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**BEFORE THE
CALIFORNIA ENERGY RESOURCES AND
CONSERVATION COMMISSION**

In the Matter of:

Preparation of the
2009 Integrated Energy Policy Report
(2009 IEPR)

Docket No. 09-IEP-1G

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**Comments of the California Large Energy Consumers Association
on the Issues Raised During the June 29, 2009
Joint Integrated Energy Policy Report and Renewables Committee Workshop:
Electricity System Implications of 33 Percent Renewables**

The Workshop Notice for the June 29, 2009 Workshop on Electric System Implications of 33% Renewables (“33% RPS”) provided important preliminary input concerning the assessment of the feasibility and cost of a 33% RPS policy. It also raised a number of key questions related to the implementation of such a policy. The California Large Energy Consumers Association (“CLECA”) believes that there remain several critical unanswered questions. In providing responses to the questions posed in the Workshop Notice, we point out that it is important not to lose sight of two facts: 1) 33% RPS is only one of several GHG mitigation strategies available to California, and perhaps the most expensive; and 2) the implementation of a 33% RPS policy cannot be addressed on a California-only basis without the incurrence of unnecessary additional costs and potential operational concerns – our utilities operate in a WECC-wide context.

What are the potential electricity integration issues that need to be addressed in order to achieve the 33 percent renewables goal by 2020? Are any of these issues not being addressed by ongoing studies or in identified policy development proceedings?

There are several operational issues related to the achievement of a 33% RPS goal by 2020 that have not been addressed adequately by policy makers to date. While the CAISO has performed a *preliminary* study on the operational issues associated with 20% RPS, it has not completed this study, and it does not anticipate having a complete operational assessment of 33% implementation until next year. From an operational perspective, there is much to be done to address the minute-by-minute requirements for ancillary services to support the grid as the amount of renewable electricity increases from present levels to the proposed 33% RPS level. These requirements will vary, depending on the location and performance of the intermittent renewables actually developed. Since output will vary by location, combinations of solar and wind resources in different locations are likely to provide more stable output than reliance on resources in only one location. Furthermore, the choice of solar technologies is important. The intermittent nature of solar PV, in the case of cloud cover for example, is substantial, while solar thermal technology includes some limited storage and could include more. The role and cost-effectiveness of quick-start CTs, vs. storage, vs. demand response to balance intermittent resource impacts has not been adequately studied. These resources could have very different cost impacts on consumers. Furthermore, a view of renewable resources WECC-wide, taking into account different wind and solar regimes, might allow for operational alternatives that would be significantly less costly in aggregate than pursuing resources only on a control-area or even a California-only basis. In addition, changes to operating practices across WECC to better share and coordinate operations could facilitate renewables integration. We believe that WECC is considering such changes.

We are concerned that the preliminary results developed in the CPUC/EE/Aspen and Nexant studies, while worthwhile, have not sufficiently addressed these operational issues and their related costs. While these studies have contributed to our understanding in a useful way, their authors admitted their limitations in their presentations. Furthermore, we have not yet been able to read the Nexant study and review its results. Lastly, we commend the CPUC/E3/Aspen

study for addressing the challenges in meeting the 2020 time line. There will need to be an assessment of what other resources might be needed if this deadline cannot be met, and under various circumstances, e.g. changed regulation and possible shut down of some OTC generation facilities, delays in construction of new transmission, unavailability of sufficient manufacturing facilities for new generation or storage technologies, etc.

What impact will related policies, especially energy efficiency and combined heat and power goals in the California Air Resources Board AB32 scoping order, have on the amount of renewable energy needed to achieve 33 percent by 2020?

The E3 studies performed for AB 32 implementation demonstrate that EE and CHP are significantly more cost-effective approaches to GHG mitigation than is the massive addition of renewable generation resources. If the ARB's EE and CHP goals cannot be reached, and more renewables must be added, the cost to consumers will increase significantly. Conversely, if EE and CHP goals can be met and exceeded, the cost to consumers is likely to decrease. It is imperative that the relevant regulatory agencies act to reduce or eliminate current, unjustifiable barriers to the implementation of more CHP if the ARB goals are to be met. We await the results of CPUC deliberations on standard contracts for utility purchase of power from CHP facilities of less than 20 MW and the commencement of a rulemaking to address barriers to the addition of more CHP. The latter is critical for CHP being contemplated for a customer's own on-site use, which is not addressed by the current proceedings.

What impact will related policies have on the electricity system implications of 33 percent renewable energy by 2020? For example, how would policies supporting the use of energy storage systems (e.g., pumped hydro, compressed air, etc.), geothermal generation, or biomass generation affect the electricity system implications of 33 percent renewable energy by 2020? What level of penetration would be needed?

Regulatory agencies must include consideration of the cost and operational impacts, as well as the availability, of increased penetration of biomass and geothermal generation compared

to solar and wind alternatives, as well as the potentially significant costs and uncertain impacts of various storage technologies. The State has already decided to promote major additions of solar PV, despite its high cost, in the expectation that this will lower prices in the long run. There are numerous subsidies currently in place for this technology (including direct rebates, net metering and tax subsidies), subsidies that are paid for by the same ratepayers who are paying the costs of the 33% RPS implementation. There are tax and regulatory subsidies for all of these renewable technologies. The actual cost to utilities of buying renewable power is subject to confidentiality restrictions, so customers have no idea what these projects cost. The CPUC study indicates it used RETI cost data, not market data, in its cost estimates, and it did not have the ability to perform the operational studies. Someone, somewhere, should be undertaking an analysis that incorporates these important additional considerations.

What impact will the exhaustion of above-market funding from the CPUC for two of the IOUs have on California's ability to meet the 33% RPS goal? What other uncertainties need to be considered?

The role of the above-market funding from the CPUC will be affected by current 33% RPS legislation pending in the California Assembly and Senate. Such legislation is contemplating overall cost caps as well as possible means of bypassing these cost caps. There should not be an unlimited supply of above-market funding for 33% RPS or for any other resource. The very 33% RPS goal and its tight time line may encourage potential generators to exercise some degree of market power and ask for higher prices. We must remember as well that 33% RPS is only one means of meeting GHG requirements, and one of the most expensive. GHG reduction in the transportation sector, more cost-effective EE, more CHP, etc., are other options. The state should not pursue a policy of 33% RPS by 2020 *at any cost*. Indeed, the implementation of GHG mitigation policy as well as 33% RPS should be carefully monitored and off-ramps provided if the

costs get out of hand. There should indeed be an overall cost cap separate from the current above-market funding available under current statute.

If you have any questions about these comments, you may reach me at 707 937-6203.

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Respectfully submitted,

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CLECA/079/PLEADING/COMMENTS ON CEC 33% RPS WORKSHOP