**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 INDICATED PRODUCERS ON POINT OF REGULATION ISSUES

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 Indicated Producers

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The Indicated Producers[1] (IP) submit the following comments on the Administrative Law Judge's ruling (ALJ Ruling) issued on November 28, 2007.

I. OVERVIEW AND SUMMARY OF RECOMMENDATIONS

The Commission seeks comments on the appropriate point of regulation for the natural gas sector. The natural gas sector debate materially lags the electricity sector due to a lack of national or global debate on small-source combustion and a slower start in California's discussion. In addition, data useful to the debate have yet to be developed or accessed. The relative depth of the debate thus precludes a fully informed response.

With these limitations in mind, the Indicated Producers generally support the initial recommendations offered by Staff in their July 12, 2007 *Preliminary*

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[1] Member companies include Aera Energy LLC, BP West Coast Products LLC, ConocoPhillips Company, Chevron U.S.A. Inc., and Occidental Energy Marketing, Inc.

Staff Recommendations for Treatment of Natural Gas Sector Greenhouse Gas Emissions (Staff Report). Specifically, Staff's direction is on solid ground in several areas:

- Regulation of the natural gas sector should not duplicate electricity or industrial sector regulation;
- Any cap-and-trade program arising from AB 32 must include natural gas emissions to enhance carbon market liquidity and ensure cost-effective emission reductions;
- Emissions within the scope of the natural gas sector are best regulated at the local distribution company level.

In addition to these recommendations, these comments recommend that combined heat and power emissions be regulated within a separate sector. These and other issues are discussed below.

II. THE SCOPE OF REGULATION FOR THE NATURAL GAS SECTOR MUST BE LIMITED TO PRECLUDE DUPLICATIVE REGULATION

The scope of the natural gas sector GHG regulation remains unsettled. One simple objective, however, must be made clear: natural gas sector regulations must avoid duplicating GHG regulation of entities regulated in the electricity and industrial sectors. The Commission should look to Staff recommendations in addressing this foundational issue.

The initial ruling and Staff recommendations propose a scope for the natural gas sector that avoids imposing duplicative regulation on entities. The initial ruling recommends that the scope be limited to addressing:

(1) combustion of natural gas by non-electricity generator end-use customers and

(2) all transmission, storage and distribution of natural gas within California.

Commission Staff goes further to recommend excluding the following from the scope of the inquiry: natural gas used in electric generation, industrial customers regulated by CARB, and emissions associated with transportation.[2] CARB defines smaller end-use customers, not regulated as point sources, to be those that emit 25,000 $MTCO_2$ or less per year.[3] Consistent with Commission Staff recommendations, the Commission should focus on developing regulations which lower GHG emissions arising from the combustion of natural gas by end-use customers falling outside the scope of source-specific regulation in the electricity or industrial sectors.

III. ANY CAP-AND-TRADE PROGRAM ARISING FROM AB 32 MUST INCLUDE NATURAL GAS EMISSIONS

A cap-and-trade program can achieve mandated emissions reductions at the least cost as required by AB 32. Including all regulated sectors in the cap-and-trade program, including natural gas, will enhance market liquidity and better serve the state's reduction goals. An expansive cap-and-trade program will also ensure parity between regulated sectors.

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2 Staff Recommendations, at 15-16. Staff also observes that the amended scope does not include emissions associated with extraction, gathering and processing of natural gas. Id. at 2.

3 Presentation of the CARB Workgroup Reporting General Stationary Combustion GHG Emissions, dated June 25, 2007, p. 19 (http://www.arb.ca.gov/cc/ccei/presentations/GSCSlides_6_25_07.pdf).

A. Cap and Trade Program Advances AB 32 Objectives

Adoption of a cap-and-trade program that includes as many sectors as possible will ensure that emission reductions can take place at the least cost. Consideration of compliance costs is consistent with AB 32 which expressly requires regulators to consider the cost of reducing emissions:

> *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 minimizes costs and maximizes benefits for California's economy, improves and modernizes California's energy infrastructure and maintains electric system reliability, maximizes additional environmental and economic co-benefits for California, and complements the state's efforts to improve air quality.*[4]

As explained in the MAC Report, a cap-and-trade program allows the market to make cost effective decisions about how to comply with emission-reduction programs.[5] Moreover, as long as regulators lower the permitted emissions from year to year, reductions will occur.[6] Finally and most importantly, a cap-and-trade program provides continuing incentives to market participants to identify and invest in emission-lowering tools.[7]

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4 Cal. Health & Safety Code § 38501.

5 MAC Report, at 7.

6 MAC Report, at 7.

7 MAC Report, at 7.

B. Including the Natural Gas Sector in the AB 32 Cap-and-Trade Program Enhances Market Liquidity, Better Serves the State's Reduction Goals and Ensures Consistency Among Sectors.

A cap-and-trade market will work best if its scope is maximized to include as many sectors as possible. Where a cap-and-trade market is adopted for other regulated sectors, it should also incorporate the natural gas sector.

California's annual emissions for all sectors total roughly 500 $MMtCO_2e$. Regulators should seek to maximize the tons included within the scope of a cap-and-trade program. Including the electricity sector will bring roughly 20% of these emissions under the cap-and-trade umbrella. The Staff Report suggests that including natural gas combustion from smaller sources could add 7-10% of the state's emissions to a cap-and-trade program.[8]

Maximizing the scope of the cap-and-trade program aids California in ensuring carbon market liquidity and effective results. Adding the natural gas sector means more emissions allowances (and a few additional players) in the carbon market. More emissions and more players mean greater liquidity, which enhances market operation.

Including natural gas in the cap-and-trade program also advances the goal of consistency. As Staff recommendations suggest, ensuring equity in treatment within the energy sectors is an important objective.[9] If a cap-and-trade program is adopted for the electricity sector, for example, the same cost-effective tool must be available to the natural gas sector.

[8] Staff Report, Table 3, at 7.

[9] Staff Report, at 15 ("*To ensure consistency of treatment among various sectors of the California economy, and in particular the energy sectors, staff recommends that natural gas-related emissions be treated in a manner similar to the treatment of electricity-related emissions in the final approach adopted by ARB.*").

IV. SMALL-SOURCE NATURAL GAS EMISSIONS SHOULD BE REGULATED AT LOCAL DISTRIBUTION COMPANY LEVEL

In general, source-based regulations, as implemented in the European Union's Emissions Trading Scheme and the Regional Greenhouse Gas Initiative, best align incentives for reductions with the emitter and allow accurate tracking of emissions. Regulating natural gas emissions at the stack for small sources, however, is impractical and infeasible. Moving upstream, the best alternative is to regulate emissions at the local distribution company (LDC) level.

A. Source-Based Regulation Is Not Feasible for the Natural Gas Sector.

Source-based regulation of GHG emissions in the natural gas sector is not feasible due to the administrative complexity of identifying and regulating millions of small sources. Staff observes that residential and commercial end users combust natural gas for space heating, water heating, and operating appliances such as ovens, dryers, furnaces and stoves. As Staff observes, "*[t]here are millions of residential and commercial end users, so regulation at every point of combustion is impractical.*"[10] To complicate matters further, unaccounted for emissions are released into the atmosphere in the process of transmission, storage and distribution. Due to the number of emitting sources, regulating each "source," equivalent to "stacks" in the electricity sector, is infeasible.

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10 Staff Recommendations, at 3.

B. Small-Source Natural Gas Emissions Are Best Regulated at the LDC Level.

As CPUC Staff recognizes, regulating emissions in the natural gas sector should be done at the LDC level. Regulation at the LDC level is best for the following reasons:

- Majority of emissions within the contemplated scope of regulation arise from combustion of natural gas by smaller, un-permitted end-use customers served by one of the three largest California utilities;
- Due to numerous sources of GHG emissions in the natural gas sector, regulation at each point of combustion is impractical; and
- Existing programs will be invaluable tools that can lower natural gas combustion by smaller end-use customers.

These factors are discussed below.

The bulk of emissions that would be included in the natural gas sector as contemplated arise from small, un-permitted end-use customer use. Approximately 13.87% of the state's GHG emissions are attributable to end-use combustion of natural gas from sources other than gas-fired electric generation.[11] Removing large industrial sources from this value, whose emissions will be separately addressed by CARB, puts the natural gas sector in the range of 7-10% of total state emissions.[12] Relying on this data, Staff observes that, "*affecting end user consumption is the largest potential source of GHG emission reductions.*" [13] Also, Staff notes that "*[o]ver 90% of end-users are served by the state's three biggest investor-owned natural gas utilities . . . .*"[14] Based on Staff's

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11 Staff Recommendations, at 6-7.
12 Staff Report, Table 3, at 7.
13 Staff Recommendations, at 9.
14 Staff Recommendations, at 3.

observations, an LDC-based approach with heavy reliance on programmatic tools can effectively target the emissions under the scope of this inquiry.

Staff's recommendation, however, requires clarification. Staff states that "*[r]egulation of emissions from smaller end users should be at the distribution utility level.*" There are two ways in which this proposal can be interpreted: regulation at the retail sales level (including all retail sales) or regulation at the retail distribution level (based on transportation volumes). These comments recommend the latter interpretation, as explained below.

The proposed "load-based regulation" of the electricity sector currently under consideration by the CPUC places the point of regulation on "load serving entities" (LSEs). LSEs include all retail sellers of electricity, including utilities and other electric service providers. In other words, the regulation attaches to the commodity sale at retail.

An LSE-based approach, like that under consideration in the electricity sector, would not be suitable for the natural gas sector. First, in the electricity sector, a retail provider can reduce the emissions in its portfolio by changing the mix of resources to include generation with fewer emissions. In contrast, in the natural gas sector, a retail provider cannot alter emissions by altering resource mix. ***The emissions attributable to a retail provider are simply a function of the size of the load it serves***. Second, the extent of retail competition in the natural gas sector is much greater than in the electricity sector. Roughly 9% of load in the electricity sector is served by non-utility LSEs,[15] and retail access may remain stagnant with Direct Access suspended. In contrast, 94% of California's

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[15] *See* http://www.eia.doe.gov/cneaf/electricity/st_profiles/california.html.

industrial natural gas load[16] and 35% of commercial load is served by non-utility commodity sales (i.e. gas marketers) in California.[17] As a result, a more significant portion of the natural gas commodity market is likely to shift among retail providers over the course of the compliance period. Most retail contracts have a term of one or two years. The frequent load-shifting among providers makes initial allocation of allowances and tracking difficult. Third, the inherent risk in a retail provider's shifting customer base may result in reflecting not only carbon allowance costs in its price, but a risk premium to accommodate the compliance burden. This risk could even cause some marketers to simply exit the retail market for smaller sources, leaving those sources with fewer options.

Placing compliance at the LDC as ***distributor,*** not seller, of natural gas would avoid all of these problems. The LDC would bear compliance responsibility for all gas it transports, including utility and non-utility sales volumes. Taking this approach would also increase the simplicity of the program.

Admittedly, regulating at the LDC level would overlook direct deliveries by interstate pipelines (e.g., Kern and Mojave) and Direct Sales (self-use). While these volumes represent roughly 20% of all gas consumption,[18] they would be beyond the "small" definition for purposes of the natural gas sector regulation and addressed directly by CARB under AB 32. The response provided by Kern

16 In the SoCalGas and PG&E service territories, virtually 100% of noncore commercial and industrial load is served (or should be served) by non-utility supply as a result of the Commission's Decision 90-09-089.

17 *See* http://tonto.eia.doe.gov/dnav/ng/ng_cons_acct_dcu_SCA_a.htm.

16 Staff Report, at 4.

River Gas Transmission Company's (KRGT) data response[19] supports this conclusion. Data Response 1b lists the meters and operators for direct deliveries by KRGT for 2004-2006. In all cases, the meter is associated with an electric generation facility (e.g., Juniper Generation), oil and gas producing field operations (Chevron, Aera, Oildale, McPherson) or large industrial operations (U.S. Borax).[20] Each of these operations is the type of operation likely to be addressed separately by CARB, and deliveries to each industrial facility will comfortably exceed 25,000 $MTCO_2e$ annually.

C. Regulation at the Wholesale Level Is Administratively Complex and Is More Susceptible to Legal Challenge.

Moving the compliance obligation further upstream from the LDC is not a viable option. Placing the point of regulation at the wholesale level will create administrative problems and expose the adopted regulations to legal challenge.

Although the scope of the natural gas sector has not been definitively established, the initial ruling suggests that the focus of the natural gas sector will be on emissions associated with combustion of natural gas by residential, small commercial and small industrial customers. Given this limited scope, regulating emissions at the wholesale level would be over-inclusive. Unlike the electricity sector, not every "first sale" into California would be consumed within the natural gas sector; many of the first-sale volumes would be consumed by entities regulated within the electricity or industrial sectors. Regulation at this level

[19] Administrative Law Judges' Ruling Extending Deadline for Comments and Incorporating Responses to Staff Data Request on Natural Gas Issues, December 10, 2007 (December 10 Ruling), Attachment E, Data Response 1b.

[20] The Indicated Producers observe that KRGT's data response is incorrect. KRGT identifies Racetrack as an Aera Energy LLC delivery point; instead, this point is a Chevron point associated with the rest of its "Kern River Field" deliveries.

therefore would require tracking systems that attribute an end-use to a volume when it enters the wholesale market. This type of tracking would be truly impracticable, since gas may be sold and resold in the wholesale market many times before reaching its point of consumption. Yet without this type of tracking, there would be no assurance that only wholesale volumes that ultimately land within the scope of the natural gas sector would be counted.

Direct regulation of wholesale transactions is also more susceptible to legal challenge. The Natural Gas Act (NGA) provides FERC exclusive authority to regulate wholesale natural gas transactions exposing wholesale regulation to the risk of preemption. NGA cases demonstrate that preemption is likely only when (i) a state regulation is "unmistakably and unambiguously" directed to regulate transactions that are within Congress' jurisdiction or (ii) a state regulation stands as an obstacle to the execution of Congressional objectives.[21] Arguably, California's implementation of AB 32 regulations, as described in the statute, would constitute an exercise of its policy powers given that it is directed to promoting the health and safety of its citizens.[22] It is possible, however, that regulation at the wholesale level will be challenged on the grounds that the regulation directly impacts wholesale transactions. In short, even though an NGA challenge could be overcome, it is likely that while placing the point of

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21 *Northwest Central Pipeline Corp.*, 489 U.S. at 511-515;*Transcontinental Gas Pipeline Corp. v. State Oil and Gas Bd. of Mississippi*, 474 U.S. 409, 422 (1985); *Northern Natural Gas Co. v. State Corp. Comm'n of Kansas*, 372 U.S. 84, 92 (1963).

22 States derive the authority to regulate matters of local concern from their police powers. *Maine v. Taylor*, 477 U.S. 131, 138 (1986); *Lewis v. BT Investment Managers, Inc.*, 447 U.S. 27, 35 (1980). Importantly, included among these police powers is the ability of states to promulgate statutes directed to promoting the health and safety of its citizens. *See Maine*, 477 U.S. at 138; *Huron Portland Cement Co. v. Detroit*, 362 U.S. 440 (1960); *Welch v. Board of Supervisors of Rappahannock County, Virginia*, 888 F.Supp 753, 758 (W.D.Va 1995).

regulation at the wholesale level will increase the regulation's exposure to legal challenge.

V. RESPONSES TO SPECIFIC QUESTIONS

3. Questions to be Addressed in Comments

3.1. General

> *Q1. What do you view as the incremental benefits of a market-based system for GHG compliance in the natural gas sector, in the current California context?*

As a general matter, a cap and trade program will allow California to reach emissions targets at a lower cost.[23] Regulated entities are permitted to pursue the lowest cost reductions within the cap-and-trade system, beyond the boundaries of their facilities or industries.

Identifying the incremental benefits for the natural gas sector of a market-based system, compared with a programmatic approach, presents a challenge. Energy efficiency, the primary GHG reduction tool in the sector, holds the most potential to achieve reductions within the sector. Energy efficiency goals, however, can be pursued in parallel with a cap-and-trade program. And while other sector-specific reduction tools may arise given proper incentives, it is difficult to anticipate today what those tools might be. Consequently, one could argue that the bulk of sector-related reductions could be achieved with a programmatic approach.

The benefits of a market-based approach for the natural gas sector, however, lie beyond the sector itself. By designing a broader cap-and-trade system that includes the natural gas sector, California will enhance carbon market liquidity. Increased liquidity will bring a more efficient and effective market, bringing clearer incentives for reduction. In addition, the broader system will ensure fairness and consistency among sectors as California pursues its goals. These statewide benefits alone merit inclusion of the natural gas sector in a cap-and-trade program.

> *Q2. Can a market-based system for the natural gas sector provide additional emissions reductions beyond existing policies and/or programs? If so, at what level? How much of such additional emission reductions could be achieved through expansion of existing policies and/or programs?*

As stated in response to Q1, the most promising sector reductions will arise from

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23 MAC Report, at 7.

energy efficiency, and energy efficiency goals are advanced today through programmatic measures. While additional tools will develop with incentives, it is difficult to identify or quantify the benefits of those tools today. A technical workshop or additional modeling may invite a more informed response to this question.

3.2. Principles or Objectives to be Considered in Evaluating Design Options

Q3. What objectives or principles should the Public Utilities Commission and the Energy Commission use to determine the appropriate method of regulating GHG emissions in the natural gas sector, and why? Please rank the objectives you propose, in order of importance, adding any objectives not covered above.

Since any regulatory scheme would be adopted to fulfill the objectives of AB 32, goal attainment should be the paramount objective. Also, since source-based regulations are infeasible for this sector, special attention should be paid to the scope and accuracy of the program adopted and the simplicity in administering it to ensure goal attainment.

3.3. Basic Design Questions: Scope of GHG Regulation

Q4. Should GHG emissions from the natural gas sector be capped under AB 32? Are there certain sources of emissions within the sector that should be exempt from an enforceable cap?

The regulatory approach adopted for the natural gas sector should be equitable and consistent with other sectors, as Staff observes. To this end, if emissions for other sectors are capped, the natural gas sector should be capped as well.

Q5. For each of the following sources of GHG emissions, state whether the sources described should be subject to an enforceable cap and, if so, whether the cap should be covered by a cap-and-trade approach or only by programmatic measures For sources you recommend covering programmatically, what specific programmatic actions should be taken? For sources you recommend covering in a cap-and-trade program, are there specific programmatic measures that should be undertaken as complementary to the cap-and-trade program? For each source, discuss how your recommended approach is likely to affect rates.

a. Natural gas combustion in the residential, commercial, and small industrial segments of the natural gas sector.

Yes. Combustion within these segments should be included in the natural gas sector to the extent they are not otherwise regulated within the electricity or industrial sectors. Existing programmatic measures (i.e. energy efficiency programs using rebates, rate reductions, etc) remain the best alternative here. The level and intensity of the programs could be expanded to accelerate retirement of vintage equipment with modem, more efficient equipment.

b. Natural gas combustion by natural gas vehicles.

Natural gas sold for combustion in natural gas vehicles (NGVs) must be counted and addressed in California's AB 32 GHG reduction efforts. It is not clear at this point, however, whether NGV fuel is best addressed within the natural gas sector or directly by CARB as it determines the appropriate way to address emissions from the transportation sector. Further review is required.

c. Combustion-related emissions from operating the infrastructure (including infrastructure related to proprietary operations) used to deliver natural gas to end users within the State.

LDC combustion-related emissions, which arise mainly from compression, can be directly addressed with relative ease at the proposed point of regulation. Proprietary pipelines, to the extent that their pipeline-related combustion emissions are material and not included in another sector (e.g., EOR or refining operations), could be addressed by CARB directly and included in a cap-and-trade program. Likewise, to the extent that interstate pipelines have material in-state combustion-related emissions[24] from operating delivery infrastructure (i.e., compressors), they could also be directly addressed by CARB.

d. Fugitive emissions, including from pipelines, storage facilities, and compressor stations.

Fugitive emissions are often calculated and reported for criteria air pollutant permitting purposes under state and federal regulations.[25] Department of

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[24] Attempting to regulate emissions from interstate pipeline infrastructure outside of California would raise issues under the Dormant Commerce Clause. Moreover, the magnitude of these emissions is unlikely sufficient to justify the associated difficulties in sustaining such a regulation under legal challenge.

[25] See, e.g., South Coast: Rule 463 - Storage of Organic Liquids (www.aqmd.gov/rules/reg/reg04/r463.pdf); South Coast: Rule 466 - Pumps and Compressors (www.aqmd.gov/rules/reg/reg04/r466.pdf); South Coast: Rule 466.1 - Valves and Flanges

Transportation regulations likewise address fugitive emissions in monitoring, although with less frequency.[26] Extension of those programs to fugitive methane missions for GHG tracking and reduction purposes may be feasible.

e. Non-combustion uses of natural gas (please specify).

Utility data responses suggest some degree of difficulty in identifying natural gas delivered to a customer for feedstock use. Part V of the Staff Data Request asked the utilities to identify feedstock uses of natural gas. PG&E respond that it is "*unaware of any such customers in our service territory; however, we do not have any methods by which to identify such customers.*"[27] SoCalGas/SDG&E observe that end-users use natural gas as feedstock for hydrogen production, heat treatment or composite material manufacturing.[28] They provide data on customers using natural gas as a feedstock for hydrogen production from a steam methane reforming process. Like PG&E, however, SoCalGas/SDG&E state that they "*do not keep track of these volumes and [are] unable to estimate the amount of feedstock for other commercial and industrial applications.*"

In addition to these feedstock uses, natural gas can be used (but not combusted) in the course of enhanced oil recovery. Natural gas can be injected to maintain reservoir pressure. This use of natural gas is not typical, however, due to the market opportunity cost of using the gas for this purpose.

In each of these cases, the feedstock use or other non-combustion use of natural gas does not belong within the natural gas sector. Principally, methane used for these purposes will be addressed by CARB in the course of its regulation of larger facilities (e.g., refineries, EOR operations). Consequently, feedstock volumes delivered to these facilities should be excluded from the natural gas sector to avoid duplicative regulation. Looking at the issues from another angle, regulating methane feedstock used in the production of other fuels that will be combusted (e.g., gasoline) should not be regulated within the natural gas sector. Natural gas sector regulation of these volumes could lead to double counting, first in the use of feedstock and second in the combustion of the fuel product.

f. Other sources of natural gas sector emissions not listed

(www.aqmd.gov/rules/reg/reg04/r466-1.pdf); South Coast: Rule 467 - Pressure Relief Devices (www.aqmd.gov/rules/reg/reg04/r467.pdf).

26 See 49 CFR 192.705/706 for transmission surveys and monitoring respectively and 49 CFR 192.721/723 for distribution surveys and monitoring respectively.

27 December 10 Ruling, Attachment A at 4.

28 Id., Attachment C, at 9.

above (please specify).

Q6. *For the sources you recommend exempting from an enforceable cap, how would emission reductions be achieved?*

As proposed above, combustion related emissions from interstate or proprietary pipelines would fall outside the *natural gas sector* cap and, instead, be addressed by CARB under the multi-sector cap-and-trade program. For example, proprietary pipeline operations associated with enhanced oil recovery facilities could be addressed as a part of that facility. Likewise, natural gas used for non-combustion purposes could be regulated as a part of the industrial process (hydrogen production, ammonia production, etc.) rather than the natural gas sector.

Q7. *As the Public Utilities Commission does not currently have authority to oversee all potential GHG-reducing programs for all kinds of natural gas entities in California, which agency(ies) should regulate in such areas? For example, should ARB require that publicly owned utilities meet energy efficiency targets? Would additional legislation need to be enacted?*

IP takes no position on this question at this time.

3.4. Basic Design Questions: Point of Regulation

Q8. *If you believe that the natural gas sector and other sources of emissions related to combustion of natural gas' should be included in a cap or cap-and-trade system, where should the compliance obligation be placed: upstream, as close to the fuel source as possible (for example, on natural gas processing plants and pipelines) or midstream/ downstream (large point sources and, for smaller users, the local distribution company level)? If you suggest another option for assigning responsibility, please describe in detail.*

Please refer to Section IV. The point of regulation should be placed at the LDC level, regulating natural gas transported (rather than sold) by the LDC.

Q9. *Should core aggregators or natural gas marketers bear responsibility for the GHG emissions of the customers for whom they procure natural gas?*

No. Please refer to Section IV.B.

> *Q10. If ARB chooses to individually regulate emissions from facilities in certain sectors as well as emissions from other large point sources, what level of GHG emissions should ARB use as the threshold to define large point sources? Explain your reasoning.*

CARB's current threshold of 25,000MTCO$_2$ annual emissions for direct coverage is reasonable. For non-combustion sources, a similar 25,000 MTCO2 equivalent seems appropriate.

3.5. Deferral of a Market-based Cap-and-Trade System and Coordination with Other States

> *Q11. In developing recommendation to ARB, should the Public Utilities Commission and the Energy Commission give consideration to actions other states may take regarding the regulation of natural gas sector GHG emissions? If so, how?*

IP is currently unaware of efforts that other states are undertaking to regulate the GHG emissions associated with natural gas combustion by small sources.

> *Q12. Is it important that the regulation of California natural gas sector GHG emissions be consistent with actions taken by other states?*

It is important that California's AB 32 regulations not create advantages or disadvantages for natural gas supply based on the source of supply. Consistency with other states will tend to minimize any such effect. That said, as long as deliveries to all similarly situated California end-users are treated similarly, competitive distortions are more likely to arise in the regulation of in-state production facilities than in the proposed small-source natural gas sector.

> *Q13. Would deferral of a cap-and-trade program for the natural gas sector facilitate or hinder California's integration into a subsequent regional or federal program?*

An argument can be made that California has an opportunity to provide leadership in a regional or federal program if it continues down the road to implementation of AB 32. This leadership could increase the likelihood of broader adoption of California principles, although that broader adoption is certainly not assured. California may, however, be able to bring the same influence to bear in regional or national negotiations as evidenced in the Western Climate Initiative.

If California seeks to provide cap-and-trade leadership, it should do so with a system incorporating the broadest range of emissions as discussed in Section IV. Natural gas emissions from small sources should be included.

> Q14. *If neither a regional system nor a national system is implemented within a reasonable timeframe, should California proceed with implementing its own cap-and-trade system for the natural gas sector? If so, how long should California wait for other systems to develop before acting alone?*

A cap-and-trade system for the natural gas sector should be adopted as a part of any California cap-and-trade program.

> Q15. *If a market-based cap-and-trade system is not implemented for the natural gas sector in 2012, how would you recommend addressing early actions that entities may have undertaken in anticipation of a market?*

In the absence of a market-based cap-and-trade system, documentation of early action efforts will be very important. Once a cap-and-trade program is available, early action credit can be made available to those entities that voluntarily reduced emissions. To ensure that these entities receive the proper credit, regulators should establish reporting protocols and flexibility in baseline period selection. Regulators should then honor these early guidelines when a regulatory approach is ultimately adopted.

3.6. Relationship to GHG Regulatory Approach in the Electricity Sector

> Q16. *For purposes of natural gas GHG regulation under AB 32, does it matter what is decided regarding electricity sector type and point of regulation? For example, would a load-based cap for the electricity sector necessitate a similar type of cap for the natural gas sector, with local distribution companies as the point of regulation? If applicable, explain the relationships you see between the electricity and natural gas sectors for AB 32 purposes.*

Regulators should strive to regulate as close to the source as possible. That said, this point may vary from sector to sector. In the case of the natural gas sector (small source combustion), a source-based program is not feasible and a "first seller" approach presents complex practical and legal challenges. An LDC-based approach is the only reasonable solution if this sector is included under a cap-and-trade program.

Q17. If the electricity sector is not included in a California (or wider) cap-and-trade system, could/should the natural gas sector be included? What are your reasons?

Adoption of a cap-and-trade program will ensure that emission reductions can take place at the least cost. For this reason, reliance on a cap-and-trade approach should be maximized to include as many regulated sectors as possible. Regulators should include the natural gas sector into California's cap-and-trade system even if the electricity sector is not included.

Q18. What implications might there be for fuel switching if GHG emissions for one sector (electricity or natural gas) are capped and GHG emissions for the other sector are not? Would such fuel switching likely lead to an overall decrease, or increase, in GHG emissions?

IP takes no position on this question at this time, although the inquiry is important. To allow parties to provide an informed answer to this question, the Commission should investigate the potential for and impact of fuel switching in California.

Q19. How should the GHG emissions of cogeneration, combined heat and power, and distributed generation end users be considered and regulated (e.g., in the electricity sector, in the natural gas sector, or as a point source)?

A separate combined heat and power (CHP) sector should be created to appropriately consider and regulate these resources. An extensive discussion of this proposal was provided by the Energy Producers and Users Coalition and the Cogeneration Association of California in their electricity sector comments.[29] Briefly summarized, CHP resources are an invaluable tool that the state can use to lower emissions. Because CHP resources sit astride the industrial and power sectors, however, separate measures require consideration to avoid discouraging CHP development and operation. Placing these resources in a separate sector best facilitates this goal.

[29] EPUC/CAC Comments on Allowance Allocation Issues, at 18-24.

3.7. Recommendation and Comparison of Alternatives

Q20. *Please explain in detail your proposal for how the natural gas sector should be treated under AB 32. Address whether the following emissions sources should be subject to an enforceable cap, and if so, whether reductions in the cap should be achieved by a cap-and-trade approach or only through programmatic requirements: end-user combustion of natural gas, combustion-related emissions from operating the infrastructure, fugitive emissions from pipelines and compressor stations, and non- combustion uses of natural gas. Identify the appropriate point of regulation for each source of emission that should be included in a cap or a cap and-trade system. Should there just be a sectoral cap, or entity-specific caps as well? Should there be a cap-and-trade system? Address the relationship between programmatic strategies (e.g., energy efficiency programs and pipeline leak detection programs) and a sectoral cap. Discuss any legal concerns or need for new legislation to implement your recommended approach.*

Please see Section IV.

Q21. *Describe how your recommended approach satisfies each one of the principles or objectives set forth in Section 3.2.*

Please see Section IV.

Q22. *How does your recommended approach differ from the Public Utilities Commission Staff's preliminary recommendations for the natural gas sector attached to the July 12, 2007 ruling?*

IP's recommendation to include the natural gas sector into a cap-and-trade program and to encourage heavy reliance on programmatic measures is consistent with Staff's recommendations.[30]

December 12, 2007

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
Seema Srinivasan
Counsel to the Indicated Producers

30 Staff Report, at 15.

CERTIFICATE OF SERVICE

I, Karen Terranova hereby certify that I have on this date caused the attached **Comments of the Indicated Producers on Point of Regulation 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 December 17, 2007 at San Francisco, California.

Karen Terranova

Karen Terranova