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

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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 opening comments on economic modeling issues under AB 32. PG&E's comments are presented as follows: (1) an executive summary; (2) general comments on the E3 economic model; (3) general comments on the CPUC staff workpaper ("Staff Workpaper"); (4) responses to the specific questions listed in the ALJs' Ruling; and (5) a table summarizing recommendations for E3 and the modeling effort.

II. EXECUTIVE SUMMARY

PG&E has two overarching goals with respect to AB32 implementation. These are: 1) To achieve long-term and sustained reductions in greenhouse gas emissions; and 2) To manage the costs and reliability impact of achieving these reductions on behalf of our customers. PG&E commends the CPUC for establishing an "open architecture" for AB 32-related modeling and E3 for an excellent start on the modeling itself. Economic modeling of the costs and benefits of AB 32 emissions reduction options is essential in order that policymakers and stakeholders may understand the potential impacts and cost effectiveness of those options prior to issuance of any decisions on the design of AB 32 regulations and strategies.

To this end, a key first step in looking for GHG reductions is to use modeling to identify and prioritize cost-effective emission reduction measures across all sectors to help evaluate policy and implementation alternatives. While the Staff Workpaper is focused on in-sector (electricity and natural gas) analysis of potential reductions for AB32 policy consideration ("...the development of strategies for reducing GHG emissions occurring in the electricity and natural gas sectors,"[1/]), the overall modeling analysis should cover emissions reduction opportunities from all sectors rather than looking at in-sector reductions only. PG&E recommends that the CPUC, CEC, and CARB model and analyze all sectors, including transportation, in the inclusive and open architecture approach E3 has used here, before finalizing assumptions or drawing any conclusions regarding emissions reduction measures in the electricity and gas sectors.

A key outcome of the modeling should be a multi-sector GHG emissions reduction cost curve at a level of specificity measured in $/ton of CO2 reductions for each measure, not merely for each scenario in aggregate. CARB should be able to use the outputs of the modeling in an integrated approach which determines the most cost-effective measures across all of the sectors and then develops programs and a regulatory design to capture each.

In terms of implementation, by definition, the most cost-effective emissions reduction measures in the electric and gas sectors will require that emissions sources serving both investor-owned utilities (IOUs) and local publicly owned utilities (POUs) be subject to substantially the same measures and regulatory requirements. POUs serve

1/ ALJs Ruling, Attachment A, "Greenhouse Gas Emissions Reduction Measures for the Electricity and Natural Gas Sectors Under Consideration as Part of R.06-04-009," (hereafter "Staff Workpaper"), p.1.

25% of the electric load in California, but more importantly are responsible on a load-calculated basis for nearly 42% of the source-specific CO2 emissions in the electric sector.[2/] The economic modeling of AB 32 reductions must be "all-source" across all sectors and all entities within the electric and gas sectors, and must evaluate *marginal* costs and benefits of various reduction alternatives, including recognition that it may cost less per ton of CO2 to reduce emissions from high-carbon portfolios, such as those from higher GHG emitting POUs. The modeling must take into account not only prospective opportunities for emissions reductions that have not yet been undertaken, but also the "diminishing returns" available for reductions that already have been undertaken in the past by entities such as PG&E and other IOUs that have implemented robust CEE and renewable energy procurement programs under the direct supervision of the CPUC and CEC.

III. GENERAL COMMENTS ON E3 MODEL

PG&E believes that E3 has created a useful model to estimate cost impacts to the customers of LSEs of incremental renewables and energy efficiency measures compared to existing programs. E3's open process and open architecture is to be commended and should serve as a model for future modeling efforts. While further overall modeling is necessary to develop comprehensive GHG emissions cost curves, the E3 tool follows a utility planning framework that should aid policymakers and stakeholders in evaluating electric and gas sector measures in the overall context of a multi-sector AB 32 model.

In more detail below, PG&E provides recommendations for improvements in the

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2/ CAISO,"A Primer on California Greenhouse Gas Regulation" (http://www.caiso.com/1be8/1be8be6045ea0.pdf) and ARB, "Staff Summary of the California Climate Action Registry Power/Utilities GHG Reporting Protocol"(http://www.arb.ca.gov/cc/ccei/presentations/powerprotocolfacts_final.pdf)

E3 model in key areas as E3's modeling work continues to be refined. PG&E has focused on the general methodology in the E3 model, rather than focusing on particular numerical inputs. PG&E understands that a subsequent ruling will ask about numerical input assumptions and model results. In addition to the issues discussed in this section, further recommended modifications to the E3 model are described in the response to specific questions in Part V and in the summary of PG&E's overall recommendations in the table in Part VI.

A. Summary of Key Issues

The following summarizes PG&E's preliminary comments on specific components of the E3 model:[3/]

- **Electric Demand Forecast**:[4/] PG&E supports E3's approach of assuming that 100% of current goals are embedded in the CEC 2008-2018 load forecast. In addition, though, the analysis of AB32 implementation measures should account for and include analyses of load uncertainty.
- **Renewables**:[5/] Despite the various cost and supply uncertainties currently facing renewables given strong demand across the WECC, E3 nonetheless assumes that almost unlimited amounts of renewables can be added. For instance, both BAU and Aggressive cases assume very large amounts of wind (18,000 MW and 22,000 MW within WECC respectively, including 5,000 MW and 10,000 MW in

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3/ PG&E notes that the E3 modeling effort is ongoing and therefore PG&E intends to continue evaluating the assumptions and output of the model as they becomes available. For that reason, our comments are necessarily preliminary and subject to revision as more information becomes available.

4/ E3 Stage 1 Modeling Documentation, Section 11.

5/ E3 Stage 1 Modeling Documentation, Section 26.

CA).[6] PG&E believes these assumptions are overly-optimistic. E3 should consider adding an additional renewable resource supply case that includes a more limited development potential for renewables by 2020, in order to take into account the difference between physical potential and feasible potential.

- **Operational feasibility of wind & other intermittent resource additions:**[7] Analysis should verify minimum load conditions that affect the ability of the electric sector to absorb large amounts of intermittent renewable generation in the areas where these resources are developed or if insufficient transmission is in place to access and deliver this energy to load centers. Alternatively, where system integration is unavailable, storage costs, to the extent they may be reasonably estimated based on future technologies, should also be added to all intermittent renewables costs to take into account the lack of system integration.
- **Energy Efficiency:** PG&E recommends modifications to both quantities and costs of CEE modeled by E3. The BAU case models 100% of current market potential; the aggressive case models 100% of net economic potential.[8] As noted by the CPUC staff during the Joint CEC/CPUC Energy Action Plan meeting on December 11, these CEE projected savings are at unprecedented levels; thus, there is substantial uncertainty associated with such large amounts of assumed CEE, whether based on identifiable (i.e. from the Itron analysis) or additional, hypothetical amounts. This uncertainty should not be ignored in

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6/ Stage I GHG Modeling Workshop at the CPUC Presentation Slides (PDF).

7/ E3 Stage 1 Modeling Documentation, Section 28.

8/ E3 Stage 1 Modeling Documentation, Sections 7 and 11.

either modeling or policy setting, but should be specifically analyzed and taken into account.

- o Although E3 estimates that achieving all cost-effective electric efficiency will cost ~ $1.2 to $1.5 Billion per year,[9/] costs may be substantially higher. Modeling of costs should be refined to incorporate the cost of decay, additional cost for early retirement of inefficient measures, and total customer costs.
- o Contrary to E3's model,[10/] energy efficiency potential estimates should not assume unforeseen technological breakthroughs and that the same aggressive growth rate for energy savings from IOU programs between 2008-2016 will continue for 2016-2020.
- o E3 should reflect an analysis of whether additional CEE in POU service territories may be potentially greater than additional IOU potential rather than assuming equal potential based on the closest IOU.[11/]

- **LSE Cost Responsibility:** In the E3 methodology, CO2 reductions are achieved by CEE and RPS only.[12/] PG&E would like to see as a model output a cost/ton GHG figure for CEE and RPS by each LSE, to understand relative impacts to each LSE.

9/ E3 Stage 1 Modeling Documentation, Section 12, Section 35.5 and Section 12.6, Appendix B and E3's GHG Calculator.

10/ E3 Stage 1 Modeling Documentation, Section 12 Table 8.

11/ E3 Stage 1 Modeling Documentation, Section 12.2.a.1.d.

12/ E3 Stage 1 Modeling Documentation, Section 12.

- **Sensitivity analyses:** E3 has indicated that they have done sensitivity analyses.[13/] PG&E would like to see the results of these analyses, which should be helpful in guiding any further analyses that may be needed. The AB32 implementation alternatives should be tested over a range of input assumptions for: (a) load growth, (b) availability and cost of CEE and RPS additions, including integrating intermittent resources and transmission, and (c) natural gas market prices. Uncertainty ranges around important inputs should be made explicit.

B. Load Growth Assumptions

The CEC's *California Energy Demand 2008-2018: Staff Revised Forecast* contains language that is ambiguous in its characterization of whether CEE savings are included or not included in energy demand projections.[14/] The degree to which current and/or proposed target levels of customer energy efficiency savings (either accomplished through standards or programs or through other means) are captured (either explicitly or implicitly) in the current projections is a very important factor in the modeling of emissions reduction opportunities. The new CEC load forecast released in mid-November 2007[15/] only has a 1.3% annual growth. PG&E believes that given its low growth, the CEC forecast embeds all the uncommitted CEE. Therefore, PG&E supports E3's approach of assuming that 100% of current goals are embedded in the

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13/ Stage I GHG Modeling Workshop at the CPUC Presentation Slides (PDF).

14/ CEC, "California Energy Demand 2008-2018: Staff Revised Forecast," November 2007. (http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF).

15/ It appears that the E3 analysis does not use the most recent update to the CEC load forecast issued in November of 2007.

load forecast.[16/]

One aspect of the demand forecast not yet factored into the E3 analysis is load forecasting uncertainty. Since it is impossible to guarantee the certainty of the demand forecast, actual GHG emission reductions cannot be estimated with certainty. Therefore, the analysis of AB32 implementation solutions should account for the range of uncertainty in the demand forecast.

PG&E recommends that:

(1) The demand forecast be updated again once the degree of CEE double-counting is known with more certainty for purposes of determining the baseline for AB 32 implementation.[17/]

(2) Sensitivity analyses be conducted to take into account load forecast uncertainty.

C. Energy Efficiency Economic Potential and Costs

PG&E views the assessment of energy efficiency as needing closer examination and further refinement. PG&E believes the energy efficiency economic potential for IOU programs is too high in the E3 model, and perhaps infeasible, and the estimated costs to achieve energy efficiency levels are likely under estimated.[18/] Currently, the model extends the growth rate of potential in 2008- 2016 from the out-of-date 2006-2016 Itron Potential Study to estimate the potential for the 2016-2020 period.[19/] This

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16/ E3 Stage 1 Modeling Documentation, Section 11.

17/ D.07-12-052 anticipates " this issue will be the subject of significant evaluation in both the CEC IEPR update for 2008 and in the 2008 Long Term Procurement Proceeding." (p.45).

18/ E3 Stage 1 Modeling Documentation, Section 12.6, Appendix B.

19/ E3 Stage 1 Modeling Documentation, Section 12, Table 8. PG&E understands that E3 acknowledges that "the Itron 2006 EE potential studies are currently under revision, and this new data will be incorporated into our analysis as soon as it is publicly available."

assumption may overstate EE potential, does not reflect increased saturation of IOU energy efficiency measures, and should not be used in calculation of potential. Assuming a hypothetical capture rate for energy savings can be continued after the EE potential is substantially or completely exhausted, the model appears to implicitly make assumptions about currently unidentified technologies available in the future. As E3 notes, it will (and PG&E believes should) update the model upon the release of the Itron potential study addressing the period through 2020.[20/] The updated model should make explicit assumptions about realizing savings above the potential identified in the study, and preferably make such assumptions controllable by the model user for sensitivity analysis.

The E3 model should increase the costs required to implement unprecedented increasing levels of energy efficiency. E3 estimates that it will cost $1.2 to $1.5 Billion per year to achieve 100% of cost-effective electric efficiency, equal to approximately $260/metric ton.[21/] E3 also estimates that it will cost approximately $800 million to achieve 75% of economic potential by 2020.[22/] These costs are probably too low. The cost calculations should reflect the additional cost of replacing efficient technologies

20/ E3 Stage 1 Modeling Documentation, Section 12, Footnote 22. The CEC's website indicates that "the Itron Energy Efficiency Potential Study will be posted when available" (http://www.californiaenergyefficiency.com/resources.html).

21/ PG&E derived this $260 per ton figure by using the net savings in E3's model for PG&E by 2020 of 14,718 GWh for a cost of $1.533 billion as noted on page 62 of Attachment B of the November 9, 2007 ALJ Ruling. Assuming that CEE displaces gas combined-cycle generation at 7500 Btu/kWh or 0.4 metric ton/MWh, then the cost per ton equals $1.533 billion divided by (14.718 GWh*1000 MWh/GWh*0.4 metric tons/MWh), or $260/ton.

22/ E3 Stage 1 Modeling Documentation, Section 126, Appendix B and E3's GHG Calculator.

which do not remain in service to 2020 (for example, if an efficient copying machine[23/] is installed in 2010, it would be expected to last six years and the customer would 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.

PG&E's comments on the potential for additional energy efficiency are further discussed in comments on the Staff Workpaper below. PG&E recommends E3's modeling be revised as follows:

- As it has indicated it will do, E3 should use the 2007 Itron Potential Study for its GHG modeling. Results should be considered interim until the new Itron study, after being publicly reviewed and evaluated, replaces the current assumptions. The interim results should not be used as a basis for any policy decisions as the results may not be realistic or feasible.
- E3 should incorporate into its model the entire cost of each CEE measure, including costs of decay, additional incentives for early retirement, opportunity costs for businesses, and contingency costs. PG&E requests that discussion of these estimated costs occur as part of the E3 Modeling Workgroups.
- E3 should make explicit assumptions for the sources of CEE savings, specifying the technology, cost and load shape of these savings, particularly savings not arising from the 2007 Itron Potential Study.
- PG&E concurs with E3 that gross savings should be used, not net, to account for all of the GHG avoided by CEE measures. PG&E encourages E3 to adjust the analysis

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23/ 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.

and tables in the "Energy Efficiency" section to reflect the changes. E3 should also remove the following statement because the measurement of CEE net savings varies between regulatory agencies: "The CPUC and Energy Commission only allow utilities to earn credit for EE savings that are a direct result of utility EE programs, and which would not have happened anyway, in the absence of the program."[24/]

- Finally, accurate and reasonable costs and potential for CEE within the service territories of the POUs should not be based on the closest IOU, as is done in the E3 analysis.[25/] E3 should update these assumptions based on the POUs' possible lower cost and higher potential relative to the more mature IOU programs.[26/]

D. Renewables

Adding additional renewable generation is further discussed in PG&E's comments on the Staff Workpaper below. To better account for renewables costs and uncertainty in the E3 modeling, PG&E proposes the following modification and sensitivity analysis be included by E3:

1. Add a sensitivity case that limits renewable resource supply to a midpoint between 20% and 33%, given the uncertainty of achieving a 33% RPS level by 2020. This case would account for the steep supply curves the IOUs are facing in their renewable procurement efforts, as indicated in the Staff Workpaper.

2. Include a storage cost component for all intermittent renewables, not just for wind integration. Given the lack of widespread commercial deployment and

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24/ E3 Stage 1 Modeling Documentation, Section 2.a.3 and Section 12.

25/ E3 Stage 1 Modeling Documentation, Section 12.2.a.1.

26/ E3 Stage 1 Modeling Documentation, Section 12. AB 2021 September 17, 2007 CEC Workshop Presentation, "Summary of Staff Report, Findings and Recommendations" CEC Presentation shows that POUs represent 32% of electricity consumption for 2006 and only 5.4% of the GwH energy savings for California.

technological uncertainty, further work group efforts may be required to estimate these costs.

E. California Solar Initiative and Self-Generation

Costs for the California Solar Initiative (CSI) in the E3 model are low relative to current costs. E3 uses an installed cost of $8/Watt for the BAU case and $4.60/Watt by 2016 in the market transformation case.[27/] These figures are too optimistic. Costs have actually increased since the start of the CSI and are now above $9.00 per Watt.[28/] The worldwide polysilicon shortage may keep pricers higher for the next year or so, at least.[29/] E3's $8/Watt figure comes from a February 2007 Itron report that was based on the SGIP program installations in 2006.[30/] The Itron report did not reflect the increase in costs for solar installations, and it only examined installations 30 kW or greater, since, in 2007, those under 30 kW were rebated through the CEC's ERP program. Larger installations typically have lower module costs and lower balance of system costs. Since the CSI program includes smaller installations, using the Itron study as a starting point for CSI underestimates costs. CEC data for the ERP program and installation costs from the CSI program, in conjunction with data from the SGIP program, can be used to calculate a reasonable cost curve.[31/]

27/ E3 Stage 1 Modeling Documentation, Section 13.

28/ Based on preliminary PG&E analysis of ERP, SGIP and CSI data on installed costs.

29/ See http://www.policymatters.net/langton solar.php.

30/ See E3 Stage 1 Modeling Documentation, Section 13, stating their source as: Itron, CPUC Self-Generation Incentive Program: Solar PV Costs and Incentive Factors Final Report (http://www.itron.com/pages/news_articles_individual.asp?nID=itr_014827.xml).

31/ CEC, "Emerging Renewables Program Systems Verification Report 2004-2005, publication # CEC-300-2005-019" (http://www.energy.ca.gov/2005publications/CEC-300-2005-019/CEC-300-2005-019.PDF) and "Emerging Renewables Program Guidebook," EIGHTH EDITION. (http://www.energy.ca.gov/2006publications/CEC-300-2006-001/CEC-300-2006-001-ED8F.PDF) ; CPUC, "California Solar Initiative Staff Progress Report September 2007" (ftp://ftp.cpuc.ca.gov/puc/energy/solar/california_solar_initiative_staff_progress_report_septemb

Even under a market transformation scenario, it is unlikely that installed costs will decline to \$4.60/Watt. The price of modules will only affect about half of the installed costs. It is unlikely the balance of system costs (which include labor) will decrease sufficiently to achieve the market transformation assumption.

Finally, the location of CSI installations should include both customers of IOUs and POUs. In D.06-12-033, the CPUC reduced the goal of the IOU CSI from 3000 MW to 1940 MW. According to the CPUC, 65% of the legislatively-established statewide CSI budget was allocated to the IOUs, so the CPUC reduced the IOU goal accordingly.[32/] Future modeling should reflect this allocation among the customers of IOUs and POUs. If 3000 MW is to be reached, the POU-driven programs and the CEC's residential new construction program[33/] will presumably be responsible for 35%, or 1060 MW.

IV. GENERAL COMMENTS ON STAFF WORKPAPER

PG&E responds to the issues raised in the Staff Workpaper in this section. As a general comment, the Staff Workpaper is very focused on in-sector (electricity and natural gas) analysis for consideration of AB 32 emissions reduction measures, to the exclusion of other sector reductions.[34/] Emissions reduction costs and benefits in the electric and gas sectors should not be evaluated in isolation, but should be examined and

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er_2007.pdf). Data for the CEC's Emerging Renewables Program (ERP) can be found at: http://www.energy.ca.gov/renewables/emerging_renewables/index.html; data for the SGIP program can be found at: http://www.pge.com/suppliers_purchasing/new_generator/incentive/available_funding_and_program_statistics.html; and data for the CSI program can be found at: https://pge.powerclerk.com/default.aspx?P=7.

32/ D.06-12-033, page 29.

33/ See the CSI program website http://www.gosolarcalifornia.ca.gov/index.html.

34/ Staff Workpaper, p.1.

compared with emissions reduction opportunities from all sectors rather than looking at in-sector reductions only.

A. Energy Efficiency: Beyond Currently Targeted Levels

PG&E agrees with the Staff Workpaper that capturing energy savings in the future will become more difficult because "achievement of existing goals themselves will require unprecedented rates of program success and measure implementation."[35] In recent decisions from the CPUC and CEC, the agencies have stated their intention to embark on a path to achieve all cost-effective energy efficiency (CPUC, D.07-10-032 and CEC, 2007 IEPR dated December 5, 2007), and in the CEC's case, to do so by 2016. This is an aggressive vision that will require careful evaluation and significant legislative and regulatory initiatives beyond current programs, including establishing and enforcing new building and appliance codes and standards, new IOU and POU programs, expanded customer education and acceptance, and raising acceptance in the building industry and among appliance manufacturers for such technological and cost-effective improvements in energy utilization.

Given the lack of evaluation and economic analysis of these significant new legislative and regulatory initiatives in the CEE area, the State needs to conduct an energy efficiency potential study through 2020, including how fast this potential can be reached. As of today, no potential study exists beyond the date of 2016 for the IOUs. Through participation in the CPUC's workshops on the EE Strategic Plan, PG&E is aware that Itron and the CPUC are currently developing a study of EE potential through 2020. PG&E is unaware of the release date of that study but recommends that: (1) the

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35/ *Id.*, p.6. *Also see*, November 9, 2007, ALJ Ruling in R.06-04-009, Attachment A, Section 3.2.1.

study be released for public review and comment jointly in this AB 32 proceeding and the CEE proceeding to ensure that estimates of costs and CEE and GHG reduction potential are fully evaluated and accurately modeled; and (2) the study be expanded to include POUs using data on the efficiency of installed equipment specific to their service territories to ensure use of consistent methodology in examining Statewide energy efficiency potential.

With this updated and comprehensive potential CEE study, analysis can be developed detailing how fast that potential can be realized. Realizing high levels of CEE potential may require the replacement of still functioning equipment and appliances. Some equipment and appliances currently in place will last beyond 2016 (e.g. a relatively new electric motor, or many household appliances). If the CPUC and CEC's goals of achieving all cost-effective energy efficiency by 2016 are to be met, initiatives for early replacement will need to be developed from a policy, cost, and practical implementation perspective.

PG&E supports the continued exploration of additional energy efficiency in the water sector, but urges the CPUC to wait until the proposed Water-Energy Pilot is complete before incorporating water-related electricity measures into the potential study and modeling used for AB 32 because the pilot may find that certain measures are not cost-effective. Additionally, effectively pursuing saving water-embedded electricity may require new legislation if undertaken outside AB 32's regulatory scope. PG&E also supports exploration of "white tags" for use in developing a trading market for CEE benefits, but requests that the CPUC/CEC hold a formal proceeding to look into their possible use. PG&E is concerned that use of white tags may lead to gaming; decreased participation in utility programs; double-counting of savings, emissions reductions, and economic benefits; and may substantially increase transaction and administrative costs. The CPUC/CEC should wait until the utility REC market is functioning to learn from its process and practical experience.

PG&E agrees that customer compliance with the CEC's building codes and appliance standards holds potential for delivery of additional energy efficiency. The CEC and local governments must be involved in this process by streamlining the permitting process for new installations, considering point-of-sale efficiency standards, and by improving compliance processes. Evaluation of the potential for additional CEE based on improvements in building codes and appliance standards must be completed as part of AB 32 modeling and must take into account the separate regulatory responsibilities of the CEC, local governments and the federally-established national appliance efficiency standards.[36/]

Finally, California should ensure that AB 32 energy efficiency measures are evaluated assuming they are applied to POUs to the same extent applied to IOUs. POU cost-effective energy efficiency potential should be greater than from IOUs, given the more robust IOU CEE programs that have been in place many years. POUs have offered different energy efficiency programs than IOUs, in some cases, for fewer years, and, thus, as a group should have more "low-hanging fruit" in terms of cost-effective additional CEE. Thus the potential for CEE-related measures to be applied in IOU

36/ PG&E notes that the California Climate Action Team's 2006 and 2007 climate strategies included enhanced building and appliance energy efficiency standards as separate strategies, but have not yet provided any emission reduction estimates, costs, or savings attributable to those strategies. See *Final Report -- Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report,* October 15, 2007, Exhibit 2, p.7.

service territories as well as the potential for new, more efficient building construction should be identified and evaluated in the service territories of POUs.

B. Additional Renewables: Beyond Currently Targeted Levels

The Staff Workpaper states that "increased procurement of renewable energy on the scale anticipated by the Energy Action Plan (33%) will be a central component of achieving the level of GHG reductions required under a GHG cap covering the electric sector." PG&E believes the Staff Workpaper is premature in its conclusion regarding the GHG emissions reduction potential attributable to adopting RPS targets above the current 20% by 2010 level, because major issues associated with expanded renewables procurement still need to be resolved.

PG&E strongly supports California's goals of achieving significant and feasible increases in the use of renewable energy to serve our customers' incremental needs for power over the next several decades. We are continuing to fully incorporate the State's preferred loading order for CEE and renewables into our long-term resource planning, and we intend to fully comply with the States' 20 percent Renewable Portfolio Standard (RPS). However, prior to concluding that expanding existing RPS requirements will provide significant and feasible GHG reductions, additional feasibility assessments should be performed in conjunction with all major stakeholders (IOUs, CAISO, CPUC, CEC) to resolve critical issues, As PG&E has noted in previous regulatory filings,[37/] the principal issues associated with expanding renewable procurement to 33% are:

37/ Pacific Gas & Electric Company, "2006 Long-Term Procurement Plan," Volume 2, pp. I-16 to I-19, and Pacific Gas & Electric Company, "Comments on the Draft Report Achieving a 33% Renewable Energy Target, Dated November 1, 2005." PG&E recommends that the CPUC, CEC and ARB consult these previous filings on renewable energy policies as part of the consideration and modeling of emissions reductions potential attributable to expanded renewables in this proceeding.

- Ensuring Adequate Sources of Supply
- Ensuring Adequate Transmission Infrastructure
- Resolving Integration Issues
- Resolving Over-Generation/ Storage Issues

The Renewables Market and Resource Potential

Developing additional renewable resources to meet increased demand in California and the WECC will become increasingly challenging. While E3 models and the Staff Workpaper imply that there is virtually unlimited wind and solar resource potential in the WECC,[38/] the IOUs have demonstrated through their procurement efforts that transmission availability is increasingly becoming a critical element in meeting the State's renewables goals and that the remaining undeveloped renewable resources are in remote locations, away from major load centers.[39/] In addition, the Staff Workpaper does not assess in detail the fact that the renewables market has become a seller's market since the California RPS Program was established in 2003. In 2003, only 10 states had RPS Programs. By 2007, approximately 30 states had enacted RPS Programs or voluntary goals of some degree, with some RPS targets ranging up to 30 percent (as a percentage of retail sales), and corresponding implementation timeframes ranging from the next five to fifteen years.[40/] In the future, the demand for renewable energy is estimated to intensify and may exceed supply as more states establish RPS Programs and current RPS states re-evaluate their targets. The National Renewable Energy Laboratory (NREL) estimates that the demand for clean energy will outpace supply by 37 percent in

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38/ Staff Workpaper, p.7; E3 Modeling Documentation Sections 16, 19, 26, figures 1 and 3..

39/ *2007 Integrated Energy Policy Report*, California Energy Commission, December 2007, p.151, fn. 175, referencing PG&E's Long-Term Procurement Plan, Vol. 1, p. V-49 (public version.)

40/ www.dsireusa.org.

2010.[41/]

The IOUs are already facing steeper renewables supply curves in their procurement efforts as renewables prices have doubled in New England, the Mid-Atlantic and the Plains states, while increasing by 50 percent in the West.[42/] In addition, prices of raw materials and equipment have also increased with rising demand, with order backlogs of up to two years being common with wind turbines and solar photovoltaic cells, largely attributed to increased global demand.[43/] Renewables developers are frequently encountering permitting and siting-related problems in the remaining undeveloped locations.[44/]

Transmission

PG&E concurs with the Staff Workpaper that availability of new transmission is one of the key issues to increasing renewable penetration. Given the remote locations of a substantial portion of the remaining undeveloped renewable resources, significant upgrades in 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, generally considerably longer than it takes to construct a renewable generating facility. The CAISO agrees with the CEC that, in California alone, the 33% RPS case will require 128 new or upgraded transmission line

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

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

43/ *2007 Integrated Energy Policy Report*, California Energy Commission, November, 2007, p.176 (http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CTF.PDF)..

44/ *2006 Renewable Energy Investment Plan*, California Energy Commission, p.23 (http://www.energy.ca.gov/2006publications/CEC-300-2006-003/CEC-300-2006-003-CMF.PDF); *2007 Integrated Energy Policy Report*, California Energy Commission, November, 2007, p.132 (http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CTF.PDF) .

segments and upgrades to accommodate new generation resources, at an estimated cost of $6.4 Billion, excluding land and right of way costs.[45/] Transmission limitations will impact how quickly and at what total cost California will be able to add increased renewables to its mix.

Integration

The Staff Workpaper correctly identifies that given the intermittent characteristics of many renewable resources, as their deliveries increase, additional balancing of generation and load will be required, necessitating the build-out of additional dispatchable generation (hydro or fossil-fired), which will result in higher costs. The CAISO's recent report, "Integration of Renewable Resources" has the following conclusion regarding balancing generation and load with respect to expanded renewable procurement:

> Extensive changes will be required in the type of new generation built in the state: new units must have greater operating flexibility to start up and shut down without long delays: they must be able to operate at lower minimum loading levels and they must have faster ramping capability and regulation capacity.[46/]

To increase renewable procurement and given the desire to retire the aging fossil-fired boiler units, full recognition should be given to units with faster and more durable ramping capabilities.

Over-Generation and Energy Storage

While over-generation was not mentioned in the Staff Workpaper or the E3 model, resolving the potential problems associated with over-generation could add substantial costs to procuring renewables. Over-generation occurs when significant

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

46/ CAISO, "Integration of Renewable Resources," November 2007, pp. 20.

amounts of uncontrolled generation exceed minimum loads. This usually occurs at night, during periods of high "as available" generation and low loads. For example, wind produces much of its energy off-peak.[47/] In addition, 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.[48/]

During off-peak, low load periods, energy prices may be zero or negative as the CAISO will need to pay adjacent control areas to take this excess power or pay generators to curtail output. Most of the CCGT plants needed to meet peaks the next day may not be able to turn off overnight. Without the ability to reduce baseload generation, the CAISO will experience minimum load conditions that will limit how much off-peak energy it can accept. In the future, this issue will only intensify 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. However, on a large-scale basis, with few exceptions (e.g. hydroelectric pumped storage), current storage technologies are not commercially feasible or geographically available for integrating intermittent resources. New commercially ready technologies will be required and may not be commercially available for many years. Significant challenges to commercialization of energy storage

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47/ "Intermittency Analysis Project: Appendix B, Impact of Intermittent Generation on Operation of California Power Grid," (CEC-500-2007-081-APB), California Energy Commission, July 2007.

48/ "Wind Performance Report Summary 2002- 2003," (CEC-500-2006-060), California Energy Commission, June, 2006.

technologies are:

- High capital costs ($1 million to $1.5 million per MW of capacity)
- The efficiency of new systems is low, less than 75% for many technologies
- The amount of storage capability is limited[49/]
- Storage systems are a net negative device, more resembling a load than a generator.[50/]

In order to complete the modeling process for AB 32 emissions reduction modeling and evaluation, a reasonable approximation of projected storage costs will need to be modeled.

Recommended Analyses Regarding AB 32 Emissions Reductions from Incremental Renewables

PG&E recommends the following analyses be included as part of the evaluation of potential AB 32 emissions reductions from incremental renewables:

- Additional integration studies:[51/] A comprehensive study evaluating the integration of significant amounts of intermittent and off-peak resources into the grid, including costs impact, operational changes required, and the facilities and infrastructure needed.

- Consideration of the impact of extension or non-extension of both the state (solar property tax credit) and federal tax (PTC and ITC) subsidies associated with renewable energy.

- Consideration of the impact of new tax subsidies and credits aimed at the first deployment of new storage technologies

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49/ CAISO, "Integration of Renewable Resources," November 2007, pp. 91-92.

50/ See http://www.caiso.com/1ca5/1ca5a7a026270.pdf.

51/ Pacific Gas and Electric Company, "Comments on the California Energy Commission's 2007 Integrated Energy Policy Report, Draft Committee Report," pp. 16.

- Consideration of the impact of approval of the proposed Emerging Renewable Resource Programs (ERRP) of PG&E and SDG&E. In addition to expediting commercialization efforts of new renewable technologies, ERRP funded projects for energy storage will be complementary to the DOE and CEC funded R&D projects. SCE has stated their intent to propose an ERRP to concentrate on the integration of renewable technologies.
- Consideration of the expeditious approval of filed tariffs for power purchase agreements compensating PG&E customers for exports to the grid from renewable generation up to 1.5 MW.
- Consideration of expansion of the SGIP program to include any renewable customer generation up to 1 MW.[52/]

C. Increased Combined Heat and Power (CHP)

The following comments apply to both the Staff Workpaper and the E3 Model. As the CPUC explores the use of CHP for emissions reductions, it should be clear that only efficient CHP meaningfully reduces electric sector GHG emissions. CHP is a baseload, must-take resource providing no operational flexibility and with the same over-generation issues as described in section IV.B. As energy efficiency and renewable resources are also must-take resources, adding large amounts of GHG-emitting CHP might increase the challenges for adding these resources with no additional operational flexibility. Thus, CHP's impact on the GHG footprint associated with PG&E's delivered electricity is unclear and may not be positive.

52/ Starting January 1, 2008, the Self-Generation Incentive Program will be available only for wind and fuel cells. The description in the Staff Workpaper should be modified to reflect this fact, deleting references to small-scale photovoltaic (which has been transferred to the CSI) and microturbines (which will no longer qualify for rebates).

Evaluation of the CEC potential of CHP in the 2005/ 2007 IEPR

The CEC market potential study for CHP needs to be updated and modified.[53/] While there are efficient CHP applications, the 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.[54/] In simple terms, the alternative to CHP baseload generation is not an aging powerplant with a higher than 10,000 Btu/kWh heat rate which is only operated for load following or peaking. CHP should be compared to new CCGTs and boilers. Because the CEC potential study does not conduct the correct comparison, the CHP benefits are over-stated.

Additionally, the market potential needs to be validated against what is possible. For example, the Aggressive Market Access case projects 2,869 MW[55/] of new export MW compared to a little more than 900 MW of EOR based CHP electrical generation presently in the PG&E area.[56/] To add 2,800 MW of export generation with the same thermal efficiency as EOR CHP means that the oil field reserves would have to be several times greater than they are at present. This is not a tenable assumption.

Reliability Effects of Increased Reliance on CHP

As the CPUC has found, customer generation only provides distribution benefits

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53/ CEC, Assessment of California's CHP Market and Policy Options for increased Penetration (CEC-500-2005-060-D at http://www.energy.ca.gov/2005publications/CEC-500-2005-060/CEC-500-2005-060-D.PDF).

54/ *Id.*.

55/ *Id.*, p.9.

56/ PG&E's "Cogeneration and Small Power Production Annual Report," filed with the CPUC and posted on the PG&E public web site.

under narrow circumstances.[57/] For these same reasons, customer-owned CHP does not contribute significantly to reliability or resource adequacy requirements. Additionally, concerns remain about whether the electric system can absorb baseload, must-take generation in the amounts projected by the CEC potential.

Evaluating Potential GHG Reductions from CHP

PG&E recommends that the GHG reduction potential of CHP be limited to deployment of efficient CHP when it is cost-effective and reduces the overall carbon footprint compared to alternatives. PG&E believes there are sufficient subsidies in place to enable evaluation of expansion of efficient, cost-effective CHP including: implementation of the recently-enacted AB 1613, which will provide payment for grid exports from CHP up to 20 MW; recently-determined QF payments; waiver of standby-charges for much CHP; and exemption from DWR power charges. Even though recent deployment of CHP has been hampered by market barriers such as uncertainty in natural gas prices, PG&E also believes that if the SGIP were extended to provide incentives for clean CHP under 1 MW, more customers may find it cost-effective to implement this choice.[58/] PG&E does not believe that establishment of any additional subsidy should be assumed as part of evaluating the GHG reduction potential of CHP at this time.

D. Carbon Capture and Sequestration

According to the Staff Workpaper, "coal integrated gasification combined cycle (IGCC) and coal IGCC with carbon capture and sequestration (CCS), are new generating technologies that have the potential to reduce GHG emissions while continuing to permit

57/ See CPUC Decision No. 03-02-068.

58/ By clean, efficient CHP, PG&E refers to the standard to be defined by the California Energy Commission pursuant to the requirements of Assembly Bill 1613.

the use of an abundant and inexpensive fuel."[59/] After accounting for the energy needed for capture and compression, an IGCC plant with CCS could reduce CO2 emissions by approximately 80-90 percent compared to a power plant without CCS.[60/] California has the technical potential to store 5.2 GT CO2 in oil and natural fields, and the capacity in deep saline formations may be one or two orders of magnitude greater. The Intergovernmental Panel on Climate Change (IPCC) estimates that CCS has the potential to abate CO2 emissions worldwide by between 15-55% of the cumulative mitigation effort needed by 2100.

However, the realistic resource potential in the 2020 timeframe depends on the extent to which technology, financial, regulatory and legal barriers can be removed. While many component technologies for CCS have already been developed, there is relatively little experience in combining CO2 capture, transport and storage into a fully integrated CCS system. More importantly, regulatory uncertainties and legal issues regarding property rights and liability are significant barriers for CCS that must be resolved before the CCS could play any major role in meeting AB 32's GHG emission reduction goals. We agree with the Staff Workpaper's assessment that the timeframe for large-scale deployment of CCS is likely to be after 2020.[61/]

In order to be in a position to consider accelerated deployment as part of post-2020 GHG emissions reductions, California should continue to participate in

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59/ Staff Workpaper, p.10.

60/ See for example UNEP, "A simplified guide to the IPCC's "Special Report on Carbon Dioxide Capture & Storage," p3 (http://www.unep.org/dec/docs/CCS_guide.pdf). Also see Eric Williams, Nora Greenglass and Rebecca Ryals, (2007) "Carbon Capture, Pipeline and Storage: A Viable Option for North Carolina Utilities?" p5 (http://www.env.duke.edu/institute/carboncapture.pdf).

61/ E3 Stage 1 Modeling Documentation, Section 24.

partnerships such as WESTCARB to advance technology assessments and demonstrations, and spur efforts to develop lower cost carbon capture technologies and storage. The state should also work with the federal government to address the legal, regulatory, and safety barriers and issues associated with CCS. One important issue is the development of a legal framework and long-term stewardship to address long-term liability associated with carbon sequestration, since the residence time for stored CO2 needs to be effectively in perpetuity, outlasting project operators and insurance companies.

Another carbon capture technology that is not identified in the Staff Workpaper is oxyfuel combustion. Oxyfuel combustion systems use high-purity oxygen instead of air in the combustion process, which yields a highly concentrated stream of CO2 and water vapor. The water vapor is condensed for removal and CO2 is thus captured. Oxyfuel combustion has potential in California, including use with natural gas and biomass. However, the technology needs to be developed and the same pre-2020 regulatory and legal hurdles regarding long term CO2 storage exist here as well. A 50 MW zero emissions demonstration plant is currently under development in Bakersfield, where the some of the captured CO2 will be available to nearby oil producers for enhanced oil recovery.

E. Increased Conventional Non-carbon Sources

New large hydro

The potential for new large hydropower resource additions that involve new dams will be determined by the complex interrelationships among multiple stakeholders for enhancing water supply reliability in California by building new dams or enlarging existing dams. Broad support from federal, state, and local stakeholders (counties, agriculture, non governmental organizations, etc.) will have to come together; and many parties will have to work in concert to agree on the right location and operating constraints for new infrastructure (dams, power generation) and to better coordinate the required governmental authorizations. If a stakeholder consensus supporting a new or enlarged dam for storing water can be developed, the potential for developing new large hydro could become quite high.

A critical component of the discussion of additional hydro potential would be the evaluation of conventional (generate-only) and pumped storage (pump or generate) options. Current state forecasts of timing and location of additional wind energy and other intermittent and off-peak renewables will inform the choice between conventional and pumped storage technology.

The realistic long-term potential for new large hydro, or new large hydro pumped storage – from a climate change perspective – depends on the climate change impacts on the snowpack. If climate change alters precipitation patterns, as many scientists predict, the amount and location of potential for both water supply and new hydro development will be altered significantly.

Nuclear

New nuclear units currently are subject to legal restrictions in California. However, nuclear units could be built outside of the state (e.g., Palo Verde was designed for 5 units originally, but only 3 were built) and power imported via new transmission. The potential for such out-of-state nuclear within the timeframe covered under the modeling effort should be evaluated.

F. Biomethane

"A Roadmap for the Development of Biomass in California," published by the CEC in November 2006, states that "By 2020, the state could triple its biomass-to-electricity generating capacity and increase its production of biofuels a hundred-fold, both from resources now considered feasible to use as feedstock and through at least a modest increase in dedicated biomass crops."[62/] In this report, biomethane is defined as "methane derived from anaerobic digestion of biomass."[63/] Note however that biomethane can also be produced through thermochemical and other biochemical processes. If thermochemical conversion becomes commercial, PG&E has used CEC and UC Davis data[64/] to calculate that 5-10% of its natural gas system throughput theoretically could be replaced by biomethane. Both technology demonstration and economics at commercial scale remain to be tested to determine feasibility.

G. Comments on CAT and CEC IEPR analysis

In assessing greenhouse gas reduction potential in the electric sector, the CPUC Staff Workpaper indicated that its analytical work has benefited from the Updated Climate Action Team (CAT) Macroeconomic Report issued in September 2007 and the California Energy Commission's Scenarios project in the 2007 Integrated Energy Policy

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62/ CEC, "A Preliminary Roadmap for the Development of Biomass in California, page X (http://www.energy.ca.gov/2006publications/CEC-500-2006-095/CEC-500-2006-095-D.PDF).

63/ *Id.*, p.11.

64/ "California Biomass Facilities Reporting System," UC Davis Biomass Collaborative, http://cbc2.ucdavis.edu/cbc/biomasssResource/resourceByCounty.asp; CEC PIER Collaborative Report: "Biomass in California," June 2005 (CEC 500-01-016).

Report.[65/] PG&E has concerns about some aspects of both reports. Economic conclusions, costs, and emissions reduction estimates from these reports should be subject to a more complete analysis and review. PG&E has recommended that the CAT and ARB consider providing for independent peer review of the modeling and analyses contained in the Climate Strategies Update, in order to strengthen the analysis and conclusions for "hands on" use in the scoping and implementation of specific AB 32 strategies. PG&E's key points on the CAT and IEPR are summarized below.[66/] For more information, please review the documents cited.

Concerns with the CAT include:

- Substantial differences in the results of the 2006 CAT Report and 2007 updated version suggest the need for rigorous review of the Climate Strategies Update, especially with respect to completeness.

- The CAT may have used electricity prices that are too high relative to current prices, causing the study to overstate the costs avoided by reducing GHG emissions through energy efficiency and renewable power resources. PG&E believes it is essential that the energy price assumptions be periodically updated throughout the AB 32 implementation period given the significant impact that

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65/ Staff Workpaper, p. 11, citing CEC, 2007 Integrated Energy Policy Draft Report (http://wssascon/EP/EPPA/IRP/IEPR/CEC%20IEPR%20Reports/2007%20IEPR%20-%20Draft.pdf) and Updated Macroeconomic Analysis of the Climate Strategies Presented in the March 2006 Climate Action (http://www.climatechange.ca.gov/events/2007-09-14_workshop/final_report/2007-10-15_MACROECONOMIC_ANALYSIS.PDF).

66/ For PG&E's comments on the CEC's IEPR see http://www.energy.ca.gov/2007_energypolicy/documents/2007-10-15_hearing/committee_report_public_comments/Guliasi_Les_Pacific_Gas_and_Electric_2007-10-19_TN-42932.pdf and for PG&E's comments on the CAT report see http://www.climatechange.ca.gov/events/2007-09-14_workshop/comments/PG+E_Comments_Updated_CAT_Report_2007-09-28.pdf.

changes in energy prices can have on the costs and benefits of emissions reduction measures.

- CAT analysis of the costs and benefits of a 33% Renewable Portfolio Standard are not accurate. PG&E has expressed concerns about the assumptions and results in the CRS Draft Report relied upon for this strategy.

- CSI analysis needs to be updated and reviewed to ensure that all economic costs are included.

- The energy savings and funding figures vary from what has been adopted at the CPUC without explanation or analytical support. The funding for 2014-2020 seems to use a different metric than the one used for 2005-2013.

- The estimated 4 – 18 million metric tons of potential emissions reductions from the Municipal Utilities is too wide a range and very difficult to support because the assumed future municipal utility energy efficiency and renewable energy programs have not been identified, implemented or evaluated.

Concerns with the CEC Scenario Analysis in 2007 IEPR:

As a part of the 2007 IEPR, the CEC assessed the implication of very high penetrations of energy efficiency and renewable resources in its Scenario Analysis. The final 2007 IEPR, however, does not mention the limitations of the Scenario Analysis that the underlying documentation acknowledges. The CEC's *Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report* states:

> "This project provides useful information, but the need to produce the results within the available time and budget imposed limitations on data assumptions, modeling assumptions, and uncertainty characterization assumptions.

- The data assumptions suggest imprecision in the results and indicate that the results are not useful as point estimates.
- The modeling assumptions suggest limitations in the representation of the electric system physical operations, market operations, and regulatory operations and thus imply that one should exercise caution in deciding which policy questions these results can meaningfully address.
- The uncertainty characterization assumptions suggest that results are likely to be sensitive to the incorporation of additional sources of uncertainty; thus, readers should exercise caution in making pronouncements that imply that the results would carry through even if additional sources of uncertainty were evaluated."[67/]

The following statement from the draft 2007 IEPR, deleted in the final 2007 IEPR, reinforces the point that the Scenario Analysis should not be used to support important policy decisions: "Due to its design, the study provides broad indications of results from 'what if' assumptions that may not be feasible at the cost, or in the timeframe, assumed."[68/] Given these limitations, PG&E does not find the results of the CEC's Scenario Analysis to be robust enough to support policy decisions surrounding AB 32, including a 33% RPS target.

V. RESPONSE TO SPECIFIC QUESTIONS

Questions Related to Attachment A, Identification of Emission Reduction Measures

Q1. Does Attachment A cover all of the viable emissions reduction measures available in the electricity and natural gas sectors? If not, what other measures should be considered for the purposes of forecasting emissions reduction potential within these sectors? Please include suggested data sources and references for information regarding any additional measure you propose.

PG&E RESPONSE:

No. PG&E believes that cross sector GHG reduction curves are needed and that the joint proceeding should not focus on emissions reductions only from the electricity

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67/ Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 IEPR, p.12.

68/ Draft 2007 IEPR, p.58.

and natural gas sectors. Thus, while Attachment A may many of the viable emissions reduction measures available *in* the electricity and natural gas sectors, it does not cover all of the measures available *for* those sectors. An example of possible low cost reductions not covered is the plug-in hybrid electric vehicle. While electricity sector emissions might increase, California emissions on the whole will decrease. The electricity sector could be compensated through offsets or increased allocation of allowances. Likewise, enhanced codes and standards applicable to buildings, appliances and to other goods and services would affect emissions in the electric and gas sectors.

Q2. Are there emission reduction measures identified within Attachment A that you believe, based on currently available information, should not be implemented as a means to achieving emission reductions within the context of AB 32? Please justify your answer.

PG&E RESPONSE:

No measure should be implemented without a fully developed cross sector set of cost curves. In particular, a 33% RPS with CEE goals reflecting 100% economic potential appear to be extremely expensive and may not be feasible. Implementing these without examining GHG reductions opportunities across all sectors would be premature and potentially unnecessarily costly.

Q3. What means beyond policies currently adopted by the two Commissions hold potential for the delivery of additional energy efficiency?

PG&E RESPONSE:

Additional energy efficiency may be possible through:

- More stringent building and appliance standards;
- Increased enforcement of building and appliance standards;
- More rapid turnover of inefficient appliances and other equipment; and

- Consistent implementation of CEE by POUs as well as IOUs, taking into account credit for past CEE programs.

Q4. What means beyond policies currently adopted by the two Commissions hold potential for the integration of additional renewable resources into the grid?

PG&E RESPONSE:

As discussed above, policies to develop energy storage, integration of intermittent resources, and transmission are needed to add large amounts of renewable resources. Additional policies (such as tax subsidies and ERRP-related funding) to facilitate commercialization of energy storage technologies would also be beneficial.

Q5. How might an emissions reduction strategy within the electricity sector be targeted to displace the most carbon intensive aspects of California's electricity resource mix?

PG&E RESPONSE:

A source-based cap will motivate generators to include GHG compliance costs in the dispatch price. A WECC wide source based cap that applies directly to all sources, including coal-fired generation, may have some limited impact on dispatch. PG&E agrees with the CEC Scenario analysis outcome that "Absent a carbon cost adder affecting dispatch, an actual carbon tax on usage, and/or explicit constraints on coal use, coal power generation prices are so much lower than natural gas prices that coal will continue to be dispatched regardless of resource additions promoted by policy makers."[69/]

A CO2 price will reduce operating margins for coal facilities relative to natural gas facilities and other lower carbon technologies. This fact, along with the relatively

69/ 2007 IEPR, p.47.

high per MW installed cost of new coal facilities, make coal in the WECC a relatively less attractive investment when considering new resource additions.

Questions Related to Attachment B, Modeling Approach and Data Sources

Q6. Does E3's modeling documentation adequately document the methodology, inputs, and other assumptions underlying its model? If not, what additional documentation should be added?

PG&E RESPONSE:

PG&E suggests the following addition to the E3 Model documentation:

1. More explanation on how generation is assigned to load. The list of generation facilities used does not appear to be a standard CEC list. PG&E knows that not all of the generation we own or have long-term contracts with is assigned to us, but we cannot tell with the way the facilities are listed. Some entries appear to be aggregations of generation facilities. Some generation facilities appear to be missing, and some names are abbreviated so such that PG&E is unable to identify them. PG&E suggests that the database be modified to include all generating units by their full names, using the EIA database, the CEC database, and publicly available information on utility contracts with Qualifying Facilities. Both the EIA plant number and the CEC plant number should be included.

2. Users would find extremely useful a handbook on how to conduct sensitivity analyses, such as changing natural gas prices or assumptions on CEE potential.

Q7. Provide feedback, as desired or appropriate, on the structure and approach taken by E3 in its GHG Calculator spreadsheet tool.

PG&E RESPONSE:

The goal of the modeling exercise should be to come up with a multi-sector GHG emissions reduction cost curve. As such, while the output of E3 is a good start and reflects a great deal of work, it should set the stage for cross-sector evaluation of the most cost effective GHG reduction measures across all sectors. The addition of an outputs $/ton for each measure, not for each scenario in aggregate, would facilitate cross sector comparison. The aggregate number does not convey which measures are the most cost effective. LSE specific $/ton information should be presented to help determine the relative cost burden of each LSE.

Q8. Provide feedback, as desired or appropriate, on the data sources used by E3 for its assumptions in its issue papers. If you prefer different assumptions or sources, provide appropriate citations and explain the reason for your preference.

PG&E RESPONSE:

Uncertainty as to availability and cost of CEE, DR, RPS and other resources should be included in the analysis of the supply curves. Single point forecasts of cost and availability of preferred resources mask the uncertainty decision-makers face today in deciding how to best reduce future CO2 emissions. The ability to change the inputs and conduct sensitivities is as important as the ability to change the percentages of RPS and CEE assumed.

The new (but yet to be released) Itron/CPUC potential study for energy efficiency potential though 2020 should be incorporated into the model <u>only after</u> parties have had an opportunity to examine that the methodology and assumptions used to calculate the potential and associated costs are accurate and reasonable.

For CSI, as explained above, E3 should examine the CEC data for the ERP program and installation costs from the CSI program to calculate a more reasonable cost curve.

Finally, for the list of generation facilities, E3 should use the EIA database and the CEC database. Both the EIA plant number and the CEC plant number should be included.

Q9. Are uncertainties inherent in the resource potential and cost estimates adequately identified? Does E3's model provide enough flexibility to test alternative assumptions with respect to these uncertainties?

PG&E RESPONSE:

PG&E is concerned that the uncertainties inherent in resource potential and cost estimates are not adequately identified. E3 should include a toggle to evaluate the possibility that CEE and RPS supply is not available in the amounts anticipated by 2020. In the main worksheet, E3 could have a "low resource development" switch that, when chosen, forecasts costs if less RPS and CEE are developed in the 2020 timeframe. Renewable resource supply could be modeled at a midpoint between the current 20% mandate and the proposed 33% by 2020 target. CEE could be modeled at 75% of economic potential.

Q10. Has the E3 model adequately accounted for the implications of increased reliance on preferred resources (renewables, efficiency) on system costs?

PG&E RESPONSE:

No. Closer examination of the uncertain availability and cost of preferred resources is needed as discussed in PG&E comments above.

Q11. Should E3's model, in Stage 2, attempt to model potential market transformation scenarios, in the form of cost decreases, new technologies, or behavioral changes? What might be an appropriate way to characterize such potential for market transformation?

PG&E RESPONSE:

A certain amount of market transformation would need to occur to support the prices and amounts currently modeled by E3. Further market transformation should not be modeled in this timeframe.

Although technological developments in renewable energy are anticipated to increase supply and drive down costs in the future, the approximate timing and expected impact are very difficult to estimate. Cost curves in the renewables market continue to climb, as additional states enact RPS programs and more renewable energy is procured as a result of mandates and voluntary efforts. Therefore, given the uncertainty in regard to the cost outlook, it is suggested that anticipated cost decreases from the commercialization of future renewable technologies may not be available in this time frame and should not be incorporated into the GHG modeling effort.

The range of uncertainty with respect to availability and cost should be enough to capture market transformation or behavioral changes. At the end, policy makers need to weigh the validity or likelihood of scenarios that require market transformation, and be willing to adjust the programmatic targets if the expected transformation does not occur. In other words, if for example, the RPS target is increased on the expectations that RPS prices will decrease because of market transformation, policymakers need to be willing to lower the target if prices remain high because transformation does not occur or because suppliers do not reduce their prices.

Q12. What specific flexible GHG emission reduction mechanisms to mitigate the economic impacts of achieving the desired GHG emission reductions should be modeled in Stage 2?

PG&E RESPONSE:

Other alternatives within the electric sector and in other sectors need to be compared before a policy decision is made regarding increased reliance on preferred resources. In Phase 2, E3 should include a variety of market based mechanisms, including trading with other in-state sectors and offsets from various geographic scopes, including the Clean Development Mechanism. The importance of looking CEE and RPS as GHG reductions measures within the context of a larger cost curve of GHG emissions reductions opportunities cannot be emphasized enough.

Q13. What output metric or metrics should be utilized to evaluate the least cost way to meet a 2020 emission reduction target for the sector?

PG&E RESPONSE:

The appropriate metric for determining whether a reduction measure is cost effective is $/metric ton for the measure. This figure should be used in the context of a larger multi-sectoral cost curve, including offsets from various geographic radii.

VI. SUMMARY OF RECOMMENDATIONS FOR E3 AND MODELING

The following table summarizes the changes PG&E recommends that should be made to the E3 Model:

TOPIC	E3 Assumptions	PG&E Recommendations
Model results	N/A	Results should be presented in $/ton for each LSE and for each measure, rather than the aggregation that is given.
Sensitivities	N/A	E3 should prepare a handbook on how to conduct sensitivity analyses, including on (a) load growth, (b) availability and cost of CEE, and RPS additions, integration, storage, and transmission, and (c) natural gas prices. E3 should explicitly account for the uncertainty associated with the major inputs assumptions.
CSI forecast	The no-market transformation costs of	These costs are too optimistic based on recent evidence in California. E3 needs to examine

	$8 and market transformation costs of $4.60	the CEC data for the ERP program and the CSI installation data in order to calculate a more reasonable cost curve. In the near-term, there should be no decrease in costs. Spread CSI responsibility to POUs
Load growth	CEC 2008-2018 Forecast, adjusted for energy efficiency achievements	Update the load forecast again after the energy efficiency double-counting in the CEC load forecast is finally determined.
Intermittent resource integration & firming costs	Wind integration cost adder only	Verify that there is enough load capable of absorbing the large amount of wind generation assumed in the reference cases, and/or that there is sufficient transmission added to make that energy useful in other areas. Add energy storage costs for all intermittent renewables, not just integration costs for wind.
Energy efficiency	2006-2016 Itron Potential Study	Use the 2007 Itron Potential Study, once this is publicly vetted, rather than the old Itron study, for CEE potential through 2020. Increase the costs required to implement unprecedented increasing levels of energy efficiency. Update these assumptions based on POUs different cost and increased potential.
Energy efficiency	N/A	Make explicit assumptions for the sources of CEE savings, specifying the technology, cost and load shape of these savings.
Fuel Price Forecasts	SSG-WI forecast for all fuels is scaled so that CA natural gas matches MPR forecast	E3 should compare its projections of the 2020 prices of each fuel, including natural gas, to those contained in the recently issued 2008 EIA Energy Outlook. Depending on the results, E3 should consider revising its assumptions regarding the 2020 price of each fuel, specifically the assumption that all fuel prices should be increased by the same ratio as the ratio between the 10/4/07 MPR natural gas price and the SSG-WI natural gas price.
Assigning Generations to LSEs	SSG-WI list	Use generation facility lists from CEC and EIA.
Installed Capital Cost	EIA AEO 2007	E3 should review the 2008 Energy Outlook, and where appropriate revise the model's assumptions about the current capital costs of al generation technologies.
New generation	No low case developed	Add a toggle for results if CEE and

resources and cost - renewables		renewables are not able to show up at all.
CHP	N/A: E3 has indicated they are adding	Only efficient CHP should be included in the analysis. The potential for efficient CHP must be validated. CHP should also be modeled as a must take, baseload resource, and the cost and GHG emissions of incremental CHP additions should be allocated between electric and non-electric sectors. Estimates of GHG reductions for efficient CHP should be calculated using a new CCGT and boiler as alternatives.
Phase 2	N/A	E3 should include a variety of market based mechanisms, including trading with other in-state sectors and offsets from various geographic scopes, including the Clean Development Mechanism.

VII. 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 defer any decisions or recommendations on the design of an AB 32 regulatory mechanism for the electric and gas sectors until the modeling is completed and has been evaluated and subject to peer review and comment by interested parties.

Respectfully Submitted,

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By:______________________________

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