COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY ON THE CALIFORNIA AIR RESOURCES BOARD AB 32 SCOPING PLAN PROGRAM DESIGN AND POLICY SCENARIO DESIGN FOR INITIAL MODELING ACTIVITIES

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I.

INTRODUCTION

Southern California Edison Company (SCE) appreciates the opportunity to provide comments to the California Air Resources Board (CARB) on the analytic design and policy scenario selection in CARB's modeling activities as part of the AB 32 Scoping Plan process.

At the February 6, 2008 Program Design Technical Stakeholder Working Group Meeting, CARB staff described a two-stage modeling process. First, an initial set of modeling runs will evaluate a set of policy scenarios along with a set of core measures. CARB staff will then present the results of these initial modeling runs at an April 4, 2008 workshop, and these results, along with stakeholder comments, will be used to design additional policy scenarios and measures to be evaluated in the second stage of modeling efforts. SCE understands that CARB is currently soliciting comments on its initial modeling activities, and that comments on additional policy scenarios and modeling activities should be provided after the results of the initial modeling activities are known. As such, SCE reserves its suggestions for additional policy scenarios for CARB's second stage of modeling activity for future comments.

SCE has structured these comments so that Section II addresses the policy scenarios for CARB's initial modeling and Section III addresses the core measures. As part of the California Public Utilities Commission's (CPUC) modeling efforts for the electricity sector, SCE has previously filed comments on the model created by Energy and Environmental Economics, Inc. (E3). SCE attaches those comments to this submission as an appendix.

II.

POLICY SCENARIOS

CARB staff have identified the following five policy scenarios for CARB's initial modeling efforts:

- Additional direct regulations;

- A cap-and-trade program that includes all large stationary industrial and commercial sources, including electricity generators;
- A cap-and-trade program with trading regionally or nationally that includes all large stationary industrial and commercial sources, including electricity generators;
- A cap-and-trade program with trading regionally or nationally that includes all large stationary industrial and commercial sources, including electricity generators and transportation fuels; and
- A carbon fee applied to fuels throughout the California economy at the distribution level.

SCE offers the following comments on the policy scenarios.

A. CARB's Initial Modeling Efforts Will Not Demonstrate the Full Benefits of a Cap-And-Trade Program Unless Full Implementation of a Comprehensive Cap-And-Trade Program is Considered

At the February 6 meeting, CARB staff described the initial modeling runs as bookends, with full cap-and-trade compared to complete direct regulation. While SCE agrees with this basic approach, in order to appropriately compare the economic benefits of a cap-and-trade program to direct regulation, CARB must consider full implementation of a comprehensive cap-and-trade program. A broad multi-sector cap-and-trade program benefits the environment and the economy by identifying the lowest cost opportunities for real greenhouse gas (GHG) emission reductions both within and beyond the capped sectors. CARB's initial modeling activities should evaluate the lowest possible cost of implementing a cap-and-trade system by considering full implementation of a comprehensive cap-and-trade program.

B. CARB Should Include Unrestricted Offsets in its Initial Modeling Efforts

As the Market Advisory Committee to CARB determined, offsets provide a valuable opportunity for California to provide real, verifiable emission reductions at the lowest cost to the economy. The Market Advisory Committee concluded:

> By encouraging emissions reductions in areas or sectors outside the cap-and-trade program, offsets broaden the reach of the program and help promote the achievement of overall emissions-reduction goals at lower cost.[1]

SCE understands that CARB intends to compare and contrast the economic costs of a full cap-and-trade program to direct regulation. However, if CARB's initial modeling efforts do not include offsets, CARB will not identify all of the benefits of a cap-and-trade program. Accordingly, because any comparison between direct regulation and a restricted cap-and-trade program will not identify the true benefits that a cap-and-trade program can provide to California, CARB should include offsets as part of its evaluation of a cap-and-trade program.

C. Allowance Value Must Be Returned to Entities Incurring Economic Harm

CARB staff have indicated that the cap-and-trade scenarios within the initial modeling runs will assume full auctioning of allowances. Although CARB staff have also proposed that they will consider some method of free allocation for some of the scenarios presented at the April 4 workshop, SCE suggests that in order to accurately compare the costs and benefits of a cap-and-trade program to direct regulation, allowance value must be returned to entities that suffer economic harm. Restrictions on allocation will needlessly increase the costs of a cap-and-trade program, and will not provide an accurate point of comparison to direct regulation.

D. CARB Should Not Use its Limited Resources To Model a Carbon Fee or Tax

One of the policy scenarios CARB staff are considering for the initial modeling runs is a carbon fee, otherwise known as a carbon tax, applied to fuels throughout the California economy. Such a carbon tax may never be adopted and, even it were, it is difficult to predict how such a tax would be designed and implemented. SCE therefore believes that modeling a hypothetical carbon tax would have limited utility. CARB should not use its limited time and

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[1] Market Advisory Committee to the California Air Resources Board, Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California at 61-62 (Jun. 30, 2007).

resources to model a carbon fee or tax during its initial modeling. CARB's time and resources could be better used modeling other scenarios.

III.

CORE MEASURES

CARB staff have identified the following seven core measures that will apply to all policy scenarios in the initial modeling runs:

- Greenhouse gas tailpipe emission standards;
- Low carbon fuel standard;
- Continued energy efficiency beyond current programs;
- 20 percent renewable portfolio standard;
- Discrete early actions adopted by the Board in 2007;
- Reductions in vehicle miles traveled; and
- Controls on high global-warming potential (GWP) gases.

SCE agrees with CARB's efforts to incorporate a standard set of core measures in all of CARB's modeling efforts. SCE also supports a broad approach to achieving California's GHG reduction goals, including coverage of the transportation industry in GHG reduction programs. Moreover, SCE supports CARB's activities identifying and approving discrete early actions, and agrees with CARB staff that these programs should be incorporated into CARB's baseline for modeling purposes. In order to identify the most effective and efficient means of achieving the State's GHG reduction goals, CARB's initial modeling efforts should incorporate existing regulatory standards. These existing regulatory standards include discrete early actions, the current 20% Renewables Portfolio Standard, and energy efficiency (EE) measures within the electricity sector.

However, CARB's cap-and-trade modeling activities should only assume additional regulatory programs that would reasonably occur as a component of a broad-based cap-and-trade program. For example, California has developed a resource stacking order that ranks cost-effective EE as the most preferred resource. As retail prices increase under a cap-and-trade

program, some EE measures that are currently not cost-effective will become cost-effective. While these marginal EE measures may be incorporated into CARB's cap-and-trade modeling, they should not be considered core measures. CARB should not assume additional direct measures in its modeling baseline. In order to accurately compare the cost of cap-and-trade scenarios and direct regulation, additional direct measures should be considered within CARB's direct regulation policy scenario. In this way, the cost of any additional programs can be accurately compared to the cost of a cap-and-trade program.

IV.

CONCLUSION

SCE appreciates the opportunity to provide these comments on CARB's initial modeling efforts and looks forward to working with CARB as it develops additional policy scenarios as part of its overall AB 32 Scoping Plan.

Respectfully submitted,

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APPENDIX

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

BEFORE THE CALIFORNIA ENERGY COMMISSION

In The Matter Of, AB 32 Implementation – Greenhouse Gas Emissions.	))))))	Docket 07-OIIP-01

RESPONSE OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) TO ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENTS ON MODELING-RELATED ISSUES

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RESPONSE OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) TO ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENTS ON MODELING-RELATED ISSUES

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

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RESPONSE OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) TO ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENTS ON MODELING-RELATED ISSUES

Pursuant to the "Administrative Law Judges' Ruling Extending Comment Deadlines and Addressing Procedural Matters," issued November 20, 2007, Southern California Edison Company ("SCE") comments on the documentation for the model created by Energy and Environmental Economics, Inc. ("E3") to assess how different methods of reducing greenhouse gases ("GHG") will achieve emission reduction goals for the electricity sector and how such reductions will affect utility costs and consumers' electricity bills.

In order to most fully assess E3's report, SCE has organized its comments to first address the specific questions posed by the "Administrative Law Judges' Ruling Requesting Comments on Modeling-Related Issues," issued November 9, 2007 ("Modeling Ruling"). Following those responses, SCE provides specific comments as necessitated by each section of E3's report. The section headings below each correspond to either a question or section of the report.

I.

RESPONSES TO APPENDIX A OF THE MODELING-RULING (EMISSIONS REDUCTION MEASURES)

Question 1. 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.

Grid applications are not among the emissions reduction measures addressed in Attachment A. Grid applications are projects that lower electrical losses or reduce greenhouse ("GHG") emissions through infrastructure changes to the electrical grid (e.g., wires, substation). One example of a grid application is the replacement of existing distribution get-a-ways having aluminum cable with copper cable. Such change may significantly reduce electrical losses and thereby reduce GHG emissions at a cost that is competitive when compared to the cost of alternatives.

Another example of an overlooked, yet potentially competitive, grid application is the replacement of existing lower-voltage facilities, such as transmission lines, with higher operating voltage facilities. A project that increases transmission line voltages from 500 kV to 765 kV could aid the State's GHG reduction efforts by reducing electrical losses.[1]

Additionally, GHG emissions can be reduced by identifying grid projects that can help displace local generation with lower-emitting generation resources. Since average network generation may be lower-emitting than certain specific and existing generation resources, certain grid projects could lead to lower overall emissions as higher-emitting units are displaced.

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[1] One reason utilities use high voltage lines is because electrical losses are lower for circuits having higher voltage than for those with lower voltages, if all other things are equal. Accordingly, electrical losses (and therefore emissions) can be reduced if the voltage for 500 kV lines is increased to 765 kV. Transformer losses could also be analyzed. Transformers are large contributors to electrical system losses. Transformers have losses merely by operating, even if no load is being served (no-load losses). Transformers also have load losses which increase with use (called load losses). Total transformer losses are the sum of load and no-load losses. An estimate of the incremental cost of replacing distribution transformers with larger transformers having lower total losses could be performed and compared to other abatement options.

As grid projects were not assessed by E3, their impact has not yet been evaluated. The examples set forth above, and others, should be assessed and, if competitive, added to the State's repertoire of potential emission abatement options.

Question 2. 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 AB32? Please justify your answer.

SCE has no comment on this question at this time.

Question 3. What means beyond policies currently adopted by the two Commissions hold potential for the delivery of additional energy efficiency?

SCE has no comment on this question at this time.

Question 4. What means beyond policies currently adopted by the two Commissions hold potential for the integration of additional renewable resources into the grid?

SCE strongly recommends that the two Commissions focus their efforts on understanding the grid impacts of increased penetration of the market by renewables; expediting transmission planning, permitting, and construction; authorizing the use of unbundled, tradable renewable energy credits ("RECs") for use when meeting the renewable portfolio standard ("RPS"); and ensuring that responsibility for meeting California's RPS and emissions goals is shared equally among all electric utilities (i.e., investor-owned utilities ("IOUs") and of publicly owned utilities ("POUs"). SCE sets forth the specific challenges each of these suggestions addresses below.

<u>Understanding the grid impacts of increased renewable penetration.</u> Few studies have identified the cost or system effects of higher renewable penetration and how to mitigate such effects on the power grid. The variable output of intermittent resources like wind and solar generation affect frequency and voltage regulation and provide challenges to effectively balancing load and maintaining system reliability. In order to understand the full effect of any

recommendation of increased renewable standards, it is critical that the effect of higher renewable resource levels be more fully understood.

Expediting transmission planning, permitting, and construction. Unavailable transmission continues to be one of the greatest barriers to bringing renewable resources on-line, especially in areas where new renewable resources are considered technically and economically feasible. However, the current pace of transmission planning, permitting, and construction does not support the RPS requirement of ensuring that transmission is available when new resources are ready to come on-line.[2] Quickening all scheduling aspects of building new transmission facilities would likely help allow maximum integration of renewables into California's resource mix.

Additionally, SCE suggests continued review of options for fixing an already congested and ever growing California Independent System Operator ("CAISO") interconnection queue.

Authorizing the use of unbundled, tradable RECs for RPS compliance. SCE endorses the use of unbundled and tradable RECs as a way of complying with California's RPS legislation.[3] RECs provide load-serving entities ("LSEs") with additional flexibility and options when contracting for renewable energy.[4] Given the importance of the State's RPS goals and current challenges facing LSEs with regard to RPS compliance, the additional flexibility provided by RECs is an important addition to the RPS program that should be authorized by the California Public Utilities Commission ("CPUC").[5]

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[2] SB 1078 (Sher 2002), codified at Pub. Util. Code Section 399.11 established the Renewable Portfolio Standard and requires annual procurement targets of 1% per year toward achieving this goal.

[3] *See* "Pre-Workshop Comments of Southern California Edison Company (U 338-E) Regarding Tradable Renewable Energy Credits," filed August 17, 2007, at 1.

[4] The need for RECs will be exacerbated if new transmission is not built and available by 2020.

[5] *See* "Post-Workshop Comments of Southern California Edison Company (U 338-E) regarding Tradable Renewable Energy Credits," filed November 13, 2007, at 3.

Ensuring responsibility to meet the State's RPS and emissions goals are shared equally among all electric utilities. It is unreasonable and impractical for IOUs and their respective customers to be responsible for the full cost and complete implementation of the State's total RPS and GHG emissions goals. Municipal utilities and their customers should also be held to the same standards as the IOUs and required to contribute equally to California's requirements. The CPUC and California Energy Commission ("CEC") should adopt rules and regulations that will most swiftly enable equitable compliance among all of the State's electric utilities.

Question 5. 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?

A source-based carbon cap is the best way to displace carbon from the State's electricity resource mix. A regional cap and trade system is preferable to a California-only approach and a national system is better than a regional approach because it reduces the potential for leakage and allows consistent measurement and tracking. A cap and trade system would effectively displace the emissions from high carbon intensive emitters because it effectively adds an appropriate level of cost to high GHG emitters. A California first-seller approach in which emissions from plants outside the state become the responsibility of the purchaser at the first point of sale inside California effectively places a higher price on out-of-state high GHG-emitting units. If a regional system were within the realm of possibility to effect the necessary California reductions under Assembly Bill ("AB") 32, such a system would more effectively reduce emissions from high GHG emitters than a California-only system in two ways.

First, a regional/federal source-based cap would reduce or eliminate the susceptibility of California's emissions reduction program to leakage to other states within the Western Electricity Coordinating Council ("WECC"). Reducing leakage is an aim of AB 32 and would

ensure that emission reductions are real and that emissions from power imports are not simply being transferred to other states.

Second, it would allow emitters to utilize the most-effective means of reducing emissions. By granting emitters planning choices, they each become responsible for most cost-effectively managing their emissions. This will lead to lower-carbon choices.

It should be noted that the Western Climate Initiative ("WCI"), while a welcome start to a regional approach, does not encompass the whole of the WECC. Thus, while the WCI would begin to move toward an effective regional approach to controlling GHG emissions from power generation, a much-preferred approach would involve the entire WECC.

II.

RESPONSES TO APPENDIX B (E3 GHG CALCULATOR)

Question 6. Does E3's modeling documentation adequately document the methodology, inputs and other assumptions underlying its model? If not, what additional documentation should be added?

E3's modeling documentation does not provide all of the information necessary to assess its underlying model. SCE lists the additional information it requires for complete assessment of the model, below:

- E3 should provide a document detailing values and equations for all tabs other than the "Main" tab included in its Excel spreadsheet;
- The current modeling documentation leaves unclear how E3 captured transmission losses—such losses should be included in the assessment of dispatch decisions and a description of the magnitude of such losses and how they were incorporated would be helpful to analysis of the model;

- E3 should document its methodology for retiring generation resources (called "Generation Subtractions") and the resources subtracted. Without such documentation it is unclear if E3's model replaces generic generation with renewables or if it is modeling actual retirements of existing generation;
- E3 should document its assumed emission rate values for each fuel type. As the primary output of the GHG model is total emissions, it is vital that stakeholders be able to review E3's assumptions for calculating total emissions. Accordingly, the emission rates used in PLEXOS should be discussed and disclosed in a table as part of Attachment B or in a similar location;
- As the E3 report is being disseminated via the internet, it would be helpful to have web links provided for all E3 referenced documents that are accessible via the internet;
- As reflected in the "Source of Simulation Data for 2008" chapter, some Seams Steering Group – Western Interconnect ("SSG-WI") data has been modified by PS (e.g., existing and future resources) and some data is internal to PS (e.g., natural gas burner-tip prices).[6] It would be appropriate to more clearly identify "PS" and the referenced modifications to the SSG-WI database; and
- While E3 is charged with evaluating the respective potential impacts of AB 32 compliance on both the electric and natural gas sectors, most if not all discussions to date have been associated with the electric sector. By what means, assumptions, and schedule will E3 perform an analysis of the natural gas sector?

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[6] *See* "CPUC GHG Modeling 2008 PLEXOS Data Sources" at Table titled "Source of Simulation Date for 2008."

Question 7. Provide feedback, as desired or appropriate, on the structure and approach taken by E3 in its GHG Calculator spreadsheet tool.

SCE has two primary concerns regarding the approach taken by E3 in the GHG Calculator spreadsheet tool. First, the GHG Calculator does not consider load growth from electrification of other sectors. As individual sectors evaluate ways to reduce GHG emissions, it is becoming evident that many sectors will rely on electrification for their emissions reductions. Large-scale electrification will have a dramatic impact on electric load. While SCE supports electrification as a viable means of achieving significant emissions reductions, its impact on the electric sector should be fully explored by E3. In its modeling, E3 should include an assessment of the effect of electrification on California's emissions reductions. Specifically, the effects of electrification can be modeled by adjusting load forecasts to include the increased electrical demand resulting from sectors switching from fossil fuel to electricity.

Second, E3's GHG Calculator seems to have been formulated from the perspective that a load-based cap and trade system will be adopted in California. Because it is impossible to trace all loads to generation under a load-based approach, accurate emissions data for approximately 40% of California's power is missing from E3's model. Instead, E3 has substituted the emissions rate of a generic power pool to those resources. The assumption that 40% of California's power is appropriately represented by looking to a generic power pool is significantly flawed and will distort E3's model results, especially the result of any analyses on an LSE level. Accordingly, E3's assumptions and ensuing model results will be best suited for a statewide level analysis.

Question 8. 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.

E3's methodology for retiring generation resources (called "Generation Subtractions") is not thoroughly described. Without such documentation it is unclear if E3's model replaces generic generation with renewables or if it is modeling actual retirements of existing generation.

Question 9. 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?

No, the uncertainties inherent in the resource potential and cost estimates are not adequately identified. There are three specific input sensitivities that the GHG Calculator needs to consider further. Each of these encompasses a great degree of uncertainty and has the potential to significantly alter the output of the GHG Calculator.

First, E3's model must make provisions for inclusion of uncertainties associated with capital costs for generation and transmission. Simply trying to select a single, best estimate for a capital cost value is impossible given the current construction climate. Accordingly, E3 should employ a range of values (e.g., high, medium, and low case) in order to determine the possible range of outcomes for this variable.

Second, the status of tax credits for renewables is questionable. Some tax credits are set to sunset, while others may be instituted in the future. To account for these uncertainties, the model should evaluate the entire range of possible scenarios for tax credits.

Finally, E3's current model designates wind power as the preferred resource based on TRC. This designation does not reflect that the cost margin between wind and solar power is narrow. The gap is so narrow that in a few years technological developments could lower the cost of solar resources resulting in the two technologies switching places in the cost rankings. Since wind and solar powered generators have very different operating characteristics, the model

should also be run with solar power as the preferred resource. Incorporating such changes will allow the State to evaluate a near future where solar power is the preferred resource.

Question 10. Has the E3 model adequately accounted for the implications of increased reliance on preferred resources (renewables, efficiency) on system costs?

No, the GHG Calculator does not account for scarce supply of renewable resources. As more unions/countries/states take action to reduce GHG emissions, the demand for clean resources will increase. This increase in demand, combined with the current shortage of concrete, steel, building supplies and qualified contractors, as well as a backlog of supply for wind turbines, will likely lead to a scarcity of renewable resources and higher prices for those in existence. The E3 Calculator does not currently recognize this effect of increased demand for renewables. It can do so by factoring the supply crunch into its Renewable Supply Curves.[7] As currently calculated, E3's wind supply curves show 400,000 GWh of wind energy available at a busbar cost of $60/MWh or less. This implies over 160,000 MW of wind power can be installed at that cost or less before 2020. In reality, only a fraction of that capacity can be installed before 2020 at that price. E3's documentation should be modified to reflect a more realistic supply curve that accounts for wind turbine manufacturing capabilities.

Question 11. 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?

During Stage 2, E3 should evaluate the operational impacts of wind power's high penetration rates. The European experience has already demonstrated that high levels of wind resources within a system create unique operational challenges. While E3 has done a good job of capturing integration and firming costs for wind power, it is notable that the least-cost

dispatch of PLEXOS does not account for the intermittency of wind. In order to accurately evaluate any market transformation, E3 should include all relevant factors, including resource intermittency.

Question 12. 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?

SCE has no comment on this question at this time.

Question 13. What output metric or metrics should be utilized to evaluate the least cost way to meet a 2020 emission reduction target for the sector?

The \$/mton CO_2e metric should be utilized in both the E3 and Energy 2020 models, as required by AB 32.[8] Using this consistent metric will allow comparison of the results of both models.

Emission reduction programs for all sectors should be evaluated using the dollar per ton of GHG emission reduced (typical units are \$/mton CO_2e) metric. This is a fungible metric for evaluating varied emission reduction measures across all sectors. It is commonly used by industry and international organizations. Using this common metric will allow the results of E3's model to be compared to the output of the Energy 2020 model, which will be used for other sectors.

In addition to using a similar metric when comparing the results of these two models, it is important to note that the cost of the emission reductions must be disaggregated from the cost of power in the electricity sector.

Continued from the previous page

[7] *See* "CPUC Greenhouse Gas Modeling Renewable Supply Curves."

[8] *See* Cal. Health and Safety §§38505(d), 38560.

III.

COMMENTS ON SPECIFIC SECTIONS OF APPENDIX B

A. Comments on Modeling Methodology for Reference Case and Target Cases

1. 2008 PLEXOS Data Sources

While generally acceptable, E3's use of PLEXOS data raises two issues for SCE. First, E3's model uses WECC data for PLEXOS. That data is based upon SSG-WI data. SCE has experience with the SSG-WI data and has concluded that it requires several layers of review in order to be considered accurate. Although E3 acknowledges that the WECC database is new and will likely require revision, it may not be the most accurate warehouse for information. A more accurate alternative might be achieved with the purchase of a different database. Second, the documentation provided by E3 does not include a discussion of how transmission ratings and nomograms are incorporated. Without such documentation, it is unclear how nomograms such as the Southern California Import Transmission Nomogram ("SCIT") are incorporated, whether nomograms are honored, and whether transmission ratings are honored in E3's modeling.

2. Assigning Generation to LSEs

The following comments are based upon the information provided in E3's "Template for Party Information on Generators" spreadsheet, as posted on E3's website. SCE's review was specific to units assigned to SCE for year 2008 and year 2020.

SCE recognizes the challenge placed upon E3 in developing a database that reflects the operational and ownership characteristics of the generation facilities located in the WECC, especially given the confidentiality associated with many of the power purchase contracts involving merchant power plants, utilities, and energy service providers.

SCE has reviewed the database and at this time offers no specific changes to the assumptions regarding generation assignments made by E3. SCE's review of the generation

assignments indicates that E3 is assuming that the majority of the assignments in year 2008 continue into 2020. SCE comments that this assumption is very broad based, e.g. most of contracted transactions effective in year 2008 are probably not extended thru 2020. As such, SCE believes that the existing assumptions, as a whole, are best left as is and that making changes that reflect only SCE's perception are inappropriate.

3. Ensuring Sufficient Resources to Meet Loads

E3's documentation provides no information about retirement of generation resources. This failure to retire resources results in a WECC end-state that contemplates a 16,000 MW surplus in 2020.[9] Such a planning scenario is not consistent with the planning scenarios being used by most entities which comprise the WECC.

If in fact a 16,000 MW surplus existed, many resources would likely be retired. Such retirement of resources would change the mix of resources being assessed and would likely lead to system operability issues (since the addition of intermittent wind resources would require greater ramping capability).

Second, E3 states, "Pumping load is assumed to drop to zero during system peaks."[10] This assumption is incorrect. Not all pumping loads can be reduced to zero at the time of the peak load. A more realistic assumption would be to assume that pumping load drops by 50%.

Third, E3's resource calculations seem to assume that California is the only state that will be using Demand Response programs in the future.[11] Instead of assuming zero Demand Response for other states, E3 should include an estimate for other states' programs if they are cost-effective.

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[9] "CPUC GHG Modeling – Ensuring Sufficient Resources to Meet Loads," at 3 (Table 5).
[10] "CPUC GHG Modeling – Ensuring Sufficient Resources to Meet Loads," at 3 (Table 5).
[11] *Id.* at 4 (Table 5).

Fourth, in Table 4, E3 seems to conclude that the Pacific Northwest (including Utah) region is the only area adding any significant amount of combined cycle generating turbine ("CCGT") technology. Without justification this assumption does not make business sense. If E3 cannot justify its assumptions with regard to such resources, the resource calculation should be modified.

Lastly, E3's analysis assumes coincidence of peak loads throughout the WECC. This assumption is wrong. As the CPUC and parties to this proceeding are aware, WECC non-coincidence has and continues to be a major contributor to the ability of states to share resources for capacity purposes throughout the WECC. Accordingly, E3 should revise its assumptions regarding coincidence of peak load throughout the WECC.

B. Comments on Inputs to E3 Base Case and Target Cases

1. Comments on General Input Assumptions

a) Reference Case Policy Assumptions

The reference case recommends demand response assumptions of five percent of peak demand for IOUs and none for others.[12] This assumption must be revised. If demand response is cost-effective for IOUs, it should also be cost-effective for POUs. An assumption that does not capture the full effects of all entities using demand response to reduce emissions inherently fails to comply with the mandates of AB 32.

Additionally, the reference case recommends LSE load forecasts that are an extrapolation of CEC information out to 2020. These forecasts are not accurate. The CEC forecast contains errors in its assumptions regarding the amount of available energy efficiency. In addition, the amount of energy efficiency assumed by the CEC is inconsistent with that used

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[12] "CPUC GHG Modeling 2020 Reference Case Input Assumptions," at 2.

by other WECC entities and therefore biases the forecast to be significantly too low when compared to the other areas.

b) Financing and Tax Incentive Assumptions for New Resources

(1) Financing Assumptions

Upon review, although calculation of generation costs on a single spreadsheet instead of using a full generation cost model for each asset type may lead to some margin of error, the generation cost calculation in the model seems to provide a fair approximation of costs. A few of the simplifying assumptions that would contribute to a margin of error include the setting of the book life at a term equal to contract life – if actual asset life is not equal to the book life assumed in the model (i.e., 20 years for independent power producer and 30 years for IOUs and municipal utilities), the model may overstate costs of longer life assets and understate costs of shorter life assets; and the exclusion of preferred stock in financing assumptions – California utilities have preferred stock as a component of their capital structure. A more accurate financing assumption would include preferred stock in lieu of the 50/50 debt to equity assumption.

(2) Tax Incentive Assumptions

The E3 model contains assumptions that are generally a good representation of the tax incentives and credits available under Federal and California tax law. The following nuances should be considered when actual identified projects are modeled:

- Tax rates used assume all projects are located in California. The tax rates could be different if projects are located in other states;
- Taxpayer could also be eligible for the Section 199 Manufacturer's Deduction which would provide additional benefits;

- California does not conform to the federal accelerated depreciation method ("ACRS/MACRS"). However, the California asset lives could be different from the book asset lives;
- Deferred taxes should be considered as applicable; and
- Some of these credits and incentives have sunset dates before 2020.[13]

c) Fuel Price Forecasts for the WECC

SCE has reviewed the fuel price forecast used by E3 in its PLEXOS production cost model. Since E3's analysis involves always treating natural gas units as the marginal units, relative to generators being displaced to reduce green house gas emissions, SCE's review was focused on natural gas prices.

SCE accepts E3's use of $8.79/MMBtu (2020 nominal dollars) as a reasonable price of natural gas delivered to a generator in California in the year 2020. SCE also accepts as reasonable E3's assumptions regarding rationing fuel prices within the SSG-WI data base as a method of maintaining relative price differences between WECC regions.

Similar to an earlier comment regarding how changes to technology may cause solar to become more economic than wind as a renewable resource, technology advancements in fossil-fueled generation may also result in a change in the economic dispatch order and resulting GHG emission values.

d) Assumptions Regarding 2020 RPS Requirements in the WECC

Overall, the information collected by E3 regarding the RPS in various areas within the WECC is accurate and the assumptions made are reasonable. SCE notes four areas related to the 2020 RPS that should be added in order to make the model's analysis more

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[13] Additional comments to the tax section of the E3 presentation are attached hereto as Appendix A.

complete. Each of these suggestions pertains to assumptions regarding the types of generation that can be imported from one region to another.

The types of generation classified as renewable by E3 are not homogeneous across all states within the WECC. For example, Oregon allows hydroelectric power up to an average of 50 MW per year, while California caps the size of eligible hydroelectric power at 30 MW. If this constraint were added to the E3 model, it would not allow hydroelectric power greater than 30 MW, which is eligible for the Oregon renewable standard, to meet California's renewable standard. Accordingly, E3 should include a constraint on the size of eligible hydroelectric power in its assessment of the 2020 RPS requirements.

The E3 models should address California's requirement that in-state renewable generation be scheduled into the state is not addressed.[14] This requirement could affect the amount of imports available for transmission from one area to another for purposes of meeting a renewable standard. E3's documentation leaves unclear whether this issue was addressed. Including assumptions related to this constraint will yield a more accurate picture of the amount of renewables that will be available within and outside of California.

E3's assumptions about the renewables standard do not reflect the reality of penalties and alternative compliance payments and how those impact the export strategies of generators and LSEs in various areas. The current E3 assumption is that California can only import renewable energy from other WECC regions to the extent that the available renewable power in that region is in excess of the region's own consumption. E3 should consider layering on an additional economic filter to account for the opportunity cost of a generator or LSE meeting its state's renewables standard. In theory, if a generator can sell its renewable energy for more than its state's penalty or alternative compliance payment, from an economic perspective, the generator or LSE may be willing to sell its generation out-of-state in lieu of using the generation to satisfy the in-state renewable target.

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[14] Renewables Portfolio Standard Guidebook, Draft Guidebook, December 2007, at 29.

E3 assumes that the entire state of California will reach 20% by 2020 based on the various goals established by municipal utilities. While SCE understands the reasoning behind this assumption, it is important to note that municipal utilities are not regulated by the CPUC and, therefore, may not have the same incentives to reach their goals as regulated entities. Accordingly, E3 should consider reducing the "20% by 2020" assumption.

2. Comments on Load Forecast Assumptions

a) CA LSE and WECC Load and Energy Forecasts

The demand forecast referenced in E3's modeling documentation as the basis for creating the resource expansion plan is the CEC's California Energy Demand 2008 - 2018 Staff Revised Forecast.[15] E3's documentation seems to have mistakenly reported the CEC data. For 2008 and as extrapolated for 2020 the Peak Demand and Energy numbers do not match. The numbers from the CEC forecast are significantly higher than E3's reported numbers. To the extent E3 purports to rely on CEC data, it should revise its numbers to reflect what the CEC reported. The error and corrected values are set forth below.

E3 Model Documentation Values for SCE			CEC Forecast Values for SCE		
	Peak Demand (MW)	Energy (GWh)		Peak Demand (MW)	Energy (GWh)
2008	21,476	87,532	2008	23,272	105,054
2020	25,777	106,018	2016	26,382	118,497

3. Comments on Demand-Side Resources and Costs Assumptions

a) CSI Forecast

E3's CSI assumptions are very aggressive and should be revised. In its documentation, E3 identifies 1,091 MW of solar resources in the business-as-usual reference

[15] "CPUC GHG Modeling CA LSE and WECC Load and Energy Forecasts," at 1.

case by 2020, 3,000 MW of solar for the aggressive reference and target cases by 2020, and $8/W used for cost. While it may be possible to install 1,091 MW of solar power by 2020, vast market transformation will be required to install 3,000 MW of solar power by 2020. Rather than choose a realistic aggressive target, E3 has chosen a target that is basically infeasible. The aggressive target should be revised downward to reflect what could be considered an aggressive amount, under current market conditions. In addition to overly aggressive reference and target cases, E3's CSI forecasts are flawed because they use an $8/W cost figure. A more accurate cost range is $9 to $10/W.

In addition to the overly aggressive assumptions described above, E3's assessment of the value to be derived from solar power appears to be inconsistent. While all of the MWs assigned in both the reference cases are credited only to IOUs, the 3,000 MW goal includes the IOU version of CSI ($2.1 billion), the CEC New Solar Homes Partnership ($400 million), and the Municipal Utilities CSI programs ($700 million). With this budget in mind, the assigned value of 1,376 MW for SCE is too high.[16]

b) Demand Response Forecast

The demand response forecast used by E3 is consistent with the current goal of five percent of system peak. Nevertheless, it is unrealistic to expect that this goal will be met. Currently, demand response goals are under review in a proceeding at the CPUC. If the CPUC alters the goals, E3 should modify its model accordingly. In the interim, the demand response goals approved by the CPUC for each IOU, through the Long-Term Procurement Plans ("LTPPs"), should be utilized.

4. Comments on New Generation Resources and Costs

For each of the resources assessed in the E3 model, assumed design, procurement, construction, and start-up costs are low. SCE's recent discussions with original equipment

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[16] Similarly, the values for other IOUs may be too high.

manufacturers (e.g., combustion turbine generators, steam turbine generators, wind turbines), Engineering, Procurement & Construction ("EPC") companies, and other engineering companies indicate that costs for raw materials (e.g., steel, copper), manufactured goods (e.g., structural steel, concrete, copper wire, combustion turbines, steam turbines, heat recovery generator, boilers), construction manpower/labor, design engineers are rapidly increasing. Accordingly, while E3's cost assumptions can be used to conduct a comparison of the relative costs to construct various types of new generation resources, E3's cost assumptions should not be used for definitive cost estimation of the cost of energy ("COE"). If a definitive COE is required, an updated, definitive cost for a specific resource in a specific area with site specific criteria should be developed.

a) Wind Resources, Cost, and Performance

E3's documentation overstates the amount of commercially viable wind resources. Specifically, E3 includes Class 3 wind sites within California. Such sites should not be included in the model.

Class 3 wind sites should not be included in the resource estimates because the industry does not generally consider them economically viable. E3 itself seems to recognize the limitation on such resources for wind resources outside of California as its model does not include Class 3 or Class 4 wind sites found outside of California.

Additionally, E3's model assumes that a current, mainstream wind turbine to be rated at 2.5 MW.[17] While recent installations of up to 3.0 MW have started within the past year, 1.5 MW is the most common size. If E3 does not wish to revise its model in this fashion, it could incorporate size options for wind turbines. This feature would allow for the true state of wind technology to be reflected in model results, rather than reflecting an overly simplistic and optimistic scenario.

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[17] "CPUC GHG Modeling New Wind Generation – Resource, Cost, and Performance Assumptions," at 1.

Lastly, the model should allow for adjustments to the filter percentages in the Environmental Exclusions.[18] Currently, E3's assessment only excludes 50% of Department of Defense lands. However, based on a rudimentary survey of areas within SCE's service area, it is clear that other factors preclude the use of Department of Defense lands (i.e., flight patterns and potential interference with radar related to military operations).

b) Biomass Resources, Cost, and Performance

E3 should verify the heat rate assumptions it has chosen for the base cost of biomass and biogas projects.[19] The heat rate E3 has assumed for biomass seems extremely low and the heat rate it has chosen for biogas seems extremely high. Because heat rates depend on the on prime mover technology to generate electricity from biomass or biogas, the model should incorporate different selections based on the prime mover technology.

Additionally, the E3 model includes a value of 600 MW potential assumed for biomass based on the assumption that no municipal solid waste ("MSW") gasification will be developed. This assumption is contrary to previous CEC findings. According to the "CEC Draft Report on Biomass," the technical potential of biomass statewide is estimated to be close to 4,700 MWe.[20]

c) Geothermal Resources, Cost, and Performance

The cost of expanding an existing facility within a known and proven resource area is significantly lower than the cost of developing a new, remote resource area such as south central Nevada or eastern California. E3's model does not recognize this business

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[18] *Id.* at 72

[19] "CPUC GHG Modeling New Biomass and Biogas Generation – Resource, Cost, and Performance Assumptions," at 3-4.

[20] "CEC Biomass Resource Assessment in California, Draft Report," April 2005.

reality for geothermal resources. In order to accurately model such resources, E3 should revise its model that includes multiple geothermal plant selections.[21]

Additionally, SCE disagrees with the assumption that no fossil fuel is used at geothermal facilities. Geyser facilities fire natural gas as part of the hydrogen sulfide abatement process while other geothermal plants use propane. Some geothermal plants use hydrocarbon working fluids that can leak into the atmosphere. Rather than assign an emissions rate of zero to all geothermal facilities, E3 should assign GHG emissions rates by reference to the particular plant technology. SCE suggests the following categories of geothermal resources:

- binary plants that have zero GHG emissions from the wells, but VOC emissions from the generation process;
- flash plants that have high fugitive GHG emissions from high GHG potential wells;
- flash plants that have low fugitive emissions; and direct steam plants such as Geysers.

d) Concentrating Solar Power Resources, Cost, and Performance

E3's documentation does not seem to take into account that newer hybrid solar plants seeking permits today incorporate CCGTs with concentrated solar thermal (as opposed to a gas fired-boiler and a solar-powered boiler).[22] Such new hybrid plants produce a majority of their energy from the non-renewable source. The E3 report does not currently recognize this difference and should to more accurately capture the full extent of emissions from concentrating solar power technologies.

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[21] E3 has done this for multiple fossil fired selections. *See* "CPUC GHG Modeling New Geothermal Generation – Resource, Cost, and Performance Assumptions," at 2.

[22] http://www.energy.ca.gov/sitingcases/index.html Energy Facilities Siting/Licensing Process.

E3's reference case utilizes six hours of thermal storage as an assumption for concentrated solar power.[23] This assumption does not accurately represent the actual operations of plants within the State. To more accurately capture how plants operate, SCE recommends making storage a variable in the model and creating an option for inserting a Concentrated Solar Plant ("CSP") without storage and/or adjust the hours of storage. To this end, E3 should revise Tables A and B in this section to include multiple types of CSP (i.e., with and without storage) and corresponding capacity factors. SCE also suggests that separate cost numbers be provided, one linked to the increased cost of the solar field to support storage and another linked to the storage cost itself. Such factors are included to some extent in the 2006 Black & Veatch study as well as the Sargent & Lundy forecast already cited by E3.[24]

Finally, E3's model ignores the viable option of installing small-scale distributed solar on warehouse rooftops, commercial buildings, or multi-family housing developments. It does so by assuming that urban areas cannot support such solar power.[25] E3 should revise its model to reflect the uses of solar power in urban areas.

5. Comments on All-in Resource Costs By Zone

a) Renewable Energy Supply Curves

See response to question no. 10 above.

b) Transmission Costs

Generally, the transmission cost assumptions and estimates utilized by E3 appear reasonable, but certain components of E3's assessment require revision or modification. These components are set forth below.

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[23] "CPUC GHG Modeling New Concentrating Solar power (CSP) Generation – Resource, Cost, and Performance Assumptions," at 1.

[24] *See id.* at 5-6.

[25] *Id.* at 2.

(1) E3 Appears to Have Reasonably Estimated Transmission Cost Components

E3 appears to have reasonably estimated major transmission cost components such as right-of-way, transmission lines, transmission substations, and voltage support infrastructure.[26] However, E3 should review certain figures for accuracy.

For example, Table 4-3 in this section seems to have incorrectly reported 500 kV Line Termination (substation) costs to be $26 million. This table was extracted from the CEC 2007 IEPR, which in turn relied upon cost estimates from the Frontier Line study group. Frontier estimates for 500 kV substations should be around $50 million for a single substation, therefore the estimated $26 million may be low.[27]

Additionally, Table 1 utilizes a $1600/MW-mile metric to estimate resource interconnection costs. The report labels this metric as a rule of thumb. It would be helpful if some additional information justifying this metric were disclosed. Similarly, reporting the sources used to derive the estimated "levelized interconnection costs for conventional resources" reported on page 137 would create a more complete report.

Lastly, SCE suggests that E3 disclose system upgrade costs, which are not included in the current transmission cost methodology.[28]

(2) E3's Cost Methodology Appears Reasonable

The cost methodology used in E3's GHG Model also appears to be reasonable. The methodology is reasonable because, among other things, it attempts to quantify changes in delivery costs between resource locations. Intuitively, delivery costs increase as the

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[26] Due to the mix of cost references relied upon, there may be some inconsistency of costs between references such as right-of-way costs, but such differences are not considered too important in this type of screening analysis.

[27] Frontier study group estimated the following: $50 million per 500 kV AC substation (equipment will include the following: (a) three 500/230/345 kV transformers – 3 * $8 M = $24 M; (b) one set of shunt reactors - $10 M; and (c) Terminal Equipment $16 M.

[28] System upgrade costs that can be significant, but are normally omitted in screening analyses since they require lengthy technical studies to estimate.

distance between the location of resources and the load they serve increase. The GHG Model captures this relationship using a delivery costs per mile metric.[29] There are however a couple of controversial assumptions in that assessment.

First, E3 notes that new conventional generation like nuclear and coal resources will be located within 25 miles of a backbone transmission system. While this may be true, how one uses that assumption in estimating delivery costs is important. A new nuclear or clean coal generator would be dispatched as a baseload resource due to its size and technology. Large new base load generation resources will require new dedicated transmission lines because of insufficient capacity in existing lines. As a result, even if new conventional resources are located near a backbone transmission grid, it is unlikely that existing transmission capacity could accommodate such new resources. Accordingly, it would be helpful if the report described delivery cost implications of assuming nuclear and coal resources will be located within 25 miles of a backbone transmission system. For example, is it assumed that existing grid facilities located 25 miles away have capacity to integrate new generation? If so, this assumption should be disclosed. Additionally, E3 should consider including system upgrade cost estimate for new large resources in its analysis as these costs normally increase with the size of generation installation.

Second, E3 states it has utilized the National Renewable Energy Laboratory ("NREL") transmission assignment method that assumes 10% of total transmission capacity for each line is available for transmission of new wind resources.[30] This is not a reasonable assumption because it assumes no congestion on all lines. As E3's analysis attempts to estimate the effect of integrating large quantities of resources, transmission congestion should be considered.

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[29] Delivery costs here include major transmission cost components, but not all costs. For instance, system upgrades, annual losses, operating and maintenance, telecommunications, transmission service fees, etc., were not estimated, but are generally not significant in a screening analysis. One exception is system upgrade costs which can be significant, but are normally omitted from screening analyses since their estimation requires lengthy technical study.

[30] "CPUC GHG Modeling Transmission Cost Assumptions," at 5.

Third, another area that is left vague by E3's analysis is the scaling used when estimating future transmission line costs. E3 tabulates point-to-point transmission costs by scaling costs using 250 MW and 500 MW increments.[31] Transmission projects do not typically increase in 250 MW increments. E3 seems to recognize this for some projects when it increases them in 1,500 MW steps, but others are inexplicably increased in 250 MW increments.

c) Wind Integration Costs

With regard to wind integration costs, E3 states, "To account for this, we assume that all wind will be integrated into the largest control area in the region."[32] This assumption may lead to incorrect assessment of wind integration costs. It may do so because it fails to acknowledge that smaller areas may have greater difficulty integrating intermittent wind energy than larger areas. Larger areas may have more resources capable of meeting ramping or other operational needs than smaller areas.

Additionally, E3 conducted a regression analysis on 32 data estimates of integration costs for wind resource penetration between five percent and 30 percent of total system generation capacity, which were included in ten publicly available studies for North American utilities. Generally, this is an appropriate method to estimate wind integration costs at varying penetration levels. However, E3's study describes a series of hypothetical scenarios that seem inconsistent. Although SCE aggress with the conclusions E3 makes regarding integration costs, the lack of consistency in its modeling will detract from these conclusions. Accordingly, SCE recommends revising the evaluation to use the following assumptions for a 50,000 MW Control Area:

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[31] Some of the transmission cost estimates used by E3 are less lumpy. For instance, a line from WY appears to have reasonable lumpiness in 1,500 MW increments. Other lines, like from San Diego are lumpy in 250 MW increments initially, then 1,500 MW later as transmission capacity is increased. This lumpiness may be reasonable if based upon transmission upgrades having such lumpiness.

[32] "CPUC GHG Modeling Cost of Integrating Wind Resources," at 3.

- 10% Penetration = 5,000 MW Wind ➔ 15,000 GWh (34%cf) @$3.13/MWh = $47 million
- 20% Penetration = 10,000 MW Wind ➔30,000 GWh (34%cf) @$6.26/MWh = $188 million
- 30% Penetration = 15,000 MW Wind ➔ 45,000 GWh (34%cf) @$9.39/MWh = $423 million

d) Firming Costs

Although E3's values for firming penalties seem reasonable, E3 should include a non-thermal solar resource in this table with a corresponding firming penalty. As currently documented, E3's Table 1 only includes a solar thermal resources. As E3 recognizes that "intermittent resources such as wind and solar energy are not always available to produce energy during system peaks," a non-thermal solar resource in this table with a corresponding firming penalty would be appropriate.

e) Resource Ranking and Selection

SCE has identified the following errors in E3's analysis of resource ranking and selection:

- Table CA-3 appears to contain a typographical error. The regional multiplier for the other states should not be 1.20 for all states;
- While E3's delivered energy prices are reasonable, a sensitivity analysis should be conducted to determine if price changes by plus or minus 10 – 20% in any specific technology would drastically change the conclusions; and
- When using its data to determine the lowest cost resource, E3 appears to utilize the total delivered cost as the primary basis for resource selection. If too much baseload generation (e.g., geothermal) is added, then lack of dispatchability and surplus

generation in evening hours becomes an issue that must be assessed. Neither the E3 nor the PLEXOS model seems to accurately measure the effect of such resource decisions.

f) California Resource Zones

E3 estimates that California has a total of 53,044 MW of wind generation resource potential; 3,008 MW of geothermal potential; 221 MW of RPS-eligible small hydro potential; 89,650 MW of CSP potential; 300 MW of total biogas potential; and 600 MW of total biomass. E3 arrives at these estimates based on public reports from NREL, the CEC, and other sources. These estimates are grouped into approximately 30 zones in and around California. While these zones and the estimated resources seem reasonable, E3 leaves unclear whether the resource potential in these zones is incremental to what is installed and operating today, or if it represents the total potential including those resources installed and operating. Stakeholders would benefit from further description of the intent behind E3's tables/zones.

6. Comments on Reference Case and Target Case Results

a) Aggressive Policy Results

SCE has forecasted that its 2008 CO_2 emissions will be around 26 million tons. The results shown in both the Business-as-Usual and Aggressive Policy papers indicate that SCE's 2008 CO_2 emissions total about 30.5 million tons of CO_2. This 13% difference is significant and indicates a likelihood that lack of complete generation and contract data for each LSE is resulting in calculated values that may have large margins of error.

7. Comments on Model Benchmarking

a) Electricity Sector Emissions Benchmarks

E3 should utilize the California Air Resources Board's ("CARB's") most recent GHG emission inventory to ensure consistency with statewide efforts. Accordingly, E3 should use the 1990 Baseline inventory recently approved by CARB.

8. Comments on GHG Calculator

E3 states that it will benchmark GHG Calculator results with production simulations. E3 should document its proposed benchmarking methodology and state the timing for such benchmarking. It is critical that stakeholders be allowed to review E3's proposed methodology as it may justify the use of a spreadsheet rather than a production simulation. As this benchmark will likely be used to develop California's GHG policy, it is critical that the benchmarking evaluation be conducted with the greatest level of accuracy.

a) Brief Calculator Description

The description that was last updated November 7, 2007 on the E3 website provides a good, high-level view of the calculator and its intended functions and purpose. The description sufficiently summarizes what is seen on the "Main" tab of E3's GHG calculator. However, as SCE has noted above, it would be helpful for stakeholders to have access to a document, which captures details on values and equations listed on tabs other than the "Main" tab.

IV.

OTHER

A. Party Information on Generators

The following comments and concerns exemplify why E3's data assumptions[33] and modeling approach will provide results that are appropriate for a statewide analysis of the impacts of GHG in the electric sector. They will also explain why such an approach is not appropriate on an LSE basis.

CO_2 Rate Assumptions. The emission rates (lb/mmBTU) used by E3 appear to be the same for each respective fuel type. That is, all coal units have an assigned 208 lb/mmbtu emission rate and all natural gas units have an assigned 117 lb/mmbtu emission rate. This assumption may result in inaccurate GHG emissions levels, especially for those emissions from combined cycle units burning natural gas.

E3 is assuming that a generation facilities within California is either owned (in part of in full) by one of the five largest electric utilities (i.e., Pacific Gas and Electric ("PG&E"), SCE, San Diego Gas & Electric ("SDG&E"), Sacramento Municipal Utility District ("SMUD"), Los Angeles Department of Water and Power ("LADWP")), by a utility that is grouped within a respective "Northern Other" and "Southern Other" utility, or that it a generation facility can be classified as "ownership unspecified" and allocated to a "Northern CA Powerpool" or "Southern CA Powerpool." This assumption is intuitively appropriate for a production cost model that will evaluate results on a statewide basis.

E3 is planning to analyze GHG scenarios on both a statewide and LSE level. However, E3's modeling assumptions reflect specific information pertaining to the five largest electric service providers in California, which are also LSEs, but reflect at best minimal information pertaining to the other LSEs operating within California. Calculating a GHG impact for some,

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[33] Based on information in E3's "Template for Party Information on Generators" spreadsheet.

but not all individual LSEs will provide inaccurate information and may lead to decisions that are inaccurate and more costly to implement.

V.

CONCLUSION

SCE appreciates the opportunity to comment on E3's documentation and urges E3 to incorporate the suggestions contained herein.

Respectfully submitted,

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Appendix A

Taxes and Tax Incentives

For all types of ownership, income taxes are based on the levelized equity return, and are adjusted for any available tax incentives. The model assumes a 35% federal tax rate and an 8.84% state tax rate, resulting in a 40.7% marginal tax rate.[34] Taxable income is calculated using book depreciation, adjusted for any accelerated tax depreciation[35] and full tax benefit of interest. The model currently assumes no state-level accelerated depreciation tax benefits, as is the current case in California.[36] Any production or investment tax credits are applied, and taxes are grossed up such that the owner achieves its target after-tax return on equity.[37] Taxes are levelized over the appropriate ownership term, then divided by the plant capacity to achieve a 2008 levelized $/kW charge. Property taxes are assumed to be 1% of the total project capital costs, and property tax amounts are also levelized.

Tax and Policy Incentives

Many of the generating technologies in the GHG calculator are eligible for a variety of tax breaks and other incentives from either the federal or state government. Currently available federal government tax benefits include investment tax credits ("ITC"); production tax credits ("PTC"), and accelerated depreciation. California state-level incentives include property-tax incentives and Supplemental Energy Payments. The model assumes that the state-level SEP and property tax incentives would no longer be available in 2020, nor would federal incentives with cumulative capacity limitations.

Other federal tax benefits are assumed to be permanently available at 2008 levels. Therefore, the current ITC is assumed to apply to geothermal and solar thermal assets in 2020, and the current production tax credit ("PTC") is assumed to apply to biogas & biomass, large and small hydro, and wind projects. Table C below details current tax policy.[38]

The calculator assumes that the investment tax credit will continue to be available only if a project is under independent power producer ("IPP") ownership, and that accelerated depreciation and PTC benefits would be available to both IOUs and IPPs. Because municipal utilities do not pay taxes, the cost of their projects is not impacted by tax benefits.

The ITC is applied to eligible project costs; therefore the calculator provides an input that allows users to reduce total capital costs by a multiplier to obtain the eligible project costs. In the base case, the model assumes that 75% of total project costs are ITC-eligible costs, and that the entire ITC is available in the first year. The term of the PTC is 10 years. The first year PTC amount is escalated by inflation over the 10-year term, then present-valued to 2008. Both ITC and PTC are also levelized in 2008 dollars.

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[34] This state rate assumes projects located in California. If the project was located in another jurisdiction, the rate will in most cases be lower.

[35] The book-tax depreciation differences should be offset with full deferred tax. The benefit of accelerated depreciation is equal to the rate of return, multiplied by the deferred tax balance for each year.

[36] However, California tax lives are frequently different from book lives. CA taxable income is computed using the state lives with deferred taxes applied to any book-tax differences.

[37] In addition, the deduction under Section 199 may be available for these projects. These benefits are computed using the applicable rate (6% or 9%), subject to a limitation for wages paid.

[38] Certain credits have sunset dates before 2020.

GHG Model
Taxes and Tax Incentives
2007

Technology	Depreciable Life		Incentives	
	Federal	California	Federal	California
Coal IGCC (Integrated gasification combined cycle)	7YRS MACRS	7 YRS SL	20% ITCC (limited to first 4GW of new IGCC capacity)	NO CA incentive available
Coal IGCC with CCS	7YRS MACRS	7 YRS SL	20% ITCC (limited to first 4GW of new IGCC capacity)	NO CA incentive available
Coal ST (Advanced coal)	20 YRS MACRS	ADR-28 YRS 200DB	15% of ITCC (limited to first 3GW of new capacity)	NO CA incentive available
Natual Gas Combined cycle combustion turbine (CCCT)			None	NO CA incentive available
Natural Gas CT			None	NO CA incentive available
Nuclear	15 YRS - MACRS	ADR-20YRS 200DB	1.8c/kWht PTC for first 8 years by 2020	NO CA incentive available
Biogas & Biomass:				CA SEP eligible (see requirements)
- Closed loop biomass (organic plants raised specifically for fuel)	5 YRS - MACRS	5 YRS SL	1.9c/kWh PTC for first 10 years if in service by 2008	
- Open/landfill gas/municipal solid waste (agricultural livestock or vegetation waste)	5 YRS - MACRS	5 YRS SL	1.0c/kWh PTC for first 10 years if in service by 2008	
Geothermal	5 YRS - MACRS	5 YRS SL	1.9c/kWh PTC for first 10 years if in service by 2008	CA SEP eligible (see requirements)
			10% permanent production tax credit	
Large Hydro	20 YRS MACRS	ADR-50 YRS 200DB	Incremental addition at existing generator, or generation built at existing non-hydroelectric dam: 1.0c/kWh Production tax credit for first 10 years if in service by 2008	NO CA incentive available
Small Hydro	20 YRS MACRS	ADR-50 YRS 200DB	Incremental addition at existing generator, or generation built at existing non-hydroelectric dam: 1.0c/kWh Production tax credit for first 10 years if in service by 2008	CA SEP eligible (see requirements)
Solar Thermal	5 YRS - MACRS	5 YRS SL	30% ITC if in service by 2008	AB 1451(Leno) - §73 Property tax exemption-1/1/2010
			10% permanent production tax credit	CA SEP eligible (see requirements)
Wind	5 YRS - MACRS	5 YRS SL	1.9c/kWh PTC for first 10 years if in service by 2008	CA SEP eligible (see requirements)

	IRC §45 Electricity Produced from certain renewable resources
	IRC §45 is a component of the general business credit under IRC §38
IRC §45(a)	Credit rates and phaseout - For electricity produced in 2005, the amount of indexed credit is 1.9 cents per kilowatt-hour
IRC §45(b)(3)	The credit is reduced (up to 50% of the allowed) for grants, tax-exempt bonds, subsidized energy financing, and other types of credits that may have been claimed with respect to the production facility
IRC §48(a)(2)	For periods after 12/31/2005, the business investment credit for solar energy property is 30% of the basis of qualified energy property placed in service in that year
IRC §48(a)(4)	The basis of energy property that is financed by tax-exempt private activity bonds or subsidized energy financing must be reduced
IRC §48(a)(3)	Energy property includes property that meets the following requirements: 1. must be solar property; 2. the construction, reconstruction, or erection of property must be completed by the taxpayer 3. the property must be depreciable or subject to amortization deductions 4. the property must meet quality and performance standards that are in effect at the time of acquisition.
	The energy credit is not available for energy property that is owned by utility. The energy credit cannot be claimed for any property that is part of a facility that produces electricity for which the renewable electricity production credit is allowed (§45).
IRC §168(e)(3)(B)(vi)(I)(II)(III)	MACRS recovery period for solar energy properties
Rev Proc 87-56	Accelerated cost recovery class lives
CA Energy Commission	Renewable Portfolio Standard Eligibility Guideline (3/07)

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commissioner's Rules of Practice and Procedure, I have this day served a true copy of RESPONSE OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) TO ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENTS ON MODELING-RELATED ISSUES on all parties identified in the attached service list(s).

Transmitting the copies via e-mail to all parties who have provided an e-mail address. First class mail will be used if electronic service cannot be effectuated.

Executed this **7th day of January, 2008**, at Rosemead, California.

/S/ RAQUEL IPPOLITI
Raquel Ippoliti
Project Analyst
SOUTHERN CALIFORNIA EDISON COMPANY

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

BEFORE THE CALIFORNIA ENERGY COMMISSION

In The Matter Of, AB 32 Implementation – Greenhouse Gas Emissions.	))))))	Docket 07-OIIP-01

REPLY COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON MODELING-RELATED ISSUES

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Dated: **January 18, 2008**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

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REPLY COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON MODELING-RELATED ISSUES

Pursuant to the Administrative Law Judges' Ruling Extending Comment Deadlines and Addressing Procedural Matters, issued November 30, 2007, Southern California Edison Company ("SCE") respectfully submits these reply comments on the documentation for the model created by Energy and Environmental Economics, Inc. ("E3") to assess how different methods of reducing greenhouse gases ("GHG") will achieve emission reduction goals for the electricity sector and how such reductions will affect utility costs and consumers' electricity bills.

I.

GHG EMISSIONS COSTS SHOULD BE INCORPORATED INTO THE OPERATING COSTS OF GENERATING FACILITIES

In its opening comments, the Southern California Public Power Authority ("SCPPA") asserts that incorporating GHG emissions costs into the operating costs of generating facilities to alter dispatching should not be considered an appropriate emission reduction measure.[1] In particular, SCPPA argues that the "adverse impact of internalizing the cost of GHG emissions in wholesale electricity prices could be substantial and could have a profoundly adverse economic impact on consumers."[2] SCPPA relies on an analysis presented in this proceeding by Bruce Biewald of Synapse Energy, Inc.[3] SCE disagrees with SCPPA. Incorporating GHG emissions costs into the operating costs of generating facilities is a cost-effective and efficient way to reduce emissions.

Internalizing emissions costs allows the market to find the lowest cost options to reduce GHG emissions. When emissions costs are internalized into the operating costs of generating facilities, and thus into wholesale power prices, there is a price signal to the market which creates an economic incentive to reduce GHG emissions. Sending this price signal to the market encourages energy efficiency, conservation, development of clean resources, and innovation in new clean technology, without the need for complex and difficult to administer regulations. Regulators do not have the burden to administratively determine the most effective means to reduce GHG emissions. The price signal to the market incentivizes the most cost-effective GHG reduction options.

Furthermore, while internalizing GHG emissions costs will increase the cost of power, utilizing a market will be more cost-effective than command and control measures in reducing GHG emissions. According to the Electric Power Research Institute ("EPRI"), command and

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[1] SCPPA Opening Comments at 2-5.
[2] *Id.* at 4.
[3] *Id.*

control GHG regulations would diminish economic welfare 30% more than a comprehensive market system.[4]

Finally, the Synapse Energy, Inc. analysis relied on by SCPPA in its opening comments is flawed. For the reasons stated in the SCE/Pacific Gas and Electric Company ("PG&E") presentation attached hereto as Appendix A, the Synapse Energy, Inc. model has significant flaws and the results distort the economic impacts under load-based and source-based GHG emissions caps, greatly overstating the benefits of a load-based cap. Neither E3 nor the California Public Utilities Commission ("CPUC") and California Energy Commission ("CEC") should not use the Synapse Energy, Inc. analysis in their GHG modeling efforts.

II.

E3'S MODEL IS NOT APPROPRIATE TO ANALYZE GHG SCENARIOS ON A LOAD-SERVING ENTITY BASIS

SCE's opening comments explain that, although E3's data assumptions and modeling approach will provide results that may be appropriate for a statewide analysis of GHG scenarios in the electricity sector, E3's analysis is not appropriate on an individual load-serving entity ("LSE") basis. Among other things, E3 appears to use the same emission rates for each fuel type, which may result in inaccurate GHG emissions levels, especially for those emissions from combined cycle units burning natural gas. Moreover, E3's modeling assumptions reflect specific information pertaining to the five largest electric utilities in California, but minimal information pertaining to the many other LSEs operating within California. Modeling GHG scenarios for some, but not all, California LSEs will lead to inaccurate information and could lead to decisions that are not only inaccurate but more costly to implement. Finally, E3's modeling assumption that an LSE that owns a generator or has entered into a power purchase agreement with a

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[4] EPRI, Program on Technology Innovation: Economic Analysis of California Climate Initiatives: An Integrated Approach, Volume 1: Summary for Policymakers at § 3.2.2, 3-6 (June 2007) (available at www.epriweb.com/public/000000000001014641.pdf).

generator is allocated that unit's energy proportional to the ownership share is problematic. While that assumption may be correct for a market that operates without bilateral agreements and where all contracts for capacity include exclusive assignment of generated energy, this scenario does not reflect either the current or projected future operation of the California electricity market. An LSE with a contract for a unit's capacity may not have any contractual commitment for the unit's energy, and bilateral agreements exist between entities that allow energy transfer without capacity transfer. Therefore, E3's assumptions do not reflect actual operating conditions.

Other parties' opening comments support SCE's conclusion that E3's modeling is problematic at the LSE level. The Northern California Power Agency ("NCPA") states that E3's model does not provide accurate or adequate information about publicly-owned utilities.[5] Similarly, the Sacramento Municipal Utility District ("SMUD") asserts that E3 failed to accurately attribute all of SMUD's specified resources to SMUD.[6] San Diego Gas & Electric Company ("SDG&E") and Southern California Gas Company ("SoCalGas") note that they disagree with most of the assumptions in the E3 model used to derive entity-specific results.[7] Finally, the Los Angeles Department of Water and Power ("LADWP") notes the problems with E3's assumptions about LSE resource planning in 2020, and states that "unintended consequences can arise" when extrapolating E3's modeling to LSE-specific results as would be done in Stage 2.[8]

SCE agrees with these parties' concerns regarding the accuracy of LSE-specific results in E3's modeling and the application of the E3 model to GHG scenarios at the LSE level. For these reasons, SCE believes the E3 model should not be applied to model scenarios on an individual LSE basis. Moreover, as SCE has explained in prior comments, accounting for GHG emissions under a source-based or first seller approach is more accurate then accounting for such emissions

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[5] NCPA Opening Comments at 2.
[6] SMUD Opening Comments at 7.
[7] SDG&E/SoCalGas Opening Comments at 8.
[8] LADWP Opening Comments at 5-9.

under a load-based approach. Therefore, E3's modeling of actual GHG emissions will be more accurate if a source-based or first seller model is used.[9]

III.

E3 SHOULD MODEL DIFFERENT FUEL PRICE SCENARIOS

In their opening comments, the Natural Resources Defense Council ("NRDC") and the Union of Concerned Scientists ("UCS") assert that:

> In its current form, the E3 model does not account for the effect of increased reliance on preferred resources on reducing natural gas prices. Instead, the E3 model assumes that natural gas prices are unchanged between the reference and the target cases, even though natural gas demand may be much lower in the target case. The assumption that natural gas prices will not be affected by substantially reduced demand is a significant oversight of the E3 model.[10]

SCE has reviewed the documents referenced by NRDC/UCS in their comments and acknowledges the potential for decreased natural gas demand within the electricity sector based upon two main factors:

1. Replacing old, less efficient simple-cycle peaker gas units with new, more efficient CHP/CC gas units will allow the same (or more) energy to be produced while burning less fuel; and

2. An increase in renewable energy and implemented energy efficiency measures will displace a proportionate share of energy from marginally priced natural gas units.

Without diminishing the validity of NRDC/UCS's concern, however, it is important to look at the other side of the coin and consider that another section within the CEC's 2007 Integrated Energy Policy Report includes a scenario describing how natural gas could be used as

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[9] The Western Power Trading Forum's ("WPTF") opening comments note that because E3's GHG calculator was developed to model a load-based approach, it cannot quantity the benefits of alternative systems such as a source-based approach or a first seller approach as currently configured. WPTF Opening Comments at 9. SCE supports a first seller regulatory approach to satisfying the State's GHG abatement goals. Incorporating a first seller model into the GHG calculator would provide a more realistic assessment of a first seller approach. Because this calculator models a load-based cap, it does not include emissions costs in the dispatch price. In a first seller approach, the emissions cost would be included in the dispatch price.

[10] NRDC/UCS Opening Comments at 17.

a complementary strategy to meet GHG emissions reductions.[11] This scenario and a subsequent recommendation discuss how the demand for natural gas could increase under a strategy to displace coal power plants in the Western Electricity Coordinating Council ("WECC") and the eastern United States with natural gas fired power plants.[12]

Rather than initiating a potentially time consuming discussion on the appropriate fuel prices to use in PLEXOS for production cost/economic dispatch modeling purposes, SCE believes E3's intent is to use their GHG calculator as a means to efficiently and quickly evaluate scenarios and analyze sensitivity cases, which of course should include changes in fuel prices. These analyses would help determine the feasibility of different emissions scenarios under a range of fuel prices while avoiding a prolonged process of determining a "correct" natural gas forecast.

IV.

E3'S TREATMENT OF WIND INTEGRATION COSTS SHOULD BE CLARIFIED

As SCE explained in its opening comments, E3 should clarify its treatment of wind integration costs. In particular, E3's graphical display using wind penetration in % MW[13] and then in % GWh[14] should be revised for consistency. E3's reference to 30,000 GWh of wind energy having a wind integration cost of $275 million may suggest that 30,000 GWh is synonymous with 30% wind capacity penetration. However, 30,000 GWh is more closely associated with 20% wind capacity penetration using E3's assumed control area size of 50,000 MW and wind capacity factor of 34%. The wind integration costs for 30% wind capacity for the 50,000 MW control area assumed by E3 would, using E3's values, have an associated cost of over $400 million. When calculated for a control area with a coincident peak of 70,000+ MW

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[11] CEC 2007 Integrated Energy Policy Report at 241-42.

[12] *Id.*

[13] E3's CPUC GHG Modeling Stage 1 Documentation at 145, Fig. 5 (http://www.ethree.com/GHG/R0604009_ Attachment _B_v2.pdf).

[14] *Id.* at 146, Fig. 6.

(*i.e.*, the CEC's projected demand for California beyond 2018),[15] the values would be significantly higher. The tables below clarify the treatment of wind integration costs.

E3's Wind Integration Costs (Chapter 28)

Back Calculated	Assumed	Back Calculated	Assumed	Assumed	Assumed	Calculated
				Starting Point		Cost
Percent Penetration (%)	System Capacity (MW)	Wind Capacity (MW)	Capacity Factor (%)	Wind Energy (GWh)	($/MWh)	$
6.7%	50,000	3,358	34%	10,000	3.13	$ 31,300,000
13.4%	50,000	6,715	34%	20,000	6.26	$ 125,200,000
20.1%	50,000	10,073	34%	30,000	9.39	$ 281,700,000

E3 10,000 GWh of wind energy is implied to be equivalent to 10% MW penetration of wind capacity, which is incorrect
Implied Conclusion: Wind integration costs are $30 Million for 10% penetration, $125 Million for 20% penetration, and $280 Million for 30% penetration

SCE's Wind Integration Costs using E3's Values and a Calculated Wind Energy for Assumed MW penetration value

Assumed	Assumed	Calculated	Assumed	Calculated	Assumed	Calculated
Starting Point						Cost
Percent Penetration (%)	System Capacity (MW)	Wind Capacity (MW)	Capacity Factor (%)	Wind Energy (GWh)	($/MWh)	$
10.0%	50,000	5,000	34%	14,892	3.13	$ 46,611,960
20.0%	50,000	10,000	34%	29,784	6.26	$ 186,447,840
30.0%	50,000	15,000	34%	44,676	9.39	$ 419,507,640

Conclusion: Wind integration costs are $45 Million for 10% penetration, $185 Million for 20% penetration, and $420 Million for 30% penetration

V.

IMPLEMENTATION OF A 33% RENEWABLES PORTFOLIO STANDARD PRESENTS SIGNIFICANT CHALLENGES

NRDC/UCS's opening comments argue that "California should immediately adopt a 33% Renewables Portfolio Standard (RPS) to ensure the development of additional renewable resources to serve the state."[16] NRDC/UCS assert that "[t]he CEC Intermittency Analysis Project (IAP) concludes the state's electricity system, if bolstered by transmission upgrades and

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[15] CEC 2007 Integrated Energy Policy Report at 45.
[16] NRDC/UCS Opening Comments at 7.

prudent resource planning, can readily accommodate 33% renewables penetration with minor changes to system operation and infrastructure."[17]

SCE has discussed the need for legislation in order to adopt a 33% RPS requirement and other challenges surrounding a 33% RPS in other forums and does not repeat that discussion here.[18] SCE does note, however, that NRDC/UCS significantly understate the challenges of implementing a 33% RPS. SCE agrees with PG&E's opening comments that major issues associated with expanded renewables procurement still need to be resolved.[19]

A recent California Independent System Operator ("CAISO") study regarding the integration of renewable resources concludes that:

> The good news is that this study shows the feasibility of maintaining reliable electric service with the expected level of intermittent renewable resources associated with the current 20 percent RPS, *provided* that existing generation remains available to provide back-up generation and essential reliability services. The cautionary news is the "*provided*" part of our conclusion. Regulatory actions under active consideration threaten the economic viability of much of this essential generation. Moreover, current regulatory policies assigning high on-peak availability factors to intermittent generation will eliminate the theoretical — but not the real — need for the essential generation currently provided by existing power plants, and regulators may be unwilling to support sufficient forward procurement of generation.[20]

Furthermore, in discussing the CEC's IAP, the CAISO states that "[i]t would be erroneous to conclude that there are no serious integration problems" with even a 20% RPS.[21] Contrary to NRDC/UCS's suggestion that the changes to system operation and infrastructure needed to accommodate a 33% will be "minor," the CAISO notes that the IAP report concluded that "[m]ajor new transmission facilities and upgrades of existing transmission will be required

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[17] *Id.*

[18] *See, e.g.*, Southern California Edison Company's 2006 Procurement Plan Volume 1B, R.06-02-013, at 74-88 (Dec. 11, 2006).

[19] PG&E Opening Comments at 17-23.

[20] CAISO, Integration of Renewable Resources, Transmission and operating issues and recommendations for integrating renewable resources on the California ISO-controlled Grid, Letter from CEO (November 2007) (emphasis added) (available at http://www.caiso.com/1ca5/1ca5a7a026270.pdf).

[21] *Id.* at 19.

for the 20% RPS and especially to accommodate the 33% RPS goal."[22] The CAISO also concludes that increasing the RPS from 20% to 33% could more than double integration costs and problems:

> The variability of wind generation energy production from a small number of units is usually much less than the variability of system load changes. The system operator is accustomed to dealing with daily load forecast errors, changes in hourly load forecasts and the unpredictability of loads. As the amount of wind generation in an area increases, it will reach a point where its variability is greater than the variability of load. As wind generation further increases, the amount of variability will increase non-linearly. This study focused on the 20% RPS. An increase of the RPS to 33% could more than double the integration problems and costs.[23]

SCE shares PG&E's concern that the CPUC and the CEC adequately evaluate all of the challenges associated with GHG emissions reductions from incremental renewables.

VI.

CARBON CAPTURE AND SEQUESTRATION SHOULD BE CONSIDERED AS A GHG EMISSIONS REDUCTION OPTION

The Green Power Institute's ("GPI") opening comments state that until there is "a sound demonstration of the technical viability of carbon sequestration," carbon capture and sequestration ("CCS") "should not be considered as a real option for meeting greenhouse gas emissions reduction goals in any timeframe of interest to planners and regulators."[24] SCE disagrees. SCE believes that CCS technology has the potential to reduce GHG emissions, and has submitted an application with the CPUC to perform a feasibility study of a clean hydrogen generation plant.[25] No environmental parties to that proceeding (which include Californians for Renewable Energy, The Utility Reform Network, and NRDC) claimed that CCS was not ripe for

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[22] *Id.* at 20.
[23] *Id.* at 14 (emphasis added).
[24] GPI Opening Comments at 4.
[25] A.07-05-020.

consideration.[26] The CPUC recently issued a proposed decision granting SCE's application.[27] Moreover, the National Energy Technology Laboratory (of the Department of Energy) projects that by 2012, it will have developed CCS technologies with 99% permanence.[28] CCS should not be excluded as an option for reducing emissions to meet the State's AB 32 goals.

VII.

E3 SHOULD PROVIDE MORE DETAILED DOCUMENTATION EXPLAINING ITS MODEL

SCE agrees with the sentiment expressed by several parties in their opening comments that more detailed E3 modeling documentation is needed in order to assess the underlying model.[29] It is difficult to build a meaningful scenario with the current documentation, and it would be useful to have examples of scenario build-outs documented by E3 to ease calculator usability. As explained in SCE's opening comments, E3 should provide a document which captures details on values and equations listed on tabs other than the "Main" tab on its GHG calculator. E3 should also provide the other documentation requested in SCE's opening comments.[30] In addition, SCE recommends that the CPUC conduct a workshop or seminar where E3 could explain how to use the GHG calculator. Such a workshop or seminar would make it easier for the parties to use and assess E3's model, and would also provide the parties with an additional opportunity to ask E3 questions about its modeling.

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[26] NRDC/UCS support consideration of CCS as an option for meeting GHG emissions reduction goals in this proceeding. NRDC/UCS Opening Comments at 3-5.

[27] *See* Proposed Decision issued on Jan. 15, 2008 in A.07-05-020.

[28] *See* http://www.netl.doe.gov/technologies/carbon_seq/overview/images/CS%20Program%20Milestones.jpg.

[29] *See, e.g.*, SCPPA Opening Comments at 12-13; SMUD Opening Comments at 6-7; GPI Opening Comments at 7; The Independent Energy Producers Association Opening Comments at 2-3.

[30] SCE Opening Comments at 6-7.

Respectfully submitted,

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January 18, 2008

APPENDIX A

Customer Cost of Load-Based Cap vs. First-Seller

November 7, 2007

Background

- Synapse Energy Economics, Inc. analyzed the differences between a Load-Based Cap and a Source-Based Cap and their corresponding economic impacts on the California electricity market. Bruce Biewald, president of Synapse, presented the findings at the CPUC/CEC Joint En Banc Hearing on August 21, 2007

- Synapse concluded that a "load side carbon cap is likely to cost California consumers significantly less than a supply side cap", to the possible extent of $5 billion annually

- However the assumptions used in the Synapse model are flawed and the results distort the economic impacts to customers under load-based and source-based caps

- Both PG&E and SCE have engaged Synapse to gain a better understanding of the model; Synapse has responded to the inquiries but PG&E and SCE both feel that deficiencies remain in the analysis

Impacts of a Carbon Cap on Power Prices

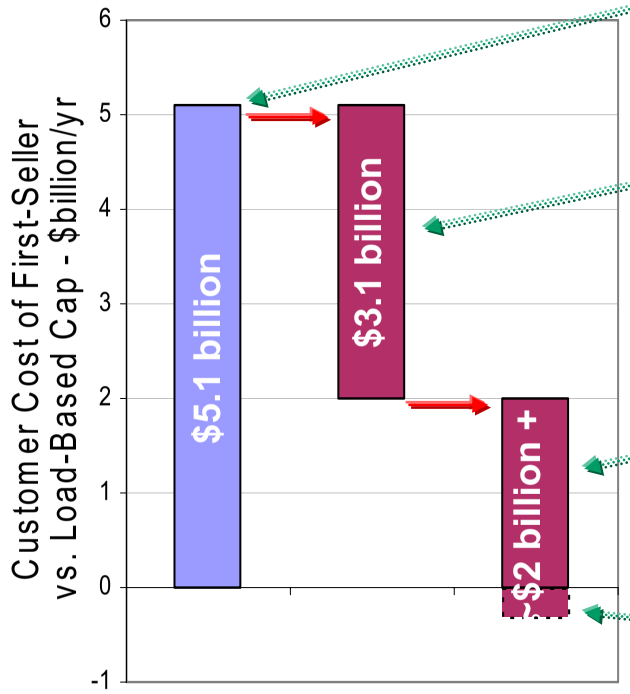
- Under a First-Seller approach:
  - Costs of emissions are internalized by generators
  - Power prices will reflect the GHG attributes of the marginal generator
- Under a Load-Based Cap:
  - The marginal generator will set the market price for electricity that excludes CO_2 compliance costs
  - As the point of regulation, Load-Serving Entities' (LSEs) customers will have to pay the CO_2 compliance cost separately

Under a Load-Based Cap, clean generators will negotiate bi-laterally with many LSEs for contract prices that reflect the value of their "clean power", including:

- The market price of electricity, and
- The CO_2 compliance costs LSEs' customers avoid by buying clean power

Results

Synapse Energy greatly overstated the benefits of a Load-Based Cap



A "Benefit" of $5.1 billion/year was presented by Bruce Biewald at the En Banc

But, if you allocate allowances to Load-Serving Entities (LSEs) instead of Generators, this benefit is reduced by $3.1 billion/year

And recognize that Clean Generators will negotiate higher prices with many LSEs to capture the economic value of their "clean power"

Thus, a Load-Based Cap will cost the <u>same</u> or <u>more</u> than First-Seller, depending on the default emission rate.

[The Synapse Energy presentation was delivered by Bruce Biewald at the CPUC/CEC en banc hearing on August 21, 2007. The presentation and spreadsheet are available at: http://www.synapse-energy.com]

$3.1 Billion Impact of Allowance Allocation on Customer Costs

- In Synapse's presentation, allocating allowances to generators rather than LSEs on behalf of their customers increases customer costs by $3.1 billion/year.
- The point of regulation, however, should not alter the allocation of allowances.
- Synapse acknowledges that, under a generator-side cap, allowances can be allocated to generators or to LSEs.

- If you allocate allowances to Load-Serving Entities (LSEs) instead of generators, customer costs are reduced by $3.1 billion/year

~$2 billion: Significant Flaws in the Synapse Model

1. Synapse model ignores economic dispatch:
   - –After the CO2 cost is internalized in Source-based scenario, Synapse indicates utilities will buy more high-cost Nat Gas electricity, even though Imp Coal remains cheaper.
2. The model ignores the heat rate curve for natural gas generation:
   - –In the Load-Based Cap scenario, natural-gas-fired generation increases, but its marginal costs do not.
3. The model uses a “weighted market price”:
   - –Instead of a market-clearing price, Synapse calculates a weighted average of each dispatchable category’s Generation times its “Marg Cost”.
4. The model lacks a market clearing price:
   - –Each category of dispatchable generators, including imports, is paid that category’s “Marg Cost”, not a market-clearing price.
   - –e.g. assumes hydro is paid $55 and gas $80, even though in reality in present and future short-term markets lower-emitting and higher-emitting generators receive same electricity price.

Utility Analysis: Customer Costs Are Similar Under Load-Based Cap and First Seller

- Overall electricity costs to customers are likely to be similar under Load-Based Cap and First-Seller, because Renewable Generators will bargain with many Load-Serving-Entities (LSEs) for full value, including LSEs' emission-compliance cost for High Emitters.

	Merchant Generator		
Assumptions	Renewables	GasCC	High Emitter
Running Cost	~$0/MWh	$50/MWh	$25/MWh
Emission Cost @ $20/metric ton	$0/MWh	$8/MWh	$10/MWh
Today's Market			
Wholesale-Market Price (set by GasCC, excluding Emission Cost)	$50/MWh	$50/MWh	$50/MWh
First-Seller			
Wholesale-Market Price (set by GasCC, including Emission Cost)	**$58/MWh**	$58/MWh	**$58/MWh**
Load-Based Cap			
Wholesale-Market Price (set by GasCC, excluding Emission Cost)	avoid wholesale market	$50/MWh or bilateral	$50/MWh
Additional Emission Cost paid by LSE	$0/MWh	$8/MWh	$10/MWh
Total Cost to Ratepayers	**$58-$60/MWh**	**$58-$60/MWh**	**$60/MWh**

Today: LSE pays same spot price for merchant Renewables, GasCC and High Emitters, set by GasCC.

First-Seller: As in Today's market, LSE pays same spot price for Renewables, GasCC and High Emitters, based on marginal GasCC's emission cost.

Load-Based Cap: Renewables and GasCCs will bargain with many LSEs for highest contract price, including benefits of their lower CO2 emissions relative to High Emitter.

Load-Based Cap: Depending on level and application of default emission rate, either leakage may occur or LSEs may pay more for High Emitters and Renewables.

Pacific Gas and Electric Company

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company

Appendix

- Flaws in Synapse Energy's model
- Impact of default emission rate on economic impacts and leakage

Flaws in Synapse Energy's Analysis (1)

- The Synapse analysis ignores economic dispatch
- Synapse: After the CO2 cost is internalized, Synapse indicates utilities will buy more high-cost Nat Gas electricity, even though Imp Coal remains cheaper
- Reality: Utilities will procure least-cost energy, including internalized CO2 costs

		No CO2 Cost		30 CO2 Cost $/ton				*Economic Dispatch*		
Category	Type	Generation (GWh)	Marg Cost ($/MWh)	CO2 Price Effect	Adj Price ($/MWh)	Adj Gen (GWh)	Gen Costs (M$)	*Generation (GWh)*	*Adj Price ($/MWh)*	*Gen Costs (M$)*
Dispatchable	Nat Gas	93,562	80.0	16.6	96.6	105,931	10,232	*93,562*	*96.6*	*9,037*
	Imp Hydro/Nuclear	19,016	55.0	0.0	55.0	19,016	1,046	*19,016*	*55.0*	*1,046*
	Imp Gas	19,016	80.0	16.6	96.6	19,007	1,837	*19,016*	*96.6*	*1,838*
	Imp Coal	38,033	45.0	31.2	76.2	27,118	2,066	*38,033*	*76.2*	*2,898*
	Oil & Other	4,611	125.2	36.9	162.1	4,300	697	*4,611*	*162.1*	*748*
	Coal	2,145	30.0	46.8	76.8	1,012	78	*2,145*	*76.8*	*165*
Fixed	Renewables	23,648	55.0	0.0	55.0	23,648	1,301	*23,648*	*55.0*	*1,301*
	Hydro	39,632	30.0	0.0	30.0	39,632	1,189	*39,632*	*30.0*	*1,189*
	Nuclear	36,155	40.0	0.0	40.0	36,155	1,446	*36,155*	*40.0*	*1,446*
		275,819				275,819	19,892	*275,819*		*19,667*

Electricity from gas-fired plants costs more than from coal, but demand for gas-based electricity increases. This violates economic dispatch.

[Table copied from Synapse worksheet "Near Term" rows 59-69. Italics added by PG&E]

Flaws in Synapse Energy's Analysis (2)

- The Synapse model ignores increasing marginal costs of natural gas generation
- Synapse: In the Load-Based Cap scenario natural gas generation increases, but marginal costs do not
- Reality: As natural gas generation increases, less efficient units will come online, increasing the marginal cost (of natural gas generation)

Load-Based Cap Scenario

Category	Type	Capacity (MW)	Generation (GWh)	Marg Cost ($/MWh)	CO2 Rate (Tons/MWh)	CO2 Price Effect	Adj Price ($/MWh)	Rel Price Change	Adj Gen (GWh)	CO2 Emis (kTons)	Gen Costs (M$)
Dispatchable	Nat Gas	36,700	93,562	80.0	0.553	16.6	80.0		105,931	58,577	8,474
	Imp Hydro/Nuclear	4,000	19,016	55.0	0	0.0	55.0		19,016	0	1,046
	Imp Gas	4,000	19,016	80.0	0.555	16.6	80.0		19,007	10,541	1,521
	Imp Coal	8,000	38,033	45.0	1.040	31.2	45.0		27,118	28,203	1,220
	Oil & Other	1,031	4,611	125.2	1.230	36.9	125.2		4,300	5,289	538
	Coal	389	2,145	30.0	1.560	46.8	30.0		1,012	1,578	30
Fixed	Renewables	5,479	23,648	55.0	0	0.0	55.0		23,648	0	1,301
	Hydro	10,088	39,632	30.0	0	0.0	30.0		39,632	0	1,189
	Nuclear	4,324	36,155	40.0	0	0.0	40.0		36,155	0	1,446
		74,011	275,819						275,819	104,188	16,766

Original Demand

Original Prices

Adjusted Demand has been copied from Source-Based scenario, but…

… Adjusted Prices do not change.

[Table copied from Synapse worksheet "Near Term" rows 76-86. Captions added by SCE]

Flaws in Synapse Energy's Analysis (3)

- Instead of a market-clearing price, Synapse calculates a "weighted market price" as a weighted average of each dispatchable category's Generation times its "Marg Cost".

Category	Type	Generation (GWh)	Marg Cost ($/MWh)
Dispatchable	Nat Gas	93,562	80.0
	Imp Hydro/Nuclear	19,016	55.0
	Imp Gas	19,016	80.0
	Imp Coal	38,033	45.0
	Oil & Other	4,611	125.2
	Coal	2,145	30.0
	Weighted Market Price ($/MWh)		70.33

["Weighted Market Price" formula in Synapse worksheet "Near Term" cell Q26.]

Flaws in Synapse Energy's Analysis (4)

- Synapse analysis lacks a market-clearing price
- Synapse: Each category of dispatchable generators, including imports, is paid that category's "Marg Cost", not a market-clearing price.
- Reality: Low-emitting and high-emitting generators receive the same electricity price, both in today's WECC spot markets and in the future Integrated Forward Markets of the California Independent System Operator.

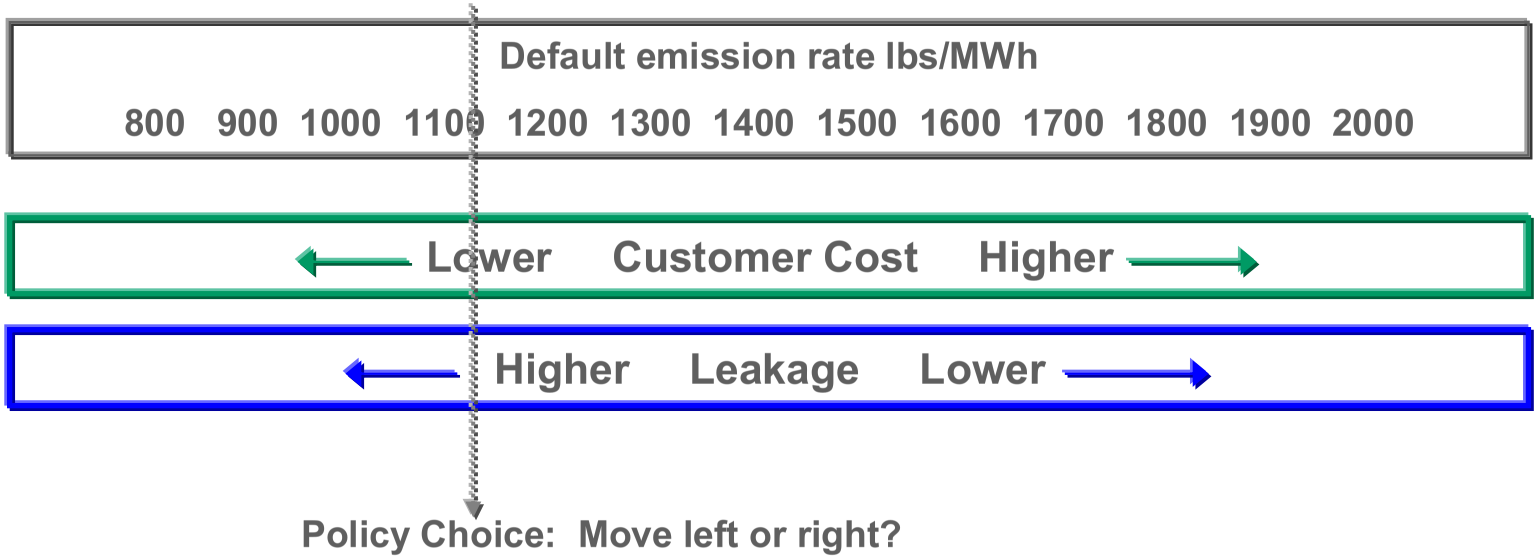
Category	Type	Generation (GWh)	Marg Cost ($/MWh)	Gen Costs (M$)
Dispatchable	Nat Gas	93,562	80.0	7,485
	Imp Hydro/Nuclear	19,016	55.0	1,046
	Imp Gas	19,016	80.0	1,521
	Imp Coal	38,033	45.0	1,711
	Oil & Other	4,611	125.2	577
	Coal	2,145	30.0	64

Imp Gas Generation (19,016 GWh) * Imp Gas Marg Cost ($80/MWh) = Imp Gas Gen Costs ($1,521M)

[Table copied from Synapse worksheet "Near Term" rows 25-31.]

Impact of Default Emission Rate

- A default emission rate is needed for "unspecified" purchases (i.e., cannot be traced to a specific generator)
  - Under a Load-Based Cap, both imports and in-state purchases can come from unspecified sources
  - Under First-Seller only imports can come from unspecified resources
- A high default rate will increase customer costs: Low-emitters will have greater value to LSEs and will demand higher prices in negotiations
- A low default rate will increase leakage: More emissions from high-emitters will be lost



CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of REPLY COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) ON MODELING-RELATED ISSUES on all parties identified on the attached service list(s). Service was effected by one or more means indicated below:

> Transmitting the copies via e-mail to all parties who have provided an e-mail address. First class mail will be used if electronic service cannot be effectuated.

Executed this **18th of January 2008**, at Rosemead, California.

_/s/ Raquel Ippoliti_____
Raquel Ippoliti
Project Analyst
SOUTHERN CALIFORNIA EDISON COMPANY

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