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California Energy Commission
Docket Office, MS-4
Re: Docket No. 11-IEP-1G Renewables
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Re: California Energy Commission Docket No. 11-IEP-1G: Comments Related to Committee Workshop on Renewable, Localized Generation

To Whom It May Concern:

On May 9, 2011, the California Energy Commission ("Energy Commission") held a Committee Workshop on Renewable, Localized Generation (the "Workshop") in connection with the 2011 Integrated Energy Policy Report ("2011 IEPR"). Southern California Edison Company ("SCE") participated in the Workshop and appreciates this opportunity to provide these follow-up comments. SCE also looks forward to working with the Energy Commission, the Governor's office, and other regulatory agencies to help design a policy to achieve the Governor's Localized Energy Resources ("LERs") goals.

SCE's comments will respond to the themes presented in the Request for Comments, which was attached to the Workshop Agenda. Accordingly, these comments will be divided into the following six distinct categories:

1. Developing a policy design for the Governor's proposal for LERs;
2. The European experience integrating large amounts of LERs;
3. Developing renewable generation on state property;
4. How research development and demonstration ("RD&D") can help advance LERs;
5. Responses to specific questions posed at the Workshop;
6. Clarification Regarding Distributed Generation Matrix.

In the first section, SCE will stress the importance of ensuring system reliability and mitigating customer rate increases in designing a LERs program. Next, SCE will describe the European experience in implementing LERs and describe some of the ways that the United States landscape for implementation of a LERs program is more challenging. SCE will then respond to specific questions posed to SCE representatives by Energy Commission Chair Robert Weisenmiller and Commissioner Carla Peterson at the Workshop. Lastly, SCE will recommend clarifying changes to one of the documents presented at the Workshop.

As a preliminary matter, SCE notes that throughout these comments and SCE's other communications with the Energy Commission, the Governor's office, and other regulatory bodies, SCE will use Governor Brown's original broad term - Localized Energy Resources or LERs, rather than the often misused and misunderstood term "distributed generation." The use of this broad term, LERs, reflects the many types of resources that can provide environmental benefits and efficiency at a local level. This term is consistent with SCE's belief that energy policies should be technology neutral. Construing LERs too narrowly may result in policies that lead to a suboptimal solution to California's electricity challenges and impose unnecessary costs on California electricity customers.

I. Developing a Policy Design for the Governor's Proposal for LERs

SCE looks forward to working with the Energy Commission and the Governor's office through their working conference this summer to develop reasonable policy goals for LERs in the state of California. Such forums are essential to inform policymakers of the potential system reliability and electricity rate impacts associated with LERs. Setting targets without adequate input from effected stakeholders could put both electric system reliability and California's economic development at risk. When considering the Governor's proposal for LERs, system reliability concerns and electricity rate impacts should be two of the highest priorities.

In order to maintain system reliability, SCE will need to invest in major distribution and transmission system upgrades to accommodate significant volumes of LERs. These upgrades will come in two forms. First, significant changes will need to be made to the existing system hardware and will require the implementation of multiple new technologies. Second, SCE and other load serving entities will need the ability to collect data about and provide control over new LERs projects, which will require the development of a new, sophisticated control system and the establishment of new compliance standards for participating LERs projects. As elaborated in Section IV below, a reasonable timeline for implementation is necessary to allow California to take advantage of significant technological developments in an efficient and effective manner.

Though exact system upgrades are impossible to predict, SCE, with the other Investor Owned Utilities ("IOUs") and the California Independent System Operator ("CAISO"), have initiated a project to identify potential scenarios resulting from increased penetration of LERs. While this project will not precisely estimate the resultant distribution and transmission system upgrades, it will indicate a potential range of reliability impacts that such a policy could have on the system. The team expects to have preliminary results of the project by mid-summer and looks forward to disseminating them broadly, including to the Energy Commission and at the Governor's LER workshops. The Energy Commission, the Governor's office, and other policymakers should consider the ramifications of these significant and necessary system upgrades as they design state policy regarding LERs. Similarly, the agencies will need to understand the impact on municipal utilities and other distribution service providers.

The Energy Commission must also consider the customer impacts of any proposed policy toward LERs. A significant increase in LERs could cause substantial rate pressure on all electricity customers. The capital investment required for transmission and distribution system upgrades combined with the efforts necessary to properly implement and utilize the upgraded system will

undoubtedly increase costs for electricity customers. Additionally, any incremental subsidy given to qualifying generators as incentives would add to these escalating costs. Furthermore, these rate increases should be considered in the context of other initiatives such as the California Air Resources Board's ("CARB") pending cap and trade program, electricity providers' continuing efforts to reach 33% renewables per the Renewables Portfolio Standard ("RPS") and procurement of Combined Heat and Power ("CHP") resources. SCE urges the Energy Commission and the Governor's office to consider the various options for funding in developing the timeline and strategy for implementing the Governor's proposal.

II. The European Experience Integrating Large Amounts of Distribution-Level Resources[1]

Europe can provide a valuable example of the technical upgrades that would be required to increase LERs in California. European electrical systems have many key differences from those in California, many of which make the European systems more accessible and suitable for the interconnection of distribution-level resources. One important difference is the basic distribution system design. Most California distribution systems are composed of radial distribution circuits operating from 4 to 16 kV and have many distribution transformers serving small groups of residential/commercial customers (3 – 12 customers per transformer). In Europe, networked distribution lines operate at 21 kV or similar voltages and serve large neighborhood transformation stations that provide three phase power to large groups of customers (100 – 200 customers per transformation). Since higher-voltage circuits can usually handle distribution-level resources with more ease, the European design was able to integrate many more distribution-level resources per customer than will the average California circuit.

However, even while the European system design allows for the integration of distribution-level resources closer to stronger portions of the distribution system, the European system has experienced problems with regulation of power output and customer voltage. Because of these problems, grid codes have been put in place to specify the devices that need to be used to support connection of distribution-level resources to the grid. For example, the German grid code has specifications for voltage/VAR control, low voltage ride-through, and active power curtailment. California would need to conduct an extensive analysis to determine the proper levels for similar and additional specifications in order to reliably integrate significant numbers of LERs to the grid.

Additionally, Europe has developed ripple communications systems to control resistance water heaters to manage peak demand. This system has been easy to implement because of the relatively small number of customer distribution transformers serving large groups of customers. Though this ripple system was initially deployed for load control, it was convenient and cost effective to use it to control power output from localized generation. However, it would be much

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[1] As the KEMA report points out, in Europe, the term "distributed generation" is generally used to refer to "generation connected to low-voltage and medium-voltage distribution grids close to energy consumers, and generation used by energy consumers for self supply," regardless of the system's size. However, the term is subject to variation within Europe, with Spain relying on a more complex categorization. As already stated, it is important to establish and abide by a clear definition of the term LERs for California -- one that is broad enough to ensure grid reliability and mitigate customer rate increases. As the European definitions of "distributed generation" do not always include all resources that would be considered LERs, the experiences of these programs can be viewed as a example of how using such a restrictive definition poses significant and costly distribution challenges. *See* KEMA Memo: Distributed Generation in Europe – Physical Infrastructure and Distributed Generation Connection, at p. 32, available at http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-09_workshop/documents/ (follow the "Memo 1_Physical Infrastructure and DG Interconnection.pdf" hyperlink).

more difficult and expensive to implement a similar system in California because of the large number of customer distribution transformers, each serving a small number of customers.

Current specifications for grid interconnection in California lag behind those in Europe, and would have to be extensively amended to implement LERs. In the United States, the Institute of Electrical and Electronics Engineers Standard 1547 ("IEEE 1547"), which specifies how distribution-level resources are to be interconnected to the grid, was conceived and put in place in a time when these resources were expected to be widely scattered. If a policy similar to what the Governor is considering is implemented, this assumption of low penetration rates needs to be reexamined. IEEE 1547.8 is being assembled to better take into account high penetration scenarios, but significant work will be required to implement this new standard. This new portion of the standard is expected to have many sections similar to what has been done in Europe. These will probably include sections on volt/VAR control, fault current contribution, low-voltage ride-through, harmonic contributions, and curtailment of power output under emergency conditions. SCE will be a significant contributor to these new sections based on our research work and experience with interconnection of large LER projects. However, it may take several years to finalize the standards process and add these new requirements. In the interim, load serving entities would need to put their own rules in place to avoid having a large base of installed equipment that does not support the grid under a high-LER-penetration scenario.

III. Developing Renewable Generation on State Property, Installing Renewable Energy on State Buildings and Other State-Owned Property

Europe can also provide useful background in understanding the barriers to installing renewable generation on state-owned property, and SCE appreciates the information provided by KEMA on this topic.[2] In considering renewable generation on state-owned property, however, SCE maintains the same two priorities: ensure system safety and reliability and mitigate rate increases for California electricity customers. SCE agrees with the Energy Commission's desire "to install renewables on state properties through existing programs and at no net increase in cost to the state."[3] However, it is unclear how the state will accomplish this goal of minimizing costs. SCE encourages the Energy Commission to ensure that customers do not carry the burden of funding this initiative.

Additionally, SCE commends the Energy Commission Staff for highlighting "Integration [of] Renewable Energy" and "Interconnection" as key barriers to high penetrations of LERs.[4] However, there is little indication that these system reliability concerns have been taken into account in developing estimates of the potential LER capacity (measured in megawatts) on state-owned property. SCE urges the Energy Commission, the Governor's office, and other policymakers to continue to consider the impact of these significant technical barriers associated with the installation of LERs on state-owned property.

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[2] *See* KEMA Memo: Distributed Generation Options on Public Property, at p. 2, available at http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-09_workshop/documents/ (follow the "Memo 3 DG Options" hyperlink)

[3] California Energy Commission, Staff Report CEC-150-2011-001. Developing Renewable Generation on State Property: Installing Renewable Energy on State Buildings and Other State-Owned Property. April 2011. Pg 1.

[4] Ibid. Pg 5 – 6, 33-46.

Energy Commission Staff also note in their Staff Report the importance of the state's loading order, "which calls for meeting new electricity needs first with energy efficiency and demand response; second, with new generation from renewable energy" resources.[5] In addition, staff recommends that implementation of LERs "be consistent with the state's loading order and prioritize buildings that have already received energy efficiency upgrades."[6] SCE supports the Staff recommendation of prioritization of state facilities. However, it is not clear from the Staff Report or Workshop how this prioritization will be determined. More importantly, there is no evidence that state facilities have pursued all cost-effective energy efficiency and demand response measures before the installation of LERs at or near these facilities. SCE encourages the Energy Commission to follow California's Energy Action Plan and fully explore whether state buildings have exhausted all reasonable energy efficiency and demand response opportunities before installing LERs.

IV. How Research Development and Demonstration (RD&D) Can Help Advance Distributed Generation

Issues related to integrating large amounts of LERs at the distribution level may be divided into two major areas: 1) system level issues and 2) local issues.

System level issues for high penetration LERs are similar for both distributed and utility scale sources. The variable output of these sources adds to the existing variability of load, placing additional demands on dispatchable sources, which for now are mostly gas fired units. Both the amount of reserves and the required ramp rates are affected. RD&D areas which may help overcome these difficulties include:

1. Solar and wind forecasting.
2. Efficiency monitoring for small Combined Heat and Power facilities.
3. Economic communications and control technologies for controlling LERs by system operators.
4. Technology research for energy storage (e.g., battery and flywheels) to ease ramp rate demands on thermal units.
5. Model development for frequency control and system stability to accommodate the increased variability between balancing authorities and the loss of inertia from replacing rotating machines with inverter based generation, including the use of advanced demand response.
6. Research to provide the Power System Stabilizer ("PSS") functions of voltage regulation on LERs similar to the requirements presently used on large generators.

Local issues involve managing the capacity of circuits with variable combinations of load and generation, mitigating voltage excursions due to variable LER output (both steady state and transient), impacts of LERs on protection relaying schemes, viability of anti-islanding schemes, and complications of planning and operations. SCE has accomplished extensive work in these areas including testing of inverters, construction of inverter models, simulation of high LER penetration scenarios, and suggestion of potential improvements to inverters to make integration

[5] Ibid. Pg 16.
[6] Ibid. Pg 17.

easier. While the following list is not exhaustive, it provides some RD&D areas which may help overcome these difficulties:

1. "Smart" inverters for photovoltaic applications which provide active control of real and reactive power output as a function of local voltage and frequency, low voltage ride-though, fault current limiting, transient overvoltage limitation, and harmonic control. For example, pilot implementations of such smart features on circuits with high renewables penetration could yield information that would inform standards writing bodies.
2. Low cost, high speed communications to facilitate economic control of LER for protection, anti-islanding, and operations. For example, emerging 4G technologies could be demonstrated in a substation-centric radio network providing protection functions.
3. Distribution circuit topology changes to improve circuit performance to be more tolerant of variability.
4. Energy storage to avoid curtailment of LER output during times of local circuit constraints and to mitigate variable output. Community energy storage systems similar to those piloted by AEP in Columbus could be tested in this application.
5. Inverters create much higher order harmonics than traditional grid assets. The effects of these higher order harmonics could be studies in a field setting to ascertain the effects on customer and utility equipment.

The existing electric power system developed into its present state over more than a century. System models grew and developed over this same timeframe. State policy goals require a significant change to the structure of this system in less than a decade. The characteristics of loads are also changing over time. Of particular concern is the impact of power changes of greater frequency at higher ramp rates on the dispatchable generating assets. Predicting the performance of this future system presents a challenge to system modelers since they will lack opportunity to validate their models against actual system performance until after the changes have been realized. There is a risk that the models will not correctly identify all of the issues that will arise in the new structure. Further RD&D will be necessary to mitigate this risk and include:

1. Developing models to evaluate the performance of the distribution grid and comparing the results through laboratory tests and field data.
2. Benchmarking models against existing situations in Europe where higher penetration levels exist.
3. Using laboratory and field testing to validate assumptions contained in models.

Research work to help implement high penetration of LER devices needs to be distribution utility-driven because integration performance can only be verified on the grid. The Public Interest Energy Research ("PIER") program needs to support these efforts through close coordination with the distribution utilities.

V. Responses to Specific Questions Posed by the Commissioners at the Workshop

(i) <u>What are SCE's primary concerns and issues with the existing Solar Photovoltaic Program ("SPVP") program?</u>

SCE's SPVP program has successfully installed and interconnected 29 MW of utility owned solar photovoltaic ("PV") projects, with an additional 43 MW at various stages of development. Recently, SCE filed a Petition For Modification ("PFM")[7] with the CPUC that will make the following changes to the SPVP program:

a. 250 MW are proposed to be removed from the utility-owned generation ("UOG") and original independent power producer ("IPP") SPVP targets (125 UOG/ 125 IPP) and a new 250 MW IPP solicitation for competitively priced PV projects in the 1 – 20 MW range will be initiated.
b. The ground-mount allotment is proposed to be increased to 20% in the UOG and IPP to accommodate existing goals.

These changes are primarily intended to address concerns about the SPVP program and its impact on customer costs. Through competitive solicitations, SCE received offers and signed contracts with ground-mounted projects that were significantly less expensive than the roof-installed projects in its SPVP. The proposed changes are expected to reduce customer costs by $300M Present Value Revenue Requirement ("PVRR").

Other concerns and issues with the SPVP program are identified in Table 1 (SPVP Program Issues) below.

Table 1 – SPVP Program Issues

Reliability	Interconnection	Commercial	Environmental Health & Safety
Voltage Fluctuations	Uncertainty of Costs	Limited Leasing Opportunities	Protection from Electrical Hazards
Reverse Power Flow	Lengthy Process	Rooftop Mounting Constraints	Rooftop Construction
Grid Harmonics	Varies by Project Size	Rooftop Structural Liability	

SCE will work with the Electric Power Research Institute ("EPRI) to develop a whitepaper on the "lessons learned" from implementing the program.

(ii) <u>For solar PV projects, what is the ratio of bids submitted to contracts executed?</u>

In any of these competitive programs, the ratio of bids submitted to contracts executed is dependent on market conditions at the time of the solicitation. Depending on how the program is structured, such market conditions take into account the competitiveness of solar PV projects against other technologies (e.g., in the Renewable Auction Mechanism ("RAM") and RPS solicitations), and also the competitiveness of a specific solar PV project against other solar PV projects (such as in the SPVP solicitations).

The ratio of bids submitted to contracts executed from the last solicitation for each of these programs is as follows. First, in the 2010 Request for Offers ("RFO") for the SPVP program, the ratio of bids submitted to executed contracts was approximately 4 to 1. As the CPUC has stated, "SCE's Solar PV Program and its other procurement efforts suggest that the market for smaller scale projects appears robust with a significant number of competing sellers."[8]

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7 *See* SCE Petition For Modification of Decision 09-06-049; A.08-03-015 (dated Feb 11, 2011).
8 D.10-12-048, p. 17 (decision adopting a Commission-approved procurement process for large investor-owned utilities – the RAM).

Next, in the 2010 Renewable Standard Contract ("RSC") program, SCE's voluntarily adopted predecessor to RAM, SCE received bids from projects representing roughly 2500 MW, 10 times more capacity than the program goal of 250 MW.[9] SCE ultimately signed contracts with 259 MW(ac) of renewable projects, and 239 MW(ac) of this capacity was solar PV projects. Thus, in the 2010 RSC solicitation, solar PV was clearly the most competitive technology.

Finally, SCE executed eight contracts through its 2009 RPS solicitation, and all eight projects were solar PV projects, representing over 850 MW of capacity. Based on the data from SCE's recent solicitations, current renewable energy trends have shown a significant market response for PV systems.

(iii) Does SCE expect to see more issues on legacy or new distribution circuits? What are the key reliability vulnerabilities? Does SCE have a goal for modernizing the distribution system?

The individual components of SCE's existing distribution system are reaching the end of their useful lives. Underground cable is the most troublesome type of the system component due to the time, cost and difficulty of detecting and addressing underground cable defects. To manage this issue, SCE has implemented a preemptive replacement program based on the probability of equipment failure due to age. SCE will continue to replace all cable and other system components until it reaches a long-term, steady-state replacement rate.

(iv) How are distribution system interconnection requests handled (compared to transmission)? What are the bottlenecks in the interconnection process?

Interconnection requests to SCE's distribution system are processed under SCE's Wholesale Distribution Access Tariff ("WDAT"), which was recently amended to eliminate the previous distinction between large generator procedures (for generating facilities larger than 20 MW) and small generator procedures (for generating facilities no larger than 20 MW). Under the revised procedures, all generation interconnection requests, regardless of size, are processed under the same set of integrated generation interconnection procedures ("GIP"). The interconnection procedures outline the studies that must be conducted to identify and allocate the financial responsibility for network upgrades, distribution upgrades, and interconnection facilities required to be constructed in order to maintain the reliability and safety of the distribution system.

The integration of small and large generator interconnection procedures was required due to the large backlog of interconnection studies, which was created from the unprecedented number of interconnection requests received by SCE, as well as the high degree of interdependency between the interconnection studies for all interconnection requests, regardless of size. This bottleneck lead to delays in completing interconnection studies on a timely basis, not just because of the work involved in performing the studies, but also because of delays required by

[9] SCE procured these MW through its voluntary RSC Program solicitation. SCE is no longer authorized to utilize its RSC Program for procurement of projects up to 20 MW in size. *See* D.10-12-048, Conclusion of Law No. 5, pp. 86-87 ("The IOUs should be required to use RAM exclusively for the procurement of system-side renewable projects up to 20 MW in size with the exception of other Commission-approved programs such as the utility solar *photovoltaic programs already authorized* by the Commission and annual RPS solicitations; IOUs should not use voluntary programs that target the same market segment or bilateral negotiations.") (Emphasis added.)

waiting for studies connected with earlier queued interconnection requests to be completed. SCE filed its amendment to the GIP on March 1, 2011. SCE's amendment to its GIP was approved by FERC in April of 2011. SCE expects that the revisions will create a more efficient and comprehensive set of interconnection procedures, reduce the overall time in which interconnection studies are performed, provide more equitable cost allocation for upgrade costs, give interconnection customers enhanced deliverability options, and allow for an expedited study process for generating facilities that are electrically independent of other interconnection requests.

VI. Clarification Regarding Distributed Generation Matrix

SCE would add the following points of clarification with respect to the CPUC Matrix on CPUC Distributed Generation Programs (the "DG Matrix").[10] First, SCE suspects that "CHP Competitive Procurement Program" cell in the "Program" column is actually referring to the QF/CHP Settlement Agreement. If so, the DG Matrix should be clarified to reflect this. Likewise, the "Capacity Size Limit (MW)" column should be revised to include "$\geq$ 5", rather than ">5" to reflect that this is for facilities with a nameplate capacity of greater than *or equal to* 5 megawatts. Additionally, the information in that row about when the solicitation will occur (i.e., "First solicitation anticipated to be held in April/June 2011") should be clarified. The first solicitation will occur within ninety (90) days after the effective date of the Settlement. The CPUC approved the QF/CHP Settlement Agreement and the associated CHP Pro Forma Contract in D.10-12-035. That being said the Settlement Effective Date will not occur until there is a final and non-appealable FERC decision on the investor owned utilities; FERC 210(m) Application to terminate the PURPA must-take obligation. While, the CPUC approved the Pro Forma in D.10-12-035, FERC approval is still forthcoming. Accordingly, SCE recommends that the text in this cell of the DG Matrix be replaced with the following text: "First solicitation anticipated to be held within 90 days from the effective date of the Settlement, which is still pending."

Thank you again for the opportunity to offer these comments and please feel free to contact me if you have any questions concerning the matters addressed herein.

Sincerely,

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[10] *See CPUC Distributed Generation Programs Matrix*, available at http://www.energy.ca.gov/2011_energypolicy/documents/2011-05-09_workshop/presentations/ (follow the "03b CPUC Clinton DG Programs Matrix Jan 2011.pdf " hyperlink).