**Joint Gas Utility Comments**
**Regarding Inclusion of Suppliers of Natural Gas in Cap & Trade**

## I. Introduction

These comments are submitted jointly on behalf of the Southern California Gas Company (SoCalGas), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric, Southwest Gas Corporation, and publicly owned natural gas local distribution utilities (POUs) serving the Cities of Palo Alto, Long Beach, and Vernon (hereinafter "natural gas utilities" or "utilities") in support of the California Air Resources Board (ARB) rulemaking related to the inclusion of suppliers of natural gas to the smaller end-use customers in California's cap-and-trade program. The natural gas utilities would like to thank ARB for the opportunities to participate in the workshop and file comments on this rulemaking.

The utilities share a strong desire to work with ARB to develop a cap-and-trade rule for small natural gas customers (i.e. those emitting 25,000 MT CO2e or fewer per year) to achieve the emission reduction goals under AB 32, while facilitating a smooth transition for these small customers and provide opportunities for the utilities to work with ARB and other state regulators to expand programs to reduce greenhouse gas emissions (GHG). The utilities believe rules can be developed to achieve the above-stated objectives without causing significant customer bill increases or undermining California's economic recovery.

## II. Background

The scope of this rulemaking covers smaller natural gas users in households and businesses, like restaurants, dry cleaners, hospitals and hotels. Larger natural gas customers, like electric generation facilities, came into the cap-and-trade program in the first compliance period and are directly regulated. The smaller gas customers will be regulated by way of the natural gas utility from which they purchase services. The smaller customers use natural gas primarily for essential needs, like space heating, water heating and cooking.

These smaller natural gas customers have invested in cost-effective, successful efficiency and demand-side-management programs over the past two decades, which have reduced both natural gas consumption and related GHG emissions, on a *per capita* basis. These programs have, in large part, been offered and managed by the natural gas utilities. Recently, the CPUC authorized $150 million and $180 million over the next 2 years for increased energy efficiency natural gas programs for PG&E and SoCalGas, respectively. In addition, the utility Energy Savings Assistance programs provide electric and gas energy efficiency improvements for low income families; for 2013-14, the gas portion of this funding will total approximately $390 million statewide. Furthermore, the utilities are in the process of implementing solar water heating programs with financial incentives totaling $250 million. The utilities are also looking into or implementing other programs, like biofuel integration, natural gas vehicle transportation support, vehicle electrification, natural gas delivery system efficiency opportunities, and wide-scale fugitive emission reductions for future GHG emission reduction opportunities. The utilities are enthusiastic about the potential for GHG emission reductions in these above-mentioned areas.

**Joint Gas Utility Comments**

As we have seen in the past, environmental goals can be achieved through a comprehensive approach by the utilities, often through the deployment of emerging technologies, all while minimizing customer bill impacts. California regulators and the natural gas utilities have, over the past decades, worked together to make California a leader in energy efficiency, demand-side-management, new renewable energy resources, and the adoption of alternative transportation fuels. As utilities work with state regulators, benefits from all programs are passed directly to their customers for their benefit as well as to promote the environmental goals. For example, a steady commitment by the utilities in energy efficiency alone has resulted in *per capita* emissions either dropping or remaining flat. For example, in 1990 the GHG emissions associated with smaller natural gas users (below 25,000 MT) were 24.06 MMT for SoCalGas and today they are 22.06.

The smaller natural gas customer covered under the proposed rule is served through a cost-of-service approach, regulated by the California Public Utilities Commission or the local municipal utility's governing body. Under this cost-of-service methodology, all compliance costs, whether it is purchasing cap-and-trade allowances or investing to expand programs to reduce GHG emissions, will be funded by customers. Conversely, any value from savings achieved through conservation or other programs will be returned to customers. This accrual of cost impact and value to customers, rather than the utility, is the reason for the utilities' proposal.

Finally, for all customers below 25,000 MT CO2e, the utility will be the point of regulation (and source of any carbon-related costs) under the proposed rule. This is true whether the utility provides both natural gas commodity purchase and delivery, or just delivery (for "transport-only" customers) services.

## III. Utilities' Proposal

The natural gas utilities propose the following framework to address small natural gas customers:

- A full administrative allocation of allowances to each NG LDC in 2015, to be held for the benefit of the customers;
- Administrative allocation in 2015 will be based on the 2011 verified data for each LDC's GHG emission profile;
- After 2015, a steady decline of administrative allocation through 2020;
- Requirement that each natural gas utility continue to offer and expand cost-effective energy efficiency and demand-side-management programs to reduce GHG emissions through 2020, with program design to be determined by the appropriate regulator (CPUC or local governing body); and
- The utilities will continue to work with state regulators and their local governing bodies to propose, expand and develop feasible cost-effective programs to reduce GHG emissions, including energy efficiency and methane emission reduction programs.

**Administrative Allocation in 2015**: A full administrative allocation in 2015 will recognize the reductions achieved by smaller customers to date which have brought the overall GHG emissions below 1990 levels, and provide transition assistance to manage customer bill impacts.
As mentioned above, for decades small customers invested in measures at their homes and businesses to reduce natural gas usage and make their homes and businesses more efficient. This collective effort and early action resulted in dropping their total emission below 1990 levels, despite population growth in California. By providing a full administrative allocation in 2015 to current verified data (2011), ARB will recognize this early action and historic long-term investments.

**Declining Allocation:** The natural gas utilities propose a diminishing allocation for each of the subsequent years of the second and third compliance periods (2016-2020) in order to ease small gas customers into a price signal. The utilities recommend using the rate of decline of the "cap adjustment factor for all other direct allocation" in Table 9-2 of the cap-and-trade regulation (i.e. 9.85% cumulatively from 2015-2020) to reduce the allowance allocation to natural gas suppliers for the 2016-2020 allowance budgets from the initial allocation level in 2015. This rate of decline is included in the calculation of the allowance allocation of most of the entities receiving an administrative allocation.

Even though the small customer GHG emission profile is currently below 1990 levels, more reductions can and should be encouraged on a market basis through a gradual decline in administrative allowance distribution starting in 2016. Between 2016 and 2020, this decline can provide appropriate market incentive to invest in additional energy efficiency, demand-side-management (EE/DSM), and other emission reductions programs, including support for alternative vehicle fuel adoption, methane emission reductions in the gas delivery system, and customer site methane leak detection and correction. Based on currently approved investments in EE/DSM programs, despite projected growth, the future GHG emission profile for small customers served by major California gas utilities are expected to remain flat (continue to be below 1990 levels) through 2020.

**2011 Emission Data as Baseline for Initial Allowance Allocations**: The data reported and verified under ARB's mandatory reporting regulation (MRR) is the best source for this historical information, because the data was reported using a standardized methodology and was verified by an independent third party. As such, the data is of the quality necessary to be the basis for important public policy decisions, and has the detail needed to distinguish natural gas customers that are covered entities from those that will be covered by natural gas suppliers. Because 2011 is the only data year for which verified MRR reports from natural gas suppliers are currently available, it should be considered the basis for the initial allocation to natural gas suppliers in 2015.

## IV. Policy Considerations

### a. Managing AB 32 costs and economic impacts

An initial full allocation to the natural gas utilities is appropriate because it ensures that small natural gas customers will experience a moderated transition and keep cap-and-trade program costs manageable. It also acknowledges the substantial early investments in GHG reductions that natural gas utilities and their customers have made since 1990--more than $2.2 billion have been invested in natural gas energy efficiency statewide. More importantly, a full administrative allocation in 2015 with a steady incremental decline through 2020 can help mitigate any customer bill spikes and associated costs. Without an administrative allocation, there will be roughly a $1 billion (53 MMT $CO_2e$ X a $19 allowance price) *annual* increase in statewide costs to residential, commercial and small industrial natural gas customers at a tenuous time in the state's economic recovery.

For example, the cumulative cost increase without an administrative allocation for PG&E's small natural gas customers—roughly 45% of the state—is approximately $2.34 billion between 2015 and 2020.[i] If prices climb to the third tier of the Allowance Price Containment Reserve (APCR), PG&E estimates a bundled system-wide natural gas cost increase of 25% in 2015 and 32% in 2020. These estimated cost increases do not take into account the projected increase in natural gas transmission and distribution costs in future years and thus do not reflect PG&E's General Rate Case (GRC) or Gas Transportation and Storage (GT&S) rate cases, which will also impact small natural gas customers' rates.

Utility industry research has shown that customers tend to react to their bill as whole. That is to say, they will not differentiate cost increases resulting from cap-and-trade vs. transmission and distribution investments. The natural gas utilities urge ARB to consider cap-and-trade cost impacts in light of all future customer bill impacts and understand the totality of bill increases small natural gas customers will be facing. Significant increases could weaken economic recovery and possibly result in customer backlash against the cap-and-trade program.

**Joint Gas Utility Comments**

While all small gas customers will be affected by allowance allocation, the impact will vary according to CPUC and POU tariffs for each rate class and type. Without an administrative allocation of allowances from ARB, some customers may experience double-digit bill increases (for bundled customers) and triple-digit bill increases (for transport-only customers) for cap-and-trade compliance costs alone. Bundled customers are provided natural gas delivery and procurement services from their natural gas utility, while transport-only customers are provided only delivery service from the utility and buy their natural gas from a third party. The percent bill increases for these customers in 2020 compared to 2012 (prior to cap & trade costs impacting bills) are summarized in the table below. The bill impacts listed below assume the ARB provides zero administrative allowance allocation to small gas customers in 2015 through 2020.

The bill impact ranges are based on the ARB reserve (floor) price and the price of the third tier of the APCR in 2020, and *do not* include the anticipated increases in natural gas service costs mentioned above.

## Customer Bill Impacts – PG&E Example

| | 2012 Bill vs. 2020 Bill | |
|---|---|---|
| | Bundled Customers[1] | Gas Delivery-Only[2] Customers |
| Residential | 6.1% to 29.3% | 10.8% to 51% |
| Small Commercial | 7.8% to 37.4% | 17% to 79.4% |
| Large Commercial | 10% to 47.5% | 28% to 128.5% |
| Industrial Distribution | 13.6% to 63.8% | 38.1% to 174.0% |
| Industrial Transmission | 17.1% to 80% | 87.6% to 401.1% |
| Electric Generation (D/T) | 17.7 % to 82.7% | 126.1% to 583% |
| Electric Generation (BB - Confidential PG&E / <15 customers) | 18.6% to 86.7% | 199.1% to 934.8% |

### b. Regulated / Cost-of-Service Businesses

Full allocation to natural gas utilities is appropriate because, as in the electricity sector, ARB can be assured that all value from the allocation to natural gas utilities will be for the exclusive benefit of customers, and that no shareholder profit (or transfer to the City's general fund for POUs) will result. Natural gas suppliers are cost-of-service entities, and the California Public Utilities Commission (CPUC) or local governing boards of the publicly owned utilities have oversight on retail rates. Through these regulatory entities, the value of allowances allocated to natural gas suppliers will be dedicated to the exclusive benefit of small natural gas customers. As a result, ARB can easily address legitimate concerns about outsized and immediate natural gas bill increases for small customers through administrative allocation to natural gas suppliers. In contrast, other fuel suppliers (e.g. suppliers of reformulated gasoline blendstock for oxygen blending (RBOB) and distillate fuel oil, suppliers of liquefied petroleum gas) do not face similar oversight of their retail rates by the CPUC or a

[1] Illustrative Bundled Customer bills include, in addition to transportation and public purpose programs rates, an illustrative annual average procurement rate based on a particular forecast of procurement costs for all customer classes.

[2] We recognize that gas delivery-only customers will purchase the commodity from other suppliers and so the customer's total impact (delivery plus commodity) will be similar to that of the utility's bundled customers. However, there is a risk that the perception of triple-digit increases in the utility bill may result in customer backlash against the program.

local governing body, thus ARB cannot be assured that the value of any allowances allocated to other fuel suppliers will be for the exclusive benefit of their retail customers.

### c. Allowance Consignment

Allowance consignment is not necessary and requiring consignment of administratively allocated allowances will add cost and complexities to cap-and-trade compliance that will be borne by natural gas customers. Natural gas utilities should be handled in a manner similar to vertically integrated municipal electric utilities, where the administrative allocation they receive is available for direct compliance. This treatment with regard to consignment is appropriate for several reasons.

***Natural Gas Utilities Have a Level Playing Field***

The point of compliance regulation under cap-and-trade differs between natural gas suppliers and electric sector. In the electric sector the compliance lies with generators and importers, which are often different entities than the electric distribution utility. The electric distribution company may also own generation and have a direct compliance requirement, but they are also purchasing from the CAISO markets. However, the allowance allocations go to the utility, for the benefit of its customers. Therefore, electric IOUs and other utilities who are members of the CAISO are required to consign cap-and-trade allowances in order to prevent market advantage over generators and others in the electricity market. On the other hand, natural gas LDCs are the point of compliance and so are not faced with the same industry structure (i.e. the eight natural gas utilities that would consign their allocated allowances would be exactly the same eight natural gas utilities buying those allowances back in the auctions). The natural gas utility market structure is more analogous to the vertical integration of the non-CAISO publicly owned electric utilities. Therefore, the natural gas utilities' proposal parallels the approach provided to those electric public utilities not in the CAISO market under the existing regulation.

***Consignment Poses Significant Risks to Natural Gas Utilities***

Consignment also poses several specific risks to the natural gas utilities operations. If the utilities are required to buy all the allowances they need to meet their compliance obligation, they would face a greater risk of not meeting their compliance obligation, and of exposing customers to greater price risk. This situation would also severely constrain larger utilities' holding limits; compared to if they were allocated known amounts of allowances on known dates beginning in 2015. Second, if utilities are required to buy all their allowances but are not always buying the same number of allowances as they consign to each auction, and allowance prices increase sharply, the cost of compliance could exceed the value of consigned allowances, leading to higher overall bill impacts to customers. Third, if these utilities had to procure all the allowances they need, they would have to participate more aggressively in the quarterly auctions, which require a substantial collateral posting requirement. For example, if a major natural gas utility, like Southern California Gas Company, planned to buy one quarter of the allowances for its annual natural gas supplier obligation at each quarterly auction in 2015, it would have to buy approximately 5 million allowances per auction, which is several times more than what it needs to buy for its current obligation in the first compliance period, assuming the same approach.

Since the collateral posting is based on the maximum bid in a participating entity's bid spreadsheet, PG&E and SoCal Gas could have hundreds of millions of dollars of working capital locked up for approximately one month for each auction. If there were a liquidity emergency, the ability of these entities to respond would be limited by the amount of working capital tied up as auction collateral. Finally, there is more risk than benefit to customers of NG LDCs going into the market to buy their allowances, because natural gas utilities would essentially be "price-takers" who would consign and buy back allowances at any price to meet their obligation. For electric utilities and generators, electric procurement and dispatch decisions are based in part on a market price of carbon, after which entities close their position by buying compliance instruments to cover their obligation. Natural gas utilities, on the other hand, do not have the same procurement and dispatch alternatives between resources with different carbon contents, so they provide gas service and incur carbon market exposure irrespective of the allowance price, and thus are price-insensitive.

***Not Consigning Does Not Significantly Impact Liquidity***

When fuel suppliers come under the cap in 2015, the program's annual allowance budget will increase to 394.5 million allowances, from 162.8 million allowances in 2013. At that point, allowances for natural gas utilities, if provided in proportion to expected emissions, would only represent thirteen percent of the market. Therefore, not consigning the allowances from the NG LDCs represents a relatively small change in the volume of allowances available at auction.

***Direct Use of Allowances for Compliance is Administratively Efficient***

The direct use of administratively allocated allowances for compliance is the most efficient method of returning allowance value to customers. Some stakeholders have commented that not requiring consignment prevents the CPUC from making policy around the method of allowance value return, and by default, returns allowance value on a volumetric basis. Some stakeholders believe that returning value on a volumetric basis negates the carbon "price signal" and that the value should be returned on a flat, or non-volumetric basis. Setting aside arguments for volumetric return or otherwise, the CPUC-jurisdictional natural gas utilities, the investor-owned utilities, believe that the cost allocation phase of their respective general rate cases is the appropriate place for those parties to propose changes to rate design. The CPUC has exclusive jurisdiction over investor-owned utility ratemaking under the California Constitution. Likewise, the governing boards of publicly owned utilities have jurisdiction over POU retail rate design. Those seeking to affect rate design are encouraged to bring their arguments to those venues.

Natural gas rate design and disposition of allowance value are under CPUC jurisdiction for IOUs and parties will have ample opportunity to be heard on these detailed issues at the CPUC, and in the context of overall retail rate design. In making its decisions in these areas, the CPUC can balance the concerns of various parties (including ARB's with regard to GHG cost impacts) and if warranted, could design tailored solutions to address level playing field concerns across fuel types (e.g., a separate retail rate structure for natural gas vehicles).

## V. Conclusion

The natural gas utilities respectfully submit these comments for consideration by the ARB for the proposed rule for small natural gas customers. There have been significant achievements by customers to reduce GHG emissions -- bringing their emissions profile to below 1990 levels. This early action should be recognized by ARB in the rule design, while also providing new incentives to promote further emission reductions, and avoid dramatic customer bill increases. The proposal outlined above provides the ARB with a balanced and effective approach to meeting statewide climate goals. Working together, small customers, gas utilities and the ARB can make AB 32 and the cap and trade program a continued success.

[i] This assumption is based on 117 MMT $CO_2e$ x $20 and average temperature years.