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**RE: May 17, 2010 Workshop on Allowance Allocation for a California Cap-and-Trade Program**

Dear Ms. Van Ommering:

San Diego Gas and Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) appreciate the opportunity to submit these written comments concerning the May 17, 2010 workshop discussion of potential changes to the Preliminary Draft Regulation (PDR) for a California Cap-and-Trade Program, issued November 24, 2009. As indicated at the workshop, ARB is soliciting input on allowance allocation and potential benchmarking approaches for industrial sector allocation. It was mentioned that cost containment would be the topic of a future workshop, so while SDG&E and SoCalGas strongly support including cost containment elements in the PDR, the topic is not addressed in these comments except as to how it relates to allowance allocation.

The comments below are divided into four sections: 1) electric sector allowance allocations; 2) small residential, commercial, and industrial natural gas customer sector (small gas customer sector) allowance allocations; 3) benchmarking for allowance allocation in the industrial sector; and 4)provision of allowances for a cost containment reserve. In the electric sector, ARB should allocate close to 100 percent of the allowances to regulated local distribution companies (LDCs) for the purpose of implementing AB 32 policies to the benefit of their customers who bear the cost of the program. In the small gas customer sector, ARB should allocate close to 100 percent of the allowances to regulated local distribution companies for purposes of implementing AB 32 policies to the benefit of their customers who bear the cost of the AB 32 program. SDG&E and SoCalGas support the use of benchmarks and transitional aid in the allocation of allowances in the industrial sector, but recognize it is a very difficult process to do properly. And lastly, SDG&E and SoCalGas suggest the ARB not use allowances within the cap to "fund" an allowance reserve for price mitigation, but permit the use of offsets beyond the ARB established limit.

## ELECTRIC SECTOR

### Wholesale Market

Putting a price on carbon in electric wholesale markets will have the desired effect of moving electricity buyers away from high carbon content fuels to low carbon content fuels. The long-term price signal will encourage fuel substitution of lower emitting natural gas for higher emitting coal, and substitution of zero carbon resources for natural gas and coal. Wholesale electricity buyers are highly responsive to price, so that the cap-and-trade will have the desired impact of AB 32 in reducing GHG emissions in the electric sector.[1]

As an exception to the ARB conceptual goal of providing a uniform economy-wide carbon price, ARB has adopted three complementary policies related to procurement of electricity in wholesale markets that are not tied to the price of carbon. The first policy is the 33% Renewable Electricity Standard (RES), the second is the California Solar Initiative, while the third is the combined heat and power (CHP) policy.[2] Each of these policies is described in the Scoping Plan and each has an associated GHG reduction target.[3] The funding of the RES and CHP investments is supported by long-term contracts with wholesale electric buyers, while in the case of distributed Photovoltaics (PV), the technology is promoted through the long-term subsidies inherent in net energy metering tariffs. To ease the transition to the cap-and-trade market, free allowances should be provided to offset the higher costs of electricity procured in the wholesale electricity markets.

Future costs of expanding to a 33% Renewable Electricity Standard included in the Scoping Plan are estimated to cost $133 per metric ton (MT) of reduction.[4] Based on the estimated reductions in the

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[1] It is recognized that because California imports a large amount of high GHG content power, California purchasing less carbon-intensive power does not guarantee lower emissions if surrounding states have no price on carbon. Low carbon power may come to CA while high GHG content power goes to states without a carbon price. This form of leakage called "reshuffling" is unavoidable as long as surrounding states are willing to take the high GHG content power that CA does not take because of the carbon cost.

2 Enhanced energy efficiency, the other major policy, is discussed in the section below in the context of retail market GHG reduction measures.

[3] ARB Scoping Plan, Table 2, page 17. The California Solar Initiative is referred to as "Million Solar Roofs."

[4] ARB, Scoping Plan, Table G-I-2, page G-I-7.

most recent RES workshop (11-12 MMT) and a carbon price of \$30/MT CO2e,[5] this complementary policy translates to \$1.1-1.2 billion in annual added costs to retail electricity providers, who are the California wholesale electricity market buyers.[6]

The Scoping Plan also envisioned the development of GHG-reducing combined heat and power technologies through a procurement-related program. Based on the updated ARB economic analysis, there is a potential GHG reduction of 5 MMT through installation of CHP. The costs for CHP from the Scoping Plan were estimated to be zero-added cost over wholesale electricity costs. But in the ARB updated economic analysis, the cost of reducing GHG through acquisition of CHP rivals the cost of renewables per metric ton of GHG reduced.[7] If the cost of GHG reduction from CHP is as high as the costs of renewables per metric ton of reduction, the above market costs to wholesale electricity buyers could be over \$500 million per year.[8]

The CPUC has approved direct spending of \$898 million on direct incentives for distributed photovoltaics (PV) over the past 3 years in addition to the rate subsidies provided by net energy metering.[9] Based on Scoping Plan projection of 2.1 MMT reduction from this complementary policy, considering the subsidies from the net energy metering alone (ignoring the costs of the direct incentives provided), the above market costs for distributed PV is in the range of \$500 million per year based on the recent CPUC analysis.[10]

SDG&E agrees that local distribution companies should monetize the free allowances provided in a double-sided auction, as proposed by ARB on slide 34, with funds used in a transparent way to offset the added procurement costs of renewable generation, distributed photovoltaics, combined heat and power, and other approved investments that support the purposes of AB 32 and are paid for by

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[5] ARB, May 20, 2010 workshop presentation, slide 36. A price of \$30/MT is used throughout these comments based on the CPUC decision to use the value for the MPR and energy efficiency programs and the use of the value by E3 in its recent update on GHG modeling.

[6] (\$133-30) x 11 million = \$1.13 billion

[7] ARB, Updated Economic Analysis of California's Climate Change Scoping Plan, Table 13, page 37. If table 13 is correct, the cost per metric ton of GHG reduction is similar for CHP and renewables. There is a question as to whether this table is correct based on the comparison to the May 20 workshop presentation concerning the amount of GHG reduction from renewables in the Scoping Plan.

[8] At a carbon market price of \$30/MT CO2e, 5 MMT x \$(133-30)/MT = \$515 million.

[9] CPUC, 2009 Annual Report, page 24.

[10] CPUC Energy Division, Introduction to Net Energy Metering Cost Effectiveness Evaluation, table 3, page 7. The E3 study finds the net cost to be 12 cents/kWh. ARB Scoping Plan assumes reduction of 0.45 MT/MWh. Calculation is [\$0.12/kWh x 1000 kWh/MWh x (2.1 MMT/ 0.45 MT/MWh)] – 2.1 MMT x \$30/MT CO2e] = \$497 million including the kWh generated and used onsite.

electricity consumers.[11] Electric LDCs would be required to purchase any allowances necessary for their own generation (and import responsibility as first jurisdictional entities) emissions through auctions or other market transactions to assure a level playing field with merchant generators.

**Retail Market**

The ARB Scoping Plan also has complementary policies related to the retail electricity market: 1) direct support for expanding local distribution company (LDC) energy efficiency programs, and 2) indirect support through state and local government energy efficiency programs, regulations, and standards. The ARB should fund, through the provision of free allowances, incremental LDC energy efficiency programs necessary to overcome known market barriers and achieve AB 32 goals. California has implemented effective energy efficiency programs in California for years, and since 2008 greatly expanded electric energy efficiency programs to assist the state in attaining its GHG reduction goals. According to its 2009 Annual Report, the CPUC has approved investor-owned utility (IOU) spending on energy efficiency of $3.1 billion for 2010-2012 ($1.03 billion per year).[12] This early action increased energy efficiency spending by $1.0 billion over 2006-2008 energy efficiency spending ($333 million per year) by the investor-owned utilities.[13] In recent Decision 10-04-029, the CPUC further expanded energy efficiency programs by approving an increase in the GHG adder to $30/ MT CO2e to expand the energy efficiency programs by enhancing the cost effectiveness of IOU energy efficiency programs. The ARB should consider providing free allowances to LDCs to offset the costs borne by non-participating customers who bear the costs of energy efficiency investments without the corresponding benefit. Unlike for direct compliance entities, implementation of energy efficiency programs does not bring a direct benefit to all electricity customers, only to the subset installing such measures. Providing free allowances for the benefit of non-participating ratepayers would mitigate their double payment for reducing GHG emissions, once through complementary policies and once through the cost placed on carbon through the cap-and-trade program.

Second, ARB should acknowledge the free allowance allocations to investor-owned utilities for the benefit of their customers will have little impact on the carbon price passed on to the majority of

[11] It is recognized that providing free allowances is equivalent to auctioning and providing allowance value to local distribution companies to implement these AB 32 policies.

[12] CPUC, 2009 Annual Report, page 22.

[13] CPUC, 2008 Annual Report, page 21, $2.1 billion authorized for 2006-2008 EE programs.

retail customers due to rate design considerations. If the carbon price is high, low usage electric customers will not see the price increase since rate increases for low usage customers are capped by SB 695 legislation. Any shortfall in collections is made up by higher usage customers, so those customers would experience more than just the added price due to carbon, they would also pay additional for the shortfall of revenues recovered from low usage customers.

The ARB should also be aware that current rate design for residential electricity customers already provides a market price signal that equals or exceeds the impact of a carbon price on rates. If the price of GHG is $30/MT CO2e, the price impact on a SDG&E residential customer would be 1.1 cents/kWh ($30 x 0.35 MT/MWh x 1 MWh/1000 kWh x 100 cents/$) absent any SB 695 rate limitations. But if one looks at SDG&E's May 2010 residential rates (Schedules No. DR plus EECC), the baseline rate is 12.9 cents per kWh, 100-130% of baseline is 15.0 cents/kWh, 130%-200% is 26.7 cents/kWh, and above 200 % is 28.7 cents/kWh. The marginal price for increasing electricity consumption far exceeds the carbon cost that would be passed on to the majority of customers through average rates.

Electricity-intensive industries and small business will experience the increase in carbon price through the average retail rate. But for consistency with the large industrial sector, free allowances should be provided to electric LDCs to moderate price increases as a form of transition assistance. Providing free allowances for this purpose is consistent with the Governor's March 24, 2010 letter to the Ms. Mary Nichols, Chair of the ARB Board. The Governor stated, "It is critically important that California's program be designed in a way that gives businesses and industries in this state sufficient time to reduce their emissions in a cost-effective manner without unnecessary short-term costs."

**Allocation to the Electric Sector Local Distribution Companies**

The workshop presentation contemplates ARB developing several new structures including a community benefit fund allocation process (slide 35) and the California Carbon Trust (slide 37). Given that IOUs already have significant programs that support low income assistance that reduce the impact on disadvantaged customers, a limited amount of electric sector funds should be used for a separate new ARB community protection program. One IOU program is CARE, which provides a direct 20 percent bill reduction for income eligible households. The CPUC has approved $2.6 billion in funding of the CARE program for 2009-2011, or on an annual basis, $870 million.[14] Investor-

[14] CPUC, 2009 Annual Report, page 20. The other program is the low income energy efficiency which can be targeted to impacted communities.

owned utilities have low income energy efficiency programs that can be used to fund targeted activities related to ARB's community protection goal of reducing GHG and co-pollutant emissions. The CPUC has approved nearly $1 billion for low-income energy efficiency for 2009-2011 ($330 million per year) that can be targeted to the potentially most disadvantaged communities impacted by AB 32.[15] Funding of the Community Benefit fund from the electric sector should be limited to funds necessary for other AB 32-related activities such as those mentioned on slide 35 - adaptation, land use planning, and natural resource conservation.

The IOUs also collected $62.5 million in 2009 through a public purpose program surcharge to fund the Public Interest Energy Research (PIER) Program.[16] The PIER program RD&D spending is overseen by the California Energy Commission (CEC) and significant monies have been devoted to RD&D activities that result in a lower carbon content of energy. The electric sector funding of AB 32 energy innovation goals should not duplicate the PIER program, but should be limited to supporting project types that are distinct and separate from the PIER RD&D.

Given the substantial funding for activities contemplated by ARB are already being funded by electric LDCs, only a small portion of allowances from the electric sector should be dedicated to these and other AB 32 activities as well as replacing ARB fees.[17]

Providing allowances close to 100 percent of electric sector emissions has the support of almost all electric utilities in the State as evidence by the March 26, 2010 letter to Ms. Mary Nichols, Chair of ARB, from the Joint Utilities group. The CPUC and Local Governing Boards should be given the flexibility as to how to use the allowance value given the cost of complementary policies and smooth transition will far exceed the allowance value.[18]

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[15] CPUC, 2009 Annual Report, page 20. In addition, $216 million is targeted to low income CSI installations (see page 25)

[16] CEC, Public Interest Energy Research 2009 Annual Report, pages 1-2. The CEC states, "Energy Commission funded research will help lead California to a clean energy future through research investments that will help meet the state's greenhouse gas emission goals, continue improving the smart grid, achieve a higher penetration of renewable resources, move toward zero net energy smart communities, and create careers in modern clean technology industries for a sustainable California economy."

[17] ARB's administrative fees should also be part of this percentage that is not provided as free allowances to local distribution companies but simply auctioned, consistent with the Governor's recommendation in his March 24, 2010 letter.

[18] EAAC, Allocating Emissions Allowances Under a California Cap-and-Trade Program, Table 3, page 32 shows $21.9 billion assuming a $60/MT price. Based on the Scoping Plan, page 11, the electricity sector is 23 percent of emissions. So at $30/MT, 23% translates to $2.5 billion per year. The costs for complementary policies described above total $3.5 billion (and does not include incremental energy efficiency of publicly owned utilities). Added transition assistance for low income customers and for commercial and industrial customers would increase that even further.

**Allocation Between Electricity Local Distribution Companies**

SDG&E recommends an allocation of allowances between local distribution companies for the benefit of their ratepayers based on a combination of retail sales and historical emissions: 75 percent based on retail sales and 25 percent based on historical emissions.[19] Further, the basis for the retail sales and emissions should be based on averages for 2006-2008.

The rationale for the split between retail sales and historical emissions is based on 1) the cost impact of the complementary policies, 2) low income customer and business assistance, and 3) allowing for transition to a federal program. California desires to lead the nation and so its policies may inform and influence the final federal program. Ratepayers of electricity local distribution companies are spending significant funds on complementary policies such as renewables and energy efficiency and should not be penalized for these actions by having to pay twice for carbon reduction. Similar thinking should be brought into national discussion of carbon reduction; LDCs with dedicated programs that lower GHG emissions should be provided with free allowances.

In California, these significant complementary policies are implemented for the most part based on a percentage of retail sales, directly or indirectly.[20] All LDC customers are paying for the above cap-and-trade carbon market costs for low emitting electric generation technologies and all non-participating LDC customers are paying for energy efficiency without corresponding benefit. The allocation policy should recognize the double payment of implementing AB 32 with required funding of both the complementary policies and the cost of carbon in a cap-and-trade program. It should provide a significant portion of free allowances to LDC ratepayers for this purpose.

SDG&E does support some allocation based historical emissions in the electric sector for purposes of transition. For higher emitting local distribution companies, the cost of carbon in the cap-and-trade program will create a higher cost impact. The impact on low income customers would be larger for those consumers who are customers of the higher emitting LDCs. Low income assistance would also be higher for higher emitting LDCs (if LDCs have a similar distribution of low income customers).

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[19] This allocation between retail sales and historical emissions refers only to the initial allocation and does not include potential transition over time. As transition assistance is reduced over time, the allocation should move to 100 percent based on retail sales.

[20] Net energy metering caps are based on peak demand, which is most closely related to retail sales and energy efficiency program spending seems to be closely related to utility size and retail sales. CHP procurement policies have not been determined, but potentially could be implemented like renewables for the purposes of GHG reduction. It is acknowledged that high emitting LDCs may expand energy efficiency more than other LDCs because the carbon price will make more energy efficiency cost effective, but to date there is no evidence that high emitting LDCs are spending more proportionally for energy efficiency.

Similarly, electricity-intensive and small business should be afforded a period of transition similar to large industrial customers. Providing a significant percentage, such as 25 percent, to be based on historical emissions initially provides higher emitting LDCs with funds to provide for a smoother transition to the cap-and-trade market for electricity-intensive industries and small businesses. Basing the split of historical emissions based on 2006-2008 as suggested in proposed federal cap-and-trade programs provides both alignment with the likely federal program and a clear benefit for early action. Those that have aggressively pursued energy efficiency and acquisition of renewable energy will not be disadvantaged by their actions in the allocation of free allowances. Splitting the retail sales based on historical figures provides some benefit for areas harder hit by the recession. Their retail sales will have fallen farther than others, providing some additional protection if the economy rebounds.

## SMALL RESIDENTIAL, COMMERCIAL, AND INDUSTRIAL NATURAL GAS CUSTOMER SECTOR

### Wholesale Market

Unlike the electric sector, wholesale natural gas buyers cannot alter the carbon content significantly by changing the source location of the natural gas procured. Natural gas LDCs, as the point of compliance, have very limited ability through their purchases to reduce GHG from the small gas customer sector.[21]

### Retail Market

Similar to small electricity users, small natural gas consumers are too numerous, and their emissions too small, to effectively participate in a cap and trade program. At the same time, gas LDCs are not in a position to exert direct control over their decisions that impact overall emission levels. If no allocation of free allowances is made to gas utilities as the compliance entity for small customers, the cap-and-trade program will be relying solely on end-use natural gas customer's response to price to effect a change in GHG emissions.

But it is well documented that there are market barriers to this segment's purchase of energy efficient equipment in response to price. To address this situation, California has implemented effective

21 Purchasing biomethane in place of natural gas does reduce the GHG content of the fuel, but supplies of biomethane will continue to be limited for some time to come. To the extent the CPUC authorizes gas LDC purchases of biomethane, free allowances provided to gas LDCs could be used for the above market costs of biomethane.

energy efficiency and RD&D programs for many years, so that this sector's emissions are already near or at 1990 levels.

And like the electric IOUs, gas utilities regulated by the CPUC have expanded gas energy efficiency programs since 2008. In light of the proven historical effectiveness of energy efficiency measures and RD&D in California's natural gas industry, gas LDCs should be provided with allowances to pay for the energy efficiency programs, both programs for all small gas customers and those energy efficiency programs targeted to low income customers, and to pay for effective RD&D. These have proven effective and should continue to reduce GHG emissions in the sector.

California's history of success in reducing GHG emissions in this sector should not be ignored, but should be highlighted as an example for the rest of the country by funding the actions that have reduced the small gas customer sectors' GHG emissions through the allocation of free allowances to gas LDCs. Given that gas utilities are fully regulated by the CPUC, or a Local Governing Board in the case of publicly-owned gas utilities, providing free allowances to gas LDCs will directly benefit small gas customers directly by use of the allowance value to further the goals of AB 32 and avoid double payment by LDC ratepayers who are bearing the cost of the AB 32 program.

Second, ARB should recognize that rate design for gas utilities regulated by the CPUC already provides a price signal for residential natural gas customers that equals or exceeds the potential future impact of a carbon price on rates. If the price of GHG is \$30/tonne $CO_2e$, the gas commodity price would increase by 15.9 cents per therm. But if one looks at SoCalGas' May 2010 residential rates (Schedule No. GR), the baseline rate is 73.7 cents per therm, while the non-baseline rate is 97.7 cents per therm. The non-baseline rate is 24 cents per therm higher than the baseline rate. Thus the retail rate already incorporates a higher marginal price for additional usage than would occur with the price on carbon reflected in average rates.

Third, the ARB should consider the impact on low income consumers. Gas LDCs have a substantial number of low income customers. In the SoCalGas service area, over 29 percent of customers are currently enrolled in the CARE program that provides a 20 percent bill discount.[22] Likewise, SDG&E has 22 percent of customers enrolled in CARE.[23] A large rate increase from the incorporation of the cost of allowances in rates will mean that these customers will experience double digit rate increases unless allowances are provided to mitigate the impact and transition these

[22] 2009 Annual Report by SoCalGas on Low Income Programs

[23] 2009 Annual Report by SDG&E on Low Income Programs

customers to the cap-and-trade program. In addition, spending on the CARE program will increase proportionately and that will be borne by other LDC ratepayers on top of the direct rate increases. Fourth, small commercial and industrial gas customers deserve the same transition assistance being provided to large industrial gas customers. The ARB has indicated that in addition to providing allowance value to deter leakage, free allowances would also be provided short-term to "provide a transition period to smooth market start-up." The current staff thinking on slide 81 is to provide 100% free allowances based on a benchmark declining to 30 percent over time. The same type of transition assistance should be provided to smaller commercial and industrial customer beneath the 25,000 MT limit so as to not disadvantage small customers in the same industry. Here again, provision of free allowances for transition would be consistent with the Governor's May 24, 2010 letter.

Allowances should be provided to gas LDCs' customers to transition to the cap-and-trade program and avoid rate shock upon entry into the cap-and-trade program in 2015. If the price of GHG is \$30/tonne CO2e, the baseline rate for SoCalGas would increase by almost 22% and the non-baseline rate by over 16%. Including the impact of low income assistance, small business assistance, plus the cost of energy efficiency and RD&D, the impact on some small gas customers could be an increase well over 30%. This level of increase would be considered "rate shock" by the CPUC. In the ARB modeling of AB 32, the impact of the cap-and-trade and other complementary policies ranged from a low of 12% increase to a high of 87% increase and would be higher than the price impact on any other sector.[24] ARB should provide for transition and avoid rate shock through the allocation of free allowances to natural gas LDCs on behalf of their customers.

For all of the above reasons, the ARB should allocate allowances close to 100 percent of the sector emissions to gas LDCs for the benefit of their customers when the sector enters the cap-and-trade in 2015. Such an allocation will protect low income customers and small business, will avoid double payment by LDC customers for energy efficiency and RD&D programs, and will avoid rate shock. Such an allocation would also be consistent with proposals contained in federal cap-and-trade proposals that provide a substantial portion of free allowances to the sector and with the ARB thinking on a rebate program as described on slides 38 -40. Gas LDCs are rate regulated so that allowance value will go to the small natural gas consumers who face the incidence of the carbon price.

[24] This is confirmed by Table 20 of the Updated ARB Economic Analysis, Table 20, page 46.

**Allocation Between Gas Local Distribution Companies**

Since the carbon content of all gas LDCs is similar, the split between gas LDCs would only be a question of whether to use an historical basis or to use an updating approach. SoCalGas and SDG&E recommend the split of allowances based on historical retail deliveries from 2011-2013, potentially adjusted for energy efficiency improvements that have occurred since 2006 and the adoption of AB 32. Since this sector enters the cap-and-trade in 2015, the use of a historical time period close to the entry period is desired. Ending in 2013 will provide a year to compile the data and determine whether to make adjustments for energy efficiency. Because natural gas usage varies based on different temperature conditions for a subset of customers, using a three year average will provide an averaging of the weather conditions. Adjustments for energy efficiency should be made if the ARB determines that some LDCs have more aggressively pursued energy efficiency than others so that those that LDCs that have aggressively pursued energy efficiency will not have their customers disadvantaged in the allocation of free allowances.

**BENCHMARKING**

In theory, SDG&E and SoCalGas support allocation of free allowances to the industrial sector on an output-based benchmark approach to reduce leakage. Benchmarking provides reward for early actions by compliance entities in the industrial sector and incentive for high emitting firms to lower their emissions. It further provides an example for federal programs to reward firms that take early action as most businesses in California have already done.

In practice, developing measures of competitiveness appear to be extremely complex and ripe for litigation. As shown on slide 61, the factors to be considered are each very daunting to accurately quantify: product differentiation, transportation costs, existing cost advantages, fixed plant costs, capacity utilization, global production capacity, and agglomeration economies. It is especially complex when the potential for leakage will change constantly as surrounding states join the Western Climate Initiative. A review of these factors will be needed before each compliance period to accommodate changing western state participation and improved quantitative analysis.

The benchmark measures provide another set of challenges for ARB. Data to make apples-to-apples comparisons are limited on the state level, and even with the data available, it appears to be a highly statistical exercise based on the presentations at the WCI symposium on benchmarking.

Benchmarks based on best practices in the United States would be possible. The requisite data appears to be available on a national basis based on the presentations at the WCI benchmark symposium and there would be a much broader sample to develop the benchmark. Further, using a national benchmark would not require any changes as CA linked to other Western states. It also provides the data necessary for a federal program to adopt this type of approach that rewards early action. However, given the highly statistical nature and complexity of best practices benchmarks, ARB may want to follow the approach of the proposed federal programs and use industry averages in order to develop allocations in the near term.

A major concern about any of the approaches to benchmarking is the impact of only considering direct emissions in the development of benchmarks.[25] Specifically, what impact does that have on fuel substitution and on the treatment of combined heat and power (CHP)? Slide 71 indicates that Staff's thinking is that benchmarks would be based on direct emissions with no technology-specific benchmarks. The ARB should carefully think through the development of the benchmark to avoid creating an incentive to substitute electric technologies in production processes solely based on the fact that there would be no direct emissions.[26] An efficiency benchmark should be constructed to be neutral.

Similarly, the benchmark should not artificially discourage CHP by only considering direct emissions. Since the ARB wants to promote efficient CHP, it seems that a separate benchmark should be established for facilities that have CHP or that the benchmark should be adjusted to account for the higher efficiency but also higher direct emissions when CHP is used in industrial processes.[27]

**Cost Containment and Allowance Allocation**

In slide 29, the ARB proposes that a "small portion of overall allowances initially dedicated to a strategic reserve and forward auctioning." SDG&E and SoCalGas are opposed to any allowances in the current compliance period being dedicated to a strategic reserve. This removal of allowances from the market will increase the price of allowances and will put ARB in the position of being able to arbitrarily manipulate the market by its choices on how many allowances to withhold from the

[25] Another issue with benchmarks is their potential indirect impact on energy efficiency through perception. Setting a benchmark for the purpose of providing free allowances to avoid leakage should not be a signal for firms concerning energy efficiency efforts. Just because a firm subject to competition is provided with free allowances equal to its emissions should not reduce the incentive of the firms to pursue new, innovative energy efficiency measures for competitive advantage.

[26] It is recognized that electricity will have the carbon price incorporated, but on an average basis, not a marginal basis.

[27] It is recognized that electricity will have the carbon price incorporated, but on an average basis, not a marginal basis.

market.[28] A preferred strategy is to create strategic reserve allowances with added offsets, offsets that are above the proposed four percent limit. Expanding the supply of allowances at the price ceiling through the use of offsets avoids manipulation of the market price via ARB reserve holding strategies while maintaining environmental integrity of the cap-and-trade program. This approach is consistent with the Governor's recommendation that the ARB "consider how to assure an ample supply of high-quality offsets to help companies comply with carbon reduction strategies in a cost-effective manner."

Thank you for the opportunity to comment.

Sincerely,

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[28] The exception would be if the price floor was hit and there were unsold allowances in an auction.