Rulemaking No.: 04-03-017

Exhibit No.:

Witnesses: Carl Silsbee
Scott Lacy
Akbar Jazayeri

SOUTHERN CALIFORNIA
EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

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

Before the

Public Utilities Commission of the State of California

Rosemead, California

April 13, 2005

LW050980058

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I.

INTRODUCTION

A. Background

In their August 6, 2004 Ruling (the Ruling), the Assigned Commissioner and Assigned Administrative Law Judge directed parties to submit testimony on the subject of a cost-benefit methodology applicable to Distributed Generation (DG). The Ruling directed parties to (1) identify the relevant perspectives for purposes of cost-benefit testing, (2) identify the appropriate costs and benefits applicable to each perspective and propose methods to quantify the applicable cost and benefit factors, (3) identify specific sources of data inputs, and (4) propose equations/calculations defining the tests.[1] In addition, the Ruling requests utilities to provide specific proposals to make relevant information and data necessary to calculate costs and benefits available to parties, asks parties to address disclosure of DG operational data, and directs parties to address program monitoring, measurement and evaluation issues.[2]

The Commission opened the subject rulemaking on March 16, 2004. In its Order Instituting Rulemaking, the Commission identified as one of its goals the development of a cost-benefit analysis methodology for Distributed Energy Resources (DER) and net energy metering. Since that time, the Commission has solicited and has received a number of comments on this topic. Based on the comments received to date, there appears to be general support for the following threshold conclusions which both shape and guide the choice of an appropriate DG cost-effectiveness methodology.

1. The DG cost-effectiveness methodology must take into consideration the variety of ways in which a DG facility can be used. DG can provide primary, supplemental or back-up generation for a customer ("Self-Generation DG"), DG can sell wholesale power into the

[1] Ruling, p. 8. In addition, the Ruling encourages parties to present illustrative examples of the application of their recommended methodology.

[2] *Id.*, pp. 9-10.

grid ("Merchant DG"), and DG can be deployed at specific locations at a utility's request to reduce or defer the need for distribution system investments ("Distribution DG").

2. The DG cost-effectiveness methodology should allow results to be presented from a variety of perspectives to account for differences in the "sponsorship" of particular DG applications. For instance, viewing DG cost effectiveness from the perspective of a customer considering a Self-Generation DG application is useful to understand and design appropriate incentive policies, while viewing DG cost effectiveness from the perspective of a utility seeking to maximize overall ratepayer value reflects a core responsibility of utilities and the Commission.

3. Utility rate designs and tariff provisions (such as standby charges) are a key element in the cost effectiveness of Self-Generation DG for the participating customer and the impact that these units have on the rates paid by other customers. Thus, implicit subsidies (created by rate designs for which customer bill savings do not match avoided cost savings) and explicit subsidies (waiver of tariff charges or direct payments to participants) are important policy variables which must be considered by the Commission.

The DG cost-effectiveness methodology that SCE proposes in this testimony addresses all of these threshold considerations.

B. Summary and Organization of Testimony

There are three broad elements of a cost-effectiveness analysis: the framework or structure of the analysis, the specific categories of benefits and costs used in the analysis, and the methods used to quantify the benefits and costs. In Section II, SCE describes the appropriate framework for a DG costs-effectiveness analysis. SCE supports an approach similar to that in the Demand Side Management (DSM) Standard Practice Manual which presents benefits and costs from the perspective of participating customers, non-participating customers, and an all-ratepayers or societal perspective. Also in Section II, SCE describes the categories of benefits and costs that should be included in this analytical framework, and addresses the specific benefits and costs listed in the Ruling.[3] With this background, Section III then describes how SCE currently incorporates DG in its procurement and distribution system planning. For procurement planning, SCE forecasts Self-Generation DG and incorporates it as a reduction in customer demand. SCE supports a principle of customer choice, in which customers are provided a reasonable opportunity to participate in DG without undue subsidy or discrimination. For distribution system planning, SCE considers DG as an alternative to "wires-based" approaches for meeting customer needs. This chapter also addresses compliance with the requirement in Public Utilities Code Section 353.9 that the net cost of certain tariff provisions established for DG be recovered from within each applicable customer class. Section IV addresses avoided cost savings, the principal overall ratepayer benefit associated with DG units. In R. 04-04-025, the Commission is reviewing the results of a project directed by the Commission staff to develop an avoided cost quantification methodology and is considering the applicability of this methodology to other resources, including DG. Section V presents several examples of applying cost-effectiveness analyses to hypothetical DG projects. SCE presents illustrative results for a rooftop solar project serving a residential customer and a combined heat and power (CHP) turbine project serving a medium-sized commercial customer. Finally, Section VI addresses the issues associated with access to utility data and measurement and evaluation protocols that have been raised in the Ruling.

II.

COST-BENEFIT FRAMEWORK AND ELEMENTS

A. Cost-Benefit Framework

A cost-benefit analysis compares the likely benefits of a project with its likely costs, to assist a decision-maker in choosing whether to go forward with a project. In the case of DG, a cost-benefit analysis can also provide information that will assist the Commission in making DG policy decisions, including whether to extend, eliminate or modify ratepayer-funded DG subsidy programs.

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[3] *Id.*, pp. 5-7.

The Ruling points to the California DSM Standard Practice Manual (SPM) as a potential starting point that a number of parties have advocated for in developing a DG cost-benefit methodology. Since the Ruling, the Commission has released a report prepared by Itron (the Itron Report) which proposes to use an SPM framework for evaluating the Self Generation Incentive Program (SGIP).[4] SCE concurs with using a multi-perspective framework similar to the Standard Practice Manual for evaluating DG programs, and is generally supportive of the recommendations contained in the Itron Report. The SPM framework provides a flexible approach suitable for assessing different types of DG (*i.e.*, Self-Generation DG, Merchant DG and Distribution DG) and for investigating public policy choices associated with direct and indirect forms of incentives provided to DG units. It is a particularly useful tool in the context of this proceeding because it allows for customer choice (participant perspective) while also identifying the impact on other ratepayers (non-participant perspective). Figure II-1 provides more detail regarding the various perspectives that should be used for DG cost-benefit analyses, and lists the specific cost and benefit elements that should be included under the various perspectives. Additional information on these cost and benefit elements is provided in the sections that follow.

Figure II-1: DG Cost and Benefit Analysis Framework

	Participant Perspective	Non-Participant Perspective	All-Ratepayers or Societal Perspective
Benefits	• Electricity Bill Savings • Revenue From Sale of Power Or Ancillary Services • Improved Customer	• Avoided Capacity Cost Savings • Avoided Energy Cost Savings, Including Losses and Internalized	• Avoided Capacity Cost Savings • Avoided Energy Cost Savings, Including Losses and Internalized

[4] Sebold, Frederick D., et. al., "Self Generation Incentive Program: Framework for Assessing the Cost-Effectiveness of the Self-Generation Incentive Program," Itron (undated). In general, SCE concurs with Itron's recommended analysis framework. The differences between the cost effectiveness framework described in this testimony and in the Itron report are minor and technical in nature.

	Reliability (Backup) • Utility Incentives and Tax Credits	Environmental Costs • Avoided T&D Investment Cost Savings • WDAT[5] Revenues	Environmental Costs • Avoided T&D Investment Cost Savings • Tax Credits (All-Ratepayers Only) • Improved Customer Reliability
Costs	• DG Unit Capital Costs, Including Environmental, Metering and Interconnection Costs • DG Unit Operation and Maintenance Costs • DG Unit Fuel Costs, Net of Thermal Host Requirements • WDAT Charges	• Electricity Bill Savings • Utility Incentives • Utility Interconnection Costs (Not Charged To Participants) • Utility Administrative Costs	• DG Unit Capital Costs, Including Environmental, Metering and Interconnection Costs • DG Unit Operation and Maintenance Costs • DG Unit Fuel Costs, Net of Thermal Host Requirements • Utility Administrative Costs

From a participant perspective, Self-Generation DG benefits are the bill savings that the customer receives from operation of the DG unit plus any additional reliability benefit the customer may gain from being able to operate the DG unit during system outages, if the unit has such capability. Bill savings should take standby charges and non-bypassable charges into consideration, with any waiver of these otherwise applicable charges treated as a program incentive. Merchant DG benefits from the sale of power and ancillary services. The benefits from Distribution DG installed on a customer's side of the meter would include not only the benefits associated with Self Generation DG (*i.e.*, bill savings), but also the payments received from the utility under a performance contract.

DG costs consist of the DG equipment costs including installation, pads or enclosures, costs imposed by building codes or local permitting requirements, fuel and other operating costs, maintenance costs, and any distribution system upgrade cost paid by the DG owner. To the extent that a DG facility

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5 "WDAT" refers to the Wholesale Distribution Access Tariff.

requires electrical interconnection facilities, mitigation of distribution system impacts (*e.g.*, protection equipment and relays), environmental controls, emission offsets, or special metering, these costs should be included in the cost of the DG unit. However, for larger Merchant DG units, interconnection costs related to system upgrades and network facilities may be refunded by the utility pursuant to FERC generator interconnection standards. If so, then ratepayers ultimately pay utilities for the distribution system upgrade costs, shifting them to a cost from the non-participant perspective. Merchant DG units may also need to take service under a Wholesale Distribution Access Tariff (WDAT) in order to make wholesale sales. In general, SCE regards it as the customer's responsibility to consider benefits and costs before proceeding with a Self-Generation or Merchant DG option. Thus, the participant perspective is the primary cost-benefit test for these options.

From a non-participant perspective, DG benefits generally fall into categories of savings due to avoided generation costs and, if applicable (*e.g.*, Distribution DG), avoided T&D costs. For Self-Generation DG, avoided generation costs should be measured at the customer voltage level thereby giving appropriate credit for savings in delivery system losses. T&D cost reduction/deferral only becomes applicable in a Self-Generation DG scenario when a DG customer provides physical assurance of firm load reduction at times when the delivery system is stressed, so that delivery system investments can truly be deferred. These benefits accrue to ratepayers, since they reduce the costs that a utility incurs to provide service to its customers. Offsetting these benefits are non-participating customers' DG costs, which generally arise from a shift of fixed-cost recovery to non-participants from "participating" Self-Generation DG customers. Thus, a portion of the participant's bill savings acts as a form of transferred cost to other ratepayers and has the potential to introduce cross subsidies. These types of cross subsidies, where they exist, should be a conscious instrument of public policy and not simply accepted as an inadvertent effect of rate designs in which the electricity payments avoided by the participants through bill savings exceed the level of costs actually avoided. Thus, the non-participant perspective is particularly important for designing appropriate incentives and understanding the impacts that additional DG units have on overall utility rate levels.

From an all-ratepayers/societal perspective, the benefits of DG are the avoided costs, including avoided T&D costs, if any. The costs of having additional DG are the costs of installing and operating the DG unit itself and any distribution system upgrade costs. In general, the all-ratepayers/societal perspective addresses whether DG promotes overall economic efficiency. There are distinctions between the all-ratepayers and societal perspectives which may be of concern when evaluating specific programs. For example, tax payments avoided by the utility (due to lower system investment levels and thus lower utility return on investment, for instance) are commonly included in the all-ratepayers perspective, but can be excluded from the societal perspective since these are transfer payments that "wash out" among different classes of citizens. Similarly, federal tax credits received by a DG owner can be included in the all-ratepayers perspective but would be considered a "wash" of equal and offsetting transfer payments among citizens from the societal perspective.

B. <u>Appropriate Benefits to Include in the Cost-Benefit Analysis</u>

The Ruling includes a lengthy list of benefits that different parties have asserted should be included in a cost-benefit analysis of DG facilities. Below, SCE explains its views on the appropriateness of including these benefits in cost-benefit analyses of DG.

Reduction or Deferral of Distribution and Transmission Capital Investment. SCE agrees with including avoided or deferred T&D costs as a benefit in the non-participant and all-ratepayers tests where appropriate. However, in general, SCE does not believe that DG facilities connected to the distribution system can reliably defer transmission investment, since transmission facilities are heavily interconnected to provide sufficient reliability. DG facilities may be able to defer distribution investments in particular locations if the DG customer is willing to provide "physical assurance" that the customer's load will be interrupted when necessary.[6] The amount of any such avoided T&D benefits will require a case-specific analysis. (See Section III.B below for additional testimony on this topic).

[6] SCE agrees with the recommendation in the Itron Report that the value for avoided T&D benefits be set at zero for the SGIP analysis, because SGIP DG units do not provide physical assurance. (*See* Itron Report, page 5-5.)

Reduced T&D Line Losses: A DG facility located at a customer site can avoid line losses associated with supplying power to the customer from a more remote generator. Such benefits should already be included in the avoided generation costs. SCE's practice is to use a line loss multiplier which varies based on voltage level.

Avoided Commodity Costs –Energy & Capacity: SCE agrees with including avoided generation costs as a benefit in the non-participant and all-ratepayers tests. These benefits may need to be adjusted to reflect the particulars of a DG application—for instance, its contribution towards meeting resource adequacy requirements or its ability to avoid utility provision of ancillary services.

Enhanced Reliability: A customer itself may benefit from a DG facility that can operate disconnected from the system during a utility power outage, and thus improve the overall reliability of the customer's electricity supply. This is a benefit to the customer itself and might be included in the participant test. However, since this is principally a customer benefit, SCE sees no need to speculate about the numeric dollar value of this enhanced reliability to the individual customer.

Improved Stability and Power Quality: SCE agrees that it may be possible for some customers with particularly stringent electricity requirements to benefit from specially designed DG facilities that can improve customer voltage stability or power quality. Similar to enhanced reliability, this is a benefit in the participant and all-ratepayers tests.

Provision of Ancillary Services/VAR Support: Self-Generation DG facilities do not provide ancillary services; rather, they may reduce the requirement for a utility to procure ancillary services. As such, they are a component of avoided generation costs. Merchant DG may sell ancillary services, making this a potential benefit in the participant and all-ratepayers tests. To the extent SCE needs voltage support in a local area and a DG facility is a cost-effective means for providing such support, this could be taken into consideration in distribution system planning.

Environmental Impacts (Avoided NOx Emissions, Avoided CO2 Emissions, etc.): Environmental costs that are internalized in the overall investment or operating cost of the generation resources avoided by the DG facility should be included in the avoided generation costs. In many cases, effects such as water quality impacts are addressed as part of obtaining permits, and applicable governmental agencies may require appropriate mitigation. A reasonable estimate of such costs should be included in the avoided generation costs. It must also be recognized that the DG itself may produce environmental externalities. To the extent that avoided pollution externalities on the utility system are treated as benefits, any pollution externalities associated with the DG unit must be considered to be an additional cost of DG from the all-ratepayers/societal perspective.

Emissions of CO2 and other greenhouse gases (GHGs) are a special case. In Decision 04-12-048 (utility long-term procurement plans), the Commission adopted a policy of considering GHGs in the resource selection process in order to account for the potential risks of future regulation of GHG emissions. However, the GHG adders used in the resource selection process will be an analytic tool only and will not be charged to ratepayers or paid to generators.[7] As a result, it may be appropriate to exclude a GHG adder from the non-participant test. Because the non-participant test is particularly important for understanding cross subsidies created by DG incentive programs and for designing appropriate incentive levels, this is consistent with not charging the cost of GHG adders to ratepayers.[8]

Thermal Load Provided in Combined Heat & Power Applications: SCE agrees that the value of the thermal load provided by a DG facility can be included in the participant and all-ratepayers tests.

[7] D.04-12-048, *mimeo*, pages 152-153.

[8] This is consistent with the recommendation contained in the Itron Report, which proposes to include an environmental adder associated with avoided generation costs in the societal test, but not the non-participant test. (*See* Itron Report, pages 7-2 and 7-3.)

The Itron Report proposes to characterize this benefit as the implied reduction in fuels that would otherwise be used to directly serve thermal requirements.[9] An alternative (and commonly used) analytical approach is to net the cost of alternative boiler facilities and the fuel that would be used by such facilities to produce thermal output from the costs of the DG facility, so the cost-benefit analysis focuses exclusively on the customer's decision to provide combined heat and power from the DG facility incremental to the use of a stand-alone boiler. Figure II-1 employs this latter analytical approach.

Increased Responsiveness to Load Growth: SCE's procurement activities seek to maximize customer value consistent with applicable Commission requirements.[10] Thus, Merchant DG facilities that are particularly responsive to utility needs may be able to capture competitive advantages in responding to utility procurement activities by achieving superior revenues from the sale of their power. Load growth responsiveness should not be included as a benefit for Self-Generation DG facilities since such facilities reduce the amount of system power that customers demand and free up other resources to serve load growth. This process is no more "responsive" to load growth than ordinary procurement and less certain in terms of the time patterns of reduced demands and freed-up resources.

Lower market prices for power: In general, SCE does not expect that DG facilities will result in lower market prices for power because DG facilities will substitute for other utility generation resources and SCE will meet its resource adequacy requirements regardless of the extent of DG investment.

Increased employment in California and tax revenues: Promotion of economic activity as a result of DG facility installation should not be included as a benefit, since this would ignore the

[9] *See* Itron Report, pages 6-2 and 6-3. SCE does not oppose this recommendation. Because Itron intends to calculate separate non-participant test measures for electric and natural gas ratepayers, there may be advantages to identifying gross, rather than net, consumption of natural gas in the evaluation of the Self Generation Incentive Program.

[10] For example, SCE is required to procure power in accordance with its Commission-approved AB 57 procurement plan.

corresponding adverse impacts in other sectors of the economy where there is less spending as a result of the additional DG investment (such as lower spending on central station power plants). Typically, cost-benefit analyses treat such impacts as being netted out in the economy at large, and thus exclude them from the quantification of benefits and costs.

National security benefits/reduced security risk to grid: Externality effects such as these are difficult to quantify and likely to be completely insignificant. Absent clear demonstration that there are tangible externality effects, such benefits should not be included in a DG cost-benefit analysis.

Conservation of natural gas: Currently, SCE's avoided generation costs are heavily influenced by the cost of natural gas, so the cost-benefit analysis (non-participant and all-ratepayers perspectives) will reflect any reduction in natural gas consumption as a result of operation of a DG facility. Moreover, many DGs burn natural gas as a fuel at a higher heat rate than in central station power plants.

Avoided utility cost of capital/finance costs: These cost savings are a component of avoided generation and T&D costs.

Avoided utility administrative, maintenance, insurance, and installation costs: These cost savings are a component of avoided generation and T&D costs.

Tax and other incentives: Tax credits and other incentives that are not "funded" by other ratepayers should be included as a benefit (or a reduced cost) in the participant and all-ratepayers tests. Since tax credits are a transfer payment among different tax payers, they should be excluded in a cost-benefit analysis using the societal perspective.

C. <u>Appropriate Costs to Include in the Cost-Benefit Analysis</u>

The ruling includes a lengthy list of costs that different parties have asserted should be included in the cost-benefit analysis of DG facilities. SCE describes its views on the appropriateness of including these costs below.

Costs to mitigate distribution system impacts (e.g., interconnection study costs, upgrade costs): Costs incurred by the DG owner to mitigate distribution system impacts should be included as a component of the overall investment cost of the DG facility from the participant perspective. To the extent the utility bears such costs, they should be included in the non-participant and all-ratepayers tests.

Utility revenue loss due to displaced usage of transmission and distribution facilities: From a participant perspective, one of the primary benefits of a DG facility is the reduction in utility bills associated with the reduced purchase of electricity from the utility. From the non-participant perspective, these bill savings are a revenue loss. From the all-ratepayers perspective, the bill savings and revenue loss net out and do not influence cost effectiveness. There is no need to separate the revenue losses into specific categories, such as T&D revenues, generation revenues, and so forth.

Utility/DWR revenue loss due to avoided commodity purchase – energy, capacity, bonds: SCE agrees with including bill savings/revenue losses associated with commodity purchases in the appropriate cost-benefit tests.

Costs for Enhanced Reliability: Any costs incurred by the DG owner to enhance reliability of the DG facility should be included as part of the installed cost of the facility.

Costs for Improved Stability and Power Quality: Any costs incurred by the DG owner to improve the stability and power quality attributes of the DG facility should be included as part of the installed cost of the facility.

Costs for Ancillary Services/VAR Support: Any costs incurred by the DG owner which enhance the ability of the facility to provide ancillary services and/or VAR support should be included as part of the installed cost of the facility.

Utility loss of revenue due to displaced thermal load, cost of ratepayer incentives for CHP generators: As an electric-only utility, SCE suggests treating the price of natural gas as equal to the underlying avoided cost. We recognize that the impacts of a DG facility on overall natural gas consumption may have distributional impacts on other utilities' ratepayers if gas rates do not match gas avoided costs. SCE is not opposed in principle to including such effects, but observes that this will require modifications to the structure of the perspectives shown in Figure II-1 to separate SCE ratepayers from other utility ratepayers. SCE agrees with including ratepayer-funded incentive payments (including waiver of tariff charges ordinarily applicable to standby customers) as a benefit in the participant test and a cost in the non-participant test.

Costs for Increased Responsiveness to Load Growth: SCE is not sure what costs are intended to be reflected by this item. In general, any additional costs incurred by the DG owner to provide increased responsiveness should be included as part of the DG facility costs.

Environmental Controls (NOx Emissions, CO2 Emissions, etc.): The environmental control costs incurred by the owner of the DG facility should be included in the cost of the DG facility. SCE supports including only those environmental costs which are internalized in the cost of the DG facility. SCE recognizes that this may result in inconsistent valuation of emissions, since fossil-fuel-fired DG facilities are frequently subject to less stringent control requirements than central station power plants.[11] The Commission may wish to take the differential emission rates of DG and central station power plants into consideration in the design of DG incentive programs.

Lower market prices for power, payments for installed capacity: SCE does not understand what is intended by listing these items as a potential cost.

Increased employment and taxes: Costs incurred by the DG owner associated with labor expenses and taxes should be included in the operating costs of the DG facility (participant perspective). Labor costs and taxes should also be included in the all-ratepayers test. However, it may be appropriate to exclude taxes from the societal perspective since they are a "wash" among members of society.

Costs for increased national security: SCE does not understand what is intended by listing this as a potential cost.

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[11] The Itron Report recommends a different treatment, where the NOx and PM-10 emissions from non-renewable DG are valued at the offset costs which apply to central station plants. However, this recommendation is made as a "simplifying assumption" based on lack of an alternative valuation approach. (*See* Itron Report, page 5-8, footnote 25.)

Conservation of natural gas: SCE does not understand what is intended by listing this as a potential cost.

Building code or local permitting requirements: Any costs incurred by the DG owner associated with meeting building code or local permitting requirements should be included as part of the installed cost of the facility.

Loss of utility plant investment revenue: To the extent that SCE invests less as a result of DG facilities which reduce or defer investment in generation and T&D facilities, SCE anticipates that its equity investors and lenders will have other comparable investment opportunities. Thus, utility investment revenue loss can be considered to "net out" in the economy at large and is not appropriately included as a DG facility cost.

Administrative, maintenance, installation costs: SCE agrees with including administrative, maintenance and installation costs incurred by the DG owner in the participant and all-ratepayers tests. In addition, any administrative costs incurred by the utility in coordinating and facilitating the installation and operation of the DG facility which are not charged to the DG owner should be included as a cost in the non-participant and all-ratepayers tests.

Emissions offsets: Any emissions offset costs incurred by the DG owner should be included in the participant and all-ratepayers tests.

Special metering: Any special metering costs incurred by the DG owner should be included in the participant and all-ratepayers tests. Any such costs which are incurred by the utility and not charged to the DG owner should be included as a cost in the non-participant and all-ratepayers tests.

Cost of tax and other incentives: Tax credits and other incentives that are not "funded" by other ratepayers should be excluded from the all-ratepayers test. Since tax credits are a transfer payment among different tax payers, they should be included in a cost-benefit analysis using the societal perspective. As a result, they offset the corresponding tax credit received by the DG owner which is included in the participant test.

D. Distribution Benefits

Because much has been made of the claimed benefits to the distribution system from DG, it may be helpful to review these benefits in the context of particular DG applications.

1. Self-Generation DG

As discussed earlier, Self Generation DG can provide primary, supplemental or back-up generation for a customer. As the name implies, Self-Generation DG provides power solely for the customer's own use. The DG customer may also take delivery of energy from the utility to meet customer demand not covered by the DG unit (supplemental power) and may also receive back-up power from the utility to serve load if and when the DG unit fails.

From a non-participant and all-ratepayers perspective, Self-Generation DG provides little, if any, benefit to the utility's transmission and distribution system. Because most Self-Generation DG customers continue to receive both supplemental and back-up power from the utility, the utility generally does not defer, reduce or avoid transmission and distribution related costs when a customer is a Self-Generation DG customer. Utility transmission and distribution facilities must be available to serve a Self-Generation DG customer's full load requirements, just as they are available for any other utility customer who does not have DG. The utility must plan and install capacity on its system as part of its obligation to serve and meet peak-load requirements. The utility has no guarantee that a customer's DG facility will be operating at the time of a system or circuit peak and, therefore, must plan and construct facilities to meet peak demand.

2. Merchant DG

There may be instances where a customer who owns DG desires to sell generation back to the grid, *i.e.*, Merchant DG. From a utility planning and operating point of view, there is still no benefit to the utility's T&D system from the Merchant DG unit. The utility must still construct and maintain its system to meet customer peak demands whether there is a Merchant DG on the system or not.

3. Distribution DG

SCE agrees that Distribution DG, *i.e.*, DG deployed at the utility's request at specific locations to reduce or defer the need for distribution system investments, does provide a measurable benefit to the distribution system. However, as the Commission has already acknowledged, the DG unit must meet specific requirements to provide these system benefits.[12] Specifically, the DG unit must:

1. Be located where the utility would require distributed generation in lieu of circuit/system upgrades;
2. Be on-line and available when required by the utility, or willing to curtail a corresponding amount of load if not operational during requested periods of time by the utility (*i.e.*, physical assurance); and,
3. Provide the capacity size required to meet the utility's needs.[13]

Unless a DG unit is specifically located on a circuit of a utility's system that is facing load growth and will need to be upgraded or supplemented with an additional feeder, the utility will not avoid any distribution costs as a result of the DG unit operating on the circuit. For example, a DG unit may be located on a circuit with a capacity of 8 MW. If the peak-load on that circuit is only 4 MW, even a DG unit capable of generating 3 MW 100% of the time will not result in any benefit on that circuit. Although the DG unit may be providing an additional 3 MW of capacity on the circuit, the capacity is not needed in that specific area of the system. Therefore, the DG unit has not resulted in any T&D system or circuit investment deferrals.

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[12] D.03-02-068, p. 18.

[13] The August 6 Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo notes that this proceeding will not consider modifications to these criteria.

A DG unit must be constructed and fully operational in time to meet a utility's requirements. Generally, SCE does not plan to implement construction and other changes to its distribution system five and ten-years in advance of predicted load growth. While SCE uses a ten-year planning horizon to annually review the adequacy of capacity on its distribution and transmission systems, SCE specifically focuses on the detailed planning and design of particular portions of its system, and specific alternatives for correcting projected system deficiencies on its distribution system 12-18 months in advance. The alternatives that SCE considers during this process encompass a range of options such as the consideration of alternative project locations, consideration for load balancing between substations, and DG applications as a general approach for meeting load growth.

If a DG unit is to be considered as a distribution alternative, the DG unit must be dependable and reliable, and must not be located where the DG unit would negatively impact the operational flexibility of the distribution system and degrade the reliability of service to the utility's customers. Adverse system conditions are not predictable. Because such conditions may develop over a very short period of time, the DG unit must be available for the utility's use at any time and on a moment's notice just as a "wires" solution would be. The DG unit must also be maintained in good working order so it is a reliable alternative to a wires upgrade. If a wires upgrade is deferred in favor of a DG alternative, SCE must have physical assurance that the DG unit (or the corresponding load reduction) will be available when needed.

Moreover, in the end, the DG alternative must be cost effective when compared to a wires solution. In Section III.B below, SCE will discuss briefly how it looks at DG alternatives and cost effectiveness in its distribution planning process.

III.

POTENTIAL USES OF A DG COST-BENEFIT METHODOLOGY

In the following section, SCE will discuss what role, if any, the proposed cost-effectiveness methodology should play in utility procurement planning, distribution planning and rate design.

A. Utility Procurement Planning

SCE's long-term procurement plan identifies the need for new resources and new resource commitments, and identifies strategies designed to achieve a balanced supply/demand portfolio that meets SCE customers' expected demand plus a reserve margin. As part of its development of this procurement plan, SCE develops a forecast of Self-Generation DG, and uses this forecast to reduce the demand forecast which is an input into the simulation models used to evaluate the costs of various resource strategies.

This approach treats DG resources as capable of reducing both the actual load to be served by SCE and the associated reserve margin requirements. The forecast included in the resource plan is based on capacity ratings of DG resources. The resources included are existing interconnected DG resources, planned DG resources that SCE has been informed of by customers, and forecasted DG installations. Associated energy is based on SCE's estimate of capacity factors for DG resources.

SCE does not explicitly assess the cost effectiveness of Self-Generation DG as part of the procurement planning process. SCE regards such analyses to be the responsibility of the customer, and expects that customers will make a decision to invest in DG based on an analysis of their specific costs and benefits.

SCE has not made a forecast of new Merchant DG in its procurement plan. Over the next few years, there is a growing need for new generation resources to be physically installed and committed to the service of retail customers in California. SCE anticipates that a portion of these requirements will be met by purchases from third-party generators pursuant to a Commission-approved procurement plan. In general, Merchant DG units will be able to compete in utility procurement solicitations.

B. Distribution System Planning

As noted above, DG can potentially play a role in transmission and distribution system planning. SCE uses a number of resource planning evaluation programs and applications to determine projects and expenditures necessary to maintain reliability, serve customer load growth, and interconnect generation to its system. Two of these programs are the Distribution Substation Plan (DSP) and Transmission Substation Plan (TSP). These applications are discussed briefly below.

1. SCE's Distribution Substation Plan (DSP) and Transmission Substation Plan (TSP)

SCE reviews the adequacy of its transmission and distribution system capacity annually. Using a ten-year planning horizon, SCE maintains a plan for the improvement and expansion of the distribution system to meet load growth. During the annual updates to the ten-year plan, SCE specifically focuses on planning for the next year's load requirements by studying detailed action plans and alternatives for maintaining substation adequacy, and developing cost estimates for these action plans.

The SCE distribution system consists of approximately 4,100 distribution circuits. By far, the vast majority of these circuits have adequate capacity based on the equipment currently installed and the near-term projected load in the local area. There are, however, areas identified each year that as a result of load growth are projected to exceed the current rated capacity or other operational criteria, and therefore need system improvements.

As part of the Distribution Substation Plan, SCE annually forecasts load growth and reviews requirements for its distribution substation transformer banks (B-banks) over a ten-year planning horizon. The plan's objective is to provide for adequate capacity to serve the local maximum coincident customer demand (at the maximum temperature expected over a ten year period). Substations (B-stations) connect the higher voltage (115 kV and 66 kV) subtransmission networks to the primarily radial distribution system (33 kV, 16 kV, 12 kV, and 4 kV). SCE's Distribution Engineering organization ("Engineering") analyzes and projects temperature-adjusted peak demand growth each year comparing it to local system capacity, and develops distribution-substation and transmission-substation program plans (collectively referred to as the "DSP/TSP"). The outcome of this process is an updated DSP/TSP which includes the identification of specific projects to accommodate the forecasted increases in local loads.

The identification of system facility requirements through technical studies and the development of alternatives to meet these requirements is an iterative process. When technical studies identify a potential system condition that exceeds the criteria and guideline limits, SCE identifies alternatives for correcting the projected system deficiency. The alternatives encompass a range of options such as the consideration of alternative projects, project locations, load balancing between substations, and DG applications as a general approach for meeting local load growth.

2. Valuing Distribution System Deferral

The Commission has in essence already directed that distribution system deferral value should be viewed from both the all-ratepayers and non-participant perspectives. In D.03-02-068,[14] the Commission directed that "the compensation paid to the distributed generation solution would be no greater than that calculated for the deferral of a planned capital addition" and "should not exceed the cost of the planned addition multiplied by the short-term carrying cost of capital and the number of years of deferral."[15]

The Commission concluded that this process is consistent with the Operations and Planning Workshop Report prepared in R.99-10-025 which found that the utilities should be

[14] Adopted in R.99-10-025 (Rulemaking into Distributed Generation).

[15] D.03-02-068, p. 19.

responsible for determining the threshold at which DG is considered as an option for distribution system enhancement. This approach is consistent with the fact that a case-specific analysis is required when evaluating whether a deferred capital investment in a portion of a distribution system (for instance, the difference in incremental cost between installing smaller voltage cable versus larger high-voltage cable) results in cost savings. In order to adequately define the costs of deferred capital expenditures, a site specific analysis of the amount of load that may be deferred must be performed, given physical assurances, the time duration, and the foreseeable requirement to install the deferred capital based on other future load growth on the circuit.

If a utility owns the DG facility, then a cost-effectiveness analysis from the participant perspective does not apply. The cost of the DG facility will be compared with the cost savings from deferring transmission or distribution investments, which are the central focus of the non-participant and all-ratepayers perspective. In performing these calculations, if there are any opportunities for the utility to produce power from the facility, then the avoided generation cost savings associated with this power production will be taken into account in the cost-benefit analysis.

C. <u>Implications of Public Utilities Code Section 353.9</u>

The Ruling indicates that the Commission's development of a cost-benefit methodology is required in order to comply with the requirements of Public Utilities Code Section 353.9.[16] This Section states:

> In establishing the rates required under this article, the commission shall create a firewall that segregates distribution cost recovery so that any net costs, taking into account the actual costs and benefits of distributed energy resources, proportional to each customer class, as determined by the commission, resulting from the tariff modifications granted to members of each customer class may be recovered only from that class.

The phrase "rates required under this article" refers to the provision in section 353.13 that states:

[16] Ruling, p. 3.

> The Commission shall require each electrical corporation, in establishing these rates, to ensure that customers with similar load profiles within a customer class will, to the extent practicable, be subject to the same utility rates, regardless of their use of distributed energy resources to serve onsite load or over-the-fence transactions allowed under sections 216 and 218.

Therefore, the firewall provisions of section 353.9 will be triggered if satisfying the above requirement of Section 353.13 (or the requirements of Section 353.3) results in any "net costs" to other customers. In that case, such "net costs" may be recovered only from the class to which the DG customer belongs.

Consistent with Decision No. 01-07-027, SCE proposed and the Commission adopted, in the Rate Design Phase of SCE's 2003 General Rate Case (GRC), a cost-based standby rate schedule that separates the eligible customer's load into supplemental, back-up and maintenance load.[17] Supplemental load of standby customers will be billed at the same charges applicable to the customers in the same class without self-generation units. SCE will charge standby customers for their back-up and maintenance load at a lower rate than their otherwise applicable tariff (OAT) to account for the diversity of the back-up load and the requirement that maintenance power must be scheduled with SCE. In exchange, standby customers will be subject to a reservation capacity charge. SCE believes that this structure would actually result in a lower total bill for many standby customers than if they are billed on their OAT. Given the cost-based nature of this standby rate structure, there are no "net costs" to be segregated and recovered from the customer class to which the standby customer belongs.

However, if the Commission decides in this or future proceedings to exempt DG customers from a portion of the charges on such a cost-based standby rate schedule, which SCE believes it should not, then the results of a cost-benefit analysis need to be utilized to determine the appropriate ratemaking treatment for the revenue shortfall resulting from that exemption. If such exemptions cannot be justified

[17] Decision 05-03-022 adopted a settlement among all active parties in Phase 2 of SCE's 2003 GRC resolving all contested issues including the design of standby rates.

by the cost-benefit analysis, then the associated revenue shortfall should be recorded by customer class in sub-accounts of a memorandum account to be recovered only from the appropriate class (*i.e.,* the customer class to which the DG customer belongs.) If, however, it can be shown that the exemption is justified by the cost-benefit analysis, then there need not be any special treatment of the associated revenue shortfall. It will automatically be reflected in SCE's balancing accounts and will be paid for by all customers who presumably are also receiving the benefits of the DG.

IV.

COORDINATION WITH THE AVOIDED COSTS BEING DETERMINED IN R. 04-04-025

Avoided-cost savings are the reduction in resource costs that occurs as a result of installation and operation of a DG unit. These savings represent the major source of benefit for many DG units and are thus a critical element of DG cost-effectiveness analysis. In 2003, the Energy Division initiated efforts to develop an avoided-cost quantification tool for DSM program evaluation. Energy and Environmental Economics (E3) was hired to perform the work, and issued a final report in October 2004 (the E3 Report) containing its recommended measurement approaches to each of the avoided-cost elements identified in the Energy Division scope of services.[18] Subsequently, the Commission opened a separate rulemaking (R.04-04-025) to consider the merits of this recommended approach to quantifying avoided costs and the suitability of this approach for other avoided-cost applications, including DG. In that proceeding, SCE provided comments on the appropriateness of the E3 methodology for DSM program evaluation and for other applications. The suitability of the E3 avoided cost forecasts for DG will be addressed in a later phase of R.04-04-025.

[18] Energy and Environmental Economics, Inc. and Rocky Mountain Institute, "Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs," Prepared for the California Public Utilities Commission Energy Division, October 25, 2004.

V.

COST-BENEFIT EXAMPLES

The Ruling encourages parties to provide illustrative examples showing the steps involved in their proposed cost-benefit test methodology. Below, SCE illustrates its proposed approach using two prototype DG applications: (1) a solar panel installation in a residential tract neighborhood, and (2) a gas-fired CHP unit installed at a medium-sized business. Both of these examples involve customer-sponsored Self-Generation DG. As a result, the primary value of performing a cost-benefit analysis is to provide useful information regarding distributional impacts for the purpose of considering incentive program design. These examples are intended simply to illustrate SCE's proposed methodology, and the specific cost-benefit results should not be relied upon for any purpose other than this. Costs and benefits are shown using net present value figures. For simplicity, where specific input values can vary over time, such as gas prices or utility rates, we have retained the initial values over the 10-year horizon of the analysis rather than attempting to provide a forecast.

A. Description of the Two Hypothetical DG Projects

The solar DG example assumes that the utility coordinates with a residential home developer to install solar panels on 100 new homes in a new tract development. Each solar panel unit can supply 5 kW, and the panels have an expected life of 10 years. The participant perspective reflects the viewpoint of the ultimate homeowners rather than the developer, which effectively assumes that any costs and cost savings associated with the solar panels are passed on to the homeowner by the developer. Installation cost for the 100 panels is $4.5 million ($9/watt). There are no significant ongoing maintenance costs.

The combined heat and power (CHP) example assumes that a medium-size business customer installs a 75 kW microturbine, which operates between 8:00 a.m. and 8:00 p.m. each weekday, producing both electricity and thermal output. The unit is sized to meet thermal requirements (no excess thermal output), and the electrical output is utilized entirely at the customer's site. The microturbine has an assumed life of 10 years, and replaces an existing functional boiler that would not normally require replacement during this period. Based on the efficiency of the existing boiler, about two-thirds of the fuel consumed by the microturbine is attributable to the production of electricity. (That is, the microturbine uses three times as much natural gas to produce combined heat and power output as the boiler would consume to produce just the thermal output.)

Routine maintenance takes place during periods when the microturbine would normally not operate. In addition, the unit experiences one forced outage lasting for 24 hours approximately every 8 months. Installed cost of the microturbine is $235,000, and ongoing operation and maintenance costs are 1.5¢per kWh.

B. Quantification of Bill Savings

The solar project customers are assumed to take service under the residential domestic tariff (Schedule D).[19] This is an increasing-block energy rate schedule with baseline and non-baseline usage charges. Rates are not time differentiated and there is no demand metering. The customers are assumed to be eligible for net energy metering. In order to simplify the analysis, it is assumed that the customer's annual usage just matches the output from the solar panels. This results in the customer avoiding a combination of energy priced at baseline and non-baseline rates. The monthly customer charge is not avoidable.

The CHP facility customer is assumed to take service under a general service tariff (Schedule GS-2). For simplicity, bill savings are calculated using the non-time-of-use option. This tariff has seasonal demand charges, an increasing block energy rate schedule (kWh per kW), and a monthly customer charge. The customer electrical load is assumed to exceed the output of the CHP facility during all hours when it operates. Thus, when the CHP facility operates successfully for the entire month, the customer avoids a demand charge for 75 kW of usage. Since the DG facility only operates

[19] The tariffs used in the illustrative calculations are those that were in effect as of October 2004.

during weekday daytime hours, it is assumed that it displaces first block energy usage. The monthly customer charge is not avoidable as a result of the CHP facility.

Both the solar unit and the CHP facility are assumed to receive a waiver of standby charges and departing load cost responsibility surcharges which would otherwise be added to their normally applicable tariff. Thus, the applicable standby charge and departing load charge (DLC) are removed from the calculated bill savings and shown as a separate benefit in the cost-benefit analysis.

Table V-1. Solar DG Example Annual Bill Savings (Per Customer)

Bill Component	Tariff Rate	Usage Reduction	Bill Savings
Energy Charge*	$0.12547/kWh	8,580 kWh	$1,076.53
Customer Charge	$0.88/day	--	--
Bill Savings			$1,076.53
Standby Charge	$6.832/kW-mo	5 kW	$409.92
Departing Load Charge (DLC)	$0.01719/kWh	8,580 kWh	$147.49
Standby/DLC Waiver Savings			$557.41
Total Bill Savings, Net of Standby/DLC Waiver			$519.12

*Average between Baseline and Non-Baseline charges.

Table V-2. CHP DG Example Annual Bill Savings

Bill Component	Tariff Rate	Usage Reduction	Bill Savings
Facilities-Related Demand Charge	$5.979/kW-mo	65.628 kW	$4,708.68
Summer Demand Charge	$8.349/kW-mo	65.628 kW	$2,191.71
First Tier Energy Charge	$0.91911/kWh	204,129 kWh	$18,761.73
Customer Charge	$72.16/month	--	--
Bill Savings			$25,662.12
Standby Charge	$7.019/kW-mo	65.628 kW	$5,527.72
Departing Load Charge (DLC)	$0.01207/kWh	204,129 kWh	$2,463.84
Standby/DLC Waiver Savings			$6,900.39
Total Bill Savings, Net of Standby/DLC Waiver			$18,761.73

C. Quantification of Avoided Cost Savings

Generation avoided cost savings are based on the marginal generation costs that SCE has recommended for revenue allocation and rate design purposes in its 2003 GRC.[20] Marginal energy costs are based on a production simulation model. Marginal capacity costs are based on the annualized value of a combustion turbine proxy resource. The capacity values are assigned to time-of-use period using a loss-of-load probability analysis. The aggregate CT proxy value is about $79.78/kW. These values are shown in the table below.

Table V-3. Generation Marginal Cost

Time Period	Marginal Energy Cost (¢/kWh)	Marginal Capacity Cost ($/kW)
Summer, On-Peak	4.61	66.56
Summer, Mid-Peak	4.05	5.66
Summer, Off-Peak	3.21	0.00
Winter, Mid-Peak	4.23	7.56
Winter, Off-Peak	3.34	0.00

For the solar DG example, the installed capacity of the solar panels represents perhaps a 10% to 15% reduction in peak demand on the distribution circuit that supplies the housing tract. Assuming that there are no requirements that the homeowners periodically maintain and replace the solar panels as necessary to assure their continued ability to operate at full capacity on peak, there will be no cost savings associated with the physical configuration of the service interconnection and final line transformer sizing. However, in order to illustrate how T&D benefits might be included in an analysis, this illustrative example assumes that there will be savings associated with deferring transformer capacity additions at the distribution substation which "feeds" the distribution circuit.[21] Actually, such

[20] *See* A. 02-05-004, Exhibit SCE-31 (SCE Rebuttal), page 43.

[21] As noted above (p. 9), SCE does not believe that DG facilities connected to the distribution system can reliably defer distribution investment unless the DG facility is sited at a particular location and the DG customer is willing to participate in a physical assurance scheme. SCE considers it unlikely that an acceptable physical assurance scheme could be developed in connection with solar DG installations.

impacts will be case specific, since the 500 kW "nameplate" capacity of the solar panels is only a small fraction of the capacity of a typical distribution substation transformer and there may not be any requirement for homeowners to maintain the panels in working order. Distribution marginal costs identified in SCE's 2003 GRC marginal cost study are $51.46 per kW, and about one-third of these costs are attributable to distribution substation investment. Thus, for the purpose of this illustrative example, avoided distribution costs of $17.50/kW are assumed. For the CHP facility example, it is assumed that the customer is unwilling to provide physical assurance, so there are no distribution system cost savings.

D. Program Incentives

Both the solar and CHP DG examples are assumed to receive a waiver of otherwise applicable standby charges and customer generation departing load cost responsibility surcharges. The solar project also receives a waiver of departing load non-bypassable charges, and these subsidies are incorporated in the analysis as program incentives. As a residential application, the solar DG is assumed to be eligible for the CEC's Emerging Renewables Program, with an incentive of $3.00/watt (as of 2004).[22] In addition, the solar DG project customers are assumed to receive a tax credit equal to 7.5% of the installed cost of the solar panels net of the CEC incentives. The CHP facility is assumed eligible for a level 3 non-renewable SGIP incentive equal to the lower of $1.00/watt or 30% of the total project cost of the CHP facility (as of 2004).

E. Cost-Benefit Results

Results of the cost-benefit analysis are shown in Tables V-4 and V-5 for the solar and CHP DG examples, respectively. Neither example is cost effective from either the customer perspective or the all-ratepayers perspective.

Table V-4. Solar DG Example Cost-Benefit Results Per Customer (2005$, NPV)

	Participant Perspective	Non-Participant Perspective	All-Ratepayers Perspective
Benefits	25,380.95	5,857.27	5,857.27
Bill Savings	3,920.88		

[22] The incentive levels used in the illustrative calculations are those that were in effect for 2004.

CECS Tax Incentive	17,250.00		
Standby/DLC Waiver Savings	4,210.07		
Avoided Gen Cost		5,295.52	5,295.52
Avoided T&D Cost		561.75	561.75
Costs	45,000.00	25,380.95	45,000.00
Investment Cost	45,000.00		45,000.00
Operating Cost	0.00		
Bill Savings		3,920.88	
CECS Tax Incentive		17,250.00	
Standby/DLC Waiver		4,210.07	
Total	(19,619.05)	(19,523.69)	(39,142.73)

Table V-5. CHP DG Example Cost-Benefit Results (2005$, NPV)

	Participant Perspective	Non-Participant Perspective	All Ratepayer Perspective
Benefits	264,248.71	106,276.38	106,276.38
Bill Savings	133,464.20		
SGIP Incentive	70,425.00		
Standby/DLC Waiver	60,359.51		
Avoided Gen Cost		106,276.38	106,276.38
Avoided T&D Cost		0.00	0.00
Costs	360,087.97	264,248.71	360,087.97
Investment Cost	234,750.00		234,750.00
Operating Cost	125,337.97		125,337.97
Bill Savings		133,464.20	
SGIP Incentive		70,425.00	
Standby Waiver		60,359.51	
Total	(95,839.26)	(157,972.33)	(253,811.59)

VI.

OTHER ISSUES

A. Access to Utility Cost and Benefit Information

The Ruling observes that parties may need access to utility data to assess and monitor the cost effectiveness of a DG project or program element. Further, respondent utilities are directed to make specific proposals to make relevant information and data available.

For the most part, utility information necessary to assess Self-Generation DG cost effectiveness is publicly available. Bill savings are the principal benefit of such projects, and these savings can be assessed by applying customer-specific load data and the operating characteristics of particular DG facilities to the tariff information posted on utility web sites. Merchant DG competes against the market, since the principal benefit of such projects is revenue from the sale of power. While SCE has expectations about future market prices, this is commercially sensitive information that SCE does not disclose to market participants. More importantly, a potential Merchant DG project should rely on its own best estimate of future market conditions, not SCE's estimates, when contemplating investment decisions.

Access to utility avoided generation cost information is largely unnecessary for a DG owner, since avoided-cost savings influence the distributional impacts associated with a DG facility, not the participant's cost effectiveness. This information, to the extent it is confidential, is available to public decision makers and certain non-market participants subject to various confidentiality arrangements. For the purpose of exploring appropriate incentive policies, the marginal generation costs adopted in utility general rate case proceedings provide a suitable estimate of avoided generation costs.[23] These marginal cost values are a generally valid measure of avoided generation cost, even though they may not fully reflect near-term procurement opportunities available in the wholesale market. For example,

[23] See for example A.02-05-004, SCE 2003 General Rate Case, Exhibit 31 (SCE Rebuttal on Marginal Cost Issue).

SCE's proposed marginal generation costs in the 2003 GRC were based on the "full cost" of a CT proxy, even though it is possible that less expensive generation sources may be available for purchase.

The value of Distribution DG in reducing or deferring T&D investment is time dependent and location specific, so it is not practical to rely on generic avoided cost measures for assessing cost effectiveness. In Section III.B, SCE described how it incorporates DG project options in distribution expansion planning decisions. As part of its GRC applications, SCE provides a comprehensive listing of expected distribution expansion investments for a five-year forecast period. In its 2006 GRC testimony, SCE identified high growth areas within its service area and provided cost information for numerous subtransmission and distribution substation upgrade projects (including associated construction of new distribution circuits) anticipated in the 2005-2008 period.[24] This may provide information to potential DG projects as to locations where DG potential may exist, and allow developers to contact SCE for further information as to SCE's needs.

B. <u>Program Measurement and Evaluation Issues</u>

There currently exist a number of DG subsidy programs which provide direct financial incentives, exemption from various utility tariff charges, and/or access to special tariffs. These include:

- The Commission's Self-Generation Incentive Program (SGIP);
- The California Energy Commission's (CEC's) Emerging Renewables Program;
- Standby exemptions for DG defined as "distributed energy resources" in P.U. Code Section 353.1 and "ultra-clean and low-emissions" in P.U. Code Section 353.2;
- Departing Load (DL) Cost Responsibility Surcharge (CRS) exemptions granted by D.03-04-030; and
- Net Energy Metering (solar, wind, AB 2228 Biogas, and SB 1240 NEM Pilot FC).

[24] *See* A.04-12-014, SCE 2006 General Rate Case, Exhibit SCE-3, Volume 3 Part 2, Chapter IV (Transmission and Distribution Capital-Load Growth Planning Programs).

The value of these subsidy programs to utility customers hinges upon the DG facilities achieving specific performance requirements (such as efficiency and emission rates) and, in some cases, minimum production durations. Engineering calculations and an initial site visit may be sufficient to determine "expected" performance and initial eligibility for program participation or tariff exemptions. However, these threshold requirements do little to ensure continued operation or ongoing performance.

For example, in the case of the SGIP, incentives are granted based on engineering calculations and an initial site visit, but no ongoing monitoring is required to receive or retain the incentive payments for many classes of SGIP projects.[25] Although program participants are required to demonstrate up front that the installation is "permanent," there is no operational performance requirement or persistence measurements required by the CPUC.[26] The draft fourth-year evaluation of the SGIP program found that roughly 70% of the cogeneration projects evaluated did not meet the required efficiency requirements.[27] Without program changes, California utility ratepayers will pay $875 million dollars toward SGIP-funded DG through January 1, 2008, with little or no follow-through to assure they will receive the expected benefits.

In response to a one-time data collection requirement imposed upon the utilities by ALJ Cooke's Ruling to Implement P.U. Code Section 353.15 on March 26, 2003, SCE attempted to collect operational performance data from its customers with DG installations.[28] SCE received a less than

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[25] Although the SGIP requirements make provision for monitoring visits for measurement and evaluation purposes, the SGIP Handbook specifies that "...[r]esults of measurement and evaluation activities will have no bearing on the incentive payment previously received, with the exception of projects utilizing renewable fuels (Level 1 fuel cells and Level 3-R systems)..." (Section 5.2.3).

[26] The SGIP Handbook requires "contractual permanence" corresponding to twice the warranty period, which is five years for Levels 1 and 2 systems and three years for Level 3R and 3N systems. (Section 2.8).

[27] "Metered data collected to date suggest that nine of the 29 monitored Level 3/3-N projects achieved the 218.5(b) overall system efficiency target of 42.5%." SGIP Fourth-Year Impact Report (DRAFT), page 1-4. The SGIP Third Year Impacts Evaluation Report contains even poorer results, showing that approximately 90% of the cogeneration projects evaluated did not meet the required efficiency requirements. Itron Third-Year Impact Report, October 29, 2004, pages 9-25 through 9-26.

[28] SBX1 28 was adopted on May 22, 2001, and established Article 3.5: Distributed Energy Resources. Public Utilities Code Section 353.15 states:

(*Continued*)

enthusiastic response to this data collection effort. Other than periodic sampling efforts associated with SGIP evaluation, SCE is unaware of any ongoing efforts by the Commission to collect or evaluate performance information from customers receiving SGIP incentives or tariff exemptions.

In D.03-04-030, the CPUC determined that the specific attributes of certain DG technologies (eligibility for SGIP incentives or NEM, compliance with more stringent emissions standards, or cogeneration), warranted shifting of historic and future costs resulting from the energy crisis to nonparticipating customers. In compliance with the decision, the CEC developed a DL CRS exemption process. While the utilities have begun collecting "expected" performance data, the CEC has not yet developed an enforcement mechanism to ensure that the DG units actually perform at the qualifying levels. Without a monitoring program, ongoing compliance cannot be verified, leaving open the possibility that nonparticipating customers will be subsidizing DG customers that do not meet the requirements associated with the subsidies established by the Commission.

Continued from the previous page

(a) In order to evaluate the efficiency, emissions, and reliability of distributed energy resources with a capacity greater than 10 kilowatts, customers that install those resources pursuant to this article shall report to the commission, on an annual basis, all of the following information, as recorded on a monthly basis:

(1) Heat rate for the resource.

(2) Total kilowatt hours produced in the peak and off-peak periods, as determined by the ISO.

(3) Emissions data for the resource, as required by the State Air Resources Board or the appropriate air quality management district or air pollution control district.

(b) The commission shall release the information submitted pursuant to subdivision (a) in a manner that does not identify the individual user of the distributed energy resource.

(c) The commission, in consultation with the State Air Resources Board, air quality management districts, air pollution control districts, and the State Energy Resources Conservation and Development Commission, shall evaluate the information submitted pursuant to subdivision (a) and, within two years of the effective date of the act adding this article, prepare and submit to the Governor and the Legislature a report recommending any changes to this article it determines necessary based upon that information.

SCE therefore encourages the Commission to develop a data collection, monitoring and enforcement program sufficient to ensure that nonparticipating customers are indifferent to choices made by customers that install DG.

APPENDIX A

STATEMENT OF QUALIFICATIONS

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF CARL H. SILSBEE

Q. Please state your name and business address for the record.

A. My name is Carl H. Silsbee, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Manager of Regulatory Economics in the Regulatory Policy and Affairs Department. In this position, I am responsible for marginal cost studies and related studies to support rate design, performance based ratemaking, and a variety of special projects. I have held the position since November 1985.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor's degree in Engineering from Harvey Mudd College in 1974 and a Master's degree in Engineering-Economic Systems from Stanford University in 1975. I joined Southern California Edison in 1981. Prior to my present position, my responsibilities have included coordinating and preparing operating and maintenance expense forecasts for general rate cases, preparing revenue requirement analyses in support of Certificate of Public Convenience and Necessity (CPCN) applications, and filing, avoided cost pricing for qualifying facilities and supporting wholesale rate case applications before the Federal Energy Regulatory Commission. I have previously testified before this Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor Section I (Introduction); All of Section II (Cost-Benefit Framework and Elements), with the exception of subsection II.D.;

Section III.A (Utility Resource Planning) and Section III.B.2 (Valuing Distribution System Deferral); Section IV (Coordination with the Avoided Costs Being Determined in R. 04-04-025); Section V (Cost-Benefit Examples); and Section VI. (Other Issues) of SCE's Testimony as identified in the Tables of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF AKBAR JAZAYERI

Q. Please state your name and business address for the record.

A. My name is Akbar Jazayeri, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Director of Revenue and Tariffs Division in the Regulatory Policy and Affairs (RP&A) Department. In this capacity, I oversee all California Public Utilities Commission jurisdictional ratemaking, revenue requirements, revenue forecasting, load research, pricing and tariff functions. I also direct the activities of the Federal Energy Regulatory Commission (FERC) Rates and Regulation Section of RP&A Department.

Q. Briefly describe your educational and professional background.

A. I have a Ph.D. degree in economics from the University of Southern California (USC). As a research assistant at USC, I was involved in modeling industrial and commercial demand for electricity by time-of-use. My Ph.D thesis concentrated on developing a new econometric approach to modeling peak load pricing policies. I have been employed by Southern California Edison Company (SCE) since May 1982.

I joined SCE as a market analyst in the Conservation and Load Management Department. My areas of responsibility included evaluation of load impacts and persistence of various conservation measures and analysis of appliance choice by residential customers. Starting in 1984, I worked as a load research analyst for two years. In this position, I was involved in sample design and estimation of load profiles for various rate schedules, research in alternative sample design methodologies, and evaluation of load characteristics of cogenerating customers.

I then worked as a Regulatory Specialist for two and one-half years. In that capacity, I coordinated the estimation of present and marginal cost revenues and I was involved in various rate design functions. I held various supervisory and management positions in the Revenues and Tariffs Division prior to assuming the position of Manager of Pricing and Tariffs in January of 1998. I was promoted to my current position in March 2001. I have previously testified before this Commission and the FERC.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor Section III.C. (Implications of Public Utilities Code Section 353.9) of SCE's Testimony as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF SCOTT R. LACY

Q. Please state your name and business address for the record.

A. My name is Scott R. Lacy, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am currently a Senior Engineer in our Distribution Engineering Department responsible for supervising our Radio/Television Interference (RTVI) and Power Quality (PQ) groups. In that capacity, I oversee the response to customer complaints with electric service and propose changes to SCE's distribution system installed facilities and construction standards in order to mitigate future power quality issues. I also represent SCE's Distribution Engineering Department at the Rule 21 Working Group meetings, coordinated by the California Energy Commission, as well as at other meetings related to Distributed Generation interconnection issues.

Q. Briefly describe your educational and professional background.

A. I received my Bachelor of Science degree in General Engineering from the University of Redlands. I hold a Professional Engineering License in the State of California. I joined SCE in 1990 as a regional engineer in the Distribution Engineering Department. Since that time, I have held various jobs within SCE in the Distribution Engineering Department, including supervising regional and staff engineers, providing engineering support to various organizations involved with the design and construction of the distribution system and identifying distribution system upgrades designed to maintain capacity and reliability. Prior to my current position, I was the Senior Distribution Field Engineer, Eastern Zone Lead, where I supervised the performance of several Distribution Field Engineers and Technical Specialists and was responsible for the overall performance of the distribution and subtransmission system throughout the entire Eastern Zone area. I was also responsible for performing required studies, such as load flows, protection coordination studies, VAR planning, and reliability studies. I was transferred to my current position as a Supervisor of the RTVI and PQ groups in September of 2004.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor Section II.D (Distribution Benefits); and portions of Section III.B (Distribution System Planning) of SCE's Testimony, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

From: <Case.Admin@sce.com>
To: <docket@energy.state.ca.us>
Date: Wed, Apr 13, 2005 4:23 PM
Subject: R.04-03-017_DER OIR (DGOIR/DGOII): SCE 's Prepared Direct Testimony

To all parties of record on the official service list for CPUC Docket No. R.04-03-017 & CEC Docket No. 04-DIST-GEN-1 and 03-IEP-1:

The attached PDF file below includes the Prepared Direct Testimony of Southern California Edison Company (U 338-E), in Rulemaking 04-03-017, which is being served via electronic service today, April 13, 2005. Along with the submission of this testimony, SCE is hereby withdrawing the earlier Prepared Direct Testimony served on October 4, 2004. The Prepared Direct Testimony served today thus replaces SCE's previously filed testimony in its entirety.

(See attached file: 05-04-13 R.04-03-017 SCE Prepared Direct Testimony.pdf)

Hard copies are being sent via Overnight Courier Service to President Michael R. Peevey, ALJ Kim Malcolm and served via First Class Mail to all other parties.

Regards.

Case Administration
Southern California Edison Company
Telephone (626) 302-4875
Fax (626) 302-3119
Case.Admin@SCE.com