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)
AB 32 Implementation	CEC Docket 07-OIIP-01

COMMENTS OF THE ENERGY PRODUCERS AND USERS COALITION AND THE COGENERATION ASSOCIATION OF CALIFORNIA ON THE PROPOSED FINAL OPINION

Michael Alcantar
Nora Sheriff
Alcantar & Kahl LLP
1300 SW Fifth Avenue
Suite 1750
Portland, OR 97201
503.402.9900 office
503.402.8882 fax
mpa@a-klaw.com
nes@a-klaw.com

Counsel to the
Cogeneration Association of California

Evelyn Kahl
Seema Srinivisan
Alcantar & Kahl LLP
120 Montgomery Street
Suite 2200
San Francisco, CA 94104
415.421.4143 office
415.989.1263 fax
ek@a-klaw.com
sls@a-klaw.com

Counsel to the
Energy Producers and Users Coalition

October 2, 2008

TABLE OF CONTENTS

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)
AB 32 Implementation	CEC Docket 07-OIIP-01

COMMENTS OF THE ENERGY PRODUCERS AND USERS COALITION AND THE COGENERATION ASSOCIATION OF CALIFORNIA ON THE PROPOSED FINAL OPINION

The Energy Producers and Users Coalition (EPUC)[1] and the Cogeneration Association of California (CAC)[2] submit the following comments on the Proposed Final Opinion in this proceeding pursuant to Article 14 of the Commission's Rules of Practice and Procedure

I. INTRODUCTION AND OVERVIEW

The Proposed Final Opinion (PFO) addresses issues of critical importance to California's electricity industry and its energy consuming economy. The recommendations that the CPUC and CEC (Commissions) will provide to the California

[1] EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP West Coast Products LLC (including Atlantic Richfield Company), Chevron U.S.A. Inc., Shell Oil Products US, Exxon Mobil Corporation, THUMS Long Beach Company, Occidental Elk Hills, Inc., and Valero Refining Company - California.

[2] CAC represents the combined heat and power and cogeneration operation interests of the following entities: Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Kern River Cogeneration Company, Sycamore Cogeneration Company, Sargent Canyon Cogeneration Company, Salinas River Cogeneration Company, Midway Sunset Cogeneration Company and Watson Cogeneration Company.

Air Resources Board (CARB), if adopted, will affect the prices paid by electricity consumers, the availability and reliability of California's electricity supply, the types of generating resources developed to serve California load, the price of manufactured goods and services and the competitiveness of California industry. The Commissions have thus taken their responsibility very seriously, weighing a variety of alternatives in reaching the proposals in the PFO.

Despite these clear efforts, the PFO's recommendations undervalue the risks the proposed greenhouse gas (GHG) program brings to the industry and economy. In particular, while setting the stage to move toward a more informed combined heat and power (CHP) policy, the recommendations create a high degree of risk and uncertainty for these operations.

The PFO offers a clear recognition of both the benefits of CHP and the barriers to continued CHP operation and development. Its recommendations go one step further, boldly committing to review and enhance California's CHP policy to capture the benefit of CHP as a GHG reduction measure. The PFO also recognizes that load served by CHP resources should be treated equitably with grid-served load under the program.

While the PFO begins to contemplate a more informed policy, its recommendations do not go far enough. If the PFO is adopted without change, the Commissions will not only miss an opportunity to promote CHP but will also risk the continued operation of existing CHP. The PFO falls short of its potential in several areas. The proposal:

- ♦ Splits the emissions of a single CHP facility into two separate sectors with potentially different GHG treatment, overlooking the integrated nature of these operations and heightening regulatory uncertainty for these important resources.
- ♦ Rejects the "double benchmark" approach to allowance allocation, not only declining an opportunity for CHP incentives but overlooking the need to offset the potential for disincentives that arise when emissions from

electricity consumed on-site are moved from the utility side to the customer side of the ledger.

- ♦ Fails to address GHG cost recovery for CHP facilities participating in the CPUC's Qualifying Facilities (QF) program, overlooks the record, and leaves unnecessary uncertainty for existing QF operations and future development.

- ♦ Recommends one treatment for CHP facilities that export electricity and another treatment for CHP that serves only on-site load, a dichotomy that lacks a reasonable basis and could result in differential treatment of similarly situated competitors within an industry and also suboptimal sizing of CHP facilities.

Further attention to these issues in developing a final decision is warranted.

Beyond these critical CHP issues, the PFO requires additional refinements to ensure the efficient and reliable performance of the proposed GHG program. EPUC/CAC offered recommendations to address most of these over the past year in their comments to the Commissions and continue to support those recommendations.[3] Rather than repeat all prior arguments, however, these comments refer the Commissions to prior comments and offer a set of limited refinements to address the most immediate concerns. These comments request that the Commissions:

1. Recommend to CARB that CHP facilities be treated as a single source of emissions to avoid arbitrary allocation of emissions between sectors and differential treatment of the emissions from a single "stack". In the absence of creating a CHP sector, the Commissions should include recommendations regarding treatment of thermal emissions.

2. Propose a "double benchmark" allowance allocation method for CHP. At a minimum, the Commissions should recommend to CARB that an adjustment to the CHP emissions allowance be made to avoid disincentives caused by the increased direct emissions responsibility resulting from CHP installation.

3. Adopt a clear policy removing GHG cost recovery uncertainty for CHP plants participating in the CPUC's QF program.

---

[3] *See Comments of the Energy Producers and Users Coalition and the Cogeneration Association of California on Allowance Allocation, Combined Heat and Power, Modeling and Flexible Compliance, June 2, 2008* (EPUC/CAC June 2008 Comments); *Reply Comments of the Energy Producers and Users Coalition and the Cogeneration Association of California on Combined Heat and Power, Allowance Allocation, and Modeling*, June 16, 2008.

4. Propose comparable treatment of *all* CHP generation above CARB's emissions threshold, whether it provides both grid and on-site deliveries or only on-site deliveries.
5. Clarify that *all* load served directly by CHP will be treated comparably and equitably under the allowance allocation provided to entities serving grid load.
6. Ensure equitable allocation of allowances to bottoming cycle facilities engaged in supplemental firing.
7. Recommend a limited new entrant reserve for the first four program years for high efficiency CHP plants to encourage early investment.
8. Clarify that CHP must not be treated as a mandatory GHG reduction measure for industrial sites given the sizable investment and industrial process implications attendant to CHP applications.
9. Recommend that CARB examine risk to electricity supply and reliability prior to implementing an allowance auction if use of an auction is proposed.
10. Adopt an unspecified resource default value that will encourage source-specific contracting.
11. Provide additional detail regarding the transition of retail provider allowance allocation from historic emissions to a sales basis.
12. Consider economic impact on natural gas-fired generation in designing fuel allocation factor.
13. Be cautious in designing a mandate requiring retail providers to procure 33% energy from renewables.

Each of these issues is discussed below.

II. THE COMMISSIONS SHOULD SEIZE THE OPPORTUNITY TO ADVANCE CALIFORNIA'S CHP POLICY.

Throughout this proceeding, EPUC/CAC advanced a framework that would strengthen California's CHP policy consistent with goals set by the CPUC, CEC and CARB. The framework was based on four foundational measures. First, CHP should be placed in a single sector or, at a minimum, CHP emissions should be treated on a combined basis.[4] Segmenting emissions between the electricity and industrial sectors adds unneeded complexity, imposes additional regulatory burdens, and risks overlooking the benefits of CHP. Second, CHP should receive an administrative allowance allocation using a "*double benchmark*" approach.[5] This approach would eliminate any disincentive to CHP resulting when off-site electricity emissions are moved on-site and could provide active incentives to CHP development. Third, promoting CHP requires providing certainty that CHP participating in the CPUC's QF program will recover GHG costs in the power price received.[6] Fourth, a new entrant reserve with priority access for CHP projects should be created to avoid delays in CHP development.[7] EPUC/CAC continue to support this framework as the best approach to advancing CHP policy. If the Commissions are unwilling to adopt this entire framework, as the PFO suggests, certain limited changes to or clarifications of the PFO's proposed solution are required. These refinements identified in Section I are discussed further below.

A. In the Absence of Creating a CHP Sector With a Double Benchmark Allocation, the Commissions Must Make Clear Recommendations Regarding Treatment CHP Thermal Emissions.

EPUC/CAC requested that the Commissions address CHP emissions in a single sector with a "*double benchmark*" allowance allocation. This approach recognizes that CHP emissions come from a single "*stack*" and that any allocation of the emissions between thermal and electrical output is necessarily arbitrary. The PFO, instead, limits its recommendations to the treatment of CHP electricity emissions.[8] It leaves the regulations relating to a CHP's thermal emissions to CARB with no recommendation regarding the allocation of emissions between industrial and electricity sectors. The

[4] EPUC/CAC June 2008 Comments, at 50.
[5] EPUC/CAC June 2008 Comments, at 51-54.
[6] EPUC/CAC June 2008 Comments, at 58-60.
[7] EPUC/CAC June 2008 Comments, at 35.
[8] PFO, at 239-40.

PFO thus misses the opportunity to provide greater certainty to CHP and, further, presents the potential for disincentives if emissions from a single CHP plant receive two different treatments.

A double-benchmark allocation methodology, which the PFO rejects, would have allocated emissions to CHP facilities taking account of both of its outputs. While the PFO's allocation of allowances to CHP for electricity emissions in some ways mimics one part of the double benchmark, the failure to address treatment of CHP thermal emissions leaves a great deal of regulatory uncertainty. As the PFO correctly notes: "[w]*hether inclusion of CHP in a cap-and-trade system would produce a disincentive is in large part a function of the allowance allocation method*."[9]

It should, therefore, come as no surprise that where CHP electric and thermal emissions are considered independently, CHP disincentives can arise. The PFO proposes to allocate allowances to CHP for electric emissions using an output based approach. If industrial allowances for thermal output are allocated in a different manner, a distortion could result. For example, if industrial allowances are allocated based on historic emissions, and the CHP emissions are split between sectors in a way that minimizes emissions attributed to the industrial sector, a CHP plant could receive a lower allocation than it otherwise might receive under other methods.

To avoid the complexity, arbitrary nature, controversy and distortion that could arise from the proposed treatment, the Commissions should reconsider a recommendation to CARB to treat CHP emissions together as a single source using a double benchmark method. At a minimum, if separate treatment is mandated, the Commissions should recommend that (a) CARB allocate allowances for thermal output using an output-based allocation (OBA) method no less favorable than the method provided for electricity output under the Commissions' recommendations; or (b) to avoid

[9] PFO, at 236.

potential disadvantages created from differential sector treatment, CARB should permit a CHP operator to choose its desired method of emissions allocation between sectors depending upon the nature of its operations. Giving this flexibility to a CHP operator will ensure that any distortions resulting from splitting emissions are minimized.

B. The Commissions Must Address GHG Cost Recovery for CHP Under the CPUC's QF Program to Maintain Existing and Encourage New CHP Projects.

The PFO overlooks concerns raised by stakeholders that generators may not be able to recover their carbon costs in their contract or market prices.[10] As EPUC/CAC explained: "*A GHG program design that places a material risk of carbon cost recovery on generators in the program's infancy thus could threaten the availability of electricity supply to California consumers*."[11] Resolution of this question in the Commissions' final decision is a critical step in bringing the regulatory certainty required to support new investment.

The regulatory uncertainty stemming from GHG cost recovery is limited to a subset of generation, including certain fossil-fired merchant and all QF generation. Utility-owned generation faces no uncertainty because the costs the utility incurs will be passed on to its ratepayers through cost-of-service ratemaking. Renewable resources face no risk since they will have no compliance obligation or carbon costs. Even recently contracted gas-fired merchant supply – SCE's Walnut Creek facility – provides

---

[10] *See EPUC/CAC June 2008 Comments at 7-11. See also Comments of Calpine Corporation on Emission Allowance Allocation Policies and Other Issues*, June 2, 2008 (Calpine June 2008 Comments), at 9; *Comments of the Independent Energy Producers Association on Emission Allowance Allocation, Flexible Compliance, and Combined Heat and Power*, June 2, 2008, at 4; *Comments of Southern California Edison Company on Administrative Law Judges' Ruling Updating Proceeding and Requesting Comments on Emission Allowance Policies and Other Issues*, June 2, 2008, at 3, 5; *Dynegy Comments on Emission Reduction Measures, Modeling Results, and Other Issues; Incorporating Materials Into the Record, and Recommending Outline for Comments*, June 2, 2008 (Dynegy June 2008 Comments), at 4

[11] *Id*., at 7.

for a pass-through of GHG costs.[12] Consequently, the failure to address this issue most significantly affects QF CHP resources.

The Commissions could materially advance the viability of CHP as a GHG reduction measure and its QF program by expeditious resolution of the carbon cost recovery question in the final decision. Without repeating the arguments in full, carbon cost risk is material in the economics of power production; at very conceivable carbon prices, a CHP project can quickly fall into negative returns without carbon cost recovery.[13] For existing plants, negative returns mean suspended operations. A potential for negative returns and the surrounding uncertainty also means that new CHP projects do not get built and existing projects may not have the means to continue operations.

The CPUC's 2007 decision outlining its QF program does not address this question.[14] This problem may be due, in large part, to timing. The initial prehearing conference in the case was held in November 2004. Parties served testimony in August 2005, and hearings took place in January and February of 2006.[15] As a result, the issue, while being discussed under Staff supervision in the related implementation proceeding, has never been addressed by the full Commission or even an Assigned Commissioner. Resolution is long overdue, and the final decision presents an opportunity to bridge this gap.

The Commissions should make two determinations in the final decision to resolve the regulatory uncertainty. The determinations should address each of the two pricing mechanisms adopted in Decision 07-09-040.

[12] *See* SCE's Walnut Creek application A.08-04-011, Vol. 4, at 46.

[13] Illustrative financial examples were provided by EPUC/CAC in their June 2008 comments at pages 8 through 10.

[14] D.07-09-040, issued September 20, 2007, makes no reference to GHG or carbon costs.

[15] D.07-09-040, at 11-12.

First, the Commissions should make clear that as long as QFs are paid at administrative prices mandated in the CPUC's 2007 decision, the QF may pass through to the utility its actual, demonstrated GHG compliance costs. The current formulation of this administrative price does not include carbon costs; it includes a capacity price, an operations and maintenance adder and an energy price calculated by multiplying a heat rate by the price of natural gas.[16] Consequently, if this formula remains in place in 2012, QFs will receive no compensation for carbon costs, immediately undermining the viability of existing projects. The Commissions thus should find that a QF may pass through any actual demonstrated GHG compliance costs while this administrative price is in place.

Second, the Commissions should address the treatment of carbon costs in the shift from an administratively determined QF price to a more market-based price. The 2007 decision provides that: *"[o]nce MRTU is fully operational, the Commission should adjust the Market Index Formula to take advantage of the energy market information revealed by the existence of MRTU day ahead market prices*."[17] More specifically, the CPUC found that *"[w]hen both the CAISO's day-ahead market is fully functioning for purposes of deriving SRAC prices we will adjust the MIF accordingly*."[18] In order to assure that QFs are adequately compensated for their actual carbon costs if and when this shift occurs, additional steps are required to assure that the market fairly reflects a carbon cost component.

In its reference to a paper by Resources for the Future, the PFO appears to recognize the possibility that the market will not fully reflect carbon costs during the transition period.[19] Likewise, NERA has pointed out in a 2007 report, the extent to which a firm can pass costs on in prices depends on:

> *regulatory conditions, exposure to international competition, the degree of imperfections in competition, as well as a range of other complex market*

[16] *See generally* D.07-09-040 and pages 1-2 (summary of pricing).
[17] D.07-09-040, at 149, Conclusion of Law ¶ 6.
[18] D.07-09-040, at 68.
[19] PFO, at 216.

> *interactions that can vary significantly between industries, products and markets. Where there is not perfect competition, or where imports compete, pass-through is unlikely to correspond to full costs.*[20]

Finally, as EPUC/CAC explained in their June 2008 comments, the MRTU outcome with respect to carbon prices is far from clear.[21] Simply assuming that "the market will provide" gives little comfort to those with existing or planned CHP projects. While a four-year transition may seem limited from a policy perspective, it is very material from the view of businesses forced to address these issues on a daily basis.

How should the Commissions address the market risk of carbon costs in the context of QF pricing? A fairly simple measure will begin to bring certainty to the CHP arena. Optimally, the CPUC would defer the move to market prices until after both the MRTU had been implemented and the inclusion of carbon costs in that market had been validated. Since that issue is not within the scope of this proceeding, however, a second-best alternative should be considered. The Commissions should provide that beginning on January 1, 2012, they will track the extent to which MRTU prices reflect carbon costs incurred by generators.[22] It should further find that, to the extent it cannot be demonstrated that the MRTU prices do in fact adequately reflect those costs, unrecovered carbon costs may be passed through to the utility by QFs under their contracts. This will place these resources on par with utility resources and other merchant plants, such as Walnut Creek.

The regulatory uncertainty surrounding the QF program is significant – the QF Policy Case case (R.04-04-003/R.04-04-025) has been proceeding for five years and

---

[20] Harison, Klevnas, Radov, and Foss, September 2007, *Complexities of Allocation Choices in a Greenhouse Gas Emissions Trading Program*, NERA Economic Consulting, prepared at the request of the International Emissions Trading Association, at 36.

[21] EPUC/CAC June 2008 Comments, at 13-18.

[22] While the Commissions need not determine a precise measure at this point, alternatives exist. For example, if carbon costs are included in the market, the market price will reflect, *at a minimum*, the market marginal heat rate, as determined by the CAISO, is multiplied by the cost of gas, plus O&M costs plus the current GHG cost.

seems far from closure today in light of a recent writ challenging D.07-09-040.[23] The Commissions can, however, take a positive step to secure this program with a reasonable finding on GHG cost recovery by QFs.

C. All CHP Above CARB's $MMTCO_2e$ Threshold and the Load It Serves Should Be Treated Similarly.

The PFO distinguishes between those CHP facilities that export power and those that solely serve on-site load.[24] The PFO's recommendations would apply to CHP that exports some or all of its electrical output, but CHP serving only on-site load is relegated to the treatment ultimately provided by CARB for Distributed Generation. The Commissions should modify the PFO to provide for comparable treatment of these resources provided they meet the minimum size threshold.

First, a point of clarification is necessary. The PFO speaks in terms of exports and "on-site" use. Clarification is required to make clear that when the term "on-site" is used, it refers to any use by private wires as specified in Public Utilities Code §218(b). On-site load for the PFO's purposes also includes what are commonly referred to as "*over the fence*" transactions, where CHP delivers power using private distribution wires to a nearby load (§218(b)(2)).

Second, there is no jurisdictional rationale that requires the Commissions to limit recommendations concerning CHP serving only on-site load. While neither the CEC nor the CPUC have jurisdiction over purely on-site power deliveries, neither do these agencies have jurisdiction over publicly owned utilities. Yet because CARB holds the ultimate AB 32 authority and will implement the Commissions' proposed regulations, the Commissions may make proposals to CARB beyond their typical jurisdictional

---

23 *See* So. Calif. Edison Company and The Utility Reform Network v. Public Utilities Commission (B210398).

24 PFO, at 236-237.

boundaries. Consequently, avoiding recommendations to CARB to address purely on-site deliveries has no jurisdictional basis.

Third, differential treatment of CHP facilities could affect competition. On one hand, a refinery may have in the past “thermally matched” its CHP plant to its operations, generating 100% of the thermal energy using CHP and exporting excess power to the grid. Another competing refinery, due to regulatory conditions at the time of its project development, may have only “electrically matched”, generating only a portion of its thermal requirements using CHP and limiting electrical production to on-site use. There is no reasonable basis for treating these facilities differently. Doing so would have competitive impacts.

Fourth, the potential harm of differential treatment is heightened by the PFO’s proposal to allocate the value of some portion of available allowances to retail providers. The PFO proposes that the value of specified allowances be allocated to retail providers on behalf of their load to be used for AB 32 purposes.[25] The PFO also provides, in the context of topping cycle CHP, that CHP serving on-site load is appropriately treated in this context as a retail provider.[26] Whether or not the CHP facility exports a kWh or retains all electrical production on site, and whether the CHP facility is a topping cycle or bottoming cycle facility, all load served by a CHP facility should be treated similar to load of other load serving entities. (Allocation of allowances to bottoming cycle facilities not engaged in supplemental firing will require additional consideration during the first four program years when these allowances are allocated based on historic emissions.)

Finally, one additional detail warrants the Commissions’ attention to avoid differential treatment among CHP. Typically, whether an industrial facility is importing power from or exporting CHP power to the grid is determined at a single “net” meter at

---

[25] PFO, at 223-225.
[26] PFO, at 15 and 245.

the facility's site boundary. Power produced and on-site load served are netted before reaching the meter at the point of interconnection. While this arrangement is typical, it is not universal. In some cases, to provide increased reliability in the event of grid disturbances, load and generation for a site may be interconnected to the grid through multiple meters at the same voltage level and located near one another. As a result, power may be simultaneously exported and imported across these meters with the export power physically flowing back into the site to meet any net demand. For purposes of GHG emissions, the result of these two configurations is the same. The final decision should clarify that CHP treatment should be comparable regardless of the metering configuration for the industrial site.

For these reasons, the final decision should modify the PFO to provide that all CHP above CARB's metric tonne threshold and the load that CHP serves should be treated similarly for the purposes of GHG compliance and allowance allocation. Comparable treatment should be provided regardless of whether a facility net exports its output to the grid or how its net impact on the grid is metered. Moreover, retail providers,[27] including any type of CHP directly serving load – whether topping or bottoming cycle – should receive the same value allocation.

[27] The Commissions must be duly cautious in applying the term "retail provider" to CHP facilities. The policy expressed in the PFO is sound, but treatment of CHP as a retail provider is not appropriate in the context of the State's procurement obligations. The Legislature, in the context of renewable portfolio obligations, resource adequacy and the general operation of retail markets, has made clear that CHP serving load under Section 218(b) is not a "retail seller" (PU Code §399.12(i)), "load serving entity" (PU Code §380) or "electric service provider" (PU Code §394(a), §8340(e) & §218.3). Consequently, treatment of CHP as a "retail provider" should be restricted to the very narrow purpose provided by the PFO.

D. Equitable Allocation of Allowances to Bottoming Cycle Facilities Engaged in Supplemental Firing Should Be Considered When Allocation Factors Are Considered for Natural Gas and Coal Resources.

The PFO provides that zero emitters such as renewables and bottoming cycle facilities not engaged in supplemental firing should not receive allowances.[28] While acknowledging that it would be appropriate to allocate allowances to bottoming cycle facilities engaged in supplemental firing, it notes that use of an allocation factor may be appropriate to avoid an over-allocation of allowances. Since bottoming cycle facilities engaged in supplemental firing generate emissions, the Commission must ensure that these facilities, like other emitters are treated equitably in the administrative allocation of allowances. This issue should be explored at the time the coal and natural gas allocation factors are considered.

E. The Commissions Should Propose a Limited New Entrant Reserve.

The PFO does not expressly recommend the adoption of a new entrant reserve. The reasoning underlying this approach appears to be two-fold. First, the PFO contemplates a four-year transition to full auction, at which point all emitters – whether incumbent or new entrant – will be on equal footing in acquiring their allowances.[29] Second, because the PFO provides for an output based allocation with updating, any disadvantage for a new entrant will be resolved after the first period (presumably a year) of operations.[30] The PFO acknowledges, however, that "*to avoid a competitive advantage to existing deliverers, it may be desirable to have a small set-aside of*

[28] PFO, at 207.
[29] *See* PFO at 145.
[30] *See* PFO at 161.

allowances for a new entrant's first year of operation, if allowances were allocated exclusively through output based distributions to deliverers."[31]

The Commissions should propose that CARB adopt a new entrant reserve for years during which some portion of allowances will be allocated administratively. This approach would, as the PFO suggests, avoid competitive disadvantage for new entrants. Equally as important, however, a new entrant reserve will ensure that GHG regulation does not contribute to a delay of investment in CHP. At GHG prices of any materiality, deferral of investment would be a consideration if new entrants were not entitled to the same level of administrative allocation as incumbents.

A new entrant reserve could be limited in quantity and access. As EPUC/CAC proposed in earlier comments,[32] a new entrant reserve should provide for priority access to efficient CHP. This approach would support the expressed policy aim of increasing CHP – the most efficient means of fossil-fired generation – as a GHG reduction measure.

F. The Commissions Should Clarify that CHP Will Not be a Mandatory GHG Reduction Measure for Industrial Sites.

The Draft Scoping Plan under consideration by CARB raises a potential ambiguity in the treatment of CHP. For the industrial sector, CARB's Draft Scoping Plan proposes the use of energy audits for industrial facilities with more than 0.5 $MMTCO_2E$ per year of greenhouse gas emissions.[33] It notes that it would require applicable facilities to undertake an energy efficiency audit.[34] The audit would not only identify potential measures that could reduce the facility's emissions, it would also include

31 PFO, at 161.
32 EPUC/CAC June 2008 Comments, at 36
33 CARB Draft Scoping Plan, at 36.
34 *Id.*

information about the cost of these measures.[35] Among these measures, the CARB Draft Scoping Plan appendices observe that the installation of new CHP may be one way to reduce a facility's emissions.[36]

Efficient CHP can be a beneficial GHG reduction measure for an industrial site. Compared with other measures, however, CHP is not a simple choice. CHP is a capital intensive solution, with installed capacity costs for a new plant hovering between \$1800/kW and \$2200/kW. Moreover, CHP may force an industrial site away from its core business into a new market – the power market – which brings with it new financial and regulatory risk. CHP thus may not be cost-effective or feasible in all situations. A company may decide that, on the whole, installation of high-efficiency boilers is the optimal solution to serve its long-term thermal and power requirements, given its other business mandates.

The CPUC and CEC are the experts in this state on CHP development and operation. Given this expertise, the final decision should clarify for CARB that CHP cannot be a mandated measure for an industrial site; the choice of whether to employ this measure must be left with the energy consuming customer.

---

35 *Id.*
36 *Id.*

III. REFINEMENTS TO PFO'S ALLOWANCE DISTRIBUTION PROPOSAL REQUIRED TO ENSURE EFFICIENT AND RELIABLE PERFORMANCE OF GHG PROGRAM.

A. If an Auction is Proposed, the Commissions Must Highlight for CARB the Need to Examine Industry Risk Prior to Implementing an Allowance Auction.

Stakeholders, including EPUC/CAC,[37] provided comments in this proceeding highlighting the need for caution in implementing a material auction for GHG allowances in the electricity sector. They warned that, for a variety of reasons, a rapid or material movement to an auction of GHG allowances presented risk to electricity supply and reliability. The factors underlying this caution should not be ignored. Among them, stakeholders pointed out that an auction in the GHG market has never been tested,[38] and there are already predictions of RGGI's failure. [39] In addition, carbon costs may not be fully reflected in power prices, particularly for existing contracts, [40] and the outcome and impact of the CAISO's Market Redesign and Technology Update is unknown. [41]

---

[37] *See, e.g.* EPUC/CAC June 2008 Comments beginning at 26; Calpine June 2008 Comments, at 10-12; *Corrected Comments of the Division of Ratepayer Advocates' on Electricity Sector Responsibility, Allowance Allocation, Flexible Compliance Mechanisms, and Modeling*, June 2, 2008 (DRA June 2008 Comments), at 8-9; *Northern California Power Agency Comments on Assigned Administrative Law Judges' Rulings and Staff Papers Regarding Recommendations to the California Air Resources Board for the Electricity Sector*, June 2, 2008, at 9-11; *Opening Comments of the California Municipal Utilities Association on Recommended Greenhouse Gas Emission Reduction Policies*, June 2, 2008, at 3; *Sacramento Municipal Utility District's Comments on Administrative Law Judge's Ruling Requesting Comments on Emission Allowance Allocation, Combined Heat and Power, and Flexible Compliance Policies*, June 2, 2008, at 9-10; Dynegy June 2008 Comments, at 8-9, 12.

[38] *See, e.g.* EPUC/CAC June 2008 Comments at 28-29; DRA June 2008 Comments at 8.

[39] States Aim to Cut Gases by Making Polluters Pay, *New York Times*, Sept. 15, 2008, http://www.nytimes.com/2008/09/16/us/16carbon.html?_r=1&adxnnl=1&oref=slogin&ref=business&pagewanted=all&adxnnlx=1222452097-4LcGk6vi1NzrPiI3rCDD/Q; RGGI's Rules: Northeast Launches First U.S. Carbon Cap, But Will It Work?, *Wall Street Journal*, Sept. 24, 2008, http://blogs.wsj.com/environmentalcapital/2008/09/25/rggis-rules-northeast-launches-first-us-carbon-cap-but-will-it-work/.

[40] *See, e.g.* Calpine June 2008 Comments at 9; *Reply Comments of the Western Power Trading Forum on Design of Greenhouse Gas Regulatory Strategies*, June 16, 2008 (WPTF June 2008 Reply Comments), at 7; *Reply Comments of the Independent Energy Producers Association on Allocation, Flexible Compliance, Combined Heat and Power, and Modeling Issues*, June 16, 2008, at 1-2, 3-5; Dynegy June 2008 Comments at 4; DRA June 2008 Comments, at 10.

[41] *See, e.g.* EPUC/CAC June 2008 Comments, at 11,13-16; *Opening Comments of the*

The PFO acknowledges but quickly dismisses these concerns without adequate justification. It concludes: "*While grid reliability is of paramount importance, we do not find merit in these parties' arguments that allowance allocation policies could have a detrimental effect on grid reliability*."[42] The PFO places its faith in the economic principle that GHG costs should be reflected in market prices and that flexible compliance will allow an opportunity to "*ease potential allowance demand spikes, as well as reduce the impact of abnormal hydropower years or other anomalies that may affect electricity generation or demand*."[43]

The PFO's dismissal of these concerns lacks support. The Commissions have gone to great lengths to estimate rate impacts and the costs related to the supply curve of reduction measures. They have not, however, undertaken a single examination of impact on the proposed regulation on reliability. Their conclusion thus is planted in the assumption that "the market will provide." The PFO fails even to cite a single study prepared by the Regional Greenhouse Gas Initiative or European Union Emissions Trading Scheme on reliability impacts to support its conclusion. Moreover, one of the only studies referred to, undertaken by Resources for the Future, suggests that the market may not provide.[44] If reliability truly is "of paramount importance", the Commissions have failed to give the issue a fair review in implementing the proposed regulations.

The prudence of an auction has been further called into question with the recent events in the financial markets. Recently the CAISO suspended the ability of Lehman

---

Los Angeles Department of Water and Power on Policies Regarding Emission Allowance Allocation, Flexible Compliance, Treatment of Combined Heat & Power, Non-Market-Based Emission Reduction Measures and Emission Caps, and Greenhouse Gas Modeling Results, June 2, 2008, at 17.

[42] PFO, at 144.

[43] PFO, at 145.

[44] PFO, at 216.

Brothers to schedule in the California market.[45] Similarly, Morgan Stanley, which has been the most active financial player in these proceedings, recently "*lost close to one-third of the assets in its prime brokerage last week* …" according to Reuters.[46] Prior to that, Constellation Energy sold itself in a last-ditch effort to stave off bankruptcy when its commodity bets went bad.[47] A key factor for regulated emitters will be their ability to hedge their GHG risks through effective financial market products. While it is impossible to know what financial products will be available when the GHG program launches, at a minimum, a review of financial market conditions must be undertaken prior to moving forward with an auction.

B. Unspecified Resources Should Receive an Allocation That Encourages Source-Specific Contracting.

The PFO does not address the appropriate allocation factor to use for unspecified resources. As several parties have observed in the past, GHG regulations should be designed to minimize contract shuffling and leakage. For this reason, it is critical that the Commission adopt an unspecified resource default value that is no more than (and potentially lower than) the natural gas allocation factor.

Resources that report their emissions should not be penalized as a result of the provision of allowance allocations to cover emissions associated with unspecified resources. Under the proposed allocation scheme, the Commission would allocate allowances using a fuel-specific allocation factor. The findings of fact reveal that the allocation to coal will be higher than that of natural gas generation.[48] If the default emissions value used for non-specified resources is higher than a natural gas-fired facility, out-of-state resources will have the incentive to sell all power but coal-fired

---

45 *See* http://www.caiso.com/2047/2047ce07345f0.html
46 *See* http://www.reuters.com/article/marketsNews/idUSN2628726620080926.
47 *See* http://www.mddailyrecord.com/article.cfm?id=8610&type=UTTM.
48 PFO, at 278, Finding of Fact ¶ 29.

power as unspecified resources. The higher the default value the more incentive there will be to "game" the system. This runs counter to the Commission's focus on limiting windfall profits and should be discouraged. To mitigate the potential for this type of contract shuffling, the Commission should recommend an unspecified default value that is less than the emissions of a natural gas reference resource. While it should provide directional guidance in the final decision on this issue, further details can be examined in later proceedings when actual OBA fuel allocation factors are developed.

C. Additional Detail Regarding Transition of Retail Provider Allowance Allocation From Historic Emissions to Sales Basis Needed to Limit Regulatory Uncertainty.

The PFO recommends that allowances allocated for retail providers should be allocated first on the basis of historic emissions and then on the basis of sales.[49] While it recommends such a transition, the PFO provides no information on the actual transition process. Like the information describing the transition from an allocation to an auction,[50] the final decision would best serve the interest of regulatory certainty by providing regarding the transition in the allocation of allowances for retail providers from a historic emission-based allocation to one based on sales.

D. Fuel Allocation Factor Evaluation Must Consider Economic Impact on Natural Gas-Fired Resources

The PFO's chosen fuel-differentiated output-based allocation scheme is directed to mitigating economic harm:

> *In weighing the evaluation criteria, we find that a primary consideration in the early years of a cap-and-trade program is to ensure that economic harm is mitigated to the range of market participants in the electricity sector, including customers, retail providers, and deliverers.*[51]

---

[49] PFO, at 203-204.
[50] *See* Table 5-3, PFO, at 204.
[51] PFO, at 206, 208-209.

Appropriately, the allocation factor for this fuel-based differentiation is deferred for further evaluation.[52] When this issue is addressed, the Commission must also consider economic impact on natural gas resources. Depending on the allocation factors used, preventing economic harm to those deliverers with coal-fired generation can expose natural gas fired generation to more economic harm. EPUC/CAC's very rough calculation based on the PFO, for example, suggests that CHP resources would be required to go to the market to purchase a material portion of their allowances in 2012 assuming a 2:1 coal:gas ratio. Critical to the agencies' ongoing discussion of allocation factors will be calculations that identify precisely how the allocation will impact both natural gas resources, including CHP, and coal resources.

IV. THE COMMISSIONS SHOULD BE CAUTIOUS IN DESIGNING A MANDATE REQUIRING RETAIL PROVIDERS TO PROCURE 33% ENERGY FROM RENEWABLES.

The PFO's Ordering Paragraph 3 recommends **"***that ARB adopt a requirement that each retail provider meet 33% of its retail sales using renewable energy sources by 2020*."[53] The design of this mandate cannot be viewed in isolation, but will influence the State's ability to achieve other policy objectives.

The feasibility of implementing a 33% renewables policy is currently an issue that is under consideration in the long-term procurement proceeding (LTPP) (R.08-02-007).[54] In that proceeding, stakeholders are evaluating the feasibility of achieving this objective given several existing barriers including inadequate transmission infrastructure, load profiles of different renewable resources and other operational considerations.[55] Also under consideration in that proceeding will be the cost and emissions associated with integrating certain renewable resources which require high emitting back-up generation.

---

52 PFO, at 209.
53 PFO, at 288.
54 Scoping Ruling Issued in R.08-02-007, at 8-9.
55 *Id.*

Implementing a 33% renewables mandate without careful design consideration may impede the balanced achievement of AB 32 objectives. Depending upon the level of “must take” resources in the utility portfolio during minimum load conditions – including nuclear, hydro, geothermal, interchange, wind and existing CHP – the State’s ability to integrate additional desired resources into utility portfolios may be compromised. For example, an imbalanced stack during minimum load conditions could undermine the CHP targets identified by CARB in its Scoping Plan. A review of this and other questions is under way in the LTPP proceeding. Recommendations to CARB regarding the design of a 33% renewable procurement program should be deferred until this analysis is complete.

V. THE FINAL OPINION MUST REFLECT MODELING AND POLICY FINDINGS ON CHP

The PFO discusses the environmental benefit and regulation of CHP policy in detail. Not all findings are reflected in the proposed findings of fact, however, despite the fact that similar findings related to renewables and energy efficiency are included. Proposed findings of fact to more completely reflect support for policy decisions are reflected in Attachment A.

VI. CONCLUSION

For all of the foregoing reasons, the Commissions should adopt the recommendations proposed in these Comments as specified in Attachment A's Proposed Findings of Fact and Conclusions of Law.

Respectfully submitted,

Michael Alcantar
Nora Sheriff

Counsel to the
Cogeneration Association of California

Evelyn Kahl
Seema Srinivasan

Counsel to the
Energy Producers and Users Coalition

ATTACHMENT A

Findings of Fact

1. Energy efficiency is the cheapest and most effective resource for reducing GHG emissions in the electricity and natural gas sectors.

2. Many non-price market barriers to energy efficiency investment exist and will continue to exist even if a GHG emissions allowance cap-and-trade program is implemented.

3. As the cost of GHG mitigation becomes reflected in the cost of energy, more energy efficiency opportunities should become cost-effective. However, as more “low-hanging fruit” energy efficiency is achieved, incremental energy efficiency options may become more expensive.

4. Achieving the goal of all cost-effective energy efficiency will require a continuation of existing direct regulatory/mandatory requirements, expansions of existing requirements and development of new ones where appropriate, and implementation of other innovative approaches such as market-based strategies.

5. Renewable mandates play an important role in achieving aggressive renewable energy penetration, since they provide a long-term signal that can lead to market transformation of new renewable technologies and potential cost reductions.

6. E3 estimates that GHG emissions reductions obtained through achievement of 33% electricity from renewables may have an average incremental cost of $133 per ton, compared to the current 20% RPS mandate.

7. Renewable energy provides environmental co-benefits, including reducing other non-GHG pollutants, when sited in California.

8. Significant implementation barriers exist to the continued of renewable energy in California.

9. Increased renewable energy penetration would increase fuel diversity.

10. California's longer term 2050 GHG reduction goals will require significantly reducing the GHG footprint of the electricity sector.

11. Having all retail providers deliver 33% renewable energy to their customers by 2020 would be an important first step in achieving this transformation.

12. It is reasonable for the State of California to set as a target that all retail providers deliver 33% renewable energy to their customers by 2020.

13. CHP mandates will play an important role in increasing CHP penetration.

14. E3 estimates that GHG emissions reductions obtained through achievement of the Accelerated Policy Case may have an average incremental cost of negative $161 per ton, compared with its Reference Case.

15. Like renewables and energy efficiency, the emissions savings facilitated by CHP provides environmental co-benefits, including reducing other non-GHG pollutants, when sited in California.

16. E3's approach and analysis to estimating costs from reducing GHG emissions are reasonable for the purpose of informing our recommendations to ARB.

17. E3 estimates that the Accelerated Policy Case, including aggressive targets for EE, RPS and CHP, would result in GHG emissions totaling 79 MMT CO2e for the electricity sector in 2020.

18. We did not study the cost and rate impacts on consumers of increasing energy efficiency goals, renewable energy mandates, or levels of CHP beyond those in E3's Accelerated Policy Case. Prior to increasing these policies/mandates, the costs of additional reductions should be compared against the costs of mitigating GHG emissions across the California economy.

19. Linkage with a regional emissions trading system that includes all jurisdictions in the Western electricity grid would more likely result in coal-fired

generators operating less, would significantly mitigate opportunities for deliverers to mask the carbon intensity of electricity through "contract shuffling," and may result in low-carbon generation displacing either coal or natural gas-fired generation depending on time and location.

20. The Western Climate Initiative has issued draft design principles that target an opening date of January 1, 2012 for a linked regional cap-and-trade program.

21. Linking with other state cap-and-trade programs through the Western Climate Initiative would remove or mitigate some of the challenges of a California-only approach.

22. Auctioning of allowances would provide market liquidity, ensure that all deliverers have equal access to allowances, and avoid the need for a set-aside or other administrative accommodation for new entrants.

23. There is an expectation that if allowances are auctioned GHG compliance costs would be internalized in wholesale electricity prices, sending more accurate price signals that would encourage participants in the electricity sector to reduce emissions.

24. It is not clear that wholesale electricity prices will be sufficient to allow deliverers to recover all GHG compliance costs especially for those deliverers in existing contracts and those subject to administratively determined sales prices.

25. We commit to evaluating the issue of carbon cost recovery in more detail given its direct relationship to grid reliability.

26. To encourage the investment in new low carbon resources, and ensure equitable treatment with existing resources, it is appropriate to establish a new entrant reserve that provides allowances with priority to low carbon resources including CHP.

27. Auctioning allowances would result in entities with compliance obligations bearing the full financial responsibility for emissions associated with electricity that they deliver to the California grid.

28. Auctioning would preclude windfall profits from allowance rents to independent deliverers.

29. Distributing some free allowances to deliverers would reduce short-term impacts on generating resources, and would help generators adapt to the new regulatory environment.

30. A transition to auctioning would help protect ratepayers if problems arise as ARB implements AB 32 and experience is gained with the auctioning process.

31. A transition to 100% auctioning by 2016 would ensure that any allowance rents would be short-term and would give existing high-emitting resources time to adjust their generation investments.

32. It is reasonable to introduce auctioning in a phased approach, with 100% auctioning by 2016, so that California can reap initial benefits from auctioning and, at the same time, provide some protection and stability while the cap-and-trade market develops and matures.

33. A fuel-differentiated output-based allocation approach with distributions limited to emitting deliverers would provide all deliverers with allowances roughly in proportion to the amount they need and would reduce the potential for allowance rents.

34. A fuel-differentiated output-based allocation approach with distributions limited to emitting deliverers would avoid undue economic harm to California electricity consumers who are currently locked into a certain degree of dependence on coal.

35. In a fuel-differentiated output-based allocation approach, it is reasonable that a higher weighting factor be applied for all coal generation delivered to the California grid.

36. If 100% auctioning is not implemented by 2016, an important longer-term goal of deliverer distributions should be to provide strong incentives for GHG reductions.

37. It is reasonable that allowance distributions to deliverers transition toward an output-based approach that weights all types of generation equally, to be reached by 2020 if 100% auctioning is not achieved by that time.

38. A centralized auction in which retail providers rather than the State own most or all of the electricity sector allowances at the time they are auctioned would simplify the auctioning and revenue distribution process, in that auction revenues would pass directly to the retail providers.

39. A centralized auction in which retail providers are required sell any allowances they receive would remove anti-competitive concerns regarding the distribution of allowances to retail providers.

40. It is reasonable to require that retail providers sell any allowances they receive in a centralized auction.

41. Allocating allowances to retail providers based on historical emissions in their electricity portfolios would accommodate carbon-intensive retail providers that may face relatively high rate impacts due to compliance costs.

42. A long-term priority for allocating allowances is to provide strong incentives for increased reliance on low- and non-emitting resources and to provide consistent signals to all retail providers regarding the value of low-emitting portfolios.

43. It is reasonable to transition allocation of allowances to retail providers from an historical emissions basis to a sales basis by 2020 because a sales-based

allocation would provide a long-term incentive to reduce reliance on high-emitting resources.

44. To meet the goals of AB 32, California is preparing to implement ambitious energy efficiency ~~and~~ , renewable energy and CHP mandates.

45. Meeting the targets for the electricity sector outlined in ARB's Draft Scoping Plan will require significant additional expenditures on energy efficiency measures, ~~and~~ the development of new renewable resources, and the development of CHP policy.

46. It is reasonable to require that all auction revenues be used for purposes related to AB 32 and that all auction revenues from allowances allocated to the electricity sector be used for the benefit of the electricity sector.

47. Electricity delivered to the California grid by CHP facilities is indistinguishable from electricity delivered from non-CHP sources.

48. With respect to GHG emissions, all electricity generated by a CHP facility is identical whether the electricity is delivered to the grid or consumed on-site.

49. It is reasonable to use the same generating capacity size threshold as that used for other deliverers to determine which CHP facilities should be included in a multi-sector cap-and-trade program.

50. While it would be appropriate to create a CHP sector to track and manage the emissions associated with CHP's dual outputs, we do not recommend the creation of such a sector at this time but urge further consideration of this approach by the ARB.

51. Instead, the emissions of CHP facilities will be tracked and attributed to two different sectors: the electricity sector for electricity emissions and the commercial or industrial for thermal emissions.

52. To prevent the creation of CHP disincentives, we recommend that allowances to cover thermal emissions be allocated in an output-based manner that is no less favorable than the method adopted for electricity output.

53. Due to the complexity, controversy and potential distortion surrounding splitting CHP emissions, individual CHP operators will choose its desired method of emissions allocation between sectors depending upon the nature of its operations.

54. CHP facilities deliver a portion of their electricity to the grid and, for GHG regulatory purposes, also should be treated comparable to deliverers for the portion of electricity that is consumed on-site, regardless whether the CHP plant is a topping or bottoming cycle facility.

55. It is reasonable to allocate allowances to CHP facilities using the fuel-differentiated output basis, as described in this decision.

56. To the extent that CHP facilities provide electricity that is consumed on-site, distributing allowances to CHP facility operators of both topping and bottoming cycle CHP on the same basis as retail providers would provide equitable treatment for CHP facilities.

57. All CHP above CARB's size threshold and its load should be treated similarly regardless of the relative amounts of energy consumed on-site or delivered to the grid.

58. In order to further the CHP objectives reflected in the Accelerated Policy Case and CARB's draft recommendations, it is appropriate to examine the existence of CHP barriers.

59. To remove uncertainty for CHP facilities participating in the CPUC's QF program, we clarify that these facilities will be permitted to pass through the actual costs of GHG compliance through their contracts with the purchasing

utility to the extent the utility cannot demonstrate that the QF contract prices permit full recovery of these costs.

60. We conclude that the proposed administrative pricing formula adopted in D.07-09-040 does not reflect GHG costs and permit GHG cost recovery under the QF contracts to the extent this pricing formula remains in place upon the implementation of the GHG program.

61. We will require an examination of the extent to which MRTU-based pricing for QFs adopted in D.07-09-040, if implemented, permits full recovery of GHG costs within the first six months of the date of GHG program implementation and will permit pass through of any unrecovered costs by contract .

62. We also determine that CHP is appropriate categorized as an emissions reduction measure and commit to opening a new rulemaking to evaluate CHP barriers in detail.

63. Given the sizeable investment and industrial process implications attendant to CHP operations, it is not appropriate to treat CHP as a mandatory GHG reduction measure.

64. Linking California's cap-and-trade program with other trading systems would add liquidity and efficiency to California's trading market.

65. Bilateral linkage would allow California to ensure that any allowances accepted by California entities from other systems are of comparable quality to California allowances.

66. It is reasonable for California to pursue bilateral linkage with other local, regional, national, and international GHG cap-and-trade systems that have comparable stringency, monitoring, compliance, and enforcement provisions.

67. Unique characteristics of the electricity sector necessitate that the cap-and-trade market include a reasonable range of flexible compliance options in order

to provide needed flexibility to the sector while maintaining the environmental integrity of the emissions cap.

68. Permitting entities with compliance obligations to borrow emission allowances would delay reductions and could make it more difficult to achieve AB 32's reduction goals. Other flexible compliance measures offer the potential to aid obligated entities to manage their obligations with less risk to the program's environmental integrity.

69. Price triggers and safety valves could very likely distort or defeat the cap-and-trade market by creating uncertainty that investments in emissions reduction technologies will achieve returns commensurate with the level of reductions needed to meet the State's emissions reduction goals.

70. Declining allowance prices over time are likely to indicate that the market is working to drive sufficient investment toward the required emissions reductions.

Conclusions of Law

1. The administrative allocation of allowances that we are proposing is facially neutral, as between interstate and intrastate commerce, and does not have a discriminatory purpose or effect. The allowances would be allocated based on fuel-differentiated output, whether the generation of the electricity occurs in California or elsewhere.

2. The auctioning of allowances that we are proposing is facially neutral, as between interstate and intrastate commerce, and does not have a discriminatory purpose or effect.

3. 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."

4. The use of an allocation based on fuel-differentiated output-based criterion would not violate the dormant Commerce Clause.

5. The auctioning of allowances would not violate the dormant Commerce Clause.

6. Under the California Constitution, Article XIII A, Section 3 a tax can only be enacted by not less than a two-thirds vote of the Legislature.

7. A regulatory fee does not require a Legislative vote of not less than two-thirds because it is enacted under a state's traditional police power, not its taxing authority.

8. Under *Sinclair Paint Co. v. State Bd. of Equal.* (1997 15 Cal.4th 866, 875-876) regulatory fees imposed to pay for the expenses of a regulatory program or to defray the actual or anticipated adverse effects of the payer's action are not taxes imposed for revenue purposes.

9. Under *Sinclair Paint Co. v. State Bd. of Equal.*, (1997) 15 Cal. 4th 866, 870, fees must "bear a reasonable relationship to those adverse effects."

10. Our recommendation that any revenue generated from initial purchases of allowances be used to further the purposes and goals of AB 32, and not deposited in the state's general fund for non-AB 32 uses, does not violate Article XIII A, Section 3 of the California Constitution.

11. Our recommendation that revenue generated from initial purchases of allowances be reasonable in relationship to the adverse effects caused by the corresponding emission of GHGs, does not violate Article XIII A, Section 3 of the California Constitution.

12. Using auction revenues to provide rate relief to customers generally, or to low income customers who spend a larger proportion of their incomes on utility services, furthers the goals of AB 32, and is therefore a permissible use of auction revenues.

13. An historical emissions-based distribution of allowances to retail providers can be designed to recognize voluntary early actions these retail providers have taken to reduce emissions, consistent with Section 38562(b)(3). Section 38580(a) requires ARB to monitor compliance with, and enforce, the regulations it issues, but does not prohibit the use of out-of-state offsets or credits.

14. Section 38564 encourages linkage with the GHG-reduction programs of other states and nations.

15. AB 32 permits linkage to other GHG-reduction programs and the use offsets from outside of California.

16. Section 38562(b) describes things that ARB should do in "adopting regulations" "to the extent feasible." It does not require each and every project carried out by private parties under those regulations to have the described effects.

17. Section 38570(b) requires ARB to do certain things "to the extent feasible" prior to the inclusion of any market-based compliance mechanism (such as offsets) in the AB 32 regulations.

18. Sections 38562(b) and 38570(b) require ARB to balance a number of potentially conflicting goals, including minimizing costs.

FINAL ORDER

IT IS ORDERED that:

1. We recommend that the California Air Resources Board (ARB) set energy efficiency requirements in its Scoping Plan at the level of all cost-effective energy efficiency, with energy efficiency goals for investor-owned utilities set based on those adopted by the California Public Utilities Commission (Public Utilities Commission) in Decision 08-07-047.

2. We recommend that ARB work with the California Energy Commission (Energy Commission) and the Public Utilities Commission to develop approaches using a combination of direct regulatory/mandatory requirements and other potentially market-based strategies to achieve all cost-effective energy efficiency.

~~3. We recommend that ARB adopt a requirement that each retail provider meet 33% of its retail sales using renewable energy sources by 2020.~~

4. We recommend that ARB undertake the emission allowance allocation in steps for the electricity sector, determining first the total number of allowances to create for each year or other appropriate time period, for all of the sectors included in the cap-and-trade program, and then the number of allowances to allocate to the electricity sector based on its proportion of actual historical emissions in California (including emissions attributed to electricity imports) during the chosen baseline year(s).

5. We recommend that the trajectory of the multi-sector emissions cap and the required annual reductions be generally a straight-line reduction between 2012 and 2020 for all sectors including electricity.

6. <u>We recommend that ARB evaluate risk to electricity supply and reliability prior to implementing an allowance auction.</u>

7. We recommend that, for 2012, ARB distribute 20% of the allowances allocated to the electricity sector to retail providers, with a requirement that they sell the allowances through a centralized auction, and distribute 80% of the allowances without cost to electricity deliverers.

8. We recommend that ARB increase the portion of allowances allocated to the electricity sector that are distributed to retail providers and sold at auction by 20% each year so that all of the electricity sector allowances are auctioned in 2016 and each year thereafter.

9. We recommend that for the portion of allowances distributed to deliverers, ARB distribute the allowances using a fuel-differentiated output-based approach with distributions limited to emitting deliverers, as described in this decision.

10. We recommend that, if ARB adopts less than either 100% auctioning as the ultimate goal for electricity sector allowances or phases in 100% auctioning later than 2016, ARB phase out the weighting factors used to determine allowance distributions to deliverers starting in 2016, so that the distribution methodology would transition to a pure output-based approach by 2020.

11. We recommend that, for electricity sector allowances that will be auctioned, ARB distribute all or almost all allowances to retail providers on behalf of consumers, with the requirement that retail providers sell the allowances in a centralized auction and receive the revenues.

12. We recommend that ARB initially distribute electricity sector allowances to retail providers (which will be required to sell them at auction) in proportion to the historical emissions of the retail providers' portfolios, transitioning to a sales basis by 2020.

13. We recommend that ARB require that all allowance auction revenues be used for purposes related to Assembly Bill (AB) 32, including the support of investments in renewables, energy efficiency, new energy technology,

development of CHP, infrastructure, customer bill relief, and other similar programs.

14. We recommend that ARB require all auction revenues from allowances allocated to the electricity sector be used for the benefit of consumers in the electricity sector.

15. We recommend that ARB allow the Public Utilities Commission for investor-owned utilities and the governing boards for publicly-owned utilities to determine the appropriate use of retail providers' auction revenues consistent with the purposes of AB 32.

16. We recommend that ARB require each publicly-owned utility to demonstrate annually to the Energy Commission that its use of auction revenues during the prior year was consistent with the purposes of AB 32.

17. We recommend that, for combined heat and power (CHP) facilities that exceed the minimum size threshold that ARB sets for other deliverers, ARB include the emissions associated with CHP-generated electricity consumed in California in the electricity sector in any multi-sector GHG emissions cap-and-trade program.

18. We recommend that ARB treat entities that deliver CHP-generated electricity to the grid just like other deliverers for GHG regulatory purposes, and that ARB treat CHP operators comparable to deliverers for purposes of regulating GHG emissions associated with CHP-generated electricity used on-site, as described in this decision. Recognizing that they may be the same entity, the deliverer for the CHP electricity delivered to the grid and the CHP operator for CHP electricity used on-site should be responsible for surrendering allowances for the portion of CHP-generated electricity delivered to the grid and the portion used on-site, respectively. To the extent that allowances are distributed for free to deliverers, the deliverer for CHP delivered to the grid and

the CHP operator for CHP electricity used on-site should receive allowances on the same basis as deliverers of electricity from other sources.

19. We recommend that ARB treat CHP operators comparable to retail providers for the portion of CHP-generated electricity that is used on-site. To the extent that allowances are distributed to retail providers, the CHP operator should receive allowances on the same basis as retail providers and should be required to sell the received allowances at auction and use the proceeds for purposes consistent with AB 32.

20. We recommend that ARB avoid mandating that any individual industrial facility install CHP as a GHG reduction measure but permit each facility to determine whether to employ this measure based on the facility's economic analysis.

21. We recommend that, if ARB adopts a cap-and-trade program, ARB not pursue a California-only program, but rather pursue bilateral linkage with other states in the Western Climate Initiative to help create a regional cap-and-trade market.

22. We recommend that ARB, in developing a cap-and-trade program, avoid creating any price triggers or safety valves.

23. We recommend that, if ARB develops a cap-and-trade program, ARB establish three-year compliance periods and allow unlimited banking of emissions allowances and offsets.

24. Rulemaking 06-04-009 is closed.

This order is effective today.

Dated ______________________________, at San Francisco, California.

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 September 12, 2008, at San Francisco, California.

/s/ ROSCELLA GONZALEZ
Roscella Gonzalez

Peevey Attachment A
Peevey Attachment B

CERTIFICATE OF SERVICE

I, Amie Burkholder, hereby certify that I have on this date caused the foregoing document, Comments of the Energy Producers and Users Coalition and the Cogeneration Association of California on the Proposed Final Opinion to be served on all known parties by either United States mail or electronic mail, to each party named in the official service list obtained from the Commission's website, attached hereto, and pursuant to the Commission's Rules of Practice and Procedure.

Dated October 2, 2008, at San Francisco, California.

Amie Burkholder

____

Amie Burkholder

R.06-04-009 Service List

dhecht@sempratrading.com

steven.schleimer@barclayscapital.com
steven.huhman@morganstanley.com
rick_noger@praxair.com
keith.mccrea@sablaw.com
kyle_boudreaux@fpl.com
cswoollums@midamerican.com
Cynthia.A.Fonner@constellation.com
kevin.boudreaux@calpine.com
trdill@westernhubs.com
todil@mckennalong.com
steve.koerner@elpaso.com
jenine.schenk@apses.com
jbw@slwplc.com
kelly.barr@srpnet.com
rrtaylor@srpnet.com
smichel@westernresources.org
roger.montgomery@swgas.com
jgreco@terra-genpower.com
Lorraine.Paskett@ladwp.com
ron.deaton@ladwp.com
snewsom@semprautilities.com
curtis.kebler@gs.com
dehling@klng.com
npedersen@hanmor.com
mmazur@3phasesRenewables.com
ej_wright@oxy.com
vitaly.lee@aes.com
tiffany.rau@bp.com
klatt@energyattorney.com
rhelgeson@scppa.org
douglass@energyattorney.com
aimee.barnes@ecosecurities.com
pssed@adelphia.net
bwallerstein@aqmd.gov
akbar.jazayeri@sce.com
cathy.karlstad@sce.com
Nancy.Allred@sce.com
rkmoore@gswater.com
dwood8@cox.net
atrial@sempra.com
apak@sempraglobal.com
daking@sempra.com
troberts@sempra.com
liddell@energyattorney.com
kmelville@sempra.com
marcie.milner@shell.com

rwinthrop@pilotpowergroup.com
tdarton@pilotpowergroup.com
lschavrien@semprautilities.com
GloriaB@anzaelectric.org
llund@commerceenergy.com
thunt@cecmail.org
mdjoseph@adamsbroadwell.com
jeanne.sole@sfgov.org
john.hughes@sce.com
marcel@turn.org
nsuetake@turn.org
dil@cpuc.ca.gov
fjs@cpuc.ca.gov
achang@nrdc.org
rsa@a-klaw.com
ek@a-klaw.com
kgrenfell@nrdc.org
mpa@a-klaw.com
sls@a-klaw.com
epoole@adplaw.com
agrimaldi@mckennalong.com
bcragg@goodinmacbride.com
dhuard@manatt.com
jsqueri@gmssr.com
jarmstrong@goodinmacbride.com
lcottle@winston.com
mday@goodinmacbride.com
smalllecs@cwclaw.com
vprabhakaran@goodinmacbride.com
jkarp@winston.com
edwardoneill@dwt.com
jeffreyGray@dwt.com
cjw5@pge.com
ssmyers@att.net
lars@resource-solutions.org
alho@pge.com
bkc7@pge.com
aweller@sel.com
jchamberlin@strategicenergy.com
beth@beth411.com
kerry.hattevik@nrgenergy.com
kowalewskia@calpine.com
hoerner@redefiningprogress.org
janill.richards@doj.ca.gov
gmorris@emf.net
cchen@ucsusa.org
tomb@crossborderenergy.com
kjinnovation@earthlink.net
bmcc@mccarthylaw.com
sberlin@mccarthylaw.com

Mike@alpinenaturalgas.com
joyw@mid.org
brbarkovich@earthlink.net
bdicapo@caiso.com
UHelman@caiso.com
wamer@kirkwood.com
mary.lynch@constellation.com

abb@eslawfirm.com
glw@eslawfirm.com
jdh@eslawfirm.com
BDombrowski@calretailers.com
mclaughlin@braunlegal.com
dkk@eslawfirm.com
jluckhardt@downeybrand.com
rachel@ceert.org
lmh@eslawfirm.com

westgas@aol.com
scohn@smud.org
atrowbridge@daycartermurphy.com
dansvec@hdo.net
jnelson@psrec.coop
akelly@climatetrust.org
cynthia.schultz@pacificorp.com
kyle.l.davis@pacificorp.com
ryan.flynn@pacificorp.com
jason.dubchak@niskags.com
bjones@mjbradley.com

kcolburn@symbioticstrategies.com
rapcowart@aol.com
harry.singh@rbssempra.com
Kathryn.Wig@nrgenergy.com
sasteriadis@apx.com
george.hopley@barcap.com
mdorn@mwe.com
myuffee@mwe.com
vb@pointcarbon.com
garson_knapp@fpl.com
gbarch@knowledgeinenergy.com
smindel@knowledgeinenergy.com
brabe@umich.edu
bpotts@foley.com
james.keating@bp.com
jimross@r-c-s-inc.com
ahendrickson@commerceenergy.com
tcarlson@reliant.com
ghinners@reliant.com
zaiontj@bp.com

julie.martin@bp.com
fiji.george@elpaso.com
echiang@elementmarkets.com
fstern@summitblue.com
nenbar@energy-insights.com
nlenssen@energy-insights.com
bbaker@summitblue.com
william.tomlinson@elpaso.com
kjsimonsen@ems-ca.com
jholtkamp@hollandhart.com
Sandra.ely@state.nm.us
bmcquown@reliant.com
dbrooks@nevp.com
anita.hart@swgas.com
randy.sable@swgas.com
bill.schrand@swgas.com
jj.prucnal@swgas.com
keith.layton@swgas.com
ckmitchell1@sbcglobal.net
chilen@sppc.com
emello@sppc.com
dsoyars@sppc.com
tdillard@sppc.com
leilani.johnson@ladwp.com
randy.howard@ladwp.com
Robert.Rozanski@ladwp.com
robert.pettinato@ladwp.com
HYao@SempraUtilities.com
rprince@semprautilities.com
LeeWallach@SolelUS.com
rkeen@manatt.com
nwhang@manatt.com
david@nemtzow.com
harveyederpspc@hotmail.com
slins@ci.glendale.ca.us
jrathke@capstoneturbine.com
sgillette@capstoneturbine.com
bjeider@ci.burbank.ca.us
rmorillo@ci.burbank.ca.us
case.admin@sce.com
Jairam.gopal@sce.com
tim.hemig@nrgenergy.com
bjl@bry.com
sfirooz@firstwind.com
tcorr@sempraglobal.com
jlaun@apogee.net
jkloberdanz@semprautilities.com
jennifer.porter@energycenter.org
sephra.ninow@energycenter.org
dniehaus@semprautilities.com

jleslie@luce.com
ekgrubaugh@iid.com

karambelas@fce.com
mona.lloyd@att.net
pepper@cleanpowermarkets.com
gsmith@adamsbroadwell.com
lmiles@adamsbroadwell.com
Diane_Fellman@fpl.com
hayley@turn.org
mflorio@turn.org
Dan.adler@calcef.org
mhyams@sfwater.org
tburke@sfwater.org
norman.furuta@navy.mil
amber@ethree.com
annabelle.malins@britishconsulatesf.gov.uk
filings@a-klaw.com
lfletcher@nrdc.org
nes@a-klaw.com
obystrom@cera.com
sdhilton@stoel.com
scarter@nrdc.org
abonds@thelen.com
brbc@pge.com
cbaskette@enernoc.com
fred.wellington@navigantconsulting.com
jwmctarnaghan@duanemorris.com
kkhoja@thelenreid.com
ray.welch@navigantconsulting.com
spauker@wsgr.com
jwmctarnaghan@duanemorris.com
rreinhard@mofo.com
pvallen@thelen.com
steven@moss.net
policy@recurrentenergy.com
Cassandra.sweet@dowjones.com
hgolub@nixonpeabody.com
jwoodruff@nextlightrp.com
jscancarelli@flk.com
jwiedman@goodinmacbride.com
koconnor@winston.com
mmattes@nossaman.com
bobgex@dwt.com
derek@evomarkets.com
bwetstone@hotmail.com
jen@cnt.org
cem@newsdata.com
lisa_weinzimer@platts.com
ELL5@pge.com

GXL2@pge.com
jxa2@pge.com
JDF1@PGE.COM
KEBD@pge.com
sscb@pge.com
SEHC@pge.com
svs6@pge.com
S1L7@pge.com
vjw3@pge.com
karla.dailey@cityofpaloalto.org
wetstone@alamedapt.com
dtibbs@aes4u.com
ralf1241a@cs.com
jhahn@covantaenergy.com
tdelfino@earthlink.net
andy.vanhorn@vhcenergy.com
sean.beatty@mirant.com
joe.paul@dynegy.com
info@calseia.org
gblue@enxco.com
Patricia.R.Thompson@gmail.com
sbeserra@sbcglobal.net
monica.schwebs@bingham.com
phanschen@mofo.com
wbooth@booth-law.com
josephhenri@hotmail.com
pthompson@summitblue.com
dietrichlaw2@earthlink.net
alex.kang@itron.com
Betty.Seto@kema.com
JerryL@abag.ca.gov
jody_london_consulting@earthlink.net
steve@schiller.com
ahaubenstock@brightsourceenergy.com
svolker@volkerlaw.com
mrw@mrwassoc.com
rschmidt@bartlewells.com
lwisland@ucsusa.org
tandy.mcmannes@solar.abengoa.com
stevek@kromer.com
clyde.murley@comcast.net
nrader@calwea.org
carla.peterman@gmail.com
elvine@lbl.gov
rhwiser@lbl.gov
C_Marnay@lbl.gov
epoelsterl@sunpowercorp.com
ksmith@sunpowercorp.com
philm@scdenergy.com
rita@ritanortonconsulting.com

cpechman@powereconomics.com
emahlon@ecoact.org
esprague@consol.ws
richards@mid.org
rogerv@mid.org
tomk@mid.org
fwmonier@tid.org
johnrredding@earthlink.net
clark.bernier@rlw.com
rmccann@umich.edu
grosenblum@caiso.com
mgillette@enernoc.com
rsmutny-jones@caiso.com
saeed.farrokhpay@ferc.gov
e-recipient@caiso.com
dennis@ddecuir.com
david@branchcomb.com
kenneth.swain@navigantconsulting.com
kdusel@navigantconsulting.com
gpickering@navigantconsulting.com
lpark@navigantconsulting.com
pmaxwell@navigantconsulting.com
david.reynolds@ncpa.com
scott.tomashefsky@ncpa.com
ewolfe@resero.com
cmkehrein@ems-ca.com
bsb@eslawfirm.com
djw@eslawfirm.com
Audra.Hartmann@Dynegy.com
Bob.lucas@calobby.com
curt.barry@iwpnews.com
dseperas@calpine.com
dave@ppallc.com
dbwalker@edf.org
dschwyze@energy.state.ca.us
jose@ceert.org
wynne@braunlegal.com
kgough@calpine.com
kellie.smith@sen.ca.gov
kdw@woodruff-expert-services.com
pbarthol@energy.state.ca.us
pstoner@lgc.org
bernardo@braunlegal.com
steven@lipmanconsulting.com
steven@iepa.com
wtasat@arb.ca.gov
etiedemann@kmtg.com
ltenhope@energy.state.ca.us
obartho@smud.org
wwester@smud.org

bbeebe@smud.org
bpurewal@water.ca.gov
dmacmull@water.ca.gov
kmills@cfbf.com
karen@klindh.com
ehadley@reupower.com
sas@a-klaw.com
egw@a-klaw.com
alan.comnes@nrgenergy.com
kyle.silon@ecosecurities.com
californiadockets@pacificorp.com
Philip.H.Carver@state.or.us
samuel.r.sadler@state.or.us
lisa.c.schwartz@state.or.us
cbreidenich@yahoo.com
dws@r-c-s-inc.com
jesus.arredondo@nrgenergy.com
charlie.blair@delta-ee.com
Tom.Elgie@powerex.com
clarence.binninger@doj.ca.gov
david.zonana@doj.ca.gov
ahl@cpuc.ca.gov
ayk@cpuc.ca.gov
agc@cpuc.ca.gov
aeg@cpuc.ca.gov
blm@cpuc.ca.gov
bbc@cpuc.ca.gov
cf1@cpuc.ca.gov
cft@cpuc.ca.gov
dsh@cpuc.ca.gov
edm@cpuc.ca.gov
eks@cpuc.ca.gov
cpe@cpuc.ca.gov
hym@cpuc.ca.gov
jm3@cpuc.ca.gov
jnm@cpuc.ca.gov
jbf@cpuc.ca.gov
jk1@cpuc.ca.gov
jst@cpuc.ca.gov
jtp@cpuc.ca.gov
jzr@cpuc.ca.gov
jol@cpuc.ca.gov
jci@cpuc.ca.gov
jf2@cpuc.ca.gov
krd@cpuc.ca.gov
lrm@cpuc.ca.gov
ltt@cpuc.ca.gov
mjd@cpuc.ca.gov
mc3@cpuc.ca.gov
pw1@cpuc.ca.gov

psp@cpuc.ca.gov
pzs@cpuc.ca.gov
rmm@cpuc.ca.gov
ram@cpuc.ca.gov
smk@cpuc.ca.gov
sgm@cpuc.ca.gov
svn@cpuc.ca.gov
scr@cpuc.ca.gov
tcx@cpuc.ca.gov
zac@cpuc.ca.gov
ken.alex@doj.ca.gov
ken.alex@doj.ca.gov
jsanders@caiso.com

ppettingill@caiso.com
mscheibl@arb.ca.gov
gcollord@arb.ca.gov
jdoll@arb.ca.gov
pburmich@arb.ca.gov
vwelch@arb.ca.gov
dmetz@energy.state.ca.us
deborah.slon@doj.ca.gov
dks@cpuc.ca.gov
kgriffin@energy.state.ca.us
ldecarlo@energy.state.ca.us
mpryor@energy.state.ca.us

pperez@energy.state.ca.us
pduvair@energy.state.ca.us
wsm@cpuc.ca.gov
ntronaas@energy.state.ca.us
hlouie@energy.state.ca.us
hurlock@water.ca.gov
hcronin@water.ca.gov
rmiller@energy.state.ca.us