an AB 32 cap to govern instead. We firmly believe that our existing energy efficiency, renewables, and emissions performance standard policies are the foundation upon which our other additional 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.

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[9] 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."

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. Indeed, this was the preliminary recommendation of the Public Utilities Commission in D.06-02-032, which was adopted prior to the passage of AB 32. The context of that prior decision, however, was very different from the current situation with AB 32. At that time, the Public Utilities Commission contemplated GHG regulation that 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. However, some parties, including TURN, CAISO, CMUA, DRA, PG&E, and SDG&E, 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. To meet this goal, development of a cap-and-trade program should be undertaken immediately.

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 reliance on additional mandatory reductions. This is because emissions trading maximizes flexibility in achieving emissions targets by allowing obligated entities to rely on the least-cost options across the entire economy.[10] This, in turn, provides strong incentives for investment in research and innovation in technologies that lower GHG emissions. The system also allows market participants to manage risk associated with compliance obligations.[11] Finally, it should efficiently distribute the cost of GHG reductions across all capped entities.

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[10] As detailed in Section 4.4.2, *infra*, the ability of entities to rely on alternative least-cost options does not exist to a meaningful extent in the natural gas sector.

[11] As detailed in Section 4.4.2, *infra*, opportunities for risk management are significantly lessened in the natural gas sector due to the inability of small end-users to mitigate variations in allowance prices.

For all of these reasons, we believe that California should proceed to design a cap-and-trade system. We also agree with several parties, including NRDC, 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 investments in energy efficiency and renewable energy. 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. 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.

We are also 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 is responsible for the electricity when it is delivered onto the electricity 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.

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.

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[12] Market Advisory Committee report, at 42.

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

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[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.

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. 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 Updgrade (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 express similar positions.

<u>Contract Shuffling</u>

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.

Compatibility with AB 32

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, 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 argues 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, 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.

<u>Other requirements in conjunction with generator cap-and-trade</u>

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. WTPF 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, 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

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[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.

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. NRDC/UCS state that marketers and brokers should be treated as first sellers, even though they usually do not take title to the power. 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, 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." WTPF 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.

<u>Incorporation of price of carbon into energy market prices</u>

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 describes 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 submits 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.

<u>Interaction with MRTU and wholesale markets</u>

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 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, NRDC and Calpine suggest 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 submits 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 views 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, 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 and SCE express concern that this option is vulnerable to challenges under the FPA and the Commerce Clause.

3.3.2. Discussion

As stated in Section 3.3.2, we recommend that ARB adopt a cap-and-trade program that includes the electricity sector in California. 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 how each potential point of regulation meets what we believe are the five most important criteria. Those criteria are:

1. **Environmental integrity.** Here we focus on how each option minimizes 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.**
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.

5. **Legal issues.**

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, consider legal issues related to the deliverer approach, and address GHG regulation of multi-jurisdictional utilities.

3.3.2.1. Environmental Integrity

In assessing the viability of the four options for point of regulation, this 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 chief concern here for California's electricity sector is 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. Thus, to be effective, any system we design must address imported power in some way. Since we have already determined that

we are recommending design of a cap-and-trade system for California that includes the electricity sector, we now examine options for cap-and-trade design and how well they address both in-state generation and imported power.

First we discuss the option where in-state generators are 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 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 in different ways. With retail providers as the point of regulation, integrity of the system is addressed by holding retail providers responsible for all of the power they deliver to consumers. In order to make such a system function, 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.

For the deliverer point of regulation, the entity that first delivers the power to the electricity grid in California is held responsible for its emissions. This captures emissions from electricity generated within California and electricity imported into California from out-of-state. For the hybrid in-state

generators/retail providers for imports option, imports are handled by making the retail providers responsible for imports, with emission reduction requirements equivalent to those required for in-state generation.

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.

Finally, in a cap-and-trade system that includes multiple sectors, most other sectors of the economy will be regulated at the source. Thus, it appears that some form of a source-based approach to electricity cap-and-trade is likely to be the most compatible.

Under this criterion, we conclude that the retail provider point of regulation is least likely to be compatible with a national or regional system, or even a multi-sector cap-and-trade system in California. This is because, as discussed above, most existing and proposed cap-and-trade systems are source-based in nature. While theoretically it is possible, as some parties argue, that a retail provider system for California's electricity sector could be compatible with a California multi-sector system or 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). 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 is at the generator level. Therefore, any of these three options offers a better chance of being compatible with a regional or national system, as well as offering a better chance to integrate the electricity sector within a California multi-sector cap-and-trade program.

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 raises serious concerns 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 time it is generated until 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

is also 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 are responsible for 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 is responsible for 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 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.

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

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 what causes the biggest disadvantage to 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 no such impact. 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 perverse incentive that induces clean imports to sell to California on a specified basis under the in-state generator/retail provider hybrid approach would also 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. Further erosion of the vertically integrated portion of the industry and/or decreased reliance on long-term, unit-specific contracts 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 with a deliverer point of regulation would be determined.

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 is responsible for the electricity either (1) on the portion of the physical scheduling

path where it is first delivered to a point of delivery on the transmission grid within California or (2) where the generator's facilities are interconnected to the distribution system in California. Recognizing that electricity is an instantaneous commodity, we deem that the party with responsibility for power at the point where it is delivered to the California grid to be the owner, or "deliverer," of the electricity at that point for purposes of establishing GHG responsibility. This is also the entity that will be required to surrender allowances associated with its GHG emissions.

Thus, deliverers would include generators, retail providers, marketers, and any other types of entities that deliver power to the California grid. Compliance obligations under the deliverer approach would apply for all power with GHG emissions that is delivered to the California grid, except for power that is wheeled through California.[17] In addition to power from conventional fossil-fueled power plants, the compliance obligation would apply to power delivered to the California grid from combined heat and power (CHP) or distributed generation facilities, and to non-zero emission power delivered to the grid from renewable resources. We recognize that ARB's reporting thresholds are such that this compliance obligation would not apply to certain small facilities.

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[17] As we determined 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. AB 32 would not regulate emissions associated with power wheeled through California. We did, however, recommend 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.)

Consistent with this determination, for in-state California generation the owner of the power at the point of delivery to the California grid usually would be the owner or operator of the generating unit, or an entity that has a tolling arrangement with the generator. For imports that have E-tags, the owner at the point of delivery to the California grid would be the entity that is listed as the Purchasing/Selling Entity at the first point of delivery in California.

There are three possible exceptions to this deliverer formulation. First, there are California balancing authorities (specifically, LADWP and possibly Turlock Irrigation District) that control transmission to sources located outside of the State that are considered part of their 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 first deliveries to "a point of delivering within a California balancing authority" rather than deliveries to "a point of delivery within California." If that approach were taken, deliveries to the interconnections at those plants from the surrounding balancing authority 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.

The second exception occurs for multi-jurisdictional utilities that serve retail customers in a service territory that overlaps the state border, specifically, PacifiCorp and Sierra Pacific. As we explain in Section 3.3.2.8 below, the structure of these multi-jurisdictional utilities does not lend itself to the deliverer form of GHG regulation. In Section 3.3.2.8, we find, instead, that multi-

jurisdictional utilities should be regulated using a retail provider-based approach.

The third possible exception relates to power whose deliverer, as generically defined above, is a federal entity not subject to California regulation. In that situation, we propose that the deliverer be the first non-federal entity thereafter responsible for the electricity on the physical scheduling path.

The treatment of renewable generation under a deliverer approach must also be considered. The emission profile of most renewable generation will be considered to be zero for most technologies. Therefore, entities that deliver power produced from such sources to the California grid would not be required to obtain and retire emission allowances. However, renewable generation that has GHG emissions would be treated like any other generation, in that the deliverer would have a GHG emissions compliance obligation. The treatment of renewable generation could become more complicated, however, depending on future developments regarding tradable RECs.

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. If the definition of RECs to be developed in that proceeding were to specify that GHG emission attributes are embedded in RECs, and if a renewable generator were to sell unbundled RECs to an entity that uses the RECs for GHG emission compliance purposes, it may be appropriate to hold the deliverer of the resulting null power to the California grid responsible for surrendering allowances associated with the null power.[18]

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[18] Currently, contracts for bundled RPS-eligible power purchases (where both the generation and its renewable attributes are sold to one purchaser in one transaction)

Footnote continued on next page

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 in other markets, including compliance with renewable generation requirements, compliance with GHG emissions requirements, or compatibility with voluntary markets. Thus, on a broader basis, it may be appropriate to hold any deliverer of power generated from renewable sources to the California grid responsible for emission allowance requirements if a REC associated with that power has been defined to include GHG emission attributes and the REC, separately from the power, has been sold into a market to be used for GHG emission compliance purposes. If such developments occur, ARB may need to address the treatment of null power in its reporting and compliance regulations.

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

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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.)

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[19] 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.

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[19] 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.[20]

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

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[20] 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.

exclusively regulate, nor a requirement to obtain a license to engage in those activities.[21] 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[22] (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

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21 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.

22 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.

electric generation, wholesale sales of electricity, or the consumption of electricity.[23] 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), and because the FPA expressly leaves room for state regulations dealing with electricity, the deliverer approach is not preempted by the FPA. 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.

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 allowances are surrendered after the end of the compliance period (or

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[23] 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.

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.[24] 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 offsets or other flexible compliance mechanisms. In short, the GHG regulatory program we are proposing would not prevent even high-GHG

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[24] 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.)

sources from providing reliability services when needed. Thus, there will be no conflict with the FPA's electric reliability provisions.

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 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 the Legislature in March 2006).[25] 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.

Finally, we conclude that using a deliverer point of regulation for the electricity sector does not regulate extraterritorially in violation of the Commerce

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

Clause. A state statute or regulation may be struck down as impermissibly extraterritorial if it regulates commerce that occurs wholly outside the state. The 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.

Other Legal Issues

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:
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> . . .
>
> (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) 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.[26]

3.3.2.8. Treatment of Multi-Jurisdictional Utilities

California's multi-jurisdictional utilities should be treated differently from the other deliverers in the system. Since the balancing authorities of these retail providers encompass both California and non-California portions of their service territory, the imports into California occur within the balancing authority and no E-tags are generated. 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 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 applicable.[27]

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

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[26] 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 3.3.2.6, our recommended deliverer point of regulation would not cover power that is merely wheeled through California.

[27] We note that, while not a regulated utility in California, the Western Area Power Administration, Lower Colorado Region, is a balancing authority in California with service characteristics comparable to PacifiCorp-West and Sierra Pacific.

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 this approach, 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 load-based approach.

Regulating the emissions associated with the multi-jurisdictional utilities' deliveries of electricity to the California grid on a retail provider basis, with GHG emissions attributed based on a proportional share of their electricity sales in California, appears to be the only reasonable approach. Therefore, this is the approach that we recommend to ARB for the multi-jurisdictional utilities.

3.3.2.9. 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. The only exception to this recommendation is that we recommend that the GHG emissions associated with the multi-jurisdictional utilities' deliveries of

electricity to the California grid be regulated on a retail provider basis, as we have explained.

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.

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 free 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 free 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, NRDC).

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 recommends 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 states that auction proceeds should be returned to the ratepayers that bore the costs of obtaining the credits. 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. Free Distribution Options

The alternative to selling allowances through auction is administrative allocation, either to deliverers or potentially to other entities such as retail providers. Some parties believe that deliverer-based systems should rely

exclusively on auctions and, therefore, limit their recommendations regarding free distributions to their use in retail provider-based systems.

EPUC/CAC support administrative distribution and strongly oppose full auction. Caithness and Dynegy favor free 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 free 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 free allocations of emission allowances.

Regardless of the initial emission allowance distribution methodology, we expect that there would be active trading of emission allowances. Even with

initial free 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 want to participate in the market.

As Morgan Stanley points out, auctioning rather than initial free allocation of allowances would promote allowance market liquidity. The increased trading opportunities would assist in finding least-cost emission reduction investments and would improve incentives for investing in energy efficiency and low-GHG technologies and fuels. Because of the increased pursuit of lower-cost emission reductions, auctioning would promote the accurate reflection in allowance prices of the true cost of marginal emission reduction measures. These benefits due to increased liquidity would tend to reduce allowance prices and the cost of GHG emission reductions.

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 free allocations.

Impacts on entities with compliance obligations and on customers would depend on the use that is made of auction proceeds. A major difference between auctioning and free distribution of allowances is that 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 allocations could result in windfall profits to

deliverers. For these reasons, and in light of the potential benefits of increased market liquidity on allowance prices, we conclude that auctioning of at least a portion of the allowances is superior to free allocations in terms of reducing costs to consumers of achieving GHG emission reductions.

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 all needed allowances. However, risks associated with price volatility can be tempered to a significant extent through the use of flexible compliance alternatives, which we will consider in more detail later in this proceeding.

One issue of particular concern is how new entities with compliance obligations would obtain allowances. A beneficial aspect of auctions is that new entrants would have the same access to allowances as other market participants, with no need for administrators to anticipate new entrants' need for free 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 these benefits, we conclude that at least some portion of the allowances available to the electricity sector should be auctioned. As an integral part of this recommendation, we conclude that at least some of the proceeds from the auction of allowances for the electricity sector should be used 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. We will examine 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. 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 whether a portion of allowances should be allocated administratively in a deliverer-based system and, if so, what the initial mix should be and whether to transition over time to greater reliance on auctions. Several parties recommend that there be a gradual transition over several years from relatively more free allocations initially to relatively greater reliance on allowance distribution via auctions. Distributing some amount of allocations for free 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. However, other parties raise concerns with any free allowance allocations to deliverers, including the potential for windfall profits, the potential for revenue shifts among deliverers based on non-GHG factors, and uncertainty 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 freely distributed, the manner of the free allocation must be determined. Options recommended by parties for determining allowance allocations range from use of historical emissions to output-based metrics. In addition, some parties recommend direct distribution of allowances to retail providers, which would then be required to sell the allowances at auction. Many of 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 free 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 at least 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. 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: reliance on direct emission reduction measures to achieve AB 32 goals 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. 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 eight 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, distributed generation, and natural gas used in industrial processes that is not combusted. 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, 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 and 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 Leiberman-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 and 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, 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 reports 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 also asserts 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 and 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, 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 believes 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, SCE, and PG&E, support regulating natural gas vehicles as part of the transportation sector, rather than the natural gas sector. SDG&E believes 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 and 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 supports designating CHP facilities as point sources, arguing that this approach would make attributing GHG emissions between industrial and electric generation unnecessary.

NRDC and 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 and 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 sector. 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 and 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 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 believes 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. This conclusion applies equally to natural gas used by power plants, CHP, and distributed generation to the extent their electricity is delivered to the California grid.

For gas-fired CHP plants that utilize electricity and useful thermal heat on site, the portion of the natural gas used in these processes should be considered part of the natural gas sector. Likewise, 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.

Parties make a compelling case for excluding emissions from natural gas vehicles from the natural gas sector, by instead including them in the transportation sector. We agree that those emissions are more appropriately treated as transportation sector emissions.

Finally, some natural gas is used for non-combustion purposes. 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 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 CHP and distributed generation facilities for the portion of electricity and, for CHP, thermal ouput 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, DRA, 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.

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, SDG&E and 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 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.

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.

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 among. SCE, SMUD, and IP argue that a broad-based, multi-sector cap-and-trade system will 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 and UCS point out that excluding a single sector form an economy wide cap-and-trade sytsem 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.

<u>Amount of Reductions Due to Cap-and-Trade</u>

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 and 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 and 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 and 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. 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.

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.

AB 2021 requirements 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. However, as with the electricity POUs, this target is not binding on the natural gas POUs. Recognizing that only a few POUs deliver natural gas, we still view the lack of a requirement that natural gas POUs meet energy efficiency targets as problematic.

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 the same minimum requirements in the areas of energy efficiency. Such equal requirements would create a level playing field among different types of natural gas entities and not systematically

disadvantage some relative to others. Therefore, our recommendation that ARB adopt mandatory levels of energy efficiency savings required from POUs applies to both natural gas and electricity 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.

For reasons similar to those applicable to the electricity sector, we see little advantage of implementing a cap system in the natural gas sector, compared to reliance on the direct programmatic approaches described above. 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, and Southwest Gas, prefer that California rely only on programmatic measures to achieve GHG reductions in the natural gas sector. Other parties, including NRDC, 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 programs are the only reliable near-term options available for reducing GHG emissions in the natural gas sector.

Second, because energy efficiency 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 would reduction 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'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, it may become appropriate to add the natural gas sector to the multi-sector GHG emissions cap-and-trade system.

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

El Paso/Mojave, IP, Lodi, SDG&E, 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 __________, and reply comments were filed on ___________ by ___________.

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 set statewide energy efficiency goals at the level of cost-effective investment in energy efficiency.

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 if they exceed the adopted energy savings goals and assesses penalties if they fail to meet the goals.

5. It is reasonable for the State of California to apply the same minimum requirements in the areas of 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, 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, 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 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.

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. 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.

16. 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.

17. 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 offsets or other flexible compliance mechanisms.

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

19. 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) based on the amount of GHG emissions associated with that electricity.

20. "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).)

21. "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).)

22. 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.

23. 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.

24. 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.

25. It is reasonable to regulate the GHG emissions associated with the multi-jurisdictional utilities' deliveries of electricity to the California grid on a retail provider basis, with GHG emissions attributed based on a proportional share of their electricity sales in California.

26. The auctioning of at least some portion of the emission allowances available to the electricity sector would promote liquidity in the emission allowance market, 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.

27. It is reasonable to require that at least 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, all proceeds from the auctioning of allowances for the electricity sector would be used in ways that benefit electricity consumers in California.

28. 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.

29. 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 free distributions are undertaken.

30. 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.

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

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

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

34. The only reliable near-term options for reducing GHG emissions in the natural gas sector are energy efficiency programs.

35. 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.

36. 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.

37. 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.

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

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

40. 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. However, the statute does not require that POUs comply with the energy efficiency goals set by the Energy Commission.

2. SB 1068 as amended by SB 107 requires that IOUs, CCAs, ESPs, and POUs obtain at least 20% of delivered electricity from renewable sources by 2010.

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

4. The 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.

5. 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.

6. 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.

7. 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.

8. 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.

9. 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.

10. 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.

11. 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.

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

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

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

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

16. 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."

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

18. 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.

19. 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.

20. Our recommended deliverer point of regulation would not cover power that is merely wheeled through California.

INTERIM ORDER

IT IS ORDERED that:

1. We recommend that the California Air Resources Board (ARB) adopt mandatory levels of energy efficiency savings for publicly owned utilities (POUs), the same as those required of investor owned utilities (IOUs) by the California Public Utilities Commission (Public Utilities Commission), and consistent with energy savings requirements as recommended by the California Energy Commission (Energy Commission).

2. We recommend that ARB require POUs to deliver at least 20 percent renewable electricity to their customers by a date certain, perhaps 2015 or 2017.

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

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

5. We recommend that ARB design a multi-sector cap-and-trade system for greenhouse gas (GHG) emissions in California, to be implemented in 2012. This GHG emissions cap-and-trade system should include the electricity sector.

6. We recommend that, for the electricity sector, ARB establish the compliance obligation in the GHG emissions cap-and-trade system on the entities that deliver power to the California electricity grid, as described in this decision.

7. We recommend that ARB regulate the emissions associated with multi-jurisdictional utilities' deliveries of electricity to the California grid on a retail provider basis, with GHG emissions attributed based on the proportional share of their electricity sales that are made in California.

8. We recommend that at least some portion of the GHG emission allowances available to the electricity sector be auctioned, with at least some portion 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. It may be appropriate to include 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
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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
CalEnergy Operating Corporation	CalEnergy
California Manufacturers and Technology Association	CMTA
California Independent System Operator	CAISO
California Municipal Utilities Association	CMUA
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
Climate Protection Campaign	CPC
Community Environmental Council	Environmental Council
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	

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Cogeneration Association of California	EPUC/CAC
Environmental Defense	Environmental Defense
FPL Energy Project Management, Inc	FPL
Green Power Institute	GPI
Independent Energy Producers Association	IEPA
Indicated Producers	Indicated Producers
International Emissions Trading Association	IETA
Kenneth C. Johnson	Johnson
Lodi Gas Storage, LLC	Lodi
Los Angeles Department of Water and Power	LADWP
Modesto Irrigation District	Modesto ID
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
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

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Southern California Edison Company	SCE
Southern California Public Power Authority	SCPPA
Southwest Gas Corporation	Southwest Gas
Sustainable Conservation	Sustainable Conservation
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)

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed document is current as of today's date.

Dated February 8, 2008, at San Francisco, California.

/s/ TERESITA C. GALLARDO
Teresita C. Gallardo