Union of Concerned Scientists
Citizens and Scientists for Environmental Solutions

Green Power Institute

January 4, 2010

Mr. Gary Collord
Energy Section, Stationary Source Division
California Air Resources Board

Submitted via email to gcollord@arb.ca.gov

Subject: UCS and GPI comments on ARB'S proposed technical, economic, and environmental analyses for the 33% Renewable Electricity Standard.

Dear Mr. Collord:

The Union of Concerned Scientists (UCS) and the Green Power Institute (GPI) appreciate the opportunity to provide feedback on the Air Resources Board (ARB) *Proposed Technical Feasibility Analysis for the Renewable Electricity Standard* (technical analysis) and *Proposed Economic Analysis for the Renewable Electricity Standard* (economic analysis). While these comments are focused on ARB's technical analysis, many of the comments pertaining to expected costs to achieve a 33% Renewable Electricity Standard (RES) and the limitations of the analyses conducted by the California Public Utilities Commission (CPUC), the Renewable Energy Transmission Initiative (RETI), and the California Independent System Operator (ISO) are also relevant for the ARB's economic and environmental analyses.

Plausible Compliance Scenarios

The ARB plans to analyze the technical feasibility of achieving a 33% RES by 2020 in part, by using the scenarios developed in RETI and by the CPUC for the *33% RPS Implementation Analysis* (CPUC analysis) in proceeding R.08-02-007.[1] UCS and GPI have actively participated in the CPUC 33% analysis proceeding and have attached the comments previously submitted to the CPUC for ARB staff reference. In addition, Gregg Morris, on behalf of GPI, is an active member of the RETI stakeholder steering committee.

UCS and GPI believe some of the assumptions made in the RETI and CPUC analyses overstate the cost and timeline implications of achieving 33% renewables by 2020. For instance, the RETI effort performed cost estimates for one future 33% renewables scenario. RETI did not construct a "business-as-usual" reference case in order to compare the results of the 33% renewables scenario. RETI itself makes it clear that the costs estimated for the implementation of the 33% renewables scenario are not all attributable to renewables. It is important that the ARB technical and economic analyses recognize this fact. A "business-

[1] *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results*, California Public Utilities Commission, June 2009, available at: http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf

as-usual" scenario would require generation and transmission investment that were not investigated in RETI. Moreover, much of the transmission investments identified in RETI can be considered "no-regrets" investments that the state will need whether or not it moves forward to develop 33% renewables by 2020. The RETI Phase 2A Executive Summary states, on page 1-2:

> The Phase 2A conceptual transmission plan is designed to facilitate meeting the goal of obtaining 33% of the state's electricity from renewables by 2020. But large investments in transmission infrastructure will be needed between now and 2020, regardless of state energy-supply mix. Many elements of the RETI conceptual transmission plan would likely be required under non-renewables-based planning scenarios. The estimate of the aggregate cost of the conceptual transmission plan presented in this report thus cannot be attributed only to the state's renewable-energy programs.[2]

Unfortunately, in the collective push to implement the state's aggressive renewable policy goals, the RETI data have at times been interpreted to be the marginal cost of implementing a 33% RES. In fact, this misapplication of the data grossly overestimates the cost of implementing a high-renewables future, compared with the cost of any other future scenario, such as a "business-as-usual" scenario.

The study plan for ARB's economic analysis, as presented at the December 14, 2009, ARB workshop, proposes to take the output of the E3 Calculator used in the CPUC's 33% analysis and feed it into statewide economic models that will be used for estimating job impacts and other macro-economic indicators. The same caveat should be applied to this application of the data as is discussed above. The E3 calculator constructs detailed and complete build-outs for the renewables side of their scenarios, but much less detailed and complete build-outs for the fossil side of the supply mix. As a result, any macroeconomic indicators that are calculated using data produce by the E3 calculator should not be attributed specifically to the implementation of a high-renewables energy policy in California, or the price of renewables so determined will be grossly inflated.

The CPUC 33% analysis compiled four distinctly different compliance scenarios and calculated relative costs; an analysis of timelines and barriers to achieving 33% renewable by 2020 was additionally conducted for the scenario that most closely represented the types of contracts the investor-owned utilities (IOUs) have signed to meet current RPS obligations. None of these scenarios were intended to represent the most likely or least expensive way to achieve 33% by 2020.

For example, the CPUC analysis did not assume that any portion of a regulated load-serving entity's (LSE's) renewable energy procurement obligation could be satisfied with unbundled renewable energy credits (unbundled RECs), which are renewable energy contracts that fail to meet the state's definition of delivered renewable energy. Assuming

[2] Available at: http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F-REV2.PDF

some use of unbundled RECs would increase the supply of compliance options and lower compliance costs. In its *Proposed Concept Outline for the Renewable Electricity Standard*, the ARB offers that LSEs could satisfy some portion of their RES compliance obligation with unbundled RECs. Since unbundled REC contracts that originate from out-of-state generation fail to displace in-state fossil resources, hedge ratepayers against natural gas price fluctuations, or provide clean-tech jobs inside California, UCS and GPI believe the ARB should limit unbundled REC transactions to no more than 20 to 30% of an LSE's RES compliance obligation, an amount that is roughly comparable to the amount of electricity that the state imports. The ARB technical analysis should analyze the use of unbundled REC contracts, but assume a limited role to ensure the RES program achieves the additional benefits of delivering renewable energy directly into the California grid.

In addition, it is important to note that both the CPUC and RETI analysis assumed no declining capital costs for renewable technologies over time. Although a certain level of uncertainty exists over the future costs of all electricity generation, UCS and GPI believe it is highly likely that solar technology costs will decrease relative to conventional generation costs over time as the market for solar continues to expand. The recent decline in prices for solar PV modules is evidence to this trend. [3] Therefore, ARB's analyses should assume that the costs of maturing and evolving technologies such as solar PV and solar thermal will decline relative to the cost of conventional technologies over time.

<u>Site and Resource Availability</u>

UCS and GPI agree that ARB should incorporate data from the RETI and the CPUC analyses to determine site and resource availability, however the ARB should consider that the assumptions made in these two analyses may have underrepresented the amount of renewable energy projects that could be built to satisfy a 33% RES. For instance, RETI focused on where to build new transmission trunk lines and therefore did not focus on renewable energy projects that could be built using existing transmission infrastructure. As a result, the RETI effort was focused on resources that occur in resource-rich regions, such as wind, solar, and geothermal, and only peripherally dealt with naturally dispersed or distributed resources, such as PV, biomass, and biogas, and even some wind, solar and geothermal resources. Distributed generation (DG) projects that can connect to the grid at the distribution level are not dependent on building new transmission lines and can facilitate implementation and reduce costs of the 33% RES. Since the exclusive use of RETI data underestimates the potential benefits from distributed renewables of all varieties, the CARB analysis should take this into account in applying information produced by RETI.

Although the CPUC analysis modeled four distinctly different procurement paths to achieve 33%, the *Barriers and Timelines* section only looked at the 33% reference case, which constructed a compliance scenario based on the trend of contracts signed to meet current RPS obligations. This portfolio is heavily dependent on new central station solar thermal projects, most of which will require new transmission. The recent decline in PV prices, the

[3] *See*: J. Bartlett, R. Margolis, and C. Jennings, *The Effects of the Financial Crisis on Solar Photovoltaics, An Analysis of Changes in Market Forecasts from 2008 to 2009*, National Renewable Energy Laboratory, September 2009, available at: http://www.nrel.gov/docs/fy10osti/46713.pdf

new feed-in tariff created with SB 32, and the utility-scale solar PV programs, which aim to install 1 GW of wholesale solar PV generation between two IOUs, may stimulate the PV market in California. Although utility-scale PV installations can occur in remote areas and require new transmission, wholesale PV generation can also be installed at the distribution level where additional transmission capacity is not needed. The CPUC has started a new proceeding which will construct a timeline and barriers analysis for the high distributed generation or "high DG" scenario analyzed in its 33% RPS analysis. [4] The ARB technical analysis should incorporate the findings of the CPUC "high DG" timelines analysis and consider how recent policies to encourage more wholesale PV generation at the distribution level could enhance the opportunities to reach a 33% RES in a timely and cost-effective manner.

The ARB technical analysis should also incorporate the results of the Programmatic Environmental Impact Statement (PEIS) which is currently being developed by agencies within the Department of Interior and the Department of Energy, to evaluate utility-scale solar energy development on federal lands.[5]

Transmission Access and Grid Improvement Needs:

As stated above, the ARB technical analysis should assess the role renewable DG resources can play in meeting a 33% RES, since these facilities would not be dependent on the construction of new transmission. It was not within the scope of RETI to identify the existing congestion within the distribution system, so RETI analyses were unable to provide answers on where new DG would be the most valuable.

The RETI analyses was based strictly on existing technologies and does not take into account some of the likely technological innovations that will ease renewable integration and grid management in the next decade. These innovations include not only improvements in renewable generating technologies, but also in a diverse set of new transmission and distribution technologies, including storage and electric and plug-in hybrid vehicles which can be broadly categorized as smart grid. While it is impossible to predict the future of technological innovation for analytical purposes, assuming only the use of existing technology is guaranteed to overestimate the future cost of implementing a 33% RES infrastructure for California. The CPUC RPS analysis also shares this limitation in assuming that only currently commercial technology is deployed. The ARB technical analysis should address the value that storage and other smart grid innovations will contribute to grid management and renewable energy integration in the next decade.

Finally, when assessing the impacts of unbundled RECs on grid reliability, the ARB should consider how California's long-term reliance on out-of-state RECs could be tenuous once RES obligations for other states within the WECC begin to grow. ARB's environmental analysis should also address how heavy reliance on unbundled out-of-state RECs may cause less fossil displacement and therefore less reduction in criteria air pollutants.

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[4] More information on the Renewable Distributed Energy Collaborative can be found here: http://www.cpuc.ca.gov/PUC/energy/Renewables/Re-DEC.htm

[5] More information on the solar PEIS can be found here: http://solareis.anl.gov/

Generating Facility and Transmission Permitting and Development

As the state works to reduce project and transmission permitting delays, it is reasonable to expect that future renewable energy and transmission project development will occur along faster timelines compared to historic trends. However, there is no question that permitting and siting renewable energy projects and transmission remain one of the major challenges to reaching a 33% RES by 2020. The ARB's technical analysis should examine how the state's new PV policies and declining prices for PV modules may allow LSEs to achieve a 33% RES with a higher percentage of projects that are not dependent on new transmission construction or receiving permits for large development sites.

In addition, ARB's analysis should incorporate the findings of the federal agency solar PEIS and the recently enhanced coordination between state agencies through participation of the Renewable Energy Action Team, and the development of a Desert Renewable Energy Conservation Plan.

Program Administration and Administrative Barriers

UCS and GPI agree with the ARB that the RES rule should be developed in a way that "utilizes, to the greatest extent practicable, the structures, policies and implementation mechanisms established by the CEC and PUC for the existing RPS program."[6] UCS and GPI believe the ARB technical analysis should assess whether certain deviations from current RPS law, including changes to the definition of eligible renewable resources or the way compliance is measured (currently it's a MWh standard; ARB is considering a GHG standard), would cause administrative delays and market uncertainty without significant compensating benefits.

Eligible Resources

UCS and GPI believe that given the environmental and market implications of expanding or modifying the definition of eligible renewable resources, as well as the tight timeline established in Executive Order S-21-09, it is neither necessary nor appropriate for the ARB to change the existing definitions of eligible resources.[7] The recently enacted Assembly Bill 920 allows net-metered solar PV that is not used on-site to be sold to a utility and counted for RPS credit. UCS and GPI believe that because this surplus generation does not reduce a utility's load obligation, it should be treated like other forms of PV generation sold to utilities, and therefore eligible for credit under the RES.

Compliance Metrics

UCS and GPI believe assigning a greenhouse gas (GHG) reduction value to each MWh of RES eligible generation may create technology winners and losers, which could introduce added uncertainly into the renewable energy financing market, and jeopardize project development and ongoing contract negotiations. In addition, UCS and GPI believe the process of assigning a GHG reduction metric will be an administrative burden for ARB staff

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[6] *Proposed Concept Outline for the Renewable Electricity Standard*, California Air Resources Board, October 2009, p. 1, available at: http://www.arb.ca.gov/energy/res/meetings/103009/resconceptoutline.pdf

[7] Executive Order S-21-09 directs the ARB to establish a 33 percent renewables by 2020 standard by July 31, 2010.

that will introduce avoidable controversy and delay to the rulemaking process. The ARB technical analysis should assess whether assigning a GHG reduction metric would skew renewable procurement towards certain RES-eligible technologies, and whether such shifts could threaten resource diversity.

Purchase and Use of RECs

The ARB's technical analysis should consider the long-term sustainability of designing California's RES program to rely heavily on the purchase of out-of-state, unbundled RECs. Specifically, the ARB should analyze whether out-of-state REC contract providers will be willing to sign long-term contracts, or simply short term deals while they wait for RES programs within their own states to ramp up. A program that relies too heavily on short-term out-of-state REC contracts may shift focus away from making important decisions about permitting in-state renewable energy projects and building new transmission, which are issues the state needs to resolve in order to meet its long-term renewable energy goals.

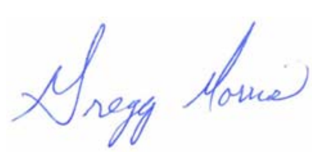
The ARB should also analyze the implications of a parallel federal RES program, where one state and one federal REC is issued for every MWh of renewable energy generated. If both a state and federal REC are not retired simultaneously, states like California which have higher state RES obligations than the federal RES obligation, will be left with surplus federal RECs which could be sold to other states. Unless a federal REC is retired each time a state REC is retired, states with weaker renewable energy standards will benefit from California renewable energy generation that has already been accounted for through the state's compliance program.

RES Applicability

Although UCS and GPI believe it is reasonable to provide additional RES compliance flexibility to certain LSEs with exceptionally small loads or unique resource bases, UCS and GPI see no reason to completely exempt any regulated utility with fossil resources in its load profile, especially coal, from achieving the state's renewable energy goals. Instead, UCS and GPI suggest that ARB establish a threshold below which LSEs are given extra compliance flexibility, such as allowing several regulated entities to pool renewable energy procurement obligations or allowing these entities to purchase a larger amount of unbundled REC contracts to satisfy RES compliance obligations.

Thank you for the opportunity to provide these comments. If you have any questions, please contact Laura Wisland at lwisland@ucsusa.org or Gregg Morris at gmorris@emf.net.

Sincerely,



Laura Wisland, Clean Energy Analyst
Union of Concerned Scientists

Gregg Morris, Director
The Green Power Institute

Attachment 1

UCS Comments on Energy Division's 33% RPS Implementation Analysis Preliminary Report

R.08-02-007

August 26, 2009

The Union of Concerned Scientists ("UCS") appreciates the opportunity to provide feedback on the California Public Utilities Commission's ("CPUC") 33% RPS Implementation Analysis Preliminary Report ("33% RPS Implementation Analysis"). In addition to the specific comments below on the inputs, assumptions, and methodologies used in the RPS Calculator, UCS has completed the list of technical questions provided by Energy Division staff.

In general, UCS is concerned that 33% RPS Implementation Analysis concludes that achieving a renewable energy level penetration of 33 percent by 2020 is "highly ambitious" without recommending policy and process reforms to energy procurement, as well as transmission and power plant permitting, that could greatly improve the chances of meeting California's stated renewable energy goal. Moreover, the release of the preliminary report several weeks before the release of supporting inputs and assumptions has made it extremely difficult for UCS and no doubt other stakeholders to explain the analyses behind the report's conclusions, as well as highlight any concerns regarding assumptions to offer alternative interpretations.

The 33% RPS Implementation Analysis analyzes the relative costs of four 33 percent renewable energy scenarios, none of which are intended to represent the most likely or least-expensive way of achieving a particular 33 percent RPS by 2020 target. UCS is concerned, however, that the report has overestimated the costs of reaching 33 percent renewables, and that the report's "33% Reference Case" scenario has been misinterpreted as an estimate of the *likely* cost of achieving a 33 percent RPS. UCS cautions against calling any 33 percent scenario a "reference case" which could make it appear to be the most likely case. The term "reference case" should be eliminated and each scenario should have a name that describes the assumptions that define it. For example, the current "33% Reference Case" should be renamed something like "33% RPS, delivered only, current-pipeline preferred," to reflect the fact that it only allows delivered resources to be developed, and that it forces construction of all projects in currently listed in the CPUC database.

UCS is especially concerned that E3's model did not assume any RPS compliance using renewable energy credits (RECs) that do not meet the current "delivery" definition within California Public Resources Code 25741 (aka "undelivered RECs"). UCS believes that it is reasonable to assume some portion of future RPS compliance will be met with undelivered RECs and offers 20 percent undelivered RECs as a conservative assumption.

While UCS recognizes that some uncertainty around cost and procurement strategies exist, ultra-conservative assumptions introduce a significant bias against renewables. In order to obtain the best possible comparison between scenarios, this process should try to use the *most likely* estimates of the costs and constraints facing renewables, rather than worst-case or best-case assumptions. In a number of places UCS recommends mainstream, well-documented assumptions, to replace the more conservative assumptions currently used in the RPS Calculator.

Specific recommendations are provided in the individual sections below.

RPS Calculator

Capital Costs of Transmission Lines

The "Inputs and Assumptions" report states that the "transmission costing model [used for this analysis] was the same as that used for the GHG Calculator."[8] However, the transmission costs used for non-RETI (i.e., non-California) zones in the 33 percent RPS analysis are actually about twice as high as those shown in the GHG Calculator's transmission workbook.[9] This is partly explained by the fact that the 33 percent RPS analysis assumes that AC lines will be used, instead of the less expensive DC lines assumed in the GHG Calculator transmission workbook. However, E3 does not explain why they changed this assumption. Further, the transmission costs used in the 33% RPS analysis are significantly higher than those shown for AC lines in the GHG Calculator transmission workbook (see table below).

For non-California zones, UCS recommends that the 33 percent RPS analysis use the costs for DC lines shown in the GHG Calculator transmission workbook[9] (column 1 below). If there is a strong reason to prefer AC lines for the 33% RPS analysis, then we

[8] Inputs and Assumptions white paper, p. 10.
[9] http://www.ethree.com/GHG/Transmission_Line_Cost_2007-11-16.xls

recommend using the costs for AC lines shown in the transmission workbook (column 2 below).

Table 1. Cost of 3000 MW transmission line from each CREZ, in GHG Calculator Transmission Workbook and RPS Calculator

	GHG Calculator Transmission Workbook[9]		**RPS Calculator**
	DC	**AC**	**AC**
Alberta	$3,611	$5,976	$7,998
Arizona-Southern Nevada	$1,503	$1,833	$2,840
British Columbia	$3,019	$4,767	$5,100
Colorado	$2,959	$4,706	$5,250
Montana	$2,615	$4,040	$6,090
New Mexico	$2,228	$3,278	$4,522
South Central Nevada	$1,503	$1,833	$1,905
Northwest	$2,212	$3,166	$4,467
Utah-Southern Idaho	$2,006	$2,844	$4,052
Wyoming	$2,701	$4,196	$5,796

Ancillary Benefits of Renewable Collector Transmission Lines

The RETI Phase 2A final report notes that "transmission lines approved for the primary purpose of delivering renewable generation to the grid will provide other benefits to consumers such as increased reliability, decreased congestion, and greater system efficiency" and that because of this, "the cost of those Collector lines which provide interstate transfer capacity, should not be attributed solely or primarily to renewable energy development."[10]

Based on this view, UCS recommends that the cost of transmission lines to out-of-state CREZs be partly prorated to reflect these ancillary benefits.

One way to do this would be to use a simple rule of thumb, e.g., counting only 80% of the cost of these lines (we cannot recommend a specific value without further analysis). Another option would be to assume that these lines can deliver some additional energy and peak-serving capacity from non-renewable out-of-state sources, reducing the need to build CCGTs and CTs in California to provide this service (on the "Cost Impacts" worksheet of the RPS Calculator).

[10] http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F.PDF, p. 1.21

Transmission Costs and Sizing Assumptions

The RPS Calculator assumes in most scenarios, that no transmission can be built to out-of-state zones. In addition, transmission capacity is capped at 3,000 MW or less[11]. Because of these limits, the proposed portfolios exclude some inexpensive CREZs and use only part of the resources in others, while going on to develop higher-cost resources elsewhere.

UCS recommends that the RPS Calculator allow transmission to be built to all cost-effective zones in all scenarios except those where constraints on transmission construction are explicitly being considered. We also recommend that the RPS Calculator include more potential transmission configurations for each CREZ, allowing transmission lines of 6,000 MW or more to be built to lower-cost, large-resource CREZs. Finally, we recommend that for each scenario, an effort is made to identify the optimal size of transmission line to each available CREZ, except in cases where lower limits on the size of transmission lines are being studied.

If the 3,000 MW limit is intended to ensure that renewable power development is spread more widely, that goal should be described and justified, and the model should achieve it by a more direct means.

The exact amount of transmission to each CREZ could be selected via trial and error, or via an optimizing approach. Near-optimal transmission capacities for each scenario could be found by using a macro that does the following: (1) reset the transmission capacity for each zone to 0 MW; (2) test the marginal cost per MWh of renewable power for each zone, if that zone's transmission capacity were increased to the next larger configuration; (3) increase transmission capacity to the CREZ with the lowest marginal power cost. Steps (2) and (3) would be repeated until enough transmission is built to satisfy the active RPS. Then all remaining 0 MW zones would be set to the smallest allowed transmission configuration. UCS is happy to provide an example workbook that performs these steps if that would be helpful.

Expansion of Path 15

The RPS Calculator assumes that the state must build enough south-to-north transmission capability along Path 15 to allow Northern California to use 43 percent of the total nameplate

[11] Inputs and Assumptions white paper, p. 10.

capacity of renewable power in the state, while Southern California simultaneously uses 57 percent. These ratios are based on the ratio between peak loads in the state. UCS identifies several problems with this assumption and recommends solutions for each.

(1) This assumption is a crude approximation of the dynamic flow of power in the state – it is quite possible that during hours of peak electricity demand due to higher solar concentration, Southern California will receive a greater share of its power from renewables than Northern California does. An hourly analysis of power flow in the state would be a more effective way to assess the need for transmission expansion.

UCS recommends that the "33% Reference Case" (or renamed equivalent) assumes no upgrades are needed to Path 15, and that this assumption be re-examined after the California Independent System Operator (CAISO) releases is 33% RPS Integration Analysis, preferably using hourly modeling.

(2) Even if it is assumed that both parts of the state must obtain an equal share of their peak demand from renewable power, the calculation described above should be based on the "reliable capacity" from each project, rather than the full nameplate capacity. It is unlikely that all renewable projects in the state would ever produce power at their full nameplate capacity simultaneously. Elsewhere in the RPS Calculator, it is assumed that renewable power projects produce an amount of power equal to their reliable capacity during the system peak hour.

UCS recommends the RPS Calculator's Path 15 analysis assume renewable power generation based on reliable capacity during system peak hours.

(3) According to the WECC Path Rating Catalog, Path 15 tends to be congested with several thousand megawatts of *north-to-south* flow during summer peak hours. Consequently, new power projects in the southern part of the state would first need to reverse this large north-to-south flow before they could begin to load the line in a south-to-north direction.

If the RPS Calculator's Path 15 analysis is retained, UCS recommends the existing north-to-south flow should be included as an offsetting term in the calculation of on-peak transfer limits.

(4) The RPS Calculator uses a transfer limit of 2000 MW for Path 15. However, this is the limit for *north-to-south* flow.

If the RPS Calculator's Path 15 analysis is retained, UCS recommends the Path Rating Catalog's limit for *south-to-north* flow be used, which is 4800-5400 MW.

Projects in CPUC Energy Division Database

UCS believes the RPS Calculator can answer three important questions pertaining to the IOU renewable energy projects listed in the CPUC Energy Division's database: (1) How much will an RPS scenario cost if the sunk costs of these projects are correctly accounted for? (2) How would the cost of the RPS scenario change if most or all of the projects in the CPUC database are developed? (3) Which types of projects in the CPUC database would not be included in a "least-cost" approach to the RPS, and why?

The modeling assumptions and techniques in the current version of the RPS Calculator are not specific enough to answer these questions. UCS recommends several changes to the techniques used to incorporate these projects into the RPS portfolio. These changes help separate accounting questions ("What are the sunk costs of projects in the CPUC database?") from policy questions ("How do costs change if we assume the projects in the CPUC database are developed instead of the least expensive projects on the supply curve?"), and make it easier to explicitly compare different treatments of projects in the CPUC database ("Have IOUs chosen the least expensive projects?").

Credit for Sunk Costs of Renewable Projects in CPUC ED database: When ranking CREZs, the RPS Calculator applies a credit that zeros out the cost of any projects in that CREZ that appear in the CPUC ED database and are deemed likely to be completed.[12] This is meant to account for the "sunk" costs of projects, making these zones more likely to be developed. This credit causes the RPS Calculator to strongly prefer zones that have large numbers of projects in the CPUC ED database. However this credit appears to overstate the sunk costs and inaccurately reflect the type of benefit that would be achieved by developing these zones.

To be more specific, if transmission is not built to a CREZ where many projects are already far along in the planning process, and is instead built to a new zone with little previous interest, there will be two types of loss. The first loss will be the costs already spent on planning renewable energy projects in the first zone, which will need to be paid again if transmission is built to a new zone instead. These costs are likely to be much lower than the credit given in the RPS Calculator, which is 100 percent of project costs. The second loss will be the time already

[12] Ranking & Selection white paper, p. 11.

spent on planning and approving projects in the first zone, which will need to be added to the RPS development timeline if transmission is built to a new zone instead.

UCS recommends a more accurate estimate be developed of the true sunk costs of projects in the CPUC ED database. One possibility would be to develop a generic estimate of the dollars-per-project or dollars-per-kilowatt already invested in projects of each type (solar thermal, wind, etc.) that have reached each step of the CPUC's pipeline (shortlisted, approved, etc.). These estimates could then be prorated based on the perceived risk of each type of project (e.g., high-risk projects are less likely to be completed, so there is less chance that their planning effort will be recouped, so the credit for their sunk costs should be prorated downward). The final results can be aggregated to produce a dollars-per-kilowatt credit for sunk costs for each type of resource in each CREZ. If this type of calculation is too onerous, an alternative would be just to apply a greatly reduced version of the current sunk-costs credit, perhaps equal to 5-10% of project costs. (In either case, we recommend that the sunk-costs credit be calculated per-resource, per-CREZ, instead of only per-CREZ, so that it can be applied on a more granular basis, e.g., if CPUC wind projects but not CPUC solar projects are developed in a single CREZ.)

UCS also recommends that the effect on the RPS timeline from using or abandoning CPUC database projects be investigated separately, by comparing separate scenarios that explicitly force or do not force the inclusion of projects in the CPUC database. This issue is discussed further below.

There two additional problems with the way the "sunk costs" credit is currently applied in the RPS Calculator:

(1) The "sunk costs" credit is applied in the ranking process for selecting CREZs to develop but not in the final evaluation of the cost of the RPS. This embeds a sort of "bait-and-switch" in the process of selecting projects from the supply curve: projects are selected based on a sunk-costs credit (which is currently very high and exerts a strong influence), but the projects have much higher costs in the final evaluation, raising the cost of the RPS. This switch causes the RPS Calculator to select an overly expensive set of projects and CREZs, inflating the apparent cost of the RPS. It would be more appropriate to include an accurate credit for the sunk costs of projects in the CPUC pipeline, *and use this credit it in both the ranking and evaluation stages of the model*.

(2) The RPS Calculator currently applies a different sunk-costs credit for different policy scenarios, which does not reflect the reality that the sunk costs in each CREZ are the same, no matter what future policy is selected. In this case, the sunk-costs credit is being used in a fairly opaque way to try to investigate how costs will change if more or less preference is given to projects in the CPUC database. It would be better to address that question by adding a separate scenario which explicitly forces construction of these projects. The current arrangement can muddy the distinction between a 20% and 33% RPS. For instance, if the model is given the same choice of projects and transmission lines for both a 20% and 33% RPS, one would expect the CREZs developed in the 20% case to be identical to the top-priority ones from the 33% case. However, since the credit for sunk costs currently changes between these cases, the model actually ranks different CREZs at the top of its list in these two cases. This instability can be avoided by using the same sunk-costs credit in all policy scenarios.

UCS recommends that the RPS Calculator apply a more accurate credit for the sunk costs of projects in the CPUC ED database, and that the same credit be used in all scenarios, and in both the ranking and evaluation phases of the model. This will make the RPS Calculator more stable and transparent, and ensure that it accurately accounts for these sunk costs.

Wind and Photovoltaic Integration Costs

The RPS Calculator uses an integration cost of $7.50/MWh for ranking wind and photovoltaic projects, but in the final assessment phase, the integration costs are calculated as $4.09 to $4.27/MWh in the 33% Reference Case. This means that the ranking process incorrectly discriminates against wind and photovoltaic projects.

UCS recommends a tentative integration cost of around $4.25/MWh be used in the ranking process for wind and photovoltaic projects.

UCS also requests documentation of two minor questions about the integration cost calculation:

(1) The wind integration cost calculation includes an embedded assumption that wind or photovoltaic power make up 10% of the nameplate capacity in out-of-state regions that export wind power or PV electricity to California ('Cost Impacts'!AI297 and 'Cost Impacts'!AI307). This assumption should be documented, and possibly amended to more realistic values.

(2) The Resource Ranking and Selection white paper cites E3's GHG Calculator[13] as the source of a regression equation for the integration cost of wind power. The GHG Calculator documentation shows a wind integration cost of ($31.3/MWh)*wind_share, but the RPS Calculator uses $2.95/MWh + ($11.38/MWh)*wind_share ('General Inputs'!$C$42:$D$42). The source of the new equation should be documented.

Blanket Exclusions of non-California Wind Resources

E3 used an National Renewable Energy Laboratory (NREL) database to identify potential wind projects outside of California. However, they excluded 70-90% of the best wind sites from this database because they considered it "implausible" that only high-quality wind sites would be developed.[14] The small number of good projects remaining are then assigned for local use, which significantly raises the apparent cost of renewable power for California. If, as the NREL data indicate, there actually are a large number of high-quality wind projects available, then the natural conclusion should be that these *will* be developed first. The modeling effort should draw conclusions from the existing data rather than reshaping the data to match the modelers' preconceptions.

UCS recommends these blanket exclusions be dropped from the model, or justified by more specific land-use modeling.

Costs for Renewable Generation Projects

The Inputs and Assumptions report states that "E3 derives average cost and performance characteristics from the sites included in the RETI analysis, which provides site-specific cost information for sites within California."[15] However, the capital costs shown on the same page for wind ($2,491/kW) and solar thermal ($4,924/kW) are significantly higher than reported in RETI or in other cost assessments, and this difference is not explained. The operation and maintenance (O&M) costs in the RPS Calculator are also inconsistent with those in RETI or other published studies. We also note that the generator costs used in the RETI process tend to cover broad ranges, and are themselves poorly documented. On the other hand, the California Energy

[13] http://www.ethree.com/GHG/28%20Wind%20Integration%20Costs%20V2.doc
[14] Inputs and Assumptions white paper, p. 3
[15] Id. p.12.

Commission (CEC), as part of the 2007 IEPR process, has conducted a thorough, stakeholder-reviewed study of the cost of new central-station power plants in California.

UCS recommends that the RPS Calculator use the capital and O&M costs for renewable power plants shown in the "Comparative Costs of California Central Station Electricity Generation Technologies" (CEC COG) report prepared the CEC's 2007 IEPR.[16] For technologies not covered by the CEC COG report (e.g., for distributed PV systems), UCS recommends that the RPS Calculator use the midpoint of the cost range specified in the RETI Phase 1A Final Report.

Table 2 shows capital costs reported by a number of other published sources, as well as the capital costs that we recommend using for the 33% RPS assessment. Table 3 shows O&M costs from the same sources, and our recommendations. It should be noted that the costs shown in these tables are for *California* projects – where necessary we have converted national average costs to California costs, using multipliers given by E3 in the RPS Calculator workbook. For example, the 2008 Wind Technologies Market Report[17] from Lawrence Berkeley National Laboratory shows that the average capital cost of wind farms built in the U.S. in 2007-08 was $1850/kW. Applying E3's multiplier of 1.081 indicates that a project in California would be expected to cost around $2,000/kW, which is what we have shown in Table 2. The same LBNL report showed average O&M costs of $8/kW-year for wind projects completed after 2000 throughout the U.S.; we converted this to $9.04 in California using an O&M multiplier of 1.13. Conversely, the costs listed in Table 2 and Table 3 should be *divided* by these multiplier to obtain estimates of the *"U.S. average"* cost of wind projects for use in the RPS Calculator.

[16] http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF
[17] p. 34, http://eetd.lbl.gov/EA/emp/reports/2008-wind-technologies.pdf

Table 2. Comparison of capital cost of California renewable power projects, between RPS Calculator and other studies ($/kW, including AFUDC)

	Geothermal (binary)	Wind	Solar Thermal (trough)	Photovoltaic
US DOE Annual Energy Outlook 2009[18]	$2,180-$5,604	$1,782-$2,122	$3,851-$6,273	$4,131-$6,524
CEC Cost of Generation Study 2007[19]	$3,562	$2,000	$4,190	
RETI Phase 1A Final Report[20]	$3,000-$5,000	$1,900-$2,400	$3,800-$4,800	$6,500-$7,500
LBNL Wind Technology Report 2008[21]		$2,000		
Navigant, for AZ Dept. of Commerce[22]			$4,231-$5,949	$3,638-$9,923
RPS Calculator	$4,576	$2,491	$4,924	$7,065
UCS Recommendation[23]	**$3,562**	**$2,000**	**$4,190**	**$7,000**

As noted above, the CEC's Cost of Generation study has received stakeholder review, is focused specifically on the cost of developing generation capacity in California, and is more comprehensive and better documented than the RETI costs. The LBNL Wind Technologies Market Report from Lawrence Berkeley National Laboratory is the most comprehensive publicly available review of the costs of recently completed wind projects. The Navigant study for the Arizona Department of Commerce cited in Table 2 is based on industry interviews, uses similar methods to the CEC's Cost of Generation study, and is one of the few recent studies available of the cost of solar thermal projects. The U.S. Department of Energy's Annual Energy Outlook is one of the most widely used data sources for energy modeling in the U.S. As can be seen from Table 2, the costs currently used in the RPS Calculator are significantly above the typical range

[18] Costs ranges are for projects built between 2008 and 2030. Capital cost adjusted from national average to California level using E3's multiplier, then AFUDC applied using ratios from CEC COG study; http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf, p. 104
[19] http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF, p. 41
[20] http://www.energy.ca.gov/2008publications/RETI-1000-2008-002/RETI-1000-2008-002-F.PDF, ch. 5
[21] Capital cost adjusted for California, using E3 multiplier; http://eetd.lbl.gov/EA/emp/reports/2008-wind-technologies.pdf, p. 34
[22] Capital cost adjusted from Arizona to California using E3's multipliers, then construction interest applied using CEC COG ratios; 25% reduction applied to account for lack of storage; http://www.azcommerce.com/doclib/energy/az_solar_electric_roadmap_study_full_report.pdf, pp. 66-67, 84
[23] Values from CEC Cost of Generation study where available, otherwise midpoint of RETI range.

for most of these studies, biasing the model toward higher costs for renewable power. Using costs from the CEC Cost of Generation study will correct this bias.

Table 3. Comparison of O&M cost of California renewable power projects, between RPS Calculator and other studies ($/kW-year)

	Geo-thermal (binary)	Wind	Solar Thermal (trough)	Photo-voltaic
US DOE Annual Energy Outlook 2009[24]	$186	$34	$64	$13
CEC Cost of Generation Study 2007[25]	$160	$64	$87	
RETI Phase 1A Final Report	$209	$50	$66	$35
LBNL Wind Technology Report 2008[26]		$9-$49		
Navigant, for AZ Dept. of Commerce[27]			$41-$70	$13-$39
RPS Calculator	$0	$73	$81	$54
UCS Recommendation[28]	**$160**	**$64**	**$87**	**$35**

Inspecting Table 3, it is clear that the O&M costs currently used in the RPS Calculator are also biased somewhat above the values shown in other studies (except for the undocumented reduction of geothermal O&M to zero). Using the O&M estimates from the CEC Cost of Generation study will reduce this bias. (It should be noted that the published Cost of Generation report shows only *levelized* O&M costs, including the effect of inflation; actual year-by-year O&M costs can be obtained from the 2007 Cost of Generation workbook maintained by the CEC.)

Declining Capital Costs for Renewable Generation Technologies

There is a good chance that the cost of renewable power projects will decline in the future, as they have done historically. The cost of wind farms and photovoltaic modules has risen recently as a result of a weak dollar, manufacturing constraints (leading to increased profit

[24] p. 89, adjusted to Calif. level using E3's multiplier
[25] CEC Cost of Generation Model workbook, version 9.1/1-23-08, first-year O&M for Merchant Plant, including insurance, ad valorem, fixed and variable O&M (Income Statement, cell F22)
[26] p. 42; projects >20MW, cost adjusted to Calif. using E3 multiplier
[27] capital cost adjusted from Arizona to California using E3 multipliers
[28] Values from CEC Cost of Generation study where available, otherwise from RETI.

margins), and elevated commodity prices. However, each of these trends is self-limiting: manufacturing capacity is being added rapidly, potentially leading to sharp drops in prices as demand drops off this year; and the cost of commodities and foreign currencies cannot continue to rise indefinitely, unless the U.S. experiences years of macroeconomic decline, in which case fossil fuels will also grow more expensive. Meanwhile, experience with manufacturing and installing wind and solar power systems has continued to increase, which can only drive the underlying costs downward. More details on these trends are given in the attached memo[29], previously submitted as part of the CPUC's LTPP proceeding. However, we recognize that it is difficult to forecast how far or how soon capital costs for these technologies will begin to decline, so we accept E3's methodology of using constant costs for these technologies in the Reference Case, provided the costs are reasonably indicative of likely near-term costs.

UCS recommends the addition of a sensitivity case in which the cost of renewable technologies declines by 1-3%/year, reflecting the type of technological progress that has historically been seen in the industry.

Effect of RPS on Natural Gas Prices

Compared to the 20 percent RPS scenario, the all-gas scenario would significantly raise demand for natural gas in California. Because there is a limited supply of natural gas, both to California and nationwide, this would be expected to raise the price that Californians pay for natural gas, and in turn raise the cost of electricity produced from this fuel. Conversely, a higher RPS target of 33 percent would reduce California's demand for natural gas, reducing prices both in California and nationwide.

Economists at Lawrence Berkeley National Laboratory ("LBNL") recently reviewed a number of studies of the effect of reductions in national gas consumption on natural gas prices.[30,31] They found that each 1 percent reduction in national natural gas consumption would yield long-term reductions in national natural gas prices of 0.8–2 percent, with a typical value of

[29] M. Fripp and C. Chen, "Renewable Technology Cost Trends and Projections", Memorandum to Simon Baker, CPUC Energy Division, November 24, 2008, attached.

[30] Ryan Wiser and Mark Bolinger. "Can deployment of renewable energy put downward pressure on natural gas prices?" *Energy Policy.* Volume 35, Issue 1, January 2007, Pages 295-306. http://dx.doi.org/10.1016/j.enpol.2005.11.021 or http://repositories.cdlib.org/cgi/viewcontent.cgi?article=5782&context=lbnl

[31] Ryan Wiser, Mark Bolinger, Matt St. Clair. "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency." Report number LBNL-56756. Berkeley, CA: Lawrence Berkeley National Laboratory, January 2005, pp. 34-35. http://eetd.lbl.gov/ea/EMS/reports/56756.pdf

1.2 percent. Further, LBNL researchers found that there is a "regional multiplier" of about 3, so that the price of natural gas in California would be reduced by about 3.6 percent for each 1 percent reduction in national natural gas demand caused by reduced consumption in California. This multiplier would apply up until the time when new gas pipelines can be built in response to high prices.

Given these findings, it appears more likely that a strong RPS in California will reduce regional natural gas prices, rather than leaving them unchanged, as is currently assumed in the RPS Calculator. UCS recommends that this effect be modeled using the natural gas price elasticity and regional multiplier shown in the LBNL report cited above.

To be more specific, UCS recommends that the RPS Calculator calculate an adjusted natural gas price for each scenario, as follows:

$$\text{(gas price adjustment factor)} = \frac{\text{(active case Calif. gas consumption)} - \text{(base case Calif. gas consumption)}}{\text{(base case U.S. gas consumption)}} \times 1.2 \times 3$$

$$\text{(adjusted natural gas price)} = \text{(base case natural gas price)} \times [1 + \text{(gas price adjustment factor)}]$$

In the equations above, the "base case California gas consumption" could be the total amount of natural gas consumed in either the all-gas scenario or the 20% RPS scenario. UCS recommends using the 20 percent RPS scenario, since the current RPS requirement has already been factored into market perception of future natural gas prices. The "base case U.S. gas consumption" can be any credible estimate of nationwide natural gas consumption in 2020, e.g., the 22 quadrillion Btu forecast in the Energy Information Administration's Annual Energy Outlook 2009.[32] We have included the regional multiplier from the LBNL report in the recommended calculation, because it appears unlikely that high natural gas prices would induce the construction of new natural gas pipelines to California before 2020.

It should be noted that this calculation only includes the effect of gas demand reduction on the cost of California electricity. There will be additional benefits in the form of lower natural

[32] http://www.eia.doe.gov/oiaf/aeo/excel/aeotab_2.xls

gas prices for California's residential, commercial and industrial sectors, and for gas users in other parts of the country. Further, if other states follow California's lead on the RPS, California's natural gas prices will fall further. (For example, a report from the American Council for an Energy-Efficient Economy found that if energy efficiency and renewable energy were used to reduce nationwide natural gas consumption by 22 percent by 2020, natural gas prices would fall by about 29 percent.[33]) However, these effects may be difficult to model as part of the 33% RPS analysis, so we recommend the conservative approach outlined above, including only the direct effect on California's electricity costs.

Assignment of Renewable Resources to Local Use Before California Use

The RPS Calculator assigns the lowest-cost resources in each non-California zone to local (non-California) RPS requirements, and then makes the remaining resources available for use in California. No market or policy mechanism is suggested that could lead to this outcome. In reality, local power companies and California utilities will likely contract for renewable power projects simultaneously. It is difficult to forecast which states' companies are likely to sign these contracts first, but a more realistic assumption would be that the best projects will be split on a pro-rata basis between California and local demand.

UCS recommends that out-of-state renewable energy projects be divided between local and California demand on a pro-rata basis based on their respective RPS targets, or using a simple rule of thumb, such as a 50-50 split.

UCS appreciates the opportunity to submit the above technical comments on the 33% Implementation Analysis. Responses to Energy Division's technical questions are included as attachments to these comments.

Sincerely,

Laura Wisland Union of Concerned Scientists 2397 Shattuck Avenue, Suite 203 Berkeley, CA 94704	Matthias Fripp Consultant to Union of Concerned Scientists 2397 Shattuck Avenue, Suite 203 Berkeley, CA 94704

[33] R. Elliot and A. Shipley. "Impacts of energy efficiency on natural gas markets: updated and expanded analysis." Report number E052. Washington, D.C.: American Council for an Energy-Efficient Economy; 2005. http://www.aceee.org/pubs/e052full.pdf

Attachment 2:

UCS Response to Technical Questions for 33% RPS Implementation Working Group and Transmission Constrained Working Group

Questions on 33% RPS Implementation Analysis Preliminary Results report

1. Has this study produced information that is useful for planning or policymaking purposes? Would a more detailed study provide additional value for either planning or policy purposes, or both?

   UCS believes the study has been useful for policy purposes, but its efficacy as an "analytical framework for policymakers to understand the tradeoffs inherent in any 33% RPS program," was limited by the delayed release of the technical assumptions underlying the results. This delay has resulted in the inability of stakeholders to effectively respond in a timely fashion to the initial reactions of the results of the report.

   UCS believes a revised study that combines stakeholder comments on this preliminary report with the CAISO's integration analysis, due for release this fall, is necessary.

2. Do you agree with the study's general conclusions that (a) the 2020 timeline is aggressive, (b) the state's process reforms are likely to speed the timeline, (c) the state faces risks that are outside of its control that can affect the state's ability to achieve 33% on a given timeline, (d) the rate impacts of 33% relative to 20% are in the 3-10% range, and (e) there are tradeoffs among the different strategies for achieving 33%?

   UCS believes getting to 33% renewables by 2020 is a challenging but achievable goal. UCS believes that recent process reforms to enhance coordination between state and federal agencies, combined with a new federal administration that has placed a higher priority on building renewable energy transmission and projects are just beginning to pay results. In addition, the implementation of new procurement tools like the project viability calculator will enhance the ability of the state to achieve the 33% RPS goal within the 2020 timeframe.

3. The goal of the resource ranking and selection process was to produce "plausible", but not necessarily "optimal" portfolios for achieving a 33% RPS by 2020. Under the assumption that 33% itself is plausible, do you believe the resource mixes that are modeled are "plausible"? If not, what would a plausible resource mix be? How would you alter the modeling process to produce plausible portfolios?

UCS believes the portfolios modeled in the study are plausible but is concerned the portfolios may appear costlier than in reality due to the assumption that no compliance will be satisfied with renewable energy credits ("RECs") that fail to meet the current delivery definition in California Public Resources Code Section 25741(a) ("undelivered RECs"), as well as the assumption that renewable energy technology costs will not decline over time. Please see our attached comments for more detail.

4. The 33% RPS Reference Case relies heavily on resources that have been selected through IOU solicitations and are therefore represented in the CPUC ED RPS project database. Do you agree with the methodology for treating CPUC Database resources (i.e., treating their costs as "sunk" for ranking purposes)? If not, what would be an alternative method of incorporating those projects?

   UCS is concerned that the current methodology strongly prefers projects in the CPUC database over less-expensive projects, which significantly raises the apparent cost of a 33% RPS. Please see the attached comments for our analysis and recommended changes.

5. After exhausting the CPUC ED Database projects, the model fills the remaining need using RETI pre-ID or proxy projects. Do you agree that RETI is a reasonable source of additional project availability and performance data?

   UCS believes that RETI is a reasonable source of additional project availability and performance data.

6. In addition, the model relies on out-of-state resource availability and performance data from E3's GHG Calculator (the original data came from NREL and EIA). Do you agree that out-of-state projects are characterized accurately and are a reasonable source of energy to meet California's RPS needs?

   In the attached comments, UCS submits several reasons why the GHG Calculator does not accurately represent out-of-state resource availability and performance data. UCS also believes E3's model should assume that some percentage of RPS compliance will be satisfied through the purchase of RECs that fail to meet the state's current delivery requirement. UCS believes a 20 percent undelivered REC limit is a conservative and realistic assumption.

7. The final source of project data is the original estimates of DG potential developed by E3 and Black & Veatch. Do you agree that these estimates are plausible and a reasonable source of information for a study of this nature?

   UCS believes the estimates of DG potential developed by E3 and Black & Veatch are plausible, and potentially underestimated given the high transmission penalty (5 cents per kWh) to "remote" DG projects located near non-urban substations. The DG estimate may also be underestimated by the decision to not include development in urban open spaces that are not rooftops, such as vacant lots or parking lot structures.

8. The 33% RPS Reference Case relies very heavily on solar thermal resources, which are largely untested at utility scale. Do you believe it is reasonable to rely on 7200 MW of solar thermal resources coming online by 2020?

   An estimate of 7200 MW of solar thermal resource capacity by 2020 is generally consistent with the projections for large scale solar thermal resources made by the Center on Energy Efficiency and Renewable Technologies, which relied upon industry growth trends projected by Navigant Consulting in a September 15, 2008 report of the solar industry.[34]

9. The High Wind Case relies on substantial quantities of in-state wind resources. However, many of the projects identified are "proxy" projects from the RETI database, rather than projects that have been identified by developers. In addition, solar projects are heavily represented in the CPUC Database. Given the model's preference for wind resources due to cost, why do you think that more wind projects haven't been selected for development through IOU solicitations?

   Wind developers may not be bidding in as many projects as have been identified through RETI due to risks associated with congestion on existing transmission lines. UCS believes this issue should be further examined in the revision of this report after the CAISO's 33% Integration Analysis Report has been released.

10. The High Out-of-State case relies on substantial quantities of wind from Wyoming and geothermal from northern Nevada. Do you think it is plausible to rely on these resources coming online by 2020, including transmission to California? Are there other challenges with out-of-state resources, such as limited availability of firming and shaping capacity?

    UCS believes that some of these resources will contribute to California RPS requirements as undelivered RECs and will therefore not require transmission to California.

11. The High DG case relies on 15,000 MW of in-state solar PV resources. Do you believe it is plausible to develop PV resources on this scale by 2020? Are there any operational issues associated with relying on this quantity of PV resources that the study did not consider? Are the PV potential estimates reasonable and plausible?

    UCS believes it is plausible to expect California to develop 15,000 MW of in-state solar resources in the next ten years. The development of a feed-in tariff policy, of which there are ongoing efforts at both the legislature and the CPUC, should provide added stimulation to the small-scale renewable energy market, especially PV developers. Specific operational issues associated with developing 15,000 MW of in-state solar PV are impossible to conclusively identify in this study since the model has minimal spatial detail and lacks temporal detail. UCS expects integration issues associated with PV and other renewable resources to be

[34] Schell, Lori, Value Proposition of Large Scale Solar Power Technologies in California, Empowered Energy for the Center for Energy Efficiency and Renewable Technologies, May 2009, p. 6.

addressed in the CAISO's 33% Integration Analysis. In addition to considering the CAISO report, the CPUC should consider how demand response resources could contribute to the spinning reserve market, as well as how other advancements in electricity grid storage and flexibility will alleviate operational challenges.

12. All of the cases assume that new transmission is required to deliver most (but not all) of the RPS resources to load. Do you agree that new transmission is needed in most cases, or are new resources likely to be able to make more use of the existing transmission system, e.g., by displacing existing fossil resources in the hourly dispatch?

    UCS believes the RETI Phase 2A final report accurately lays out transmission needs for the state, although some of these needs may be reduced by examining the potential to use existing lines (which RETI did not do). In addition, the retirement of once-through-cooling plants may free up additional capacity. Also, given the fact that more renewables are expected in southern California, and that the main congestion in the state is north-to-south flow in the summer, we would expect renewables to actually ease congestion, e.g., on Path 15. Please see our attached comments for additional information.

13. Do you believe it would be an improvement to the study methodology to account for the ability of the existing transmission system to accommodate new renewable resources? What would be a good method of doing this?

    UCS believes that identifying where renewable energy can be accommodated by upgrading existing transmission capacity is extremely important from both an efficiency and environmental protection standpoint. UCS believes the best method for identifying upgrade opportunities is through a statewide transmission assessment that includes the CAISO, and all transmission owners including the publicly owned utilities.

Attachment 3

The Green Power Institute Comments on Energy Division's 33% RPS Implementation Analysis Preliminary Report

R.08-02-007

August 26, 2009

Introduction

Pursuant to the July 24, 2009, and August 10, 2009, emails from Jaclyn Marks, the Green Power Institute (GPI) respectfully submits: *Comments of the Green Power Institute on the 33% RPS Implementation Analysis Preliminary Results*, in R.08-02-007, the **Order Instituting Rulemaking to Integrate and Refine Procurement Policies Underlying Long-Term Procurement Plans**. Our comments address issues related to the June, 2009, *33% RPS Implementation Analysis* report, including balanced treatment of costs and benefits, balanced treatment of transmission infrastructure needs, balanced treatment of baseload renewables, renewables integration, and taking advantage of current economic conditions.

The *33% RPS Implementation Analysis* relies heavily on the RETI Phase 1 reports. The RETI documents are a primary source of information on both the costs and locations of renewable resources in California, as well as on transmission costs. Therefore, it is important to understand the scope and limitations of RETI, particularly as they relate to the data that have been used in the *33% RPS Implementation Analysis*.

The RETI project was initiated as an effort to investigate the need for developing new transmission trunk lines in California to access remote, renewables-rich resource areas of the state. It was not, and never has been, an effort to produce an optimal renewable resources build-out plan for California. Its focus has always been on renewables-resource zones that need new transmission access, not renewables located in areas that do not need major transmission upgrades to provide access. Resources in the latter category include DG, most biomass and biogas, as well as isolated wind, geothermal, and solar projects that can be developed within the constraints of the state's existing transmission system. In many cases these resources are easier to develop than resources that are located in identified CREZs, precisely because they do not need extensive transmission investments. But they receive less emphasis in the RETI reports, which are focused on developing access to CREZs.

RETI's analysis has been performed within the context of California's existing electric-transmission grid. It is well known that the state's grid is inadequate for existing conditions, and will need a great deal of investment in order to meet the state's future needs regardless of the mix of supply resources that are ultimately deployed. For example, even in the case of the Tehachapi transmission project, which is clearly intended to provide transmission access to wind generators, at least half of the proposed investment is for SCE system upgrades that are needed regardless of whether the Tehachapi generators are ever connected to the grid. This makes it difficult to be able to attribute transmission investments to particular programs, like the RPS.

Balanced Treatment of Costs and Benefits

One of the significant limitations of the *33% RPS Implementation Study* is that it is focused only on the costs, not the benefits, of renewable energy development. This is understandable given that it is designed to examine the implementation of existing state policy (33-percent renewables by 2020), not the efficacy of the policy. However, the unfortunate result of not dealing with the benefits side of the equation is that the essential rationale for the enactment of the policy is left out of the analysis, and it is easy to forget why the expenditures are being made.

A good example of the pitfalls of this focus only on costs is the statement in the *33% RPS Implementation Analysis* report that the hedging value of renewables is limited to instances in which gas prices are very high:

> A 33% RPS can serve as a hedge against natural gas prices, but only under very high natural gas and GHG allowance prices. Thus, the hedging value in itself is not a very strong justification to do a 33% RPS. [33% Implementation Analysis, pg. 9.]

Of course, hedging in the financial sense is designed to protect against price spikes, so we are a bit perplexed about the claim that hedging against "very-high" prices would be considered to be of questionable value. But the greater problem with this statement is that it completely ignores the hedging value of renewables against the risks of climate change, and the resulting damages that climate change is expected to bring. Climate science is extremely complex, and the exact risks posed by climate change are poorly understood, but there is no doubt that there is an enormous hedging value in terms of climate-change mitigation in reducing the rate of emissions of greenhouse gases. This can only help to reduce the risks of reaching critical tipping points, or ease the rate at which greenhouse-gases are increasing their concentrations in the atmosphere.

Balanced Treatment of Transmission Infrastructure Needs

One of the flaws in the *33% RPS Implementation Analysis* is that it presents a very unbalanced consideration of the transmission needs for scenarios with different amounts of renewables. This is because the analysis only looks at the transmission needs of renewables. For example, the 33% scenario in the report provides enough transmission to access seven more CREZs in the state than the 20% scenario. However, the 20% scenario does not provide for the transmission investments needed to access and supply the non-renewable electricity that will substitute for the higher-renewables build-out in the 33% scenario, which represents about 13% of the state's electricity needs. Moreover, the all-gas scenario is constructed virtually without any consideration of the transmission needs of the required additional new gas generators, which would be quite difficult to site near developed areas. This is neither realistic nor balanced.

The result of looking only at transmission infrastructure needs that are related directly to renewables, as the *33% RPS Implementation Analysis* does, is that there is an implication that alternative scenarios do not have alternative transmission needs of their own. In fact, from a public-policy perspective, the portion of transmission cost for a renewables-rich transmission scenario that should be attributed specifically to renewables should be defined as the **net difference** between the total cost of the transmission build-out for the renewables and alternative scenarios. This is not done in the *33% RPS Implementation Analysis*, with the result that the report attributes far too much transmission cost to the renewables account than is justified. It is also not done in the RETI phase 2A report.

Balanced Treatment of Baseload Renewables

In the opinion of the GPI, a major limitation of the *33% RPS Implementation Analysis* is that it fails to include a scenario that is weighted to baseload renewable resources like biogas, biomass, and geothermal. These resources provide a great deal more energy per MW of installed capacity than intermittent renewables, and they do not present the kinds of grid-operability issues that come with intermittent renewables. The *33% RPS Implementation Analysis* has high-wind and high-solar scenarios, but no high-baseload-renewables scenario. Baseload renewables currently provide more than 67 percent of the renewable energy being produced in California, and their potential future contribution to California's energy supply, in our opinion, is seriously undervalued in the *33% RPS Implementation Analysis*.

Renewables Integration and the Need for Fossil Generators

One of the reasons that the *33% RPS Implementation Analysis* report takes such a grim view of the possibility of meeting the 33% renewables-by-2020 goal is due to the perceived integration requirements for adding that level of renewables, particularly intermittent resources, to the grid. However we believe that many of the parties that are studying integration requirements, including the CAISO and this Commission, are too narrowly focused on current grid technology and operating procedures. In fact, there are a variety of upcoming smart-grid technologies that could fundamentally change the way that renewables are integrated into the grid. Some of the promising new technologies include smart-grid controls, on-grid storage, and smart-charging of electric vehicles, including plug-in hybrids.

The *33% RPS Implementation Analysis* reports that in the 33% Reference Case significant quantities of new fossil capacity are added in the early years of the scenario, which becomes surplus capacity in the later years of the study timeframe (ten years). This is an important modeling result that warrants careful monitoring on the part of the Commission over the next several years, in order to make sure that this scenario does not play out in practice. It also should serve to remind the Commission and the IOUs that the time to improve their procurement practices and procedures is now.

Taking Advantage of Current Market Conditions

We support, in principle, the use of functional competitive markets for optimal resource allocation. However, it is important to understand that in some circumstances markets may be out of balance and not functioning competitively, and thus not able to act efficiently. In such circumstances it is necessary to tailor regulatory programs to the circumstances at hand and act accordingly, rather than acting as if the markets are functioning efficiently when that is simply not the case.

A case in point is the renewable-energy market, which is driven in large part by concerns about climate change, and policy initiatives that are being taken to combat it. At the present time the demand for renewables in California, which is driven by statutory mandates, outstrips supply, with the result that all three of the large California IOUs are running deficits in their renewables-procurement obligations (APTs). Moreover, the deficits are on a troubling trend of increasing every year. Putting more even pressure on the market for the development of new renewable-energy-generating capacity, increasing numbers of neighboring states, and possibly the entire country, are adopting renewables mandates of their own. Under the circumstances, it seems to us that regulations ought to be designed within the context of guiding markets that are **not** functioning competitively. This often is best served by cost-based regulation, rather than by reliance on a marketplace that is seriously out of balance.

Before the mid-2008 economic collapse, the cost of developing new renewable-generating capacity was elevated because the demand for new renewables-generating equipment and engineering on a worldwide basis was clearly outstripping the supply. The result was high prices and long lead times for new projects, even as learning-curve considerations suggested that prices for many technologies should be coming down. With the fall 2008 economic downturn still in effect, demand for new renewables-generating equipment has slackened significantly, and the cost for new capacity has fallen accordingly. However, another aspect of the downturn has been a dramatic drop in the cost of natural gas, which will result in a significant decrease (probably several cents) in the MPR that will be calculated for the 2009 RPS solicitations, compared to recent solicitation rounds.

In our opinion, what we are in significant danger of doing in California is establishing an RPS-procurement pattern in which we contract for lots of renewables when the costs of developing new renewables are inflated by an imbalance of demand over supply. Then, when the economy is down and new renewables projects can be developed for less, new contracts will not be possible because of the mechanics of the MPR, and a great opportunity will be lost.

Conclusion

The *33% RPS Implementation Analysis* provides a great deal of useful information about what it will take for California to implement its 33-percent renewables by 2020 policy. However, the study does have some serious limitations that limit its usefulness as a policy tool. The study dwells only on costs, rather than balancing the costs against the benefits that the policy is intended to produce. The study presents an unbalanced treatment of transmission requirements that are attributable to renewables, and severely undervalues the potential future role of baseload renewables in the state. We would like to see these deficiencies corrected before the report is finalized.

Dated August 28, 2008, at Berkeley, California.

Respectfully Submitted,

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Attachment 4:

GPI Response to Technical Questions for 33% RPS Implementation Working Group and Transmission Constrained Working Group

1. Q: Has this study produced information that is useful for planning or policymaking purposes? Would a more detailed study provide additional value for either planning or policy purpose, or both?

A: The study highlights the need to prioritize policy goals. Some of the goals are competing, and we as GPI, as well as other parties and the Commission, need to decide which of the goals we consider most important. The GPI sees market transformation and in-state renewable generation as being very important goals, but we also need to keep the pressure on for the overall 33% x 2020 goal. For planning purposes the timelines and scenarios presented in the report can help to give a picture of what might happen as renewables are developed, but it is important for the Commission to be flexible and adjust as circumstances warrant.

2. Q: Do you agree with the study's general conclusions that (a) the 2020 timeline is aggressive, (b) the state's process reforms are likely to speed the timeline, (c) the state faces risks that are outside of its control that can affect the state's ability to achieve 33% on a given timeline, (d) the rate impacts of 33% relative to 20% are in the 3-10% range, and (e) there are tradeoffs among the different strategies for achieving 33%?

A: (a) The 2020 timeline is aggressive, but it is not unachievable. The 2020 timeline is feasible, as long as obligated LSEs move aggressively to achieve it. Postponing the timeline will simply result in more foot dragging, and not accomplish anything.

(b) The state's process reforms are likely to speed the timeline, but only if they can be passed and acted on quickly and implemented effectively.

(c) The state will always face outside and uncontrollable risks to achieving the 33% goal on any given timeline, but some of these risks can be mitigated by effective forward planning, or corrected before they happen. Having a diverse group of renewables can also buffer against any given set of risks.

(d) We do not agree with the study's general conclusion that the rate impact of 33% renewables relative to 20% will be in the 3-10% range. We believe that this is still very much an open question. The study suffers from an imbalanced treatment of the risks and transmission needs of renewables vs. alternative scenarios, and the imbalanced treatment tends to exaggerate the costs of renewables. In particular, the study includes substantial costs for the transmission improvements associated with developing new renewables zones (CREZs), but does not include a consideration of the transmission needs and costs of new fossil generators, which are themselves not trivial. Moreover, the study fails to distinguish between what RETI calls "no regrets" investments, which serve system-wide needs, and investments that are specific to opening up remote renewables-rich zones, instead leaving the impression that all new transmission proposed for the state is attributable to the renewables program. Only a small fraction of the total is attributable directly to renewables.

(e) There are tradeoffs among the different strategies for achieving the 33% goal. These tradeoffs invoke the need to set priorities about which policy goals we seek to promote as the most important. It will also be important to look at assessments of likely-to-become operational, which would help to elucidate how much capacity is likely to actually come through the development obstacle course when comparing the strategies. This might help to show if certain strategies are more realistic or resilient than others.

3. Q: The goal of the resource ranking and selection process was to produce “plausible”, but not necessarily “optimal” portfolios for achieving a 33% RPS by 2020. Under the assumption that 33% itself is plausible, do you believe the resource mixes that are modelled are “plausible”? If not, what would a plausible resource mix be? How would you alter the modelling process to produce plausible portfolios?

A: We think that the modelled resource mixes are “plausible,” based on the scenarios that have been presented. However, we believe that an important scenario has been left out of the analysis: one that is geared towards baseload renewables in California like biogas, biomass, and geothermal. Baseload renewables provide approximately 67% of the renewable energy that is being generated in California today, and there are sufficient resources in the state to develop considerable additional baseload-renewable generating capacity. A scenario weighted towards baseload renewables is needed.

4. Q: The 33% RPS Reference Case relies heavily on resources that have been selected through IOU solicitations and are therefore represented in the CPUC ED RPS project database. Do you agree with the methodology for treating CPUC Database (i.e., treating their costs as “sunk” for ranking purposes)? If not, what would be an alternative method of incorporating those projects?

A: We do believe that the base-case scenario should rely heavily on the existing portfolio of RPS contracts, although we cannot comment on the exact methodology that was employed in the analysis. In order to properly treat the contracts in the existing portfolios, it is important that realistic estimates of their probability of success be employed, including, for example, using lower probabilities for technologies that are not commercially demonstrated than for technologies that have been proven in the commercial marketplace. The GPI recommends using a probability of success of no greater than 70% for projects using commercial technology. The probability of success for some of the more exotic technologies that have been proposed in California should be very low indeed, some close to zero.

5. Q: After exhausting thee CPUC ED Database projects, the model fills the remaining need using RETI pre-ID or proxy projects. Do you agree that RETI is a reasonable source of additional project availability and performance data?

A: RETI seems like a reasonable source of information for additional project data, especially as we know of no other source of information that might provide similar data. However, it is important to understand the limitations of the database for the RETI project. In particular, the RETI project was designed specifically to study the extension of transmission access to remote, renewable-resources rich areas of the state (CREZs), and therefore the study focuses on resources lying in identified CREZs. Resources that are located outside of CREZs, like most of the biogas and biomass resources in the state, as well as DG, are given relatively less consideration in the RETI study than resources inside the CREZs. In a study like the *33% RPS Implementation Analysis*, the non-CREZ resources should be accorded at least equal consideration to those in CREZs.

6. Q: In addition, the model relies on out-of-state resource availability and performance data from E3's GHG Calculator (the original data came from NREL and EIA). Do you agree that out-of-state projects are characterized accurately and are a reasonable source of energy to meet California's RPS needs?

A: In our opinion out-of-state projects should be considered, but not relied upon too extensively to meet California's RPS needs. While using some out-of-state resources may be necessary, the Commission should keep the utilities' focus on developing in-state resources. Out-of-state resources may also require more transmission needs and planning among multiple states. RETI also produced a database of possible out-of-state generators. This information should be compared to the information in the E3 Calculator, and augmented as appropriate.

7. Q: The final source of project data is the original estimates of DG potential developed by E3 and Black and Veatch. Do you agree that these estimates are plausible and reasonable source of information for a study of this nature?

A: We do not have enough information in this area to comment.

8. Q: The 33% RPS Reference Case relies very heavily on solar thermal resources, which are largely untested at utility scale. Do you believe it is reasonable to rely on 7200 MW of solar thermal resources coming online by 2020?

A: It is a little unfair to make the blanket statement that solar-thermal resources are largely untested at utility scale, particularly considering the fact that some 400 MW of solar-thermal generators (troughs) have been operating under commercial conditions in California for some 20 years. Nevertheless, it is true that a good deal of the projects that make up the referenced 7,200 MW of solar-thermal-generating capacity under-development do indeed employ technology that has not been commercially demonstrated. As the GPI has argued consistently in the RPS and LTPP proceedings, these projects must be assigned lower expectations of achieving operational status than projects employing commercially-proven technologies.

The question asks whether it is reasonable to rely on the 7,200 MW of solar-thermal-generating capacity coming online by 2020. In fact, it is not reasonable to rely on any particular project or set of projects coming online, regardless of the commercial status of the technology being deployed. Every contract in the portfolio should be treated as having a statistical probability of success. In our opinion, projects with strong developers and employing commercially-proven technology should be assigned an expected-success probability in the neighbourhood of 70 percent, lacking better, project-specific data. Projects based on pre-commercial technologies should be assigned appropriately lower probabilities of success, in some case much lower. If the probabilities assigned are reasonable, and the portfolios are large and diverse enough to avoid statistical anomalies, then planners should be able to rely on the calculated expected value of operating renewable-generating capacity that will result from a given portfolio of contracts.

9. Q: The High Wind Case relies on substantial quantities of in-state resources. However, many of the projects identified are "proxy" projects from the RETI database, rather than projects that have been identified by developers. In addition, solar projects are heavily represented in the PUC Database. Given the model's preference for wind resources due to cost, why do you think that more wind projects haven't been selected for development through IOU solicitations?

A: The GPI is not privy to the solicitation process.

10. Q: The High Out-of-State case relies on substantial quantities of wind from Wyoming and geothermal from northern Nevada. Do you think it is plausible to rely on these resources coming online by 2020, including transmission to California? Are there other challenges with out-of-state resources, such as limited availability of firming and shaping capacity?

A: It is certainly possible for these resources to come online by 2020. The bigger question is whether the transmission needed to bring it to market will be developed. If California allows the use of unbundled RECs for RPS compliance then the power does not have to be transmitted into California, however it does have to go to some load center where it will be adequately valued, and substantial transmission investments will be needed in any scenario. One problem with relying on out of state resources is that as RPS programs and greenhouse-gas reduction laws become more widespread, the resources will be harder to secure as regional competition amps up.

11. Q: The High DG case relies on 15,000 MW of in-state solar PV resources. Do you believe it is plausible to develop PV resources on this scale by 2020? Are there any operational issues associated with relying on this quantity of PV resources that the study did not consider? Are the PV potential estimates reasonable and plausible?

A: The high DG case would be difficult but not impossible to achieve by 2020. The question is: Why are there no scenarios with intermediate levels of DG? Would a case with a more middle amount of DG be possible to develop? The difference could be made up of other in-state resources and out of state resources. One problem with all of the developed scenarios is that they take extreme views of developing the various renewables, rather than optimizing on a balanced mix of renewables.

12. Q: All of the cases assume that new transmission is required to deliver most (but not all) of the RPS resources to load. Do you agree that new transmission is needed to most cases, or are new resources likely to be able to make more use of the existing transmission system, e.g., by displacing existing fossil resources in the hourly dispatch?

A: California's existing transmission system is inadequate for serving the load that currently exists in the state. Regardless of the composition of the future mix of generating sources that feed the grid, major transmission investments will be needed. Most of the transmission elements that are included in the conceptual transmission plan that was recently released in the phase 2A report of RETI are categorized as "no regrets" investments, which means that they are probably needed regardless of the composition of the future energy supply mix. Even in the case of the Tehachapi transmission project, which was conceived specifically to bring transmission access to a known wind-resource-rich region of the state, fully half of the proposed investment will be for transmission elements that were identified as needed in the system long before the development of the Tehachapi project was initiated. When all of the state's transmission needs are assessed to the development of renewable resources, simply because those are the supply resources highest in the state's loading order, it makes the costs of instituting the renewables program look much higher than they really are. The RETI report notes:

> The Phase 2A conceptual transmission plan is designed to facilitate meeting the goal of obtaining 33% of the state's electricity from renewables by 2020. But large investments in transmission infrastructure will be needed between now and 2020, regardless of state

energy-supply mix. Many elements of the RETI conceptual transmission plan would likely be required under non-renewables-based planning scenarios. The estimate of the aggregate cost of the conceptual transmission plan presented in this report thus cannot be attributed only to the state's renewable-energy programs. [RETI Phase 2A Final Report, page 1-2.]

13. Q: Do you believe it would be an improvement to the study methodology to account for the ability of the existing transmission system to accommodate new renewable resources? What would be a good method of doing this?
A: It would be an improvement in the study methodology to give equal consideration to resources located outside of CREZs, particularly those with minimal transmission needs, as to resources located inside CREZs. It should be noted that at all stages of transmission planning, upgrades to the existing system are always considered before new transmission elements are contemplated. That is simply good engineering practice.

14. Q: Do you believe that a detailed mapping of 33% RPS resources is valuable for transmission and procurement planning? Why or why not?

A: We think it is useful because it helps to show what kinds of transmission investment might be needed, and how much procurement will be needed. However new technologies and other unpredictable changes to the study scenarios need to be taken into account, and are hard to map. All of these kinds of studies need to be taken as planning resources and not used as an actual reality.

15. Q: Please include any additional comments on the report, including the implementation timelines and assumptions used to build the implementation timelines?

Dated August 28, 2008, at Berkeley, California.

Respectfully Submitted,

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