**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA
AND THE CALIFORNIA ENERGY COMMISSION**

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies	R.06-04-009
AB 32 Implementation	07-OIIP-01

COMMENTS OF THE ENERGY PRODUCERS AND USERS COALITION AND THE COGENERATION ASSOCIATION OF CALIFORNIA ON ALLOWANCE ALLOCATION ISSUES

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

Counsel to the
Cogeneration Association of California

Evelyn Kahl
Seema Srinivasan
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 31, 2007

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	R.06-04-009

COMMENTS OF THE ENERGY PRODUCERS AND USERS COALITION AND THE COGENERATION ASSOCIATION OF CALIFORNIA ON ALLOWANCE ALLOCATION ISSUES

The Energy Producers and Users Coalition[1] (EPUC) and the Cogeneration Association of California[2] (CAC) (jointly, EPUC/CAC) submit the following comments on the allocation of greenhouse gas (GHG) emissions allowances under a cap and trade program, pursuant to the October 15, 2007 Administrative Law Judge's Ruling.

I. OVERVIEW AND SUMMARY OF RECOMMENDATIONS

The importance of the method used to distribute emissions allowances in an emissions cap-and-trade program cannot be overstated. As NERA Economic Consulting observed in its September 2007 study:

> *The initial allocation of allowances is widely regarded as among the most important design features, both because emissions allowances are*

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, Chevron U.S.A. Inc., ConocoPhillips Company, ExxonMobil Power and Gas Services Inc., Shell Oil Products US, THUMS Long Beach Company, Occidental Elk Hills, Inc., and Valero Refining Company – California

2 CAC represents the power generation, power marketing 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.

valuable assets – the amounts at stake for a GHG program in Europe or the U.S. could be in the billions of euros or dollars per year – and because the method of allocation can affect the performance of the cap-and-trade program.[3]

Initial allowance distribution takes on an even greater importance in the electric power industry. Depending upon the forecast of carbon value, the cost of a full allowance auction in the electric power industry could range from more than $700 million (at $8/MTCO$_2$) to more than $5 billion (at $50/MTCO$_2$). To the extent California gets it wrong, the result could be immediate and disastrous. An approach yielding excessive windfall profits to generators would not be a positive result. A more significant problem, however, could lie in an approach that overburdens power producers, leading to a constrained power supply and shortage rents. This risk, informed by California's experience in the energy crisis of 2000-01, is no doubt at the forefront of energy regulators' minds in designing an allowance distribution method for the electricity sector.

With these and other concerns in mind, EPUC/CAC recommend that regulators employ an administrative allocation method of distribution in the electricity sector in the first phase of the AB 32 program. An administrative allocation is a wiser choice at this time for several general reasons:

- State, national and global experience fails to provide a foundation for a full auction. The U.S. has extremely limited experience with emissions allowance auctions of any kind. And no jurisdiction – U.S. or international – has ever implemented a 100% auction approach. While the notion of a 100% auction has gained traction in the Regional Greenhouse Gas Initiative (RGGI), experimenting with this fashionable distribution theory would be unwise in light of the high stakes in California's electricity industry.

---

3 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 2.

- While any form of allowance distribution presents some risk in terms of price impacts on consumers, an auction presents a greater threat: overburdening power producers with allowance costs could lead to unprofitable operations, which in turn could lead to constrained power supplies and shortage rents. This risk is highest for existing contracts and generators – particularly combined heat and power (CHP) facilities -- who are price-takers at administratively determined prices. The risk extends more broadly to all generators due to leakage and to the extent robust and liquid competitive wholesale markets do not yet exist in California.

- California, unlike the European Union (EU), has a variety of strong regulatory tools that it can employ to mitigate the potential for windfall profits under an administrative allocation.

- Auctions draw capital from regulated firms and would slow down needed investment in more GHG efficient technologies and projects.

In addition, and vitally important to EPUC/CAC members, is the potential impact of an auction on the development and ongoing operation of CHP facilities. Requiring CHP operators to purchase emissions allowances to cover both emissions from thermal and electricity production would penalize CHP for investing in efficient technology that lowers total global emissions.

For all of these reasons, EPUC/CAC recommend that the CPUC and CEC make the following recommendations to the Air Resources Board (ARB):

1. Rely predominantly on administrative allocation for GHG emissions allowances in the electricity sector; any use of an auction should be phased in over time and limited to a nominal percentage in the first phase so that California can learn from its own market experience.

2. To the extent an auction mechanism is employed, address directly the potential impact on existing contracts and administrative price-takers to avoid overburdening and constraining resource availability.

3. Place CHP facilities in a separate sector to enable the development of allocation methods that will encourage this important tool to reduce the state's GHG emissions. Under an administrative allocation, CHP should be allocated allowances using the "double benchmark" approach

employed in the EU-ETS. To the extent an auction is employed, further measures are required to ensure that CHP is not discouraged.

These comments explore these issues and respond directly to the questions presented in the October 15 ruling.

II. LEGAL AUTHORITY TO DISTRIBUTE EMISSIONS ALLOWANCES BY AUCTION IS UNCLEAR.

It is unclear whether California possesses the legal authority to auction allowances. An auction fails to meet the criteria of a valid tax or regulatory fee. Accordingly, any current attempt by California to auction allowances would be vulnerable to legal challenge.

In order for California to impose a regulatory fee, the cost of an allowance must bear a fair or reasonable relationship to the payors' burden or benefit on the regulatory activity.[4] Under the circumstances, there is little information, aside from market predictions, that CARB can use to assign a market-value to an allowance. Since there is an insufficient basis to assign an estimated allowance value, it would be impossible to demonstrate that use of an auction amounts to a valid regulatory fee.

A valid tax can be imposed on California citizens only when the authorizing legislation is passed by a two-thirds majority of the Legislature or a vote of the people.[5] AB 32 is a statute that required only a majority vote.[6] Accordingly, it does not provide the authority to impose a tax. Under existing

---

4 *San Diego Gas and Electric Co. v. San Diego County Air Pollution Control District*, 203 Cal.App.3d 1132, 1146 (1988); *Beaumont Investors v. Beaumont-Cherry Valley Water District*, 165 Cal.App.3d 227, 235 (1985).

5 Cal.Const.Art.XIII.

6 See legislative history for AB 32 indicating that bill required majority vote, http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_history.html.

legislation, a GHG auction system in California, therefore, would constitute an invalid tax.

III. EMISSIONS ALLOWANCES IN THE ELECTRICITY SECTOR SHOULD BE DISTRIBUTED ADMINISTRATIVELY IN THE FIRST PHASE OF ITS AB 32 PROGRAM.

The distribution of emissions allowances is one of the most important issues in any emissions regulatory framework. The question of allowance distribution has a heightened importance, however, in the electric power industry. Adoption of an allowance distribution method that overburdens producers presents a high risk of power shortages and shortage rents. Given this importance, the Commission should take a conservative approach in deciding the method of allowance allocation. The conservative approach, in light of both history and existing conditions, calls for distribution of allowances by administrative allocation in the initial phase of the AB 32 GHG program.

The recommendation for administrative allocation rests on several grounds. First, California cannot turn to any significant experience – state, national or global -- with emission allowance auctions to inform a GHG auction program. A high potential thus exists for unintended consequences. Second, a "big bang" auction in the electricity sector will have a material impact on the California economy, both in terms of direct and indirect costs. Annual direct costs to power producers alone could range as high as $5 billion. This could result in power supply constraints and shortage rents. Third, the risk of "windfall profits," which appears to the primary factor driving current auction proposals, is largely within the control of California regulators. Fourth, most importantly to

EPUC/CAC, an auction will discourage the development of energy efficient CHP – a solution with significant potential for GHG reduction. These considerations, when combined, weigh heavily in favor of administrative allocation for the electricity sector.

A. CALIFORNIA CANNOT DRAW FROM EXPERIENCE TO INFORM THE DESIGN OF A GHG ALLOWANCE AUCTION.

California historically has enjoyed a position of leadership in certain areas of regulation, including both environmental and energy regulation. State regulators are not strongly risk averse in advancing state policies through new regulatory designs. While this general approach has served the state well, there have been material, unintended consequences from California's bold moves – particularly in the electricity sector's 2000-01 crisis. In establishing its leadership in GHG regulation, regulators thus must move carefully, drawing on as much experience as possible in regulatory design. Moving boldly to a 100% auction in the face of extremely limited global experience with emissions allowance auctions could cause history to repeat itself.

The only jurisdiction to implement a GHG program – the EU – lacks any experience with auctions, although partial auctions are now under consideration for ETS Phase II. Likewise, U.S. experience with criteria pollutant programs rests almost exclusively with administrative allocations. Finally, those jurisdictions which have adopted 100% auction programs under RGGI, such as the State of New York, have not yet implemented an auction and thus provide no relevant experience upon which California can rely.

1. EU-ETS Allocation Experience

Allowance distribution in Phase I of the EU-ETS, beginning in 2005, has been achieved almost entirely through administrative allocation. Auctioning in Phase I of the EU-ETS as an allocation method has been applied by only four EU Member States and only to a limited extent. In Phase I, while the scale of auctioning varied, the maximum auction allocation was 5% of total allocations:[7]

- 5% in Denmark;
- 0.75% in Ireland;
- Hungary has assigned 2.5%; and
- Lithuania 1.5%.

The Denmark experience, using a 5% auction, is noteworthy. While Denmark had the most experience with auctioning, the auction they used was very limited and reflects the concerns they had about using such a mechanism. Denmark used auctioning to allocate allowances for 1.7 $MTCO_2$ of the 33.5 $MTCO_2$ available allowances per year (5%).[8] The Danish Energy Authority, however, expressed the following concerns over auctioning before the first round of EU-ETS allocations:

> *The auctioning of CO2 emission allowances was also considered as an alternative allocation method. Some writers argue that this is the most efficient allocation method. While this may be true* ***theoretically*** *if every Member State introduces emissions trading simultaneously,* ***it involves great difficulties in case of a first-mover initiative*** *as the Danish CO2 Quota Act. The capital investment needed by the industry to purchase the allowances is in practice a tax on the total electricity production (not only the marginal CO2 emissions as in the actual scheme) and would therefore be devastating to the power industry as long as other Member States do not have similar arrangements. The devastating effect could be avoided*

7 http://www.climnet.org/euenergy/ET/0506_NAP_report.pdf.

8 http://glwww.mst.dk/transportuk/word/DK%20NAP%20eng%20april.doc

by recycling the auction revenues back to the power industry. This might however raise new state aid issues.[9]

Ultimately, the allowances that were earmarked by the Danish government for auctioning were sold only to two companies: Greenstream from Finland and Cargill International. The proceeds from these sales accrued to the Danish government rather than the GHG reducing program.

For all practical purposes, California cannot look to the only functioning GHG program – the EU-ETS – for guidance, should it elect to walk down the auction path. Instead, it should look to the EU for evidence of the importance of learning by doing, and resist any material auction in the first phase of the AB 32 program.

2. Title IV SO_2 Acid Rain

The federal Title IV SO_2 Acid Rain program has also had very limited experience with an auction. Since, 1995, allowances under the federal Title IV SO_2 Acid Rain program have been allocated administratively for each year. Only 2.8% of available allowances have been auctioned. This provides little basis to conduct a large GHG experiment using a 100% auction. More importantly, the proceeds from the limited auction are returned to the industry in proportion to the underlying allocation of the remainder of the allowances. In other words, the auction in not only limited, its proceeds are also used to mitigate the cost impact on the industry.

---

9 http://www.ghgprotocol.org/DocRoot/6FsOBJXLaLck3X9FToIp/Danish_CO2_cap_Final.pdf (emphasis added).

3. NOx State Implementation Plan

Allowances under the NOx state implementation plan (NOx SIP Call), which is directed to addressing the reduction of nitrous oxide emissions, have been distributed to incumbent producers at no cost. This program therefore provides no information about the use of auctions.

4. Clean Air Interstate Rule

When the Clean Air Interstate Rule (CAIR) NOx trading program is implemented in 2009, the regulation of NOx emissions will change. In particular, the EPA will no longer administer the cap-and-trade programs adopted under the NOx SIP Call Rule. Instead, the CAIR Model Rule contemplates administrative allocation of allowances.

5. Regional Greenhouse Gas Initiative

The RGGI program contemplates the use of an auction mechanism but the success of this proposal remains to be seen. RGGI contemplates a minimum of a 25% auction of emissions allowances. New York, one of the member states of RGGI, has adopted a 100% auction approach to GHG regulation of its electricity sector.[10] As the recent NERA study points out, however, the New York State Department of Environmental Conservation opted to use an auction based on its view that a free allocation would result in a windfall for generators because the allowance value would be reflected in energy prices regardless of the level of free allocation. [11] Importantly, New York's proposal "*was not*

10 NY CRR Proposed Part 242: Supbart 242-5.3 CO_2 Allowance Allocations

11 NERA at 36.

accompanied by any empirical assessment that RGGI participants would suffer no losses in profits under 100 percent auctioning…." Instead, its conclusion was predicated on the misperception that under an auction scheme, all firms would recover the costs of the trading program and have no adverse effects.

In short, the use of an auction by RGGI member states seems to be based on speculation. Since RGGI will not be implemented until 2009, it also provides no actual experience upon which a California auction can be based.

B. THE "BIG BANG" OF A 100% AUCTION RISKS A MATERIAL IMPACT ON ELECTRIC SERVICE RELIABILITY.

Given the lack of experience with an auction mechanism, introducing 100% auction of emissions allowances would amount to a "big bang" with detrimental impact in California's electricity industry ranging from more than a half a billion dollars to more than 5 billion dollars.[12] Assuming that compliance responsibility ultimately rests with the GHG emitter, and carbon costs cannot be fully recovered in prices, generators could experience material reductions in after-tax cash flow. For example, a generator with operating and financial characteristics consistent with those adopted in Resolution E-4049 would experience a reduction in after-tax cash flows of about 18% and 113% (negative

---

[12] California's electricity sector accounts for approximately 20% of the state's GHG emissions, or roughly 100,000,000 metric tons of CO2. (CARB Draft GHG Emissions Inventory: http://www.arb.ca.gov/cc/ccei/inventory/tables/rpt_inventory_ipcc_all.pdf) Assuming an auction achieving the CPUC's $8 carbon adder price, the sector-wide impact would be approximately $800,000,000. Taking a higher forecast of carbon value of $40-$50 MTCO2 would yield a range of $3.85 to $5.0 billion. See *Oxford Economic Forecasting* (2006): 'DTI Energy Price Scenarios in the Oxford Models', available at http://www.berr.gov.uk/files/file35874.pdf . Estimates of California carbon values have been as high as $110 MTCO2. *See Program on Technology Innovation: Economic Analysis of California Climate Initiatives: An Integrated Approach*, Volume 1: Summary for Policymakers, at 3-13.

cash flow), associated with un-reimbursed allowance costs of $8 and $50/MTCO_2$, respectively. It is impossible to predict precisely how the industry would respond to such a dramatic change but significant reductions in an entity's cash flow is certainly not an incentive for continued operation.

The weight of an auction could fall on supply reliability, undermining one of the express legislative objectives of AB32.[13] While the long-range goal of AB 32 may be to shut down higher-emitting resources, an auction could accelerate this result in the short-run if allowance costs result in unprofitable operations. An auction is also likely to affect those resources that are not designated as higher-emitting resources. As NERA noted in its report, there is a misperception that firms would recover their allowance costs in the market under an auction scenario. 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 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.*[14]

A generator paying a price per ton of CO_2 emissions may not recover the full cost of its emissions allowances in its power sales price, resulting in a squeeze on the generator's margin. Depending upon the extent of the squeeze, a rational generator may have no alternative but to shutter existing generating resources or decide not to build new resources within the state.

---

13 Cal. Heath & Safety Code § 38501(h): "*It is the intent of the Legislature that the State Air Resources Board design emissions reduction measures to meet the statewide emissions limits for greenhouse gases established pursuant to this division in a manner that ...improves and modernizes California's energy infrastructure and maintains electric system reliability....*"

14 NERA at 36.

The following table highlights the potential impact on return on equity (ROE) of carbon allowance costs.

Un-Reimbursed GHG Allowance Cost (\$/Metric Ton)	Resolution E-4090 Return on Equity (%)	Change In CPUC Adopted ROE (%)
\$0.00	12.78%	0%
\$5.00	10.92%	-15%
\$10.00	8.99%	-30%
\$15.00	6.96%	-46%
\$20.00	4.82%	-62%
\$25.00	2.52%	-80%
\$30.00	-0.02%	-100%

In other words, a generator paid the "market referent price" approved by this Commission would be unprofitable at a carbon cost of \$15-20/MTCO2 when compared with a risk-free return on treasury bills in the 4.5%-5.0% range unless the generator were reimbursed for this cost in its power sales price. Assuming a carbon price of \$50 $MTCO_2$, the result for a generator paid under this formula would be a ridiculous negative net cash flow of up to \$88 million over a 20-year period. [15]

It is impossible to know in advance of implementation precisely how an auction will affect power producers. Absent further CPUC action, CHP and other QF generators could be the hardest hit, as discussed in Section D below. Suffice it to say, however, the potential exists for a full auction to materially affect supply availability – a consequence the state cannot afford.

---

[15] *See supra*, n. 12.

C. THIS RISK OF WINDFALL PROFITS IN CALIFORNIA'S POWER INDUSTRY IS CONFINED BY REGULATION.

The fear that an administrative allowance distribution will "overcompensate" regulated firms for costs incurred under a GHG program is the "*root of recent increased interest in auctioning allowances*," both nationally and internationally.[16] As the MAC Report observes, there can be little doubt that this phenomenon occurred in Phase 1 of the EU-ETS.[17] The fear of windfall profits, however, should not drive decisions on the distribution of emissions allowances in the electricity sector. Unlike conditions in the EU, California holds a variety of regulatory tools to limit any such result under an administrative allocation.

The price for energy and capacity from the majority of resources serving California consumers falls under state regulatory oversight. For example, the ownership classification of 2005 electrical generation of 287,977 GWh[18] of power produced indicates the following:

- √ The CPUC controls directly the pass through of costs for power sold from investor-owned utility generation, which accounts for roughly 23% of the state's annual generation.
- √ Local governments and State agencies control the costs passed through to consumers by publicly owned utilities, which account for about 16% of the state's generation.
- √ The CPUC administratively determines the price paid for power generated by Qualifying Facilities (QFs) under PURPA and the recent program adopted in Decision 07-09-040. In addition, power generated by QFs that is not sold to the grid is self-supplied with no risk of "windfall profits." Likewise, prices paid to renewable resources are also subject to regulatory oversight. Consequently, regulators have adequate tools available to mitigate the risk of windfall profit-taking by

---

16 NERA at 36.
17 MAC Report at 56.
18 The data, which were not readily available in a useful form, were compiled using public data from the California Energy Commission and the Energy Information Administration.

QF and renewable power, which accounts for roughly 22% of the state's generation.

√ The only areas in which there might lie a risk of potential for windfall profits are in-state merchant generation and imported power. To the extent these resources are committed to long-term bilateral contracts for sale to the investor-owned utilities, however, the CPUC holds jurisdiction to regulate the extent to which carbon value is reflected in the price paid by the utility.

CALIFORNIA 2005 ELECTRICAL ENERGY GENERATION
TOTAL PRODUCTION, BY RESOURCE TYPE
(Gigawatt Hours)

	Generation Ownership Classifications					
Fuel Type	**IOU[a]**	**Muni[a]**	**Governmental & Irrigation Dist[a]**	**Non-CHP QFs, Independent & Merchant[a]**	**CHP[a]**	**Total[b]**
Hydroelectric	17,633	7,525	14,374	358	0	39,891
Nuclear	36,155	0	0	0	0	36,155
Coal	12,440	11,482	0	1,035	3,173	28,129
Oil	26	2	3	42	75	148
Gas	1,079	10,807	1,153	46,458	36,550	96,047
Geothermal	0	0	1,039	13,340	0	14,380
Organic Waste	0	943	0	3,303	1,780	6,027
Wind	0	35	0	4,049	0	4,084
Solar	0	2	0	658	0	660
Other	0	0	0	0	0	0
Energy Imports						62,456
Total Generation:	67,333	30,798	16,570	69,243	41,577	287,977
Percent of Total:	23.4%	10.7%	5.8%	24.0%	14.4%	100.0%

[a]Ownership Classifications derived from data reported to the U.S. Department of Energy, Energy Information Administration (EIA) for 2005 (EIA-906/920 Monthly Time Series File)

[b]Total 2005 GWh of production by resource type compiled from California Energy Commission (CEC) generation data posted on the CEC webpage.

In stark contrast, EU member states had little or no control over the prices at which power was sold, either at wholesale or retail, as the EU electricity market was liberalized and there were no regulated price control mechanisms in place. This is still the case today.

There is no doubt that some risk exists that generators may seek or take windfall profits if emissions allowances are allocated administratively. That risk, however, particularly when mitigated through regulatory oversight, is outweighed by the risk of a "Big Bang" auction to California's power supply and economy.

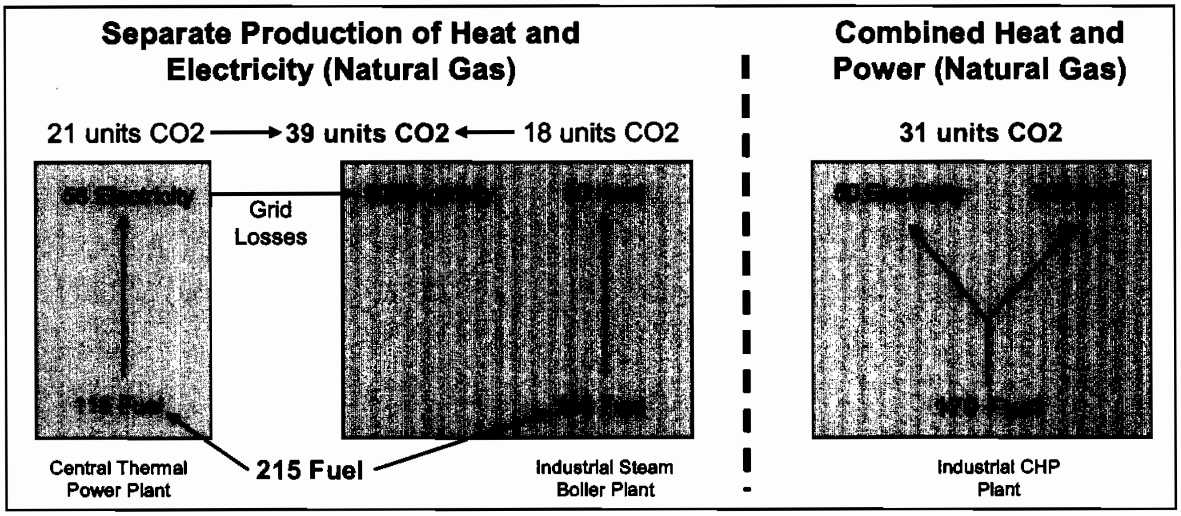
D. An Allowance Auction Will Discourage the Development of CHP as an Important GHG Reduction Measure.

Beyond the general allocation debate, regulators in the electricity sector must consider various interests within the sector. Specifically, an allowance auction differentially affects customers who elect to install CHP facilities on their premises, potentially discouraging CHP development and operation.

When an industrial site invests in a high efficiency CHP plant, total emissions from the production of electrical and thermal energy used by the industrial consumer are decreased. In particular, as explained below, the emissions attributable to CHP are significantly less than the emissions released as a result of separate central power generation and industrial boiler installations. *While global emissions decrease, however, emissions at the industrial site, however, are higher, thereby increasing a CHP customer's GHG allowance requirements.*

An auction system, therefore, can penalize a CHP facility by requiring it to purchase more allowances than it would have needed had it not invested in CHP. Use of the diagram below helps illustrate the difference between separate production of heat and electricity (on the left in the illustration) and CHP (on the right).

ENERGY FLOWS FOR SEPARATE AND COMBINED HEAT AND POWER GENERATION



In this example, an industrial facility producing heat from a steam boiler, and purchasing electricity from a utility, is responsible for 39 units of CO_2 emissions (18 units of CO_2 emitted on-site and 21 units of CO_2 emitted off-site). In contrast, the CHP facility will produce the same amount of heat and will use the same amount of electricity but will emit a total of 31 units of CO_2, with all of the emissions on-site. A CHP facility therefore decreases overall global emissions by 8 units (39 less 31), but increases its on-site emissions by 13 units. Consequently, in an auction system, the CHP facility will need to acquire 13 additional allowances (31 less 18) in order to cover the total emissions from thermal and electric production and operate normally.

One could argue that a CHP facility would be paying for the additional emission costs even if it purchased its electricity from the utility. In other words, by installing CHP, a customer would simply be paying for its emissions costs directly at auction, rather than indirectly through utility rates. This argument, however, fails in two material respects.

1. The degree to which these costs are fed through, if at all, to industrial and other consumers through utility rates is a highly complex and uncertain question. The answer will depend upon market design, allocation methodologies and, as discussed in Section III.B, the efficiency with which the market translates the carbon price signal.

2. Even if auction costs were reflected perfectly in utility rates, the auction costs for a gas-fired CHP would always exceed the auction costs for a utility portfolio which contains a mix of nuclear, hydro and renewable resources. Due to the inclusion of these zero-emitting resources, California IOUs are reported to have average portfolio emissions rates of between 300 and 600 pounds per MWh, whereas a CHP facility might be expected to emit between 600-900 pounds per MWh. Thus, although CHP represents a significant benefit when compared properly to the *marginal resource*, the average cost of carbon faced by a CHP plant thus could be two to three times the cost embedded in utility rates. This distortion would penalize CHP facilities.

Consequently, for the CHP facility, there is little reason to believe that the market will eliminate the financial disadvantage created under an auction when indirect emissions for electricity are moved on site with CHP.

Avoiding an auction of emissions allowances would avoid this penalty, assuming a sufficient administrative allocation to CHP plants. The considerable challenge for CHP is to ensure that any auction system, at the very least, does not penalize new or existing CHP plants and ideally, given its significant efficiency benefits when compared to other fossil-fueled facilities, provide incentives. CHP-specific solutions are address in Section IV below.

IV. CHP RESOURCES REQUIRE AND DESERVE SEPARATE TREATMENT UNDER ANY ALLOWANCE DISTRIBUTION METHOD.

The paradox faced by CHP discussed in Section III.E – decreasing global emissions but increasing on-site emissions – demonstrates that without thoughtful and deliberate rules, GHG regulations could easily dissuade companies from the continued operation of or investments in CHP. To best support CHP operation and further development, the following recommendations must be adopted:

- Create a CHP sector that would protect CHP resources under both a load-based or first-seller regulatory model
- Allocate allowances based on double benchmarking for CHP resources;
- Where an auction is mandated, make careful adjustments to ensure CHP investments are not penalized; and
- Where a load-based model is adopted, make adjustments to accommodate the interface of the electricity and CHP sectors.

A. Separate Sector Best Addresses Allocation for CHP Resources

CHP is the most efficient technology for converting primary fuel into electricity and heat. Current California CHP capacity is roughly 9.2 GWe, which saves from 11-22 million $MTCO_2$ emissions annually compared with separate production of thermal and electric energy.[19] According to the CEC's 2005 CHP Assessment,[20] an additional 2,000 MWe to 7,340 MWe could be developed in California by 2020, for another 2.4 to 8.8 million MT of GHG reduction. Therefore, a fundamental criterion for success of the GHG reduction program, as it has been in the EU-ETS, should be to promote the increased use of CHP in all

19 The range depends upon the assumption used to determine the power generation emissions that were displaced with the CHP development.

20 Darrow, K., McNulty, S., Price, S., EPRI (2005). *Assessment of California CHP Market and Policy Options for Increased Penetration: PIER Collaborative Report.* (CEC-500-2005-173)

relevant sectors. CHP should be maximized to increase primary energy savings, GHG reductions and conservation projects for excess fuel.

A separate CHP sector is warranted given that it sits astride the power and industrial sectors and thus risks being undervalued. In fact, to reflect the complexities and difficulties faced by CHP a number of EU Member States have given special attention to CHP. This has ranged from placing CHP in a separate sector (e.g. the UK) to allocation based on double benchmarking (e.g. Germany). The Commission of the European Community has also adopted a cogeneration or CHP directive. [21] This directive provides studied values for separate thermal and electrical production efficiencies that can be employed in the development of CHP principles under the ETS. This allows the authorities to deal specifically with CHP in a way that is materially different from other emitters of GHG and that reflects the benefits CHP brings to GHG reductions.

B. California Should Allocate Allowances Administratively to CHP Employing a "Double Benchmark" Method.

Benchmarking, in general, is a means of allocating permits not according to actual emissions but on the basis of the emissions of a typical, and often 'best available technology (BAT), plant for a given energy output. Thus, installations with efficiencies greater than the benchmark receive enough (or excess) allowances to cover their emissions, while less efficient installations are short of allowances. Benchmarking therefore provides a clear incentive for efficiency.

---

[21] Decision of the Commission of the European Community, 21 December 2006, establishing harmonized efficiency reference values for separate production of electricity and heat in application of Directive 2004/8/EC of the European Parliament and of the Council.

Where technically sound benchmarking methodologies exist, administrative allocation using a benchmark may be appropriate. "Double Benchmarking" is technically sound and best suited to allocation for CHP. This method is designed to reflect CHP's efficiency advantage over separate generation; this means that allowance allocation for the electrical output is based on the emissions of a conventional power plant while allocation for the heat output is based on the emissions of a conventional boiler or steam plant. Double Benchmarking provides the most clear and direct forms of incentive for the operation and further development of CHP installations. To effectuate this approach, regulators would provide CHP installations with allowances administratively in an amount equal to benchmarked values for the separate generation of electrical and thermal energy. This approach requires no baseline year, nor any review of history.

The EU provides useful experience in this regard. Germany has used double benchmarking for CHP in Phase 1 of the EU-ETS. The German program rewards the CHP plant for carbon savings against best alternative technologies (Combined Cycle Gas Turbine and gas boiler). The Netherlands, similarly, employs a Double Benchmark approach. As noted above, the EU's cogeneration directive also provides efficiency values that can be used to achieve the same result. A more detailed discussion of these approaches can be found in a white paper prepared by Dr. Simon Minett of Delta Environment and Engineering on behalf of EPUC/CAC.[22]

C. If California's Cap and Trade Design Makes Some Level of Auction Necessary for the CHP Sector, Careful Adjustments Must Be Made.

Without modification, an auction scenario would require an industrial site with CHP to procure more emissions allowances that it would otherwise be required to procure if it purchased grid power and operated a boiler. Under this scenario, an industrial consumer of electricity may receive a distorted incentive to use higher-emitting grid power rather than to rely on CHP facilities. This effect could discourage both operation of existing CHP facilities and the development of new facilities. Regulators can choose from a range of options, which either neutralize this effect or provide varying levels of incentive, to achieve their policy goals. For illustrative purposes, the recommendations rely on the scenario presented in Section III.E and assume a 100% auction.

1. Option A: Strongest CHP Incentive

The strongest incentive for CHP operation and development would be to provide all needed allowances to CHP plants using administrative allocation. This option for CHP provides the clearest signal possible that regulators are incentivizing CHP over alternative forms of fossil-fired generation. In effect, the CHP site would be receiving carbon-cost free

22 Minett, S., (May 2007) CHP Policy Assistance: A Report for the Energy Producers and Users Coalition and the Cogeneration Association of California.

electricity and also carbon-cost free heat, effectively putting CHP on par with non-fossil sources of heat and electricity.

There is a precedent for free allocation to CHP within an auctioning system. In the context of the second phase National Allocation Plans for the EU Emissions Trading System, Sweden has proposed that it will impose auctioning for all new generation plants except CHP for the period 2008 – 2012. It is not clear what would happen to new CHP built after the NAP II period, nor has this proposal been accepted by the Commission, but the aspects of the Swedish NAP being contested by the European Commission do not relate to CHP. We also understand that a senior EU official involved in ETS design supports the principle of fully free allocation to CHP in an auction system.

2. Option B: Moderate CHP Incentive

Under this scenario, using the diagram on page16, CHP buys allowances equivalent to stand-alone heat production (18), less the overall carbon savings achieved through the installation of CHP (8—39 less 31). The facility thus buys 10, with free allocation of 21. Here the CHP facility buys at auction what it would have been required to buy pre-CHP (18 units - meaning the CHP plant is effectively getting carbon-cost free electricity) with an added incentive based on the overall carbon savings arising from the investment. The free allocation of 21 is a strong incentive for CHP and could, for example, be made available as a specific stimulus for new CHP schemes.

3. Option C: Low Incentive

The amount of allowances to be purchased at auction would have to cover the full emissions minus the benchmark heat emissions which would be allocated for free. Based on the present example, this would provide a free allocation of 18 units, leaving the CHP operator having to buy 13 allowances. This option incentivizes both the operation of high efficiency CHP incumbents and new entrants while avoiding the creation of any distortions on the electricity market. In effect, the CHP operator would have to enter the auction to buy allowances for its electricity production, but it would be exempt from buying allowances to cover its heat production in recognition of the global carbon savings introduced by cogeneration. This allocation method maintains some incentive to invest in cogeneration instead of boilers. This is true because the CHP operator would, in all circumstances – whether replacing electricity or heat generating plant - see a reduction in the CO_2 allowances that need to be purchased.

4. Option D: Low Incentive

Under this scenario, CHP buys allowances to cover emissions associated with its heat production (18 units of CO_2). The facility, therefore, will get a free allocation of 13 units of CO_2. This is the same as Option B, without the additional incentive of 8 free allowances based on global carbon savings – in other words, the facility is required only to buy the same quantity of allowances as it would have pre-CHP. This level of support would at least ensure that there should be no disincentive to existing or new CHP (provided centralized electricity generation is not subsidized in the trading system).

D. Coordination with a Load-Based Electricity Sector Model

Because part of the production of a CHP plant may be sold to an LSE, as well as be used on site, the EPUC/CAC proposals present a complication under a Load-Based model. Under a Load-Based model, electricity sector allowances would be allocated to the LSE, rather than the producer. Within the CHP sector, however, allowances would be allocated directly to the CHP producer. It is important, therefore, to avoid double allocation for CHP MWh delivered to the grid for resale by an LSE.

Two adjustments would be required to accommodate the interface of the electricity and CHP sectors. First, the allocation to LSEs would need to be adjusted to remove allowances corresponding to CHP deliveries into the LSE portfolio to avoid double allocation. Second, when power is sold by the CHP plant to the LSE, the power would enter the LSE's portfolio as zero-emissions power. It would do so because the compliance obligation for the CHP emissions would have to be met by the CHP plant itself and no further LSE compliance thus would be required.

V. THE COMMISSION MUST PROVIDE DIRECTLY FOR RECOVERY OF GHG COSTS UNDER EXISTING CONTRACTS AND THROUGH ADMINISTRATIVELY DETERMINED PRICES TO MAINTAIN A SUFFICIENT AND STABLE SUPPLY OF POWER TO CALFIORNIA CONSUMERS.

Implementing an auction-based allowance allocation system carries a particular risk for generators with contracts in place when AB 32 is implemented, as well as generators paid under administratively determined prices. The MAC Report stated: "*Some independent power producers may operate under long term fixed price contracts and thereby not be able to pass through costs until those contracts expire. Whether these producers should receive a free allocation in the interim should be evaluated carefully.*"[23] Likewise, Professor Robert Stavins of Harvard University's John F. Kennedy School of Government has concluded that "*consideration should be given to the implications of long-term contracts for generators' and cogenerators' ability to recover any new allowance costs.*"[24]

Contracts executed before final implementation of AB 32 may not squarely address responsibility for carbon-related costs or will address them inadequately. Likewise, without modification, the CPUC's short-run and long-run avoided cost formulas for QFs would not compensate generators for the cost of carbon allowances. Under a system of free allocation of allowances, there would be no immediate injury to these generators. In the case of an auction, however, existing contracts and QFs would face a strong potential of becoming immediately unprofitable. A rational operator of an unprofitable generation facility would choose not to operate.

Consider the per kW impact of a \$8/MTCO$_2$ carbon adder on QFs compensated under SRAC or LRAC:

---

23 MAC Report at 56.

24 Stavins, Robert, *Comments on the Recommendations of the Market Advisory Committee to the California Air Resources Board* (June 2007).

Line	Description	Value	Units
	Assumptions:		
1	Capacity Factor	92.0%	
2	CO_2 Natural Gas Emission Rate	118	LBS/MMBtu
3	CO_2 Emission Allowance Requirement[a]	4.7	Metric Tons per kW
4	SRAC Capacity Rate	$32.53	per kW-yr
5	LRAC Capacity Rate	$91.97	per kW-yr
		SRAC (Dollars)	**LRAC (Dollars)**
	Fixed Cost Related Revenue Per D.07-09-040		
6	Total Cost of Avoided Resource	$64.13	$156.97
7	less: Ancillary Service/Contract Length Adj	$14.82	$10.00
8	less: Fixed Cost in Energy Payment Adj	$16.78	$55.00
9	Total D.07-09-040 Fixed Cost Payment	$32.53	$91.97
10	Project Cash Flow Before CO_2 Allowance[b]	$26	$63
11	CO_2 Allowance Cost at $8/Metric Ton	$38	$38
12	Project Cash Flow After CO_2 Allowance	-$12	$25
13	Reduction in Project Cash Flow	147.6%	60.3%

[a]Based on 2003 CA Natural Gas CHP average heat for projects reporting to EIA.
[b]Based on 2006 MPR Levelized cash flow as a percent of total Fixed Cost Revenues; Calculated as 40% of Line 6

The table above demonstrates that, even with a very conservative price of \$8/$MTCO_2$ reductions in project margins will be 142.9% for SRAC and 58.4% for LRAC. At \$50/$MTCO_2$, reductions in project margins will be 922.4% for SRAC and 376.9% for LRAC. In short, an auction can have significant impacts on reducing CHP facility margins.

For these reasons, EPUC/CAC again recommend the administrative allocation of allowances. In the event an auction is mandated, however, the Commission would be well-advised to provide for existing bi-lateral contracts and for price takers under QF regulations. In this circumstance, GHG regulations must provide for the pass through of the seller's direct and actual carbon cost incurred to meet its obligation to the utility.

VI. RESPONSES TO SPECIFIC QUESTIONS

Q1. Please comment on each of the criteria listed by the MAC. Are these criteria consistent with AB 32? Should other criteria be added, such as criteria specific to the electricity and/or natural gas sectors? In making trade-offs among the criteria, which criteria should receive the most weight and which the least weight?

Each of the principles identified by the Ruling is a reasonable objective for the program. Of the principles noted, particular weight should be placed on solutions that will actually reduce GHG emissions in the sector. In particular, regulators should promote a program that:

a. Promotes investment in low-GHG technologies and fuels (including energy efficiency) and

b. Avoids perverse incentives that discourage or penalize investments in low-GHG technologies and fuels (including energy efficiency).

Additional, more focused principles for the electricity industry should be adopted. Energy regulators should aim to:

√ Ensure a continued and reliable supply of electricity.
√ Encourage energy independence and customer participation in efficient supply development through solar and combined heat and power technologies.
√ Maintain the economic health of California's business.
√ Forestall growth in reliance on imported power.

Finally, regulators should be discerning in applying the principle of "ensuring that environmental benefits accrued to overburdened communities." Although it is common knowledge, it bears repeating that carbon emissions themselves are a long-term global problem and have no unique local effect. Concerns about environmental justice reside not with GHG but with the correlation between carbon emissions and criteria pollutants.

Q2. Broadly speaking, should emission allowances be auctioned or allocated administratively, or some combination?

EPUC/CAC recommend administrative allocation for the reasons discussed in Section III above.

> Q3. *If you recommend partial auctioning, what proportion should be auctioned? Should the percentage of auctioning change over time? If so, what factors should be used to design the transition toward more auctioning?*

California needs to learn by doing, as the European Union has done. Auctions should be phased in a cautious, measured manner, after evaluations are completed to review leakage and impacts on the economy and systems are designed for the appropriate use of auction revenues. If auctioning is included in the early program design, it should be limited to a nominal percentage. EU-ETS Phase 2, for example, sets the auction percentage at 5%.

> Q4. *How should new market entrants, such as energy service providers, community choice aggregators, or (deliverer/first seller system only) new importers, obtain emission allowances, i.e., through auctioning, administrative allocation, or some combination?*

New entrant CHP plants should receive allowances in the same manner as existing CHP plants, through administrative allocation. In terms of the optimal conversion of fossil fuels to useful products, CHP is the best solution, maximizing the energy yield of the fuel and minimizing the carbon footprint. Thus the treatment of new entrants should encourage CHP in preference to heat-only boilers or central power stations. In the EU-ETS many countries' New Entrant Reserve reflect a preference for CHP.

Thus EPUC/CAC recommend that treatment of new entrants should favor the development of CHP plants that are more efficient and provide greater GHG benefits than other combustion technologies. New entrants CHP plants should receive allowances in the same manner as existing CHP plants and here we recommend administrative allocation.

> Q5. *What are the important policy considerations in the design of an auction?*

While EPUC/CAC do not support the use of an auction in allocating allowances, Section IV of these comments provides specific recommendations for the design of an auction that would include CHP. Significant evaluation of impacts to the economy and industries, as well as program design elements, are necessary before auctions can be properly implemented.

> Q6. *How often should emission allowances be auctioned? How does the timing and frequency of auctions relate to the determination of a mandatory compliance period, if at all?*

EPUC/CAC have no view on this question at this time.

Q7. *How should market power concerns be addressed in auction design? If emission allowances are auctioned, how would the administrators of such a program ensure that all market participants are participating in the program and acting in good faith?*

An informed recommendation would require an assessment of market power for generation serving California consumers. Additionally, the conclusion may be different under a first seller approach, where there are many regulated entities, compared with a load-based approach, where fewer entities are regulated. Finally, this information still would not provide the entire picture for a potential exercise of market power if non-generator interests are permitted to participate in the initial auction. Should California elect to pursue an auction, further study of this issue is required.

Q8. *What criteria should be used to designate the types of expenditures that could be made with auction revenues (including use to reduce end user rates), and the distribution of money within those categories?*

AB 32 and this Rulemaking are aimed at reducing GHG emissions. Auction revenues should be used to further this purpose, and California should resist the temptation to use this revenue as a stealth tax or revenue source for any other purpose.

The MAC Report presented a variety of options for investment or use of auction revenues. The MAC proposed to use revenues for efficiency programs, distributing allowances for free to LSEs to deliver energy efficiency, income tax reductions, rebates to state residents and programs to support workers at firms affected by competition from unregulated jurisdictions. While EPUC/CAC do not support an auction of GHG allowances in the first phase of the AB 32 program, any auction revenues derived under AB 32 due to electricity sector emissions should be used primarily to expedite attainment of the state's GHG reduction goals through electricity sector investments in facilities subject to an auction.

Electricity sector investments can address all classes of consumers. Investment in programs advancing conservation, energy efficiency and residential solar solutions would benefit the residential and commercial classes. Investment in programs advancing energy efficiency, customer-specific renewable installations and CHP projects would benefit large commercial and industrial customers.

Auction revenues should not be used to reduce rates – a purpose that falls outside the primary AB 32 goals and raises Dormant Commerce Clause concerns. To the extent rate reductions occur, however, they must be shared equally among customer classes since all classes will bear the price consequences of the regulation.

A particularly beneficial measure in the event of an auction would use auction revenues to encourage reduction projects by emitters participating in the auction.[25] Specifically, regulated firms should be permitted to set-aside auction payments in an escrow account for reinvestment to the extent they can employ the payments in cost-effective local GHG reducing projects.[26] For example, the program could permit an electric generator to retain auction revenues to invest in repowering or aftermarket reduction technologies to reduce on-site generation emissions. In the case of an industrial site, auction revenue retention may stimulate the installation of energy efficient on-site resources, including CHP, solar or wind projects.

This revenue retention measure brings with it a variety of benefits. First, while an auction takes needed capital for reduction projects out of the hands of regulated firms, auction revenue retention would partly mitigate this result. Second, permitting self-direction of auction revenues would increase the likelihood of capital investment by favorably changing the ability of the project to compete for the firm's internal capital, because the funds would require the firm to "use it or lose it". Third, it would expedite achievement of reductions of GHG emissions in the electricity sector. Fourth, the plan could reduce the administrative bureaucracy required to develop and administer centralized reduction programs; those costs would be borne by the emitter. Fifth, in some locations, local benefits would accrue to the extent the GHG reduction projects carried co-benefits in the form of reductions in correlated criteria pollutants. Finally, given the obvious concern regarding impact on firms competing in markets outside California's GHG program, the revenue retention approach would seem to mitigate the impact on the firm and its workers by encouraging continued investment in California assets.

Q9. What type of administrative structure should be used for the auction? Should the auction be run by the State or some other independent entity, such as the nonprofit organization being established by the Regional Greenhouse Gas Initiative?

EPUC/CAC have no view on this issue at this time.

---

[25] This type of option was raised in the December 15, 2006, Summary of the Median Proposal for an Oregon Carbon Allocation Standard, which contemplated partial retention of the Carbon Dioxide Reduction Charge for specified sources.

[26] Because GHG is a long-term global commons problem, rather than a local problem, the objective of the self-reinvestment approach would be aimed at correlated or criteria pollutants.

Q10. If some or all allowances are allocated administratively, which of the above method or methods should be used for the initial allocations? If you prefer an option other than one of those listed above, describe your preferred method in detail. In addition to your recommendation, comment on the pros and cons of each method listed above, especially regarding the impact on market performance, prices, costs to customers, distributional consequences, and effect on new entrants.

EPUC/CAC take no position on the general allocation method for the electricity sector. Administrative allocations to CHP facilities, however, should be done in a separate CHP sector on a Double Benchmark basis, as described in Section IV.

Q11. Should the method for allocating emission allowances remain consistent from one year to the next, or should it change as the program is implemented?

The method of allocation should be clear and transparent so that industry can plan investments and measures to reduce GHG. An investment in a CHP plant can take from 3 to 5 years to implement from the original investigations. CHP is thus a long-term investment and requires regulatory stability. For example, in the UK since the implementation of EU-ETS, there have been no new investments in large CHP plants. There are a number of reasons for this, but one principal cause has been the phased approach for the EU-ETS, with each period resulting in a change in approach to allocation. European industry has consistently argued that Phase 3 must have a long-term perspective.

EPUC/CAC recommend that the GHG Reduction Program takes a long-term consistent approach to allocation that provides industry with a clear view of the requirements to meet its commitments.

Q12. If new market entrants receive emission allowance allocations, how would the proper level of allocations be determined for them?

EPUC/CAC comments are restricted to new market entrants that are CHP facilities. Other approaches are possible for other technologies or market players.

CHP, as stated earlier, is the most efficient conversion technique of fossil fuels into heat and power. Therefore, it is one of the key technologies to stimulate in a GHG Reduction Program. New CHP facilities should be provided with the allowances they require. Germany and the Netherlands, among others EU-ETS members, use double benchmarking. In the UK it is determined by the rated capacity of the facility multiplied by an annual load factor.

The annual load factor for new facilities can be based either on each facility's expected operating hours or by a sector specific average, for example an oil refinery will operate for at least 8,600 hours per year.

EPUC/CAC recommend that preference be given to CHP facilities in any New Entrant Reserve and that each CHP facility receive allocations based on double benchmarking.

> *Q13. If emission allowances are allocated based on load/sales, population, or other factors that change over time, how often should the allowance allocations be updated?*

EPUC/CAC take no position in these comments on the methodology used generally for administrative allocation.

> *Q14. If emission allowances are allocated based on historical emissions ("grandfathering") or benchmarking, what base year(s) should be used as the basis for those allocations?*

EPUC/CAC take no position in these comments on the methodology used generally for administrative allocation but notes that an allowance based on double benchmarking for CHP resources negates the need to establish a base year because allowances are based against current best available control technology and equipment vintage.

> *Q15. If emission allowances are allocated based initially on historical emissions ("grandfathering"), should the importance of historical emissions in the calculation of allowances be reduced in subsequent years as providers respond to the need to reduce GHGs? If so, how should this be accomplished? By 2020, should all allocations be independent of pre-2012 historical emissions?*

EPUC/CAC take no position in these comments on the methodology used generally for administrative allocation.

> *Q16. Should a two-track system be created, with different emission allowances for deliverers/ first sellers or retail providers with legacy coal-fueled power plants or legacy coal contracts? What are the factors and trade-offs in making this decision? How would the two tracks be determined, e.g., using an historical system emissions factor as the cut-off? How should the allocations differ between the tracks, both initially and over time? What would be the market impact and cost consequences to consumers if a two-track method were used?*

A two-track approach would add distortion and complication to the cap and trade system and would detract from the overall objective of a GHG emissions trading scheme. No other emission trading program has such an approach, and a two-track system could lead to integration problems with other programs. One ton of GHG emissions should be equivalent to any other ton of GHG emissions.

> *Q17. If emission allowances are allocated administratively to retail providers, should other adjustments be made to reflect a retail provider's unique circumstances? Comment on the following examples, and add others as appropriate:*
>
> *a. Climate zone weighting to account for higher energy use by customers in inclement climates, and*
>
> *b. Increased emission allowances if there is a greater-than-average proportion of economically disadvantaged customers in a retail provider's area.*

A ton is a ton, regardless of the location of the emissions. No location-specific adjustments thus should be made in allocation of allowances. Adjustments of this nature would add complexity and could lead to distortions in the allocation system, price signals or market operation.

These issues exist in Europe, where climate variations are much greater than in California and there are some very poor regions. These issues are not included in the design of the EU-ETS. The EU uses other policies and measures to address these issues. The GHG Reduction Program must not be used to tackle other societal problems.

> *Q18. Should differing levels of regulatory mandates among retail providers (e.g., for renewable portfolio standards, energy efficiency investment, etc.) be taken into account in determining entity-specific emission allowance allocations going forward? For example, should emission allowance allocations be adjusted for retail providers with high historical investments in energy efficiency or renewables due to regulatory mandates? If those differential mandates persist in the future, should they continue to affect emission allowance allocations?*

EPUC/CAC have no view on this issue at this time.

> *Q19. How often should the allowance allocation process occur? How far in advance of the compliance period?*

Allowance allocation should be clear, transparent and of sufficient duration to encourage investment. As stated earlier, industrial CHP needs a period of up to 5 years to realize a project and then a period of 10-20 years of operation. In the EU-ETS investment was delayed partly through the uncertainties surrounding allocation between Phase 1 and Phase 2. At present, CHP investors are concerned about the shape of Phase 3 which is adding to the risk profile of CHP and will affect investment decisions.

EPUC/CAC recommend that the compliance periods are at least five years and that the design of the forthcoming compliance period is undertaken at the start of the preceding period.

> *Q20. What are the distributional consequences of your recommended emission allowance allocation approach? For example, how would your method affect customers of retail providers with widely differing average emission rates? Or differing rates of population growth?*

EPUC/CAC have no view on this issue.

> *Q21. Would a deliverer/first seller point of regulation necessitate auctioning of emission allowances to the deliverers/first sellers?*

No. Admittedly administrative allocation presents a degree of complexity under First Seller for imports. The complexity, however, does not prevent implementation of a First Seller Model.

Under a First Seller Model, administrative allocation to in-state sources is relatively straightforward, similar to a pure source-based model. Either a benchmark or grandfathered approach could be applied to in-state generation sources.

Administrative allocation to cover emissions from imported power, however, presents a greater challenge. Who are the First Sellers in these transactions? To which out-of-state entities should allowances be allocated? Regulators have a few alternatives to address this issue:

1. Under a grandfathering approach, import allowances could be allocated *ex ante* to those parties who sold into the California market during the baseline or reference period used for all in-state allocations.

2. Under a benchmark approach, an allowance could be conveyed *ex post* at the benchmark rate to every MWh as it is imported into the state, provided that the MWh is tagged with its region of origin to verify its import status.

3. Allocate *ex ante* to imports under long-term contracts with LSEs using same baseline and methodology employed for in-state resources.

An administrative allocation under the First Seller approach would require modification to address self-generation and CHP. Energy from on-site generation consumed by load on the generation site introduces complications, as the power may never be "sold" or go to market. The approach could be modified to treat the on-site CHP facility as the First Seller, which would receive a direct administrative allocation.

Q22. Are there interstate commerce concerns if auction proceeds are obtained from all deliverers/ first sellers and spent solely for the benefit of California ratepayers? If there are legal considerations, include a detailed analysis and appropriate legal citations.

Yes. If California elects to distribute emissions allowances through an auction, the manner in which auction proceeds are used will affect the ability of the regulation to survive challenge under the Dormant Commerce Clause (DCC).

The DCC focuses on differential treatment that favors in-state economic interests and burdens out of state interests.[27] While the DCC does not completely preclude differential treatment, the applicable legal standards place a great deal of weight on the importance of a regulation's objective. In determining whether a regulation can pass legal scrutiny, courts balance a regulation's objective against other factors. This means that the purpose of a regulation will largely determine whether a regulation can survive legal challenge. Importantly, courts are most reluctant to invalidate regulations that are directed to health and safety issues – a clear objective of AB 32.[28] In determining the objective of AB 32 implementation, the court will examine the use of the proceeds to ensure that the stated objective of promoting health and safety is carried out. Given the nature of the DCC legal standards, the use of auction proceeds for measures that will lower GHG emissions will best protect the adopted regulation from challenge, but will not guarantee its survival.

State Regulation's Objective Is a Critical Factor in DCC Analysis

Regardless of the legal standard applied, the objective of a state regulation plays a significant role in determining whether it will survive legal challenge. The dormant commerce clause limits states from discriminating against or burdening interstate commerce.[29] Discrimination is defined as differential treatment that

---

27 *Oregon Waste Systems, Inc. v. Department of Environmental Quality of Oregon*, 511 U.S. 93, 99 (1994).

28 *Kassel v. Consolidated Freightways Corp of Delaware*, 450 U.S. 662, 670 (1981).

29 Id.

favors in-state economic interests and burdens out of state interests.[30] The first step in determining whether a state law can survive DCC challenge is to evaluate whether the law is discriminatory on its face or regulates even-handedly with only incidental effects on interstate commerce.[31] The second step involves applying the appropriate standard of review to evaluate the statute.[32]
Both legal standards used under DCC jurisprudence place much weight on the objective or purpose of a state regulation:

- <u>Facially Discriminatory Statute</u>: can survive Commerce Clause scrutiny only if:
  (i) *"the discrimination is demonstrably justified by a valid factor unrelated to economic protectionism."*[33]
  (ii) there are no *"'nondiscriminatory alternatives adequate to preserve the local interests at stake.'"*[34]

- <u>Even-Handed Statute:</u> will be invalidated only if the incidental impact of the statute exceeds the *"putative local benefit."*[35] In determining whether the incidental impact outweighs the local benefit, *"the extent of the burden that will be tolerated will . . . depend on the nature of the local interest involved, and on whether it could be promoted as well with a lesser impact on interstate activities."*[36]

The standards demonstrate that the perceived objective of regulation will be important in determining the regulation's ability to satisfy Commerce Clause standards.

Use of Auction Proceeds Must Carry Out the Regulations' Health and Safety Objectives for the Regulation's To Withstand Legal Challenge

The way in which auction proceeds are used will impact a court's perception of an adopted regulation's objective. As explained in EPUC/CAC's opening comments to the MAC Report, a regulation that shares AB 32's goals and objectives is likely to withstand a DCC challenge due to its focus on public health and welfare. Use of auction proceeds, to lower GHG emissions, would further this focus. If auction proceeds are used to mitigate compliance cost impacts, however, the focus of the regulation will, for practical purposes, be to mitigate the

---

30 Id.
31 Id..
32 Id.
33 *Wyoming v. Oklahoma*, 502 U.S. 437, 454 (1992); *Oregon Waste Systems, Inc.*, 511 U.S. at 93; *Maine*, 477 U.S. at 131.
34 *Chemical Waste Mgmt Inc. v. Hunt*, 504 U.S. 334, 342 (1992) (*quoting Hunt v. Washington Apple Advertising Comm'n*, 432 U.S. 333, 353 (1992).
35 Oregon Waste Systems, Inc., 511 U.S. at 99; *Maine*, 477 U.S. at 138; *Pike v. Bruce Church, Inc.*, 397 U.S. 137, 142 (1970); *National Solid Waste Mgmt. v. Pine Belt Regional Solid Waste Mgmt Auth'y*, 389 F.3d 491, 497 (5th Cir. 2004).
36 *Pike v. Bruce Church, Inc.*, 397 U.S. 137, 142 (1970).

in-state economic impact of GHG regulations. As demonstrated below, auction proceeds should be used to reduce GHG emissions given that health and safety statutes are uniquely positioned to resist legal challenge.

Significant weight is accorded to state efforts to protect the health and safety of its citizens. In fact, in the context of the DCC, the Supreme Court has stated that "*a State's power to regulate commerce is never greater than in matters traditionally of local concern*." Health and safety are traditional matters of local concern.[37] As a result "*regulations that touch upon safety . . . are those that 'the Court has been most reluctant to invalidate.'*"[38] Also, "'*if safety justifications are not illusory, the Court will not second-guess legislative judgment about their importance in comparison with related burdens on interstate commerce.*'"[39] Finally it states that "*[t]hose who would challenge such a bona fide safety regulations must overcome a 'strong presumption of validity.*'" [40]

Importantly, the stated objective of promoting health and safety must be carried out in reality. The Supreme Court has indicated that "*the incantation of a purpose to promote the public health or safety does not insulate a state law from Commerce Clause attack.*" [41] Regulations that only marginally further health and safety but create substantial barriers to commerce will therefore be invalidated.[42] In *Kassel*, the Supreme Court invalidated an Iowa statute where no evidence was provided that a restriction on the length of vehicles would increase safety.[43] Similarly, in *Raymond*, the Supreme Court invalidated Wisconsin regulations precluding the operation of trucks longer than 55 feet and double-trailer trucks because the record contained no evidence that the regulations would increase highway safety.[44] In contrast, in *Welch*, where plaintiffs could not overcome the strong presumption of validity, the court upheld a county ordinance which precluded the land application of sewage sludge on health and safety grounds.

Use of auction proceeds to mitigate the economic impact of GHG regulations can compromise the ability of a state regulation to withstand legal challenge because it will drastically alter the perceived objective of the regulation.[45] An out-of-state

---

37 *Hill v. Colorado*, 530 U.S. 703, 715 (2000) ("*It is a traditional exercise of the States' 'police power to protect the health and safety of their citizens.*'").

38 *Kassel v. Consolidated Freightways Corp of Delaware*, 450 U.S. 662, 670 (1981).

39 *Id.*

40 *Id.*

41 *Id.*

42 *Id.*

43 *Id.*

44 *Raymond Motor Transportation, Inc. v. Rice*, 434 U.S. 429, 437-438 (1978).

45 If the focus of the regulation appears to be directed to rate regulation, in addition to DCC issues, the adopted regulation will be vulnerable to challenge under the Federal Power Act (FPA). EPUC/CAC Reply Comments to the MAC Report explain that the purpose of the regulation can determine whether a state regulation will be preempted. *See* EPUC/CAC Reply Comments to MAC Report, at 4-8. Where a regulation could be perceived to be directed to rate reduction, the likelihood of preemption is higher. *See Northern Natural Gas Co. v. State Corp. Comm'n of Kansas*, 372 U.S. 84, 92 (1963). In

marketer or generator could reasonably argue that such a regulation is meant to extract payment from out-of-state sellers for the purpose of lowering cost impacts of in-state residents. Unlike statutes that are focused on health and safety issues, no legal presumptions are available to ensure that economically-motivated regulation can withstand DCC attack. Even worse, use of proceeds to mitigate in-state economic impact could require the state to provide evidence that the adopted regulation furthers the health and safety of state citizens. It is possible that this use of auction proceeds could still survive a DCC challenge but surviving such a claim would not be easy given the regulatory landscape.

Q23. If you believe 100% auctioning to deliverers/ first sellers is not required, explain how emission allowances would be allocated to deliverers/first sellers. In doing so, answer the following:

- *a. How would the amount of emission allowances given to deliverers/first sellers be determined during any particular compliance period?*
- *b. How would importers that are marketers be treated, e.g., would they receive emission allowance allocations or be required to purchase all their needed emission allowances through auctions? If allocated, using what method?*
- *c. How would electric service providers be treated?*
- *d. How would new deliverers/first sellers obtain emission allowances?*
- *e. Would zero-carbon generators receive emission allowance allocations?*
- *f. What would be the impact on market performance, prices, and costs to customers of allocating emission allowances to deliverers/ first sellers?*
- *g. What would be the likelihood of windfall profits if some or all emission allowances are allocated to deliverers/first sellers?*
- *h. How could such a system prevent windfall profits?*

The Comments address administrative allocation under a first-seller approach in response to Question 21. The question of windfall profits is discussed in Section III.C. EPUC/CAC take no position on whether generally the electric sector allocation should be done using grandfathering or benchmarking, but propose double benchmarking for

---

contrast, if a state promulgates a regulation pursuant to its police powers, preemption is less likely. *See Federal Energy Regulatory Comm'n*, 105 FERC ¶ 61004, 2003 WL 22255784 *5 (F.E.R.C. 2003).

CHP in Section IV.

Q24. With a deliverer/first seller point of regulation, should administrative allocations of emission allowances be made to retail providers for subsequent auctioning to deliverers/ first sellers? If so, using what allocation method? Refer to your answers in Section 3.4.1., as appropriate.

No. There is no legitimate purpose served by this approach, and it presents increased complexity in the marketplace.

This proposal, which we recognize as PG&E's proposal, achieves the same result as a general auction with one exception. Under an LSE auction or a general auction: (1) an auction occurs (2) First Sellers participate in the auction and pay for allowances; (3) First Sellers bear a compliance obligation and (4) revenues are generated that must be allocated to designated purposes. The only apparent difference between a general auction and an LSE auction is control of the auction revenues. PG&E's proposal is aimed to ensure that all auction revenues are retained for the benefit of an LSE's customers or programs.

It is unnecessary to go through the proposed distortion to achieve PG&E's goals. Regardless of where the auction occurs, the State can elect to use all or a portion of auction revenues attributable to the electricity sector for sector-specific purposes. Moreover, this distortion adds complexity by putting an LSE in the conflicting position both of auctioneer and purchaser of sector emissions allowances.

Finally, the goal of a market-based cap-and-trade program is multi-sector trading. Given this goal, and the view that "a ton is a ton", if an auction occurs, there should be a single, multi-sector auction conducted at one time. A separate sector auction or, worse yet, LSE-specific auctions, would run contrary to this goal.

Q25. If you recommend allocation of emission allowances to retail providers followed by an auction to deliverers/first sellers, how would such an auction be administered? What kinds of issues would such a system raise? What would be the impact on market performance, prices, and costs to customers?

N/A.

Q26. Answer each of the questions in Section 3.4.1. except Q16, but for the natural gas sector and with reference to natural gas distribution companies (investor- or publicly-owned), interstate pipeline companies, or natural gas storage companies as appropriate. Explain if your answer differs among these types of natural gas entities. Explain any differences between your answers for the electricity sector and the natural gas sector.

EPUC/CAC represent the electricity production and consuming interests of its members and does not address natural gas issues.

> Q27. *Are there any other factors unique to the natural gas sector that have not been captured in the questions above? If so, describe the issues and your recommendations.*

EPUC/CAC represent the electricity production and consuming interests of its members and does not address natural gas issues.

> Q28. *Considering your responses above, summarize your primary recommendation for how the State should design a system whereby electricity and natural gas entities obtain emission allowances if a cap and trade system is adopted.*

Section I of these comments provides an executive summary of EPUC/CAC recommendations.

October 31, 2007

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
Michael Alcantar

Counsel to the Energy Producers and Users Coalition and the Cogeneration Association of California

CERTIFICATE OF SERVICE

I, Karen Terranova hereby certify that I have on this date caused the attached **Comments of the Energy Producers & Users Coalition and the Cogeneration Association of California on Allowance Allocation Issues** in R.06-04-009 to be served to all known parties by either United States mail or electronic mail, to each party named in the official attached service list obtained from the Commission's website, attached hereto, and pursuant to the Commission's Rules of Practice and Procedure.

Dated October 31, 2007 at San Francisco, California.

Karen Terranova

Karen Terranova