04-DIST-GEN-1

Rulemaking No.: 04-03-017

Exhibit No.:

Witnesses: Carl Silsbee
Scott Lacy

SOUTHERN CALIFORNIA
EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

PREPARED REBUTTAL TESTIMONY OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

Before the

Public Utilities Commission of the State of California

Rosemead, California

April 28, 2005

LW051160015

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I.

INTRODUCTION AND SUMMARY

As directed by the presiding administrative law judge, parties in this proceeding submitted their supplemental or revised opening testimony on April 13, 2005. Southern California Edison Company (SCE) received opening testimony from Pacific Gas & Electric Company, San Diego Gas & Electric and Southern California Gas Company, the Office of Ratepayer Advocates (ORA), Americans for Solar Power (ASPv),[1] the California Clean DG Coalition (CCDC)[2] and PV Now. This rebuttal testimony will focus primarily on those parties that propose cost-benefit methodologies which unfairly skew the results in favor of certain distributed generation technologies, instead of an approach that fairly assesses the costs and benefits of different DG technologies and applications from a variety of perspectives.

SCE urges the Commission to reject the various quantification approaches suggested by ASPv, the proposals by ASPv and CCDC to overturn the Commission's findings on physical assurance in D.03-02-068, and various recommendations concerning cost-benefit analyses made by ORA and PV Now, as further described in the testimony which follows. Instead, the Commission should adopt a cost-benefit framework based on the California Demand Side Management Standard Practices Manual (SPM) and generally follow the methods described in a report prepared by Itron regarding an evaluation of the Self Generation Incentive Program, as described in SCE's April 13, 2005 testimony.

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[1] ASPv has indicated that it will also offer the "Testimony of Lori Smith Schell, PhD" and the "Testimony of First Solar" which were served on October 4, 2004.

[2] CCDC was previously known as the Joint Parties Interested in Distributed Generation/Distributed Energy Resources. CCDC's April 13, 2005 testimony replaces the testimony by the Joint Parties on October 4, 2005.

II.

SCE'S REBUTTAL

A. Response to ASPv's Testimony

Q1. What is your opinion of the PLEASE matrix that Dr. Schell proposes be used "to unify various perspectives and types of DG"? (October 4 Testimony at page 10). [**All responses are sponsored by Carl Silsbee, with the exceptions of Questions 13 – 16**].

A1. It is a distraction from the objectives that the Commission has set for this phase of the DER/DG OIR proceeding. By its nature, cost-benefit analysis focuses on quantitative measures. The notion that one can calculate a benefit-cost index as a simple ratio of qualitative factors creates a false sense of precision.

Moreover, the construction of the PLEASE matrix is fundamentally flawed and unable to provide a fair comparison among DG technologies and between DG technologies and central station power plants. This index is simply not usable for making decisions on incentive policy and resource choices.

Q2. What are the flaws you see with construction of the PLEASE matrix?

A2. There are at least three problems with Dr. Schell's proposed matrix. First, it is not appropriate to give each and every qualitative factor equal weight. For example, Diesel units used in DG applications are often extremely dirty. This appears to be a good reason which justifies excluding Diesel-fired DG units from some of the incentive programs administered by the CEC and CPUC. While these adverse impacts are included in the PLEASE matrix, their significance is submerged by simply summing up individual factors into an aggregate index. Second, there are a wide range of central station technologies, so it is not possible to simply compare various DG technologies to an unspecified central station power plant. For example, a solar DG facility would compare favorably to a gas-fired power plant in terms of CO_2 emissions, but would be equivalent to a nuclear plant on this factor. Third, lists such as those developed for the PLEASE matrix are highly subject to bias based on the preferences of those creating the listing. For example, a supporter of central station power plants might argue for including factors which recognize the ability of a central station power plant to reuse a brownfield site or that the larger size of central station power plants makes pollution control programs such as RECLAIM administratively feasible.

Q3. Are you suggesting that the factors listed in the PLEASE matrix are biased?

A3. No, I'm simply suggesting that the choice of which factors to include on such a list is an unnecessary debate in which the Commission need not, and should not, engage. I am concerned, however, about Dr. Schell's suggestion that there are other attributes that "can and should be included" in the PLEASE matrix with reference to the 207 distribution benefits identified in Amory Lovins' book "Small Is Profitable." A listing of reasons why distributed generation is superior to central station power plants is hardly an appropriate source of objective factors which should be added to the PLEASE matrix.

Q4. What is your opinion of Dr. Schell's observation at Page 13 of the October 4 Testimony that a study by the Princeton Environmental Institute (PEI study) is "a first step towards developing a framework" that considers both directly quantifiable avoided costs and factors such as those included in the PLEASE matrix?

A4. The presentation of benefits and costs in the PEI study is not consistent with the SPM, making it important to carefully consider the nature of the comparisons presented. The summary result presented in the PEI study and replicated in Exhibits LSS-6 and LSS-7 of Dr. Schell's October 4, 2004 testimony compare purported avoided cost savings and environmental benefits with average retail rates. In the SPM framework, the PEI study approach appears similar to the non-participant test, since it treats bill savings as a cost, except that it includes purported environmental benefits which accrue to society at large rather than to non-participating customers. Thus, the results of this analytical approach do not directly measure rate impacts. Since the cost of DG facilities is not included in the PEI study, the findings of the PEI study simply do not address whether DG is cost effective from either a participating customer or a societal perspective.

Q5. Do you agree that the PEI study demonstrates a "value premium" associated with residential solar DG applications? (October 4 Testimony at page 14)

A5. No. Although I haven't had an opportunity to thoroughly investigate the figures from the PEI study presented in Exhibits LSS-6 and LSS-7 of Dr. Schell's October 4, 2004 testimony, an initial review reveals a number of unusually high values. The PEI study values avoiding greenhouse gas emissions at \$0.019/kWh (on-peak) based on an underlying value of \$100 per ton of carbon. In contrast, the CEC has recommended a value of \$30 per ton of carbon (equivalent to \$8 per ton of CO_2).[3] The value for avoiding NOx emissions also appears high. For example, the E3 report assumes an avoided NOx value of about \$5 per pound with emission rates ranging from 0.05 to 0.20 pounds per MWh depending on the efficiency of the power

[3] *See* CPUC Resolution E-3592, Attachment B: Appendix C, page 28, April 1, 1999, citing CEC recommendations.

plant.[4] Using the higher emission rate suggests a NOx value of $0.001/kWh in comparison to the PEI study's value of $0.0137/kWh (on-peak). Finally, the avoided T&D losses of $0.0427/kWh (on-peak) from the PEI study, seem extraordinarily high—about 72% of the avoided fuel cost value of $0.0589/kWh. The overall PEI peak period avoided generation cost of $0.2844/kWh appears overstated. For comparison, the Commission recently released Market Price Referent (MPR) values for use in renewable procurement of $0.1142/kWh.[5]

Q6. Do you agree with the PEI study's conclusion that net metering can serve as an effective surrogate until electricity pricing reforms take place? (October 4 Testimony at pages 15-16)

A6. No. This conclusion is apparently premised on a belief that since DG facilities' purported value exceeds average retail generation rates, some form of subsidy is necessary to provide an accurate "surrogate for correct electricity pricing" to customers considering DG. As I indicated above, the DG avoided cost valuation appears too high. In addition, it isn't possible to draw a conclusion about price signals from utility average rates. Rate schedules involving inclining block rates, time-of-use pricing or on-peak demand charges will allow a solar DG to achieve much higher bill savings per kWh of DG production than average retail rates. Indeed, these forms of retail pricing may address at least some of the concerns expressed by the authors of the PEI study.

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4 The E3 report is described on pages 24-25 of SCE's April 13, 2005 testimony. The NOx figures cited above are at pages 73 and 78 of the E3 report.

5 See R.04-04-026, Assigned Commissioner's Ruling Issuing Revised 2004 Market Price Referents for the Renewable Standard Program, February 11, 2005.

Q7. Do you agree with Dr. Schell's addition of avoided T&D values to the PEI study results? (October 4 Testimony at page 14)

A7. No. Decision 03-02-068 found that DG's ability to defer distribution investment is time and location limited, and requires physical assurance.[6] SCE strongly supports these findings.

Q8. Do you agree with Dr. Schell's conclusion that the capacity value of a photovoltaic DG project is based on the shape of a customer's load and its coincidence with the electricity generation pattern of the DG project? (October, 2004 Testimony at page 12)

A8. No. The term "capacity value" typically refers to the capacity component of avoided generation costs. The avoided cost value of a DG project is based on how well the generation pattern matches system avoided generation costs, not the host customer's load shape. However, customer bill savings may be affected by the relationship between the customer's load pattern and the generation pattern of the DG project, depending on the customer's rate schedule.

Q9. Do you agree with Dr. Schell's recommendation to use a DG project's Effective Load Carrying Capacity ("ELCC") as the basis for computing the value of DG in avoiding T&D costs? (April 13 Testimony at page 12).

A9. No. ELCC is a generation-related measure that is not suitable for determining the impact of a DG project on localized distribution facilities. The presence of a robust transmission grid with numerous interconnected generators allows resource planners to "count" the effective capacity of

[6] D.03-02-068, Findings of Fact 2 through 7.

individual generators by using a 15% to 17% reserve margin to account for various uncertainties including the potential for generator outages. This is not applicable to lower voltage distribution facilities, where failure of a single DG project to operate at peak times could jeopardize service to all customers on a circuit unless the DG host customer provides physical assurance.

Q10. Is the estimated value of distributed solar PV of 7.8 to 22.4 cents per kWh identified by Dr. Schell consistent with the SPM approach to measuring cost effectiveness? (April 13 Testimony at page 19)

A10. No, it is not. For example, an SPM approach would identify the expected hourly deliveries of power from a solar project, calculate avoided cost savings associated with these hourly deliveries, and compute overall net present value benefits. Instead, Dr. Schell computes simple cents/kWh average generation cost ranges for her analysis. This is a flawed approach, which is not capable of producing valid results. For example, Dr. Schell calculates avoided generation capacity capital costs by taking a range of capacity costs ($419 to $616 per kW) adjusted with a fixed charge rate of 15% plus a range of associated fixed O&M ($4.33/kW to $10.20/kW) and adjusting the sum with a an ELCC of 65%. The result is divided by the expected number of hours per year a solar facility would operate (1752 hours) to express avoided cost savings on a cents per kWh basis. This creates a paradoxical result: if the number of hours that a PV project operated were cut in half, the value calculated using Dr. Schell's method would double.

B. <u>Response to CCDC's Testimony</u>

Q11. Do you agree with Ms. Yap's recommendation that the Commission adopt a modified version of the cost effectiveness methodology proposed for energy efficiency in the E3 Report?

(Testimony at page 3)

A11. No. First of all, the E3 Report proposes an avoided cost forecasting methodology, not a cost effectiveness methodology for energy efficiency evaluation. SCE has concerns with both the E3 avoided cost forecasting methodology and with the wholesale application of the E3 avoided cost forecasts to distributed generation installations.

Distributed generation, regardless of the technology, is not energy efficiency and the assumption should not be made that an adopted avoided cost forecasting methodology designed for energy efficiency can or should be applied to distributed generation. In fact, as noted in our opening testimony, the Commission has expressly reserved this very question to a separate phase of the avoided cost proceeding (R.04-04-025).

Second, SCE has concerns with some of the avoided cost components in the E3 report, including, but not limited to, calculations for the avoided costs of generation, avoided transmission and distribution costs and environmental externality values.

Q12. What are your specific concerns in those areas?

A12. SCE anticipates that the appropriateness of the E3 avoided cost forecasts will be addressed in R. 04-04-025, and not in this proceeding. However, since CCDC has recommended that the Commission adopt this forecasting methodology in this proceeding, SCE identifies some of its concerns as follows.

For **avoided generation costs,** E3 proposes to use a Combined Cycle Gas Turbine (CCGT) as the marginal resource.[7] This is not appropriate. Traditionally, resource planners have characterized generating technologies as peaking, mid-merit and baseload based on their capital and operating expenses. A peaking unit, such as a combustion turbine (CT), has relatively low capital costs and high operating costs. Due to the high operating costs, a CT operates relatively infrequently (such as 5% to 10% of the time), mostly when demand is high. A mid-merit unit, such as a CCGT, has higher capital costs and lower operating costs, and operates perhaps 50% to 90% of the time depending on its heat rate and system demand levels. A baseload unit has relatively high capital costs and low operating costs, and is typically operated as close to 100% of the time as its maintenance requirements allow.

The Commission has a long-standing policy of developing avoided generation costs using a CT proxy method for capacity and a system incremental energy cost for energy. This approach has been supported in numerous Commission decisions.[8] If one analyzes generation expansion

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[7] "For the period from 2008 through the end of 2023, we assume that the annual average cost of electricity will be equal to the full cost of owning and operating a combined cycle gas fired generator." E3 Report, page 48. "We allocate the annual generation prices to hours of the year using an hourly shape derived from the California PX hourly NP15 and SP15 zonal prices from April 1998 – April 2000, the period immediately prior to the Energy Crisis." E3 Report, page 49.

[8] A CT proxy methodology has formed the basis for most QF standard offer pricing options since the early 1980s. It has been used for DSM/EE program evaluation and for the marginal cost studies which support utility rate design over much of this same period. The CT proxy is time and seasonally differentiated to capture how capacity value varies during a year.

decisions using a linear programming algorithm, the constraint equations would seek to assure that all load is served and the objective function would seek the combination of peaking, mid-merit and baseload units that satisfy the constraint equations at minimum cost. The so-called shadow price associated with a change in customer peak demand would be the capital cost of a CT, and the shadow price associated with a change in customer usage would be the operating cost of the type of resource on the margin associated with the usage. Viewed from this perspective, the capital cost of a CCGT can be separated into a capacity-related component and an energy-related component (the so-called "energy-related capital cost" or "ERCC"). The latter component essentially reflects a cost-effective substitution of capital for fuel costs. Thus, the full capital cost of a CCGT cannot be used as a proxy for capacity value alone because a portion of the capital costs are motivated by a desire to achieve fuel savings during extended hours of operations when there is considerably more than adequate capacity to meet customer demands.

SCE is concerned about the potential bias introduced by moving away from the CT proxy approach and substituting a CCGT for both capacity and energy. The use of the full capital cost of a CCGT as a proxy for the avoided cost of capacity will misstate avoided costs for high-usage periods when CTs would be operating as the marginal units and low-usage periods when baseload units may be operating on the margin and CCGTs would not be in operation.

For **avoided T&D costs**, E3 recommends a T&D avoided-cost method that generally presumes that DSM can and will defer T&D infrastructure if implemented.[9] E3 recommends values based on T&D information submitted by utilities in rate design marginal cost studies. While these utility studies are useful in identifying how T&D costs increase across broad regions within

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[9] "E3 recommends that the utilities be allowed to de-rate the avoided T&D costs forecast in this report. T&D costs will only be reduced if a significant amount of load reduction is attained in an area, such that the utility expansion plans can be altered. Deration lessens the problem of 'overvaluation' if the utility does not expect to attain enough timely load reduction to affect its construction plans. Deration applies most to the near-term avoided costs, and less, if at all, to the avoided costs beyond ten or fifteen years." E3 Report, pages 95-96.

utility service areas in response to sales and customer growth, they are not necessarily valid in assessing the impacts of DG applications. Transmission facilities are heavily networked to provide sufficient redundancy so that reliability can be maintained even during adverse contingency conditions. Given the widespread economic consequences that are caused by transmission system failures, it is important to maintain a high degree of transmission reliability. Except in rare, unusual, and atypical cases, it is difficult to see how DG could have any substantial impact on investment in a transmission system that is designed to achieve this very high degree of reliability.

Unlike transmission, the distribution system is more radial in nature, so an outage on a distribution circuit will typically interrupt customers on the affected portion of the circuit. SCE's current reliability performance averages about one sustained outage with duration less than one hour per customer each year, with the substantial majority of outages originating at the point of transformation between transmission and distribution, or within the distribution system. This is over 99.99% reliability. In general, customer-side resources cannot provide this level of performance without being coupled with physical assurance under which an offsetting amount of customer load is interrupted when the DG facility is unavailable. Even where it is feasible for a DG facility to substitute for a distribution upgrade, there are complex issues of timing, physical assurance, and level of control. For instance, if a distribution circuit has adequate capacity in an area experiencing slow load growth, it may take years before there would be any upgrade costs that a DG facility could defer. At the other extreme, in a rapidly growing area, a DG facility might defer an upgrade soonervery soon – but only for a few years.

An additional concern with the E3 report methodology is the conversion of T&D avoided costs to $/MWh energy values using the time-dependent valuation methodology. This methodology apportions the T&D avoided costs in an area relative to temperature peaks, which fails to reflect the necessity of a DG unit providing reliable load reduction in all peak hours in order to reduce the capacity need on associated distribution circuits. In addition, this approach fails to recognize that a substantial portion of SCE's distribution circuits, primarily in mild-climate coastal areas, tend to peak in evening hours. T&D avoided costs, when applicable, are more appropriately calculated and applied on a $/kW basis.

As for the treatment of **environmental attributes** in the E3 report, it is important to note that NOx and PM-10 are regulated pollutants in California and are subject to a variety of control mechanisms and standards which vary by geographical location. In general, new pollution sources are required to purchase air emission permits that are valid until surrendered or transferred. By limiting the number of permits, air quality regulators are able to control the level of emissions from sources within the control regime. With regard to NOx, the South Coast Air Quality Management District (SCAQMD) maintains a separate control program (RECLAIM) which will have the effect of internalizing the cost of control in the market prices of energy.

While including environmental control and offset costs as part of avoided generation costs is appropriate, care must be taken to avoid double counting. Based on SCE's review of the E3 avoided-cost evaluation tool, it appears that E3 has included the cost of environmental controls and offsets in the capital cost of the CCGT facility used as a market price proxy and has recommended a separate stand-alone environmental adder. The CCGT in-service capital cost used in the E3 spreadsheet is $616/kW,[10] which is equal to the capital cost cited in the CEC study to which E3 attributes the figure.[11] According to the CEC study, approximately $12/kW of the $616/kW capital cost is associated with purchasing air emission permits. In addition, there is an inconsistency between E3's use of a new-build CCGT proxy for determining avoided

[10] See E3 Report, Table 6, page 63. This value is on worksheet "LRMC Model", cell E9 of version 21 (dated 10/20/2004) of the E3 spreadsheet.

[11] The CEC study is cited in footnote 33 of the E3 report. The $616/kW in-service cost for a CCGT is shown in Table C-10 and the air emission permit capital costs are shown in Table C-11.

generation costs, and the environmental adders, which are based on a weighted average of older and newer plants.[12]

Q13. Do you agree with Ms. Yap's recommendation to require utilities to assess the incremental cost of reduced transmission system vulnerability (i.e., an avoided transmission reliability cost)? [**Responses to Questions 13 – 16 are sponsored by Scott Lacy**].

A13. No. SCE is not solely responsible for transmission planning. Utilities like SCE that are Participating Transmission Owners (PTOs) in the CAISO, and have turned over operational control of their transmission facilities to the CAISO, are obligated to perform, in coordination with the CAISO, the necessary studies to determine the facilities needed to meet NERC,[13] WECC,[14] and CAISO planning criteria. During these studies, the CAISO, in coordination with the PTO and other market participants, must identify the need for any transmission additions or upgrades required to ensure system reliability consistent with all applicable reliability criteria. In making this determination, the CAISO, in coordination with the PTO and other market participants, considers lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, demand-side management, remedial action schemes, constrained-on generation, interruptible loads or reactive support. The CAISO process already takes into account system "vulnerabilities." It is not clear what additional vulnerabilities need to be incorporated into the analysis.

[12] "We compiled the reported and permitted emission rates for NOx and PM-10 for over 15 plants in California included [sic] emission estimates for aging plant in California." E3 Report, page 72 (footnote omitted). These values are used to construct an emission cost curve which is used to compute emission costs based on a time-on-margin analysis of new and older plants. See E3 Report, Figure 30, page 80.

[13] North American Electric Reliability Council

[14] Western Electricity Coordinating Council

Q14. Do you agree with Ms. Yap's recommendation that utilities be required to perform additional transmission system simulation studies to identify substations which face excessive stresses?

A14. No. As stated in response to Question 13, utilities like SCE that are PTOs and have turned over operational control of their transmission facilities to the CAISO are obligated to perform, in coordination with the CAISO, the necessary studies to determine the facilities needed to meet NERC, WECC, and CAISO planning criteria. Such studies identify areas of the transmission grid for which expansion, upgrades, or other lower cost alternatives may be necessary to meet applicable reliability criteria.

Q15. Do you agree with Ms. Yap's recommendation to rely on DG project diversity instead of physical assurance as the basis for including avoided T&D benefits.

A15. No. It is possible that project diversity could enhance the reliability of the DG installation but would not substitute for physical assurance. A DG owner who can provide the same level of reliability as SCE's delivery grid through redundancy should not be concerned with providing physical assurance. Without such assurance, however, the utility runs the risk of not being able to meet its obligation to serve its other customers. There is significant merit to the Commission's decision to rely on the certainty of physical assurance to back up the operation of a DG unit instead of relying on diversity. Moreover, physical assurance provides a strong incentive to the DG owner to maintain the DG unit in good repair and operate during expected local system peak periods and emergency circumstances.

Q16. Do you agree with Ms. Yap's statement in A40 that "The recent outage in Southern California Edison's service area caused by the substation failure emphasizes the need for DG reliability enhancements in California?"

A16. No. I assume that Ms. Yap is referring to the simultaneous failure of two (of three) A-banks at the Moorpark substation in early September 2004. The Moorpark substation is part of SCE's distribution system. The failure of the two A-banks was an extremely unlikely circumstance during which some of our customers briefly experienced rotating outages. A self-generating customer otherwise served by the Moorpark substation could have provided a portion of their own load during outages. However, during the time of the failure, system protective devices would have isolated any DG from the rest of the SCE system to maintain system integrity. It is unclear from Ms. Yap's testimony exactly how DG reliability enhancements would have prevented or significantly minimized the impacts of this event.

Q17. What is your reaction to Ms. Yap's observation that requiring physical assurance for DG units is inconsistent with the current practice of including avoided T&D cost benefits for energy efficiency programs without any similar requirement for physical assurance? (Testimony at pages 14-15).

A17. The decision to include avoided T&D costs in energy efficiency programs (Resolution E-3592 and D. 05-04-024) was made without the benefit of either testimony or hearings. The applicability of these avoided costs to distributed generation is under review in a phase of the Avoided Cost OIR, so the current treatment for energy efficiency programs should not be considered as precedential. Whether a DSM/EE program can avoid T&D investment is a complex issue, just as it is for DG. SCE has provided comments on this topic in the Avoided

Cost OIR, generally reflecting a view that a case-specific determination is necessary before reflecting any avoided T&D costs in DSM/EE evaluations.

Q18. Do you agree with Ms. Yap's recommendation that the Commission rely on DG cogeneration project diversity instead of physical assurance as the basis for concluding a DG project is capable of avoiding distribution costs? (Testimony at page 22)

A18. No. First of all, the Commission has already concluded that physical assurance is required before a DG project is capable of avoiding utility distribution system investments in D. 03-02-068. The Scoping Memo has excluded reconsideration of this policy choice from this proceeding.[15] Thus, Ms. Yap's testimony on this subject is outside the scope of issues to be addressed at this time. Moreover, the study cited by Ms. Yap actually demonstrates the importance of the Commission maintaining its current policy. Although the "Hedman Study" reports survey data that shows cogeneration projects have availability factors of 95% to 97%, as CCDC notes in its testimony, the study also shows that these projects actually operate around 75% of the time (service factor), since they are dispatched to meet customer needs, not utility needs. Physical assurance is an ideal mechanism to provide a DG project with the incentive to operate at times when its output is needed by the utility. Although Ms. Yap asserts that DG cogeneration project diversity is sufficient to rely upon, she provides no facts to justify this position.

[15] Scoping Memo, page 8.

Q19. Do you agree with Ms. Yap's statement in A45 that "During a DG forced outage, the utility should provide standby service if it has sufficient unused capacity in its local distribution area?"

A19. No. SCE already offers standby service to customers using DG which is available when a DG unit is not operating for any reason, not just for forced outages. However, for a customer that elects not to pay for standby service, physical assurance is necessary to permit a reduction in circuit loads to allow SCE to serve other customers on that same circuit. There is no cost-based justification for providing unused distribution capacity for a customer who decides not to pay for standby service by providing physical assurance. This situation is tantamount to a customer who places demand on a local distribution circuit with unused capacity not paying any distribution charges. This will obviously discriminate against other customers in that area who pay for distribution services.

Q20. Do you agree with Ms. Yap's statement that DG cogeneration projects have "an excellent reliability record"? (Testimony at page 22)

A20. The availability statistics shown in the "Hedman Study" may be good in comparison to other types of generators, but they are far below current distribution service reliability. A 95% reliability rate corresponds to about 18 days of outage per year. In comparison, SCE customers currently experience an average of about one hour of distribution outages per year, which is about 99.99% reliability. Even considering the potential for diversity, the contributions that DG projects can make towards distribution system reliability is limited. For example, while two units with 95% availability on the same circuit would provide a 99.75% likelihood that at least one unit would be available (1 – 5% X 5%),[16] there would only be a 90.25% likelihood that both units would be available (95% X 95%). Thus, even if project diversity can be taken into consideration, only a portion of the aggregate capacity of a group of DG cogeneration projects could be considered as reliable.

C. Response to ORA's Testimony

Q21. Do you agree with ORA's recommendation to require the use of a program administrator test in SGIP evaluation?

A21. No, the program administrator test should not be a required element of the SGIP evaluation, since it is not clear which entities would be the program administrator and what purpose would be served by this test. The program administrator test essentially compares the resource cost savings created as a result of an energy efficiency program with the direct costs incurred by the program administrator in operating or overseeing the program, including any incentives paid to elicit customer participation. Thus, the program administrator test can provide a measure of how effectively administrative costs are "leveraged." However, this test does not include participant costs, so it is not suitable as a measure of overall ratepayer or societal benefits associated with an energy efficiency program. Also, since bill impacts are not considered, the program administrator test does not address the cross subsidy impacts that are commonly measured using a non-participant test. Thus, the program administrator test is not useful for exploring incentive levels.

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[16] This ignores the potential for outages to be correlated, such as may result from cloud cover in a local area (solar) or interruptions of fuel supply (cogeneration).

D. <u>Response to PV Now's Testimony</u>

Q22. Do you agree with Mr. Schiller's observation that the SPM cost effectiveness tests are simplified screening metrics compared to resource planning approaches and do not explicitly account for risk analysis? (Testimony at pages 5-6)

A22. I do not agree that the value of SPM cost effectiveness tests is limited to a simplified screening tool. The SPM test provides decision makers with important information concerning the distributional impacts of programs in which ratepayers are being asked to pay for subsidy support. Since an important goal of the Commission in this proceeding is to develop tools that can be used to assess distributed generation incentives, the SPM test is particularly valuable. I do agree that the SPM test does not explicitly capture the impact of a particular technology on the overall risks of SCE's procurement portfolio to SCE's customers. These considerations are best dealt with in the context of a resource plan proceeding.

Mr. Schiller appears to speculate that solar photovoltaic resources may benefit in comparison to fossil-based resources due to electricity market volatility. Since solar photovoltaic projects involve high capital investments, however, they may create a potential stranded cost exposure should fuel prices fall or other technologies advance. This should be taken into consideration in a risk assessment of solar photovoltaic technology.

Q23. Should "market effects" be included in the cost-effectiveness analysis of distributed generation projects? (Testimony at pages 8-10)

A23. Mr. Schiller suggests that there should be a market development component of photovoltaic programs in order to "foster lower societal, participant and non-participant resource costs by creating market demand...sufficient to make PV cost-competitive without incentives within 10 years."[17] The Commission should evaluate distributed generation projects excluding any potential "market effects" in order to understand the potential impacts of current incentives on non-participating customers. If existing incentives result in non-participating customers subsidizing distributed generation, the question of whether "market effects" justifies this subsidy can then be addressed. Before approving incentives which result in impacts on non-participating customers, there should be a clear justification that the incentives are actually a necessary contributor to declining solar photovoltaic prices and that non-participating customers will receive appropriate long-term benefits sufficient to justify their "investment" in promoting solar photovoltaic installations.

[17] Testimony at page 10.