BEFORE THE CALIFORNIA ENERGY COMMISSION

AB 32 Implementation (Greenhouse Gas Emissions Reduction)	Docket No. 07-OIIP-01

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OPENING COMMENTS OF THE
CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES

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June 2, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

OPENING COMMENTS OF THE
CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES

The Center for Energy Efficiency and Renewable Technologies (CEERT) respectfully submits these Opening Comments on greenhouse gas (GHG) emissions reduction issues identified in Administrative Law Judges' (ALJs') Rulings issued in this proceeding on May 1, May 6, and May 13, and May 20, 2008. These Opening Comments are filed and served pursuant to the Commission's Rules of Practice and Procedure and the ALJs' Ruling of May 20, 2008 (May 20 ALJ's Ruling), which extended the time to file opening and reply comments to June 2 and June 16, 2008, respectively.

As directed by the May 20 ALJ's Ruling, CEERT's opening comments have been submitted both in this proceeding (R.06-04-009) and the California Energy Commission's (CEC's) Docket No. 07-OIIP-01. These comments follow the outline suggested in the May 20 ALJs' Ruling.

I.
GENERAL ISSUES

As directed by the May 20 ALJs' Ruling, the "general issues" to be addressed in this topic area are covered by Question (Q) 3 and Q10 through Q13 identified in the May 13 ALJs' Ruling and Q1(a), Q1(b), Q2, and Q3 identified in the May 6 ALJ's Ruling. CEERT offers comment below on Q13 (May 13 ALJs' Ruling) only. With respect to the other questions, CEERT has no comment at this time, but reserves the right to address these questions in reply comments.

Q13. For each issue addressed in your comments, do you have any recommendations about the level of detail and specificity regarding the electricity and natural gas sectors that ARB should include in the scoping plan? Is there enough information in the record in this proceeding to support that level of detail and specificity? What additional information and/or analysis may be needed before ARB finalizes its scoping plan? What determinations regarding the electricity and natural gas sectors should ARB defer for further analysis after the scoping plan is issued? Please be as specific as possible about GHG-related policies for the electricity and natural gas sectors that you recommend be resolved this year, and policies that you believe should be deferred for further analysis after the scoping plan is issued.

The successful development of an effective AB 32 Scoping Plan rests in large part on the CPUC and CEC appropriately determining the levels of "preferred" resources (i.e., renewables, CHP, energy efficiency, solar distributed generation) that the electricity and natural gas sectors must plan for and procure in order to achieve greenhouse gas emissions (GHG) reductions targeted for 2020 and beyond. It is CEERT's understanding that the Scoping Plan will include recommended levels of "preferred" low and zero GHG resources. For this purpose, CEERT appreciates inclusion of a 33% renewables target in the aggressive policy case and encourages reliance on that percentage or greater in the first June draft or second October draft of the California Air Resources Board's (ARB's) Scoping Plan.

Both proposals and drafts of the Scoping Plan, however, must also identify any barriers that must be removed to achieve the expected level of each preferred resource. Such identification must also include a plan of action, with deadlines, for removing those barriers.

Several existing reports are available to promote this effort. The CEC's Integrated Energy Policy Report (IEPR), which focused on identifying and eliminating such barriers, is a good starting point for developing such a plan. Further, the Economic and Technology Advancement Advisory Committee (ETAAC) included a number of recommendations on this topic in its final report and appendix provided to the ARB. The Commission's Staff Proposal on emissions reduction measures attached to the ALJs' Ruling of November 9, 2007, also includes several appropriate recommendations. CEERT strongly recommends that these reports be used in developing the plan for removing barriers to all preferred resources and that this plan be an integral component of the Commissions' recommendations to the ARB.

II.
ALLOWANCE ALLOCATION

Questions posed on the topic of "allowance allocation" arose generally from the ALJs' Ruling of April 16, 2008. These questions focus on detailed allowance allocation proposals, responses to a staff paper on allowance allocation options and recommendations, and related legal issues. CEERT has no comment on these issues at this time, but reserves the right to address these questions in reply comments.

III.
FLEXIBLE COMPLIANCE

Questions directed to the issue of flexible compliance were identified in the May 6 ALJs' Ruling and seek input on a detailed proposal, the scope of market and related issues, price triggers and other safety valves, linkage, compliance periods, banking and borrowing, penalties and alternative compliance payments, offsets, and related legal issues (Questions 1 – 31). CEERT's comments below focus on questions related to linkage (Q8), banking and borrowing (Q14), penalties and alternative compliance payments (Q17 and Q18), and offsets (Q21). With respect to other questions posed on flexible compliance, CEERT reserves the right to address these questions in reply comments.

D. Linkage

Q8. Should California accept all tradable units,[1] i.e., GHG emission allowances and offsets, from other carbon trading programs? Such tradable units could include, e.g., Certified Emission Reductions, Clean Development Mechanism (CDM) credits, and/or Joint Implementation credits.

All tradable units of GHG emissions reductions should be real, permanent, quantifiable, verifiable, enforceable, and additional. Further, these tradable units must meet the following statutory requirements of AB 32:

California Health and Safety Code §38561(b):

> "In adopting regulations pursuant to this section and Part 5 (commencing with Section 38570), to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:
>
> …………………………………………..
>
> "(2) Ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities.
>
> …………………………………………..
>
> "(4) Ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions.
>
> …………………………………………..
>
> "(6) Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health."

And:

California Health and Safety Code §38570 (b):

> "Prior to the inclusion of any market-based compliance mechanism in the regulations, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:
>
> "(1) Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution.

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[1] Tradable units refer to (1) GHG emission allowances that permit emission of a ton of carbon equivalent (CO2E) and (2) offsets that reflect a reduction in GHG emissions of a ton of CO2E, as addressed in Section 2.8 of the May 6 ALJs' Ruling. As used in that ruling, a credit is a broad term that refers to any tradable unit other than a GHG emission allowance issued by California.

> "(2) Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants.
>
> "(3) Maximize additional environmental and economic benefits for California, as appropriate."

Therefore, it is CEERT's position that a tradable unit can only be "accepted" for purposes of meeting GHG emission reductions if it complies with these statutory requirements and is real, permanent, quantifiable, verifiable, enforceable, and additional. The Commissions should also place geographic and quantitative limits on offsets.

G. Penalties and Alternative Compliance Payments

Four questions (Q17-Q20) were posed in the May 6 ALJs' Ruling on penalties and alternative compliance payments. CEERT addresses Q17 and Q18 below and, again, reserves the right to respond further on the other questions in reply comments.

> **Q17.** Should there be penalties for entities that fail to meet their compliance obligations? If so, how should the penalties be set? If not, what should be the recourse for non-compliance?

It is CEERT's position that entities that fail to meet their GHG compliance obligation should be penalized. The penalty per ton of CO2e could be set at a rate greater than the current market price of one ton of CO2e at the time the penalty is assessed and should be set at a high enough rate to provide an sufficient disincentive for non-compliance.

> **Q18.** Instead of penalties, should there be alternative compliance payments? What would be the distinguishing attributes of alternative compliance payments versus penalties? How would the availability of alternative compliance payments affect the environmental integrity of the cap?

These two flexible compliance methods are virtually the same. The difference between alternative compliance payments and penalties comes with their implementation. The obligated entity could be given the option of substituting its compliance obligation with an alternative compliance payment in advance of falling short of requirements. Penalties could be levied after an entity fails to meet its compliance obligation. In both cases, alternative compliance payments and penalties should be set at a rate high enough to guard against entities substituting a significant portion of their compliance obligation with either of these tools. Further, monies collected from either alternative compliance payments or penalties must be used for the purpose of lowering overall greenhouse gas emissions by providing incentives for new technology or by supporting development of new technology.

H. Offsets

Six questions were posed in the May 6 ALJ's Ruling on offsets. For purposes of these opening comments, CEERT addresses one of these questions (Q21) below.

Q21. Should California allow offsets for AB 32 compliance purposes?

CEERT's response to this question is the same as it is to Q8 (Linkage) above. All tradable units of GHG emissions reductions, *including offsets*, should be verifiable, enforceable, and additional. Further, such offsets, like the tradable units addressed in Q8, must meet those portions of AB 32 quoted above from Health and Safety Code §§38561(b) and 38570(b).

IV.
TREATMENT OF COMBINED HEAT AND POWER (CHP)

The treatment of combined heat and power (CHP) is the subject of Q1-Q24 of the May 1 ALJs' Ruling. By these comments, CEERT addresses Q2, Q3, Q13, Q16, Q18, and Q23 below. With respect to other questions posed on the treatment of CHP, CEERT reserves the right to address these questions in reply comments.

B. Regulation of CHP GHG emissions

Q2. Should GHG emissions from CHP systems be regulated in one sector? If so, which one? How?

CHP units, by definition, have both electric and thermal benefits. Regardless of the sector treatment used by the CPUC, the full efficiency and emissions benefits of *both* thermal and electrical functions of the unit must be considered, particularly when comparing the GHG benefits of these systems to conventional, central station power plants.

> **Q3.** For in-state CHP systems, should all of the GHG emissions (i.e., all of the emissions attributed to the electricity generation and to the thermal uses) be regulated as part of the electricity sector? If so, for the electricity that is delivered to the California grid, should the deliverer as defined in D.08-03- 018 be the point of regulation? And, what entity(ies) should be the point(s) of regulation for thermal usage and electricity that is not delivered to the California grid if those uses are included in the electricity sector for GHG regulation purposes?

The full thermal and electrical benefits of CHP systems must be considered, even if the emissions are only regulated in one sector – electricity or natural gas. With respect to benefits from customer-owned CHP or renewable distributed generation in a GHG context, those benefits should accrue to the customer-generator. This is especially appropriate for electricity and heat production that is used on-site and not delivered to the grid. Such an approach is fully consistent with the Commissions' current policy with respect to renewable energy credit (REC) ownership for renewable distributed generation.[2]

> **Q13.** If CHP is treated separately from the electricity sector, but is still included as part of a cap-and-trade program, how should allowance allocation to CHP units be handled?

In addition to appropriately recognizing the GHG benefits of a CHP system and appropriate allocating those benefits based on ownership, the Commission must avoid penalizing installation of CHP systems that reduce GHGs on an overall system basis and reduce criteria pollutants over central-station natural gas fired power plants.

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[2] In Decision (D) 07-01-018, in R.06-03-004, issued on January 11, 2007, the CPUC ruled that owners of renewable distributed generation own all of the RECs produced by their facilities, regardless of ratepayer subsidies, and found that: "(t)ransferring RECs from renewable DG system owners to ratepayers could adversely impact decisions to invest in solar and other renewable DG projects…[and] (t)ransferring the RECs from renewable DG systems to the ratepayers as a condition of receiving ratepayer incentives would not encourage renewable DG installation."

C. CHP As An Emission Reduction Measure

Q16. Should CHP be considered an emission reduction measure under AB 32? Why or why not?

CHP should be considered an emission reduction measure under AB 32. As the Commission staff noted in Attachment A to the ALJs' Ruling of November 9, 2007 (November 9 ALJs' Ruling):

> "By capturing waste energy, Combined Heat and Power (CHP) installments improve generation efficiency and displace the need for central station generation. Attendant with the reductions of energy use come reductions in GHG emissions, though the degree of carbon savings will depend on the technology and fuel used in the CHP unit and on the alternatives displaced."[3]

If the installation of CHP systems will result in reduced greenhouse gas emissions on an overall system basis, then they should be considered an emission reduction measure under AB 32. Further, although AB 32 is focused primarily on reductions of GHG emissions, CEERT notes that some CHP technologies provide criteria pollutant benefits over central station generation, in the form of lower NOx and PM emissions per unit of energy production. Considering the air quality provisions of AB 32, these benefits must also be considered in whatever approach the Commissions ultimately decides for CHP regulation in the context of reducing emissions of GHGs.

Q18. Should ARB and/or the Commissions consider policies or programs to encourage installation of CHP for GHG reduction purposes? Why or why not?

Q23. Should the Commissions pursue policy or programmatic measures to overcome some of the barriers to CHP deployment?

The answer to both of these questions is "yes." Some of the barriers to CHP deployment are a matter of policy, which the Commissions can affect, and some are in the domain of the legislature. CPUC Staff in Attachment A to the November 9 ALJs' Ruling correctly observed:

[3] R06-04-009 ALJs' Ruling of November 9, 2007 (November 9 ALJs' Ruling), Attachment A, at p. 8.

> "Removing market barriers and disincentives to the installation of CHP units will be essential to achieving the outer bounds of CHP market potential. Processes are underway to alter rate design and market rules as a means to removing disincentives and improving CHP penetration within the state."[4]

CEERT agrees with this statement and encourages the Commissions and the ARB to take the following three steps:

1. The first step is to set a definitive number of the amount of CHP that the Commissions expect the electricity sector to procure in order to achieve GHG emissions reductions requirements. This number should be a part of the scoping plan.
2. The second step, in terms of specific policies or programs and effectiveness, is for the Commissions to clearly identify the barriers to CHP and develop an actionable plan for removing those barriers. The Commissions should begin with the IEPR, the ETAAC report, and the Staff report attached to the November 9 ALJs' Ruling.
3. The third step is to consider a utility procurement requirement for CHP, which would serve to eliminate some of the policy and practical barriers associated with full customer ownership of all CHP. Priority should be given to CHP systems that emit zero or near-zero criteria pollutants, namely NOx and particulate matter.

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

Issues related to non-market-based GHG emission reduction measures, other than CHP and GHG emission caps, are the subject of Q1-Q2 and Q4-Q9 of the May 13 ALJs' Ruling. CEERT addresses Q1 and Q5 (electricity emission reduction measures) and Q6 (legal issues) below. With respect to other questions related to non-market-based GHG emission reduction measures and emission caps, CEERT reserves the right to address these questions in reply comments.

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[4] Id.

A. Electricity Emission Reduction Measures

CEERT provides the following comments on Q1 and Q5 identified in the May 13 ALJs' Ruling related to electricity GHG emission reduction measures as follows:

> **Q1**. What direct programmatic or regulatory emission reduction measures, in addition to current mandates in the areas of energy efficiency and renewables, should be included for the electricity and natural gas sectors in ARB's Assembly Bill (AB) 32 scoping plan?

CEERT has recommended that renewable energy procurement be increased and that the Scoping Plan include 33% renewables procurement by 2020. The Scoping Plan to be adopted by ARB adopt at the end of 2008 must contain the actual gigawatt-hours of renewable energy that the state expects the electricity sector to procure by 2020 in order to meet the goals of AB 32. It is CEERT's understanding that the Scoping Plan will include recommended levels for each resource.

CEERT supports the CPUC's and CEC's recommendations, which reflect a commitment to continuing and expanding mandatory energy efficiency and renewable procurement as part of the foundation of guaranteeing GHG emissions reductions in the electricity sector and investment in new and existing clean technology. The November 9 ALJs' Ruling included a Commission Staff proposal recommending direct regulatory emissions reduction measures for the electricity sector. CEERT largely supported the Staff's recommendations and, in its responsive comments, encouraged the CPUC and CEC to consider expanding and modifying the referenced programs now as follows:

> "With regard to combined heat and power (CHP) systems, CEERT supports the recommendation in the Staff Workpaper to remove market barriers and disincentives to the installation of combined heat and power (CHP) units, with priority given to fuel cells and other ultra-clean and low-emission[5] generating

[5] R.06-04-009 (GHG) CEERT Comments on E3 Modeling (January 7, 2008), at p. 21, Footnote 31. "As first defined in Public Utilities Code 353.2, and subsequently implemented by the California Air Resources Board."

> units.[6] Regarding renewable energy policy, CEERT has been actively involved in the implementation of the Renewable Portfolio Standard (RPS) law since its enactment more than five years ago. However, CEERT believes that substantial reform and streamlining in current RPS implementation will be required to ensure that renewable energy will be increased sufficiently to meet GHG emission reduction goals.[Footnote 33]."[7]

CEERT continues to strongly support this recommendation: Thus, *in addition* to setting recommended levels for each preferred resource in the Scoping Plan, the CPUC and CEC should develop an actionable plan for expanding these programs and removing barriers now. The CPUC and CEC should begin with reliance on the IEPR, the ETAAC report, and the Staff report attached to the November 9 ALJs' Ruling.

A key means of ensuring that the planning required is being undertaken now is the current stakeholder process, the Renewable Energy Transmission Initiative (RETI). There have been a number of worthy efforts over the years by the California Independent System Operator (CalISO), CPUC, CEC, NREL, and others to study achievement of different renewable generation scenarios, including, among other things, total renewable potential, associated costs, and affect on jobs. CEERT has also recommended that the RETI become the official renewable transmission planning mechanism for AB 32. CEERT renews that recommendation here.

Q5. What percentage of emission reductions in the electricity sector should come from programmatic or regulatory measures, and what percentage should be derived from market-based measures or mechanisms? What criteria should be used to determine the portion from each approach? By what approach and in what timeframe should this question be resolved?

CEERT's fundamental position favors the following "direct" measures to make up the bulk of GHG emissions reductions: (1) long-term integrated resource planning with a focus on

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[6] R.06-04-009 (GHG) CEERT Comments on E3 Modeling (January 7, 2008), at p. 21, n. 32. Footnote 32 states: "These policy changes include, but are not limited to: exemption from departing load charges, incentives for non-generation technologies that are not currently supported by any program, increased incentives for CHP that operates on waste gas, and other changes recommended in the CEC's 2007 Integrated Energy Policy Report."

[7] R.06-04-009 (GHG) CEERT Comments on E3 Modeling (January 7, 2008), at p. 21 and n. 33. Footnote 33 states: "These issues include, but are not limited to: deliverability requirements, unbundled renewable energy credits, and ongoing use and applicability of the market price referent."

GHG reductions, which includes a minimum 33% renewables by 2020; (2) higher penetrations of renewable and ultra-clean distributed generation resources, perhaps in the form of a distributed generation "portfolio standard," or minimum planning and purchase requirement; and (3) sustained focus by the agencies on removing barriers to renewable energy and ultra-clean distributed generation, planning and constructing transmission, streamlining processes, etcetera.

CEERT, therefore, agrees with the Commission's position to base the foundation of GHG emissions reduction on programmatic measures. The ARB has recently announced their expectation of a 60/40 split for GHG emissions reductions between regulatory requirements and market-based mechanisms, respectively. This estimation encompasses all sectors of the economy. The electricity sector has far more straightforward opportunities to reduce GHG emissions than other sectors. The electricity sector can procure increasing levels of "preferred" resources and avoid constructing or purchasing power from fossil fuel-fired electric generation. In order to actually *reduce* overall greenhouse gas emissions from the electricity sector, existing fossil generation must eventually be retired or limited in hours of operation. This remains the case even though the CPUC and CEC have decided on an approach to the electricity sector that is essentially source-based, rather than primarily load-based.

CEERT recommends that any percentage mixture of regulatory and market-based compliance with greenhouse gas regulations be set *starting* with the list of measures in the Commissions' aggressive policy case and individual LSE's procurement plans. This approach is both rational and consistent with the Commissions' stated intent to base greenhouse gas emissions reductions goals on actual programmatic approaches within the electricity sector to support preferred resources. The Commissions should then set aside a percentage of load-serving entities' (LSEs') total greenhouse gas emissions reductions requirements and require that those reductions be met with preferred resources.

D. Legal Issues

Two questions (Q6 and Q7) regarding legal issues impacting non-market based emission reduction measures were identified in the May 13 ALJ's Ruling. CEERT addresses Q6 below.

> **Q6.** Do any of the non-market-based emission reduction measures discussed in your opening comments raise any legal or regulatory concern(s) or barrier(s)? If so, please explain the legal or regulatory concern(s) or barrier(s), including citations to specific relevant legal authorities. Would additional legislation be necessary to overcome any identified legal barrier(s)? Also, explain if and, if so, how the emission reduction measure(s) could be modified to avoid the legal or regulatory concern(s) or barrier(s).

CEERT firmly endorses reliance on a 33% renewables target as part of the core non-market-based GHG emission reduction measures. CEERT has long disputed the assertion made by certain investor-owned utilities (IOUs) of a "legal prohibition" on such a target. In fact, both by statute and policy, the mandated inclusion of renewables procurement in IOU procurement plans has been part of California law for nearly 20 years and has been required for both general and renewables-specific procurement.[8]

Nevertheless, certain IOUs have cited Public Utilities (PU) Code Section 399.15(b)(1) of the RPS Program law as authority for an absolute prohibition on overall procurement targets greater than 20% renewables by 2010. This section, however, relates only to the RPS "annual procurement targets" (APTs), which are defined as procurement of at least an additional 1% of retail sales per year from renewable resources, and states, relative to the APT *only*, that a "retail seller with 20 percent of retail sales procured from eligible renewable energy resources in any

[8] See, PU Code §§701.3, 454.5(b)(9)(A), and 399.11 (et seq).

year shall not be required to increase its procurement of renewable energy resources in the following year."[9]

This statutory language, read in context, certainly does not prohibit the Commission from requiring the IOUs to plan to meet a 33% renewables target or requiring the IOUs to meet an overall renewables target of 33% by 2020. This legal interpretation has been confirmed by the Commission in Decision (D.) 04-12-048 and, most recently, D.07-12-052.[10] In this regard, the Commission, as first stated in D.04-12-048 and reiterated in D.07-12-052, has concluded: "We find that RPS targets are a floor – not a ceiling" and that the Energy Action Plan "load order places renewables above conventional generation."[11]

Similarly, neither this Commission or any other jurisdictional state agency or board is prohibited from including a 33% renewables target among its non-market-based emission reduction measures to ensure that the IOUs meet the absolute GHG emission reductions mandated by AB 32. There is no doubt that AB 32 imposes additional responsibilities on the IOUs to procure electric generation consistent with its mandates. Certainly, the statutory "limit" on APTs contained in the RPS Program law must be construed consistently with the direction and intent of AB 32. If renewable generation is the means to achieve the AB 32 target, this statutory reference to APTs certainly does not constitute a "ban" or "prohibition" on the amount of renewables required to meet that target. In fact, the most recent amendment of the RPS Program law even allows for "voluntary" procurement of renewable generation above the market price referent.[12] Further, as noted above, this Commission has already confirmed the legality

[9] PU Code §399.15(b)(1).
[10] D.07-12-057, at pp. 247, 255.
[11] D.07-012-057, at p. 247, quoting D.04-12-048, Finding of Fact 55.
[12] PU Code §399.15(d)(4).

and propriety of a 33% renewables by 2020 policy for both RPS and AB 32 compliance purposes.

VI.
MODELING ISSUES

The outline suggested by the May 20 ALJs' Ruling separated "methodology" and "inputs" as two topic areas. CEERT believes that these issues are in fact interrelated and, more specifically, that the success of a "methodology" is largely driven by the accuracy of its "inputs." With this understanding, CEERT addresses both Q8 (Methodology) and Q9 (Inputs) together below in Section 1.

A. Methodology

> **Q8**. Address the performance and usefulness of the E3 model. Is it sufficiently reliable to be useful as the Commissions develop recommendations to ARB? How could it be improved?

B. Inputs

> **Q9**. Address the validity of the input assumptions in E3's reference case and the other cases for which E3 has presented model results. If you disagree with the input assumptions used by E3, provide your recommended input assumptions.

1. CEERT Recommended Improvements to the E3 Model

The scenarios produced by any model are only as realistic as the inputs to the model, a fact generally summarized as "garbage in, garbage out." CEERT believes that many of the model inputs used by E3 to develop its scenarios are wildly inaccurate and lead to conclusions that cannot be supported. Moreover, the E3 input assumptions are in fundamental disagreement with conclusions made by other state agencies and other experts.

CEERT recommends that the scenarios developed by E3 that rely on unrealistic input assumptions be ignored. New scenarios should be developed using input assumptions based on work done by the CEC and other reliable entities.

In particular, the E3 estimates of wind integration costs must be replaced with an analysis specific to the California electric system. Such an analysis has been completed by the Intermittency Analysis Project (IAP) and adopted by the CEC and should be used in scenarios developed by the E3 calculator. The IAP report is a thorough analysis of integration costs and was peer reviewed and adopted in a public process. The study looked at operating impacts on the system, rather than costs, from adding 12,700 MW wind and 7,000 MW solar.

It is also worthwhile to point out that the IAP estimated integration costs at $0.69/MWh for wind in a 33% renewables by 2020 scenario. E3 has adjusted its original assumed range of $3.13 – 9.30/MWh to $4.09 – 6.36/MWh, but thus far not included nor mentioned IAP findings. CEERT further recommends that E3 be directed to consult with experts in wind integration cost studies performed for California at the NREL, Oak Ridge National Laboratory, and General Electric, in order to develop integration cost estimates that are pertinent to the California electric system and will stand up to scrutiny.

2. Natural Gas Price Forecasts for the E3 Model

Scenarios developed with the E3 model purport to represent reasonable expectations of future costs of electricity under various assumptions. The most important single factor determining these costs is the projected cost of natural gas.

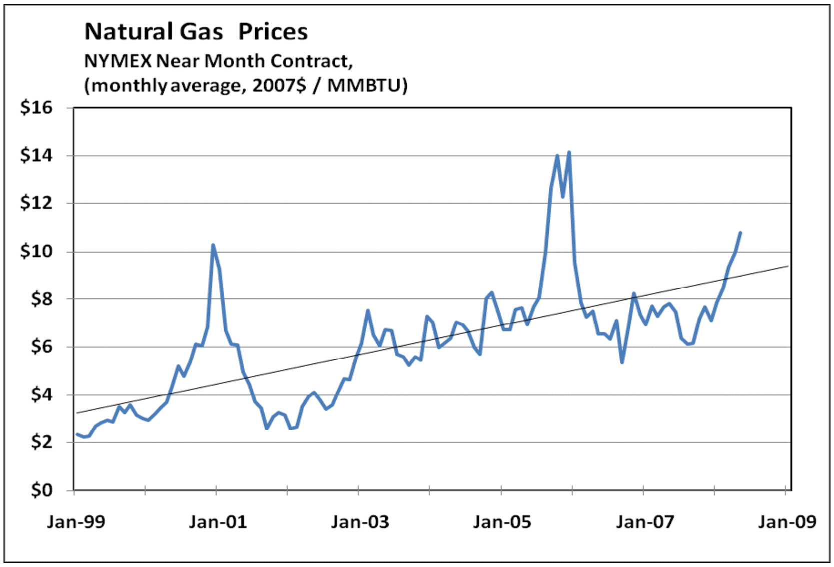
The projected cost of natural gas is the primary model input that determines whether or not measures undertaken to reduce combustion of natural gas and associated carbon emissions are ”cost effective.” If projected gas prices are unrealistically low, measures to replace gas-fired power with non-fossil generation will wrongly be seen as too expensive and “not cost effective.” CEERT, therefore, urges the Commissions to carefully consider appropriate gas price forecasts for use with the E3 model in developing its recommendations to ARB.

The future price of natural gas is, of course, unknowable. The Commissions must necessarily rely on theoretical price forecasts as inputs to the E3 model. Unfortunately, the gas price forecasts made in recent years using conventional theories have had a terrible track record. Gas price forecasts made in the last decade or so by the US Energy Information Administration, the California Energy Commission, and the CPUC's market price referent methodology bear no resemblance to actual market prices.

The bases for natural gas prices in the US are the prices established in the market operated by the New York Mercantile Exchange (NYMEX). Figure 1 below shows the average price for the NYMEX near month gas contract, adjusted for inflation, since January 1999. The linear trend in these data is shown by the straight line. The spike in the winter of 2000-2001 was associated with low levels of gas in storage, and the spike in the fall and winter of 2005-2006 was associated with the hurricanes in the Gulf of Mexico. The current rapid rise in gas prices is associated with the increase in crude oil prices which now exceed $130 per barrel (more than $20 per million British Thermal Units.)

The important feature shown in Figure 1 is that average US natural gas prices have tripled in the last decade. CEERT believes that it would be unconscionable for the Commissions to ignore this fact when developing the scenarios on which it bases recommendations for ARB.

FIGURE 1: Natural Gas Prices



In contrast to the inexorable increase in gas prices over the last decade shown in Figure 1, conventional forecasts routinely predict that gas prices will be *lower* in the future than prices at the time the forecast was made. CEERT believes these erroneous results are based on a misunderstanding of a common feature of commodity markets known as "backwardation." Whatever the justification for conventional forecasting methodology, however, the Commissions must admit that these forecasts failed completely to anticipate the spectacular increase in gas prices that has occurred.

As a result of reliance on conventional gas price forecasts, investment decisions made in recent years have increased the use of gas for electricity generation, needlessly exposing consumers to significantly higher prices. Continued reliance on conventional forecasts as the basis of recommendations to ARB would be equally misguided and would undermine the implementation of AB 32.

CEERT does not expect the Commissions to abandon completely the use of conventional gas price forecasts as inputs to scenarios developed by the E3 model. However, prudency requires that the Commissions also give serious consideration to the likelihood that gas prices may continue to increase between now and the year 2020 as they have in the past. If the trend shown in Figure 1 were to continue, gas prices, when adjusted for inflation, would be approximately $17/MMBTU by the end of the year 2020, nearly double the prices projected by conventional methodologies. Gas prices approaching the $20/MMBTU (in 2007dollars) a decade or so hence are not at all far-fetched; gas is trading today above $11 in 2007 dollars.

In CEERT's opinion, recommendations from the Commissions to ARB based solely on conventional gas price forecasting methodology—the MPR methodology, for example—would be a serious mistake. The Commissions cannot ignore actual gas price history and the fact that conventional forecasting methodology has failed to anticipate market behavior.

CEERT urges the Commissions to also consider scenarios based on projections of historical gas prices as shown in Figure 1 and to formulate alternative recommendations based on these projections. The decisions to be made by ARB are simply too important to be made without a thorough and open discussion of the gas price forecasting problem and the influence this crucial input has on the E3 model results.

3. Technology Cost Assumptions

Technology cost assumptions used in scenarios should be those accepted by stakeholders involved in the Renewable Energy Transmission Initiative (RETI) process.[13] The figures have been prepared by the renewable industry, utilities, environmentalists, and other stakeholders in a transparent process and are the most accepted representation of current renewable technology costs. The RETI process is widely considered to be the most authoritative venue for developing recommendations for transmission needed to access renewable energy resources, and scenarios

[13] Renewable Energy Transmission Initiative (RETI), Phase 1A Final Report (May 17, 2008).

developed in this proceeding should use the same input assumptions as RETI. The model could also be improved by using current costs for CHP and fuel cell resources.

4. CEERT Position on Usefulness and Application of the E3 Model

The E3 calculator is ultimately not the only tool that the Commissions should rely upon, for a number of reasons:

1. The model should not be used alone to determine the amount of preferred resources that will be selected to achieve GHG targets for any LSE. Actual, actionable resource plans are a far better starting point for such determinations.
2. The forecasts of future costs are highly uncertain, especially in energy industries. The price of natural gas 13 years hence should be considered equally uncertain, as should the cost of GHG allowances. Long-term contracts for electricity from renewable energy resources are highly predictable, unlike the price of electricity from fossil fuels, because they do not depend on or require procurement of fossil fuels. The price risk of electricity from fossil fuels must be considered as a major factor when comparing the cost of various policy cases.
3. Resource costs for preferred resources will change significantly over time. The model, should the CPUC and ARB decide to continue using this tool, should be updated periodically with changes in technology costs.
4. Preferred resources achieve many other public policy goals besides just greenhouse gas emissions reductions.

C. Results Reported by E3

At two recent workshops, E3 estimated that a GHG allowance price must be $150 per metric tonne to incent renewable development in the absence of a RPS. This price was described as applying to the delta between 20% and 33% renewables by 2020 and thus creates an expectation that costs will increase dramatically for renewables procurement above 20%. This price assumption, however, is far too high, especially given that similar estimations in other regions have estimated costs at about $50-$60 per ton. E3 should modify the calculator to reflect natural gas and intermittent renewable integration costs assumptions, as recommended in these comments. Doing so will lower this critical price assumption.

In this regard, CEERT offers the following analysis and recommendations regarding E3's underlying assumptions in general:

1. E3's comparison between 20% and 33% renewables is described as resulting from the addition of $60 per tonne to incent natural gas generation over coal generation and $90 per tonne to incent renewable generation over natural gas generation. These price assumptions, and the ultimate comparison, are not reflective of reality. California LSEs are prohibited from signing or renewing coal contracts for longer than 5 years in duration as a result of SB 1368. Further, given the expectation of future GHG regulation throughout the Western U.S. and, ultimately, on a federal basis, it is unlikely that LSEs would assume the CO2 liability of a long-term new coal contract, even without SB 1368.

2. This comparison appears to assume that all resource decisions would be made on the short-term spot market; they will not. The price per tonne of CO2 should and will not ultimately change resource decisions in the immediate term. Reliance on what may be a short-term price signal is not sufficient to spur years-long and necessary planning and transmission and resource development process.

3. Electricity resource development and procurement is changing across the entire country. Renewable procurement is happening now and will likely continue to happen due to CO2e and natural gas price risk, irrespective of the current price per tonne of CO2e.

4. A combination of supportive policy tools, removal of barriers to preferred resources, and long-term integrated resource plans and procurement based on

continually reducing GHG emissions are far superior to market forces. Further, CEERT estimates that, if and when a CO2e price gets to $150/tonne, either (a) program failure will likely already have occurred or will be likely to occur or (b) a scarcity of allowances will exist in the market, meaning that, years into the program, the costs of renewable energy and the fundamental basis of electricity procurement may have changed so significantly as to make CO2e price irrelevant to resource decisions.

VII.
CONCLUSION

In conclusion, CEERT summarizes the recommendations in these opening comments in the following list:

- The three most important items that the Commissions must include in their recommendations to the ARB are:

  1) Identification of levels of each preferred resource – energy efficiency, renewable energy, CHP and solar PV - that the electricity sector should be required to procure by 2020. A portion of the GHG emissions reduction responsibility for entities in the electricity sector should be reserved for these determined levels of preferred resources.
  2) Identification of barriers that must be removed to achieve the determined level of each preferred resource. The IEPR, ETAAC Report and Attachment A to the November 9 ALJs' Ruling in this proceeding provide a good starting place for this undertaking.
  3) Identification of a plan of action, with deadlines, for removing those barriers and making any other policy changes necessary to achieve the determined levels of preferred resources.

- Any tradable units of greenhouse gas emissions, including offsets, must be verifiable, enforceable and additional, and meet the requirements of those portions of AB 32 quoted above from Health and Safety Code §§38561(b) and 38570(b).

- Penalties should be levied on those entities that fail to meet their compliance obligation in an amount greater than the market price per ton of CO2e.

- For CHP systems, any form of GHG regulation should consider the full efficiency and GHG emissions benefits of *both* thermal and electrical functions of the unit, as well as criteria pollutant benefits, when comparing these systems to conventional, central station power plants.

- Thirty-three percent (33%) renewables procurement by 2020 must be an integral part of the electricity sector's responsibility for reducing GHG emissions.

Specific to the E3 Calculator, CEERT summarizes its recommendations as follows:

- Estimates of wind integration costs must be replaced with those of the Intermittency Analysis Project (IAP).

- Renewable technology cost assumptions used in the model should be those accepted by stakeholders involved in the Renewable Energy Transmission Initiative (RETI) process.

- The Commissions should consider the likelihood that natural gas prices may continue to increase between now and the year 2020 as they have in the past. The Commissions should include scenarios based on projections of historical gas prices as shown in Figure 1 in these comments and should formulate recommendations based on these projections.

- In general, the price per tonne CO2e will not be the most important factor in long-term resource decisions, and should not be relied upon by policymakers and load-serving entities.

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June 2, 2008

CERTIFICATE OF SERVICE

I, Sara Steck Myers, am over the age of 18 years and employed in the City and County of San Francisco. My business address is 122 - 28th Avenue, San Francisco, California 94121.

On June 2, 2008, I served the within document **OPENING COMMENTS OF THE CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES** in R.06-04-009, with electronic service, as prescribed by the Commission's Rules of Practice and Procedure and the ALJs' Ruling of May 20, 2008, on the service list in R.06-04-009 and on the California Energy Commission's (CEC's) Docket Office and designated personnel in CEC Docket No. 07-OIIP-01, with separate, additional service of hard copies by U.S. Mail to Assigned Commissioner Peevey and Assigned ALJs Lakritz and TerKeurst and the CEC Docket Office, at San Francisco, California.

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

/s/ SARA STECK MYERS
Sara Steck Myers