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

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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

[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

[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

[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

[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