Comments of Pacific Gas and Electric Company
On the California Air Resources Board's
June 2008 Discussion Draft Scoping Plan
Prepared Pursuant to AB 32,
The Global Warming Solutions Act of 2006 (HSC § 38500, et seq.)

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Pacific Gas and Electric Company ("PG&E") welcomes the opportunity to provide these initial comments on the California Air Resources Board's *June 2008 Discussion Draft Scoping Plan* ("Draft Plan") prepared pursuant Assembly Bill 32 ("AB 32"), the Global Warming Solutions Act of 2006 (HSC § 38500, et seq.). Our comments address the Draft Plan's overall approach and strategy for achieving AB 32's objectives and should be considered preliminary as we await the ARB's comparative analysis of the cost-effectiveness and technological feasibility of the measures proposed in the Draft Plan and continue our review of the Technical Appendices, released on July 22, 2008. We recognize that the Draft Plan represents ARB's first iteration of its AB 32 "blueprint" and look forward to reviewing and providing comments on ARB's Supplemental Analyses, as well as the subsequent draft versions of the Draft Plan later this year. In particular, we believe that analyses of the technological feasibility and cost effectiveness of the proposed measures in the Draft Plan are essential to allow meaningful public evaluation of the Plan and its impacts.

PG&E and our customers share California's desire to continue its leadership role on climate change, and this is why we were the first investor-owned utility to support enactment of AB 32. PG&E is a gas and electric utility serving one in twenty Americans and is committed to leadership on climate change. Our customers have invested and continue to invest in customer energy efficiency ("CEE") programs and a clean electric generating portfolio, so that our emissions are among the lowest of any utility in the nation. During the 2009 - 2011 period alone, PG&E expects to spend nearly $1.9 billion of customer funded revenue for various CEE programs that will save more than 5,784 gigawatt hours of electricity and 108 million therms of natural gas annually. The GHG emissions associated with the electricity we provide are among the lowest of any large utility in the country, approximately 40% of the CO^2 emitted by the average utility. Currently, over 50% of the electricity PG&E delivers to its customers comes from sources that emit no greenhouse gases at all.

PG&E approaches AB 32 implementation guided by five key objectives. We must:

- **Ensure environmental integrity** through mandatory, real and verifiable reductions;

- **Manage costs to California consumers and businesses** by pursuing cost-effective and technologically feasible reduction strategies and a consumer-oriented allowance allocation approach;

- **Solidify California's national leadership role** on climate change by creating a model program that can be integrated effectively with future regional, national and international programs;

- **Equitably apportion reduction obligations to ensure that all sectors pay their fair share.** Statewide reduction obligations should be apportioned to ensure that no single sector, nor its customers, assumes a disproportionate financial burden; and

- **Rely as much as possible on market and flexible compliance mechanisms** to encourage and accelerate the most efficient, cost-effective pathway to sustainable, available emissions reductions across all sectors.

With these objectives in mind, the following are our initial over-arching comments on the Draft Plan.

I. THE DRAFT PLAN PROPERLY TAKES A COMPREHENSIVE APPROACH TO ACHIEVING GHG REDUCTIONS.

The Legislature directed the ARB to consider three critical questions in designing its Draft Plan and emissions reduction regulations to achieve California's 2020 GHG reduction goal:

1. Will the emissions reduction measures work? For example, are they technologically feasible?

2. Are the emissions reduction measures cost effective? For example, is each measure cost effective compared to alternative measures or programs that could be undertaken to achieve the same quantity of reduction?

3. Are the emissions reduction measures fair and equitable when compared to the relative contribution of each source and sector to overall GHG emissions in California?

PG&E looks forward to providing its own full and complete comments on the Draft Plan when the required analyses are issued later this year and urges the ARB to quickly complete these three essential tasks so that the public and interested parties will have a full opportunity to comment.

It is often said that there is no single "silver bullet" to address the challenge of climate change and that is why it is critically important for California to pursue all "technologically feasible" and "cost-effective" options to achieve emission reduction targets as required by AB 32 (HSC § 38561(a)). The Draft Plan takes an important first step toward this comprehensive approach, relying on a wide range of measures, including market mechanisms and programs, to achieve AB 32's reduction targets. As a general matter, however, we firmly believe that the ARB and California should rely as much as possible on market and flexible compliance mechanisms to encourage and accelerate the most efficient and cost-effective pathways to sustainable emissions and reductions across all sectors. (Draft Plan, p. ES-3.)

As the individual programs described in the Draft Plan are unlikely to achieve the levels of reductions described, PG&E believes that the cap-and-trade system will be responsible for more GHG reductions than acknowledged in the draft. Because of this, offsets and flexible compliance policies should play a more central role in meeting the AB 32 goal than currently described.

II. TECHNOLOGICAL FEASIBILITY AND COST-EFFECTIVENESS EVALUATIONS AS DRAFT PLAN CRITERIA

While PG&E endorses several of the Draft Plan's criteria for developing preliminary recommendations for greenhouse gas reduction measures, including: **"Achieve the 2020 Cap"**; **"Maximize economic benefits and minimize economic harm;" "Provide leadership and influence other governments;"** and **"Assure that emissions reductions required of each sector are equitable"** (Draft Plan, pp. 49, 50), the Draft Plan does not list technological feasibility and cost effectiveness as evaluation criteria as required by AB 32 (HSC § 38561(a)).

The ARB is required to present clear evaluations for each measure for cost effectiveness and technological feasibility across all sectors, along with a full set of the input assumptions. For example, the outcome that the Pavley regulations will save $30 per month in fuel should include assumptions on inputs like the up-front vehicle cost, the miles driven per month, and whether the Low-Carbon Fuel Standard ("LCFS") has been considered in the avoided fuel emissions. Subjective inputs, like assumptions on decreasing costs based on experience or a maturing market, must be highlighted and tested.

Finally, PG&E requests that ARB present one set of cost-effectiveness evaluations without any co-pollutant quantification. As the ARB has acknowledged, they will not be able to quantify all of the co-benefits. Rather than choosing to quantify and include some of the co-benefits, co-pollutant quantification should be presented along side, but not on top of, cost effectiveness for GHG reductions.

III. DUE TO UNCERTAINTIES ASSOCIATED WITH SOME PROGRAMMATIC MEASURES, THE DRAFT PLAN SHOULD BE OPEN TO GREATER RELIANCE ON THE BROADER TRADING MARKET FOR COST-EFFECTIVE EMISSIONS REDUCTIONS.

We support the ARB's conclusion in the Draft Plan that a properly designed, multi-sector cap-and-trade program – and one ideally linked to the Western Climate Initiative ("WCI") – can achieve, real, quantifiable, timely and cost-effective GHG reductions (Draft Plan, p. 15). As discussed more fully at Section X, we believe market based mechanisms with clear and consistent rules and strong oversight – coupled with our current leading customer energy efficiency ("CEE"), renewables, and demand-side management programs – will reduce emissions, diversify our energy supply mix and help to minimize customer costs. Market mechanisms will drive the development of the next generation of clean, highly-efficient technologies and practices.

We are concerned, however, that the Draft Plan may place more reliance on regulatory or programmatic targets than is warranted given uncertainty regarding feasibility and costs, particularly in the areas of CEE, renewables, and combined heat and power ("CHP").

PG&E is committed to our current best-in-class energy efficiency and renewables programs, but programmatic mandates with specific, set-aside targets are not ideal and may not be achievable when outcomes are uncertain, technologies are not yet known, and costs are difficult to forecast. As mandates offer little choice in how to meet goals, these measures should be realistic. Instead, PG&E believes that more reliance should be placed on the ability of the market to deliver cost-effective, innovative and substantial emission-reduction opportunities and less on programmatic measures where California and California's businesses are already demonstrating bold leadership. The unprecedented reductions needed for AB 32 should be left to the market and not be expected or mandated through channels that may not be technologically feasible or cost effective. In doing so, and in leveraging market forces to seek out lower cost reductions, the Draft Plan could serve more nimbly and effectively as a map with multiple roads to achieving AB 32's targets. Therefore, in terms of overall program design, we believe that the ARB should pursue more reductions through market-based mechanisms, including offsets and other flexible compliance mechanisms, than are currently contemplated by the Draft Plan. Our specific concerns regarding renewables, CEE, and CHP are set forth more fully below.

IV. IT IS PREMATURE TO ASSUME GHG REDUCTIONS ASSOCIATED WITH 33% RPS IN THE AB 32 DRAFT PLAN.

Given the recognized uncertainty associated with achieving a 33% Renewable Portfolio Standard ("RPS") by 2020, PG&E does not believe that it is appropriate for the Draft Plan or AB 32 regulations to include firm reductions associated with this stretch goal. Further analysis is needed regarding the feasibility and cost of a 33% renewables target. The absence of such analysis, which is underway in a variety of initiatives including Renewable Energy Transmission Initiative and streamlined permitting and transmissions efforts may impede parties' ability to address the current challenges and understand what will be needed for resource developments and system reliability as more renewables come on line. Given the challenges and uncertainty associated with 33% RPS, the ARB should not rely on a 33% RPS measure or assume a set amount of GHG reductions from such a measure in the Draft Plan until further evaluation and consensus regarding its feasibility and cost effectiveness is completed.

A. Cost Effectiveness of 33% RPS

It is unclear whether a higher RPS target is cost effective vis-à-vis other measures to reduce greenhouse gas emissions. In studies prepared for the California Public Utilities Commission ("CPUC"), Energy and Environmental Economics, Inc. ("E3") has estimated that moving to 33% RPS results in implied costs of \$100 to \$200 per ton of GHG reductions.[1/] Investment to achieve a 33% renewables goal are expected to be significant – several *billion* dollars – given the costs to construct transmission to remote locations, energy storage, ramping and regulation, over-generation, and back-up dependable capacity. A comprehensive assessment of the costs to ensure system reliability and to get renewables to load centers is an essential element of measuring the cost effectiveness of a higher renewables goal. Absent such an assessment and a thorough understanding of the costs, it is premature to conclude that a fixed 33% renewables target constitutes a cost-effective measure for achieving GHG emissions reductions.

1/ http://www.ethree.com/GHG/E3_CPUC_GHGResults_13May08%20(2).pdf

Additionally, when calculating the cost-effectiveness of this measure, it is inappropriate for the ARB to divide all of the GHG reductions from going to current levels to 33% only by the costs of moving from 20% to 33%. Rather, the ARB needs to determine the cost effectiveness of 33% on its own merits, without assuming that the reductions in getting to 20% come for free. The appropriate formula is to divide the GHG reductions in moving from 20% to 33% by the costs in moving from 20% to 33%.[2/]

B. Uncertainty with Draft Plan Numbers

The Draft Plan states that moving to 33% RPS will add 48,000 GWH and reduce emissions by 21.2 MMT. PG&E understands that these numbers are against a 2005 baseline, unlike E3's *Business As Usual* ("BAU") case, which includes meeting 20% RPS and current energy efficiency goals. The Draft Plan should make clear that these numbers are not incremental to the 20% RPS goals but inclusive of them. Additionally, the ARB should ensure that the energy calculation is made after CEE is subtracted out of the load; the RPS does not apply to load served through energy efficiency. Finally, in accounting for the GHG savings of renewables, the ARB should net out any emissions associated with dispatchable facilities needed to firm the renewables deliveries and ensure system reliability. It is conceivable that these facilities will have to operate at lower minimum loading levels to firm renewables and will therefore be required to operate at a higher heat rate.

C. Current Experience with RPS: Technological Feasibility and Barriers to Achieving 33% Renewables

PG&E is trying to obtain as much renewable energy as possible, while protecting customers against unreasonable costs or threats to service reliability. A number of critical issues must be assessed prior to increasing the existing 20% RPS target. These include: (1) adequacy of supply; (2) adequacy and availability of transmission infrastructure; (3) how to integrate new renewable resources into the grid; (4) managing over-generation and storage; and (5) how developers will finance renewables projects without a multi-year extension of federal investment tax credits ("ITC") and production tax credits ("IPC").[3/] For example, regardless of our shared commitment to increased renewables, if ITC and IPC credits are not extended, some developers

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2/ Draft Plan, C-78.

3/ Pacific Gas and Electric Company, "Docket 07-OIIP-01, California Energy Commission, Opening Comments of Pacific Gas and Electric Company (U 39 E) on Economic Modeling Issues Under AB 32," pp. 17-23.

may face significant delays or simply not be able to proceed with their projects. PG&E is committed to working with state agencies and other parties to address these barriers.

1. The Renewables Market and Adequacy of Supply

Developing additional renewable resources to meet increased demand in California and the Western Electricity Coordination Council ("WECC") will become increasingly challenging. These challenges grow as more and more states adopt RPS programs and, globally, there is increased demand for renewables. As this demand has grown, manufacturing of key components has lagged, yielding "a seller's market" as demand exceeds supply. The National Renewable Energy Laboratory ("NREL") estimates that the demand for clean energy will outpace supply by 37% in 2010.[4/] Order backlogs of up to two years are common with wind turbines and solar photovoltaic cells, largely attributed to increased global demand. Additionally, as new renewables may be located in less accessible locations where new transmission lines are needed, renewables developers frequently encounter permitting and siting-related problems in the remaining undeveloped locations.

2. Transmission Infrastructure

The limited availability of new transmission capacity is one of the key obstacles to increasing renewable supply. Given the remote locations of a substantial portion of the remaining undeveloped renewable resources, significant upgrades in the transmission infrastructure will be required, both in California and throughout the WECC. Additional transmission infrastructure will be very costly and will require many years to construct, which is generally considerably longer than it takes to construct a renewable generating facility. The California Independent System Operators ("CAISO") estimates that, in California alone, the 33% RPS case will require 128 new or upgraded transmission line segments and upgrades to accommodate new generation resources, at an estimated cost of $6.4 billion, excluding land and right-of-way costs.[5/] Transmission limitations will have a direct impact on how quickly and at what total cost California will be able to increase renewables.

4/ Paul Davidson, "USA Today," October 4, 2007.

5/ California ISO, "Integration of Renewable Resources," November 2007, pp. 21.

3. Renewables Integration

The resources needed to integrate renewables to achieve a 33% goal will be substantial. The state will have to add dispatchable generation (hydro or fossil fired) and storage to provide capacity, ramping, and regulation services. A study finalized by the CAISO in November 2007 for achieving 20% RPS found that to integrate 6,700 MW of wind generation (~ 2,600 MW existing and ~ 4,100 MW new), the system would need about 250 MW for "Up Regulation" and up to 500 MW for "Down Regulation."[6/] The CAISO also found that it needed approximately 800 MW of ramping capacity to meet multi-hour ramps during the morning load increase coupled with declining wind generation[7/], plus significant increase of the supplemental energy stack for load following. Ramping and regulation resources to achieve a 33% target would, accordingly, be much greater.

4. Over Generation and Energy Storage

Over generation occurs when significant amounts of uncontrolled generation exceed minimum loads. This usually occurs at night during periods of high "as available" generation and low loads. For example, one of the largest contributors to new renewables will be the Tehachapi wind resource, whose output peaks in May and June, during periods of abundant hydroelectric power and minimum loads.

The CAISO minimum load operating conditions will limit how much off-peak energy can be accepted. While the CAISO can pay adjacent control areas to take this excess power or pay generators to curtail output, this issue will only intensify in the future as surrounding control areas, potentially with their own RPS standards and significant levels of intermittent power, will be in a similar situation, and be faced with uneconomic dispatch or shut down.

Energy storage will be critical to successfully integrating significant levels of intermittent generation and maintaining system reliability. However, current storage technologies are not commercially feasible or geographically available for integrating intermittent resources on a large-scale basis. New commercially ready technologies will be required and may not be commercially available for many years.

6/ CAISO Integration of Renewables Study, November 2007, at 7.

7/ CAISO Integration of Renewables Study at 11.

5. Uncertainty of Federal Tax Credits

A multi-year extension of federal tax credits is crucial for the development of additional renewable resources at reasonable prices for PG&E's customers. Federal tax credits, specifically the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") provide significant benefits to California and can assist in the creation of jobs and billions of dollars in investments in green technology. Such tax credits directly benefit Californians by lowering development costs and enabling the operation of more renewables. These tax credits serve to reduce renewables costs to customers by approximately 30%. PG&E, other IOUs, legislators, and renewable generators have strongly supported extensions of these tax credits; however, it is unclear if or when such an extension will be granted. Without an extension of these credits, hundreds of megawatts of renewable generation are in jeopardy, which may hinder PG&E's ability to reach the 20% RPS, much less an expanded RPS of 33%.

PG&E has also supported the extension of the California Property Tax Exclusion for a five-year period. Extension of this state tax provision will help foster growth in both utility scale and residential solar programs and serve to reduce total customer costs for solar-generated renewable energy.

6. Contract Delay and Failure

PG&E has signed forty contracts for nearly 3500 MW of renewable energy since the 20% RPS statute was enacted. However, performance under those contracts has been susceptible to delays and failures due to problems encountered by suppliers, including siting and permitting delays. Numerous other issues have been encountered that have led to contract delays including problems with avian mortality impacting wind re-powering, cultural resource restrictions affecting land usage for geothermal development, wind turbines causing radar interference issues with Air Force bases, and the lengthy process of negotiating leases for use of federal land. Unanticipated issues such as these can cause significant delays and ultimately impact compliance. In addition, increases in equipment prices are making it difficult for suppliers to obtain project financing, resulting in potential needs for contract renegotiation and project delay, or potential project default.

7. The Need for Equal Application of RPS Standards to Publicly-Owned Utilities

While many POUs have voluntary programs that establish numerical targets equal or greater than the 20% RPS for IOUs, POUs may not be using the same counting conventions that state law, as implemented by the California Energy Commission ("CEC"), requires IOUs to use. As POUs have different eligibility requirements than the IOUs, POUs may "green" their power by using (some) large hydro and renewable energy credits ("RECs") to meet their goals. In 2003, while POUs represented their renewable deliveries as being 7.6% of their combined retail sales, only 5.1% were CEC-eligible renewable sales. This uneven playing field results in customer confusion and results in a state energy policy that is applied to only two-thirds of the energy consumers in the state - that is, those energy consumers served by the IOUs. Before requiring IOUs to achieve higher levels of renewables, the state should require POUs to achieve the same RPS mandate as the IOUs and to use the same counting conventions.

V. ENERGY EFFICIENCY TARGETS ARE HIGHLY UNCERTAIN.

While the state should strive to implement all cost-effective and technologically feasible energy efficiency measures, we do not believe it prudent for ARB to assume a single numeric target for energy efficiency in the Draft Plan. The Draft Plan recommends an energy efficiency measure that would be expected to deliver statewide energy demand reductions of 32,000 GWh and 800 million therms over the 2020 BAU for a reduction of 19.4 MMT CO2e. The ambitious scope, cost, and scale of these goals should be fully acknowledged in the development of the final Scoping Plan. Achieving these goals will require unprecedented coordination and extraordinary action by multiple governmental agencies at federal, state and local levels, as well as coordination among between state agencies, utilities, and end users to create processes and new measures and mandates for energy efficiency that do not exist today. Among other conditions, the success of these goals depends on additional research and development, technology improvements, changes in end-user preferences, declining measure costs, federal waivers for California codes and standards, and compliance and enforcement with new codes and standards. Additionally, the overall energy savings assumed in the Draft Plan are acknowledged as provisional and subject to revision by the PUC. Therefore, the ARB must factor uncertainty into the Draft Plan targets and acknowledge a more realistic range of emissions reductions associated with CEE.

A. Energy Efficiency Cost Effectiveness Analysis

ARB must include cost assessment and evaluation to make sure these measures are cost effective relative to other carbon reduction strategies. PG&E is concerned that the cost numbers presented thus far by the CPUC's Energy Division Draft Plan and The Itron Goals Report ("Itron") are under-estimated and not accurate. As cost figures presented to date have no supporting documentation,[8/] PG&E is not able to ascertain what the value represents and why it does not seem to include the very significant increase in funding for CEE programs needed when utilities provide the full incremental cost of incentives. PG&E also believes that the levelized costs used in the E3 model are too low and needs more information on how these numbers were derived; PG&E has requested supporting documentation.[9/] This month, PG&E has proposed 2009-2011 energy efficiency programs that will cost $1.9 billion; these programs do not come close to funding customer incentives at the full incremental cost of measures. Given the costs of the programs as they are currently designed, PG&E is concerned that offering customer incentives at the full incremental cost of the energy efficiency measures may not be the most efficient use of resources. PG&E concurs with other California stakeholders[10/] that a careful cost-effectiveness analysis of these unprecedented energy efficient initiatives is needed.

Cost calculations should also reflect the additional cost of replacing efficient technologies which do not remain in service to 2020 (for example, if an efficient copying machine[11/] is installed in 2010, it would be expected to last six years and the customer may need an incentive to retire it and replace it with another efficient measure); costs for early retirement of inefficient but still-functioning measures; and the opportunity costs of businesses during energy efficiency

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8/ The ($9.4 billion) value presented in the CPUC Energy Division Staff Paper, May 12, 2008 seems orders of magnitude too low, given that the recommended Itron mid/high level scenario reflects a very significant increase in funding for CEE programs, where utilities provide the full incremental cost of incentives.

9/ The TRC levelized costs for PG&E is shown as $0.057 for the Mid/High Itron cases. This appears low given that these costs were $0.049 for programs in the 2006-2008 period when the level of rebates was significantly lower than is projected in the Mid and High Itron Scenarios, where rebates are set at full incremental cost.

10/ Indeed, the Division of Ratepayer Advocates in their comments on the CPUC Proposed Decision on Interim Energy Efficiency Goals for 2012-2020, July 21, 2008 state on page 4, "The Commission has never authorized full incremental funding of energy efficiency measures, but doing so would result in bigger energy efficiency budgets and higher ratepayer costs of unknown magnitude, with overall lower cost effectiveness of energy efficiency programs."

11/ See the Database of Energy Efficiency Resources at http://eega.cpuc.ca.gov/deer for "High Efficiency Copiers", measure id D03-901, which has an effective useful life of 6 years.

measure installation. Modeling should incorporate the entire cost of the measure, costs related to decay rates, additional incentives for early retirement, opportunity costs for businesses, and contingency costs.

Finally, the CEE goals should evaluate the relative cost effectiveness of CEE programs across different sources within the electric and gas sector, including the relative feasibility and cost effectiveness of CEE measures and programs undertaken by POUs, whose CEE programs have lagged behind those of investor-owned utilities' matured programs.

B. Uncertainty with Draft Plan Numbers

The Draft Plan suggests basing the energy efficiency goals on the high end being considered by the CPUC. However, adopting the high end numbers may be problematic given the level of uncertainty. The Itron Goals Report,[12/] the source of the goals' ranges, contains considerable discussion of substantial uncertainties and recommends the use of a 20% "uncertainty band."[13/] This recommendation does not appear in the CPUC's Proposed Decision or the Draft Plan. The Draft Plan must account for these wide uncertainty bands, as suggested by the Itron.

The high- and mid-level goals assume the implementation of very aggressive CEE rebates at or near 100% of incremental measure costs, followed by much higher participation rates by customers. However, evidence suggests that other behavioral factors may be more significant than full incremental measure cost rebates. For example, consumers may care more about the size of the dishwasher than its energy consumption. Additionally, the goals are predicated on the discovery of new technology, the commercialization of emerging technology, and associated declining measure costs.[14/] The setting of an absolute target for energy efficiency that depends on emerging and uncertain technologies conflicts with AB 32's mandate for measures to be "technologically feasible."

As acknowledged by the CPUC, the current Itron numbers are provisional, subject to revision,[15/] and will be updated in 2010. Detailed workpapers of Itron's work are not yet

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12/ Itron was hired by the Energy Division to assist in setting EE goals for 2012 and beyond. Itron has expertise in measuring and evaluating EE savings.

13/ Ibid, Page 82, "*Each forecast is for the expected case with the high and low values being roughly plus or minus 20% of the expected value*."

14/ Itron, Inc. Consulting and Analysis Services, Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond, April 15, 2008, see page v and 71.

15/ Proposed Decision, p. .30.

available, so Itron's specific calculations cannot be confirmed. Already, needed revisions have surfaced. Subsequent to release of the initial Itron analysis, Itron acknowledged an incorrect inclusion of 2,000 GWh of 2007 savings in the 2012-2020 figures.[16/] The PUC final decision appears to have accounted for this change, and the Scoping Plan should be modified accordingly. Such changes will continue to occur in the future, highlighting the need for flexibility to be built into the Scoping Plan.

In addition to vetting for quality assurance, PG&E recommends that the CEE goals not be adopted until revised to reflect the latest adopted DEER[17/] parameter values (using the most recent adopted Net to Gross, End of Useful Life, Cost data, energy unit savings and load shapes). In total, these updated parameters are likely to result in downward revisions to savings estimates. The CPUC Energy Division has indicated that their CEE goals timeline does not permit updating the CEE potential and goals to be consistent with the new DEER values until 2010.[18/] In PG&E's view, these updates are essential to providing more accurate, reliable, and achievable estimates of the CEE goals.

To acknowledge the ambitious and uncertain nature of its proposed goals, ARB should associate the probabilities with a range of CEE savings. Additionally, PG&E recommends the ARB develop a procedure to update the energy efficiency targets.

In addition to the great uncertainties described in the CEE goals above, it is not apparent to PG&E which CEE goals the ARB is referencing. While the Draft Plan suggests that the high end of the goals be adopted, the PUC PD suggests adopting the Mid Case.

16/ Itron has recently confirmed that its 2008-2020 estimates of energy efficiency potential that underlie the cumulative 28,000 Gwh of savings in the Proposed Decision for the utilities' service areas incorrectly includes 2000 Gwh of 2007 savings. In terms of total savings, the Proposed Decision's calculation of cumulative savings for the 2008-2020 period needs to be adjusted accordingly.

17/ Database of Energy Efficiency Resources (DEER) contains the results of EE measurement and evaluation studies which are then used to determine what EE savings are actually realized. Targets are often set on theoretical values which then need to be revised in the light of empirical analyses. Recent DEER studies have revised mainly downward many estimates of potential EE savings.

18/ Page 32.

Estimated Savings in the High, Mid, and Low Straw Man Cases
(Cumulative GWh savings in 2020)
Page 104, Itron Goals Update Report

Savings Mechanism	Low Case	Mid Case	High Case
Utility programs (gross)	12,240	19,278	19,278
Huffman Bill	6,983	4,064	5,419
Codes & standards	1,800	2,771	3,137
BBEES initiatives	1,734	2,197	3,372
Total	**23,135**	**28,783**	**31,930**

The Draft Plan target of 32,000 Gwh could either be consistent with the High Case Itron goals of 31,930 from IOU service territories alone or this figure could reflect the sum of the Mid Case Itron goals of 28,783 Gwh plus 4,000 Gwh from POU service territories. Additionally, as the PUC decision corrected an error in the Itron report, the Mid Case total is now 2,000 GWh less, around 26,000 GWh. If the ARB is referencing the Mid Case, municipal utilities, with a fourth of the state's electric load, are only being assigned a total of 4000 Gwh of cumulative savings, an amount that is one-seventh of the utility service area goals. If the ARB is referencing the High Case, municipal utilities would appear to have no energy efficiency responsibility in the Draft Plan. As CEC staff noted at the ARB's May 2, 2008, public workshop, despite serving 22% of the electricity load and being responsible for nearly 42% of the utility CO2 emissions,[19/] POUs only contribute 5.4% of energy efficiency savings. If SMUD is removed from those figures, the remaining POUs only contribute 2.7% of energy efficiency savings while serving 18% of the load. These figures show the considerable CEE savings potential in POU territory, savings that the IOUs have been accumulating for years given their thirty-year history of successful and cost effective CEE. Additional targets for energy efficiency should be applied to POUs before looking to expand already ambitious IOU programs. The state should require POUs to achieve a CEE savings target that is proportional to their emissions and generation levels and should mandate similar measurement and evaluation protocols for these POU service territories.

PG&E is also concerned that the Draft Plan may be double counting reductions for energy efficiency. For example, it is unclear if ARB has adequately accounted for energy efficiency already incorporated in load growth. When adding the High Case measures, E3 only added 20,000 GWh additionally as 12,000 GWh is already incorporated in the load growth calculations.

19/ Schulock CAISO presentation.

Additionally, to get the reductions stated in Draft Plan from 32,000 MWh, 15.2 MMT, one has to use an avoided heat rate of 8950 btu/KWh. This heat rate is much higher than the heat rate the CPUC uses to calculate the avoided emissions from a CCGT, 6704 btu/KWh. At this heat rate, 32,000 GWH saves 11.4 MMT, almost four MMT less than the number claimed in the Draft Plan. The E3 calculator shows a 10 MMT reduction in moving from the reference case goals to the High Case CEE goals. PG&E suggested the emissions savings be lowered to ~7 MMT for additional energy efficiency.

C. Current Experience with Energy Efficiency

PG&E is a leader in Energy Efficiency programs, and proactively supports state implementation of new codes and standards, and the demonstration of new energy efficiency technologies. However, there are uncertainties in implementing energy efficiency that are beyond the control of utilities and must be recognized and modeled explicitly. As previously stated, PG&E recommends that ARB take into account the range of uncertainty associated with the realization of these aggressive CEE goals.

For example, many savings are projected to come from improved building codes and appliance energy efficiency standards. However, there are acknowledged compliance issues with these codes and standards. As referenced in the April 25, 2008 edition of California Energy Markets, William Callahan, president of the Bay Area Associated Roofing Contractors, explained that many residential roofing projects require a permit, but often contractors and customers just skip the permit process. In that same article, Erik Emblem, an attorney representing sheet-metal and heating, ventilation and air-conditioner contractors, said 90% of HVAC projects have no permit. Permitted projects that meet code can run $2,000 more than projects that do not, he said.

California may create rigorous codes and standards, but if these standards are not enforced, noncompliance (‘permits not pulled’) will result in lower realized gross energy efficiency savings and GHG emissions reductions will not occur. Further, if the ARB assumes these reductions will occur, then electricity load will increase, putting pressure on the complying entities and potentially increasing costs to consumers as part of the cap and trade program. Uncertainty in achieving these programmatic goals may create undue scarcity in the cap and trade market, leaving it more vulnerable to price run-ups.

VI. THE DRAFT PLAN OVERESTIMATES THE POTENTIAL FOR GHG REDUCTIONS FROM COMBINED HEAT AND POWER.

The Draft Plan places undue reliance on CHP electric generation sources as a GHG reduction measure. Before adopting CHP as a measure, PG&E recommends that the ARB substantiate that thermal load exists to support these estimates. CHP is a GHG producing, fossil-fuel based source of electricity, so it must not be grouped with energy efficiency, which actually decreases load.[20/] CHP is typically a baseload, must-take resource that provides virtually no operational flexibility. As such, it could potentially displace or make more difficult integrating renewable electricity, also a must-take resource. Must take CHP might increase PG&E's and other utilities' GHG footprint and make integrating renewables more difficult and expensive.

A. The Draft Plan Overestimates CHP Potential and Accompanying GHG Abatement.

The Draft Plan sets an ambitious goal for increased energy production from CHP - 30,000 GWh - engendering GHG reductions of 6.9 MMT. PG&E is doubtful that this magnitude of technologically feasible, cost effective, GHG-reducing potential for CHP actually exists. For example, consider the 50 MW CHP unit installed in 2002 at the Valero Refinery in Benicia, California. According to the CEC's Fact Sheet, that size was selected because it ". . . produced the amount of electrical power that closely matched average re finery consumption and also could efficiently produce the proper amount of 600 psi stream to match the refinery's demand . . ." The Benicia Refinery has a capacity of 153,000 barrels per day, which corresponds to about 8% of California's total refining. In the unlikely case that the other 92'% of California's refining capacity has similar steam demands that are not already being met, via CHP, those steam demands would support just 540 MW of new, efficient CHP. As ARB evaluates the use of CHP for emissions reductions, it should be clear that only efficient CHP in place of existing, business-as-usual thermal load may meaningfully reduce electric sector GHG emissions. If ARB hopes to rely on CHP to reduce GHG emissions, it must first affirmatively establish that thermal load associated with 30,000 GWh of efficient, technologically feasible, cost effective CHP actually exists. Otherwise, the reduction goal tasked to CHP will not be achievable. PG&E supports use of efficient CHP, as long as the CHP projects that are implemented are truly efficient and cost effective, compared to alternative GHG emissions reduction opportunities within the electric

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20/ PG&E notes that this mistaken grouping in the Draft Scoping Plan has been corrected in Appendix E.

sector and within PG&E's portfolio, and provided there is a fair distribution of costs and benefits between CHP owners and non-CHP owners.

The ARB has derived the Draft Plan estimate on a dated draft 2005 CEC consultant study on CHP potential in California. This draft has not been updated.[21/] The ARB based the CHP measure estimate of 4000 MW on the CEC CHP Assessment's "Moderate Market Case" scenario of 4,400 MW – 1,574 MW from new onsite CHP and 2,804 MW of new export MW from very large CHP facilities over 100 MW per site.[22/] As we noted in our comments to the PUC and CEC on the E3 Aggressive Case (which also adopts the CEC CHP Moderate Market Case) PG&E cannot support this estimate for large installations. PG&E suggested using large capacity additions of 393 MW, over 2,400 MW less, because PG&E does not believe that this magnitude of sites with large CHP potential exists.[23/]

In California, favorable CHP sites have were heavily developed as a result of the popularity of Standard Offer 4, resulting from implementation of PURPA in California. While there has been some new thermal load added at large facilities in California, e.g. Valero, additional sites with the ability to use such large amounts of steam are limited in CA. When PG&E asked during the E3 conference call for the CEC/PUC proceeding where this potential would come from, a CHP representative suggested "refinery expansion." PG&E believes that with the passage of AB 32 and the increased focus on the environmental impacts of refineries, it cannot be assumed that refineries will substantially expand and therefore will have large amounts of expanded thermal load. As a great deal of the potential for large CHP may not exist, it may be inappropriate to assume that GHG emissions can be abated through installation of large CHP. The thermal load that the CHP is assumed to replace may not exist or ever be installed.

PG&E offers caution against overly ambitious estimates of CHP potential. A 2007 Lawrence Berkeley National Laboratory ("LBNL") paper, "Preliminary Estimates of Combined Heat and Power Greenhouse Gas Abatement Potential for California in 2020," states:

21/ See footnote 34, on page C-73 of Appendix C, which cites: Assessment of California CHP Market and Policy Options for Increased Penetration (CEC CHP Assessment), PIER Collaborative Report, November 2005, CEC-500-2005-173California Energy Commission, Draft Consultant report, Assessment of California CHP Market and Policy Options for Increased Penetration. Prepared by Electric Power research Institute, April 2005.

22/ Ibid, page C-74.

23/ While PG&E has queried the basis of the CHP capacity with EPRI, we have not been given access to the database on which this capacity figure is based. The model that produced the estimates is proprietary, therefore PG&E cannot reproduce the work or independently verify any assumptions.

> *We note that for many sectors, carbon emissions reductions increase from the low to the medium penetration scenarios, but decrease in the high and/or maximum penetration scenarios. CHP system efficiency decreases as penetration increases: the most attractive sites, i.e. those with a use for much of the waste heat, are assumed to adopt first; however, as penetration levels increase, CHP becomes less favorable.*

Prior to reliance on the CEC "moderate" scenario for CHP potential in California, the ARB should make available an independent estimate.

B. Draft Plan Numbers for CHP GHG Abatement are Uncertain and Need Further Scrutiny.

CHP will be a GHG-reduction measure only under certain circumstances and if it does not interfere with the expansion of renewables and other non-carbon resources. In addition to questioning the potential to add 4,000 MW of CHP; PG&E questions how 4,000 MW equates to savings of 32,000 GWh and how 32,000 GWh of CHP results in 6.9 MMT of GHG emissions reductions. The ARB appears to have used a capacity factor of 85% for all CHP, but smaller CHP facilities have much lower capacity factors. Per the E3 calculator, adding almost 4,400 MW of CHP saves only 4.9 MMT, 2 MMT less with more MWs added. CHP generation should not be evaluated assuming it displaces old and inefficient steam units that operate in a peaking mode. CHP generation may be displacing a new gas fired CCGT plus a new gas-fired boiler, or possibly a baseload or intermittent renewables resource plus a new gas-fired boiler.[24/] The result is unlikely to produce significant GHG reduction benefits.

Further, Reduced line losses should not be attributed to large CHP. The 2005 CEC assessment of the CHP market showed the most potential coming from large CHP units, which would primarily export to the electricity grid.[25/] Therefore, this large CHP will export fossil-fuel based electricity to the grid, causing the same amount of line losses as CCGTs, which may be more efficient than CHP units. Additionally, there appear to be some mistakes in the ARB's calculations 7.8%. The line loss quantity attributed to 30,000 GWh is 2,340 GWh. Even with

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24/ The CEC market potential study bases most of its assumptions about the benefits of CHP by comparing old, low efficiency, old steam turbine-based electrical generation versus thermally optimized high efficiency CHP facilities. In simple terms, the alternative to CHP baseload generation should not be an aging power plant with a higher than 10,000 Btu/kWh heat rate. Because the CEC potential study does not conduct the correct comparison, CHP benefits are over stated. CEC CHP Assessment, p. 2-20.)

25/ California Energy Commission (CEC-500-2005-173). Assessment of California Combined Heat and Power Market and Policy Options for Increased Penetration. November 2005.

the addition of distributed solar, the lines losses of 36,500 GWh would be 2,691 GWh. In total, the ARB shows that these two programs reduce line losses by 5,500 GWh.[26/] PG&E requests that the ARB recalculate the line losses to account for the fact that large CHP will export electricity to the grid and to provide the calculations to the public.

C. CHP is Not Primarily an Emissions Reduction Measure, Nor is it Energy Efficiency.

PG&E does not recommend that CHP be included in the "Energy Efficiency" category, because while CHP, when it is a customer choice option, will reduce demand, it is fundamentally different from energy efficiency and other demand management measures. Energy efficiency creates a demand reduction by reducing the amount of energy needed to accomplish the same end use application. Demand response programs reduce demand through reductions in activity by participating customers. CHP, on the other hand, like all customer generation, simply exchanges one electricity source with another. It does not reduce total electricity demand; it simply reduces the demand that the utility must serve.

D. CHP Competes with Renewable Energy in the Utility Procurement Portfolio.

Finally, in developing the framework for CHP treatment, the ARB must address the challenges associated with adding a must take, base load, non-dispatchable, fossil-fuel resource. As noted in the aforementioned LBNL study,[27/]

> *Typically, CHP is only more carbon efficient than the grid electricity it displaces when the waste heat from the generation offsets additional fuel consumption. Given the quite clean grid generation being displaced, inefficient CHP systems can ultimately lead to a net increase in emissions.*

Because CHP electricity, like renewable energy, is typically a non-dispatchable base load resource, adding fossil fuel-based CHP to the base load utility portfolio could crowd out renewable sources. Such challenges demonstrate the importance of understanding how energy resources are dispatched in California and how new CHP installations fit into this resource mix, before creating a one-size-fits-all approach to CHP treatment under AB 32.

It is critical to analyze the effect that CHP base load additions will have on resources on the margin. For example, natural gas combined cycle plants often run in "standby" mode, rather

26/ Draft Plan, p. 58, fn. 1.
27/ *Ibid.*

than being shut down altogether, in preparation for peak load deployment. However, plants operating less than at full capacity, or in stand-by mode, are less efficient. Must-take base load additions could force natural gas plants running efficiently at the margin into the less efficient "standby" mode, resulting in increased overall emissions and making maintaining grid reliability more difficult. In certain circumstances, the CAISO may need to pay to sell power outside of the CAISO if too many "must-take" generators result in excess off-peak generation.

E. Cost Effectiveness

As outlined in recent comments to the CPUC on "Additional Issues Related to Implementation of AB32 in the Electric and Natural Gas Sectors," PG&E envisions CHP units as fundamental components of a cap-and-trade regime. PG&E believes that if CHP truly represents a cost-effective means of GHG abatement, an efficient market will create financial incentives for new installations. However, the Draft Plan includes increased energy production from CHP among the list of proposed programmatic measures. It is not clear how CHP would be regulated under a mandatory programmatic regime, and PG&E looks forward to further detail and opportunity to comment on the ARB's proposal. For smaller CHP installations – which tend to serve on-site load and are less likely to actively participate in external electricity markets – economic incentives can be addressed through non-market measures, such as expanding the CPUC's Self-Generation Incentive Program to include appropriately efficient installations.

F. Current Experience with CHP-Market Barriers

The Draft Plan mentions that there are institutional barriers to CHP[28/] without elaborating on what those barriers are. Evidence shows that the market barriers for some CHP have little to do with the economics that drive other forms of electricity generation and may prove resistant. For example, many customers with a thermal load are simply not interested in learning how to own and operate a generator.

Before issuing the 2005 CHP market potential study, the CEC completed an extensive examination of distributed generation in California.[29/] CHP received ample attention in this examination, including a workshop devoted to the CHP market. CEC consultants and market participants discussed the (then) sluggish CHP market and identified the primary market barriers

28/ Appendix C refers to the draft CEC report, but did not further discuss what they were. (Appendix C, page C-73.)

29/ "Distributed Generation OII (Order Instituting Investigation)" 2004-DIST-GEN-01.

as: 1) a two-year payback hurdle (this is the equivalent of a 50% return on investment); 2) low priority accorded to energy issues; 3) reluctance to acquire necessary engineering skills for generation operation; 4) market uncertainty; and 5) complexity of ISO tariffs.[30/]

PG&E agrees that barriers to CHP development do exist; but many barriers would not respond to incentive treatment and each of these barriers would be better addressed in the appropriate forum. In fact, many issues surrounding CHP expansion – such as participation in incentive programs, obligations to fund customer programs, improvements to interconnection processes – have already been decided by the legislature or regulatory bodies. It may not be advisable to use the AB 32 implementation process as an opportunity to undo existing well-analyzed legislative and regulatory measures.

VII. RENEWABLES, ENERGY EFFICIENCY, AND CHP HAVE LIMITED IN-STATE PUBLIC HEALTH BENEFITS.

The Draft Plan appears to be operating under the assumption that electricity sector programs will have clear co-benefits in terms of reduction of co-pollutants emitted within California. The Draft Plan should be conservative in ascribing with pollutant reductions to electricity sector programs, as these programs are unlikely to show significant reductions in local criteria air pollutants or air toxics.[31/]

According to ARB data, power plants and CHP facilities together contribute between 0.27% and 1.44% of criteria air pollutants on a state-wide basis.[32/] Electricity generating facilities rank low in facilities that emit air toxics. The South Coast Air Quality Management District released a 2008 report which ranked roughly 300 facilities with air-toxics emissions in decreasing order of "Cancer Risk in a million."[33/] The highest-ranked power plant is SCE's diesel plant on Catalina Island (9 MW), which is number 88 on the list, with a Cancer Risk of

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30/ Presentations by Nick Lenssen of Primen and David Dyck of Valero Energy Corporation, "Combined Heat and Power Distributed Generation market and Policy Workshop" California Energy Commission, April 28, 2005.

31/ Toxics are benzene, formaldehyde, polycyclic aromatic hydrocarbons, etc., which are associated with cancer and other health issues. Criteria air pollutants are ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, and PM10 and PM2.5.

32/ http://www.arb.ca.gov/app/emsinv/emssumcat_query.php?F_YR=2006&F_DIV=-4&F_SEASON=A&SP=2007&F_AREA=CA

33/ http://www.aqmd.gov/prdas/AB2588/pdf/Annual_Report_2007.pdf

4.98.[34/] The big power plants in the LA Basin are also in the list, but are well above 200 in the list and have cancer risks less than 0.63.[35/]

Based on this information, CEE, CHP, and RPS measures should be evaluated for cost effectiveness based solely on GHG emissions reductions. Additionally, compliance flexibility mechanisms in the electricity sector, which have the potential for substantial cost savings, should not be limited because of limited co-pollutant emissions impacts.

VIII. THE DRAFT PLAN MAY PLACE AN INEQUITABLE BURDEN ON THE ELECTRIC SECTOR AND ITS CUSTOMERS.

Statewide reduction obligations should be apportioned under AB 32 to ensure that no single sector, nor its customers, assumes a disproportionate financial burden. PG&E is concerned that the Draft Plan places an inequitable compliance burden on utility sector customers by imposing programmatic targets that have not been shown to be cost effective or technologically feasible.

The most cost-effective measures should be pursued first to reach the state's overall GHG-reduction targets, regardless of sector. Any deviation from pursuing the most cost-effective reductions will impose needless costs on Californians. Of course, regardless of which sector actually performs the reductions, ARB should insure that all sectors bear their equitable share of overall GHG-reduction costs based on their relative contribution to overall emissions.

As noted above, ARB's Draft Plan does not yet include analyses and evaluations based on cost effectiveness and technological feasibility. For example, the Draft Plan's heavy reliance on emission reductions in the electricity sector raises concerns both in terms of technological feasibility and cost effectiveness. We expect to provide further comments after reviewing the ARB's economic analyses and Technical Appendices but are, at this time, are concerned that the electricity sector seems to be singled out for more emission reduction costs than other sectors relative to each sector's contributions to overall emissions.

34/ The worst facility in the list, Quemetco Inc., has a Cancer Risk of 22.00 Consolidated Film Industries in Hollywood, number 2 in the list, has a Cancer Risk of 21.00.

35/ Alamitos (963 MW) is number 218, with a Cancer Risk of 0.63; Redondo Beach (967 MW) is number 232, with a Cancer Risk of 0.40; Haynes (1768 MW) is number 245, with a Cancer Risk of 0.17; Valley (563 MW) is number 248, with a Cancer Risk of 0.15; Scattergood (975 MW) is number 266, with a Cancer Risk of 0.03.

IX. THE USE OF ENVIRONMENTALLY SOUND AND VERIFIABLE OFFSETS WILL BE NECESSARY TO MEET AB 32's TARGETS IN A COST-EFFECTIVE MANNER.

As PG&E believes that the cap-and-trade mechanism will play more of a critical role in reducing GHG emissions than is currently suggested in the plan, we strongly support the use of offsets as an indispensable tool in abating greenhouse gases in a cost-effective fashion. PG&E believes that there should be no geographic or quantitative limits on the use of offsets for compliance purposes, as long as the offsets meet rigorous standards. Offset protocols should be thorough, and qualifying projects which meet the protocol standards should not be subject to further case-by-case review or discounting.

For these reasons, we do not support the Draft Plan's 10% individual entity limitation on the use of offsets (Draft Plan, p. 19). The Draft Plan justifies such a limit to address ". . . the risk that unconstrained offsets could weaken the stringency of the overall cap-and-trade program" (Id.). If the need for "stringency" reflects concern that offsets may not provide real reductions in GHG emissions, the solution is strict requirements for offset quality – which PG&E supports – not arbitrary limits on offset quantity. Likewise, because climate change is a global challenge, we do not support geographic limitations on offsets, provided those offsets meet strict requirements for quality.

X. PG&E SUPPORTS THE DRAFT PLAN'S ENDORSEMENT OF CAP-AND-TRADE MARKET MECHANISMS TO ACHIEVE VERIFIABLE, TIMELY, AND COST-EFFECTIVE GHG REDUCTIONS.

PG&E supports the ARB's and the Draft Plan's conclusion that a properly designed, multi-sector cap-and-trade program - ideally linked to the WCI - can achieve, real, quantifiable, timely, and cost-effective GHG reductions (Draft Plan, p. 15). We believe market based mechanisms with clear and consistent rules and strong oversight – coupled with our current leading CEE, renewables and demand-side management programs – will reduce emissions, diversify our energy supply mix and help to minimize customer costs. Market mechanisms will drive the development of the next generation of clean, highly-efficient technologies and practices. Integration with WCI will also begin to provide the necessary harmonization of California's market - including full recognition and fungibility of allowances, offsets and other program design elements - with emerging regional, national and, ultimately, international programs. For these reasons, although the AB 32 statute provides that a cap-and-trade program must be "necessary" or "desirable," we believe it is both. (HSC § 38561(b)). A well-designed market is necessary for leveraging lower cost reductions and desirable for spurring innovation that may not come from traditional regulatory programs. We believe cap and trade program elements should include:

- **Standardized emissions' reporting** is an essential first step and must form the basis of AB 32's implementation. We believe the ARB's recent greenhouse gas reporting regulations as modified consistent with PG&E's comments will provide a sound basis for AB 32 implementation.

- **Equitable apportionment** of reduction obligations to ensure that all sectors pay their fair share. State-wide reduction obligations should be apportioned under ARB's Draft Plan and AB 32 regulations to ensure that no single sector, nor its customers, assumes a disproportionate cost burden.

- **Early actions should be recognized and credited** under specific ARB-adopted protocols and regulation, not penalized. ARB should implement expedited "early action" rules under AB 32 to recognize "early actors" that have already made investments resulting in significant greenhouse gas reductions. Ignoring prior efforts sends a signal that stepping up, taking risks and taking responsibility is not something valued by policymakers. Those that have pursued a significant amount of energy efficiency and renewables resources have already achieved the lowest cost emission reductions, while those that have not taken action have significant low cost reduction options still available to them. For example, incremental investment opportunities to avoid purchasing high emitting power are fewer and more expensive for low carbon utilities than those available to high carbon utilities that have more low-hanging fruit available, such as energy efficiency. Put more simply, customers of lower emitting utilities should pay less than customers of higher emitting utilities to achieve the goals of AB 32.

- **A clear glide path of emissions "caps" and limits** must be established over the 2012-2020 period that takes a gradual but sustained approach to meeting reductions to help create a smooth transition to a low-carbon economy.

- **A broad and liquid emissions trading market** should be created. Climate change is unlike any other air quality challenge, as it is truly a global issue. A robust market can be assured by including a broad spectrum of industry sectors and participants, ensuring that program design elements are scalable and consistent with other regions, and creating linkages to other existing and emerging regional programs such as the Western Climate Initiative and, ultimately, a federal or international program.

- **Compliance flexibility** should be provided to meet AB 32's targets in a cost effective manner. These can include banking of emissions allowances, the use of environmentally sound and verifiable carbon offsets and multi-year compliance periods. This last element is critically important to the power sector, where rain and snow-fall variability have a significant effect on year-to-year emissions.

- **Cost containment mechanisms** such as an allowance "price collar" imposing a price floor and ceiling. In the context of managing the overall GHG emission budget, a "price collar" approach can help manage volatility and macro-economic costs of a cap-and-trade program, especially during its early years, and at the same time to provide a clear and sustained CO2 price for technology investors and emissions sources that is recognized in all sectors of the economy. The price collar could function using a pre-specified ceiling price, at which any entity could purchase allowances from a reserve, for use within the current compliance period. This ceiling price should be consistent with expectations regarding technology availability and should be set to avoid massive re-dispatch of existing gas-fired plants in place of existing coal-fired plants. The reserve would contain allowances from future years under an overall GHG emission "budget." Allowances purchased from the reserve would be useable in the current year, or bankable, like other allowances. However, purchases from the reserve would mean fewer allowances distributed in future years, thereby maintaining the overall long-term GHG emission budget. The price collar would also include a minimum acceptable bid for allowances in centralized auctions, to establish a price floor. This minimum price should be sufficient to encourage adequate investment in low- and zero-carbon generation and end-use efficiency technologies. Current-year allowances that are not purchased at auctions would be transferred to future years, so that more allowances would be distributed in future years. Both the ceiling and floor price would increase annually by at lest the inflation rate.

- **A "point of regulation" should be selected under AB 32 that will promote real emissions reductions and serve as a model for emerging regional, national and international programs.** The point of regulation for AB 32 should be simple to administer, provide for the most accurate accounting of GHG emissions, and minimize leakage of GHG emissions. For these reasons, we are encouraged that the CPUC and CEC have recommended that ARB adopt a "First Deliverer" point of regulation for the electric sector. This would place the point of regulation on electric generators within California and on those that first import power generated outside of the state for delivery and consumption within California. Taking this approach will: (1) ensure environmental integrity through real and more verifiable greenhouse gas emissions reductions and by allowing for more accurate accounting and attribution of emissions and minimizing "leakage" of GHG emissions; (2) more directly impact generation investment decisions; (3) internalize GHG compliance costs in electric dispatch; and (4) because it focuses on actual emissions sources, it will enhance California's leadership position on climate change by serving as a model for emerging regional and national programs.

- **Emission allowances should be allocated and distributed in a manner that most directly mitigates costs to customers**, rewards – rather than punishes – early action; promotes early investment in clean technologies; advances energy efficiency; avoids windfalls; and positions California as a model for federal, regional and international programs. These allocation principles can be implemented by:

    - Recognizing that the customer at the end of the energy supply chain – like the households and businesses that we serve – will ultimately bear a substantial share of the costs associated with the regulation of greenhouse gas emissions. The allocation of allowances under a cap-and-trade system should be used to help mitigate these costs.

    - Avoiding creating unintended economic benefits for companies by granting free allowances to generators who would not be required to pass on this value to utility customers.

    - Avoiding penalizing early actors and their customers for investments made prior to AB 32 that has resulted in significant greenhouse gas benefits to date.

    - Ensuring that customers of lower emitting utilities pay less than higher emitting utilities to achieve the ultimate goals of AB 32.

    - Quickly transitioning AB 32's overall emissions limits to a system that requires all emitting resources to take full responsibility for their climate related costs.

    - Accelerating the development and deployment of new technologies, including renewable generating technologies, end-use energy efficiency technologies, and carbon capture and storage technologies.

    - Successfully positioning California as an overall low-emitting state in the emerging federal debate on greenhouse gas allowance allocation among higher- and lower-emitting states.

Decisions made regarding the point of regulation and to whom emissions allowances are allocated are separate and distinct public policy issues with significant economic and environmental implications, and should be addressed as such. California has an opportunity to develop an allowance allocation methodology that can both achieve the public policy objectives listed above and also serve as a model for regional, federal and international policymakers.

In the utility sector, customers will bear the lion's share of greenhouse gas reduction costs regardless of where the point of regulation is placed. For this reason, the National Commission on Energy Policy, the California Market Advisory Committee, and the Natural Resources Defense Council in separate reports have each outlined an allowance allocation methodology that we find compelling and believe can avoid the inequities and the inefficiencies that stem from an Acid Rain-style generator based allocation approach, while benefiting electricity consumers. Rather than allocating free allowances to power plants, PG&E recommends that allowances be allocated to utilities on behalf of their customers. Utilities would in turn be required to sell allocated allowances to sources regulated by the program through independently administered auctions, returning the proceeds to their customers through rebates, credits or other programs that help to mitigate costs or reduce demand. In this way, the value of the allowances flows directly to energy consumers, who ultimately bear the costs of the program. Of course, the management and sale of allowances should be subject to oversight by the state and by local boards of customer-owned utilities, and allowances should be sold to utility-owned and merchant generation on a non-discriminatory basis.

In addition to achieving the goal of mitigating consumer and business costs, the allocation of allowances among different sources of emissions can help achieve the other public policy objectives listed above. For example, by allocating allowances based on a metric that rewards efficiency, as suggested in the California Market Advisory Committee Report, as opposed to an historical emissions based approach that continues to support the use of higher-emitting, less-efficient resources, the allocation approach can send appropriate investment signals and simultaneously encourage early action. Therefore, allowances should be allocated based on an updating output metric such as retail sales, adjusted for verified energy efficiency savings. Allocation of allowances for the benefit of consumers also must take into account any disproportionate impacts on low income communities, as required by AB 32.

We are encouraged that many of the above-listed design features -- including the need for a broad market, accurate reporting, point of regulation, compliance flexibility, and clear compliance glide path -- were endorsed in the WCI's July 23, 2008 Draft Design of the Regional Cap-And-Trade Program. In this regard, we encourage ARB and the State of California to work further with the WCI Partners to address the apportionment of compliance responsibility across the WCI. It is important for California to resolve how it intends to apportion compliance responsibility among all the states in a regional cap and trade program, particularly for GHG emissions sources located outside California, such as coal- and gas-fired power plants outside California who export their power to California, but whose emissions would be regulated directly by the states in which they are located.

XI. USE OF AUCTION REVENUE

For the electric sector, PG&E supports the distribution of allowance value for the benefit of electricity consumers, while promoting investment in new low-carbon technologies or programs that also benefit customers and the communities we serve. This is because, regardless of the point of regulation, households and businesses at the end of the electricity supply chain will ultimately bear the costs - in the form of higher electricity prices - of a GHG cap-and-trade program. Moreover, AB 32 requires that good faith efforts be made to make available to disadvantaged communities in California opportunities to benefit from measures undertaken to reduce greenhouse gas emissions in the state. This is particularly important because low income earners are a large and growing segment of California's population. Therefore consumers should be entitled to the value inherent in the allowances in order to partially offset increased costs as well as provide capital to help these consumers transition to a low-carbon economy.

Auction revenues can be recycled to electric sector customers through a variety of methods. The CPUC/CEC's April 16, 2008 Ruling identified two methods for returning revenues from allowance auctions: (1) Using auction revenues to augment investments in energy efficiency and renewable energy, or (2) Using revenues to maintain affordable rates. PG&E supports the use of auction revenues for both these purposes, including use for CEE programs, direct bill reduction for all customers and targeted rate relief and CEE for low-income customers. Direct bill reductions can be designed in a way that is not tied to the volume of electricity used by the customer and thus preserve the carbon price signal benefits of a cap-and-trade program. Other funds could be dedicated to utility procurement and development of carbon-free technologies, if targeted toward applied technologies most likely to directly benefit California's electricity consumers.

Auction revenues used for energy efficiency and renewable energy investments should be allocated for this purpose based on objective and transparent emissions abatement cost-effectiveness criteria. Based on this assessment, there should be no more and no less funding than is necessary and effective, taking into account the experience of CPUC- and CEC-approved programs. Furthermore, the funding mechanism should be as streamlined and market responsive as possible, (e.g., tax credits, rebates or incentives directly to energy users or producers for demonstration of new technologies or applied research, instead of grants or pure research, in order to focus the development of new, commercially-available "green" technologies for the benefit of utility customers.) A worse outcome would be for auction revenues to be allocated for programs or projects which are less efficient and less cost effective than those that can be developed and implemented directly by consumers, businesses, and energy market participants, and which do not focus on benefits accruing to the customers of California utilities across all income groups.

In summary, we recommend that the value of the allowances be used to mitigate customer costs in a way that preserves a carbon-based price signal, assists all customers and businesses in transitioning to a low-carbon economy, advances energy efficiency, and pays particular attention to those customers who are disproportionately impacted by increases in electric rates.

XII. NATURAL GAS

Of the alternatives available to regulate and control greenhouse gas emissions, we support the use of a well-designed cap-and-trade market and generally favor bringing as many sectors as practicable into a cap-and-trade market. However, for natural gas, there is a natural division between large customers and small customers. We recommend bringing large customers into a regional cap-and-trade market but do not support bringing small natural gas customers (small commercial and residential customers) into that same cap-and-trade market at this time.

For small customers, the emissions reduction opportunities are limited almost exclusively to natural gas end-use efficiency improvements. Further, in contrast to the large industrial and transportation sectors, there are relatively fewer reduction opportunities in this sector. Most important, the bulk of these savings can best be achieved through a well-integrated set of programmatic measures directed at small customer natural gas consumption, which would include state appliance and building efficiency codes and standards, complementary utility or third-party customer energy-efficiency programs, and point-of-sale energy efficiency programs.

We support continued market assessment and modeling of emissions reductions opportunities in the small customer natural gas segment to reaffirm these observations that they should not be under a cap-and-trade regulatory regime. If it is confirmed that there will likely be little or no incremental benefit to including this segment of the natural gas sector, then it should continue to be excluded, as the cost of expanding the cap-and-trade may exceed the benefits.

Consumption of natural gas by small customers occurs literally at millions of different customer premises and end uses. Further, for some premises owners pay the bills but occupants control the usage. It is likely to be too costly and impractical for individual small customers in this segment to be directly regulated through a cap-and-trade system. Moving further upstream to the gas local distribution company would reduce, though not eliminate, the complexity and cost of moving this segment into a cap-and-trade program; however, it may have unintended consequences due to some of these unique market characteristics of the natural gas sector.

Finally, a structural and programmatic approach will not result in stranded costs or de-position California in any transition to a federal program. The reduction in GHG emissions from pursuing efficiency measures will benefit end-use consumers of natural gas throughout California under any future federal program.

While PG&E supports continued market assessment, given the small number of emission reductions available in the natural gas small commercial and residential sector, the challenge with regulating the large number of sources in this sector and the availability of effective alternative measures to reduce emissions in this sector, we recommend that the ARB not include this segment of the natural gas sector within a cap-and-trade program at this time. Instead, we recommend that GHG reductions from the residential natural gas sector be pursued through an integrated set of programmatic measures, including state appliance and building efficiency codes and standards, complementary utility, or third-party customer energy efficiency programs, and point-of-sale energy efficiency programs.

XIII. CONCLUSION

PG&E commends the ARB for its comprehensive, multi-sector approach to implementing AB 32. We are especially encouraged by the Draft Plan's embrace of market-based measures and a trading program, but recommend and hope that ARB continues to move toward an even broader and scalable market that will link with regional, national, and international efforts. More reliance on market forces will lead to great, more innovative emissions reductions sooner, and at a lower overall cost, to California and Californians. We look forward to continuing to work with the ARB to fulfill AB 32's promise.

DATED: August 5, 2008

Submitted by:

PACIFIC GAS AND ELECTRIC COMPANY

By: ____________________/S/________________

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies.	Rulemaking 06-04-009 (April 13, 2006)

REPLY COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON PROPOSED DECISION ON GREENHOUSE GAS REGULATORY STRATEGIES

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Dated: October 7, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies.	Rulemaking 06-04-009 (file April 13, 2006)

REPLY COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON PROPOSED DECISION ON GREENHOUSE GAS REGULATORY STRATEGIES

Pacific Gas and Electric Company (PG&E) provides its reply comments on the Proposed Decision (PD) on greenhouse gas (GHG) regulatory strategies under AB 32.

I. "BACKSTOP" CONSUMER PROTECTIONS SUCH AS PRICE COLLAR

The majority of parties addressing the issue of "backstop" consumer protections, including the CPUC's own Division of Ratepayer Advocates (DRA), support including a "price collar" or something similar in the design of a cap and trade program, in order to protect consumers from the risk of sustained high prices for GHG allowances in the event of market failure or market manipulation.[1]

In contrast to the support for these consumer protections, some parties[2] argue that the discretion of the Governor of California to suspend AB 32's overall deadlines under extraordinary circumstances is adequate cost containment protection and therefore a "price collar" or similar protection is unneeded.[3] PG&E and others vigorously disagree. The Governor's future discretion is not a practical or timely substitute for an effectively designed cap and trade program that includes "self-correcting" cost containment provisions. California recently experienced the consequences of relying on prospective political discretion to remedy a market failure – the result was that millions of California consumers and businesses experienced billions of dollars of higher electricity costs during the 2000- 2001 California energy crisis.

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[1] DRA, Opening Comments, pp. 6- 8; SCE, Opening Comments, pp. 17- 18; SDG&E/SoCal Gas, Opening Comments, pp. 8- 9; SCPPA, Opening Comments, pp. 21- 24.

[2] NRDC-UCS, Opening Comments, June 2, 2008, p. 21.

[3] *Ibid.,* citing Health and Safety Code section 38599.

Some parties also argue that a "price trigger" or "safety valve" would allow the overall carbon cap to be "broken," thus undermining the fundamental environmental integrity of the program.[4] However, in subsequent comments, two of the parties opposing "safety valves" and "price triggers" generally, NRDC-UCS, have distinguished PG&E's and DRA's similar "price collar" approaches—in which allowances would be made available at a pre-determined price from an "allowance reserve" from future years without changing the overall multi-year "carbon budget"—and concluded that such approaches would be "slightly better because it better maintains environmental integrity." Nonetheless, NRDC-UCS continue to oppose even this approach because in their view it creates "uncertainty in the market."[5]

Potential "market uncertainty" is not a compelling reason for denying California consumers and businesses with adequate and essential protections against a price "blow-out" or other system-wide failure in a cap and trade market. As DRA points out in their opening comments:

> "[T]he PD's recommendation against including a safety valve or price cap in a cap-and-trade system does nothing to remove or even limit uncertainty from the impact of unforeseen, extremely high allowance prices. Absent a price cap or safety valve, entities faced with skyrocketing allowance prices would have limited options: hope that the Governor intervenes to adjust compliance obligations12 and/or pay the as-yet undetermined penalty for failure to comply with the allowance requirements established by CARB.13 It is important to note that any cap-and-trade system that contains a penalty for noncompliance has an implicit price cap in place. That is, as reductions become more and more expensive, covered entities could choose to pay the noncompliance penalty in lieu of making additional reductions. Thus, instead of debating whether there should be a safety valve, California should instead consider at what price reductions are too costly."[6]

Thus, the PD should heed the recommendations of most parties as well as on-going discussion at the national level,[7] and be revised to recommend a "price collar" or a

[4] NRDC-UCS, Opening Comments, June 2, 2008, p. 21. CEERT opposes "borrowing" of allowances from future periods rather than "price triggers" or "safety valves" *per se,* but CEERT provides no explanation for its opposition. (CEERT Opening Comments, p. 11.)

[5] NRDC-UCS Reply Comments, June 16, 2008, pp. 19- 20.

[6] DRA Opening Comments, October 2, 2008, p. 7.

[7] See "Cost Containment Discussion Paper," U.S. Climate Action Partnership, pp. 4- 5, March 20, 2008, http://www.us-cap.org/; S.2191, Lieberman-Warner Climate Security Act of 2008, Managers

similar consumer protection as an essential element in a cap and trade program. We urge the CPUC and Energy Commission to recommend to ARB that it continue to explore all tools, including a price collar, that can satisfy the dual objectives of protecting consumers against excessive price impacts while also maintaining the environmental integrity of a cap and trade program.

II. TRAJECTORY OF 2012- 2020 EMISSIONS CAPS

Numerous parties agreed with PG&E that the PD's "straight-line" trajectory for 2012- 2020 emissions caps should not be adopted, but instead a more gradual trajectory should be adopted that takes into account incentives for long term investment in new emissions reduction technologies and programs.[8] In particular, SMUD pointed out that the history of California's Renewable Portfolio Standard program should serve as a cautionary note in setting "straight line" deadlines for emissions reductions under AB 32: "[S]imply mandating a straight-line increase in procurement of renewable energy has not been successful."[9]

PG&E agrees with SMUD and other parties that the PD should carefully consider the impacts on investment, technology development and sustained emissions reductions before adopting a particular trajectory for the 2012- 2020 interim emissions caps.

III. ALLOWANCE ALLOCATION

Many parties addressed the cost and rate impacts of the PD's allowance allocation recommendations.[10] In particular, LADWP submitted 22 pages of new modeling results, including a 10-page spreadsheet appendix, that it argues support the

Substitute Amendment, Section 431, establishing "Carbon Market Efficiency Board" with authority to increase amount of allowances that covered facilities may borrow from the future or expand the period from which allowances may be borrowed; see also, Murray, Newell, Pizer, "Balancing Cost and Emissions Certainty: An Allowance Reserve for Cap-and-Trade," Nicholas Institute for Environmental Policy Solutions, Duke University, August, 2008, http://www.nicholas.duke.edu/institute/carboncosts/ discussing automatic access to a limited reserve of emissions allowances as part of cost-containment provisions in national greenhouse cap and trade legislation.

[8] SCE Opening Comments, p. 16; Pacificorp Opening Comments, p. 7; SMUD Opening Comments, p. 4.

[9] SMUD Opening Comments, p. 13.

[10] E.g., NRDC-UCS Opening Comments, pp. 4- 13; LADWP Opening Comments, pp. 5- 14, Attachment 1; SCPPA Opening Comments, pp. 4- 20; SDG&E/SoCalGas Opening Comments, pp. 3- 5; SCE Opening Comments, pp. 14- 15; SMUD, pp. 5- 11; Independent Energy Producers Opening Comments, pp. 6- 10;

conclusion that the PD's recommended allowance distribution formula would create an inappropriate "wealth transfer" between ratepayers of different retail providers.[11] Likewise, SCPPA submitted 21 pages of comments disputing the PD's analysis of various alternatives for allocating GHG allowances.[12]

PG&E disputes the allegations of LADWP and SCPPA on rate and cost impacts of the PD's allocation recommendations. In fact, as NRDC-UCS argue, the PD's allocation recommendations will have the opposite effect—the PD will significantly and unfairly punish the customers of low-emitting utilities like PG&E, and instead reward higher emitting utilities and generators in the early years of the program, effectively postponing the deadlines for those utilities to make needed investments to reduce their GHG emissions.[13]

However, the concerns raised by all the parties on the cost and rate impacts of the PD's allowance recommendations have a common point on which ***all*** parties agree: ***The PD's fuel-differentiated, output-based allowance allocation is NOT supported by direct analyses of the rate and cost impacts on the customers of different retail electricity providers.*** As PG&E pointed out, based on our analysis, the fuel-differentiated allocation method, coupled with its distribution of "free" allowances to independent generators, will have significant adverse impacts on PG&E's customers that the PD has neither anticipated nor analyzed.[14] Parties also echo PG&E's concern that the untested allocation method proposed by the PD could result in windfall profits to independent generators even though there are other possible allocation methods that could prevent this outcome.[15]

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[11] LADWP Opening Comments, pp. 5- 14, Attachment 1.

[12] SCPPA Opening Comments, pp. 1- 21.

[13] NRDC-UCS Opening Comments, pp. 9- 13, including pointing out at p.12, fn.20, that LADWP has been on notice since at least 1990 of the need for emissions reductions and made a voluntary pledge in 1990 to do so. PG&E also notes that LADWP forecasts that it will only reduce its carbon intensity to 961 lbs/MWh by 2020, more than double PG&E's 2020 carbon intensity, and more than 50% higher than PG&E's carbon intensity *in 2008*. (LADWP Opening Comments, p. 6, Table 2.)

[14] PG&E Opening Comments, pp. 11- 14. Additionally, PG&E agrees with the points raised by Morgan Stanley on the need to consider treating out-of-state deliverers on a non-discriminatory basis similar to in-state emitting deliverers.

[15] NRDC Opening Comments, pp. 7- 9.

For this reason alone, the PD should be revised to require more thorough and specific analyses of the rate and cost impacts of the "fuel-differentiated, output-based" allocation proposal, along with full opportunity for all parties to comment on the analyses, ***before*** any allocation proposal is recommended to the ARB.

IV. 33% RENEWABLES EMISSION REDUCTION MEASURE

Several of the parties commenting on the PD's 33% renewable measure supported PG&E's request that additional cost-effectiveness and feasibility analysis be performed before reliance on the 33% goal as an AB 32 emissions reduction measure.[16] PG&E supports these comments.

EPUC/CAC's comments on Combined Heat and Power (CHP) highlight the complexity of dividing CHP operations into different streams.[17] PG&E agrees with EPUC/CAC that all on-site CHP should be treated similarly, but the better, more simple solution is to address delivered kWh in the electric sector and all other CHP output—both on-site thermal and on-site electric, in the industrial/commercial sector.

V. OFFSETS

Some parties recommend that the PD be revised to recommend that the ARB limit offsets to 10% of the cap as proposed in the ARB Draft Scoping Plan.[18] PG&E disagrees; artificial quantitative limits on offsets that are otherwise permanent, additional and verifiable may substantially increase costs to California consumers and businesses and preclude investments and development of environmentally sound emissions reduction projects. This proposed limitation should be rejected.

VI. CONCLUSION

PG&E recommends that the PD be revised consistent with its opening and reply comments.

Respectfully Submitted,

/s/

Dated: October 7, 2008 CHRISTOPHER J. WARNER for Pacific Gas and Electric Co.

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[16] SCE, pp. 5- 7; SDG&E/SoCal Gas, pp. 5- 6; EPUC/CAC, pp. 21-22; Modesto ID, pp. 4, 8-9.

[17] EPUC/CAC Opening Comments at pp. 12- 13.

[18] NRDC-UCS Opening Comments, p. 16. NRDC-UCS incorrectly interpret the ARB proposal as being 10% of the emission reductions in the cap and trade program. Rather, the ARB Draft Scoping Plan proposes to limit offsets to "10% percent of the compliance obligation for an individual firm," which equates to 10% of the entire cap in the market. (ARB Draft Scoping Plan, p. 19.)

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of **REPLY COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U39 E) ON PROPOSED DECISION ON GREENHOUSE GAS REGULATORY STRATEGIES** on all known parties to R. 06-04-009 by

- transmitting an e-mail message with the document attached to each party on the official service list providing an email address; or
- by first-class mail, postage prepaid, to each party on the official service list not providing an email address.

Executed on October 7, 2008, at San Francisco, California.

/s/
Martie Way

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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OPENING COMMENTS OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON
PROPOSED DECISION ON GREENHOUSE GAS
REGULATORY STRATEGIES

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

Order Instituting Rulemaking to Implement the Commission‘s Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies.	Rulemaking 06-04-009

**OPENING COMMENTS OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON
PROPOSED DECISION ON GREENHOUSE GAS
REGULATORY STRATEGIES**

I. INTRODUCTION

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E) provides its opening comments on the Proposed Decision (PD) on greenhouse gas (GHG) regulatory strategies under AB 32.

II. EXECUTIVE SUMMARY

PG&E approaches AB 32 guided by three key objectives:

1. Ensure environmental integrity through mandatory, real and verifiable reductions;

2. Manage costs to California consumers and businesses by pursuing cost-effective reduction strategies and a consumer-oriented allowance allocation approach; and

3. Solidify California's national leadership role on climate change by creating a model program that can be integrated effectively with future regional, national and international programs.

We believe that the California Legislature had these same objectives in mind when it enacted AB 32, especially regarding how California's electricity and energy systems were to be restructured to address global climate change and make a rapid -- but smooth and balanced -- transition to a low carbon California economy. Among other things, AB 32 requires that California's greenhouse gas emissions and reductions be "rigorously" accounted for, that emissions reduction strategies and measures be "cost effective" and "technologically feasible,"[1] and that the cost effectiveness of each individual measure be compared and selected based on its relative "cost per unit" of carbon reduced.[2] Just as importantly, the Legislature entrusted the California Public Utilities Commission (CPUC) and Energy Commission (CEC) with a special role in ensuring that AB 32 is designed and implemented in a manner that preserves the affordability and reliability of California's electricity system and avoids multiple, duplicative or inconsistent programs and measures.[3] Finally, the Legislature recognized that in implementing AB 32, California would be "exercising a global leadership role" and therefore should consult with other states, the federal government and other nations to facilitate the development of "integrated and cost-effective regional, national and international greenhouse gas reduction programs."[4]

PG&E is one of the earliest and most vigorous supporters of AB 32 and similar national and international initiatives to address global climate change. Moreover, PG&E's greenhouse gas emissions are among the lowest of all California electric utilities,[5] in no small part because our customers took "early action" over the last three decades to invest billions of dollars in energy efficiency and clean energy resources.

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[1] Health and Safety Code sections 38530(b)(4), 38560, 38561(a), (b), (d), (h); 38562(a),(b)(1), (b)(5), (c).

[2] Health and Safety Code section 38505(d).

[3] Health and Safety Code sections 38501(g), 38561(a), 38562(f), 38593(a).

[4] Health and Safety Code section 38564.

[5] PD, Table 5-1, p. 134.

With this history and this framework in mind, PG&E has reviewed the PD, and has concluded that it is well-intentioned but falls short in certain key respects in fulfilling the objectives identified above and required by the Legislature in AB 32. PG&E's recommended changes to the PD are summarized and discussed below:[6]

CAP AND TRADE MARKET DESIGN

1. ***A "price collar" to protect customers against a cap and trade market failure is essential.*** The PD's summary rejection of "backstop" cost containment mechanisms such as PG&E's proposed "price collar" sets a difficult precedent and would reverse the CPUC's post-energy crisis endorsement of "backstop" regulation in electricity markets. The PD should be revised to ensure that automatic "backstop" regulatory mechanisms, such as a price collar based on a multi-year "carbon budget" as proposed by PG&E and others at the national level, are included as key feature which provides essential consumer protection measure while at the same time ensuring that the state remains on the required long-term emissions reduction path.

2. ***Free allowances to independent generators should be eliminated.*** The PD's proposed grant of over $3 billion in "free" emissions allowances to fossil-fired independent power generators is counter to the lessons learned in other GHG cap and trade programs such as the European Union and RGGI and to what many policymakers and stakeholders are discussing at the federal level. It also sets a bad precedent for similar "free" allowances to states and regions with higher emissions than California, and should be rejected as we move forward to integrate with other regional and national

[6] PG&E supports the PD's recommendations on the availability of permanent and verifiable offsets, regional cap and trade markets, a multi-year compliance period, and the need for more investigation of CHP policies before new CHP programs or subsidies are considered. However, the PD errs in assigning emissions from on-site CHP electricity to the electricity sector, not the industrial sector, and then allocating allowances for such emissions. Such emissions are related to industrial uses, not electricity service, and should be treated as such.

cap and trade programs. To ensure environmental integrity, reduce compliance costs to consumers, and effectively position California for regional and federal cap and trade programs, the PD should be revised to provide for 100 percent auctioning of emissions allowances under a cap-and-trade program from the very beginning of the program, with the value of those allowances provided primarily to the electric utility ratepayers who will be paying the compliance costs for AB 32 in the costs of power passed through to them by their power suppliers.

3. ***Emissions allowance allocation principles should ensure that early actions by low-emitting entities and their customers are taken into account and not penalized.*** The PD recommends a "fuel-differentiated, output-based" method for allocating emissions allowances to generators, and a method based on LSE historical emissions profiles among different utilities, transitioning to a "sales-based" method by 2020. The intent of this provision is to mitigate the initial economic burden on high-emitting entities and utilities. Unfortunately, this method would directly penalize lower-emitting utilities and their customers for the investments they have made in low-emitting energy resources and customer energy efficiency. This fundamental unfairness should be redressed, either through more detailed analysis of the customer-specific and utility-specific rate impacts of the methodology, or through substantially reducing the initial allocation of allowances to generators and shortening the transition period to a pure sales-based allocation methodology that rewards all utilities and customers equally for their emissions reduction investments going forward.

4. ***The PD's 2020 emissions target and 2012- 2020 emissions reduction trajectory is not based on sufficient analysis to ensure that the AB 32 emissions reduction burden on electricity customers is cost-effective and feasible relative to emissions reductions in all sectors and for all identified measures.*** The PD's endorsement of a straight-line trajectory for electric sector emissions reductions and caps between 2012 and 2020 is premature until the multi-sector analysis on the timing of feasible reductions is completed. This analysis is essential to determine how quickly cost-effective and feasible emissions reductions are likely to occur. The PD should be revised to recommend that this analysis be completed prior to the final determination of emissions reduction goals and measures in the electricity sector and the emissions cap trajectory in the cap and trade market.

PROGRAMMATIC MEASURES

The PD should be revised to clarify that barriers to increased renewables must be removed and cost-effectiveness fully analyzed compared to other alternatives if a 33 percent renewables mandate is to be adopted under AB 32. The PD appears to recognize that a 33 percent renewable energy procurement mandate is dependent on further cost analysis and removal of significant barriers to renewables development. The PD should be revised to confirm and clarify this key point, i.e. that a 33 percent renewables mandate should be included as an AB 32 emissions reduction measure provided that the barriers to increased renewables development have been removed and provided that further analysis has been performed evaluating the cost-effectiveness and feasibility of the mandate relative to other alternative emissions reduction measures across all sectors.

III. DETAILED COMMENTS AND RECOMMENDED CHANGES TO PD

PG&E's detailed comments on the PD are organized under the two major issue topics in the PD: (1) The design and evaluation of a greenhouse gas emissions cap and trade market; and (2) The design and evaluation of programmatic emissions reduction measures, such as recommendations for increased renewables, customer energy efficiency, and combined heat and power.

A. Cap and Trade Market Design

1. The PD's Summary Rejection of "Backstop" Cost Containment Mechanisms Such as a "Price Collar" is Premature and Would Reverse the CPUC's Post-Energy Crisis Endorsement of "Backstop" Regulation in Electricity Markets

One of the most important lessons California learned from the 2000- 2001 energy crisis is that "backstop" regulatory mechanisms are essential to protect electricity customers in the event that unregulated or partially regulated electricity markets experience a catastrophic failure. The need for quick or automatic "backstop" regulatory mechanisms applies to other markets as well, including a "cap and trade" greenhouse gas emissions market.[7] A greenhouse gas emissions trading market, if well designed, can attract investment in new GHG reducing technologies and enable markets to determine the most economic and cost-effective means of reducing GHGs across multiple sectors of the economy. However, like any market, and especially commodities and futures markets, even the best designed greenhouse gas emissions trading market can experience failure or significant disruption through hoarding, manipulation, severe weather or other unforeseen circumstances, particularly during its start-up or transitional stages.

Thus, PG&E was surprised that the PD summarily rejects the contingent use of "backstop" regulatory mechanisms such as "price triggers" or "price collars" as part of the design of a cap and trade market under AB 32. (PD, p. 262.) The PD argues that a "price trigger" or "price collar" would distort or defeat the market certainty required to incent long-term GHG reducing investments in a cap and trade market. (PD, p. 262.) However, the PD misses the basic point of "backstop" regulation in markets – the "backstop" is intended to *save* the market from a catastrophic failure, not to *defeat* it.

The issue is not whether a price trigger or price collar "distorts" the market, the issue is at what price and over what time period does a market failure rise to a level requiring regulatory intervention to protect consumers.

PG&E agrees that *how* a price trigger or price collar is designed and implemented is a very important matter. We recognize that some policymakers and other stakeholders are concerned that a simple safety valve may both impede investment in low- and zero-carbon technologies and potentially thwart the ability to achieve legislated emission reduction goals. On the other hand, PG&E believes that a well designed price-collar mechanism, operating within an overall "carbon budget," can provide an effective means to help manage overall volatility and unexpected economic costs, and at the same time provide a clear path for technology investment and ensure that there is a "price for carbon" that is recognized within California's electricity sector and in the economy as a whole.

The elements of a "price collar" would include market intervention to make additional GHG emission allowances available to the broad, multi-sector, multi-jurisdictional market. This would restrain upward movement of allowance prices while maintaining a multi-year carbon budget. A lower bound on allowance prices could also be accomplished by specifying minimum acceptable bids in allowance auctions or by other means.[8]

However, there should be no issue as to *whether* a price trigger or price collar is needed, especially one that is designed to maintain the overall multi-year "carbon budget" over time – "backstop" regulation should always be available to protect

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[7] Events in global financial markets have underscored this point in recent weeks.

[8] The consideration of a price "floor" could include allowances that are removed from the market, to be reintroduced at a later period. This would support the economics of long-term investments in emissions reducing technologies.

consumers in the event of a market failure. In fact, as proposed for discussion and consideration by a leading group of businesses and environmental organizations and included in discussions on the national Lieberman-Warner cap and trade legislation, a "price collar" which provides for "borrowing" of allowances from future periods can provide effective back-stop protection to consumers against excessively high allowance prices, while also assuring that the overall carbon "budget cap" is still met.[9]

For these reasons, PG&E recommends that the PD be revised to ensure that an automatic "backstop" regulatory mechanism, in the form of a price collar using an overall "carbon budget," is included as an essential consumer protection measure in the design and initial implementation of a GHG cap and trade market under AB 32.

2. The PD's Proposed Grant of Over $3 Billion in "Free" Emissions Allowances to Independent Power Generators is Unnecessary, Unfair and Inconsistent with the Goals of AB 32

One of the most important issues in the design of a GHG "cap and trade" systems in the U.S., Europe and other regions is how to distribute emissions allowances in order to avoid "windfalls" or large redistributions of wealth between customers and energy producers. The PD discusses and ultimately endorses an auction of allowances as the method recommended by most policymakers for avoiding "windfalls" and uneconomic wealth transfers. (PD, p. 201.) However, contrary to the "lessons learned" in the European Union and RGGI, as well as discussions at the federal level, and for reasons that are qualitative and vague rather than based on factual evidence, the PD concludes

[9] See "Cost Containment Discussion Paper," U.S. Climate Action Partnership, pp. 4- 5, March 20, 2008, http://www.us-cap.org/; S.2191, Lieberman-Warner Climate Security Act of 2008, Managers Substitute Amendment, Section 431, establishing "Carbon Market Efficiency Board" with authority to increase amount of allowances that covered facilities may borrow from the future or expand the period from which allowances may be borrowed; see also, Murray, Newell, Pizer, "Balancing Cost and Emissions Certainty: An Allowance Reserve for Cap-and-Trade," Nicholas Institute for Environmental Policy Solutions, Duke University, August, 2008, http://www.nicholas.duke.edu/institute/carboncosts/ discussing automatic access to a limited reserve of emissions allowances as part of cost-containment provisions in national greenhouse cap and trade legislation.

that the auctioning of allowances should be "phased-in" over a four year period beginning in 2012, with 80 percent of allowances being given to power generators for free in the first year, and then declining to 20 percent in the fourth year and 100 percent auctioned thereafter. (PD, pp. 202- 204.)

PG&E has performed a simple calculation of what the free allocation of allowances to independent power generators could cost California electricity consumers, just based on a California-only cap and trade program. Assuming that 108.5[10] million metric tons of allowances were granted to the electric sector under AB 32 in 2012, then under the PD, 80 percent (or 87 million metric tons) are given out for free to first deliverers (generators) on a fuel-differentiated, output basis instead of auctioned. If the market price of an allowance is $30 per ton, and at least half[11] provided free to independent generators and the other half provided free to load serving entities such as investor-owned and publicly-owned utilities, then the potential "windfall profits" paid by consumers to those independent generators could be as much as ***$1.3 billion*** in just the first year of 2012, and ***$3.0 billion*** over four years.

The costs of these free allowances to the California economy and consumers could be even higher if free allocation is used throughout a Western cap and trade market, or on a national scale. If free allocation of allowances to generators were adopted under a nationwide GHG program in the same way proposed by the PD, the result would be that consumers and businesses in low-emitting states such as California would end up paying "windfall profits" to high-emitting states in the Midwest and South so that generators and utilities in those states could enjoy "free" emissions allowances

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[10] E3's greenhouse gas calculator uses 108 million metric tons of allowances as that available to the electric sector in 2012.

[11] E3's greenhouse gas calculator projects at least 64 MMT of 108 MMT (or 59%) in 2012 are from unspecified generation.

under the same reasoning proposed by the PD.[12]

Nor has there been any factual evidence, hearing record, or audit of the contracts or books of the independent power generators that would demonstrate or support the PD's conclusion that "free" allowances are necessary to "reduce short-term impacts on generating resources" or "to make necessary adjustments to their financial and investment plans to account for the impacts of GHG compliance obligations." (PD, p. 202.) To the contrary, generators and utilities have anticipated GHG emissions controls for nearly two decades now, and AB 32 will have been on the books for six years by the time California's first emissions reduction measures go into effect. In addition, AB 32's compliance obligations will coincide with the expiration and renegotiation of the great majority of power supply contracts entered into by independent generators and the California Department of Water Resources during the energy crisis.[13]

For these reasons, PG&E requests that the PD be revised to provide for auctioning of 100 percent of the emissions allowances granted to the electricity sector under a cap-and-trade program from the very beginning of the program, with the value of those allowances used for the benefit of the electric utility ratepayers who will be paying the compliance costs for AB 32 in the costs of power passed through to them by their power suppliers.

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[12] Most of the states in RGGI, the first US cap and trade program, provide for 100% auctioning of allowances.

[13] PG&E is also concerned about the impact of this proposal on other proceedings such as the Qualifying Facility Short-Run Avoided Cost (SRAC) proceeding. Since the SRAC is determined using some market based information, the allowance allocation proposal in the PD may lead to a potential windfall for QF's if the SRAC price reflects the carbon price but the QFs also receive allowances for free.

3. The PD's Recommendation of a "Fuel-Differentiated, Output-Based" Methodology Would Penalize Utility Customers For Earlier Investments in Renewable Energy and Energy Efficiency.

The PD's recommendation to allocate allowances using a fuel-differentiated output basis, which closely resembles an historical emissions based allocation to generators, combined with a similar allocation to retail providers based on historical emissions, rewards retail providers with a high concentration of fossil based owned generation, not once, but twice for the same high emitting facilities. Since the model provided by the CPUC's consultant E3 does not yet have the capability to model the PD's recommendation, the estimated rate impacts of this allocation proposal are not accurately addressed anywhere in the PD.

The PD's illustrative impacts rely heavily on two significant assumptions: 1) output to all fossil generation accurately models fuel differentiated output, and 2) the output method will result in only 50%[14] of the market clearing price effect. The first assumption causes the PD to underestimate the rate increase for low-emitting utilities and overestimate the rate increase for high-emitting utilities. The second assumption is, by the PD's own admission, a generalized assumption about the impact of an untested theory.[15] PG&E is concerned that the illustrative impacts in the PD summarized in Table 1 below are misleading and should not be relied upon to evaluate the rate impacts of the PD allowance allocation language. At a minimum, as described in Tables 2 and 3 below, the PD should be revised to consider two additional possible outcomes, instead of

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[14] E3 Model allows the user to select the percentage of the carbon price that will be included in electricity prices if the output method is selected. The PD suggests using 50% (PD, p. 211.)

[15] "It has been suggested that fuel-differentiated and other output-based allocation distributions to deliverers may limit the increase in wholesale electricity prices, because they would provide generators with an incentive to maintain or increase their output. We do not know the extent to which that may be the case, although the reasoning seems somewhat persuasive." (PD, p. 208.)

the outcome assumed in the PD.

Table 1 Illustrative Impacts using PD Assumptions in E3 Model:

Net Cost of CO2 (Purchases net of allowances plus MCP effect and return of CA Auction Revenue)								
$'s MM's	**PG&E**	**SCE**	**SDG&E**	**SMUD**	**LADWP**	**NoCal POUs**	**SoCal POUs**	**Water Agencies**
2012	$197	$267	$22	($5)	$132	$132	$156	$73
2016	$50	$147	$23	$6	$101	$73	$97	$18
2020	($18)	$161	$31	$1	$150	$122	$177	$52
Rate Increase (Compared to reference case)								
Cents/kwh	**PG&E**	**SCE**	**SDG&E**	**SMUD**	**LADWP**	**NoCal POUs**	**SoCal POUs**	**Water Agencies**
2012	0.23	0.30	0.12	-0.04	0.53	0.59	0.56	0.59
2016	0.06	0.16	0.11	0.04	0.40	0.32	0.34	0.15
2020	-0.02	0.16	0.15	0.00	0.57	0.51	0.60	0.42

PD Assumptions:

- CO2 price of $30/tonne
- Allocation to Generators (Output method to fossil generators only) 2012: 80%, 2016 and 2020: 0%
- Percent of CO2 cost reflected in MCP under output-based allocation: 50%
- Allocation to LSEs – 2012: 100% historical emissions based, 2016: 50% sales 50% historical emissions, 2020: 100% sales
- 100% of auction revenue returned to LSEs

Table 2 Illustrative Impacts using Historical Emissions Instead of Output to Fossil only to Model Fuel Specific Impacts in E3 Model:

Net Cost of CO2 (Purchases net of allowances plus MCP effect and return of CA Auction Revenue)								
$'s MM's	**PG&E**	**SCE**	**SDG&E**	**SMUD**	**LADWP**	**NoCal POUs**	**SoCal POUs**	**Water Agencies**
2012	$233	$256	$46	$22	$47	$120	$95	$63
2016	$38	$110	$17	$4	$76	$55	$73	$13
2020	($18)	$161	$31	$1	$150	$122	$177	$52
Rate Increase (Compared to reference case)								
Cents/kwh	**PG&E**	**SCE**	**SDG&E**	**SMUD**	**LADWP**	**NoCal POUs**	**SoCal POUs**	**Water Agencies**
2012	0.27	0.29	0.25	0.18	0.19	0.54	0.34	0.52
2016	0.04	0.12	0.09	0.03	0.30	0.24	0.25	0.11
2020	-0.02	0.16	0.15	0.00	0.57	0.51	0.60	0.42

Assumptions changed from PD assumptions:

- **CO2 price of 2012: $15/tonne and 2020: $30/tonne ($15/tonne is used instead of $30/tonne to replicate the impact of the market clearing price increase of only 50%)**
- Allocation to Generators (**Historical Emissions to generators**) 2012: 80%, 2016 and 2020: 0%

Table 3 Illustrative Impacts using Historical Emissions Instead of Output to Fossil only to Model Fuel Specific Impacts and Market Clearing Price that Reflects Full Value of the Allowances:

Net Cost of CO2 (Purchases net of allowances plus MCP effect and return of CA Auction Revenue)								
$'s MM's	**PG&E**	**SCE**	**SDG&E**	**SMUD**	**LADWP**	**NoCal POUs**	**SoCal POUs**	**Water Agencies**
2012	$467	$513	$92	$44	$93	$240	$190	$127
2016	$50	$147	$23	$6	$101	$73	$97	$18
2020	($18)	$161	$31	$1	$150	$122	$177	$52
Rate Increase (Compared to reference case)								
Cents/ kwh	**PG&E**	**SCE**	**SDG&E**	**SMUD**	**LADWP**	**NoCal POUs**	**SoCal POUs**	**Water Agencies**
2012	0.54	0.58	0.49	0.37	0.37	1.07	0.68	1.03
2016	0.06	0.16	0.11	0.04	0.40	0.32	0.34	0.15
2020	-0.02	0.16	0.15	0.00	0.57	0.51	0.60	0.42

Assumptions changed from PD assumptions:

- **CO2 price of $30/tonne**
- Allocation to Generators (**Historical Emissions to generators**) 2012: 80%, 2016 and 2020: 0%;
- Percent of CO2 cost reflected in MCP under output-based allocation**: 100%**

PG&E recognizes that rate impacts need to be reasonable for all LSEs' customers. PG&E, however, as a low emitting utility which has taken early action on behalf of its customers for many years, cannot support rate impacts to its customers that exceed those of high emitting utilities which have not taken such extensive early action. The PD proposes to 1) Provide allowances to deliverers which also receive allowances for the **same generation** as retail providers; 2) Provide allowances to all fossil based generators on a fuel-differentiated basis; and 3) Provide allowances to retail providers at the outset on a historical emissions basis. The combined effect of these proposals will raise rates for all electric consumers, and may especially harm the customers of low emitting utilities. These allocation features would also almost certainly negatively impact California in the debate over allocation of allowances in a national cap and trade program, further harming California businesses and consumers.

In addition to the great uncertainty around the ability of an output based allocation to prevent generators from passing through the value of the allowance in electricity prices, PG&E is concerned about potential distorting effects of the method on the market and on utilities and first deliverers. In any year that will be used to determine how many allowances each deliverer receives there will be incentives to generate a large amount of fossil-based generation as well as an incentives for utilities and marketers to sign up out-of-state fossil based resources, including coal. The potential impacts are increased emissions both inside and outside of California before and during the compliance period, and possibly an inefficient wholesale electric commodity clearing price.

For these reasons, the PD should reject a fuel-differentiated, output-based transitional allowance allocation method, at least until further utility-specific rate impacts and cost impacts are evaluated. This analysis should include potential negative impacts of such an allocation scheme on California's overall share of allowances in a regional or national cap and trade market, such as under the Western Climate Initiative or federal legislation.

4. The PD's Endorsement of a "Straight Line" Trajectory for Electric Sector Caps and Emissions Reductions is Premature Because an Assessment of Overall Cost Burdens, as well as Feasibility Across Sectors, Has Not Been Completed.

The PD correctly and succinctly notes that (1) ARB is required to but has not yet performed a sector-by-sector, bottoms-up analysis of the relative cost effectiveness and technological feasibility of different emissions reduction measures; and (2) There is substantial uncertainty associated with the costs and emissions reduction potential of the individual electricity sector measures. (PD, pp. 10, 65, 68, 90, 92, 94, 112, 116- 117, 123.) For renewables, in addition to the substantial uncertainty regarding transmission and integration costs, E3, the CPUC's consultant, did not assign costs of ramping, regulation, and backup dependable capacity to renewables.[16] The PD also acknowledges the uncertainty and lack of data on costs associated with achieving all economic potential of CEE. (PD, pp. 43, 73, 82).[17] Thus, the overall reduction goals and cost burdens imposed on the electricity sector, even after taking into account the PD's recommendation on allocation of emissions allowances, may still be significantly disproportionate.

PG&E believes that steady progress should take into account reductions from "Business as Usual" projections, and a "slow, stop, reduce" trajectory such as adopted by RGGI, rather than a strict straight-line trajectory, could certainly accomplish this. AB32 sets a 2020 goal for the state, but sets no target for any prior year. No modeling or analytical work has occurred to determine what the ideal trajectory should be; E3 evaluated only the year 2020. Further work on the trajectory is necessary to prevent consumer harm and unnecessary price spikes in the early years of the cap and trade program, especially as other price control mechanisms may be unavailable. Nor does the PD provide any evidence that equal annual reductions are needed to make progress toward the 2020 goal. PG&E expects that the lead times for electric sector projects

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[16] As indicated in the E3 whitepaper on firming costs (11/07), firming costs were used for ranking purposes only and not assigned to the costs of the resource. Therefore, costs of achieving 33% will be higher than assigned in the E3 model. This language should be corrected in the PD.

[17] As conveyed in an oral conversation, E3 based their energy efficiency costs on information received privately from Itron, supplemented with E3's professional expertise. According to 2008 Itron Report, the energy efficiency level associated with all economic potential remains a "theoretical benchmark." Itron adds "The program cost associated with economic potential could be very high. To attain all of the cost-effective potential, program interventions would likely have to reach each end user directly for each measure, incurring significant marketing and transaction costs. This method of promoting energy efficiency would incur a substantial labor cost and would likely require substantial increases in incentives like those associated with the full incentive case, if not higher in some cases, to overcome market barriers other than direct incremental costs. ….. It is not possible to determine the program costs that would be necessary to reach the economic potential." California Energy Efficiency Potential Study, Pg 1-3.

which reduce emissions on a sustained basis may be many years. This, by itself, raises concerns about the cost and feasibility of achieving reductions associated with a linear trajectory beginning in 2012. PG&E supports examination of the "slow, stop, reduce" approach as adopted by RGGI instead of the straight line trajectory recommended by the PD.[18] The trajectory should also be updated so that learning from the first phase of the market and overall AB 32 program can be incorporated.

Moreover, because a multi-sector cost effectiveness and feasibility analysis is otherwise required, it should be done before *any* overall electric sector emissions reductions are adopted for years prior to 2020. Likewise, the PD's endorsement of a straight-line trajectory for electric sector emissions reductions and caps between 2012 and 2020 is premature until the multi-sector analysis on the timing of possible reductions occurs.

For these reasons, PG&E recommends that the PD be revised to strongly recommend that the ARB apply the same multi-sector analysis and "proportionality of burdens" evaluation as E3 has conducted for the electric sector prior to setting reductions for all sectors. Prior to setting the trajectory of caps and reductions, analysis is essential to determine how quickly cost-effective and feasible emissions reductions can occur. The PD should be revised to require this analysis prior to the final determination of emissions reduction goals and measures in the electricity sector and the trajectory of caps in the cap and trade market.

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[18] RGGI has set a cap slightly above current emissions levels beginning in 2009. The cap level is constant from 2009 through 2014. Beginning in 2015, the cap will be reduced by 2.5% annually for an overall 10% reduction from roughly current levels by 2018.

B. Comments on Programmatic Measures

1. The PD Should be Revised to Clarify that Barriers to Increased Renewables Must be Removed and Cost-Effectiveness Fully Analyzed Compared to Other Alternatives if a 33 percent Renewables Mandate is to be Adopted Under AB 32.

PG&E strongly agrees with the PD that increased development and procurement of renewable energy and other low- or zero-emitting energy resources can play a significant role in meeting AB 32's GHG reduction goals as well as the State's longer-term 2050 goals. (PD, p.89.) We also strongly agree with the PD's conclusion that:

> "…[S]ignificant implementation barriers exist to the continued deployment of renewable energy in California. There are many sources of risk for project deployment, including uncertainties associated with the continuation of federal production/investment tax credits, availability of transmission, siting, and permitting issues. … '[M]eeting the 33% goal in 2020 is feasible, but only if the state commits to significant investments in transmission infrastructure and makes some key changes in policy.'"[19]

The CPUC's own preliminary analysis, performed by its consultant and referenced by the PD, concludes that a 33 percent renewables mandate would be one of the most costly measures to reduce greenhouse gas emissions, costing at least $133 per ton of carbon reduced.[20]

For these reasons, PG&E recommends that the PD be revised to clarify that a 33 percent renewable energy procurement mandate will require removal of significant barriers to renewables development, as well as a complete analysis of the cost-effectiveness and feasibility of the mandate compared to other alternative emissions reduction measures across all sectors. The PD should also point to the uncertainty of relying on emissions reductions from a 33 percent renewables mandate while those

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[19] PD, pp. 90- 91.

[20] PD, pp. 86, 92.

barriers and cost-effectiveness issues are still being addressed and evaluated.[21] In addition, as the AB 32 implementation process moves forward and if a 33 percent renewables mandate is included, it is essential that compliance off-ramps and flexibility be provided for issues such as transmission, system integration, siting and other permits, as well as availability of financing, all of which may be beyond the control of PG&E and other load-serving entities.

C. PG&E Supports the PD's Recommendations on Offsets, Regional Cap and Trade Markets, and the Need for More Investigation of CHP Policies

PG&E agrees with the PD's recommendations on the availability of permanent and verifiable offsets, regional cap and trade markets, multi-year compliance periods and evaluation of CHP potential. In particular, the PD recommends that offsets be available with no geographic restrictions. In addition, the PD recommends against a "California-only" cap and trade program, and instead recognizes that the full benefits of a cap and trade program can best be realized if the program is regional, national or international. Finally, the PD correctly notes the huge uncertainties regarding the potential contribution of new CHP facilities to GHG emissions reductions, and recommends further investigation in CPUC and CEC proceedings before specific programs, incentives or other CHP policies are pursued. However, the PD errs in not assigning regulation of emissions associated with on-site CHP generation to the industrial sector,

[21] The need for further cost-effectiveness and technological feasibility analysis applies to CEE and CHP as well. (PD, pp. 77- 85, 95- 102.) In particular, PG&E notes that the PD endorses the preliminary and provisional CEE goals for 2012- 2020 under AB 32 that the CPUC adopted in D.08-07-047. As noted in the PD (p.43), no data or analysis currently exists to estimate the costs of achieving energy efficiency goals up to 100% of economic potential. This analysis must be completed before adopting these CEE goals under AB 32. Additionally, the costs for achieving these CEE goals must include program implementation costs, which are not included in the Itron study relied upon by the PD. Likewise, the PD appears to support considering CHP as a possible emission reduction measure while at the same time conceding that there is no policy framework or current analysis to support the ARB's Draft Scoping Plan assumption of 4,000 MW of new CHP by 2020. (PD, pp. 101- 102.)

instead of the electricity sector.[22] CHP-generated electricity that is used on-site should be regulated as part of the industrial sector and should not receive allowances from the electricity sector, either as a first deliverer or as a retail provider. Like the thermal output of the CHP unit, such emissions are clearly related to the industrial processes used by the CHP entity, not to electricity service to retail customers. The PD also errs in apparently allocating allowances to on-site electricity twice, both to CHP owners as first deliverers and as retail providers. PG&E believes this may be an unintended error and that the PD does not intend to double allocate allowances to onsite CHP, which in any event should already benefit from competing in the cap and trade system. If the PD's reason for assigning the emissions to the electricity sector is so that the CHP entity can obtain additional emissions allowances or otherwise obtain additional financial incentives beyond those already available in a cap and trade market, that conclusion is premature until the further evaluation and analysis of CHP is completed as proposed by the PD.

IV. CONCLUSION

For the reasons stated above, PG&E commends the CPUC and CEC and their staffs for the massive and extensive findings and conclusions included in the PD. However, PG&E believes that the PD should be revised in the key areas discussed above, in order to provide sufficient assurance that rates and costs to electricity consumers will be manageable and reasonable, and that the ambitious greenhouse gas reduction goals set by the PD can actually be achieved. To this end, PG&E has attached recommended revisions to the PD's proposed findings of fact, conclusions of law and

[22] The PD's recommendation also treats similarly-situated market participants differently. Consider the example of two identical CHP facilities. If one facility exports just 1 kWh to the grid and the other none, the PD apparently would apportion all of the electricity output of the first facility to the electricity sector, despite it being virtually identical to the second facility.

ordering paragraphs, and recommends that the CPUC and Energy Commission not close this docket, but instead keep it open or renew it for further proceedings and recommendations in the next phase of AB 32 implementation.

Respectfully Submitted,

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Dated: October 2, 2008

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PG&E's RECOMMENDED CHANGES TO FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS IN PROPOSED DECISION ON GREEHNOUSE GAS REGULATORY STRATEGIES
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Findings of Fact

5. ***If implementation barriers to increased renewable development are removed, r***enewable mandates ***can*** play an important role in achieving aggressive renewable energy penetration, since they provide a long-term signal that can lead to market transformation of new renewable technologies and potential cost reductions.

11. ***If implementation barriers to increased renewables development are removed and if increased renewables are determined to be a cost-effective means of reducing GHGs compared to alternative measures, h***aving all retail providers deliver 33% renewable energy to their customers by 2020 would be an important first step in achieving this transformation.

12. ***If implementation barriers to increased renewables development are removed and if increased renewables are determined to be cost-effective compared to other measures for reducing GHGs, i***t is reasonable for the State of California to set as a target that all retail providers deliver 33% renewable energy to their customers by 2020.

13. E3's approach and analysis to estimating costs from reducing GHG emissions ***if supplemented by additional cross-sector and cross-measure analysis of cost effectiveness and feasibility*** are reasonable for the purpose of informing our recommendations to ARB.

~~***23. Distributing some free allowances to deliverers would reduce short-term impacts on generating resources, and would help generators adapt to the new regulatory environment.***~~

~~***24. A transition to auctioning would help protect ratepayers if problems arise as ARB implements AB 32 and experience is gained with the auctioning process.***~~

~~***25. A transition to 100% auctioning by 2016 would ensure that any allowance rents would be short-term and would give existing high-emitting resources time to adjust their generation investments.***~~

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

~~***29. In a fuel-differentiated output-based allocation approach, it is reasonable that a higher weighting factor be applied for all coal generation delivered to the California grid.***~~

~~***30. If 100% auctioning is not implemented by 2016, an important longer-term goal of deliverer distributions should be to provide strong incentives for GHG reductions.***~~

~~***31. It is reasonable that allowance distributions to deliverers transition toward an output-based approach that weights all types of generation equally, to be reached by 2020.***~~

~~***35. Allocating allowances to retail providers based on historical emissions in their electricity portfolios would accommodate carbon-intensive retail providers that may face relatively high rate impacts due to compliance costs.***~~

~~***37. It is reasonable to transition allocation of allowances to retail providers from an historical emissions basis to a sales basis because a sales-based allocation would provide a long-term incentive to reduce reliance on high-emitting resources***~~.

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

42. With respect to GHG emissions, all electricity generated by a CHP facility is identical whether the electricity is delivered to the grid or consumed on-site**,** ***except that electricity consumer on-site is related to the industrial process rather than to electricity services in the electricity sector.***.

45. CHP facilities deliver a portion of their electricity to the grid and, for GHG regulatory purposes, ~~***also***~~ should be treated ***as part of the industrial sector*** ~~***comparable to deliverers***~~ for the portion of electricity that is consumed on-site.

46. It is reasonable to allocate allowances to CHP facilities ***for electricity delivered to the grid*** using the fuel-differentiated output basis, as described in this decision.

47. To the extent that CHP facilities provide electricity that is consumed on-site, distributing allowances to CHP facility operators on the same basis as ***other sources in the industrial sector*** ~~***retail providers***~~ would provide equitable treatment for CHP facilities.

53. Price triggers ***or other backstop regulatory mechanisms such as a price collar and allowance reserve are essential to protect consumers from any failure or manipulation of a cap and trade market, provided that such mechanisms balance the need for customer protection, competitive markets, and environmental integrity*** ~~***and safety valves could very likely distort or defeat the cap-and-trade market by creating uncertainty that investments in emissions reduction technologies will achieve returns commensurate with the level of reductions needed to meet the State's emissions reduction goals***~~.

Conclusions of Law

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

taxes imposed for revenue purposes***, provided the fees "bear a reasonable relationship to those adverse effects."*** . **Sinclair Paint Co. v. State Bd. of Equal., (1997) 15 Cal. 4th 866, 870.**

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

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

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

13. An historical emissions-based distribution of allowances to retail providers can be designed to recognize voluntary early actions these retail providers have taken to reduce emissions ***prior to enactment and implementation of AB 32***, consistent with Section 38562(b)(3). Section 38580(a) requires ARB to monitor compliance with, and enforce, the regulations it issues, but does not prohibit the use of out-of-state offsets or credits.

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

16. Sections 38505(d), 38560, 38561, and 38562 require the Air Resources Board to consider and analyze the relative cost-effectiveness and technological feasibility of each emissions limit, emissions reduction measure and market-based compliance mechanism prior to including such limit, measure or mechanism in the AB 32 scoping plan or implementing regulations. The relative cost-effectiveness of each limit, measure and mechanism must be

analyzed on a comparative basis using the cost per unit of reduced greenhouse gas emissions adjusted for its global warming potential.

17. Section 38561(e) requires the Air Resources Board, in developing its scoping plan, to take into account the relative contribution of each source or category of source, including the electricity sector as a whole, to statewide greenhouse gas emissions by all sources, categories of sources and sectors.

18. Sections 38501 and 38561 require the Air Resources Board, in developing its AB 32 scoping plan and implementing regulations, to consult with the Public Utilities Commission and the Energy Commission on all energy related matters, including the provision of reliable and affordable electrical service, to ensure that the Board's emissions reduction limits and measures are complementary, nonduplicative, and can be implemented in an efficient and cost-effective manner.

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

FINAL ORDER

IT IS ORDERED that:

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

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

market-based strategies for all emissions reduction strategies and measures should be based on the results of the cross-sector analysis of relative cost effectiveness and technological feasibility required by AB 32.

3. We recommend that ARB adopt a requirement that each retail provider meet 33% of its retail sales using renewable energy sources by 2020***, provided that the State commits to significant investments in transmission infrastructure and removes the significant barriers to continued deployment of renewable energy in California, including uncertainties associated with the continuation of federal production/investment tax credits, availability of transmission, siting, and permitting issues.***.

5. We recommend that the trajectory of the multi-sector emissions cap and the required annual reductions be ***established*** ~~generally a straight-line reduction~~ between 2012 and 2020 for all sectors including electricity ***on a schedule that takes into account the relative cost effectiveness and technological feasibility of emissions reductions across different sectors, as well as the importance of incenting investments in new technologies and long term emissions reductions beyond 2020***. ***The burden of overall emissions reductions required of the electricity sector should be proportional to the electricity sector's overall contribution to 1990 statewide emissions.***

6. We recommend that~~, for 2012,~~ ARB distribute ~~***2***~~***100***% of the allowances allocated to the electricity sector to retail providers, with a requirement that they sell the allowances through a centralized auction~~, and distribute 80% of the allowances without cost to electricity deliverers~~. ***ARB should allocate additional allowances to the electricity sector to account for any increase in electricity sector emissions that result from emissions reduction programs or measures in other sectors, such as electricification of transportation.***

~~***7. We recommend that ARB increase the portion of allowances allocated to the electricity sector that are distributed to retail providers and sold at auction***~~

~~***by 20% each year so that all of the electricity sector allowances are auctioned in 2016 and each year thereafter.***~~

~~***8. We recommend that for the portion of allowances distributed to deliverers, ARB distribute the allowances using a fuel-differentiated output-based approach with distributions limited to emitting deliverers, as described in this decision.***~~

~~***9. We recommend that, if ARB adopts less than either 100% auctioning as the ultimate goal for electricity sector allowances or phases in 100% auctioning later than 2016, ARB phase out the weighting factors used to determine allowance distributions to deliverers starting in 2016, so that the distribution methodology would transition to a pure output-based approach by 2020.***~~

~~***12. We recommend that ARB require that all allowance auction revenues be used for purposes related to Assembly Bill (AB) 32, including the support of investments in renewables, energy efficiency, new energy technology, infrastructure, customer bill relief, and other similar programs.***~~

13. We recommend that ARB require all auction revenues from allowances allocated to the electricity sector be used for the benefit of consumers in the electricity sector***, including the support of investments in renewables, energy efficiency, new energy technology, infrastructure, customer bill relief, and other similar programs***.

15. We recommend that ARB require each publicly-owned utility to demonstrate annually to the Energy Commission that its use of auction revenues during the prior year ***complies*** ~~***was consistent***~~ with the purposes ***and regulatory requirements*** of AB 32.

17. We recommend that ARB treat entities that deliver CHP-generated electricity to the grid just like other deliverers for GHG regulatory purposes . ~~***, and that ARB treat CHP operators comparable to deliverers for purposes of regulating GHG emissions associated with CHP-generated electricity used on-site, as described in this decision. Recognizing that they may be the same***~~

~~***entity, the deliverer for the CHP electricity delivered to the grid and the CHP operator for CHP electricity used on-site should be responsible for surrendering allowances for the portion of CHP-generated electricity delivered to the grid and the portion used on-site, respectively. To the extent that allowances are distributed for free to deliverers, the deliverer for CHP delivered to the grid and the CHP operator for CHP electricity used on-site should receive allowances on the same basis as deliverers of electricity from other sources.***~~

18. We recommend that ARB treat ***GHG emissions related to any on-site*** CHP ***emissions, whether from electricity or thermal generation, as part of the industrial/commercial sector under AB 32.*** ~~***operators comparable to retail providers for the portion of CHP-generated electricity that is used on-site. To the extent that allowances are distributed to retail providers, the CHP operator should receive allowances on the same basis as retail providers and should be required to sell the received allowances at auction and use the proceeds for purposes consistent with AB 32.***~~

20. We recommend that ARB, in developing a cap-and-trade program, ~~***avoid*** creating any~~ ***include appropriate "backstop" regulatory mechanisms, such as*** price triggers or ***price collars*** ~~safety valves~~***, to protect consumers in the event of a failure of the cap-and-trade program***.

21. We recommend that, if ARB develops a cap-and-trade program, ARB establish three-year compliance periods and allow unlimited banking of emissions allowances and offsets ***without geographic restriction***.

22. Rulemaking 06-04-009 ***shall remain open for further proceedings and recommendations by the Commission and the Energy Commission during implementation of AB 32*** .

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of **Opening Comments Of Pacific Gas And Electric Company (U39 E) On Proposed Decision On Greenhouse Gas Regulatory Strategies** on all known parties to R. 06-04-009 by

- transmitting an e-mail message with the document attached to each party on the official service list providing an email address; or
- by first-class mail, postage prepaid, to each party on the official service list not providing an email address.

Executed on October 2, 2008, at San Francisco, California.

/s/

Mary B. Spearman

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies. (U 39 E)	Rulemaking 06-04-009 (Filed April 13, 2006)

REPLY COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON ADDITIONAL ISSUES RELATED TO IMPLEMENTATION OF AB 32 IN THE ELECTRIC AND NATURAL GAS SECTORS

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I. INTRODUCTION

Pursuant to the rulings of the Administrative Law Judges, Pacific Gas and Electric Company (PG&E) provides its reply comments on additional issues relating to the implementation of AB 32. PG&E's reply comments follow the general topic headings in the ALJs' suggested outline, but are organized by specific commenter or issues below the topic headings.

II. GENERAL ISSUES

As a threshold matter, several of the opening comments raise general policy issues that are based on either faulty logic or inaccurate facts, and therefore would lead to policy conclusions or decisions that would be damaging to California in general and the electric sector in particular. PG&E responds to each of these threshold policy issues in the subsections below.

A. "Cap and Trade" and Programmatic Measures Are Not Mutually Exclusive Policy Choices; Both Are Essential to the Successful Implementation of AB 32

Some commenters evaluated "cap and trade" and programmatic measures as if the two were mutually exclusive policy choices under AB 32 and as if only one or the other should be implemented under AB 32.[1/]

This is faulty logic, and should be rejected. First, California's successful and progressive customer energy efficiency (CEE) and renewable energy programs will continue, regardless of whether the ARB explicitly adopts those programs as AB 32 emissions reduction measures or assumes the programs will continue under the existing jurisdiction of the CPUC and Energy Commission. Thus, there is no "choice" between these programs and "cap and trade;" the programs will continue and will co-exist with all emissions reduction measures adopted under AB 32, including a cap and trade program.

Second, no proponent of cap and trade (least of all PG&E) is advocating that cap and trade be the exclusive means by which AB 32's 2020 goals are met. To the contrary, PG&E strongly supports other measures as well, both inside the electric and gas sector and across all sectors with GHG emissions sources in California. For example, PG&E for nearly 30 years has been a strong advocate of enhancing California's building codes and appliance standards in order to reduce energy use, and is continuing that advocacy because of the GHG-reducing benefits of further enhancing those codes and standards.

However, PG&E believes that California's successful energy efficiency and renewable programs are necessary—*but not sufficient*—to achieve AB 32's ambitious targets on a sustained, least-cost basis. This is where PG&E strongly disagrees with those commenters who would forego market-based compliance options under AB 32, including cap and trade, under the risky assumption that "command and control"

1/ SCPPA, pp. 3- 4, 73; LADWP, p.2; DRA; p.1; NRDC/UCS, p. 34.

programs and regulatory mandates will achieve the majority of AB 32's goals at least-cost to California consumers and businesses.[2/] Likewise, PG&E disagrees with those commenters whose opposition to cap and trade may be rooted more in their mistrust of market-based mechanisms in general, regardless of whether the market-based mechanism are designed and implemented in a way that enlarges the menu of options and measures available to California consumers and businesses to transition quickly and smoothly to the new, low carbon economy.[3/]

Moreover, the debate between cap and trade and programmatic measures unnecessarily creates a "win-lose" equation that would severely narrow the practical tools and policy options available to California to implement AB 32. The key issue for AB 32 implementation is *not* what measures and policy options to *exclude* from implementation, it is how many measures and options can be included that allow multiple paths and means to Californians to use their entrepreneurial and technological genius to meet—*and exceed*—AB 32's 2020 and 2050 goals. Policymakers and regulators should not be considering restricting these choices and flexible options – they should be seeking to expand them at every turn.

B. The E3 Economic Model Cannot and Does Not "Prove" that the Electric Sector Can Meet its AB 32 Goals Through Programmatic Mandates Only, Thus Making Cap and Trade and Other Compliance Options Unnecessary

Some commenters have reviewed the "reference case" for the electric sector in E3's economic modeling, and concluded that the electric sector has met or can meet its likely AB 32 2020 goals through existing programs and mandates only, and therefore a

2/ See, e.g., SCPPA, pp. 3- 4; LADWP, p.1; TURN, pp. 2- 3.

3/ TURN, pp. 7- 8; LADWP, pp. 13- 14.

cap and trade program on top of existing programs is unnecessary.[4/]

First, the E3 model itself is subject to large variability and debate over assumptions and inputs, including for its reference case. For example, PG&E presented more realistic input assumptions that would increase the reference-case GHG emissions from 108.2 MMT/yr to 112.4 MMT/yr, and cut the emission benefits of the Aggressive case renewables and CEE, from 30 MMT/yr to 18 MMT/yr.[5/] When apportioning GHG reductions among sectors, the agencies must not assume that such reductions from these uncertain and unpredecented program goals will be achieved.

To date, none of the economic models, including E3, have evaluated the relative costs and benefits of different emissions reduction measures across all sectors, not just the electric and gas sector. As a consequence, any reliance on the E3 model or other assumptions regarding electric sector emissions would ignore the AB 32 mandate that regulators choose emissions reduction measures based on cost effectiveness and feasibility across *all* sectors. Otherwise, reliance on a one-sector economic model with widely debatable assumptions and inputs for just that one sector could lead to the grossly faulty conclusion that one sector—in this case, California's electricity sector—should be asked to provide a disproportionate share of emission reductions by 2020, at a high cost. As noted in PG&E's Opening Comments, the E3 results indicate that GHG reductions using additional RPS, CHP, and CSI beyond the reference case are very expensive, at $133/metric ton, $228/metric ton, and $902/metric ton respectively.[6/]

4/ TURN, p. 3; SCPPA, pp. 13- 15.

5/ PG&E Opening Comments, June 2, 2008, pp. 101, 107, 110.

6/ *Ibid.*, p. 102.

In this regard, it is important for policymakers to look at *all* emission reduction options in *all* sectors, and a well-designed, multi-sector cap and trade program is an efficient way to do so. For example, emission reductions from the transportation sector may be less expensive. Since early February, gasoline prices have increased by about $1.00 per gallon, equivalent to about $100/CO2 metric ton.[7/] This increase may cause dramatic changes that may provide market-based incentives to cut transportation-sector emissions, at an incremental cost lower than the additional cost of reductions in electricity-sector emissions. A cap and trade program would facilitate these market-based choices and incentives.

In its Opening Comments, the Northern California Power Agency (NCPA) notes that the electricity sector's current emissions are already below the 1990 benchmark.[8/] NCPA persuasively expresses its concern that reliance on these modeling numbers may cause some policymakers to consider calling on the electric sector for more than its fair share of emission reductions.[9/] NCPA argues that "…it is incumbent upon the Joint Commissions to … make a recommendation to CARB regarding the total feasible and cost-effective reductions that can be fairly achieved by the electricity sector. The Joint Commissions should provide CARB with a recommendation on the total emissions

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7/ The average U.S. retail price for gasoline increased from about $3.00/gallon in early February 2008 to about $4.00/gallon in early June 2008, as shown in the DOE graph at: http://www.eia.doe.gov/oil_gas/petroleum/data_publications/wrgp/mogas_home_page.html. Combustion of gasoline yields 8.81 kg of CO2 per gallon, according to the California Climate Action Registry protocol: http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf p. 42). Mathematically, ($1/gallon) * (1 gallon/8.81 kg of CO2) * (1000 kg/metric ton) equals $113/tonne, rounded to $100/tonne in the text.

8/ NCPA, p. 42.

9/ *Id.*

reduction requirement for the electricity sector."[10/]

PG&E shares NCPA's concern that the electricity sector might be unfairly burdened because of faulty reliance on sector-specific economic models, such as the E3 model. Electricity customers should not be asked to reduce emissions via sector-specific measures, such as a 33% Renewable Portfolio Standard at $133/metric ton, unless it is clear that lower-cost emission reductions from other sectors, including the transportation sector, are insufficient to meet the AB32 emission targets.

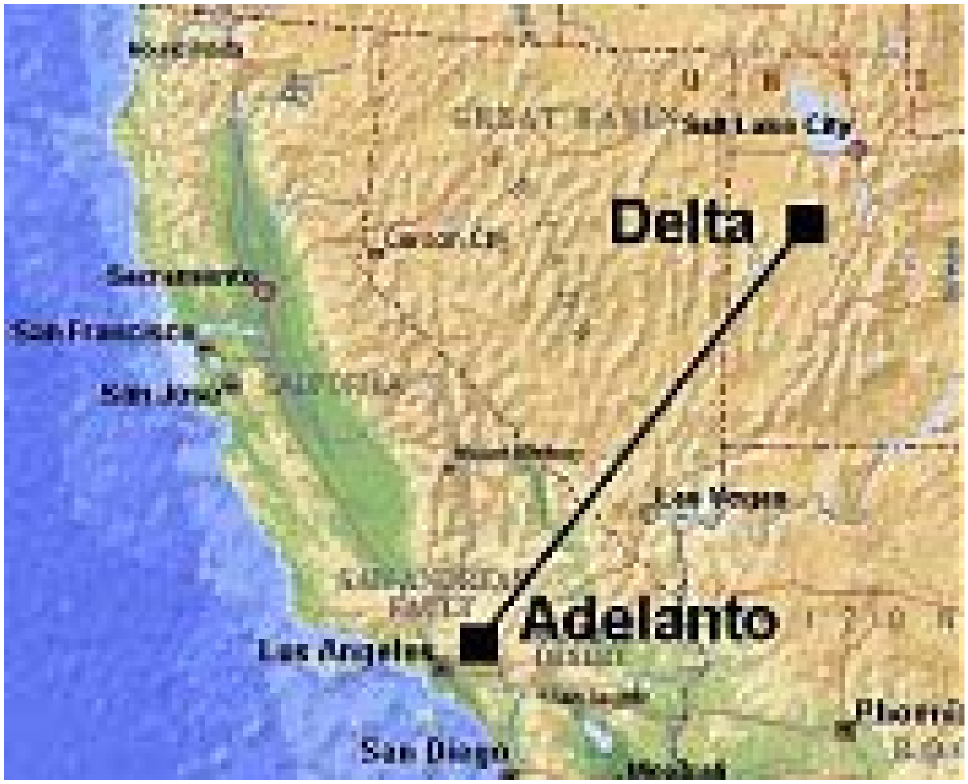
III. GHG EMISSION ALLOCATION AND AUCTION POLICIES AND METHODS

A. LADWP's and SCPPA's "Accident of Geography" Argument for Relief from AB 32 Emissions Goals Continues to Be Unsupported and Irrelevant to Allowance Allocation

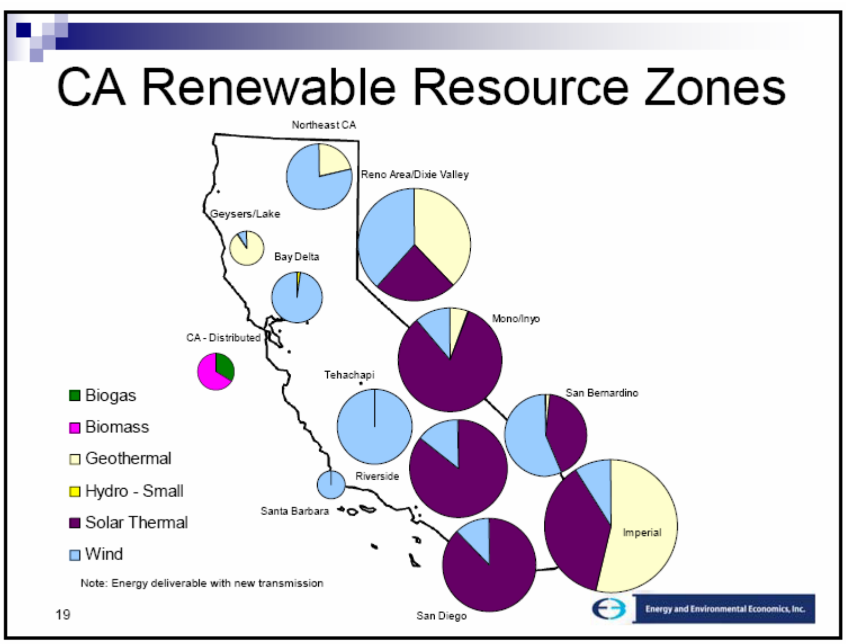
SCPPA and LADWP allude once again to the "accident of geography" argument against using an output based mechanism for allowance allocation.[11/] Their argument was unsupported and irrelevant when made in earlier comments, and continues to be unsupported and irrelevant. Rather than repeating its earlier points regarding the "non-accidental" investment of billions of dollars by its customers in clean generation and CEE programs over the last 30 years, PG&E includes below a simple map of the electric transmission paths used and built by LADWP and SCPPA to gain access to their geographically-remote coal generation facilities. Moreover, the second map, used by E3 in its presentation in this proceeding, demonstrates that LADWP and SCPPA have always been geographically closer than PG&E and other Northern California utilities to preferred and ideal sites for new renewable resources in Southern California.

10/ NCPA, p.43.

11/ SCPPA, pp. 35, 45; LADWP, p. 12.



Source:http://www.abb.com/cawp/gad02181/c6139ccf0c93c50bc1256d88004018bf.aspx



Based on these maps, it would be just as persuasive to argue that an "accident of geography" has given LADWP and SCPPA much cheaper transmission options for new renewables and low-emitting coastal powerplants than Northern California utilities, and therefore Southern California utilities should bear a greater responsibility for emissions reductions, not the reverse. But both "geography" arguments are false and irrelevant, precisely because they are based on facile references to geography which ignore the basic fundamental mandate of AB 32: California must reduce its GHG emissions and transition to a low carbon economy, and this cannot be achieved without reductions from high-emitting sources.[12/]

B. SCPPA's Request to Be Excused from Emissions Reduction Responsibility Because of Its Contracts for High-Emitting Coal-Fired Generation Would Effectively Exempt A Major Source of GHG Emissions from Regulation Under AB 32

SCPPA in its comments effectively requests an exemption for its existing coal-fired power contracts from AB 32 emissions reduction requirements:

> *"The transition schedule proposed by Staff fails to recognize that various retail providers including the SCPPA members have existing contracts with out-of-state coal plants that will not expire until later years (for example, 2019 for the LADWP contract with Navajo and 2027 for various SCPPA members' contracts with Intermountain Power Project.)"*[13/]

SCPPA is effectively requesting an exemption from AB 32 for its coal-fired contracts, in the guise of an irrelevant argument over "wealth transfer." PG&E urges the CPUC and Energy Commission to reject SCPPA's argument for an AB 32 exemption. What SCPPA proposes is an almost permanent subsidy of the customers of high-

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12/ To LADWP's and SCPPA's now-hackneyed "Why us?" complaint, PG&E is tempted to paraphrase Willie Sutton: "Because that is where the emissions are."

13/ SCPPA, p. 45.

emitting utilities funded specifically by the customers of low-emitting utilities—in violation of a cornerstone tenet of environmental law: "The polluter pays." PG&E's customers and customers of other low emitting utilities have spent billions of dollars on CEE and lower emitting generation over the course of many years. The effect of SCPPA's request is that customers of low-emitting utilities for the foreseeable future pay for CO2 reductions for SCPPA's customers as well as for themselves. SCPPA in effect is asking for an exemption from AB 32 requirements so they can continue to benefit from low-cost but high-emitting coal fired generation.

C. AB 32 Regulations Should Not Relieve Power Generators from the Terms of Their Existing Contracts. Carbon Prices and Allowance Value Will Be Passed Through to Customers As a Normal Part of Power Procurement Contracts and Ratemaking

Concerned that the value of allowances may not be used for the benefit of utility customers, NRDC and UCS propose a "use it or lose it" approach to the value of allowances it recommends the utilities receive.[14/] PG&E views a specific additional regulatory mandate as unnecessary. Under normal public utility ratemaking, revenues received by utilities on behalf of their customers are routinely allocated directly or indirectly for the benefit of those customers on an annual or other periodic basis by the regulatory authority overseeing utility rates, in PG&E's case the CPUC. Creating artificial timeframes in AB 32 regulations could conflict with this normal CPUC oversight responsibility and could create unintended outcomes such as investing in less efficient programs or rebates solely because they are expedient.

Separately, WPTF and IEP have repeated their prior stated concerns regarding the ability of power generators to pass through their costs of CO2 allowances or

14/ NRDC/UCS, p. 12.

compliance costs as part of their ongoing power contracts with buyers.[15/] WPTF and IEP take issue with the assumptions that E3 made regarding the pass through of AB 32 compliance or allowance costs upon the expiration or renegotiation of existing power contracts. WPTF and IEP argue that buyers will not allow the increased costs of carbon allowances or AB 32 compliance to be passed through under such new or renegotiated contracts, and therefore AB 32 implementing rules should in some manner address or ensure the pass through of the costs. Similarly, EPUC/CAC argue that contract provisions will threaten the financial viability of certain high-emitting generators, and therefore AB 32 regulations should be structured to ensure the continued viability of those generators.[16/]

PG&E disagrees and urges the CPUC and Energy Commission to reject the implicit invitation by WPTF, IEP and EPUC/CAC to dictate power contract terms favorable to power generators as part of AB 32 implementation. It has been widely acknowledged that electric commodity costs will increase to reflect the cost of complying with AB32, and that customers will pay for this new cost. While market prices and market conditions will govern the give-and-take of commercial parties under AB 32 regulations, just as they have for all manner of government regulations, there should be little question that suppliers will in bilateral negotiations be able to largely recoup these increased costs. In any event, for existing contracts there are a range of types of contract structures, many of which allow for the pass through of the CO2 costs or other air pollution or environmental compliance costs. This is simply one element of

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15/ WPTF, p. 29; IEP, pp. 3- 4, 45.

16/ EPUC/CAC, pp. 8- 16.

the balance of benefits and burdens inherent in any contract negotiation. There is no need to dictate through regulation the outcome of this particular contract term.

D. The Commissions Should Reject the Recommendation that Low-Emitting Utilities Receive No Allowances

A few parties suggest that there is no need for low emitting utilities to receive allowances at all based on sales or output.[17/] PG&E disagrees as it has on numerous occasions in this proceeding for the following reasons:

- Low emitting utilities have fewer and relatively more high cost reduction options available.
- Their past investments should be recognized and continued investment encouraged.
- To the extent other utilities are successful at reducing demand through energy efficiency programs and adding low emitting generation, the sales based method creates greatest reward and incentive.
- Low emitting utility customers should not have to pay twice for GHG reductions by subsidizing high emitting utility customers' reductions.
- All utilities in California should be held to the same environmental standard, allocating based on historical emissions provides permanent special treatment for a subset of retail providers in California.

The principle of rewarding "early actions" and "voluntary actions" by emissions sources, both utilities and power generators, is embedded in AB 32 itself. (Health and Safety Code 38561(f); 38562(b)(4).) Allocating allowances to sources based on output or sales is a simple and extremely effective way to incent and reward rapid and sustained reductions in emissions during the transition to 2020 and would help ensure compliance with these provisions of AB32. Excluding such incentives from AB 32's regulatory

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17/ SCPPA, pp. 37- 38; LADWP, p. 12; SMUD, p. 3.

program would forego the use of a powerful tool for not only meeting, but exceeding, AB 32's emissions targets during the 2012- 2020 transition period.

IV. FLEXIBLE COMPLIANCE POLICIES

A. Price Triggers and Other Safety Valves

To prevent short-term price spikes, the Division of Ratepayer Advocates (DRA) proposes a mechanism similar to one feature of PG&E's suggested "price collar."[18/] DRA proposes a "mechanism" that would allow ARB the flexibility to take allowances from a future compliance period and offer them for sale and use in the current period, at a price certain. Environmental integrity is maintained in DRA's proposal because the number of allowances earmarked for "the subsequent compliance period" is reduced by the number of allowances shifted from that future period to the current period. PG&E's suggestion is basically the same under the condition where allowance prices are high. PG&E suggested that allowances be taken from some period several years in the future, rather than "the subsequent compliance period," but this difference is minor.

WPTF argues that "use of a safety-valve option should be limited to true damage control and should not be triggered by price volatility."[19/] With that proviso, WPTF's recommendation is similar to DRA's and PG&E's: "…[I]f the safety valve calls for loosening of the cap in one year, for instance through issuance of additional allowances, the overall integrity of the cap should eventually be restored by a reduction in the cap in

18/ DRA, p. 25.

19/ WPTF, p. 12.

future years."[20] FPL Energy Project Management, Inc., also persuasively states the case for a price collar within the context of an overall GHG emission budget:

> "A sharp carbon price increase would be costly for existing carbon-intensive processes and ultimately consumers. Also, if the price of carbon dropped sharply it would discourage long-term investments in emissions reducing technologies. For these reasons, FPLE urges the Commissions to recommend the use of a price ceiling and price floor when auctioning carbon emissions allowances as well as using a safety valve cost control mechanism that would allow a temporary expansion of the cap against future carbon allowances."[21]

In contrast to this general support for cost containment provisions and a "price collar" or "price trigger" mechanism, NRDC/UCS summarily reject such cost containment protections.[22] Instead, NRDC/UCS argue that the discretion of the Governor of California to suspend AB 32's overall deadlines under extraordinary circumstances is adequate cost containment protection, and therefore no price triggers or price collars should be employed.[23]

PG&E vigorously disagrees. The Governor's discretion is not a practical or timely substitute for an effectively designed cap and trade program that includes "self-correcting" cost containment provisions. California recently experienced the consequences of relying on political discretion to remedy a market failure – the result was that millions of California consumers and businesses experienced billions of dollars of higher electricity costs during the 2000- 2001 California energy crisis. Well-designed

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20/ *Ibid.*, p. 13.

21/ FPL Energy Project Management, p. 24.

22/ NRDC/UCS, p. 21.

23/ *Ibid.,* citing Health and Safety Code section 38599.

cost containment mechanisms, such as the "price collar" within an overall carbon budget as proposed by PG&E, are essential to the success of AB 32.

B. Offsets – Proposals by Some Parties to Restrict Offsets by Geographical Location Are Extremely Bad Public Policy and Unlawful

Most parties commenting support use of offsets, which allow entities to invest in reductions outside of the cap and trade sectors and reduce overall economic and societal costs by providing a broader array of emissions reduction opportunities, while stimulating innovative compliance solutions. The majority of parties commenting on offsets support no geographic or quantitative limits on offsets, as long as the offsets meet rigorous quality standards.[24/] Limits on offsets may increase the costs of AB32 to the California economy without environmental cause,[25/] limit innovation in uncapped sectors, and decrease the co-benefits that offsets bring. Creating a strong offset policy will highlight California's leadership in GHG policy and encourage other regions to monetize abatement measures.[26/]

No Geographic or Quantity Limitations or Discounting. Certain parties express support for limiting offsets based on quantity or geography;[27/] some going so far as to say that out-of-state offsets are precluded under AB32.[28/] On the contrary, AB32

24/ E.g., DRA, pp. 38- 39; SCPPA, p. 69; WPTF, pp. 20- 21; Sempra, p. 33; SCE, pp. 27- 28; MID, p. 10; Morgan Stanley, p. 4; EcoSecurities, pp. 7- 8; Climate Trust, pp. 1- 8.

25/ See US EPA analysis of "Lieberman-Warner" draft federal legislation, referenced in PG&E Opening Comments, June 2, 2008, pp. 61- 62.

26/ Morgan Stanley at 18.

27/ NRDC/UCS, p. 29; TURN, p. 21.

28/ CUE/CURE, p.10. Contrary to CUE/CURE, sponsors of offset projects located outside California can consent to audit and enforcement of their projects by California in order to ensure compliance with AB 32 offset standards.

specifically directs the ARB to "facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas reduction programs."[29]

We believe limiting offsets by geographic origin, as opposed to by qualitative standards, would be a public policy mistake and a huge missed opportunity for California to lead by example. Climate change is a global issue, and California is leading the world in implementing a solution to climate change. If California were to step back and limit offsets from outside the State that otherwise deliver permanent, additional and verifiable emissions reductions, California would be indicating to the world that it was retreating from its global leadership on climate change. Moreover, by doing so, California could be greatly increasing the cost of compliance with AB 32 for California and California consumers and businesses. A robust offset policy as part of AB 32, based on and limited only by rigorous verification and audit standards, will *enhance and expand* the emissions reductions achievable under AB 32, including not only the direct benefits of GHG emissions reductions, but also the co-benefits of reducing other criteria pollutant emissions associated with the offset projects.

Additionally, limiting the use of offsets from outside California could run afoul of the Commerce Clause. Limitations that are based on geographic location and not the verifiability and quantification of offsets would discriminate against out of state offset providers and thus likely be unlawful under the Commerce Clause's *per se* discrimination test. The filter of quality should be the only limit on offset projects, not the location of the project.

The proposals by certain parties to strictly limit offsets by quantity or by

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29/ Health and Safety Code section 38564.

geographic location should be rejected.

Offsets Should Not Be Limited Based on Incomplete Co-benefits Analysis. A few parties incorrectly argue that offsets should be limited because they do not bring co-benefits.[30/] Co- benefits are defined as any two or more benefits that are derived together from a single measure;[31/] in greenhouse gas policy, co-benefits are any benefits that are ancillary to the GHG reduction. Co-benefits include economic co-benefits (e.g. rural development, green jobs, local enterprise) and environmental co-benefits (e.g. human health, natural ecologic systems). In evaluating co-benefits, California should not focus on one set of co-benefits from point sources to the exclusion of others.

CUE/CURE recommends quantity limitations because of the potential for offsets to hinder reductions of local pollutants near facilities that would have otherwise decreased local pollutant emissions by decreasing GHG emissions.[32/] Contrary to CUE/CURE, limiting offsets as a surrogate for increased local air pollution policy devalues the co-benefits of offsets and places almost singular emphasis on point sources in criteria pollutant emissions.

While there is a benefit from continuing to reduce emissions from stationary sources inside California, the majority of the criteria and toxic air pollutants come from transportation and interstate commerce. If the evaluation tools focus on stationary sources alone, California will not be addressing the main sources for toxic emissions. For example, electrification of transportation should bring important co-benefits of

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30/ NRDC/UCS, pp. 26- 28; TURN, p. 21; CUE/CURE, p.9.

31/ IES Handbook., http://www.epa.gov/ies/handbook.htm, pp. 8.

32/ CUE/CURE, p. 9.

decreased criteria pollutants. However, if AB 32 focuses solely on stationary sources, electricity production could be discouraged such that these important co-benefits never occur.

While certain "command and control" regulations could decrease local air pollutants in California, increased electricity imports could cause increased greenhouse gas emissions and criteria and toxic emissions elsewhere. California may decrease reliance on fossil fuel facilities, but if this is done at the cost of increasing output from coal generation facilities elsewhere, populations outside of the state will suffer and emissions overall will be higher.

Offsets Will Enhance, Not Stifle Incentives for Innovation in Capped Sectors. As stated in its opening comments, PG&E does not agree with commenters who argue that use of offsets will stifle innovation in the capped sectors.[33/] Incentives for technology know no state boundaries in our global economy; thus, incentives for innovative GHG emissions reduction technologies should be targeted at global markets, not to local markets through limitations on offsets or trading of emissions allowances. Open policies which focus less on state and national boundaries and more on global impact in addressing technology innovation will be far more effective and less expensive than limits on quality GHG reduction opportunities based on local or geographic interests.

Support Parallel Offsets Process DRA suggests launching a separate working group on protocols.[34/] PG&E supports such a process headed by the ARB. PG&E has

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33/ NRDC/UCS, pp. 26- 27; CUE/CURE, p. 9.

34/ DRA, pp. 40- 42.

highlighted the urgent need for California to adopt protocols early to foment the development of the offsets market by the beginning of the cap and trade market.

V. TREATMENT OF COMBINED HEAT AND POWER

A. Contrary to Some Parties, Not All CHP is Efficient and Therefore a "One Size Fits All" Policy for CHP Under AB 32 or Other Programs Is Unworkable and Unsound

Some parties commenting on treatment of Combined Heat and Power (CHP) facilities under AB 32 present their recommendations with the implied assumption that all CHP facilities are energy or GHG emissions efficient.[35/] These comments ignore the distinction that other parties (or even the same parties) draw endorsing use of the "double benchmark" criteria to determine whether a given CHP unit is efficient or actually contributes to greenhouse gas emissions reduction.[36/] To the extent that comments recommending special treatment for CHP fail to recognize this distinction, policymakers could make the fundamental error of adopting "one size fits all" policies that apply to all CHP, rather than only to CHP that, in fact, reduces GHG emissions or is otherwise energy efficient or "emissions efficient."

The difficulty in drawing the line between "efficient" and "inefficient" CHP in a regulatory sense is precisely why PG&E has concluded that CHP *does not* require and *should not* receive special subsidies, treatment or set-asides, under AB 32 or otherwise. However, should policymakers disagree, establishing a "bright line" distinction between "CHP" and "efficient CHP" is essential to any explicit CHP program or special treatment. Otherwise, policies intended to reduce carbon emissions could

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35/ EPUC/CAC, pp. 39, 41, 54, 56; CCC, pp. 5, 11; FCE, pp. 10, 17- 22; *but see* CCDC, pp. 1- 3, distinguishing between CHP generally, and "Qualifying Customer CHP."

36/ EPUC/CAC, pp. 51- 54; CCC, p. 16; CCDC, p. 4.

unintentionally encourage CHP that actually increases emissions and exacerbates global warming.

PG&E would like to reiterate the distinction between large CHP units that export to the grid, and should compete with other generators, and small units that serve on-site load, and already receive to incentives.[37/] PG&E would support including small CHP in the Self Generation Incentive Program, and currently provides incentives to fuel cell CHP. PG&E has also filed a standard offer for qualifying facility CHP up to 20 MW. The agencies must distinguish between distributed generation and large, competitive generators.

B. CHP Should Not Be Regulated In Its Own Separate Sector Under AB 32

PG&E has recommended that CHP be regulated in the industrial sector (for thermal output and electricity used on-site) and the electric sector (for electricity exported to the utility grid).[38/] The only parties suggesting that CHP be regulated in a separate sector are EPUC/CAC, Indicated Cement Companies and CCC.[39/] Other parties that stated a position felt that CHP belonged in the industrial sector, the natural gas sector, or the electric sector (for those CHP units that export electricity to the grid).[40/]

Single sector treatment of CHP does not make sense. Because the owner of a

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37/ Public Utilities Code sections 353.1- .15 exempts co-generators with capacity less than 5 MW from certain charges and provide other rate benefits. Customers may also avoid reservation charges for the period that the generator is out of service. Some customers installing CHP are exempt from some non-bypassable charges which effectively means other customers' rates increase.

38/ Other parties support separating thermal and electric outputs, including SMUD, pp. 31-32, Sempra, p. 13, CLECA, pp. 7-8.

39/ EPUC/CAC, pp. 4- 5, Appendix B, p. 17; Indicated Cement Companies, p. 5; CCC, p. 4.

40/ SMUD, pp. 31- 32; Sempra, p. 13; CLECA, pp. 7- 8.

CHP unit above a *de minimis* threshold would be the point of regulation for the entire facility, the unit should be regulated in the same sector as the facility (typically the industrial sector). Emissions associated with on-site electricity and thermal energy sources do not belong in the electric sector because they are part of an industrial process and do not interact with California's electricity market. The only exception would be for CHP units that export to the utility grid. Exported electricity should be regulated within the electricity sector, for administrative simplicity and fair treatment of all generators.

C. Contrary to EPUC/CAC, Customers that Install CHP Will Recover Their AB 32 Compliance or Allowance Costs Through the Market, Just Like Other Emissions Sources

EPUC/CAC erroneously argue that under a cap and trade program, generators would be unable to recover carbon costs and would therefore cease to supply electricity.[41/] As stated in its Opening Comments, PG&E believes that a well-designed market will reward efficient generators without the need for special subsidies, contract terms or set-asides.[42/] Efficient CHP would be financially rewarded in a cap and trade program in three ways: 1) decreased need for allowances for thermal load; 2) decreased retail electricity purchases; and 3) electricity sales that are more profitable than the marginal electricity resource.

Combined-cycle gas turbines (CCGT) are the marginal resource in California's electricity market, and under a cap and trade program, would set a market price that includes carbon costs. For example, a natural gas-fired power plant would require allowances, to cover emissions, proportional to gas burn. In other words, the facility's

41/ EPUC/CAC, pp. 8- 16.

42/ See also SCE, pp. 36- 37.

costs for natural gas and for CO_2 allowances are both operating costs. Just as current electricity prices generally cover the price-setting plant's operating cost for the natural gas it burns, future electricity prices should cover the price-setting plant's operating cost, which would cover both natural gas and CO_2 allowance costs.

Any generator, CHP or otherwise, that produces electricity that is more efficient than CCGT will receive a market price signal that includes carbon costs. Any generation source that is more emission-intensive than CCGT will compete against both marginal and more efficient resources, and emissions from those sources should not get special subsidies or set-asides to help them compete, increasing both overall costs and GHG emissions. Emissions reduction measures under AB 32, including a cap and trade program, should not be designed to preserve the profitability of individual sources that are not necessarily efficient, or to subsidize a category of sources that should compete with other sources in the electricity or other markets subject to the overall GHG regulations.

In addition, several of EPUC/CAC's cost recovery arguments are based on existing MRTU market rules, designed prior to a proposed carbon market. PG&E believes that CAISO will have opportunities, through tariff filings to FERC, to amend market mechanisms, such as price cap formulas, to account for carbon in variable costs.

EPUC/CAC imply that if costs of generation for existing CHP are not fully recovered by owners, the significant amount of power currently under QF contracts may be withdrawn from the market.[43/] PG&E believes that since most of this generation was installed decades ago, any reasonably efficient generation should be able to compete in

43/ EPUC/CAC, pp 7- 11, 58- 59.

an open market. Generators generally will include their carbon costs in the bid price and it should be expected that CHP generators will as well. If they are the most cost-effective, efficient electricity available, then they will compete well. If they are not, arbitrarily providing assistance to help them compete will simply raise prices and lead to subsidies for CHP paid for by electric customers.

CHP should not be treated as an "emissions reduction measure." Some parties representing CHP facilities, such as oil refineries, support treating CHP as an "emissions reduction measure."[44/] PG&E explained why this approach is inappropriate in its Opening Comments, and will not repeat that discussion here.[45/]

This proceeding is not the proper venue to address market barriers, incentives, or special treatment. PG&E discussed market barriers to CHP in its Opening Comments and will not repeat that discussion here.[46/] However, some parties, while responding to CPUC questions, proposed that the structure of ARB implementation include various programs and policies that will create subsidies for CHP, to be funded by electric customers.[47/] The suggestions are more appropriately addressed in other Commission or legislative venues (indeed most have already been litigated at length).

44/ EPUC/CAC, pp. 35- 36, Appendix B, p. 21; CCDC, p. 4.

45/ PG&E Opening Comments, June 2, 2008, pp. 81- 82.

46/ *Ibid.,* pp. 84- 86.

47/ EPUC/CAC, pp. 56- 60; CCDC, p. 6.

VI. NON-MARKET BASED EMISSION REDUCTION MEASURES (OTHER THAN CHP) AND EMISSION CAPS

A. Arguments For New and Expanded "Command and Control" Regulatory Mandates for CEE and Renewables Under AB 32 Are Not Supported by the E3 Model and Would Impose Excessive and Ineffective Cost Burdens on Customers

AB32 directs the ARB to reduce GHG emissions in a manner that "minimizes costs and maximizes benefits."[48/] Direct regulations that push programs goals to possibly unreachable targets run afoul of the directive to minimize costs and may place the AB32 GHG emissions reduction goal in peril.[49/] PG&E agrees with the comments of many parties urging caution in adopting expensive set-asides or new regulatory mandates for the purpose of meeting AB32 GHG reduction goals.[50/] Unrealistic programs and "command and control" mandates have high costs and implementation risks and will limit the efficiencies of the market.

For example, several parties[51/] argue that precisely because 33% renewables is too expensive to occur under a cap and trade regime, a 33% RPS "command and control" mandate is necessary "to make it happen." Such an argument presumes that the policy goal of AB32 is 33% RPS, not reducing GHG in the most cost-effective manner. Such an argument also assumes that "waving a wand" of a new regulatory mandate will make it happen. For example, some parties argue that the 33% mandate is needed to

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48/ Health and Safety Code section 38501(h).

49/ Health and Safety Code section 38501(g) states the Legislature's intent "to ensure that electricity and natural gas providers are not required to meet duplicative or inconsistent regulatory requirements" under AB 32. See also Health and Safety Code section 38562(d)(2) that requires that AB 32 regulations provide for reductions "in addition to" "any other greenhouse gas emission reduction that would otherwise occur," and Health and Safety Code section

50/ E.g., DRA, p. 47; WPTF, p. 25; Sempra, pp. 39-42; TURN, pp. 22-29

51/ Cal Wind Energy, GPI, NRDC/ UCS, p. 32.

provide investment security to renewables companies, attract investment capital, overcome regulatory barriers, and maintain stable investment in renewables.[52/]

Even as they are ignoring or minimizing the many regulatory proceedings designed to address the challenges of reaching 20% RPS, these parties are not arguing that 33% RPS is needed to meet AB32 emissions reductions goals, but are arguing that a 33% RPS *is an end in itself.*.

Fixed mandates, without regard to technical or economic feasibility, are ineffective public policy tools. As stated above, program set-asides and new regulatory mandates should only be considered when the GHG abatement measure is low-cost and other market failures exist. A 33% RPS mandate does not pass this test.

Several parties agree with PG&E's position. Parties concerned about excessive dependence on RPS and CEE to meet AB32 goals include TURN, DRA, SCE, FPL Energy Management, Morgan Stanley, and Calpine.[53/] TURN questions the value of spending over a billion dollars a year to move from the low-EE scenario to the high-EE scenario, only achieving "minimal" emissions reductions.[54/] Parties emphasize that if RPS and CEE are cost-effective carbon reduction solutions, the market will provide the incentive to enact these measures. Once the cap is put into place, programmatic approaches for the purpose of GHG reductions may include inefficient policies that may increase costs. Such approaches should be used when the GHG abatement measure is

52/ NRDC/UCS, p. 32.

53/ TURN, p. 29; DRA, p. 50; FPL Energy Management, p. 12; Morgan Stanley, pp. 19- 20; Calpine, p. 21; SCE, pp. 40- 41, 44- 45, 49.

54/ TURN, p. 29.

assuredly low cost and other market failures (e.g. the owner-tenant problem) exist.[55/] For all these reasons, it is premature to mandate specific levels of energy efficiency and renewable power procurement outside the context of the whole portfolio of carbon reduction strategies.

Certain parties oppose a cap and trade system or desire strict limitations.[56/] These parties, including several POUs, believe that reductions should occur through programs only. PG&E notes that POUs will still be able to pursue all of these programs even if the electricity sector as a whole is part of a cap and trade program. In general, CO_2 is ideally suited for management within the cap and trade context. With GHGs, the location or time of emissions is unimportant. Command and control regulations work well when technology solutions are developed and specific. On the contrary, CO_2 is a pollutant emitted across industries that may have very different marginal costs of reduction. It is not likely that California policy makers will be able to achieve the same cost efficiencies of a cap and trade market only through prescriptive, command and control program measures.

B. Cap and Trade and Energy Programs Are Not Independent or Mutually Exclusive, and Therefore AB 32 Should Not Specify Percentages of Emissions Reductions from Both

The ARB, CEC, and PUC should not assume that new "command and control" programs and mandates will provide a certain percentage of reductions. While the ARB has recently stated that it may be possible for 60% of reductions to come from "programs," this figure is highly uncertain and does not account for the fact that cap a

55/ Morgan Stanley, pp. 19- 20.

56/ CMUA, p. 2 ; CUE/ CURE, pp. 2- 3 ; NCPA, pp. 8- 9 ; SCPPA, pp. 3- 4.

trade and energy programs are not mutually exclusive. Caution should be used when citing any absolute abatement potential from any measure. If the cap is set at an extremely artificially low level because of assumptions of what aggressive regulatory mandates will bring and the mandates fail to deliver the forecast emissions reductions, high demand may put extreme upward pressure on prices. Not only will California pay for expensive mandates that may not succeed, but consumers will have to pay again as GHG abatement costs are driven up because of investment diverted to comply with the "command and control" mandates. It is very risky and expensive for policymakers to assume an unrealistic level of reductions through discrete programs or mandates, especially an exact percentage that forms the basis of the overall emissions reduction goals themselves.

C. Equal and Comparable RPS and CEE Programs Should Be Implemented by Investor Owned Utilities and Publicly Owned Utilities

PG&E agrees with WPTF and TURN that if certain energy programs and mandates are assumed in place for energy efficiency and renewable procurement as part of AB 32 emissions reductions, those programs should apply to non-CPUC jurisdictional publicly owned utilities (POUs) as well as investor-owned utilities.[57/] As PG&E noted in our opening comments, the facts indicate POUs have not pursued CEE as aggressively as investor-owned utilities.[58/] Thus, the emissions reduction potential inherent in CEE savings in POU service territories dwarfs the potential available in investor-owned utility service territories. Uneven application of state energy policy

57/ WPTF, p. 25; TURN, pp 28- 29.

58/ PG&E Opening Comments, June 2, 2008, pp 88- 89.

results in the 30% of the load served by POUs and other electric service providers having greater GHG intensity. SCPPA, NCPA, and LADWP apparently agree that POUs should take strong programmatic measures but do not appear to agree on how to ensure that the measures actually are implemented.[59/] Extending CEE targets to POUs will support achievement of low-cost GHG abatement opportunities. It will also ensure that state policy is enforced consistently and that POUs contribute their fair share to GHG emissions reductions.

D. Natural Gas Efficiency Codes and Standards Should Be Explored

PG&E supports exploring natural gas energy efficiency measures, such as time-of-sale energy efficiency requirements, appliance feebates, and building code standards for solar water heaters.[60/] In addition, PG&E signed the state's first biomethane contracts and supports examining policies to increase use of this resource. These measures and programs can be explored through existing programs at the CPUC and Energy Commission, as well as other state agencies.

VII. MODELING ISSUES

A. Several Parties Misuse or Misinterpret the E3 Modeling to Support Their Positions

As PG&E stated in our opening comments, the E3 model provides useful policy insight. However, we have noted that a few parties have made statements in their opening comments that misinterpret E3 model results. For example, LADWP concludes:

> . . .the E3 modeling states that utility rates will increase, not decrease, under cap-and-trade, irrespective of allocation methodology with no environmental benefit over existing policies and programs (i.e. reference

59/ SCPPA, p. 15; NCPA, pp. 39- 41; LADWP, pp. 4, 6.

60/ NRDC/UCS, pp. 35- 37.

case of 20% RPS and existing energy efficiency goals).[61/]

This conclusion is incorrect because the E3 model in fact does not estimate utility costs under a multi-sector cap and trade program. The main indicator of the expense of a cap and trade program, the allowance price, is *an input* to the E3 model, not an output. To support LADWP's statement, E3 would have had to model the abatement curves across all sectors, offsets, and cost containment measures. These tasks were not part of the E3 scope of work. Additionally, policy makers and LADWP should keep in mind that the cost efficiencies from a cap and trade program also stem from what cannot be modeled, even in more sophisticated models like BEAR and Energy 2020. Uncertainty, imperfect foresight, and innovation to reduce GHG emissions from technology not currently deployable all cannot be modeled. Thus, LADWP's affirmations that the modeling supports LADWP's position that cap-and-trade is a cost adder for California consumers are without merit.

Although EPUC/CAC asserts that the "E3 model demonstrates that encouragement of CHP will further the state's emission reduction efforts in a cost-effective manner,"[62/] the model does not support such an assertion. Rather, the E3 model suggests that CHP deployed under the specific circumstances modeled lowers GHG emissions, but only under those specific circumstances. CHP with the emissions characteristics modeled in the GHG calculator that displaces BAU thermal load furthers the state's emissions reduction efforts. Unless CHP is truly efficient and serving existing or BAU needs, it will not reduce emissions. CHP assumed to meet non-existent

61/ LADWP, p. 7.

62/ EPUC/CAC, pp. iii, 41- 42, 63.

thermal needs may increase GHG emissions.

Finally, GPI claims that the E3 model "demonstrates that current programmatic goals for EE and the RPS by themselves are not sufficient to provide the level of emissions reductions needed to achieve the AB 32 targets in the electricity and natural-gas sectors."[63/] This statement presumes knowledge of what those AB32 targets in the electricity and natural-gas sectors are. As PG&E stated in the opening comments, if the emissions levels of 1990 are the goal, then E3 models the sectors meeting the goals through existing RPS and CEE mandates. GPI also states that the 33% target avoids 22 – 35 million tons CO2e compared to the 20% target. PG&E ran the calculator and found that the difference between the two in the Base and Aggressive cases is 20 MMT and 17 MMT, respectively.

B. PG&E Agrees that Some E3 Inputs Should Be Revised or Updated

Natural Gas Prices: Several parties suggest that the natural gas price forecast used for 2020 is too low.[64/] NRDC suggests both raising and lowering natural gas prices, noting both recent price trends and that GHG regulation may curb demand.[65/] PG&E notes that there are many causes of recent high natural gas prices and not all of these impact 2020 price forecasts. Fundamentals driving 2020 prices may not have changed. For purposes of consistency and to take advantage of work in another proceeding, PG&E suggests using the gas price forecast methodology developed for the 2008 MPR in this proceeding.[66/]

63/ GPI, p. 29.

64/ CalWEA, pp. 9- 10; CEERT, pp. 16- 19; Solar Alliance, pp. 3, 9- 10; NRDC/UCS, p. 47.

65/ NRDC/UCS, pp. 46- 47, 50.

66/ PG&E has also suggested that this gas price forecast methodology be used in the upcoming LTPP

Energy Efficiency: PG&E suggests using the Itron low goals case in the Aggressive Case. Comments by Sempra, SCE, and TURN bolster this recommendation.[67/] SCE states that Itron staff analysis indicates that achieving above 80% of economic potential is highly unlikely. TURN questions the cost effectiveness of the Itron mid and high goals cases.[68/] Based on parties' comments and SCE and Sempra's questioning of model results, PG&E recommends that a stakeholder working group be convened to understand the E3 inputs on energy efficiency levels and costs, including the derivation of the CEE embedded in load.

Renewables: Parties comment that the costs of renewables appear both too low[69/] and too high.[70/] Costs have been increasing for both conventional and renewable resources, perhaps even more so for renewable than conventional generation. Differing cost information highlights the need to conduct sensitivities and couch results with uncertainty. Additional uncertainty exists in the renewable resource development potential, as mentioned by NCPA. Uncertainty in renewables costs and development potential underscores the importance of not using program mandates.

Wind Capacity Factor: Wind capacity values should not be increased to unrealistic levels based on assumptions of technology improvement. NRDC suggests that the capacity factor for class 4 wind be raised to 43%.[71/] However, the CEC uses a

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analysis.

67/ Sempra, p. 40; TURN, pp. 23- 26.

68/ TURN, pp. 23- 26.

69/ SMUD, p. 36.

70/ CalWEA, NRDC/ UCS, CEERT.

71/ NRDC/UCS, p. 50.

capacity factor of 34% for class 5 wind.[72/] Therefore, E3 should use the wind capacity factors it originally suggested, not inflated capacity factors based on new technology assumptions or national averages.

Transmission for Renewables: Transmission costs to integrate renewables developed far from load centers are not likely to reduce transmission needed for load growth and reliability. The full transmission costs for renewables should be attributed to the renewable generation for modeling purposes.[73/] Additionally, PG&E shares EPUC/CAC's concern that wind integration costs may be higher than modeled at high levels of wind penetration.[74/] To account for this, PG&E believes that E3's original estimate of wind integration costs should be used.

CHP Penetration in the Aggressive Case: The Aggressive case should assume that CHP is installed at the levels of the CEC Market Potential Report base scenario, as per E3's original intent. PG&E does not believe that the potential exists for the Moderate Market scenario, much less the CEC High Deployment scenario. Use of the High Deployment Scenario is inappropriate as, among many other assumptions, it assumes the "the rapid development and deployment of advanced technology."[75/] E3 assumes no technology change in the Scenarios.

VIII. CONCLUSION

PG&E commends the CPUC and Energy Commission and parties to this

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72/ http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF.

73/ NRDC/UCS suggests that transmission for 33% RPS will defer transmission needed for load or reliability (NRDC/UCS, p. 48.)

74/ EPUC/CAC, p. 75.

75/ http://www.energy.ca.gov/2005publications/CEC-500-2005-060/CEC-500-2005-060-D.PDF, pg. vii.

proceeding for the exhaustive, comprehensive and thoughtful record that has been developed on these extremely important AB 32 implementation issues. Where parties disagree, we disagree not over AB 32's goals, but over the most cost-effective, efficient means of achieving the goals in a way that maintains and enhances California's environmental leadership while at the same time managing the costs to California's consumers and businesses.

We are about to enter a new phase of AB 32 implementation, in which the two commissions and the ARB work together on a multi-sector scoping plan that would apply AB 32 to all sectors and emissions sources in California, not just the electric and gas sector. PG&E expects in this upcoming phase that parties in the electric and gas sectors are likely to be far more in agreement than disagreement. However, the implementation details of this new phase will be no less important than in the earlier phases. In particular, modeling and evaluation of the relative costs and benefits of different emissions reduction measures in different sectors, combined with design of a multi-sector cap and trade program, will be very important priorities for all parties and the public.

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PG&E looks forward to working with all parties and the ARB, CPUC, and Energy Commission as we move forward with successful implementation of AB 32.

Respectfully Submitted,

CHRISTOPHER J. WARNER

By: /s/

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Dated: June 16, 2008

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of **"REPLY COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON ADDITIONAL ISSUES RELATED TO IMPLEMENTATION OF AB 32 IN THE ELECTRIC AND NATURAL GAS SECTORS"** on the parties listed in the official service list for R.06-04-009 by

- transmitting an e-mail message with the document attached to each party on the official service list providing an email address; or
- by first-class mail, postage prepaid, to each party on the official service list not providing an email address.

Executed on June 16, 2008, at San Francisco, California.

/s/

MARTIE L. WAY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies.	Rulemaking 06-04-009 (Filed April 13, 2006)

OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON ADDITIONAL ISSUES RELATED TO IMPLEMENTATION OF AB 32 IN THE ELECTRIC AND NATURAL GAS SECTORS

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Dated: June 2, 2008

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OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON ADDITIONAL ISSUES RELATED TO IMPLEMENTATION OF AB 32 IN THE ELECTRIC AND NATURAL GAS SECTORS

INTRODUCTION

Pursuant to the rulings of the Administrative Law Judges dated April 16 and 22, 2008 and May 1, 6, 13 and 20, 2008, Pacific Gas and Electric Company (PG&E) provides its opening comments on additional issues related to implementation of greenhouse gas (GHG) regulatory strategies under AB 32 in the electric and natural gas sectors. PG&E's comments follow the topic headings and outline in the May 13, ALJs ruling.

I. EXECUTIVE SUMMARY

PG&E is a charter member of the United States Climate Action Partnership and the first investor-owned utility to support enactment of California's historic climate change legislation, AB 32. Our customers have invested and continue to invest in customer energy efficiency programs and a clean electric generating portfolio, so that our greenhouse gas emissions are among the lowest of any utility in the nation. During the 2006-2008 period alone, PG&E expects to spend more than $942 million of customer funded revenue for various customer energy efficiency programs that will save more than 3,000 gigawatt hours of electricity and 47 million therms of natural gas. The greenhouse gas emissions associated with the electricity we provide are among the lowest of any large utility in the country, approximately 40 percent of the CO2 emitted by the average utility. Over 50 percent of the electricity we deliver to our customers on average today comes from sources that emit no greenhouse gases at all.

PG&E approaches AB 32 implementation guided by three key objectives. We recommend that AB 32 implementation:

1. Ensure environmental integrity through mandatory, real and verifiable reductions;

2. Manage costs to California consumers and businesses by pursuing cost-effective reduction strategies and a consumer-oriented allowance allocation approach; and

3. Solidify California's national leadership role on climate change by creating a model program that can be integrated effectively with future regional, national and international programs.

There is no single "silver bullet" to address the challenge of climate change. All technologically feasible and cost-effective options should be on the table as part of AB 32 implementation, and the California Public Utilities Commission (CPUC), California Energy Commission (CEC), and the Air Resources Board (ARB) should carefully consider a combination of traditional regulatory programs and market-based initiatives. PG&E believes that the most effective and efficient of these potential market-based tools would be a cap-and-trade regulatory program with broad, economy-wide participation. Market-based strategies—such as cap and trade—provide economic incentives and the flexibility to cut emissions in the most innovative and cost-effective ways. This approach is key to driving development of the next generation of clean, highly energy-efficient technologies and practices. PG&E recommends that California pursue a properly designed, broad-based, multi-sector cap-and-trade system with clear and consistent rules and strong cost containment and market oversight– coupled with customer energy efficiency, renewables and demand-side management programs. We believe a properly designed, broad-based, multi-sector cap and trade program will reduce greenhouse gas emissions, diversify California's energy supply mix and help to minimize customer costs. For these reasons, we believe that inclusion of a cap and trade program as part of AB 32 implementation is both "necessary" and "desirable."

Regardless of the regulatory approach taken under AB 32, PG&E remains committed to the 20 percent Renewables Procurement Standard (RPS) target, customer energy efficiency (CEE) and Demand Side Management (DSM) programs, including deployment of "Smart Grid" technology, and clean, distributed generation. These are independent, free-standing programs that complement AB 32 and should not be displaced or duplicated by AB 32 mandates. PG&E's customers have made and will continue to make significant investments in these best-in-class programs, which serve as a model for other utilities, states and the rest of the country to follow.

II. GENERAL ISSUES

10. What evaluation criteria should be used in assessing each issue area in these comments (allowance allocation, flexible compliance, CHP, and emission reduction measures and policies)? Explain how your recommendations satisfy any evaluation criteria you propose.

PG&E Response:

In addition to the three over-arching objectives listed in the Executive Summary above, each issue relating to AB 32 implementation should be evaluated to determine if it includes the following elements and meets the following criteria:

Standardized emissions reporting is an essential first step and must form the basis of AB 32's implementation. Developing consistent and coordinated greenhouse gas emission inventories and protocols for standard reporting and accounting of greenhouse gas emissions, as previously recommended by PG&E in this docket and before the ARB, is fundamental to establishing a credible reduction program that is capable of tracking and verifying progress toward emissions goals and facilitating a tradable emissions allowance system. PG&E was a Charter Member of the California Climate Action Registry and a founding reporter of The Climate Registry, which is now comprised of 39 states, eight Canadian provinces, six Mexican states and three Native American tribes and working to develop a consistent set of reporting standards and protocols. We believe the ARB's recent greenhouse gas reporting regulations as modified consistent with PG&E's comments will provide a sound basis for AB 32 implementation.

Equitable apportionment of reduction obligations to ensure that all sectors pay their fair share. Statewide reduction obligations should be apportioned under ARB's scoping plan and AB 32 regulations to ensure that no single sector, nor its customers, assumes a disproportionate financial burden. To this end, PG&E has submitted comments to US EPA in support of California's request for a waiver from federal preemption under the Clean Air Act for the State's motor vehicle greenhouse gas emissions standards. While these standards will not entirely address greenhouse gas emissions from the transportation sector, they are an important step toward assuring that every sector bears its fair share of emission reductions.

Early actions should be recognized and credited under specific ARB-adopted protocols and regulation, not penalized. ARB should implement expedited "early action" rules under AB 32 to recognize "early actors" that have already made investments resulting in significant greenhouse gas reductions. Ignoring prior efforts sends a signal that stepping up, taking risks, and taking responsibility is not something valued by policymakers. Those that have pursued a significant amount of energy efficiency and renewables resources have already achieved the lowest cost emission reductions, while those that have not taken action have significant low cost reduction options still available to them. For example, incremental investment opportunities to avoid purchasing high emitting power are fewer and more expensive for low carbon utilities than those available to high carbon utilities that have more low-hanging fruit available, such as energy efficiency. Put more simply, customers of lower emitting utilities should pay less than customers of higher emitting utilities to achieve the goals of AB 32.

A clear glide path of emissions "caps" and limits must be established over the 2012-2020 period that takes a gradual but sustained approach to meeting reductions to help create a smooth transition to a low-carbon economy. This approach provides opportunity to leverage existing, cost-effective reduction technologies, while providing time for new technology solutions to be fully deployed; it also ensures a significant contribution from the electric sector toward a broader, economy-wide reduction goal. Providing a clear glide path with a longer-term target sends appropriate price signals, which will be vital for driving investment in low-carbon technologies. It is important to acknowledge that not all parties in the electric sector will start with the same carbon footprint in 2012. We believe, however, that the AB 32 compliance glide path should provide a quick transition for all emitters to take full responsibility for climate-related costs.

A broad and liquid emissions trading market should be created. Climate change is unlike any other air quality challenge, as it is truly a global issue. A robust market can be assured by including a broad spectrum of industry sectors and participants, ensuring that program design elements are scalable and consistent with other regions, and creating linkages to other existing and emerging regional programs such as the Western Climate Initiative and, ultimately, a federal or international program.

Compliance flexibility should be provided to meet AB 32's targets in a cost-effective manner. These can include banking of emissions allowances, the use of environmentally sound and verifiable carbon offsets and multi-year compliance periods. This last element is critically important to the power sector, where rain and snow-fall variability have a significant effect on year-to-year emissions. Additional market oversight and cost-control measures to address unanticipated and sustained market impacts should include use of a "price collar" within the context of managing the overall carbon budget, as described below, under which access to additional allowances would be triggered under pre-established cost and other criteria.

A "point of regulation" should be selected under AB 32 that will promote real emissions reductions and serve as a model for emerging regional, national and international programs. The point of regulation for AB 32 should be simple to administer, provide for the most accurate accounting of GHG emissions, and minimize leakage of GHG emissions. For these reasons, we are encouraged that the CPUC and CEC have recommended that ARB adopt a "First Deliverer" point of regulation for the electric sector. This would place the point of regulation on electric generators within California and on those that first import power generated outside of the state for delivery and consumption within California. Taking this approach will: (1) ensure environmental integrity through real and more verifiable greenhouse gas emissions reductions and by allowing for more accurate accounting and attribution of emissions and minimizing "leakage" of GHG emissions; (2) more directly impact generation investment decisions; (3) internalize GHG compliance costs in electric dispatch; and (4) because it focuses on actual emissions sources, it will enhance California's leadership position on climate change by serving as a model for emerging regional and national programs.

Emission allowances should be allocated and distributed in a manner that most directly mitigates costs to customers, rewards --rather than punishes-- early action; promotes early investment in clean technologies; advances energy efficiency; avoids windfalls; and positions California as a model for federal, regional and international programs.

These allocation principles can be implemented by:

- Recognizing that the customer at the end of the energy supply chain—like the households and businesses that we serve—will ultimately bear a substantial share of the costs associated with the regulation of greenhouse gas emissions. The allocation of allowances under a cap and trade system should be used to help mitigate these costs.
- Avoiding creating unintended economic benefits for companies by granting free allowances to generators who would not be required to pass on this value to utility customers.
- Avoiding penalizing early actors and their customers for investments made prior to AB 32 that have resulted in significant greenhouse gas benefits to date.
- Ensuring that customers of lower emitting utilities pay less than higher emitting utilities to achieve the ultimate goals of AB 32.
- Quickly transitioning AB 32's overall emissions limits to a system that requires all emitting resources to take full responsibility for their climate-related costs.
- Accelerating the development and deployment of new technologies, including renewable generating technologies, end-use energy efficiency technologies, and carbon capture and storage technologies.
- Successfully positioning California as an overall low-emitting state in the emerging federal debate on greenhouse gas allowance allocation among higher- and lower-emitting states.

Decisions made regarding the point of regulation and to whom emissions allowances are allocated are separate and distinct public policy issues with significant economic and environmental implications, and should be addressed as such. California has an opportunity to develop an allowance allocation methodology that can both achieve the public policy objectives listed above and also serve as a model for regional, federal and international policymakers.

In the utility sector, customers will bear the lion's share of greenhouse gas reduction costs regardless of where the point of regulation is placed. For this reason, The National Commission on Energy Policy, the California Market Advisory Committee and the Natural Resources Defense Council in separate reports have each outlined an allowance allocation methodology that we find compelling and believe can avoid the inequities and the inefficiencies that stem from an Acid Rain-style generator based allocation approach, while benefiting electricity consumers. Rather than allocating free allowances to power plants, PG&E recommends that allowances be allocated to utilities on behalf of their customers. Utilities would in turn be required to sell allocated allowances to sources regulated by the program through independently administered auctions, returning the proceeds to their customers through rebates, credits or other programs that help to mitigate costs or reduce demand. In this way, the value of the allowances flows directly to energy consumers, who ultimately bear the costs of the program. Of course, the management and sale of allowances should be subject to oversight by the State and by local boards of customer-owned utilities, and allowances should be sold to utility-owned and merchant generation on a non-discriminatory basis.

In addition to achieving the goal of mitigating consumer and business costs, the allocation of allowances among different sources of emissions can help achieve the other public policy objectives listed above. For example, by allocating allowances based on a metric that rewards efficiency, as suggested in the California Market Advisory Committee Report, as opposed to an historical emissions based approach that continues to support the use of higher-emitting, less efficient resources, the allocation approach can send appropriate investment signals and simultaneously encourage early action. Therefore, as discussed in more detail in Section III, below, allowances should be allocated based on an updating output metric such as retail sales, adjusted for verified energy efficiency savings.

Finally, allocation of allowances for the benefit of consumers also must take into account any disproportionate impacts on low income communities, as required by AB 32.

11. Address any interactions among issues that you believe the Commissions should take into account in developing recommendations to ARB.

PG&E Response:

Nearly all of the issues addressed in these comments are inter-dependent and should be addressed and evaluated as such in designing and implementing an overall AB 32 regulatory program. In other words, only when all of the elements of the program are fit together into a comprehensive regulatory scheme, can the costs and benefits of the entire program be evaluated.

This is why key assumptions underlying the AB 32 program, such as abatement costs across all sectors of the economy, must also be identified and agreed to on a holistic, all-in basis. Conversely, the most likely source of failure for AB 32 is to implement the regulatory program on a piecemeal, issue-by-issue basis. For all these reasons, the CPUC, CEC and ARB should act and implement AB 32 as if it were a single, integrated program with elements that are highly inter-dependent with each other, and with the ultimate costs and benefits of the program capable of being judged only after the whole program has been designed and presented for public review and evaluation.

12. In establishing policies regarding allowance allocation, flexible compliance, CHP, and emission reduction policies, what should California keep in mind regarding the potential transition to regional and/or national cap-and-trade programs in the future? Are there policies or methods that California should avoid or embrace in order to maximize potential compatibility with other cap-and-trade systems?

PG&E Response:

The most important point that policymakers should keep in mind is that climate change is a global, not a local, problem. Accordingly, California must design AB 32 regulations with the express intention and anticipation that California's program can—and, indeed, must—be transitioned into an effective national and global program as soon as practicable. Conversely, California must avoid designing AB 32 regulations in any way or form that is parochial or overly "California-specific" in addressing the aspects of climate change that are global, not local. In particular, California should avoid regulations that are limited in geographic scope or which "de-position" or "de-link" California from common elements of a regional, national or international greenhouse gas program. As discussed in more detail in the sections below, some examples that California should avoid include, *inter alia*, geographic or quantitative limits on high-quality offsets; emissions reporting or measurement protocols that are inconsistent with national or international standards; discriminatory treatment of sources of emissions that are located out of state; unwillingness to provide for reciprocal treatment and recognition of programs undertaken by other states or nations; and California-only emissions limits that discriminate against California consumers and businesses and promote and enable "leakage" of jobs, economic activity and associated emissions to neighboring states which do not have comparable GHG programs.

In order to maximize the compatibility of California's program with national and international programs, it is also essential that California endorse and implement robust and broad-based policies which support GHG emission offset projects; flexible compliance and cost containment policies, including the "price collar" approach discussed in more detail below; and policies that ensure that the reliability of electric and gas utility services to California consumers and businesses is preserved and enhanced, particularly for low income consumers and communities.

13. For each issue addressed in your comments, do you have any recommendations about the level of detail and specificity regarding the electricity and natural gas sectors that ARB should include in the scoping plan? Is there enough information in the record in this proceeding to support that level of detail and specificity? What additional information and/or analysis may be needed before ARB finalizes its scoping plan? What determinations regarding the electricity and natural gas sectors should ARB defer for further analysis after the scoping plan is issued? Please be as specific as possible about GHG-related policies for the electricity and natural gas sectors that you recommend be resolved this year, and policies that you believe should be deferred for further analysis after the scoping plan is issued.

PG&E Response:

ARB's scoping plan should include an outline of every significant element required to be included in the plan pursuant to Health and Safety Code section 38561, including, but not limited to:

- Identification of all sources and categories of sources to be regulated under AB 32;
- Identification and recommendations on all direct emissions reduction measures, alternative compliance mechanisms, and potential monetary and non-monetary incentives for achieving AB 32's overall 2020 targets;
- Detailed consideration of all impacts of the plan on energy-related matters, including electrical generation, reliable and affordable electric service, availability of statewide fuel supplies, load-based standards and limits, as well as how the scoping plan is complementary and non-duplicative of policies, programs and regulations adopted by the CPUC and Energy Commission.
- Evaluation of the total potential economic and non-economic costs and benefits of the scoping plan, using the best available economic models, emission estimation techniques and other scientific methods.
- Determination as to whether the plan can be implemented in an efficient and cost-effective manner.
- Consideration of the relative contribution of each source or category of sources to statewide greenhouse gas emissions, in order to avoid disproportionate allocation of emissions reduction responsibility among any one source or category of sources.
- Consideration of all relevant information relating to greenhouse gas reduction programs in other states, localities, and nations, including the northeastern states, Canada and the European Union.

In particular, for the electric and gas sectors, the scoping plan must include an outline of the "all-in" apportionment of emissions reduction responsibility among all the sources and categories of sources of emissions in all sectors of the California economy, not just the electric and gas sectors. This apportionment must take into account the relative differences in abatement costs and the availability of technologically feasible abatement measures among different sources and categories of sources across all sectors of the California economy, not just within one sector such as the electric or natural gas sector.

Likewise, the scoping plan must be designed to meet the criteria for AB 32 regulations under Health and Safety Code section 38562, including ensuring that (1) entities that have voluntarily reduced their greenhouse gas emissions prior to the implementation of AB 32 receive credit for their early emissions reductions; and (2) activities to be taken under the scoping plan to comply with AB 32 do not disproportionately impact low-income communities.

PG&E recognizes that the detail in the scoping plan will be less than that in the final AB 32 emissions limits and measures to be adopted by January 1, 2011. However, the scoping plan must support key issues and elements with sufficient data and modeling to adequately identify policy alternatives and support policy choices. In addition, the scoping plan must contain sufficient detail on all key elements in the final regulations so that the public and affected parties have sufficient knowledge and understanding to evaluate and comment on the *overall* costs and benefits of the AB 32 program, not just individual components. In this regard, PG&E notes with concern that, to date, ARB has released no initial proposals or guidance on certain key elements of the scoping plan, including, *inter alia:*

1) apportionment of emissions reduction responsibility and distribution of emissions allowances among different categories of sources and sectors of the California economy, especially the transportation sector;

2) economic modeling and technological feasibility studies on the relative costs and benefits of different emissions reduction measures across all sectors and categories of sources, especially sectors and sources other than the electric and natural gas sector;

3) proposed interim emissions reduction targets for each source or category of sources for the compliance period from January 1, 2012 through December 31, 2020;

4) how early actions and voluntary reductions prior to 2012 are to be "credited" under AB 32;

5) how "leakage" in the form of displacement of AB 32-regulated emissions sources by unregulated sources outside the State will be minimized; and

6) how the AB 32 regulations will avoid disproportionate impacts on low-income communities, including low-income consumers of electricity and natural gas supplied by California's electric and gas utilities.

PG&E believes that preserving the reliability and affordability of electric and natural gas service is fundamental to a sound California economy. The achievability and cost of emissions reductions in these sectors must carefully account for these critical and unique considerations.

PG&E looks forward to continuing to work with the ARB, CPUC, Energy Commission and all interested parties to ensure that the scoping plan addresses these issues. However, we remain concerned that the deadline fast approaches for issuance of the scoping plan, with key elements still to be developed.

1. Please explain in detail your comprehensive proposal for flexible compliance rules for a cap-and-trade program for California as it pertains to the electricity sector. Address each of the cost containment mechanisms you find relevant including those mentioned in this ruling and any others you would propose.

a. Discuss how your proposal would affect the environmental integrity of the cap, California's ability to link with other trading systems, and administrative complexity.

b. Address how your various recommendations interact with one another and with the overall market and describe what kind of market you envision being created.

PG&E Response:

The same question appears in Section IV, and PG&E's proposals are presented in detail there. In brief, PG&E proposes:

- Stringent quality requirements for emission offsets.
- Unlimited use of high-quality emission offsets.
- A multi-year compliance period.
- Unlimited banking of allowances.
- Credit for early action.
- A gradual and sustained trajectory for emission reductions.
- A cost-containment mechanism that operates within an overall emission budget, to produce a CO2 price floor and price ceiling ("price collar") that increase over time.

As discussed, in more detail below, PG&E's proposals for flexible compliance are similar to those adopted or being evaluated at the federal level as well as under other greenhouse gas programs, including the European Union, Canada, Western Climate

Initiative and the RGGI program in New England. As such, PG&E's proposals would help California link more readily with these regional, national and international programs.

All of the proposals rely on a multi-sector, well-designed, broad-based and liquid cap-and-trade market, plus a robust availability of high-quality, verifiable offsets, to "drive" the maximum feasible and cost-effective emissions reductions over the shortest period of time. Establishing a successful market requires balancing the need to achieve sustained emissions reductions and to do so at reasonable cost. This "up-front" success reduces the likelihood that cost containment mechanisms will be triggered. However, especially at the outset, PG&E believes more vigilant flexible compliance and cost containment mechanisms provide useful insurance while we all gain experience with these new markets.

Thus, the flexible compliance mechanisms, especially price "collars" during the initial start-up of "cap and trade" as described in more detail below, plus aggressive market monitoring mechanisms, can provide this "insurance policy," and cap-and-trade can contribute to the success of California's emissions reduction program.

2. With respect to flexible compliance mechanisms, what should California keep in mind in designing its system when considering the potential transition to regional and/or national cap-and-trade programs in the future? Are there mechanisms that California should avoid or embrace in order to maximize potential compatibility with other cap-and-trade systems?

PG&E Response:

In designing its flexible compliance and market-based mechanisms, California above all should recognize the over-arching principle that climate change is a *global* problem, not a single state or nation's problem. Thus, all AB 32's flexible compliance and market mechanisms should be designed as carefully as possible to be compatible with and transferable to the regional, national and international levels, and to provide reciprocal benefits to all climate change programs outside California as well as those within California.

In PG&E's view, access to national and international offsets, limited only by quality, will facilitate integration of a California cap and trade program with other such programs. If California were to choose to initially implement a California-only cap and trade market while waiting to link its program to regional, national or international programs, it should be recognized that a California-only market is inherently a narrower market than a regional or national market. As a result, the design of flexible compliance and cost containment mechanisms would be essential to provide added assurance that emission reductions can be obtained at a reasonable cost. To the extent this results in such mechanisms at a state level that are not established or needed at a national or international level, these mechanisms can and should be designed to be easily transitioned or modified upon implementation of a national or international program.

3. What evaluation criteria should be used in assessing flexible compliance options?

PG&E Response:

Flexible compliance options should ensure that sustained progress is made by all sources and categories of sources toward achieving the maximum feasible emissions reductions, including the 2020 targets set by AB 32. At the same time, flexible compliance options should provide California consumers, businesses, farmers and governments that are subject to AB 32's regulations the flexibility to meet those regulatory targets without inequitable or economically disruptive impacts.

Specifically, these criteria should include: 1) maintaining a long-term path toward sustained emissions reduction; 2) doing so at a reasonable cost without extreme price volatility; 3) supporting establishment of a long-term price that attracts needed investment and sets the stage for achieving the 2020 target and reductions beyond the 2020 target; and 4) integration with national and international programs.

PG&E notes that this last criterion does not require that California mechanisms must be absolutely identical to future national or international mechanisms, but that California's program be workably linkable to and able to integrate with such programs.

This requires a "balancing test" and tradeoffs that may not please every party or constituency, but which achieve an overall equitable program that demonstrates California's ability to lead the country and the world on achievable greenhouse gas emissions reduction measures and programs.

III. GHG EMISSION ALLOCATION AND AUCTION POLICIES AND METHODS

A. Detailed Proposal

1. Please explain in detail your proposal for how GHG emission allowances should be allocated in the electricity sector.

PG&E Response:

PG&E believes that allocation of GHG emissions allowances should be designed to achieve three over-arching objectives:

1. Speed the transition to a low-carbon economy, while achieving sustained and significant long-term GHG reductions;
2. Mitigate the costs incurred by customers to achieve these long-term GHG reductions; and
3. Position California well and demonstrate leadership in the context of emerging regional, federal and international GHG programs.

Allowance allocation can be a key component to creating the right incentives for long term GHG reductions as well as an important lever with which to manage costs to consumers. However, there are several critical design elements that will support these goals and enable the CPUC, CEC and CARB to design a system that results in significant emissions reductions at a reasonable cost. These additional elements, several of which are covered in this filing, include:

- Establishing a reasonable emissions reduction trajectory and allowing for flexibility in meeting annual compliance obligations that recognize both the availability of low-carbon technologies and the annual variability that will occur in emissions as a result of climatic and economic conditions beyond the control of complying entities.
- Equitable and proportionate reduction contributions from those sectors that will participate in the climate program through command and control measures or other initiatives, as well as fair apportionment of compliance responsibility for those sectors included in a cap and trade program;
- Cost containment measures, including well-established and unlimited use of high-quality offsets and other methods to mitigate costs to customers.

Based on the over-arching objectives listed above, PG&E recommends that in the electric sector, the value of emissions allowances be allocated to utilities for the benefit of their customers. Utility customers will bear the ultimate costs of meeting the sustained GHG reduction goals in the electric sector, and, therefore, those customers should receive the value of the allowances used to achieve those reductions to help mitigate their compliance costs. This approach is consistent with the interim decision by the CPUC and CEC, which has recommended that the majority of revenues from auctioning of allowances be used to benefit end-use energy consumers.

The most equitable methodology by which to allocate emission allowances in the electric sector, and the one we believe will best expedite the transition to a low carbon economy, is based on an updating output metric such as retail electricity sales adjusted for verified customer energy efficiency savings. An output-based allocation method achieves the following objectives:

- Recognizes and encourages early action, including the years leading up to 2012, as required by AB 32;
- Encourages aggressive deployment of energy efficiency and investments in low- and zero emissions generating technologies; and
- Is consistent with the recommendations the State has made on national climate change policy and supports California's leadership position in the context of emerging regional, national and international programs.

An historical emissions or grandfathering approach does not recognize prior investments made in zero or low-carbon technologies, and provides an incentive to delay such activities in the hope of accumulating more allowances. Adopting such an approach for AB 32 also would set a precedent in de-positioning California relative to other regions in the United States in the design of a federal program. As the State recently noted in its recommendations on federal climate policy, "Free distributions based solely on historic emissions will only serve to reward the biggest polluters at the expense of consumers and penalize early leadership."[1]

PG&E recommends that the value of allowances be allocated directly to local electric utilities to be held and used for the direct or indirect benefit of their customers, including a provision mandating that the allowance value be returned to utility

[1] State of California, "Recommendations for Federal Climate Policy", October 4, 2007.

customers through customer rebates and energy efficiency programs. The local electric utility would receive the value of allowances based on its proportional share of electricity deliveries. PG&E supports auctioning allowances through an independent entity on a nondiscriminatory basis to electric generating facilities and first deliverers covered by the emissions cap. The revenues generated through the auction would be allocated to local utilities for the benefit of their customers based on a predetermined allocation method. Local electric utilities are uniquely positioned for this role because: (1) they have established service relationships with electric customers; (2) they are subject to state utility commission or governing board oversight; and (3) many have existing energy efficiency and low-income programs to build on.

An auction approach is the best mechanism to encourage market liquidity and to create equal access to allowances for both utility owned and independent generation. It also works well in the context of PG&E's proposed "price collar" because a centralized auction can easily establish a minimum acceptable bid. Finally, an auction approach also has the benefit of creating a transparent price signal for the market. The ETAAC members agree there is a benefit to holding auctions, including price discovery:

> *"Some amount of auctioning is necessary for establishing a clear and early price signal. Auctions expose the true market-clearing price for all GHG emissions under a cap, whereas free allocation systems conceal mitigation prices for emission reductions that are not traded."* - ETAAC Final Report February 11, 2008, page 9-4.

Any proposal which auctions a majority of allowances creates a strong incentive for clean generation and improving the efficiency of existing fossil based generation. Conversely, any amount of allowances given for free based on current or historical emissions will result in a dampening of that incentive, particularly in the early years.

PG&E supports the Market Advisory Committee's criteria to promote investment in low-GHG technologies and fuels, including CEE. To the extent allocations are made to generators based on emissions, the finite amount of capital available to invest in energy infrastructure will be transferred to high-emitting generators. This point is illustrated in a recent report from Bernstein Research which observes that allocating allowances to unregulated power generators will materially increase their earnings under various federal legislative proposals which allocate significant proportions of allowances for free to generators.[2]

PG&E's proposal is equitable to retail providers with varying emissions rates. It is true that a utility's current emissions are one element that determines the average cost to the utility customers. It is also true, however, that low emitting utilities will have fewer low cost GHG reduction opportunities because they have already captured a significant portion of these opportunities through prior investments and actions funded by their customers in electric rates. On the other hand, high emitting utilities may have a greater quantity of lower cost emission reduction opportunities within their own portfolio, namely the ability to reduce high emitting sources in their portfolio and to increase CEE program activity using allowance prices established in auctions as a benchmark.

PG&E does not support allocating allowances for free to generators. However, if it is deemed necessary to begin the program with some allowances allocated for free to generators, the amount should be small and output-based, and the transition away from this methodology should be swift. To the extent possible, the program should minimize

[2] US Utilities: the Implications of Carbon Dioxide Regulation, October 2007; Bernstein Research; Hugh Wynne and Stephen Y. Zhang.

creating unintended economic benefits or windfalls for companies by granting free allowances to generators that would not be required to pass on this value to utility customers. The incentive to act early and reduce emissions quickly is best generated through methods that do not tie the amount of allowances entities receive to current or historical emissions. Instead, efficiency and low-emitting technologies should be recognized through an output-based allowance allocation.

If the CPUC and CEC choose not to recommend a 100% output-based allocation to utilities, then the starting point should be designed in a way that results in customers of low-emitting utilities incurring lower rate increases than customers of high-emitting utilities. Such a principle should fully recognize the rate benefits of any allocation to utility-owned fossil-based generation while at the same time reducing cost shifting from high-emitting utilities and generators to low-emitting utilities and generators. Furthermore the policy should establish a mechanism where utilities are transitioned to an allocation method that holds all utilities to the same benchmark emissions rate as quickly as possible. In this way, an allocation policy design will support and be consistent with California's economic interests and environmental leadership in the development of federal legislation that treats all low-emitting states like California fairly.

The importance of this was highlighted in a letter to Senator Boxer and the entire California delegation dated October 18, 2007 (signed by representatives from SMUD, NCPA, Sempra, FPL Group, Constellation, PG&E and Calpine) urging California's Congressional Delegation to protect California's interest:

> *"As the federal climate change debate unfolds in the 110th Congress, we want to ensure that any federal climate change*

program recognizes the important contributions that California's electric generating facilities and electric customers have already made to help stabilize and reverse the nation's current emissions trends. As our companies and customers continue to make investments and eventually participate in a federal program, we are not seeking any special advantage for California, nor are we seeking to place undue burden on higher emitting states. But we do not want California to "pay twice" for having made substantial early investments to reduce its carbon footprint."[3]

10. Describe in detail the method you prefer for returning auction revenues to benefit electricity consumers in California. In addition to your recommendation, comment on the pros and cons of each method listed above, especially regarding the benefit to electricity consumers, impact on GHG emissions, and impact on consumption of electricity by consumers.

PG&E Response:

Auction revenues can be recycled to electric sector customers through a variety of methods. The CPUC/CEC's April 16 ruling identified two methods for returning revenues from allowance auctions: 1) using auction revenues to augment investments in energy efficiency and renewable energy, or 2) using revenues to maintain affordable rates. PG&E supports the use of auction revenues for both these purposes, including use for CEE programs, direct bill reduction for all customers and targeted rate relief and CEE for low income customers. Other funds could be dedicated toward utility procurement and development of carbon-free technologies, if targeted toward applied technologies most likely to directly benefit California's electricity consumers.

Direct bill reductions can be designed in a way that is not tied to the volume of electricity used by the customer and thus preserve the price signal benefits of a cap and trade program. PG&E expects that it would develop a detailed recommendation to the

[3] October 18, 2007 letter to Senator Boxer.

CPUC and CEC for the use of any allowance value returned to electricity consumers as part of AB32 implementation.

B. Response to Staff Paper on Allowance Allocation Options and Other Allocation Recommendations

8. The staff paper describes an option that would allocate emission allowances directly to retail providers. If you believe that such an approach warrants consideration, please describe in detail how such an approach would work, and its potential advantages or disadvantages relative to other options described in the staff paper. Address any legal issues related to such an approach, as described in Questions 2 – 4 above.

PG&E Response:

PG&E recommends that, for the electric sector, the value of emissions allowances should be allocated to utilities for the benefit of their customers. This is because, regardless of the point of regulation, utility customers will bear the ultimate costs of meeting GHG reduction goals, and, therefore, those customers should receive the value of the allowances used to achieve those reductions.[4]

The use of the allowance value can significantly affect the distribution of economic costs and incentives associated with meeting GHG emission targets. For the electric sector, PG&E supports the distribution of allowance value for the benefit of electricity consumers, while promoting investment in new low-carbon technologies or programs that also benefit customers and the communities we serve. Households and businesses at the end of the electricity supply chain will ultimately bear the costs - in the form of higher electricity prices - of a GHG cap-and-trade program. Moreover, AB32

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[4] See, for example, the Congressional Budget Office's Trade-Offs in Allocating Allowances for CO2 Emissions (http://www.cbo.gov/ftpdocs/80xx/doc8027/04-25-Cap_Trade.pdf) , the National Commission on Energy Policy's Allocating Allowances in a Greenhouse Gas Trading System (http://www.energycommission.org/ht/display/ContentDetails/i/1578/pid/493), and Resources for the Future's Compensation Rules for Climate Policy in the Electricity Sector. (http://www.rff.org/documents/RFF-DP-07-41.pdf.)

requires that good faith efforts be made to make available to disadvantaged communities in California opportunities to benefit from measures undertaken to reduce greenhouse gas emissions in the state. This is particularly important because low income earners are a large and growing segment of California's population. Therefore consumers should be entitled to the value inherent in the allowances in order to partially offset increased costs as well as provide capital to help these consumers transition to a low-carbon economy.

In the electric sector, the most equitable allocation methodology, and the one PG&E believes will speed the transition to a low carbon economy, is to allocate allowances based on an updating output metric. An output method, allocating allowances to utilities based on retail electric sales and adjusted for verified customer energy efficiency savings, recognizes the investments made by utility customers who have already paid for increased supplies of low-carbon energy or for energy efficiency and demand response programs. At the same time, an updating output-based approach encourages utilities who have not made these early investments on behalf of their customers to find the most expedient and cost-effective means of doing so as soon as possible.

By contrast, a grandfathering approach, based on historical emissions, has the opposite effect. It does not recognize investments made in zero or low carbon technologies, and it provides an incentive to delay such activities in the hope of accumulating more allowances. NRDC, UCS and GPI also have voiced concern over a grandfathering approach in their comments filed with the CPUC and Energy Commission, *e.g.* "California should not shield those entities who took on the risks of high GHG-emitting resources, at the expense of those who managed the risk well, by grandfathering allowances."[5] Allocation of allowance value to utilities for the benefit of their customers based on current output or sales will ensure that the value and proceeds resulting from the auction of allowances are matched with both the investments made by customers in low carbon resources in the past and the costs incurred by customers to further reduce emissions going forward. An historical emissions based allocation also presents unique estimation challenges. Allocating to utilities based on historical emissions associated with load requires assumptions regarding emissions rates of the market purchases and non-unit-specific contracts portion of each utility's portfolio, an administrative activity that can only result in an inaccurate allowance allocation. Using an historical emissions basis for allocation to utilities also will significantly de-position California customers in emerging regional and federal programs. As pointed out in its November 14, 2007, reply comments on allocation issues in this proceeding, PG&E has performed a calculation using publicly available data from the U. S. Department of Energy, Energy Information Administration, to compare the effects on California of a national cap-and-trade program that allocates GHG emissions allowances on a "grandfathered" or historical emissions basis, to a program that allocates allowances based on output or sales. Using 2006 recorded sales and GHG emissions, and assuming an allowance price of $20/metric ton of CO2, the cost of allowances to California would be $2.1 billion per year higher under a "grandfathered" or historical emissions based allocation method, than under a sales-based method.[6]

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[5] Reply Comments of The Natural Resources Defense Council, Union of Concerned Scientists and Green Power Institute on Allowance Allocation Issues, Docket R.06-04-009, CPUC, November 14, 2007, pp. 4.

[6] Reply Comments of PG&E, Docket R.06-04-009, CPUC, November 14, 2007, pp. 23- 24.

PG&E's allocation proposal is equitable to retail providers with varying emissions rates. It is true that a utility's current emissions are one element that determines the average compliance cost to the utility customers. It is also true, however, that low emitting utilities will have fewer remaining low cost GHG reduction opportunities compared to higher emitting utilities because they have already captured a significant portion of these opportunities through prior investments and actions funded by their customers in electric rates. On the other hand, higher emitting utilities may have a greater quantity of lower cost emission reduction opportunities within their own portfolio, namely the ability to reduce high emitting sources in their portfolio and to increase CEE program activity.

Finally, PG&E's proposal is equitable because, consistent with other environmental compliance costs, those entities with high emitting resources in their portfolio should be responsible for the costs of those emissions. Those costs should not and lawfully may not be assigned and shifted to customers who do not receive the benefits of the electric output from these higher emitting resources.

An additional benefit of PG&E's method of allocation is that it does not need to change over time, because the percentage of allocated amounts will be adjusted by changes in sales and CEE. A retail sales plus verified customer energy efficiency methodology adequately adjusts for changes in the market and creates the proper incentives to aggressively pursue energy efficiency and low-emitting resources as well as facilitating the addition of new entrants and recognizing changing demographics.

9. Please address the effect that each of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your own or other parties' opening comments, would have on economic efficiency in the

economy, and the economic incentives that each option would create for market participants.

PG&E Response:

For an allocation methodology to maximize economic efficiency, it should generate the greatest reductions at the lowest cost to the overall economy. Allowance allocation also can have a significant impact on the behavior of regulated entities and end-use energy consumers. There are many studies regarding the best way to maximize the economic efficiency of a cap and trade program, and most have demonstrated that the cost to the economy is minimized when a majority of the allowances are auctioned.

For example, the Congressional Budget Office issued a report on April 25, 2007 discussing "Tradeoffs in Allocating Allowances for CO_2 Emissions." In its report, the CBO points out that "Selling Allowances Could Significantly Reduce Overall Costs: Selling emission allowances could raise sizable revenues that lawmakers could use for various purposes, some of which would lower the cap's total cost to the economy."

Two experts on cap and trade, Goulder and Pizer, have suggested that the most efficient allocation method is an auction that reduces taxes to end consumers: "Therefore, carbon taxes and auctioned permit programs that employ their revenues this way will lower the excess burden from prior taxes, giving them a significant cost advantage….The revenue-raising policies (taxes and auctioned permits) are the most cost-effective, while the non-revenue-raising policies (freely distributed permits) have distributional consequences that may reduce political resistance."[7]

[7] Economics of Climate Change. Lawrence H. Goulder and William A. Pizer http://www.rff.org/Documents/RFF-DP-06-06.pdf.

In a November 2007 report "Assessing US Climate Policy Options," Raymond J. Kopp highlights the simple tradeoff that exists in allowance allocation options: "Allowance allocation can affect two important economic dimensions of a cap-and-trade program: efficiency and equity….Generally, pursuing equity objectives means sacrificing some efficiency."[8]

To the extent that the staff proposals in this proceeding use an auction approach and are effective at recycling the revenue to the end-use consumers that are bearing the costs of AB 32, the proposals should be relatively efficient compared to proposals that do not. However, the first two staff proposals, the emissions based and output based approaches, both give a significant share of allowances to third parties for free and therefore efficiency is lost and the cost to the economy will increase. Still another proposal, by SCE, would auction a significant share of allowances but retain a portion of allowances for free allocation to generators in perpetuity. Because the amount of allowances given away for free under SCE's proposal does not decline, this methodology results in an ongoing inefficiency and unfairness that can create a significant cost to the economy, sustain excess profits for coal generators, and shift large amounts of costs to customers in perpetuity.

In D.08-03-018, the two Commissions concluded that the proceeds from the auction of GHG emission allowances for the electricity sector should be used primarily to benefit electricity consumers in California in some manner. The Commissions identified two methods for returning revenues from allowance

[8] Assessing U.S. Climate Policy Options; Raymond Kopp, William Pizer, Daniel Hall, Richard Morgenstern, Juha Siikamäki, Joseph Aldy, Ian Parry, Karen Palmer, Dallas Burtraw, Mun Ho, Evan Herrnstadt, and Joseph Maher - November 2007 http://rff.org/rff/Documents/CPF_COMPLETE_REPORT.pdf

auctions: (1) using auction revenues to augment investments in energy efficiency and renewable power, or (2) using revenues to maintain affordable rates. Please answer the following questions regarding the use of auction revenues.

11. If auction revenues are used to augment investments in energy efficiency and renewable power, how much of the auction proceeds should be dedicated to this purpose?

<u>PG&E Response:</u>

Auction revenues to be used to augment energy efficiency and renewable energy investments should be allocated for this purpose based on objective and transparent emissions abatement cost-effectiveness criteria. Based on this assessment, there should be no more and no less funding than is necessary and effective, taking into account the experience of CPUC and Energy Commission approved programs. Furthermore, the funding mechanism should be as streamlined and market-responsive as possible, *e.g.* tax credits, rebates or incentives directly to energy users or producers for demonstration of new technologies or applied research, instead of grants or pure research, in order to focus the development of new, commercially-available "green" technologies for the benefit of utility customers. A worse outcome would be for auction revenues to be allocated for programs or projects which are less efficient and less cost effective than those that can be developed and implemented directly by consumers, businesses and energy market participants, and which do not focus on benefits accruing to the customers of California utilities across all income groups.

In addition, to the extent that auction revenues are used to fund energy efficiency and renewables programs that are currently funded in utility rates, this funding source should reduce current funding needs for these programs in order to avoid double counting. PG&E would support funding of renewable and energy efficiency programs which focus on applied research and development, demonstration projects, and workforce training.

12. If auction revenues are used to maintain affordable rates, should the revenues be used to lower retail providers' overall revenue requirements, returned to electricity consumers directly through a refund, used to provide targeted rate relief to low-income consumers, or used in some other manner? Describe your preferred option in detail. In addition to your recommendation, comment on the pros and cons of each method identified for maintaining reasonable rates.

PG&E Response:

We recommend that the value of the allowances be used to mitigate customer costs in a way that preserves a carbon-based price signal, assists customers and businesses in transitioning to a low carbon economy, advances energy efficiency, and pays particular attention to those customers who are disproportionately impacted by increases in electric rates.

It is important to note that auction revenues returned to retail electricity customers will *not* lower the costs of carbon allowances they pay under a "cap and trade" program, but instead ensure that customers will have a portion of AB32 compliance costs offset by using revenues generated through allowances auctioned to power generators and other GHG emitters to reduce rates. Thus, the auction revenues should be allocated to customers using the same rate design principles applicable to other power cost refunds or credits, such as through periodic bill credits. The periodic credit or refund approach ensures that all customers are equitably treated, while at the same time not diluting or impairing the price signal of carbon included in the direct costs of power to those same customers. In order to maintain the efficiency gains created by the auction (see question 9 above), it will be important to ensure direct and indirect benefits can be received by the end-use consumer, including low income customers who may be disproportionately impacted, as quickly as possible.

13. If you prefer a combination of methods for returning auction revenues, describe your preferred combination in detail.

PG&E Response:

PG&E recommends that, for the electric sector, emissions allowances should be allocated to utilities for the benefit of their customers using both of the methods suggested in the CPUC/CEC interim decision. Please see the response to question 8 for more detail. PG&E expects to develop a more detailed recommendation on the methods for returning auction revenues to customers, including the specific percentage amount for each method, as part of further AB32 implementation.

C. Legal Issues

2. Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your opening comments, raise concerns under the Dormant Commerce Clause? If so, please explain why that allocation option(s) may violate the Commerce Clause, including citations to specific relevant legal authorities. Also, explain if and, if so, how the allocation option(s) could be modified to avoid the Commerce Clause problem.

PG&E Response:

Yes, some of the allowance allocation options discussed in the staff paper would be based not on emissions reductions, rates, intensity or gross emissions, but on fuel types used in generation or other criteria unrelated to the actual GHG emissions from the regulated sources or categories of sources. To the extent that any such non-environmental or other criteria have a disproportionate impact on out-of-state generation or deliverers of out-of-state generation, such criteria may be subject to challenge under the Dormant Commerce Clause as a discriminatory, undue burden on interstate commerce.

For example, free allocation of allowances solely to in-state generators, while omitting out-of-state "deliverers," may raise issues under the Commerce Clause. Such allocation would give allowances to in-state generators, but not to their competitors that are "deliverers" importing electricity into California. The emission inventory posted by the Air Resources Board provides insight on the quantities involved. In 2004 (the most recent year in the inventory), emissions under "IPPC Level 4, 1A1a - Main Activity Electricity and Heat Production" total 123 million metric tons of CO2-equivalent. Of that total, 23% is derived from "Unspecified Imports". If 2004 were selected as the baseline year, arguably 23% of the freely distributed allowances or allowance value would need to be shared among the out-of-state generators, merchants, brokers, utilities and other parties that happened to import electricity into California in that year. The other categories are in-state merchant generators (22%), in-state utility-owned generators (5%), in-state CHP facilities (24%), and ownership shares (presumably mostly by utilities) in out-of-state plants (26%).

3. Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your opening comments, raise legal concerns about whether they involve the levying of a tax and, therefore, would require approval by a two-thirds vote of the Legislature? If so, please explain why that allocation option(s) is taxation, including citations to specific relevant legal authorities. Also, explain if and, if so, how, the allocation option(s) could be modified to avoid such legal concerns.

PG&E Response:

Under the California Supreme Court case *Sinclair Paint Co.*,[9] a fee imposed on an entity under a regulatory program is lawful and not a "tax" if the fee is related to and has a direct "nexus" to the purposes of the regulatory program. Conversely, if the uses

[9] *Sinclair Paint Company v. State Board of Equalization*, *et al.* (1997) 15 Cal.4th 886.

of fee revenues are unrelated to the regulatory program, *e.g.* under AB 32, used for purposes other than purposes expressly authorized by AB 32, then the fee would be more likely to be construed as a "tax" requiring two-thirds vote of the Legislature in order to be lawful. Under this legal principle, there are no clear dividing lines, and the courts' review would be likely to be very fact-based, including review of the stated intention of the fee; use of the fee revenues; statutory interpretation of AB 32; and practical relationship of the fee uses to the overall legislative intent of the statute.

In particular, PG&E believes that if revenues raised from the auction of allowances under AB 32 were to be allocated to programs or purposes unrelated to direct emissions reduction measures and emissions limits implemented under AB 32, there would be a risk that the use of the revenues for these unrelated purposes would be overturned by the courts as an illegal "tax."

4. Does any of the allowance allocation options discussed in the staff paper, or in the articles attached to the staff paper, or in your opening comments, raise any other legal concerns? If so, please explain in full with citations to specific relevant legal authorities. Also, explain if and, if so, how, the allocation option(s) could be modified to avoid such legal concerns.

PG&E Response:

Yes, as mentioned above, some of the allowance allocation options discussed in the paper appear to be based on criteria other than actual emissions or emissions rates by sources of greenhouse gas emissions, *e.g*. based on fuel types or "economic harm" or other criteria unrelated and even in direct conflict with the overall emissions reduction goals of the statute. Although PG&E agrees that "equity," "cost effectiveness," and "technological feasibility" are all criteria permitted to be applied by the statute, those criteria should not and likely may not be used to apply different emissions reduction measures and emissions limits to similarly situated sources or categories of sources of emissions, such as through the allocation of allowances in a manner that effectively exempts some sources from complying with emissions limits or targets applicable to other sources.

Likewise, some of the allowance allocation options, such as those based on "historical emissions" or which fail to provide credit to sources or categories of sources for emissions reductions prior to implementation of AB 32, would violate the express requirement in AB 32 that sources of emissions receive credit for such "early actions" to reduce emissions.[10]

IV. FLEXIBLE COMPLIANCE POLICIES

A. Detailed Proposal

1. Please explain in detail your comprehensive proposal for flexible compliance rules for a cap-and-trade program for California as it pertains to the electricity sector. Address each of the cost containment mechanisms you find relevant including those mentioned in this ruling and any others you would propose.

PG&E Response:

PG&E proposes that the following elements be included in comprehensive flexible compliance and cost containment rules for the electricity sector under AB 32:

Greenhouse gas offsets. High quality greenhouse gas offsets—which allow emissions sources to invest in reductions outside of the electric sector and other regulated sectors—reduce the costs of the program by providing a broader array of reduction opportunities, while stimulating innovative compliance solutions. For example, PG&E is partnering with dairy farms in California to produce pipeline quality

[10] Health and Safety 38562(b)(3).

"biogas" to serve our customers. This effort not only reduces greenhouse gas emissions by offsetting fossil fuel use and capturing methane that would otherwise be released to the atmosphere, but it also diversifies our energy supply mix, provides additional economic opportunities to the agricultural sector and advances technology that can be deployed elsewhere in the U.S. and abroad.

Multi-year compliance periods. Cap-and-trade programs for conventional pollutants are typically based on annual compliance periods. At the end of each year, affected sources retire allowances for each ton of emissions they generated. However, in California's and the West's electricity sector, because of the variability of both demand and resources due to seasonal or annual variations in weather and precipitation, such as reduced availability of hydroelectric generation during drought conditions and increased demand for electricity during hotter than normal years, multi-year compliance periods are perfectly appropriate. Moreover, the long term nature of the climate change problem supports a multi-year approach, rather than measuring progress solely on a calendar year basis.

PG&E suggests that a three- five-year compliance period be used to strike an appropriate balance between the need to make steady progress toward meeting overall emissions targets, and the desirability of a stable CO2 market across wet and dry years and other extreme variations in weather in the West. As noted in response to Question 1c below, even a five-year period may not completely mitigate wet/dry fluctuations--California has endured droughts longer than five years.

Banking. One of the most important aspects of the cap-and-trade regulatory approach is the ability to "bank" allowances for future years. By allowing companies to, in effect, “over-comply” and carry forward any excess allowances, banking greatly encourages compliance through early action, slowing the accumulation of greenhouse gas emissions in the atmosphere. Given the long-life of greenhouse gases in the atmosphere and the cumulative effect, the more we can avoid releasing now and in the early years of a program, the more flexibility we will have in the future.

Credit for early action. Even before the comprehensive AB 32 program gets underway in 2012, early reduction credits should be used to encourage investments in low-carbon technologies. AB 32 requires that ARB provide credit to entities for their voluntary emissions reductions undertaken prior to implementation of the statute. We think that this sends the right signal to reward industry for prior action and to act now to begin to slow the growth of emissions.

Cost containment protections. Both emission reductions and economic sustainability must be key objectives of AB 32. Measures need to be put in place that are designed not only to protect the steady and sustained conversion of the economy to low-carbon sources of energy, but also to protect against extreme disruptions to the economy or to the reliability of electricity service to consumers. There should be mechanisms built into the design of “cap and trade” to ensure that extremely high CO2 prices caused by temporary or unbalanced conditions in trading markets do not jeopardize either the efficiencies of the cap and trade program or the fundamental health of the economy.

The need for an explicit cost containment mechanism within the context of an overall carbon budget is important especially during the initial start-up and early years of the program. It is during this transitional time when low- and zero-carbon technologies are developed, become commercially available and are deployed in response to carbon market prices that a mechanism is needed. It is also a time when market participants develop financial tools and strategies for managing volatility and risk, and help set a long-term forward price for CO2 to help attract investment.

The most direct means of ensuring the costs of a cap-and-trade program remain in a reasonable range is to make additional allowances available at a pre-specified price. This mechanism is usually called a “safety valve.” We recognize that some parties are concerned that a simple safety valve may both impede investment in low- and zero-carbon technologies and potentially thwart the ability to achieve legislated emission reduction goals.

PG&E believes that these risks can be avoided by a carefully-designed mechanism that balances the overall environmental integrity of the program with the need to ensure a well-functioning market and economy. In this regard, PG&E recommends a type of “price collar” approach, in the context of managing the overall carbon budget, to help manage volatility and macro-economic costs, especially during the early years of the program, and at the same time to provide clear and sustained “price for carbon” for technology investors and emissions sources that is recognized in all sectors of the economy.

The price collar could function using a pre-specified ceiling price, at which any entity could purchase allowances from a reserve, for use within the current compliance period. The reserve would contain allowances from future years under an overall carbon “budget.” Allowances purchased from the reserve would be useable in the current year, or bankable, like other allowances. However, purchases from the reserve would mean fewer allowances distributed in future years, thereby maintaining the overall long-term carbon budget. The price collar would also include a minimum acceptable bid for allowances in centralized auctions, or a buy-back mechanism, to establish a price floor. Current-year allowances that are not purchased at auctions, or are bought back, would be transferred to future years, so that more allowances would be distributed in future years. Both the ceiling and floor price would increase annually. PG&E preliminarily recommends that the price ceiling should be harmonized with expectations regarding technology availability, and should be set to avoid massive re-dispatch of existing gas-fired power plants in place of existing coal-fired power plants (see example below). PG&E also preliminarily recommends that the floor price should be harmonized with expectations regarding what is needed to ensure adequate investment in the development and deployment of low- and zero-carbon generation technologies and end-use efficiency technologies. For example, in order to retain real price signals, both the ceiling and floor prices should increase over time by at least the inflation rate.

The impact of re-dispatch can be illustrated by example. Consider a gas-fired plant with a heat rate of 10 MMBtu/MWh and a CO2 emission rate of 0.5 tonnes/MWh, and a coal-fired plant with a heat rate of 10 MMBtu/MWh and a CO2 emission rate of 1.0 tonnes/MWh. Assume that natural gas costs $5/MMBtu and coal costs $2/MMBtu. The variable fuel costs are then $50/MWh for the gas-fired plant, and $20/MWh for the coal plant. At a CO2 cost of zero, it makes sense to dispatch the coal plant ahead of the gas-fired plant, because the coal-based electricity is much cheaper. At a CO2 cost of $60/ton, however, the running costs are equal--$80/MWh for both the gas-fired plant and the coal plant. In view of the tight natural gas market, with natural gas currently priced near $10/MMBtu, it may be appropriate to consider polices that avoid a massive re-dispatch that would increase natural gas demand.

By incorporating a price collar mechanism within the context of managing the overall carbon budget associated with a cap-and-trade program, policymakers and stakeholders can ensure that long-term emission reduction goals are met, while at the same time providing for an orderly transition to a low-carbon economy through a greater degree of price predictability and reduced price volatility.

The price triggers would need to contain an essential administrative element to ensure workability. This element would be the automatic triggering of the availability of additional allowances in sufficient amounts to immediately dampen or mitigate any temporary market failures or price fly-ups that threaten the economy or consumers with "price shocks" or immediate harm. During California's 2000- 2001 electricity crisis, the "fly-up" in wholesale prices was so rapid and so extreme that it drove California's electric utilities into extreme financial distress in a matter of only months because measures to mitigate the effects of the price fly-up were not immediately and automatically taken.

In summary, PG&E believes the price "collar" proposal balances key long-term environmental objectives and helps assure that costs stay in a reasonable range, particularly during the initial AB 32 compliance period.

Scope of Market and Related Issues

a. Discuss how your proposal would affect the environmental integrity of the cap, California's ability to link with other trading systems, and administrative complexity.

b. Address how your various recommendations interact with one another and with the overall market and describe what kind of market you envision being created.

c. Describe and specify how unique circumstances in the electricity market may warrant any special consideration in crafting flexible compliance policies for a multi-sector cap-and-trade program.

d. If your recommendations are based on assumptions about the type and scope of a cap-and-trade market that ARB will adopt, provide a description of the anticipated market including sectors included, expected or required emission reductions from the electricity sector, and the role that flexible compliance mechanisms serve in the market, e.g., purely cost containment, catalyst for long-term investment, and/or protection against market failures.

PG&E Response:

A. Environmental integrity: PG&E's price-collar approach transfers allowances from future years to the current year only as necessary to prevent or mitigate unsustainably high prices, and transfer allowances from the current year to future years only as necessary to prevent or mitigate unsustainably low prices. Because allowances are transferred in time, rather than being created or destroyed, the integrity of the cap and trade program is maintained and long-term emission reduction goals are met.

B. Interactions: PG&E believes that its proposals mesh well with each other. Especially if other sectors are included, PG&E believes that its proposals will lead to a robust market with a broad spectrum of participants. That market will be scalable and reasonably consistent with other regions, easing the way to linkages to other existing and emerging regional programs such as the Western Climate Initiative, and, ultimately, a single federal or international program.

C. Unique characteristics: Although the electricity sector has several characteristics that deserve consideration in formulating a cap-and-trade approach, most are well-known and are being considered, such as the LSE's obligation to serve, the critical importance of a reliable electricity supply and the long-term, capital-intensive nature of many electricity supplies. One additional characteristic that warrants consideration in the design of AB 32 emissions limits and a cap and trade program is the fluctuating contribution of carbon-free hydroelectricity to California's electricity supply.

California's hydroelectricity supply correlates very well with the "Sacramento Valley Water-Year Index" calculated by the California Department of Water Resources. That Index has been below-normal for 5 periods lasting 4 years or more since record-keeping began in 1906. In the worst sequence, the Index was at least 28% below normal for the first 6 years of a nine-year drought that began in 1929. Multi-year compliance periods, as described above, could help meet long-term emission goals yet avoid unsustainably high allowance prices during multi-year dry spells.

In addition, the electricity and natural gas sectors are subject to the unique legal framework under which investor-owned utilities, unlike other utilities and businesses, are under a constitutional and statutory obligation to continue to provide public utility service to customers, regardless of the costs of the service or the operational difficulties. This means that, absent government approval, California's investor-owned may not choose voluntarily to withdraw from the electric or natural gas business or move their business or facilities to another state or location. Likewise, because utilities are relatively capital intensive and subject to natural economies of scale for their transmission and distribution facilities, utility customers do not have the same choice to buy electricity or natural gas service from out-of-state suppliers or manufacturers as they have for other consumer products and services. Thus, the implementation of AB 32 in the electricity and natural gas sectors must also take into account these unique characteristics.

D. Underlying Assumptions: At this time PG&E has not made any assumptions regarding ARB's decisions regarding scope or expected or required emission reductions from the electricity sector. Regarding the role of flexible compliance mechanisms, PG&E's proposals are intended to meet the dual objectives of real emission reductions, by serving as a catalyst for long-term investment and environmental integrity, and reasonable cost to consumers, by protecting against market failures and extreme droughts.

4. To what extent should the recommendations to the ARB for flexible compliance in the electricity sector depend on the ultimate scope of the multi-sector cap-and-trade program and other market design issues such as allocation methodology and sector emission reduction obligations? Can the Commissions make meaningful recommendations on flexibility of market operations when the market itself has not yet been designed? Why or why not?

PG&E Response:

PG&E recommends that AB 32 implementation include an essential, back-stop mechanism to ensure that unsustainably high allowance prices do not jeopardize the credibility of the cap and trade program or the fundamental health of California's economy. The likelihood that such a mechanism will be used can be reduced by, among other things, appropriate assignment of emission-reduction obligations, unlimited banking and streamlined availability of high-quality emission offsets, use of multi-year compliance periods, and including multiple sectors and jurisdictions in the cap-and-trade program, especially those with substantial low-cost opportunities to reduce emissions. PG&E strongly recommends that the CPUC/CEC and CARB include all of these elements into a cap and trade market design.

5. Should the market for GHG emission allowances and/or offsets be limited to entities with compliance obligations, or should other entities such as financial institutions, hedge funds, or private citizens be allowed to participate in the buying

and selling of allowances and/or offsets? If non-obligated entities are allowed to participate in the market, should the trading rules differ for them? If so, how?

PG&E Response:

The market for GHG emissions allowances and high-quality offsets should not be limited, as long as market participants meet standardized financial, operating and registration requirements and agree to be subject to regulatory oversight, verification and audits as appropriate. These non-obligated entities may help provide financial products that help complying entities meet their emissions reduction targets and manage their compliance costs more efficiently and cost-effectively.

PG&E does not recommend different trading rules for non-obligated entities and believes that administrative costs would increase if such constraints were imposed. Barriers to entry in the wholesale electricity market are relatively low in any case. An entity that wishes to become a "deliverer" and assume a compliance obligation could do so with minimal difficulty, *e.g.*, by purchasing a small quantity of electricity at an out-of-state hub, bidding it as a price-taker into a CAISO market, and then delivering it into California. PG&E does, however, recommend that all participating entities be subject to strong market oversight and standard registration and disclosure requirements.

B. Price Triggers and Other Safety Valves

Price triggers and other safety valves could be used if there is a need to intervene in normal market dynamics to restore allowance prices back to acceptable levels.

6. Should California incorporate price triggers or other safety valves in a cap-and-trade system? Why or why not? Would price triggers or other safety valves affect environmental integrity and/or the ability to link with other systems? Address options including State market intervention to sell or purchase GHG emission allowances to drive allowance prices down or up; a circuit breaker or accelerator which either slows down or speeds up reductions in the emission cap until allowance prices respond; and increasing or decreasing offset limits to

increase or decrease liquidity to affect prices. Address how these various strategies would be utilized in conjunction with other flexible compliance mechanisms.

PG&E Response:

Yes. PG&E believes it is appropriate to include such as back-stop mechanism, particularly in the early years of the program. We also recognize that some policymakers and other stakeholders are concerned that a simple safety valve may both impede investment in low- and zero-carbon technologies and potentially thwart the ability to achieve legislated emission reduction goals. PG&E believes that a well-designed price-collar mechanism, operating within an overall "carbon budget," can provide an effective means to help manage overall volatility and unexpected economic costs, and at the same time provide a clear path for technology investors and ensure that there is a "price for carbon" that is recognized within California's electricity sector and in the economy as a whole.

The elements of a "price collar" would include market intervention to make additional GHG emission allowances available to the broad, multi-sector, multi-jurisdictional market, in order to restrain upward movement of allowance prices while maintaining a multi-year carbon budget. A lower bound on allowance prices could also be accomplished by specifying minimum acceptable bids in allowance auctions or by other means.

The price collar should be used in conjunction with other flexible compliance mechanisms, including a robust supply of high-quality offsets, multi-year compliance periods, and banking and "early action" credits. PG&E does not support geographic or quantitative limits on offsets, as long as the offsets meet rigorous standards. Using allowance prices as a limit on the use of offsets might impair the stability and predictability of prices in the offset market, which could deter investors and drive up emissions reduction costs higher than necessary.

7. Should California create an independent oversight board for the GHG market?[11] If so, what should its role be? Should it intervene in the market to manage the price of carbon? If such an oversight board were created, how would that affect your recommendations, *e.g.*, would the oversight board obviate the need to include additional cost containment mechanisms and price-triggered safety valves in the market design?

PG&E Response:

Yes, preferably on a multi-sector, multi-jurisdictional basis, encompassing a regional or national program. The role of the oversight board would be to implement and enforce price collar rules; oversee trading markets and market behavior; ensure transparent and publicly-available prices; and generally complement and support the administrative and enforcement functions of the ARB under AB 32 relating to the cap and trade program. PG&E expects that a price collar could be predictable, effective and easy to administer and substantially reduce any economic incentive related to hoarding. The price pathways could be established with on-going regulatory oversight and monitoring provided by an administrative agency to enforce the terms and conditions of the price collar fairly and transparently. Guidance should be provided to the oversight agency to make the implementation of the price collar as automatic and as transparent as possible, with limited discretion provided in response to precise market conditions and events.

[11] In its Final Report adopted February 11, 2008, the Economic and Technology Advancement Advisory Committee recommends that ARB create a California Carbon Trust that could, among other functions, manage the carbon market in California similar to the way that the Federal Reserve Bank manages interest rates by adjusting the supply of emission allowances and credits through sales and purchases. That report is available at http://www.arb.ca.gov/cc/etaac/etaac.htm.

These provisions will help to ensure that the price collar has a substantial degree of cost and implementation certainty. Substantial discretion for the administrative agency might detract from the certainty and transparency that are advantages of the price collar.

In addition, as a "market transparency" measure, it may be desirable to charge some agency with preparation and release of a daily or current estimate of CO2 emissions within the capped sectors. For the electricity sector, an agency with access to confidential, real time data from electricity control centers and public data from natural gas pipelines might be able to develop a reasonably accurate daily estimate of CO2 emissions. Posting a daily update of a rolling 365-day sum of CO2 emissions might reduce day-to-day variability in the CO2 price by providing a solid information base to all market participants.

C. Linkage

The issue of linkage addresses the ability of obligated entities to buy and sell GHG emission allowances or credits with other carbon-trading systems like the Regional Greenhouse Gas Initiative and the European Union Emissions Trading Scheme.

8. Should California accept all tradable units,[12] *i.e.*, GHG emission allowances and offsets, from other carbon trading programs? Such tradable units could include, *e.g.*, Certified Emission Reductions, Clean Development Mechanism (CDM) credits, and/or Joint Implementation credits.

PG&E Response:

PG&E recommends that California accept all emission offsets that meet the standards for high quality that PG&E described above. Evaluation of allowances from

[12] Tradable units refer to (1) GHG emission allowances that permit emission of a ton of carbon equivalent (CO2E) and (2) offsets that reflect a reduction in GHG emissions of a ton of CO2E, as addressed in Section 2.8 of this ruling. A credit is a broad term used in this ruling to refer to any tradable unit other than a GHG emission allowance issued by California.

other programs may require case-by-case analysis, to determine whether there is sufficient consistency of quality and rules (e.g., length of compliance period, cost-containment mechanisms) across different carbon-trading programs.

9. If so, what effects could such linkage have on allowance prices and other compliance costs of California obligated entities? Under what conditions could linkage increase or decrease compliance costs of California obligated entities? To what extent would linkage subject the California system to market rules of the other systems? What analysis is needed to ensure that other systems have adequate stringency, monitoring, compliance, and enforcement provisions to warrant linkage? What types of verification or registration should be required?

PG&E Response:

It is axiomatic that the broader the market for emissions allowances, the lower the barriers to entry to that market, and the greater the number of market participants, the more efficient the market will be. Note that linkage can be unilateral in either direction, or bilateral:

- Unilateral by California: California permits complying entities to use allowances issued by Region X, but Region X does not permit complying entities to use allowances issued by California.
- Unilateral by Region X: Region X permits complying entities to use allowances issued by California, but California does not permit complying entities to use allowances issued by Region X.
- Bilateral, or reciprocal: California and Region X each permit complying entities to use the others' allowances.

Unilateral linkage by California cannot increase allowance prices in California. It may reduce prices: If allowance prices are initially lower in Region X, California's complying entities would purchase Region X allowances, driving up those prices and decreasing California's, until allowance prices in California and Region X were equal. The reverse is true for unilateral linkage by Region X to California: Such linkage will raise allowance prices in California unless the prices are already higher than in Region X. Bilateral linkage could increase or decrease prices for California's allowances.

Bilateral linkage would require some consistency, and possibly rule changes, between California's and the other region's markets. As with other commodity trading markets, the linked markets can develop and apply common and uniform standards for market rules, registration of market participants, contracts, third-party inspection and audit; and price transparency. The design of these systems is complex, and is probably best performed on a case-by-case basis, rather than in the abstract, using advice and guidance from experts and overseers of other commodity trading markets, such as the federal Commodities Futures Trading Commission.

10. If linkage is allowed, should it be unilateral (where California accepts allowances and other credits from other carbon trading programs, but does not allow its own allowances and offsets to be used by other carbon trading programs) or bilateral (where California accepts allowances and other credits from other carbon trading programs and allows its allowances and offsets to be used by other carbon trading programs)?

PG&E Response:

Climate change is a global challenge. Therefore, the linkage from California's perspective should be bilateral and reciprocal, provided that linkage creates a broader, more liquid trading market that maintains appropriate flexible-compliance and cost-control mechanisms. Ideally, this would mean that California can integrate its cap and trade program effectively with regional, national, and international GHG cap and trade programs. In terms of reciprocity for multi-state programs, it should be in the interests of all states to provide for reciprocal treatment of individual state programs that meet mutually-agreed, rigorous standards. On the other hand, if one state refuses to meet standards set by other states, but chooses to allow complying entities under its program to use the other states' trading markets, that is a decision of that individual state that may not be legally restricted by the other states. To the extent that a state does not agree to provide reciprocity or needed uniformity, California could consider denying complying entities under that state's program from participating in California's cap and trade market unless their state program meets California's reciprocity requirements. As long as these reciprocity requirements are applied in a non-discriminatory fashion to all in-state and out-of-state participants in California's program, there should be no Commerce Clause violation.

11. If linkage is allowed, should allowances and other credits from other carbon trading programs be treated as offsets, such that any limitations applied to offsets would apply to such credits? If not, how should they be treated?

PG&E Response:

No, there should be no limitation as long as appropriate linkage criteria are met. Limitations on use of allowances and offsets from linked programs would raise total compliance costs and might prove difficult to enforce. Both emissions allowances and offsets should be subject to comparable standards, regardless of geographic origin, so that both are usable and available to the same extent.

D. Compliance Periods

12. What length of compliance periods should be used? Should compliance periods remain the same throughout the 2012 to 2020 period? Should compliance

periods be the same for all entities and sectors? Should dates be staggered so that not all obligated entities have the same compliance dates?

PG&E Response:

As noted above, PG&E recommends a three- five-year compliance period as an appropriate balance between the need to change the way we produce and use energy, to lower the threat of climate change, and the desirability of a stable CO2 market across wet and dry years, given the annual variability in emissions in the electric sector due to weather-related variability in hydroelectric power. PG&E also recommends that rolling or staggered compliance periods be considered.

13. Should compliance extensions be granted? If so, under what circumstances?

PG&E Response:

PG&E's proposed flexible compliance and cost-containment measures, as a package, should reduce the need for extensions of compliance periods However, as under any regulatory program, there should be an opportunity for a compliance extension if unanticipated, extraordinary events occur. In any event, a "true-up" period, following the compliance period, will be needed to tally CO2 emissions, allowances, and offsets in order to demonstrate compliance.

E. Banking and Borrowing

Banking would allow an entity to buy and hold GHG emission allowances and/or credits across compliance periods; borrowing would allow an obligated entity to use its allowances from a future compliance period to meet the obligation under a current compliance period.

14. Should entities with California compliance obligations be allowed to bank any or all tradable units, including allowances, offsets, or credits from other carbon trading programs? Should entities that do not have compliance obligations be able to bank tradable units? If so, for how long and with what other conditions? Should allowances, offsets, or credits from other carbon trading programs banked during the program between 2012 and 2020 be recognized after 2020? If the

California system joins a regional, national, or international carbon trading program, how should unused banked allowances, offsets, or credits from other carbon trading programs be treated?

PG&E Response:

Yes, California entities should be allowed to bank or use allowances, offsets and credits from other jurisdictions, as long as the markets have been linked and meet minimum and reciprocal verification standards. PG&E also agrees that entities not subject to compliance obligations should be able to bank tradable allowances and credits, but subject to strong market oversight and transparent reporting to reduce the risk of hoarding or market manipulation. Moreover, there should be no time limitation on the recognition or use of allowances or credits, as long as hoarding and market manipulation are prevented. Finally, assuming California transitions to a national or international program that uses allowances, credits or offsets, all such tradable units recognized under California's program should be recognized under the national or international programs as long as they meet the minimum standards of verifiability and uniformity applicable to such programs.

The ability to bank allowances for future years is one of the most important aspects of the cap-and-trade regulatory approach. By allowing companies to, in effect, "over-comply" and carry forward any excess allowances, banking greatly encourages compliance, slowing the accumulation of greenhouse gas emissions in the atmosphere. Given the long-life of greenhouse gases in the atmosphere and their cumulative effect, the more we can avoid releasing now and in the early years of a program, the more flexibility we will have in the future.

15. Should limitations be placed on banking aimed at preventing or limiting market participants' ability to "hoard" allowances and offsets or distort market prices?

PG&E Response:

PG&E supports strong market oversight, but we do not support a specific limitation at this time. Hoarding and other market manipulation issues can be addressed in the context of developing overall oversight and market surveillance criteria for the regulatory entities charged with ensuring open and transparent markets.

The multi-year compliance period mechanism suggested by PG&E should guard against unsustainably high or low allowance prices from, *e.g.*, a succession of dry or wet years. The same mechanism would hinder market participants' ability to influence allowance prices by "hoarding." Additional protection could be provided by other mechanisms used to protect against the exercise of market power or market manipulation in commodities markets, such as that experienced in electricity commodity markets during the electricity crisis in California during 2000-2001.

16. Should entities with compliance obligations be allowed to borrow allowances to meet a portion of their obligation? If so, during what compliance periods and for what portion of their obligation? How long should they be given to repay borrowed allowances? Should there be penalties or interest payments? Should there be other conditions on borrowing, such as limitations on the ability to borrow from affiliated entities? Also address the extent to which borrowing might affect environmental integrity and emission reductions.

PG&E Response:

PG&E believes its flexible compliance and cost containment measures, and in particular its multi-year compliance proposal, may reduce the need for borrowing. PG&E does not believe that borrowing, coupled with full repayment obligations, would have any significant, long-term effect on the quality or quantity of emissions reductions.

F. Penalties and Alternative Compliance Payments

This issue addresses the amount of money charged or other requirements that could be placed on an obligated entity that does not meet its full compliance obligation.

17. Should there be penalties for entities that fail to meet their compliance obligations? If so, how should the penalties be set? If not, what should be the recourse for non-compliance?

PG&E Response:

Civil and criminal penalties for non-compliance should be designed similar to other comparable penalties for non-compliance with air emissions laws. The decision by the regulator to impose penalties should be discretionary and subject to the traditional goals of the regulatory agency to both deter willful and intentional behavior, and to provide for compensation for environmental harm. The level and imposition of penalties should be subject to mitigating factors, such as lack of intent or lack of negligence, immediacy of corrective actions, and mitigating circumstances that indicate that some or all of the non-compliance was outside the reasonable control or foreseeability of the regulated entity.

18. Instead of penalties, should there be alternative compliance payments? What would be the distinguishing attributes of alternative compliance payments versus penalties? How would the availability of alternative compliance payments affect the environmental integrity of the cap?

PG&E Response:

Alternative remedies for non-compliance, such as affirmative environmental projects or remediation, should be available to the same extent available under other environmental laws and regulations. See response to No. 17 above.

19. Would penalties and/or alternative compliance payments allow obligated entities to opt out of the market? Would this add too much uncertainty for other market participants?

PG&E Response:

Penalties and alternative compliance payments and remedies can and should be limited sufficiently to avoid effectively allowing entities to "opt out" of the market.

20. How should California use the money that would be generated by penalties and/or alternative compliance payments?

PG&E Response:

Funds generated by penalties and/or alternative compliance payments should only be used consistent with purposes authorized under AB 32 and other comparable air quality laws.

G. Offsets

In general, the GHG emissions cap in any given compliance period would be established by the number of GHG emission allowances available during the compliance period, either through direct distribution or due to banking or borrowing. Offsets and other allowed credits essentially would raise the cap for the sectors in the cap-and-trade program but would yield emission reductions elsewhere. Questions in Section 2.4 of this ruling address, among other things, whether and the extent to which credits from other trading programs should be treated as offsets for purposes of compliance with AB 32 requirements.

21. Should California allow offsets for AB 32 compliance purposes?

PG&E Response:

PG&E strongly supports the use of offsets and "early action credits" as an indispensable tool in abating greenhouse gases in a cost-effective fashion.[13] The recently released EPA analysis of the Lieberman-Warner federal legislation indicates that

[13] For purposes of this discussion, PG&E uses the term "offsets" to include not only emissions reductions outside the direct emissions limits or caps imposed by AB 32, but also to include emissions reductions implemented prior to the effective date of AB 32 regulations, *e.g*. so-called "early actions."

unlimited access to offsets decreases the cost of compliance 85% compared to a scenario with no access to offsets.[14]

PG&E believes that there should be no geographic or quantitative limits on offsets, rather, offsets should be limited only by their quality and ability to meet rigorous standards Offset protocols should be thorough, and offsets which meet the protocol standards should not be subject to further arbitrary or case-by-case discounting. As protocols will be rigorous, there is no need for California to have separate agreements with the government agencies where offset projects are located.

At the ARB workshop on April 4 on offsets, PG&E was pleased to see the universal consensus among parties that offsets should be an indispensable component of any greenhouse gas emissions (GHG) reduction program.[15]

PG&E agrees that allowing the use of offsets as a compliance mechanism will:

- Enable real GHG reductions more cost-effectively while managing the overall costs of the cap and trade program;
- Reduce the risk and transition costs associated with the early years of the cap and trade program and enhance confidence in the program by providing flexible compliance options;
- Spur technology development and innovation in sectors, sources, and locations not included in capped sectors;

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[14] http://www.epa.gov/climatechange/downloads/s2191_EPA_Analysis.pdf. Scenario 4 is 29% of the cost of Scenario 2. Scenario 5 is 1.93% of the cost of Scenario 2. Therefore, Scenario 4 is 15% of the cost of Scenario 5.

[15] The majority of parties supported unlimited use of offsets. A few parties supported the use of offsets with limits, but even these parties still supported the use of offsets.

- Provide environmental and social co-benefits, such as reduced air pollution, habitat preservation, and/or job creation, in sectors/sources not included in the program; and
- Help develop more accurate reporting methodologies for categories of offset projects, which may later be included in the GHG cap.

PG&E believes that offsets, in conjunction with a well-designed cap and trade market, serve to lower over-all administrative costs and increase incentives to innovate. As stated above, offsets will serve to decrease costs by giving entities flexible compliance options and increasing market liquidity. Further, allowing offsets without limitation will not stifle innovation in the capped sectors. The act of monetizing GHG emissions will encourage innovation to find the most cost-effective reduction opportunities all over the world - both inside the capped sectors and outside. Regulated sources have every incentive to achieve emission reductions in their capped sources in a cost-effective manner. If market failures on innovation persist, they should be addressed by incentives and targeted at technology markets, not by limiting offsets and the cap and trade tool, which addresses environmental market failures. Specific policies to address technology innovation will be far more effective and less expensive than limiting quality GHG reduction opportunities.

Using GHG cap and trade as a surrogate for addressing other policy issues holds the potential of undermining interstate and international trade of GHG offsets. Given the increased costs that national modeling shows would result, the ARB should consider restricting the use of offsets only if experience with offsets suggests that restrictions would help achieve the primary goal of GHG policy – *i.e.*, to achieve the most reductions at least cost for the long run.

PG&E urges the CEC and CPUC to recommend that ARB provide expedited approval of offset and "early action" protocols well before 2012, the effective date of AB 32, so that entities (within and without capped sectors) have an incentive to begin the planning and investment to bring projects on line given the long lead time for project development. Offset and trading markets in regulated commodities do not develop overnight; they require long ramp-ups and systems development and investment to gain the necessary interest and liquidity. Regulators should give entities the regulatory certainty to start engaging in offset projects as soon as practical, prior to the launch of the cap and trade market, so that entities have strong incentives for early GHG reduction action. Offset project lead time can be substantial. Regulatory certainty will enable offset projects to gain access to needed investments and allow entities access to offsets lower down on the supply curve. Starting the regulatory process of protocol acceptance will enable access to more offsets quickly. As we have seen in California, once the State created a Registry, mandated the creation of a project protocol, and endorsed the use of that project protocol, the offsets market grew substantially.[16]

For this reason, the CEC and CPUC should recommend that ARB launch a separate process to: (1) review in an aggressive time-frame the many existing protocols and (2) formally adopt offset protocols. This track should occur while the rest of the AB 32 elements are in development. The process should enable project participants to act using existing protocols as soon as possible.

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[16] CCAR Forestry Protocol.

22. If offsets are permitted, what types of offsets should be allowed? Should California establish geographic limits or preferences on the location of offsets? If so, what should be the nature of those limits or preferences?

PG&E Response:

No, there should be no geographic or quantitative limits on offsets, as long as the offsets meet rigorous standards. PG&E supports allowing high-quality offsets from all locations without any discounts based on location. Limiting or discounting offsets based on location would increase the cost of the cap and trade system by not allowing entities to pursue possible low cost, real GHG abatement opportunities. It also sets the stage for a very negative reciprocal policy where other cap and trade programs limit California-sourced offsets.

By mandating the use of well-designed protocols, the ARB will ensure that all offsets created will be equal. The filter of quality should be the only limit, not the location of the project. As long as the offsets are real, permanent, additional, verifiable, and enforceable, the emissions reductions are exactly the same and should not be devalued.[17] Allowing the use of offsets in regions not subject to a cap and trade starts the process of internalizing the GHG externality in those regions. This could serve as an incentive for participation in a cap and trade program, stimulating innovation and investment that would not otherwise occur or would occur later. Limits narrow the scope of the market signal to, and potential ancillary benefits from, regions not included

[17] There has been some confusion over the definition and application of the terms "real," "permanent," "additional," "verifiable," and "enforceable." PG&E believes all these terms can be simplified into the practical and auditable standards that apply to emissions of greenhouse gases and other criteria air pollutants: emissions must be measured and reported under standards and criteria accepted by both regulators and complying entities, and emissions reductions claimed under offsets must be measured and reported under the same standards and criteria. In other words, if an emissions reduction claimed under an offset is verified using the same measurement and reporting criteria applicable to directly regulated emissions, it should be accepted.

in the cap. Forgoing opportunities to lower GHG emissions, wherever these opportunities are, has a tangible, positive impact on the environment and will unnecessarily and artificially limit our ability to meet long-term GHG reduction goals.

Imposing state-level restrictions on a market that is already clearly global in nature appears counter to the intent of AB 32, which requires ARB to “make reasonable efforts to promote consistency among other existing and proposed international . . . programs.” PG&E feels that geographic limits would defeat what needs to be the overarching intent of AB 32 – to achieve maximum reductions at least cost.

For these reasons, PG&E does not support limiting offsets to regions that sign MOUs with California. Such a stipulation adds a layer of regulation unrelated to creating quality GHG abatements and creates uncertainty in the offset market.

23. Should voluntary GHG emission reduction projects, *i.e.*, projects that are not developed to comply with governmental mandates, be permitted as offsets if they are within sectors in California that are not within the cap-and-trade program? In particular, should voluntary GHG emission reduction projects within the natural gas sector in California be permitted as offsets, if the natural gas sector is not yet in the cap-and-trade program?

<u>PG&E Response:</u>

If a sector is not included in cap and trade and not subject to programmatic measures, the sector may be a source for offsets to the extent that GHG reduction projects reduce GHG emissions in a verifiable and reportable manner.

24. Should there be limits to the quantity of offsets? If so, how should the limits be determined?

<u>PG&E Response:</u>

The use of offsets that are otherwise high-quality and verified should not be limited in quantity. EPA’s recent analysis of the federal Lieberman-Warner legislation highlights this extremely important customer cost issue. As stated above, the scenario in which no international credits or domestic offsets were allowed produced results that were 85% more expensive than the scenario with unlimited access. This scenario results in allowance prices in 2020 of approximately $100 per ton. Such prices would cost our customers billions of dollars. Such outcomes would undermine the benefits of a cap and trade system and possibly endanger GHG reduction programs altogether. Arbitrarily setting quantity limits on quality offsets provides no increased environmental protection and serves only to drive up the cost of GHG reduction, frustrating the effort to successfully address the issue of global warming.

We do not support the tiered approach employed by RGGI. Price triggers are unlikely to enable participants to have adequate confidence or notice to actually make investments. Only the least expensive projects will get developed, and these are the projects that may have the most additionality concerns. Price triggers and percentage limits will stifle GHG abatement options as market participants will face great risk of being able to sell their product.

25. How should an offsets program be administered? What should be the project approval and quantification process? What protocols should be used to determine eligibility of proposed offsets? Are existing protocols that have been developed elsewhere acceptable for use in California, or is additional protocol development needed? Should offsets that have been certified by other trading programs be accepted? Should use of CDM or Joint Implementation credits be allowed?

PG&E Response:

The ARB should immediately issue regulations to establish expedited procedures and protocols for the qualification of unlimited categories of offsets, as well as to establish streamlined procedures for certifying specific projects that may not fit within generically approved offset categories. The rulemaking should be designed to allow self-certification subject to audit of projects that fit within generically approved categories, and to provide ARB approval or disapproval on an expedited basis of offset projects that do not fit particular protocols. The rulemaking should be final and effective no later than early 2009, so that complying entities can begin exploring and structuring projects prior to the 2012 effective date of AB 32 regulations.

PG&E strongly supports efforts to quickly develop an initial set of approved protocols based on the 100+ existing Climate Action Registry and other national and international protocols. As stated above, the California regulatory agencies should immediately implement a process to survey those protocols. There should be a timeline developed for protocol review and use. After approval, entities should be able to use these protocols for offset development even before the start of the cap and trade. Entities should be able to bank these offsets for compliance. Such a regulatory process would give market participants the certainty needed to invest in real GHG reductions as soon as possible.

PG&E would like to be able to engage in offset projects as soon as possible, including participating in offset funds. Engaging in projects early is necessary to meet environmental goals. Additionally, we may be able to obtain better offset prices to protect our customers if we are able to act quickly. The US will be competing in a global market to procure offsets. Acting quickly buys environmental and compliance insurance for the future. However, market participants will not engage in these GHG reduction transactions without some assurance that the reduction credits will be of value in the future. The CEC and PUC should encourage the ARB to act quickly to approve protocols and provide security to enable offset project development.

California has enrolled in the International Climate Action Partnership (ICAP). At the same time, Congress is debating a wide variety of issues relating to how domestic GHG offsets will be quantified, reported, verified and approved. PG&E advises the CEC, PUC, and ARB to seek and use input from its representatives that are engaged in the regional, national and international dialogue on how projects should proceed.

26. Should California discount credits (*i.e.* make the credits worth less than a ton of CO2e) from some offset projects or other trading programs to account for uncertainty in emission reductions achieved? If so, what types of credits would be discounted? How would the appropriate discount be quantified and accounted for?

PG&E Response:

No. PG&E opposes discounting of quality offsets. As explained above, we support using a filter of quality standards to minimize risk from projects. Discounting is arbitrary and punishes all projects, regardless of quality. Additionally, discounting poses challenges to linkage with other programs if the value of the offset is not the same in the two programs.

H. Legal Issues

27. Under AB 32, is it permissible for GHG emission allowances from non-California carbon trading programs or offsets from GHG emission sources outside of California to be used instead of GHG emission allowances issued in California? Please consider especially the provisions of Health and Safety Code Sections 3805, 38550, and 38562(a) added by AB 32.

PG&E Response:

Yes, Health and Safety Code section 38564 expressly authorizes the ARB to seek to integrate California's GHG reduction program with those of other localities, states, and nations, including use of offsets and allowances from those other programs.

28. Do any of the flexible compliance options identified in these questions or discussed in the attachments to this ruling or in your opening comments raise concerns under the dormant Commerce Clause? If so, please explain why that flexible compliance option(s) may violate the Commerce Clause, including citations to specific relevant legal authorities. Also, explain if and, if so, how the flexible compliance option(s) could be modified to avoid the Commerce Clause problem. Address, in particular, whether a policy that limits offsets to only emission reduction projects located in California would raise dormant Commerce Clause concerns.

PG&E Response:

As long as the criteria applied to flexible compliance options does not discriminate against entities located outside California in favor of entities within the State, the flexible compliance options should pass muster under the Commerce Clause. However, limits on use of offsets from outside California could run afoul of the Commerce Clause because such limits would be based on geographic location, not the verifiability and qualification of such offsets. Thus, for these legal reasons as well, California should not seek to limit the eligibility of offsets projects located outside the state, as long as sponsoring entities agree to be fully subject to the jurisdiction and regulatory oversight of California.

29. Do any of the linkage options identified in these questions or discussed in the attachments to this ruling or in your opening comments raise concerns under either the Compact Clause or the Treaty Clause of the United States Constitution? If so, please explain why that linkage option(s) may violate one or both of these Clauses, including citations to specific relevant legal authorities. Also, explain if and, if so, how the linkage option(s) could be modified to avoid the Compact Clause and/or Treaty Clause problem.

PG&E Response:

No. States and nations may lawfully enter into cooperative and extraterritorial agreements without formally entering into interstate compacts or formal treaties, as long as the agreements are lawfully authorized and approved by the legislative bodies of the respective states or nations.

30. Do any of the flexible compliance options identified in these questions or discussed in the attachments to this ruling or in your opening comments, raise any other legal concerns? If so, please explain the legal concern(s), including citations to specific relevant legal authorities. Also, explain if and, if so, how the flexible compliance option(s) could be modified to avoid the legal concern(s).

PG&E Response:

No, although PG&E's legal assessment is preliminary and subject to change as the design of flexible compliance options moves forward.

V. TREATMENT OF COMBINED HEAT AND POWER

A. Detailed Proposal

1. Taking into account and synthesizing your answers to other questions in this paper, explain in detail your proposal for how GHG emissions from CHP facilities should be regulated under AB 32.

PG&E Response:

In developing a proposal for the treatment of combined heat and power (CHP) under AB32, PG&E has focused on three overarching objectives: maximizing GHG emissions reductions; managing customer costs; and demonstrating state leadership in the transition to a national or international program. Additionally, AB 32 policy should encourage market incentives for new, efficient CHP without creating subsidies for inefficient CHP.

All CHP units that generate emission quantities above a *de minimis* level should be regulated under a multi-sector cap and trade program. A facility with a regulated CHP unit would be responsible for all emissions from that unit, either as a first deliverer (for electricity delivered to the grid), or as an industrial facility (for on-site electricity and thermal load). Units below the *de minimis* threshold could be covered through programmatic measures, similar to the approach used for residential and small commercial natural gas users. Emissions would not need to be assigned to the industrial or electricity streams for compliance purposes under a cap and trade program, as the facilities would have allowances matching all unit emissions.

Emissions would need to be assigned to the industrial or electricity sector streams for allowance apportionment and allocation purposes. For electricity delivered to the grid, allowances should be distributed to utilities on behalf of their customers and then auctioned as described in PG&E's allocation methodology. As described in more detail in the following responses, this allocation method would reward efficient CHP units in the electricity market and mitigate customer compliance costs. Emissions associated with on-site electricity and thermal loads should be allocated according to the rules for the industrial sector. In the limited cases in which efficient, cost-effective CHP reduces statewide emissions while increasing on-site emissions, it may be necessary to assign some allowances to those CHP units on a case-by-case basis through the industrial sector. In accordance with the principle for an allowance allocation method that encourages efficient CHP, an allocation method should not distribute allowances for free to CHP; as this method might reward inefficient CHP.

Ultimately, PG&E believes that in the context of AB32, CHP should not receive special status. Instead, CHP units should receive regulatory treatment equal to that of electricity generators and industrial facilities regulated under a multi-sector cap and trade system. If CHP truly represents a cost-effective means of GHG abatement, its economic value will increase and no further incentive is necessary.

B. Regulation of CHP GHG Emissions

2. Should GHG emissions from CHP systems be regulated in one sector? If so, which one? How?

<u>PG&E Response:</u>

Emissions from all CHP facilities above a *de minimis* size should be regulated under the multi-sector cap and trade program. Once the facility is deemed to have emissions above the *de minimis* size, the facility should be responsible for turning over allowances for all on-site emissions. For the purposes of compliance with the cap and trade program, emissions do not need to be separately attributed between the industrial and electricity streams. Instead, CHP emissions should be regulated as a single source for cap and trade compliance purposes. Although it is unnecessary to distinguish emissions from CHP units by sector for compliance purposes, sector classification is relevant to allowance allocation.

Accordingly, CHP units would need allowances, apportioned on a separate basis, for emissions associated with grid-delivered electricity, on the one hand, and emissions associated with the industrial heat use and on-site electricity use, on the other. Allowance allocation to CHP units would be carried out through allowance apportionment between the industrial and electric sectors and through allowance allocation among sources within each sector. Apportionment and allocation of allowances between the industrial and electric sectors for cap and trade purposes are discussed in further detail below in the responses to Questions 12- 15.

With respect to the three options Staff laid out for regulating CHP emissions in the staff paper,[18] PG&E's proposal most closely matches the third option for compliance but the first option for allowance apportionment and allocation.

3. For in-state CHP systems, should all of the GHG emissions (*i.e.*, all of the emissions attributed to the electricity generation and to the thermal uses) be regulated as part of the electricity sector? If so, for the electricity that is delivered to the California grid, should the deliverer as defined in D.08-03-018 be the point of regulation? And, what entity(ies) should be the point(s) of regulation for thermal usage and electricity that is not delivered to the California grid if those uses are included in the electricity sector for GHG regulation purposes?

PG&E Response:

In-state CHP units should be treated according to the method outlined in Question 2. The CHP facility, either as the first deliverer for emissions associated with electricity exported to the grid, or as the industrial facility for emissions associated with thermal load and on-site electricity, would be the point of regulation in the multi-sector cap and trade system.

D.08-03-018 assigns compliance responsibility for electricity-related GHG emissions to the entity that first delivers electricity to the California grid. For electricity generated in-state, the first deliverer would be the generator, in this case, the CHP unit. The CHP facility would also be responsible, as an industrial emitter, for the emissions attributed to electricity generated and used on-site. Likewise, for emissions associated with its thermal load, the CHP facility would be an industrial emitter, not a first deliverer. These different emissions streams should be regulated directly as one stream, for emissions limits and cap and trade purposes, as described in the third option in the

[18] California Public Utilities Commission and California Energy Commission. "Joint California Public Utilities Commission and California Energy Commission Staff Paper on GHG Regulation for Combined Heat and Power, R.06-04-009 and D.07-OIIP-01", May 1, 2008.

Staff working paper. However, for purposes of apportionment and allowance allocation under a cap and trade program, the attribution of emissions to streams matters and requires different treatment.

4. For out-of-state CHP systems, how should GHG emissions attributed to the electricity delivered to the California grid be regulated? If part of the electricity sector, should the deliverer of the CHP-generated electricity delivered to the California grid be the point regulation? (These questions are based on our view that, for out-of-state CHP systems, only emissions attributed to electricity delivered to California, and not attributed to other electricity or the thermal output, are subject to AB 32.)

PG&E Response:

In a California only cap and trade system, electricity imports from a CHP system should be treated like other deliveries to the grid. The CHP facility or first deliverer would report emissions associated with electricity generation, differentiating emissions attributed to thermal energy, on-site electricity, and exported electricity. For a facility located out-of-state, only the electricity delivered to the grid in California would be regulated under AB 32.

5. Should CHP units be placed in different sectors based on CHP unit capacity size?

PG&E Response:

Yes, for administrative efficiency purposes under a cap and trade program, large and small units may need to be treated differently based on capacity size and whether or not the emissions pass the *de minimis* threshold.[19] CHP facilities above the threshold should be fully eligible for and included in a multi-sector cap and trade program, with allowances allocated and apportioned between the industrial and electric sectors based

[19] There are several possibilities for what the de minimis level should be. PG&E discusses one possibility, any facility that uses more than 250,000 therms, below. The regulatory agencies should convene a discussion on the best de minimis level in a technical forum.

on the allocation methodology applied to these sectors and the emissions attributed to the various CHP outputs. CHP facilities below the threshold would be exempt from the cap and trade program and instead regulated directly as single sources with single facility-wide emissions limits or reduction measures.

The distinction between large and small CHP facilities is important for a variety of reasons. Large and small CHP generally serve different purposes. Small CHP reduces customer load and internal costs, while large CHP, which is sized to meet on-site thermal load, primarily exports electricity to the grid. Large CHP facilities tend to have owners with the economic knowledge necessary to effectively compete with other generators and sell excess electricity in the market. For smaller CHP installations which tend to serve on-site load and are less likely to actively participate in external electricity markets, economic incentives can be addressed through non-market measures, such as expanding the CPUC's Self Generation Incentive Program to include appropriately efficient installations.

6. Should any of the options for assigning the emissions of a CHP unit to one or more sectors be rejected because it might violate the dormant Commerce Clause?

PG&E Response:

No, as long as none of the options discriminates among CHP units on the basis of geographic origin outside the state or attempts to regulate extra-territorial emissions, *e.g.* on-site emissions that are not associated with electricity or products delivered inside California, the staff options should not violate the Commerce Clause.

7. Should the type of GHG regulation (*i.e.*, cap and trade or direct regulation) be different for a topping-cycle CHP unit versus a bottoming-cycle unit?

PG&E Response:

All CHP facilities above *de minimis* emissions levels should be included in the cap and trade program, in order to ensure that the cap and trade program is robust, multi-sector and liquid. Because PG&E recommends full coverage of CHP units, the distinction between bottom-cycling and topping cycling units does not matter for AB 32 compliance purposes. As explained above, the CHP facility would be responsible for compliance with AB 32 emissions limits for all on-site emissions, regardless of the CHP process or sector to which they are attributed. Assigning emissions to CHP processes does affect allowance apportionment and allocation among the industrial and electric sectors and entities, but not compliance responsibility, so the difference between bottoming-cycle and topping-cycle should be handled in reporting protocols.

8. Should the sectors used for GHG regulation be different for topping cycle and bottoming cycle CHP units?

PG&E Response:

No, the sectors should not be different for topping-cycle and bottoming-cycle units. The distinction, which matters for allowance apportionment, should be in how emissions attributed to CHP outputs are assigned to the industrial and electricity sectors. All CHP, except for the smallest units with *de minimis* emissions, should be covered in sectors included in the cap and trade regulation.

9. Should CHP be part of a cap-and-trade program or not? If so, should the entire unit or certain CHP outputs be part of the cap and trade program?

PG&E Response:

If a CHP unit has emissions above a *de minimis* level, all of the emissions generated should be part of a cap-and-trade system. Under a multi-sector cap and trade system, electricity, industrial and large natural gas sources, as well as sources from other sectors, would be regulated. Therefore, all CHP unit outputs would be covered by the cap and trade program. Although D.08-03-018 recommended excluding the natural gas sector from a multi-sector cap and trade program, it also distinguished small end-users, such as residential and small commercial customers with annual emissions below a threshold defined by the ARB, from large end-users. Most CHP facilities are not core gas customers and would not be included in the natural gas sector recommendations for residential and small customers in D.08-03-018.

For purposes of determining *de minimis* emissions, CHP units that consume more than 250,000 therms/year or greater than 500 kW are prohibited from using the core gas rate.[20] Large end-users that emit at least 2,500 metric tons of CO2*e*, the ARB's reporting threshold, or another threshold chosen,[21] are not allowed to be core gas users. Emissions from these sources (or sources larger than a specified *de minimis* level) should be captured under a cap and trade program. Emissions from very small CHP could be considered for regulation under programmatic measures comparable to those for residential and small commercial natural gas users.

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[20] PG&E tariffs, Gas Rule #12: Electric Generation or Cogeneration Customers with generation capacity of five-hundred kilowatts (500 kW) or larger will be prohibited from core service.

[21] 250,000 therms of natural gas will emit about 1,330 metric tons of CO2. Thus, there is a gap between small CHP covered in the core gas rate and the de minimis threshold currently suggested by the ARB.

10. Should electricity delivered to the California grid by a CHP unit be regulated under the deliverer point of regulation established in D.08-03-018? Why or why not?

PG&E Response:

Yes. Electricity delivered to the grid by a CHP unit should be regulated under the deliverer point of regulation established in D.08-03-018. However, this distinction will only matter for allowance apportionment and allocation, as all CHP units would comply with the emissions cap regardless of sector classification. In terms of compliance with electricity sector emissions reduction responsibility, CHP first deliverers must have the same obligations as all first deliverers, given that many large CHP units are designed primarily to export electricity to the California grid.

If a CHP unit were efficient and reduced emissions, as compared to other energy sources, then the CHP owner, both as an electricity consumer and a first deliverer, would be rewarded in a market-based cap and trade system. The owner would first meet on-site electricity use (thus reducing their utility bills) and could sell electricity to the California grid at a lower marginal cost than higher-emitting sources setting the marginal electricity price. As discussed below, this inherent market incentive for efficient CHP means that CHP owners do not need additional subsidies, should not be classified as “emissions reduction measures,” and should be treated no differently than other low emitting first deliverers, such as renewable generators or highly efficient combined cycle gas turbines.

Small CHP units included in the core gas rate (or designated to a “small CHP” category per a regulatory threshold) would not likely export significant quantities of electricity to the grid, and thus would not be first deliverers.

11. Should electricity generated by in-state CHP systems for on-site use be subject to the same regulatory treatment as CHP electricity delivered to the California grid? Why or not?

PG&E Response:

As indicated in PG&E's response to Question 9, all emissions generated at a CHP facility should be covered by the cap and trade program, so for compliance purposes, it is unnecessary to distinguish between electricity consumed on-site and electricity from the grid. However, the distinction between on-site and delivered electricity is relevant to allowance apportionment between sectors and allocation among sources in the electricity sector, as discussed in PG&E's responses to Questions 12 – 15. For these purposes, emissions associated with on-site electricity at sites with total emissions above the de-minimis level should be included in the industrial sector, not the electricity sector.

12. If CHP is regulated in the electricity sector (either as one combined unit or based only on the total electricity output or based only on the electricity delivered to the California grid), do any of the proposed staff allocation options for electricity need to be modified? How?

PG&E Response:

No. The same recommendations PG&E has made regarding allocation of allowances in the electric sector should apply to emissions associated with electricity delivered to the grid by CHP facilities. Allocation methods for industrial sector emissions would likewise apply consistently to the emissions associated with CHP thermal outputs and on-site electricity generation. Please see Section III for more comments on the staff allocation options.

13. If CHP is treated separately from the electricity sector, but is still included as part of a cap-and-trade program, how should allowance allocation to CHP units be handled?

PG&E Response:

For CHP emissions assigned to the electricity sector, allowance value should be allocated to utilities based on load served and avoided through CEE activities, according to the allocation methodology used for all other sources in the electricity sector. As CHP generators will internalize the value associated with emissions for CHP electricity exported to the grid, this method protects electricity customers in the same way as allowances allocated for the benefit of utility customers protects customers generally.

Allowances for emissions associated with on-site electricity use and the thermal load should be reported and subject to the same regulatory treatment as industrial sector emissions under a cap and trade program. As stated in previous comments on allowance allocation methodology generally, PG&E believes that any allocation option that distributes allowances based on historical emissions favors high-emitting generation sources and thus would discourage lower emitting, more efficient CHP. For more detail on the reasoning behind this conclusion, see discussion in Section III above.

When efficient CHP is installed, apportionment of allowance value related to electricity use must be re-distributed so as not to cause disproportionate harm to either the electricity sector or the industrial sector. In the examples in the table below, addition of a CHP unit with a current standard heat rate[22] causes a decrease in overall emissions

[22] 11,400 but/kWh, based on PG&E's 2006 LTP testimony; other assumptions: The 50 MW CHP displaces electricity from a 300 MW CCGT, 7400 btu/kWh, 80% capacity factor. The CHP has an 80% capacity factor. The boiler has 80% efficiency.

from a State perspective. However, depending on how the emissions are assigned to sectors, electricity and industrial sector emissions would increase or decrease.

	Before CHP	After CHP, % of electricity-related emissions assigned to electricity sector (% electricity consumed on-site, attributed to industrial sector)		
		100% (0%)	90% (10%)	85% (15%)
Total California Emissions	920	902	902	902
Industrial Sector Emissions	93	74	88	95
Electricity Sector Emissions	827	828	814	807

In this example, emissions attributed to the thermal load are assigned to the industrial sector. Emissions attributed to the electricity exported to the grid are assigned to the electricity sector. The amount of electricity used on-site and the sector to which those emissions are assigned determine if sector emissions increase or decrease. When 100% of the CHP emissions attributed to electricity are assigned to the electricity sector, electricity sector emissions increase. When 15% of the emissions attributed to electricity are assigned to the industrial sector, industrial sector emissions increase. Ultimately, the ARB must determine a process to adjust and update allowance apportionment among the affected sectors so that electricity customers do not subsidize emissions at industrial facilities, or vice versa.

14. If allowances are allocated administratively to CHP units, should the allocations take into account increased efficiency of CHP? If so, how?

PG&E Response:

No. PG&E believes that no allowances should be allocated administratively or free to CHP. A cap and trade program will reward efficient CHP, as the market will internalize the emissions value in electricity prices. As such, CHP would not need special regulatory treatment or subsidies. An allowance allocation method should be based on the general principle of returning the allowance value to the customers bearing the compliance costs.

A carbon cap and trade program should reward facilities that produce electricity with a lower emissions intensity than the intensities of competing energy sources. A facility that installs an efficient CHP system benefits financially from that efficiency in three ways, so additional incentives are not needed. First, assuming that electricity produced on-site is less emissions-intensive than grid electricity delivered from other sources, the facility would have access to an energy source with a lower marginal cost than electricity it would otherwise buy. Second, the facility could sell electricity at a lower marginal cost than competitive, higher emitting sources that set the marginal electricity price. Third, the facility would benefit from increased thermal efficiency. Therefore, a truly efficient CHP unit would have the market advantages of any other low-emitting resource, and would not require allowances or other subsidies, or special regulatory treatment.

Because not all CHP units are more efficient than other energy sources, PG&E would not support direct administrative allocation to CHP units. Such an approach could also reward inefficient CHP units. Additionally, the European Union emissions trading experience has shown that generators will include the opportunity cost of freely allocated allowances in the price of electricity, so PG&E believes that the better choice is to allocate allowance value to utilities on behalf of electricity customers.

That said, there are some instances in which in might be necessary to allocate allowances to very efficient CHP for industrial sector emissions. As shown in the example in the response to question 13, above, PG&E recognizes that in some cases efficient CHP units could yield net statewide emissions reductions, while increasing on-site emissions assigned to the industrial sector. In the very few cases in which an efficient CHP unit would reduce statewide GHG emissions, but increase on-site emissions to such an extent that the unit would be uneconomic, it might be necessary to distribute some allowances to the unit, using a methodology that ensures that the thermal output is being used. This distribution should occur through the industrial sector, as allowances needed for electricity sector emissions would be priced in the electricity delivered to the grid.

15. Are there advantages to having all emissions from in-state CHP regulated as part of the electricity sector under cap and trade (and therefore with the need for only a single set of allowances?) How should this be accomplished?

PG&E Response:

No, because under either multi-sector or single sector regulation of CHP, all the emissions from units above a de minimis level would be regulated. The ARB would issue a standardized set of allowances each compliance period, representing the total emissions limit for all sectors covered under the cap and trade program, which should have the same characteristics and the same face value at the time of issuance. Allowances should not be grouped or identified according to the sector to which they would be distributed. If the installation of CHP increases industrial sector output, the ARB should update the apportionment of allowances to the industrial sector accordingly, and vice versa.

17. What is the best approach to regulation of CHP emissions to minimize the potential for disincentivizing new installations of CHP and why is that the best approach?

PG&E Response:

The best approach for avoiding disincentives is a well-designed cap and trade market with broad multi-sector coverage, including coverage of all emissions above a de-minimis level from CHP facilities. As explained in PG&E's response to Question 4, a comprehensive, well-structured market will reward low-cost emission reduction measures. An efficient CHP unit producing electricity that is less emissions-intensive than competitive sources would use and sell low-cost electricity. No further incentives to efficient CHP would be necessary.

24. Would including all of CHP in cap and trade create a disincentive if natural gas is not regulated under cap and trade?

PG&E Response:

The majority of industrial natural gas use would be included in the multi-sector cap and trade system. As explained in PG&E's response to Question 9, large CHP facilities would be included in the cap and trade system as part of the industrial sector. Excluding residential and small commercial natural gas use would have no impact on these CHP facilities, as they should not fall in the residential and small natural gas user category. Including CHP in the cap and trade program would not affect residential and small commercial customers using very small natural gas CHP to meet their on-site load, as these customers would unlikely be first deliverers. If small CHP is efficient and economic, small natural gas and electricity customers will see financial benefits through decreased electricity and natural gas bills.

C. CHP as an Emission Reduction Measure

16. Should CHP be considered an emission reduction measure under AB 32? Why or why not?

<u>PG&E Response:</u>

No, CHP units should be treated no differently than other sources in both the industrial and electricity sector. Under a cap and trade program, such net low emitting sources would receive benefits in the marketplace due to their lower internal costs of carbon. Large CHP should not receive any programmatic set-asides or other direct or indirect subsidies or exemptions under AB 32. As explained in PG&E's response to Question 14, if large CHP is truly efficient, CHP facilities will receive financial incentives in the marketplace due to lower internal carbon costs.

Likewise, CHP cannot be analogized and considered an emissions reduction "measure" in the same sense that energy efficiency, for example, is an emissions reduction "measure." If a particular CHP installation produces electricity for export to the utility grid with fewer GHG emissions than other available sources of electricity,, there will be a natural market for that electricity. If that installation does not provide efficiency benefits, there would not. Treating CHP as a "measure" with arbitrary benefits or subsidies would mean that the natural capture of the potential efficiencies of CHP would be distorted and CHP would be "over built" from the perspective of most economically efficient methods for reducing GHG emissions. As the Staff paper indicates it is possible for some CHP installations to result in no net change in overall emissions. CHP installed without existing thermal load may actually increase overall emissions. In their July 2007 paper "Preliminary Estimates of Combined Heat and

Power Greenhouse Gas Abatement Potential for California in 2020," Lawrence Berkeley Laboratory states (emphasis added):

> "Note that for many sectors, carbon emissions reductions increase from the low to the medium penetration scenarios, but decrease in the high and/or maximum penetration scenarios. CHP system efficiency decreases as penetration increases: the most attractive sites, i.e. those with a use for much of the waste heat, are assumed to adopt first; however, as penetration levels increase, CHP becomes less favorable. Typically, CHP is only more carbon efficient than the grid electricity it displaces when the waste heat from the generation offsets additional fuel consumption. *Given the quite clean grid generation being displaced, inefficient CHP systems can ultimately lead to a net increase in emissions. This is evidenced in the industrial sector of the maximum scenario."*

Therefore, because efficient CHP may be lower emitting on a net basis than other sources of GHGs, facilities would have financial incentives to install CHP without the need for special treatment under AB 32 or special subsidies. If inefficient CHP is subsidized, overall societal emissions may increase.

18. Should ARB and/or the Commissions consider policies or programs to encourage installation of CHP for GHG reduction purposes? Why or why not?

<u>PG&E Response:</u>

No, for the reasons stated above, the ARB should not provide special subsidies or exemptions for CHP facilities under AB 32. Several programs already exist today that support development of CHP in California: exemptions from certain non-bypassable charges; waiver of stand-by charges; and participation in the Self Generation Incentive Program for fuel cell CHP units. PG&E would support extension of the SGIP program to any small CHP that met certain efficiency standards. In addition, the California Legislature recently passed, and the CPUC will soon implement, AB 1613, which provides for compensation for exported generation for CHP that is sized to meet an existing thermal load.

For larger CHP, however, there is no need for special subsidies or programs. The establishment of any subsidy, set-aside, or other program based on an assumption that CHP is automatically beneficial, is likely to distort the market and lead to over-installation of CHP in California –without producing true GHG emissions reductions. As stated above, the market will compensate efficient CHP. CHP projects with inherent increased efficiencies are economic and competitive relative to other alternatives and therefore do not need any special policies or programs to encourage their installation. Where CHP does not lower statewide GHG emissions, project economics will not improve upon implementation of a cap and trade program, and preferential treatment may be counterproductive.

Finally, PG&E notes that even the most efficient CHP may not be the best choice for California to reduce GHG emissions. New combined cycle gas turbine (CCGT) plants are extremely cost-effective, with low heat rates compared to lower capacity natural gas units. It may be easier and more cost-effective to sequester carbon at centralized 600 MW plants than at dispersed, customer-owned CHP installations. Therefore, there may be few CHP installations that represent cost-effective choices for emissions reductions. These may be limited to only those locations where boilers today exist for existing thermal load.

19. Should CHP have an efficiency threshold in order to qualify as an emission reduction measure? If so, why?

PG&E Response:

As stated above, PG&E believes that CHP should not qualify as an emissions reduction measure. Therefore, an efficiency threshold is not relevant to AB32 implementation.

20. Which of the proposed methods best achieves the objectives of an efficiency threshold and why is it the best? Is there a superior method not proposed by staff and why is it superior?

PG&E Response:

As stated above, PG&E believes that CHP should not qualify as an emissions reduction measures. Therefore, a benchmarking method that establishes an efficiency threshold is not relevant to AB 32 regulation.

21. What should the minimum efficiency threshold be (in terms of % savings) to qualify as an emissions reduction measure and why is that the appropriate minimum efficiency threshold?

PG&E Response:

PG&E, as stated, does not support CHP as an emissions reduction measure. Therefore, a minimum efficiency threshold that qualifies CHP as a measure is not relevant to AB 32 regulation.

23. Should the Commissions pursue policy or programmatic measures to overcome some of the barriers to CHP deployment?

PG&E Response:

No. Many of the barriers to CHP deployment are beyond the control of regulation. Market barriers preventing deployment of CHP today include: complexity found in Cal ISO tariffs; high payback criteria for capital investment in the commercial and industrial sectors; perceived volatility of the natural gas market; and unwillingness to acquire the necessary skills to own and operate a CHP installation.[23] None of these barriers is likely to be addressed with monetary incentives. Education, process

[23] See April 28, 2005 Committee Workshop: California's Market Potential for Combined Heat and Power (CHP) and Distributed Generation, 2005 IEPR http://www.energy.ca.gov/distgen_oii/documents/2005-04-28_workshop/2005-04-28_TRANSCRIPT.PDF.

improvement, or the arrival of a niche market player willing to own and operate generators for customers with thermal loads all could help overcome these barriers. The high payback criteria for nonresidential customers, typically one and a half to two years, means that CHP would effectively require a return on investment (ROI) of at least 50%. Education can provide an impetus for customers to lower that high market barrier. As one participant in a CEC workshop explained, he was successful at convincing his employer to consider a CHP installation as an investment (which meant it had a much lower ROI threshold requirement), rather than a capital improvement.[24] The CHP market could also develop more successfully if a player enters that is willing to own and operate CHP for customers who have a thermal load, but are reluctant to acquire the engineering expertise necessary to install CHP. In the solar generation market, for example, market penetration has improved because some solar installers are owning, operating and maintaining the solar installation for nonresidential customers.

The ARB should not pursue monetary incentives for large CHP, CHP portfolio set-asides or numerical targets, or cost-shifting from the industrial sector to electricity customers. Programmatic measures to overcome barriers or direct or indirect economic subsidies to CHP would therefore lead to market distortions. Programmatic measures are only effective at addressing certain market barriers. For example, monetary incentives can overcome a high first cost market barrier, but education programs are much more cost effective at overcoming a fear-of-the-unknown market barrier. Set-asides are only necessary for preferred non-competitive resources, such as renewables. As CHP is not a GHG neutral resource like renewables or energy efficiency, it should

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[24] *Ibid.*

not have a set-aside. As PG&E has previously noted, CHP is the only must-take, non-dispatchable resource that has GHG emissions. Adding large amounts of CHP would actually make adding must-take, non-dispatchable renewables more difficult.

D. Legal Issues

22. Are there other legal and regulatory barriers to CHP implementation in California that should be considered with respect to GHG regulation? If so, please explain in full with citations to specific relevant legal authorities. Also explain if and, if so, how the barriers could be avoided.

PG&E Response:

For the reasons stated above, PG&E believes there are no significant regulatory or legal barriers to the development of low-emitting CHP facilities in California, provided that all CHP facilities which emit significant quantities of GHGs are subject to emissions limits and are covered by cap and trade programs that are applied to other GHG emissions sources under AB 32.

VI. NON-MARKET-BASED EMISSION REDUCTION MEASURES (OTHER THAN CHP) AND EMISSION CAPS

A. Electricity Emission Reduction Measures

1. What direct programmatic or regulatory emission reduction measures, in addition to current mandates in the areas of energy efficiency and renewables, should be included for the electricity and natural gas sectors in ARB's Assembly Bill (AB) 32 scoping plan?

PG&E Response:

The following programs should be undertaken by these other state agencies and credited by ARB toward meeting AB 32 goals:

- Upgraded building codes, appliance standards, and land use planning policies, including actions by state agencies and local governments to implement and enforce the upgraded codes and standards

- Equal and comparable enforcement of Renewable Portfolio Standard (RPS) and CEE programs among load-serving entities in the state, including both investor-owned utilities and publicly-owned utilities.

- Use by the ARB, CPUC, CEC and local publicly-owned utilities of consistent and standardized measurement and evaluation protocols for energy and carbon savings across different programs and entities.

- Improved and strengthened national appliance efficiency standards, as well as waivers of any federal preemption of better California standards.

The ARB should not adopt direct regulatory mandates for energy efficiency or renewables as part of AB 32 emissions reduction measures. Instead, the ARB should include and "take credit" in its AB 32 program for realistic assumptions regarding how CPUC and CEC CEE and renewables programs as well as other state initiatives already underway by other state agencies, such as improved building codes and appliance standards administered by the CEC, will be implemented to reduce GHGs. These GHG reduction assumptions should be consistent with assumptions and projections worked out in the relevant CEE and RPS implementation proceedings at the CPUC (for IOUs) and CEC (for POUs), as well as in other state proceedings, such as the building codes and appliance standards proceedings at the CEC. Moreover, the ARB should work with the CEC and PUC through these already established proceedings to implement any direct regulatory mandates for CEE or renewables that can be credited as part of the AB 32 emissions reduction measures, because these programs are already subject to regulatory mandate and control by other agencies.

State Action to Upgrade and Enforce Codes and Standards

Many savings are projected to come from improved building codes and appliance energy efficiency standards. However, there are acknowledged compliance problems with these codes and standards. As referenced in the April 25, 2008 edition of California

Energy Markets, William Callahan, president of the Bay Area Associated Roofing Contractors, explained that many residential roofing projects require a permit, but often contractors and customers just skip the permit process. In that same article, Erik Emblem, an attorney representing sheet-metal and heating, ventilation and air-conditioner contractors, said 90 percent of HVAC projects have no permit. Permitted projects that meet code can run $2,000 more than projects that do not, he said.

California may create rigorous codes and standards, but if these standards are not enforced, non compliance (‘*permits not pulled*’) will result in lower realized gross energy efficiency savings and GHG emissions reductions will not occur. Further, if the ARB assumes these reductions will occur, then electricity load will increase, putting pressure on the sectors in the cap and trade program, despite these sectors not being legally responsible for the necessary enforcement activities. The ARB and CEC should promote compliance with standards through appropriate enforcement agencies and provisions.

Equal and Comparable RPS and CEE Mandates and Enforcement for Publicly Owned Utilities and Investor Owned Utilities

In terms of implementation, obtaining the most cost-effective amount of GHG reductions attributable to CEE and renewable energy programs requires that both publicly-owned utilities and investor-owned utilities be subject to substantially the same regulatory standards and enforcement. Publicly owned utilities serve 25% of the electric load in California, but they are responsible for nearly 42% of the utility CO2 emissions.[25] The PUC and CEC must ensure that responsibility for GHG reductions

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[25] Michael Scheible, Deputy Executive Officer, ARB, presentation, June 8, 2007: http://www.caiso.com/1bf7/1bf76d0426130.pdf.

assumed from these programs is spread out evenly among all utilities - providing credit for the earlier actions by IOUs that have reduced GHGs and considering the unrealized low-cost opportunities in areas of the state where POU renewables and CEE programs have lagged behind.

As CEC staff noted at the ARB's May 2, 2008, public workshop, despite serving 22% of the electricity load, POUs only contribute 5.4% of energy efficiency savings. If SMUD is removed from those figures, the remaining POUs only contribute 2.7% of energy efficiency savings while serving 18% of the load. These figures show the huge CEE savings potential in POU territory, savings that the IOUs have been accumulating for years given their thirty year history of successful cost effective CEE..

While many POUs have numerical targets equal or greater than the 20% RPS for IOUs, POUs may not be using the same counting conventions that state law, as implemented by the CEC, requires IOUs to use. As POUs have different eligibility requirements than the retail sellers, POUs may "green" their power by using (some) large hydro and renewable energy credits (RECs) to meet their goals. In 2003, while POUs represented their renewable deliveries as being 7.6% of their combined retail sales, only 5.1% were CEC-eligible renewable sales. This uneven playing field results in customer confusion and results in a State energy policy that is applied to only 2/3 of the energy consumers in the state -- that is, those energy consumers served by the investor owned utilities.

Ensure consistent and standardized measurement and evaluation protocols for energy and carbon savings across different programs and entities.

It is also critical for ARB that consistent and standardized measurement and evaluation protocols are established for carbon reduction strategies across different programs and different sectors. Energy efficiency savings from the IOU and the POUs need to employ the same standardized protocols; similarly, CEE goals and realized savings must employ the same consistent standards; otherwise there will be a permanent disconnect between goals and accomplishments. It is in everyone's interest for these compliance requirements to be shared evenly and responsibly across all public and private entities in California.

Strengthening Federal Appliance Standards

Another roadblock to achieving hoped-for energy efficiency savings under AB 32 is the possibility that California appliance energy efficiency standards may be preempted by federal mandates which are not as rigorous. States may only enforce their own standards until a federal standard is created. A case where this has happened is with the residential clothes washer standards, for which there are only federal energy standards. California developed water efficiency only standards in 2003 and applied for a waiver from preemption, which was rejected. This is an example of how federal preemption may leave low cost GHG emissions reductions on the table. The ARB should work with the US government to establish rigorous codes and standards even where federal standards exist.

No New Regulatory Set-Asides

The ARB should not create new-set asides or portfolio mandates for the electricity sector for AB32 purposes. Such actions defeat the cost-effectiveness goal mandated in AB32 and undermine the policy's effectiveness. California will already have challenges meeting the 20% RPS and the current CEE goals. Creating new, unreachable goals will increase costs to a level which might incite a backlash against

AB32. In E3's model, the cost of increasing from 20% RPS to 33% involves reductions that cost hundreds of dollars per ton. Rather than creating infeasible goals, the CEC and PUC should suggest to the ARB that the GHG market find the most cost effective reductions.

Premature to Adopt a 33% RPS Target

PG&E agrees with the statement by CPUC staff at the May 2, 2008 ARB workshop on the challenges of achieving a 33% RPS: "Given the implementation challenges associated with the 20% by 2010 target, the 33% goal could be difficult to implement." To date, available economic modeling by the CPUC suggests a 33% RPS target by 2020 is unrealistic, and it is premature to establish any expanded renewable procurement targets beyond the current 20% by 2010 mandate. As PG&E pointed out in its opening comments on E3 modeling issues in this proceeding, a number of critical issues must be resolved, and additional feasibility assessments performed prior to increasing the existing 20% RPS target. These issues and assessments include: (1) adequacy of supply; (2) adequacy and availability of transmission infrastructure, and (3) how to integrate new renewable resources into the grid and manage over-generation.[26] Moreover, AB 32 requires that GHG reduction strategies, including the role of new renewables, be evaluated and considered in light of all other potential strategies, so that the adopted GHG limits and emissions reduction measures "achieve the maximum technologically feasible and cost-effective reductions" in GHGs. (Health

[26] Pacific Gas and Electric Company, "Docket 07-OIIP-01, California Energy Commission, Opening Comments of Pacific Gas and Electric Company (U 39 E) on Economic Modeling Issues Under AB 32," pp. 17-23.

and Safety Code 38562(a).) Without this analytical and cost-benefit modeling, a 33% RPS target in and of itself is not consistent with AB 32.

While renewable resources may be one of the tools to achieve GHG emissions reductions, ARB should not impose new renewables mandates but instead should rely upon a set of well-integrated GHG-reducing regulatory programs and performance standards undertaken by other agencies such as the CPUC and CEC to advance renewable energy, including policies to promote and significantly expand renewable sources of electricity at a reasonable cost, and policies to promote renewable sources of natural gas. Establishment of a specific 33% target is not necessary to carry out such pre-existing policies. The CPUC, in its 2006 Long-Term Plan Decision No. 07-12-052 indicated that further analysis is needed regarding the feasibility and cost of a 33% renewables target. Absent such analysis, which is underway through a variety of initiatives including RETI, streamlined permitting and transmissions processes, and other cross-agency discussions, a higher target may impede parties' ability to fix the current processes and understand what will be needed for system reliability as more renewables come on line. Currently, adopting 33% is premature given feasibility and cost challenges. Rather than mandating increased RPS targets at this time, the agencies should allow the many processes evaluating the feasibility of this initiative to go forward.

Other Regulatory Set-Asides

CHP is discussed above in the CHP section. For the various reasons described above (clean CHP will be rewarded by market incentives in the cap and trade system without the need for subsidies), there should be no CHP set aside nor any separate CHP mandate under AB 32.

IOU CEE goals may already be larger than what is technologically feasible or cost-effective. The agencies should focus on establishing and enhancing CEE programs in areas of the state where the programs are lagging, improving compliance with existing building codes and standards, and upgrading those codes and standards.

2. Are there additional regulations that ARB should promulgate in the context of implementing AB 32, that would assist or augment existing programs and policies for emission reduction measures in the electricity and natural gas sectors?

PG&E Response:

See response under Section B.2, below.

5. What percentage of emission reductions in the electricity sector should come from programmatic or regulatory measures, and what percentage should be derived from market-based measures or mechanisms? What criteria should be used to determine the portion from each approach? By what approach and in what timeframe should this question be resolved?

PG&E Response:

As stated above, AB 32 regulations should not seek to mandate regulatory goals for CEE or renewables, but should take into account realistic assumptions on emissions reductions attributable to current and proposed CPUC and CEC programs in these areas.

Moreover, this question begs the more important question regarding the context of a multi-sector AB 32 program. AB 32 has set a goal for California as a whole, not solely for the electricity sector. If we assume that the California goal (1990) is the electricity sector goal (electricity sector 1990 levels), then the E3 modeling at the CPUC suggests that the electricity sector will meet its goal through 20% RPS and current CEE goals. According the ARB, electricity sector emissions in 1990 were 115.8 million tons.

E3's base case projects 108 million tons in 2020. If the electricity sector is part of a multi-sector cap and trade program, to the extent that other sectors can find cost-effective reductions in the electricity sector, electric sector emissions will decrease.

The relevance of this question comes into play when deciding what the level of the overall cap will be. This question can only be answered through the ARB scoping plan process. In advising the ARB what the electricity sector emissions will be and the reductions expected from current programs, the CEC and CPUC must be mindful of communicating realistic levels and not double count savings. Because the levels of CEE in the current CPUC goals already are extremely aggressive and untested, and may need to be updated for new measurement and evaluation (M&E) DEER[27] numbers, the PUC and CEC should communicate that less than the Mid-Level Itron[28] goals may be reached. When communicating the CEE potential to the ARB, the CPUC and CEC must take into account the range of uncertainty associated with the realization of these aggressive CEE goals.

The CPUC Energy Division has indicated that their CEE goals timeline does not permit updating the CEE potential and goals to be consistent with the new DEER. PG&E recommends that these updates be required if these high CEE goals are to be included in the ARB scoping plan. The new gross state EE goals for the time period

[27] Database of Energy Efficiency Resources (DEER) contains the results of EE measurement and evaluation studies which are then used to determine what EE savings are actually realized. Targets are often set on theoretical values which then need to be revised in the light of empirical analyses. Recent DEER studies have revised mainly downward many estimates of potential EE savings.

[28] Itron was hired by the Energy Division to assist in setting EE goals for 2012 and beyond. Itron has expertise in measuring and evaluating EE savings. The Energy Division used this report to develop and propose alternative EE goals related to Low, Mid and High level scenarios. See Itron, Inc. Consulting and Analysis Services, Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond , April 15, 2008.

2012-2020 can be used in ARB's scoping plan providing that the goals are revised to reflect the latest adopted M&E parameter values.

There is a need to be extremely vigilant to avoid double counting of savings. For example in the peak demand goals recommended by Energy Division, no account is taken of the dynamic pricing programs. Studies on dynamic pricing suggest that these programs could result in an 8 to 40 percent reduction in peak load. The omission of these effects from the Itron study means that Itron's estimated savings are likely to be significantly over stated and if counted could result in significant double counting of peak savings.[29] The Commission has ruled that Ag, Large Commercial, and Industrial customers be on dynamic pricing by Jan 1, 2010 while residential and small commercial customers are required to be on this pricing schedule by Jan 1, 2011.

At the May 2, 2008 ARB workshop, CPUC staff asked if targets for the sector be set based on current assumptions regarding costs and technological potential, or if they should be set as a stretch goals. PG&E believes that targets for California as a whole can be based on stretch goals under which agencies support innovation in the marketplace and R&D to reach those goals, rather than "command and control" mandates. An example of a tool that policy makers have that individual entities do not is land use and urban planning. Policy makers can foster the systems that allow for more mass transit and decreased land use. Individual actors in the cap and trade market cannot. Command and control programs should not depend on market transformation

[29] Note that page 9 of the Itron report (March 24, 2008), footnote 3, recognizes this type of interaction and states that this could *severely limit the analytic value of the scenario results.* See Itron, Inc. Consulting and Analysis Services, Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond, April 15, 2008.

assumptions and should be based on currently known technologies, because mandates under such programs offer no choice in how to meet goals.

In sum, the CEC and CPUC should be extremely careful in assuming further reductions will come from direct programs other than those programs already in place. Direct mandates should have realistic goals. Stretch goals are appropriate for policies that are encouraging innovation, but not for forcing goals that are not realistic. California will need unprecedented reductions from all sources to meet AB 32 goals. However, this should be left to the market and not forced through channels that are not inherently the most innovative.

B. Natural Gas Emission Reduction Measures

1. What direct programmatic or regulatory emission reduction measures, in addition to current mandates in the areas of energy efficiency and renewables, should be included for the electricity and natural gas sectors in ARB's Assembly Bill (AB) 32 scoping plan?

PG&E Response:

The following options listed above for electricity also apply to natural gas. Please see the text in the electricity section for further explanation:

- Upgraded building codes, appliance standards, and land use planning policies, including actions by state agencies and local governments to implement and enforce the upgraded codes and standards

- Equal and comparable enforcement of Renewable Portfolio Standard (RPS) and CEE programs among load-serving entities in the state, including both investor-owned utilities and publicly-owned utilities.

- Use by the ARB, CPUC, CEC and local publicly-owned utilities of consistent and standardized measurement and evaluation protocols for energy and carbon savings across different programs and entities.

- Improved and strengthened national appliance efficiency standards, as well as waivers of any federal preemption of better California standards.

2. Are there additional regulations that ARB should promulgate in the context of implementing AB 32, that would assist or augment existing programs and policies for emission reduction measures in the electricity and natural gas sectors?

PG&E Response:

The Climate Action Team has identified multiple categories of affirmative emissions reduction measures outside the electric and gas utility sector, with assumed emissions reductions associated with each.[30] These emissions reduction measures apply to the building and appliance sectors, to state agencies and local governments, to the transportation sector, and to the agriculture and forestry sectors, among others. To the extent that these emissions reductions also include a component for energy savings, those savings should be evaluated and included in the ARB's forecasts and emissions reduction measures.

C. Annual Emission Caps for the Electricity and Natural Gas Sectors

4. The scope of this proceeding includes making recommendations to ARB regarding annual GHG emissions caps for the electricity and natural gas sectors. What should those recommendations be? What factors (*e.g.*, potential effectiveness of identified emission reduction measures, rate impacts for electricity and natural gas customers, abatement cost in other sectors, anticipated carbon prices) should the Commissions consider in making GHG emissions cap recommendations? If sufficient information is not currently available to recommend cap levels, what cap-related recommendations should the Commissions make to ARB for inclusion in its scoping plan?

PG&E Response:

As discussed above in response to Question 13, the statutory criteria mandated by AB 32 for setting emissions reduction targets should be applied to the annual emissions caps to be set for the 2012- 2020 period. These include technological feasibility; economic efficiency; cost and rate impacts on consumers and businesses and

[30] Cite CAT Macroeconomic Report, October, 2007.

governments; and impact on low income communities and ratepayers. Overall, the trajectory of emissions targets for 2012- 2020 should take into account a rigorous and fully peer- and public-reviewed economic model of the impacts of the targets on each and every sector of the California economy, including an assessment of abatement costs and availability of emissions abatement measures across each sector. This assessment should be realistic across all sectors, and should carefully consider sales growth in the electric and gas sectors, both before and after evaluation of proposed CEE and renewables programs. To the extent electricity generating resources are assumed to remain in operation and not be replaced during the 2012- 2020 period, such as coal-fired or other high-emitting generating resources, those assumptions must be rigorously and carefully reviewed and evaluated in setting the interim 2012- 2020 targets for the electric sector. Likewise, to the extent that factors, in the transportation sector, such as federal fuel economy standards and higher gasoline prices, are expected to affect vehicle sales or miles traveled, those factors must be taken into account in setting sector-specific interim emissions limits.

Like the response to question A.5, these questions can only be answered in the context of the multi-sector cap. AB 32 mandates an overall goal for the state for 2020. Over-all cap levels should consider:

- The sectors in the cap. Sectors not in the cap should meet their reductions through programmatic measures. The capped sectors should not have to make extra reductions for uncapped sectors.
- Gradual reductions. The emissions trajectory should be gradual. It will be years before emissions are impacted by new long term capital investments

and the development of offset market. Given the inability for energy consumption to change greatly in the short term, the emissions trajectory should allow for growth in the short term, followed by gradual reductions.

Additionally, the ARB will have to apportion allowances or allowance values between sectors. The value apportioned to the electric sector should be fair and recognize the lengthy investments in CEE and RPS. Electricity customers should not subsidize reductions in other sectors.

Given the limited information currently available from ARB on the interaction of its economic modeling with the options for multi-sector 2012- 2020 emissions limits, PG&E is unable to provide additional specific comments or recommendations at this time.

D. Legal Issues

6. Do any of the non-market-based emission reduction measures discussed in your opening comments raise any legal or regulatory concern(s) or barrier(s)? If so, please explain the legal or regulatory concern(s) or barrier(s), including citations to specific relevant legal authorities. Would additional legislation be necessary to overcome any identified legal barrier(s)? Also, explain if and, if so, how the emission reduction measure(s) could be modified to avoid the legal or regulatory concern(s) or barrier(s).

PG&E Response:

Yes, as discussed by the CPUC and Energy Commission in D. 08-03-018, new legislation may be required for the ARB, CPUC or Energy Commission to adopt new regulatory mandates for renewable energy procurement under a revised Renewable Portfolio Standard as part of AB 32 implementation. In addition, the ARB, CPUC and Energy Commission probably lack legal authority to impose mandates on electric or gas utilities to achieve customer energy efficiency savings that are based on changes in building codes, appliance standards, or voluntary consumer behavioral changes. The

ARB also must meet all the statutory criteria in AB 32 before promulgating sector- or source-specific emissions limits, including the requirement that such emissions limits consider technological feasibility and cost effectiveness across different sectors.

VII. MODELING ISSUES

A. Methodology

8. Address the performance and usefulness of the E3 model. Is it sufficiently reliable to be useful as the Commissions develop recommendations to ARB? How could it be improved?

<u>PG&E Response:</u>

<u>Overview and Key Conclusions</u>

PG&E appreciates the considerable amount of work performed by E3 and appreciates the accessibility of the open-architecture and Excel platform of the model. We have found E3 to be very responsive to accommodating stakeholder concerns, especially given the large scope in a short timeframe. In responding to this question, PG&E assumes that the questions for which the PUC will use the E3 model are those listed in E3's May 6 presentation, page 7.

<u>Model Results Should Always be Represented in an Uncertainty Band</u>

When framing discussion using results of the E3 model, the Commission should present the context of the inherent limitations of any model. Models best inform policy making through highlighting differing outcomes across a range of inputs. Models will not yield a precise prediction of the future, and the E3 model is not designed to and does not capture the uncertainty associated with different outcomes. For example, there may be a much greater probability of achieving the results of the *Reference Case* than the *Aggressive Case*.[31]

E3's Aggressive Case assumes that California's electricity sector will be able to develop unprecedented levels of energy efficiency and renewables. The regulatory agencies should not assume that these aggressive targets will be achieved in the Scoping Plan. The plan must allow for uncertainty in reaching targets so that California does not have unreasonable expectations of the electricity sector. When assessing potential reductions in the electric sector, it is critical to compare the likelihood of actually realizing electric sector reductions with risks in other sectors. This may be as important as assessing the relative costs across sectors. In the response to the following question, VII.B.9, PG&E suggests more realistic input variables to better capture the electricity sector. Results communicated to the ARB should always be accompanied by the input assumptions, allow for a characterization of uncertainty around implementation as well as cost, and always be presented with full disclosure of these uncertainties.

PG&E is aware that the public has already focused on the Reference Case outcome of an emissions level of 108.2 MMT in 2020 for the electricity gas sector. However, slight changes in assumptions would change this figure. For example, if load growth continues at the 1990-2000 historic levels, 1.5%/year, then the 2020 electricity sector emissions projection becomes 114.5 MMT CO2. A few small, realistic changes in inputs change the emissions outcome substantially, and so the ARB's implementation of AB 32 must accommodate the uncertainty inherent in the sectors' 2020 emissions forecast.

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[31] PG&E will use call the 33% RPS/High EE Goals Case the Aggressive Case, per the original nomenclature.

GHG Emissions Reductions Questions

According to E3, the questions to be addressed by Stage 1 Modeling are:

- How much will various policy options reduce CO2 emissions?
- How will these policy options affect electricity rates?
- Underlying question: At what electricity sector target level do incremental improvements get expensive?

PG&E believes that the E3 Model results do provide insight to policy makers on these questions, given corrected inputs as described below. While we have not completed our analysis, we believe that the E3 model is a useful tool to guide discussions on the costs of incremental abatements in the electricity sector and the relative cost impacts of direct GHG reduction policies. For example, the E3 results do indicate that GHG abatement options using additional RPS, CHP, and CSI are very expensive, at $133/metric ton, $228/metric ton, and $902/metric ton respectively.

During the May 6 workshop, CPUC Strategic Planning Director Julie Fitch posed the question to the audience of whether the target for the sector should be based on current assumptions regarding costs and technological potential or set as a stretch goal. The E3 model provides important insight on the high potential costs of setting stretch goals in command and control programs, without the flexibility of cap and trade.

Allowance Allocation Questions

- What is the cost to the electricity sector of complying with AB32 under different policy options for California?
- What is the cost to different LSEs and their customers of these options?
- What option has the best combination of cost and fairness?

PG&E believes the current draft of the E3 model has potential to provide support for the allowance allocation analysis. More specifically, with the adjustment of some of the current underlying assumptions, the model has the potential to estimate the impact of allowance allocation on the cost and relative rate impacts to electric utility customers across California. The Commissions will need to determine what an acceptable outcome is given the complete set of the key policy implications and full recognition that the cost and amount of opportunities within each utility's portfolio to reduce emissions is not incorporated in the model and will be significantly different across utilities.

Merchant Generators Will Not Pass along Allowance Value to Consumers

It is widely recognized that merchant generators will be able to charge a price for their output that includes a full allowance cost, whether of not they receive any allowances. E3 does incorporate price impact in the market clearing price effect for open market (unspecified) purchases; however, E3 has not made these needed changes for contracted generation. The assumption included is that allowance allocation to specified generation does not impact the market price. Rather, the model appears to assume that if the user specifies that generators receive allowances, then those generators with contracts with LSEs will pass on the value of the free allowances to consumers, reducing the LSE rate impact. PG&E recommends that the E3 model not assume merchant generators with specified contracts will necessarily pass along the value of the allowances to retail customers. Contracted merchant generation should be treated similarly to an open market purchase for the purpose of estimating retail rate impacts associated with allowances allocation. This change, along with other suggested assumption changes, particularly those that result in different emissions for the LSE's in the model, will affect the relative cost impact of the allowance allocation alternatives analysis. As a result, the model does not yet in PG&E's view provide a sufficiently reasonable estimate of the relative impacts on retail rates.

Assignment of Hydroelectric Generators to LSEs

Without proper assignment of generation to LSEs, E3's results on allowance allocation impacts will not be meaningful. Although precise assignment of units to LSEs may not be transparent,[32] PG&E has a few suggested changes, shown in Attachment 1. While PG&E has provided changes for its own generation previously, we expect that further changes may be necessary for other LSEs who may not have provided the same level of information. Most of these changes known to PG&E are intended to reflect the fact that SMUD and other Northern California municipal utilities receive about 31% and 40%, respectively, of the electricity from the Central Valley Project hydroelectric units.[33]

B. Inputs

9. Address the validity of the input assumptions in E3's reference case and the other cases for which E3 has presented model results. If you disagree with the input assumptions used by E3, provide your recommended input assumptions.

PG&E Response:

PG&E suggests that inputs be changed and sensitivities be conducted in the following areas:

- Load growth: Conduct sensitivity analyses on load growth assumptions, accounting for higher load growth based on historical trends and increased demand because of climate change related temperature effects. As a sensitivity, PG&E modified input to increase 2020 load by 7,500 GWh.

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[32] E3 started with a WECC database that used aggregated hydroelectric units. The aggregation may be a necessary simplification for PLEXOS modeling, but it makes proper assignment to individual LSEs unclear in some cases.

[33] *E.g.* Shasta, Keswick, Spring Creek, and Judge Francis Carr

- Wind Capacity Value on-peak: On-peak availability of wind should be modeled at 5%; use of the larger number underestimates the amount of back-up capacity needed in the scenarios.
- CEE penetration in the Aggressive Case: Use the Itron Low Goals case to account for large uncertainties around 100% customer participation, compliance with codes and standards, and technology innovation and the need to lower the Itron High goals case to account for the new DEER values.
- RPS in the Aggressive Case: Given the uncertainty and cost and physical challenges of achieving a 33% RPS level by 2020, PG&E recommends that lower amounts of RPS goals be used in the Aggressive Case in the E3 Model. PG&E uses a sensitivity of 27% RPS (the mid-point between the 20% RPS case and 33% RPS case) in the Aggressive Case, reducing the degree of uncertainty in the ability to develop such a large amount of renewables in a relatively short amount of time.
- CHP in the Aggressive Case: As there is little evidence that there is much capacity for large CHP remaining in California, the CEC 2005 Market Assessment "base case" should be used in the Aggressive Case, as originally proposed by E3, not the CEC "moderate market case." Using this assumption, 393 MW of

large CHP is added in the Aggressive case, a much more reasonable assumption than 2,804 MW of large CHP.

- CEE costs in the Aggressive Case: Conduct sensitivity analyses on CEE costs and communicate uncertainty band. Release documentation on CEE costs.

With these sensitivities and recommendations, the Reference case has emissions of 112.4 MMT and the Aggressive Case has emissions of 94.4 MMT, not 108.2 MMT and 78.6 MMT, respectively, as the E3 model has for the cases. PG&E recommends that ranges of emissions results be used to describe the cases' results and that these ranges include the above figures. Cost figures are also uncertain and should include costs associated with the input values described above. Using such ranges when communicating the results enables the model outcome to be used in a much more realistic and dependable fashion, and evaluated next to other sectors in a more informed manner. Additionally, the uncertainty band will be wider in the Aggressive Case, with greater likelihood that the actual emissions will be higher than the current E3 Aggressive Case output.

E3 Reference Case

a) Load Growth

The emissions outcome is highly dependent on the load growth assumptions used. E3 used the November 2007 CEC mitigated load growth forecast which was then adjusted for embedded CEE for both the Reference Case and the Aggressive Case. The embedded CEE is based on the Itron 2006 Potential study's "current market potential" for the IOUs, extrapolated for the POUs. PG&E agrees with this approach, but our calculation of the "unmitigated" load growth (the load growth that would have occurred in the absence of CEE savings) suggests that unmitigated load growth should be in excess of 2% rather than the 1.6% calculated using E3's methodology.[34] Higher load growth will increase emissions by millions of tons per year for 2020. Using a low load growth forecast will underestimate emissions levels in 2020 for both the Aggressive and Reference Cases.

CEC load growth figures do not include potential increases in demand caused by climate change. In an effort to address the issues of increasing air conditioning saturation rates and global climate change, PG&E has updated our models to reflect the increasing temperature sensitivity of our load. We have also calculated our projected average temperature statistic in a manner that better reflects the results of global climate change models. The result of this is that our forecast for the PG&E load has increased significantly. A 2005 CEC report cites a previous study that estimates that forecast California energy demand may increase by as much as 7,500 GWh in 2010 relative to forecasts which do not incorporate climate change effects.[35] Adding this additional demand in 2020 adds about 4 MMT/year to the emissions output. PG&E recommends that the PUC and CEC highlight these likely global warming related sensitivities in communicating results to the ARB.

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[34] The amount of CEE that E3 backed out of the forecast appears to differ from the CEE target levels that parties agreed could be backed out per the LTPP decision.

[35] http://www.energy.ca.gov/2005publications/CEC-500-2005-103/CEC-500-2005-103-SD.PDF.

b) Reference Case Preferred Resource Additions

i. Customer Energy Efficiency

These estimates appear to be reasonable at this time, based on PG&E's review to-date. However, PG&E has not yet been able to verify the E3 Reference Case numbers. We would like documentation and further opportunity to examine these numbers.

ii. Eligible Renewables

1. RPS penetration in Reference Case

These estimates appear to be reasonable at this time, based on PG&E's review to-date.

2. Wind Value on Peak

In their changes to the GHG calculator, E3 decided to use an on-peak availability of wind of 20% based on the Intermittency Analysis Project and an expectation that "newer analysis would result in a value closer to 20% for California wind resources' on-peak capacity." On-peak availability of wind should be modeled at 5%; use of the larger number underestimates the amount of back-up capacity needed in the scenarios. This assumption applies to both the Reference Case and the Aggressive Case.

As explained in PG&E's 2006 LTPP, PG&E compared the current resource adequacy value of its existing wind generation against the actual output received at the time of the CAISO peak for each month over the last three years. This analysis shows that on average, the actual output received during the peak hour in the summer of installed capacity reliability months ranges between 0.3% to 7% of wind installed capacity.[36] In March of 2008, the CEC presented analysis indicating that wind only

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[36] PG&E's Long-Term Procurement Plan filing, Volume 1, at IV-76.

contributes 1-14% of its net qualifying capacity on very hot days in PG&E territory.[37] Net qualifying capacity ranges between 12% and 37% of installed capacity, so wind provides little reliable capacity during times of the heaviest load.

Furthermore, the capacity credit, using an ELCC methodology, does not capture the costs associated with back-up reserves that might be required by an electric service provider (ESP) to balance load, generation and reserve requirements. For example, the 24% Northern California wind capacity credit (ELCC) reported in the Multi-Year Analysis[38] is much higher than what the CAISO has historically observed for Northern California wind (< 5%) during system peaks. PG&E does not object to the use of ELCC values provided they can be modified to capture monthly variations (as the current Resource Adequacy methodology does), use actual data, and account for wind volatility and the correlation between high temperature, high load, and low wind generation, which is typical in California.

Therefore, the economic modeling of additional wind energy as a source for GHG reductions should take into account the fact that not only does wind generation provide very little on-peak capacity, but it also requires additional dispatchable and operationally flexible capacity to manage the additional regulation, ramping and load following requirements that wind energy creates at deeper penetration levels. The net result is likely to increase forecast emissions through 2020.

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[37] 2009 Resource Adequacy Implementation, California Public Utilities Commission, March 25, 2008. In the CAISO territory in its entirety, wind contributed 17-47% of the net qualifying capacity.

[38] CEC California Renewable Portfolio Standard Renewables Integration Cost Analysis: Multi-year Analysis and Recommendations page xii

- *Recommended Input Assumption:* For reasons explained above*,* PG&E's recommendation is that on peak-availability of wind should be modeled at 5% instead of 20% for the Reference and Aggressive Cases in the E3 Model.
- By using the corrected input of 5%, the cost to utilities may increase by about $155 million. In giving information to the ARB about electricity sector emissions, the CEC and PUC should include these costs.

3. CSI in the Reference Case

The assumptions appear reasonable based on PG&E's review to-date.

c) Other Resource Additions: CHP Penetration in the Reference Case

The assumptions are reasonable.

d) Proposed Modeling Changes and Sensitivities for Reference Case

The table below summarizes the suggested changes in inputs and sensitivities in the Reference Case. These changes also apply to the Aggressive Case.

Input	*E3*	*PG&E Suggestion*	*Impact on outcome*
Load Growth Sensitivity	none	Add 7,500 GWh in 2020	4 MMT/yr
Wind Capacity Value on-peak	20%	5%	$155 Million to costs

With these inputs, the Reference case has emissions of 112.4 MMT, not 108.2 MMT as the E3 Reference Case has. PG&E recommends that a range of emissions results be used to describe the Reference Case and this range include the 112.4 MMT figure. Cost figures also range and should include costs associated with the input values described above.

PG&E Comments on E3 Aggressive Case

a) Load Forecast

PG&E's comments above on the load forecast apply to both cases.

b) Preferred Resource Additions in Aggressive Case

i. Customer Energy Efficiency

1. CEE Penetration

The CEE assumptions in the Aggressive Case are unprecedented and uncertain, both in the quantity achievable and the cost. E3 uses the CEE levels from the Itron high case,[39] which need to be adjusted downwards to be consistent with the new DEER[40] values. The Itron high case CEE savings rely on a number of assumptions related to the introduction and widespread deployment of new technology, changes in end user preferences, and declining measure costs over the next five to ten years that may not come to fruition.[41] The adoption of untested technologies is contrary to the policy used elsewhere in the E3 model of not assuming new technology development. Other key uncertainties include the introductions of more energy efficient codes and standards and the degree of non-compliance associated with codes and standards. These uncertainties are beyond the control of utilities and must be recognized and modeled explicitly. When

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[39] Itron was hired by the Energy Division to assist in setting EE goals for 2012 and beyond. Itron has expertise in measuring and evaluating EE savings .

[40] Database of Energy Efficiency Resources (DEER) contains the results of EE measurement and evaluation studies which are then used to determine what EE savings are actually realized. Targets are often set on theoretical values which then need to be revised in the light of empirical analyses. Recent DEER studies have revised mainly downward many estimates of potential EE savings.

[41] Itron, Inc. Consulting and Analysis Services, Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond , April 15, 2008, see page 71.

communicating the CEE potential to the ARB, the CPUC and CEC must take into account the range of uncertainty associated with the realization of these aggressive CEE goals.

The Itron High Case CEE goals need modification for latest DEER values

E3 based the CEE potential in the Aggressive Case on Itron's high goals case. PG&E believes that these Itron high goals must be revised to reflect the latest adopted DEER parameter values (using the most recent adopted Net to Gross, End of Useful Life, Cost data, energy unit savings and changed load shapes). In many individual instances, these updated parameters will result in downward revisions to savings estimates. The Energy Division has indicated that their CEE goals timeline does not permit updating the CEE potential and goals to be consistent with the new DEER values. In PG&E's view, these updates are essential to providing better estimates of high CEE goals; especially if the high CEE goals will be included in the ARB Scoping Plan.

Uncertain and stretch nature of the EE goals.

The stretch and ambitious nature of the recommended Energy Division EE goals should be given appropriate recognition. E3 and all other analyses should incorporate the 20% uncertainty bands recommended by Itron [42] in analytic work and policy recommendations.

There are key uncertainties that affect EE savings, such as customer participation rates, non-compliance with codes and standards, and technology uncertainty. No EE programs to date have been able to achieve 100% participation. Full compliance with codes and standards cannot be assumed, as discussed in Section VI. Unlike with any of

[42] *Ibid*, Page 82, "*Each forecast is for the expected case with the high and low values being roughly plus or minus 20% of the expected value*."

the other GHG abatement measures, the E3 Aggressive Case CEE figures depend on untested technologies. For the other abatement measures, E3 assumes no new technology develops. However, the Itron high goals case depends on pay offs from innovative and uncertain technologies. Therefore, the CEE numbers should be modified to explicitly incorporate the additional uncertainty. Without this modification, the assumptions are not appropriate for the Scoping Plan.

- *Recommended Input Assumption:* Therefore, for the E3 Aggressive Case, PG&E recommends using the Itron low goals as a proxy for the to-be-lowered high goals and to allow for the large uncertainty in meeting these unprecedented goals.

- By using this corrected input, the GHG emissions from the electricity sector increase by about 3 - 5 MMTCO2e. In giving information to the ARB about electricity sector emissions, the CEC and PUC should not assume that these 3 MMTCO2e reductions will be realized.

2. Energy Efficiency Estimated Costs are Too Low

In our Phase 1 comments, PG&E stated that the CEE costs modeled were too low and requested that the estimated costs be discussed as part of the E3 Modeling Workgroups. There remains substantial uncertainty on the CEE costs used in the model.

Documentation on CEE costs needs to be presented and included in the E3 modeling work. The ($9.4 billion) value presented in the CPUC Energy Division Staff Paper, May 12, 2008 seems orders of magnitude too low, given that the recommended Itron mid/high level scenario reflects a very significant increase in funding for CEE programs, where utilities provide the full incremental cost of incentives. This is the most expensive option, as stated on page 84 of the Itron report. It is difficult to assess the reasonableness of the $9.4 million estimate since there is no supporting documentation provided for this dollar value and so it is unclear what has been included or excluded from the cost estimate. The Mid/High level Itron scenario also has the greatest uncertainty with respect to savings results since there is limited if any empirical evidence of the effectiveness of this strategy for achieving such ambitious goals.

Cost calculations should reflect the additional cost of replacing efficient technologies which do not remain in service to 2020 (for example, if an efficient copying machine[43] is installed in 2010, it would be expected to last six years and the customer may need an incentive to replace it with another efficient measure); costs for early retirement of inefficient but still-functioning measures; and the opportunity costs of businesses during energy efficiency measure installation. Modeling should incorporate the entire cost of the measure, costs related to decay rates, additional incentives for early retirement, opportunity costs for businesses, and contingency costs.

- *Recommended Input Assumption:* E3 received information on program costs and total resource costs from Itron and supplemented with costs for POUs and non-LSE programs. While the levelized costs appear too low, PG&E cannot provide more guidance on what might be more accurate input assumptions without understanding how these numbers were derived and requests supporting documentation on CEE costs.[44]

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[43] See the Database of Energy Efficiency Resources at http://eega.cpuc.ca.gov/deer for "High Efficiency Copiers", measure id D03-901, which has an effective useful life of 6 years.

[44] The TRC levelized costs for PG&E is shown as $0.057 for the Mid/High Itron cases. This appears low given that these costs were $0.049 for programs in the 2006-2008 period when the level of rebates was significantly lower than is projected in the Mid and High Itron Scenarios, where rebates are set at full incremental cost.

ii. RPS-eligible

1. RPS penetration in Aggressive Case

There are great uncertainties in costs of getting to 33% renewables and potential infeasibility of meeting the physical challenges in installing such vast amounts of renewables. Despite the various uncertainties currently facing renewables with strong demand for them in the WECC, E3 assumes that almost unlimited amounts of renewables can be added. For instance, both Reference and Aggressive Cases assume very large amounts of wind (15,000 MW and 17,685 MW within WECC respectively, including 4,293 MW and 7,122 MW in CA) can be added.[45] Renewable resource potential remains uncertain. For example, E3 based their resource assumptions for wind on NREL databases and used a potential for California of 53,044 MW. In Black and Veatch's recently completed assessment of renewable potential in the WECC, they estimated 21,099 MW of wind potential in California.[46]

Large amounts of renewables will have costs not fully considered in the GHG calculator, including for energy storage, ramping and regulation, over-generation, and back-up dependable capacity. The CAISO has stated that the increase in need for capacity, ramping, and regulation to achieve 33% RPS is not linear – it is much greater. A study finalized by the CAISO in November 2007 found that in order to integrate 6,700 MW of wind generation (~ 2,600 MW existing and ~ 4,100 MW new), the system 'would need about 250 MW for "Up Regulation" and up to 500 MW for "Down

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[45] Stage I GHG Modeling Worskhop at the CPUC Presentation Slides (PDF).

[46] April 11, 2008, *California Energy Markets*.

Regulation.[47] The CAISO also found that it needed approximately 800 MW of ramping capacity to meet multi-hour ramps during the morning load increase coupled with declining wind generation[48] plus significant increase of the supplemental energy stack for load following. However, the CAISO study did not quantify the associated costs for these needs or costs for mitigating these needs with wind forecasting and storage among others. Hence, currently there is no forecast of integration costs at high penetration levels specific to the California system for E3 to use in its estimates of integration costs. Still, these costs must be factored into the analysis and modeling.

- *Recommended input Assumption*: Given the uncertainty in cost and physical challenges of achieving 33% RPS level by 2020, PG&E recommends that lower amounts of RPS goals be used in the Aggressive Case in the E3 Model. PG&E uses a sensitivity of 27% RPS (the mid-point between the 20% RPS case and 33% RPS case) to lessen in the Aggressive Case the degree of uncertainty in the ability to develop such a large amount of renewables in a relatively short amount of time.
- By using this sensitivity input of 27% of RPS, the GHG emissions from the electricity sector increase by about 8.6 MMTCO2e. In giving information to the ARB about electricity sector emissions, the CEC and PUC should not assume that these 8.6 MMTCO2e reductions are feasible.

[47] 13 CAISO Integration of Renewables Study, November 2007, at 7.

[48] CAISO Integration of Renewables Study at 11.

2. Wind Value on Peak

E3 uses the same wind value on peak assumptions for the Reference Case and the Aggressive Case. Please refer to PG&E's comments of the wind value on peak assumptions in the Reference Case.

3. CSI in the Aggressive Case

The assumptions appear reasonable based on review to-date.

c) Other Resource Additions: CHP Penetration in the Aggressive Case

E3 has assumed CHP penetration in the Aggressive Case that may not be realistic given the number of available sites where large CHP potential still exists. PG&E recommends that E3 revert to their original proposal of using the CEC 2005 California CHP Market Assessment "base case"[49] as part of the Aggressive Case in the GHG Calculator. The use of the "moderate market case" in the GHG calculator Aggressive Case is inappropriate. The difference between the CEC "base case" and the "moderate market case" is a CHP policy subsidy that adds 2410 MW of large CHP for export to the grid. The CEC states that this is entirely composed of CHP installed for the export market: "The technical potential for this export market is largely concentrated in very large facilities – over 100 MW per site. This export market potential is entirely comprised of very large combined cycle power plants. Smaller industrial facilities with export potential are unable to earn an economic rate of return at the assumed wholesale price." (Page 2-19).

Sites with the ability to use such large amounts of steam are limited in CA. When PG&E asked during the E3 call where this potential would come from, a CHP

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[49] http://www.energy.ca.gov/2005publications/CEC-500-2005-173/CEC-500-2005-173.PDF.

representative suggested “refinery expansion.” PG&E feels that given AB 32 and the increased focus on the environmental impacts of refineries, it cannot be assumed that refineries will expand and therefore will have large amounts of expanded thermal load. As a great deal of the potential for large CHP may not exist, it may be inappropriate to assume that GHG emissions can be abated through installation of large CHP. The boilers that the CHP is assumed to replace may not or ever be in existence. Therefore, PG&E suggests that E3 use its originally proposed assumptions of using the CEC “base case” in the Aggressive Case.

- *Recommended Input Assumption:* PG&E recommends that the CHP level for the Aggressive Case be limited to 393 MW for CHP over 5 MW, as per the CEC’s CHP Market Assessment “base case” and E3’s original proposal.
- By using this corrected input, the GHG emissions from the electricity sector increase by about 3.2 MMTCO2e. In giving information to the ARB about electricity sector emissions, the CEC and PUC should not assume that these 3.2 MMTCO2e are feasible.

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d) Proposed Modeling Changes & Sensitivities for the Aggressive Case

The table below summarizes the suggested changes in inputs and sensitivities in the Aggressive Case Reference Case.

Input	*E3*	*PG&E Suggestion*	*Impact on outcome**
Reference Case and Aggressive Case			
Load Growth Sensitivity	none	Add 7,500 GWh in 2020	4 MMT/yr
Wind Capacity Value on-peak	20%	5%	$155 Million to costs
Aggressive Case Input Changes			
RPS Sensitivity	33%	27%	8.6 MMT/yr
CEE penetration	Itron High goals	Itron Low goals	4.6 MMT/ yr
CHP	2804 MW for CHP over 5 MW	393 MW for CHP over 5 MW	3.2 MMT/yr
CEE costs	none	Conduct sensitivity analyses & release documentation	

* CO2 impacts are not additive.

With these inputs, the Aggressive Case has emissions of 94.4 MMT, not 78.6 MMT as the E3 Aggressive Case has. PG&E recommends that a range of emissions results be used to describe the Aggressive Case and this range include the 94.4 MMT figure. Cost figures also range and should include costs associated with the input values described above.

PG&E has attached the E3 Resources tab with all of the corrected inputs. In addition, we have provided below recommended changes in the assignment of hydroelectric generation to LSEs. Unfortunately, we found that the Scenario Documentation tab was not updating properly to reflect the inputs and outputs shown on the Resources tab. All of the inputs we changed are found on the Resources tab and are described in the text in this section.

Assignment of Hydroelectric Generators to LSEs

PG&E appreciates E3's efforts to assign aggregated hydroelectric units to specific LSEs. E3 started with a WECC database that used aggregated hydroelectric units. The aggregation may be a necessary simplification for PLEXOS modeling, but it makes proper assignment unclear in some cases. PG&E's suggestions below are preliminary.

One example will illustrate the issue. An entry in the WECC database is named BELLOTA_19. Bellota is a PG&E substation. A sheet provided by WECC states that BELLOTA_19 represents an aggregate of "Mokelumn & Colrv Hag". "Mokelumn" undoubtedly refers to the Mokelumne River, which is the site of five units owned by PG&E and two owned by the East Bay Municipal Water District. "Colrv" refers to the Collierville unit owned by the Northern California Power Agency. "Hag" is an unknown at this point: No unit with those initial letters appears in the CEC's list of existing California generating units (http://www.energy.ca.gov/database/index.html#powerplants). Assigning BELLOTA_19 would require agreement among various parties about which units are included, and on the average-year electricity expected from each unit.

Although precise assignment of units to LSEs can be unclear, PG&E has a few suggested changes, shown in the table below. Most of these are intended to reflect the fact that SMUD and other Northern California municipal utilities receive about 31% and 40%, respectively, of the electricity from the Central Valley Project hydroelectric units (*e.g.*, Shasta, Keswick, Spring Creek, Judge Francis Carr).

Generator Assignment Information

	Ownership/Purchase shares of Nameplate MW			Current Assumptions
Generator Name	SMUD	er n-Other	Water Agencies	Northern CA Powerpool
CAMINO S_10	**100%**	0%	0%	0%
FOLSOM_5	**31%**	**40%**	0%	**29%**
KESWICK_9	**31%**	**40%**	0%	**29%**
MELONES_2	**31%**	**40%**	0%	**29%**
SHASTA_8	**31%**	**40%**	0%	**29%**
TBL MT E_10	0%	0%	**100%**	0%
TUOLUMN_6	0%	**100%**	0%	0%
WARNERVL_7	0%	**100%**	0%	0%

VIII. CONCLUSION

For the reasons stated above, the CPUC and CEC should recommend that the ARB include a well-designed, multi-sector cap and trade program as the cornerstone of its AB 32 scoping plan. The scoping plan should be supported by economic analysis and modeling of the relative abatement costs across all sectors, and should include the principles on allocation, flexible compliance, cost containment, programmatic measures and treatment of combined heat and power contained in these comments.

Respectfully Submitted,

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Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: June 2, 2008

ATTACHMENT

	Greenhouse gas emissions summary information			
	California	Total Offsets	Non-CA WECC	Total
2020 User Case (MMTCO2e):	**97.5**	**0.0**	320	417
2020 Reference Case (MMTCO2e)	108.2	n/a	327	435

Change in electricity sector average rates & costs for California in 2020, relative to reference case and 2008

Δ in 2020 rates relative to reference case ($/kWh)	$	0.004
% change in 2020 rates relative to reference case		3%
% change in 2020 rates relative to 2008		16%
Δ in 2020 utility cost relative to reference case ($M)	$	(816)
Δ in 2020 utility cost relative to 2008 ($M)	$	10,361
Δ in 2020 customer costs relative to reference case ($M)	$	4,298

Loads

			Ref. Case	User Case
Change in Annual Growth Rate	0.2%	State Average Growth	1.2%	1.4%

Energy Efficiency

Electricity Energy Efficiency

Natural Gas Energy Efficiency

Demand Response

	PG&E	SCE	SDG&E	SMUD	LADWP	N. California POU	S. California POU	Water Agencies
Ref Case DR Level in 2020 (above 2008)	5%	5%	5%	5%	5%	5%	5%	0%
User Case DR (above 2008 levels)	5%	5%	5%	5%	5%	5%	5%	0%

Photovoltaics

	Reference	User Case	
California SB1 Activities Statewide MW in 2020	847	3,000	MW

Combined Heat and Power

	New CHP Capacity	
<5MW Capacity	1573	MW
>5MW Capacity	393	MW

New Renewable Resources

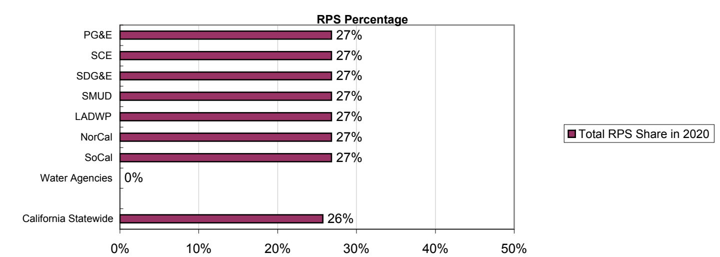
Renewable resources by transmission cluster

Average Net Cost of Incremental Renewables ($/tonne) $ 125.47

	California zones highlighted in tan.	Total Renewable Resources (MW)	Reference Case MW	User Selelected MW	Lowest-cost next increment ($/MWh)	Size of best next increment (MW)	Rank (Lowest to Highest)
1	Alberta	5,193	-	-	232	3,000	24
2	Arizona-Southern Nevada	5,699	-	-	146	3,000	11
3	Bay Delta	2,963	-	-	155	750	17
4	British Columbia	4,118	-	-	162	3,000	20
5	CA - Distributed	874	-	700	145	1,000	10
6	CFE	4,873	-	200	150	1,500	14
7	Colorado	5,337	-	-	182	3,000	22
8	Geysers/Lake	698	-	-	143	250	7
9	Imperial	5,824	2,339	4,500	136	6,000	4
10	Mono/Inyo	5,658	-	-	148	1,500	13
11	Montana	5,415	-	-	147	3,000	12
12	NE NV	1,403	-	-	191	1,500	23
13	New Mexico	5,509	-	-	150	3,000	15
14	Northeast CA	3,099	-	-	117	250	1
15	Northwest	5,534	-	-	176	3,000	21
16	Reno Area/Dixie Valley	5,658	-	-	136	1,500	3
17	Riverside	5,825	-	-	142	1,500	6
18	San Bernardino	5,658	-	-	145	1,500	8
19	San Diego	5,824	-	1,000	141	1,500	5
20	Santa Barbara	558	-	-	160	250	19
21	South Central Nevada	5,699	-	-	153	3,000	16
22	Tehachapi	5,824	4,394	4,394	145	6,000	9
23	Utah-Southern Idaho	5,564	-	-	157	3,000	18
24	Wyoming	5,398	-	-	132	3,000	2
	Total MW of User Selected Resources			10794			

Ownership of incremental renewable generation

	2020 RPS Target (leave blank for automatic allocation)	Share of new 2020 RPS	Total RPS Share in 2020
PG&E		31%	27%
SCE		27%	27%
SDG&E		9%	27%
SMUD		3%	27%
LADWP		11%	27%
NorCal		7%	27%
SoCal		12%	27%
Water Agencies	0%	0%	0%
California Statewide			26%



New Non-Renewable Resources

New Generation through 2020 by Technology Type (MW) To input detail on new gen	Coal IGCC	Coal IGCC with CCS	Coal ST	Gas CCCT	Gas CT	Hydro - Large	Nuclear	Not Used	Not Used	Not Used	Not Used
Reference Case Starting MW	0	0	0	2311	3410	0	0	0	0	0	0
User Entered MW	0	0	0	2311	3410	0	0	0	0	0	0
Assignment of new generation to LSE - note that 100% must be allocated											
PG&E	30%	30%	30%	30%	30%	30%	30%	0%			0%
SCE	37%	37%	37%	37%	37%	37%	37%	0%			0%
SDG&E	8%	8%	8%	8%	8%	8%	8%	0%			0%
SMUD	5%	5%	5%	5%	5%	5%	5%	0%			0%
LADWP	10%	10%	10%	10%	10%	10%	10%	0%			0%
NorCal	5%	5%	5%	5%	5%	5%	5%	0%			0%
SoCal	5%	5%	5%	5%	5%	5%	5%	0%			0%
Water Agencies	0%	0%	0%	0%	0%	0%	0%	0%			0%
Total CA	100%	100%	100%	100%	100%	100%	100%	0%	0%	0%	0%

New Resources Key Assumptions: Capital Cost and Operating Assumptions

Inputs used in Gen Cost Tab

To view detail on new generation cost and performance

	Biogas	**Biomass**	**Geothermal**	**Hydro - Small**	**Solar Thermal**	**Wind**	**Not Used**	**Not Used**	**Not Used**	**Coal IGCC**	**Coal IGCC with CCS**	**Coal ST**	**Gas CCCT**	**Gas CT**	**Hydro - Large**	**Nuclear**
Capital Costs (no IDC or AFUDC) 2008$/kW																
Reference (WECC Average Cost)	$ 2,554	$ 3,737	$ 3,011	$ 2,402	$ 2,696	$ 1,931	$ -	$ -	$ -	$ 2,388	$ 3,418	$ 2,066	$ 813	$ 735	$ 2,402	$ 3,333
User (WECC Average Cost)	$ 2,554	$ 3,737	$ 3,011	$ 2,402	$ 2,696	$ 1,931	$ -	$ -	$ -	$ 2,388	$ 3,418	$ 2,066	$ 813	$ 735	$ 2,402	$ 3,333
Implied CA Cost with AFUDC $/kW	$ 3,147	$ 4,604	$ 4,290	$ 3,036	$ 3,408	$ 2,380	$ -	$ -	$ -	$ 3,704	$ 6,152	$ 3,205	$ 1,054	$ 953	$ 3,036	$ 5,999
Heat Rate (BTU/kWh)																
Default	11566	15509								8309	9713	8844	6917	10807		10400
User	11566	15509	0	0	0	0	0	0	0	8309	9713	8844	6917	10807	0	10400
Tax Credits in Use? (1=Yes, 0=No)																
Default	1	1	1	1	1	1				1	1	1	1	1	1	1
User	1	1	1	1	1	1	0	0	0	1	1	1	1	1	1	1
Capacity Factor																
Default	85%	85%	90%	50%	40%	37%	100%	100%	100%	85%	85%	85%	90%	5%	50%	85%
User	85%	85%	90%	50%	40%	37%	100%	100%	100%	85%	85%	85%	90%	5%	50%	85%
On-Peak Capacity Contribution																
Default	100%	100%	100%	65%	85%	20%				100%	100%	100%	100%	100%	90%	100%
User	100%	100%	100%	65%	85%	5%	100%	100%	100%	100%	100%	100%	100%	100%	90%	100%

Fuel Prices

CERTIFICATE OF SERVICE BY ELECTRONIC MAIL OR U.S. MAIL

I, the undersigned, state that I am a citizen of the United States and am employed in the City and County of San Francisco; that I am over the age of eighteen (18) years and not a party to the within cause; and that my business address is Pacific Gas and Electric Company, Law Department B30A, 77 Beale Street, San Francisco, California 94105.

I am readily familiar with the business practice of Pacific Gas and Electric Company for collection and processing of correspondence for mailing with the United States Postal Service. In the ordinary course of business, correspondence is deposited with the United States Postal Service the same day it is submitted for mailing.

On June 2, 2008, I served a true copy of:

OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON ADDITIONAL ISSUES RELATED TO IMPLEMENTATION OF AB 32 IN THE ELECTRIC AND NATURAL GAS SECTORS

[XX] By Electronic Mail – serving the enclosed via e-mail transmission to each of the parties listed on the official service lists for R06-04-009 with an e-mail address.

[XX] By U.S. Mail – by placing it for collection and mailing, in the course of ordinary business practice, with other correspondence of Pacific Gas and Electric Company, enclosed in a sealed envelope, with postage fully prepaid, addressed to all parties of record on the service lists for R06-04-009 who do not have an email address.

I certify and declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed in San Francisco, California on June 2, 2008.

/s/

LINDA S. DANNEWITZ