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CALIFORNIA ENERGY COMMISSION
REPLY COMMENTS OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON
ECONOMIC MODELING ISSUES UNDER AB 32

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I. INTRODUCTION

Pursuant to the ruling of the Administrative Law Judges dated November 9, 2007 (ALJs' Ruling), Pacific Gas and Electric Company (PG&E) provides its reply comments on economic modeling issues under AB 32. PG&E's reply comments are presented as follows: (1) a summary of comments from parties who agree with PG&E's major points and recommendations in its opening comments; (2) responses to comments inconsistent with PG&E's opening comments.

II. MOST PARTIES AGREE WITH PG&E'S MAJOR RECOMMENDATIONS REGARDING IMPROVING THE ECONOMIC MODELING OF AB 32 COSTS AND BENEFITS

PG&E appreciates that most parties appear to provide the same or similar recommendations as PG&E regarding how to improve and enhance the economic modeling of AB 32 cost, benefits, and proposed GHG reduction measures, including an open process for reviewing and evaluating the modeling assumptions and results. For example, parties appear to agree that assumptions by E3 and the Staff Workpaper regarding future Customer Energy Efficiency (CEE) are extremely aggressive and require initiatives and actions by many entities other than LSEs, including local governments, builders and customers.[1/] The Center for Energy Efficiency and

1/ See, e.g., CEERT at 16-17, NRDC at 8, SDG&E at 9, WPTF at 2, 4, SCPPA at 11.

Renewable Technology (CEERT) correctly states that 100% of economic potential should "not form the basis of energy planning scenarios."[2/] The Natural Resources Defense Council (NRDC) notes that the energy efficiency "values adopted by E3 for the baseline scenario are relatively high."[3/]

Parties also appear to agree that sensitivity analyses are needed before model results are used. Parties note that model results are approximations and are vastly inexact.[4/] An example mentioned by several parties is that load growth may be higher than modeled because of electrification that reduces GHG emission from other sectors.[5/] Parties agree that more instruction and documentation on the E3 "GHG calculator" is needed to understand outputs.[6/]

Parties also commented that the modeling needs to look for GHG reduction opportunities beyond the electricity sector and provide a metric to compare reduction opportunities across sectors.[7/] Similarly, parties commented that, currently, the model results are more useful in showing cost impacts on a statewide basis rather than on an

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2/ CEERT at 16-17.

3/ NRDC at 8.

4/ WPTF at 3; GPI at 6,9; DRA at 1-7; Pacificorp at 23; NRDC at 17; SCE at 9- 10. PG&E notes that SCPPA's comments assume that the CEE potential for IOUs includes savings amounting to 25% from changes in building codes and appliance standards, whereas the CEE potential for publicly owned utilities does not. (SCPPA, p.8). PG&E believes SCPPA is incorrect and in fact the Itron Report, on which the CEE potential is based, excludes codes and standards from both IOU and publicly owned utility potential. ("California Energy Efficiency Potential Study," Itron, May 24, 2006, p.3-9, ES-7.)

5/ SCE at 14- 15, Pacificorp at 24, CEERT at 23.

6/ WPTF at 7, SMUD at 6, SCPPA at 15-16, SCE at 5- 7.

7/ SDGE & SoCal Gas at 7, NRDC at 19, Pacificorp at 26.

LSE specific basis.[8/] Parties have highlighted the difficulties of assigning specific generation to load, even for generation that exists today, and the inability of individual retail providers to test unique resource mixes, especially because the majority of retail providers are not represented in the model.[9/]

PG&E believes these comments represent an important and notable consensus on the next steps that the CPUC, CEC and staff and consultants should take in this modeling effort. Broadly speaking, the credibility of California's efforts to achieve significant GHG reductions and to do so fairly across all sectors depends on the credibility and validity of the economic modeling that is taking place in this proceeding and at the ARB. For these reasons, PG&E recommends that the CPUC and CEC immediately redirect the next phase of the economic modeling consistent with these important comments and recommendations by multiple parties.

III. RESPONSES TO SPECIFIC COMMENTS

A. Adopting a 33% Renewable Portfolio Standard May Not Be a Cost-Effective GHG Reduction Measure and Requires Further Analysis

A 33% Numerical Standard for Renewables is Premature

The Green Power Institute (GPI), NRDC, and the Union of Concerned Scientists (UCS) recommend that a 33% RPS target by 2020 should be adopted as a policy measure aimed at reducing GHG emissions.[10/] To date, however, available economic modeling suggests a 33% RPS target by 2020 may not be cost-effective as compared to

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8/ LADWP at 8-9, SCE at 30-31, SDG&E at 6.

9/ SCPPA at 14, 16, SMUD at 2, AReM at 2, NCPA at 2, Pacificorp at 15, LADWP at 5-8, WPTF at 8, SDG&E at 8.

10/ GPI, "Comments of the Green Power Institute on Modeling-Related Issues," p. 6. NRDC and UCS, "Comments of the Natural Resources Defense Council and the Union of Concerned Scientists on Modeling-Related Issues," p. 7.

reductions available in other sectors. PG&E remains committed to increasing the use of renewables, but as noted in its opening comments, a number of critical issues must be resolved, and additional feasibility assessments performed, prior to reassessing 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.[11/] 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 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.

Similarly, CEERT proposes that the Renewable Energy Transmission Initiative (RETI) process be designated by the CPUC as the coordinated planning process for meeting RPS targets in the current statute (20% RPS), along with becoming the official renewable planning mechanism for AB 32.[12/] This additional responsibility is inconsistent with RETI's Mission Statement. Consistent with RETI's Mission Statement, PG&E believes that RETI's principal areas of focus should be to assess competitive renewable energy zones (CREZ) and to develop detailed transmission plans

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11/ 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.

12/ Center for Energy Efficiency and Renewable Technologies, "Opening Comments of the Center for Energy Efficiency and Renewable Technologies on E3 Modeling Methodology and Staff Workpaper on Emission Reduction Measures," p. 28.

of service for each CREZ,[13] as opposed to taking on non-transmission related planning or regulatory compliance responsibilities. The output to be provided by RETI should assist the utilities in their renewable procurement planning efforts, and not substitute for those efforts, in accordance with the Commission's intention reflected in Decision 07-12-052.[14]

Integration and Transmission Issues

On the issues of integration and firming of new renewables, PG&E agrees with other parties that the costs of integration of renewable energy, especially wind, should be examined carefully and may be underestimated for purposes of this AB 32 modeling effort.[15] PG&E agrees with many parties' comments on the importance of system reliability and the need for additional analysis, including verifying minimum load conditions and sufficient transmission in the dispatch model.[16]

On the other hand, several parties propose to ignore the need for dispatchable and operationally flexible capacity to integrate wind generation. For example, CEERT argues that because wind is primarily an energy resource and because individual loads and generators do not need to be balanced, there is no need for back-up generation for wind.[17] The reality is that wind generation is intermittent and uncertain. The system does need additional generation for regulation, ramping and load following. A study

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13/ Renewable Energy Transmission Initiative Mission Statement, September 17, 2007, pp. 1-3.

14/ D.07-12-052, "Opinion Adopting Pacific Gas and Electric Company's, Southern California Edison's and San Diego Gas & Electric Company's Long-Term Procurement Plans," Findings of Fact, #33, p. 274.

15/ WPTF at Pg 4; SCCPA at pg 5.

16/ WPTF at Pg 4, 7, 8; SCCPA (9, 12-13).

17/ CEERT at 36.

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 Regulation.[18/] The CAISO also found that it needed approximately 800 MW of and ramping capacity to meet multi-hour ramps during the morning load increase coupled with declining wind generation[19/] plus significant increase of the supplemental energy stack for load following. However, the CAISO study did not quantify the associated costs for these needs nor costs for mitigating these needs with wind forecasting and storage among other mitigation techniques. 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 as desired by CEERT and NRDC. Still, these costs must be factored into the analysis and modeling.

As explained in PG&E's 2006 LTPP, PG&E compared the current resource adequacy (RA) value of its existing wind generation against the actual output received from those sources at the time of the CAISO peak demand for each month over the last three years. This analysis shows that on average, the actual output received during the peak hour in summer months from these sources ranges between 0.3% to 7% of wind installed capacity. In contrast, the RA value of existing wind generation calculated using the Commission-adopted counting rules, which ranges between 12% and 37% of installed capacity. Therefore, E3's assumption that wind resources operate at a 10%

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

19/ CAISO Integration of Renewables Study at 11.

capacity factor seems too high.[20]

CEERT also recommends E3 use an Effective Load Carrying Capability (ELCC) of about 20% for wind.[21] PG&E does not object to the use of ELCC values provided they are done correctly, use actual data, and account for wind volatility and the correlation between high temperature, high load, and low wind generation, which is the typical pattern in California. However, it is unclear how ELCC as a measure of impact to system reliability, would be used in Least Cost Best Fit (LCBF) and bid evaluation for intermittent resources like wind because it does not comport with Resource Adequacy accounting or procurement protocols. Capacity credit must be weighted to the value of capacity in the market, which typically changes seasonally. For example, capacity credit for wind production during the on-peak period in May and June are considerably higher than the July-September period when the value of that capacity is typically highest.

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[22] 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

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20/ PG&E's Long-Term Procurement Plan filing, Volume 1, at IV-76.

21/ CEERT at 36.

22/ CEC California Renewable Portfolio Standard Renewables Integration Cost Analysis: Multi-year Analysis and Recommendations page xii.

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 little or no 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 may not be significant or feasible reductions in GHGs.

In a similar vein, the Green Power Institute (GPI) argues that although intermittent renewable resources add a new component to the unpredictability of loads and supplies on the grid, the unpredictability per se is not something that is new to the grid or unmanageable.[23/] PG&E agrees that unpredictability may not be new, but the magnitude will significantly increase and require additional costs to integrate incremental wind resources. As explained above, the CAISO integration of renewable resources study finds that additional generation capacity is needed for regulation, ramping and load following requirements associated with wind.

B. Evaluating Potential GHG Reductions from CHP

In their comments, CAC-EPUC claim that existing and new "combined heat and power" ("CHP") resources could save millions of metric tons of GHG emissions, referencing an aggressive scenario from a 2005 CEC report to support their claims.[24/] What CAC-EPUC does not say is that the majority of existing CHP capacity

23/ GPI at 3.

24/ CAC-EPUC, at 3-5.

corresponds to large CHP systems greater than 20 MW, and that the CEC forecast is mostly comprised of such systems. Further, the largest of the active CHP capacity is located in the oil fields to provide steam for enhanced oil recovery (EOR).[25/] EOR generation is often sold to utilities under standard offer contracts, at above market prices, and subject to PURPA efficiency requirements that are lower than the efficiency of current available CCGT technology. Thus, it is not clear that additional CHP is likely to provide incremental GHG reduction benefits compared to other generation sources.

Nor do CAC-EPUC mention that the savings estimated in the CEC CHP Assessment were based on the assumption of efficient CHP systems against low efficiency 30- to 50-year old steam turbine based electrical generation.[26/] As PG&E pointed out in its opening comments, contrary to CAC-EPUC and the earlier CEC CHP Assessment, the alternative to CHP baseload generation is not an aging powerplant with a higher than 10,000 Btu/kWh heat rate. Any analysis of CHP fuel or emission savings should reflect realistic electric generation alternatives, which E3's analysis considers. Specifically, emissions from CHP generation should be compared to emissions from the combination of a new gas fired CCGT plus a new gas fired boiler. The result is not likely to find significant GHG reduction benefits.

An analysis of CHP fuel or emission savings should also reflect likely CHP potential. The CEC CHP Assessment's Aggressive Market Access projects a total of 5,348 MW of new CHP power—2,479 MW from new onsite CHP and 2,869 MW of new export MW. It is not clear where these numbers of new CHP projects are going to

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25/ Assessment of California CHP Market and Policy Options for Increased Penetration (CEC CHP Assessment), PIER Collaborative Report, November 2005, CEC-500-2005-173, p. 2-2.

26/ CEC CHP Assessment, p 2-20.

come from. In the PG&E area, there are presently a little more than 900 MW of EOR based CHP electrical generation. To add 2,800 MW of export generation with the same thermal efficiency as EOR does not appear to be realistic.

CAC-EPUC also argue that the actual total cost of the CHP facility is not an appropriate consideration in determining impacts on ratepayer cost because the cost of the electric power to ratepayers is the "avoided cost payments" made to the CHP facility consistent with Commission policy.[27/] However, CAC-EPUC propose that in order to maximize GHG reductions from CHP, the GHG policy framework should include: (1) portfolio set-aside for CHP power purchases by the utilities, similar to the RPS; (2) "reasonable pricing provisions" for power purchases from CHP facilities; and removal of "deployment barriers", including eliminating departing load charges.[28/]

The purpose of the E3 exercise is to determine the least cost approach to achieve a desired reduction in GHG emissions, not to create a new set-aside or non-competitive subsidy for CHP. A significant cost element of CHP cannot be arbitrarily left out in determining CHP's order in the GHG supply curve. Because there are different CHP projects with different costs, fuel efficiencies, and potential savings, it is important that the E3 analysis recognize the potential for different CHP applications and their relative differences in cost, benefits and other attributes.

PG&E recommends that CAC-EPUC's recommendations not be adopted, and instead the E3 analysis should reflect the true potential for different CHP applications, and their respective costs, and benefits, including the full cost of the CHP facilities.

27/ CAC-EPUC, at 8.

28/ CAC-EPUC, at 11.

Subsidies are outside the scope of the economic modeling exercise, and in any event should only be necessary for CHP applications that are efficient and cost-effective from a society's perspective but where those projects are not cost-effective to the CHP owner.

NRDC and CEERT also propose increased use of efficient CHP.[29/] PG&E supports use of efficient CHP, as long as the CHP projects that are implemented are truly efficient, compared to other alternatives available to reduce GHG emissions, and provided there is a fair distribution of costs and benefits between CHP owners and non-CHP owners.

SDG&E and SoCalGas propose that the Commission allow cogeneration developed pursuant to AB 1613 to come under the energy efficiency umbrella.[30/] PG&E understands this proposal as the utility being able to count the CHP savings towards its energy efficiency goals. AB1613 was designed to foster CHP installations of less than 20 MW that meet a minimum efficiency standard to be determined by the California Energy Commission by January 1, 2010. Whether small AB1613 CHP savings are counted as efficiency savings is outside the scope of the modeling effort, but also depends first on: a) what is the efficiency benchmark, which has not been determined by the CEC, and b) how the efficiency savings are allocated between the CHP owner and the electric utility customers who are required to buy the CHP's surplus energy. Given that these key elements of the legislation remain to be defined, it is too early to take a position on whether and how much of the AB1613 savings can be counted towards energy efficiency as part of the design of the AB 32 program. Furthermore, the

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29/ NRDC at 5; CEERT at 21.

30/ SDG&E and Socal Gas at 4.

definition of energy efficiency, which is an issue outside the scope of this proceeding, has an extensive legislative and regulatory history and in fact has not previously been applied to customer generation.

IV. CONCLUSION

For the reasons stated above, PG&E recommends that the E3 Model and Staff Workpaper be revised as recommended in these comments. In addition, PG&E recommends that the CPUC and Energy Commission provide that any decisions or recommendations on the design of an AB 32 regulatory mechanism for the electric and gas sectors take into account the results and conclusions upon completion of the modeling.

Respectfully Submitted,

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By: /s/

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