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May 31, 2011

California Energy Commission
1516 Ninth Street
Sacramento, CA 95814-5512

RE: Docket No. 11-IEP-1G Committee Workshop of Renewable, Localized Generation

Dear Commissioners,

San Diego Gas & Electric Company (SDG&E) appreciates the opportunity to comment on the May 9, 2011 Committee Workshop on Renewable, Localized Generation.

The workshop was focused on Governor Brown's announced goal of installing 20,000 MW of renewable energy by 2020, of which 12,000 MW is localized electricity generation. SDG&E has voluntarily committed to achieving a 33 percent renewable energy target by 2020, and made this commitment well before the 33% renewable portfolio standard became law. SDG&E continues to work toward achieving this goal. SDG&E has issued Request For Offers (RFO) asking for renewable power every year between 2003 and 2009, and currently has another renewable RFO out to the market that will generate offers from both transmission and distributed connected renewable sources. Also later this year will issue the first in series of RFOs specifically targeting renewable resources 20 MW and below. The one thing in common in all of these RFOs was a goal to achieve the state's policy goals at the lowest possible costs to customers, including the costs of transmission and distribution upgrades.

While we appreciate the underlying objectives of establishing an aggressive distributed generation target, we think that setting these types of targets should be based on a reasoned consideration of the issues and impacts, particularly the cost and system impacts. In the context of the proposed target, we have a number of reservations that need to be, but have not yet been, part of the dialogue on distributed generation goals.

Among our chief concerns are the following:

- Distributed Generation imposes significant cost cross subsidies that must be eliminated.
- Distributed Generation additions must meet the requirements of least-cost, best fit principles, in the same manner as other renewables.
- Distributed generation decisions must take into account operating impacts, and, accordingly distributed generation locations must avoid uneconomic impacts n the electric system.

- Any distributed generation program must not place disproportionate burdens on any single utility's customers.
- Counting of distributed generation toward any targets needs to reflect the vast number of distributed generation programs already in place.

We comment further on these principles below.

1. Current Rules Result in Massive Cross Subsidies That Benefit Relatively Higher Income Customers at the Expense of Relatively Lower Income Customers.

With existing retail rate design, costs that are incurred by SDG&E to provide storage, reliability, balancing and grid integration services for net metered self-generation customers are paid for not by the generating customer, but by customers that do not have distributed generation. Indeed, these customers avoid paying their share of a large range of costs, shifting to other customers the obligation to pay these costs. These shifted costs include –

- Distribution costs
- Transmission costs
- California Solar Initiative
- Self-Generation Incentive Program
- CARE
- LIEE
- PIER
- PGC portion of renewables
- Energy efficiency
- Demand Reduction programs
- Nuclear decommissioning
- Reliability services (used to be called "reliability must run)
- DWR bond charges
- Competition Transition Charge

All of these costs can and are avoided by customers that can afford solar, and they are substantial amounting up to 20 cents for every kilowatt-hour consumed. The incentive to shift to others the cost of all of these programs and services is a huge inducement to add distributed generation, but it comes at a substantial expense. These cost shifts cannot be avoided by customers that lack a feasible solar option, who must not only pay his own share of the costs of services provided and important state programs, but also the costs to serve those installing distributed generation. Moreover, the impact of these net energy metering subsidies falls disproportionately on customers, such as lower income customers that cannot qualify for CARE rates but also cannot afford to add solar to bypass the cross subsidy. This results in inequitable socio-economic impacts. For example, about 80% of SDG&E's net energy metering solar customers (those that create the cross subsidies) have incomes above $78,000 and only 10% have incomes below $47,000 (those that cannot avoid paying the cross subsidies). Pursuit of the Governor's goals without eliminating these cross-subsidies that favor the wealthy would likely result in a public backlash against solar that could prove detrimental to the state's overall low carbon objectives.

2. **Decisions To Add Distributed Generation Must Consider Both Cost Effectiveness And Utility Need For Power, But They Do Not Under Current Rules.**

Distributed Generation costs can vary widely, based on the need for distribution system upgrades in particular areas. Therefore, utilities should be able to influence, through appropriate means, where distributed generation comes onto the system, to avoid uneconomic upgrades to accommodate DG deployment in the wrong locations. Under conventional rules for adding new generation to utility systems, utilities assess projects and rank them based on principles of "least cost/best fit". This means that generation decisions give greatest weight to those projects that impose the lowest cost on the utility system and can best be integrated into the system. The overall purpose of this is to minimize the cost to customers of adding new generation – both the direct cost of the energy and capacity procured, and the system costs necessary to integrate the resource. This is a statutory requirement under the new 33% Renewable Portfolio Standard.

Addition of distributed generation does not follow this same requirement. While that was a poor idea when the addition of distributed generation was more modest, it is an abandonment of the interests of our customers to ignore least-cost, best fit principles as part of any program to expand the addition of new distributed generation, particularly as a replacement for competitively procured supply that is selected using least-cost, best fit principles. It is not hard to see examples of the impacts of such a program -- adding a large amount of must-run distributed generation could, for example, put utilities in an oversupply situation during low load hours, forcing utilities to dump power during those hours (e.g. spring), thereby wasting ratepayers investments. Under least-cost, best fit principles, these impacts would be part of the consideration of whether to add that generation. Utilities would be reviled for ignoring such impacts. A DG policy that ignores them is no more prudent.

This is not a theoretical example. There are substantial questions on the ability of California consumers to use the power from the proposed distributed generation goal. It is likely on spring days, which have the lowest loads, that must take power from renewable and nuclear power, and plants needed for load following and regulation, will greatly exceed load. This will be especially true if the vast majority of the DG uses solar technologies. During these days, must-take renewable imports flowing into the San Diego basin from the Imperial Valley would result in excess energy being forced to flow north towards Los Angeles. Existing transmission infrastructure is not sufficient to allow for such power flows to the north (assuming they have had a need for power and were not also in an oversupply situation). Modeling also showed both high voltage conditions and stability problems on the transmission system.

Furthermore, SDG&E also cannot overbuild its distribution and transmission systems to serve generation project of any size that is sold to load serving entities serving retail customers outside of SDG&E's service area. SDG&E has approximately $700 million in Industrial Development Bonds (IDBs) that must be replaced if SDG&E builds facilities beyond what is needed to serve only its retail customers located within SDG&E's service area. In the absence of any mitigation through a FERC order compelling interconnection and transmission service, SDG&E would violate this test that has been established by the U.S. Internal Revenue Service (IRS) through private letter rulings. In addition to the need to replace all of these IDBs with new, non-tax exempt debt, the consequences of a failure to abide by the conditions established by the IRS could include the need to compensate bondholders for the loss of tax benefits associated with the IDBs retroactive to the first issuance. These IDBs have allowed SDG&E to finance a portion of its facilities at very favorable interest rates since the early 1980s, which has resulted in substantial customer savings. SDG&E would be required to seek a Federal Power Act Section 211/213 order from FERC to protect the tax exempt status. Unfortunately, the CPUC's Rule 21 interconnection process does not permit SDG&E to mitigate this outcome because only a FERC order compelling interconnection and transmission services offers as much protection to outstanding IDBs as possible.

Distributed Generation policy today ignores these impacts in choosing distributed generation projects. Under any program to expand distributed generation, it must reflect least-cost, best fit principles that would recognize these kinds of impacts.

3. **Any Distributed Generation Requirement Must Reflect System Operating Impacts**

From a system reliability standpoint, SDG&E is concerned about the impact of large amounts of distributed generation resources on the distribution system. Much of the push for distributed generation is based on the unproven, and largely incorrect, assumption that distributed generation can be connected at no incremental costs and will also result in avoided future distribution system investments. This assumption is inconsistent with SDG&E's actual experience.

As was presented at the workshop, SDG&E is already seeing impacts to its distribution system from the penetration of roof top photovoltaics, with is now about 100 MW. SDG&E has requested in its 2012 general rate case incremental costs of $54 million in 2012 and continuing through years afterward to mainly to accommodate achieving the 33% RPS goal and expected forecasted distributed generation (based on the current CEC rooftop solar forecast). Additionally, currently, distributed photovoltaics can impact the voltage on our local circuits and feeders, and, during some times of the year, can result in unacceptable voltage conditions. Absent the Utilities ability to limit where and how much DG is connected on a distribution circuit, customers could see substantial costs to interconnect, or an increase in rates (depending on how upgrade costs are paid for). Increasing the mandated amount of distributed generation DG further would result in even more electric distribution infrastructure costs. One appropriate means would be to ensure that distributed generation pays the full cost of upgrades necessary to connect their projects.

This would provide clearer incentives on where distributed generation might best be located.

Thus, SDG&E believes that any discussion of increasing the distributed generation target needs to take into consideration system constraints as well as operating impacts.

4. Any Distributed Generation Requirement Should Have Clearly Defined Goals And Must Not Have Disproportionate Impacts

SDG&E believes any State effort for DG should be driven by clearly defined objectives and a solid, well informed cost benefit analysis. If a goal is developed it should be a goal and not a mandate, with regular review conducted to see if it is achieving its objectives. Any goal to add additional DG should be predicated on its ability to reduce cost and increase benefits to our customers. The concern we are expressing is that the results at present are just the opposite – higher cost, and more problems. The PUC's analysis of the impacts of 33% renewables[1] made it clear that distributed generation as an option is a more expensive way of meeting the RPS (even assuming that all of the DG counts toward the RPS, which it does not, at present). Given that distributed generation is acknowledged to be a more expensive alternative for meeting RPS and AB32 goals, it begs the question to establish a distributed generation quantity goal without having a clear purpose for such a quantity, and it is not clear from the current promotion of distributed generation what the objective of the program is. Before pursuing the program, it is essential to have clear goals that go beyond setting a target level of distributed generation.

Any goal should be spread equitably across all the state electricity consumers, both those of investor-owned and publicly-owned utilities. Based on the load forecast adopt by the CEC in March, 2011, the SDG&E system peak is approximately 7.2% of the statewide peak. This is far different than some proposals we have become aware of that would assign 2000 MW of the 12,000 MW to SDG&E, or 16.6% of the statewide distributed generation goal. Nothing indicates that San Diego should bear a disproportionately higher share of this burden. Given the apparent costs and operating impacts, any program whose effect would be to impose such impacts cannot place that burden disproportionately on the customers of a single utility.

5. Consideration of Expanded Distributed Generation Must Reflect Other Principles To Minimize Cost and Operating Impacts

Expanding distributed generation necessitates developing ways to minimize costs and operating impacts. In addition to the broad principles discussed above, there are more discrete actions the State could take as it defines the scope of this program. Specifically --

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[1] California, Public Utilities Commission, *33% Renewable Portfolio Standard Implementation Analysis Preliminary Results*, June, 2009

- The scope of "distributed generation" should not be defined by size, but rather whether it connects to the distribution or subtransmission system.

- Distributed generation should not be confined to renewable supplies alone. The State has long had policies favoring distributed generation from all sources, including microturbines, fuel cells, combined heat and power, other non-renewable generation options.

- Distributed generation that currently exist or will be added under any of the State's programs should count toward any ultimate distributed generation goal the State decides to pursue. This should include the CHP settlement, the PUC's Renewable Auction Mechanism, the California Solar Initiative, the Self-Generation Incentive Program, the utilities' solar programs.

- Interconnection rules and technical specifications for PV system performance need reflect lessons learned and Germany and incorporate the new draft IEEE 1547.8 requirements.

Lastly, SDG&E has provided some short responses to the questions posed in Sections II which compares and contrasts the experience in Europe and Section II discussion about what area of Research and Development can advance DG.

We welcome the opportunity to expand on these concerns.

Sincerely,

Tamara Rasberry
Government Affairs Manager

II. Discussion on European experience integrating large amounts of DG

7) How are the European electrical distribution systems similar to or different from California?

Response:
Similar: Voltage levels similar
Differences: Europeans have 3 phase, protection – delays for equipment LTC, PQ looser, Protection for reverse power flow, DG has monitoring able to provide reactive power, fault ride through.

8) What challenges have European countries encountered from integrating distributed Renewable that are applicable to California, what actions did they take to address the challenges, and what lessons are applicable to California?

Response:
Voltage regulation problems, voltage rise problem, line upgrades large costs, frequency droop, maintenance of equipment, and safety actions taken, changed regulations and standards. California will need to implement similar line upgrades, require manufacturers of PV inverters to have more functionality and allow utilities to monitor and control. And California regulations and standards will need to be changed similar to the European standards. Substantial cost impacts.

9) As California builds out its distribution system, what lessons can be learned from The European experience?

Response:
To require advanced capability for DG equipment, and provide proper incentives and how to pay for costs of distribution upgrades.

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

1) What is the role of RD&D in advancing distributed generation and helping achieve the Governor's Clean Energy Jobs Plan and other current and future state policy goals such as the Renewable Portfolio Standard and AB 32?

Response:
R&D must be focused on mitigating the impacts of DG on the transmission and distribution system using new technology like dynamic voltage regulation and smart inverters. Also work is needed on developing advanced forecasting of DG levels.

2) Please comment on the maturity of distributed generation technologies. Which technologies or components should RD&D efforts focus on to address some of the barriers for advanced DG deployment?

Response:
Development of new inverters that can communicate with the local utility and accept set points for voltage regulation, reactive power production, frequency response, and production output are needed.

3) Are currently existing technologies and tools enough to power facilities with nearly 100 percent renewables in a technically and economically feasible manner? What are some emerging technologies that may be able to reduce costs when produced at scale?

Response:
Energy storage may offer the ability to smooth out the impacts of variability and intermittency of DG renewable and provide voltage support. More simulation and field testing is required.

4) What issues impede the deployment of distributed generation technologies in utility distribution territories that RD&D can help address? If so, please identify the issue and how RD&D can help in a manner that benefits both the utilities and customers.

Response:
Voltage and frequency regulation along with intermittency impacts are the biggest issues. Reverse power flow is also a concern. R&D needs to be focused on mitigating these impacts.

5) What other future research direction, focus, strategies or initiatives may be recommended for PIER to undertake so that RD&D can better help advance DG?

Response:
Additional technical studies examining the impact of high PV penetration on the local distribution circuit as well as the overall system need to be investigated. Rapid development of smart inverters and new dynamic voltage regulation equipment is needed.