Decision **PROPOSED DECISION OF ALJ MALCOLM** **(Mailed 9/6/2005)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Incentives for Distributed Generation and Distributed Energy Resources.	Rulemaking 04-03-017 (Filed March 16, 2004)

(See Attachment B for Appearances.)

INTERIM OPINION ADOPTING COST-BENEFIT METHODOLOGY FOR DISTRIBUTED GENERATION

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INTERIM OPINION ADOPTING COST-BENEFIT METHODOLOGIES FOR DISTRIBUTED GENERATION

This order adopts a methodology for assessing the costs and benefits of distributed generation (DG). The purpose of this inquiry into cost-benefit methodologies is to assure that the state's support for DG projects is economically sound and to assure that state policies promote as much DG as is cost-effective, consistent with our general policy to include DG facilities as high-priority energy resources. The methodology we adopt today is designed to reflect the costs and benefits of DG facilities from various perspectives and employs existing data immediately, which will be modified in the future with the development of more precise economic values for some variables.

I. Procedural Background

Public Utilities Code Section 353.9 requires the Commission to develop a cost-benefit methodology for DG projects. The statute became effective May 22, 2001. The statute states the purpose of this analytical tool is to create a "firewall" that would assure net costs of DG projects are recovered from each customer class in proportion to the projects that are, in effect, subsidized by that customer class.[1]

We have also stated our intent to use cost-benefit analyses to compare resource options as part of utility resource planning, to determine how to choose

[1] The language of Section 353.9 is as follows: "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."

among candidate DG technologies and projects for incentives and other funding, to assess project alternatives as part of utility power procurement, and to assist in measuring and evaluating the effectiveness of DG incentive programs. There may be other uses for a rigorous cost-benefit test in the future.

As part of this rulemaking, which considers a number of policy and program issues related to DG resources in California, we stated our intention to adopt cost-benefit models. We embarked on this effort collaboratively with the California Energy Commission (CEC) by conducting a workshop on May 5, 2004. The workshop focused on identifying specific types of costs, benefits, and potential methodologies to quantify them. Parties filed comments in response to the workshop. The Commission conducted hearings in this proceeding on cost-benefit methodologies from May 11-13, 2005. The matter was submitted on July 12, 2005 with the receipt of reply briefs. Active parties in this proceeding represented regulated energy utilities (Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company/Southern California Gas Company (SDG&E/SCG), and DG developers, customers and their associations (California Clean DG Coalition, First Solar, California Clean DG Coalition (CCDC), Cogeneration Association of California and the Energy Producers and Users Association (CAC/EPUC), PV Now, the City of San Diego and Americans for Solar Power (ASPv). We refer to these non-utility parties collectively in some places as “DG Proponents.”

We proceed to consider cost-benefit methods applying the principles we articulated for related issues in our previous DG Rulemaking, (R.) 99-10-025. In that proceeding, we issued Decision (D.) 03-04-060, which we use as a foundation for our inquiry here.

II. Summary of Decision

This decision adopts the following general policies and principles for cost-benefit methods used to analyze DG facilities:

- DG projects should be analyzed using a societal test, a non-participant test and a participant test;
- The variables adopted for each of the three tests include Commission-approved avoided costs, values included in utility tariffs and certain estimates for various utility administrative costs;
- The participant test should be used to reduce subsidies to "free riders," that is, those DG projects that might be constructed and operated without the incentives offered for DG development;
- The adopted cost-benefit approach should be employed as soon as possible using existing data and information, which may be subject to change as a result of changing circumstances or the findings in R.04-04-025;
- The avoided costs presented by E3 and adopted in D.05-04-025 for energy efficiency projects should be applied to DG projects, with some modifications, until the Commission has adopted avoided costs for DG facilities in that proceeding;
- The "physical assurance" requirement is retained for the purpose of estimating the value of DG projects to avoided T&D costs;
- The impacts of DG projects on market prices should be included as a benefit in the societal model;
- All relevant environmental benefits should be included in the cost-benefit models, whether or not their impacts result from regulation or compliance with state or federal law;
- Tax incentives, standby charge exemptions, and Self-Generation Incentive Program (SGIP) incentives should be considered benefits to DG projects in the participant test and costs in non-participant tests;
- The value of DG projects in terms of "market transformation" should be considered in R.04-04-025;

- The utilities shall grant priority SGIP funding to those projects that are most cost-effective and may not provide funding to those projects that do not require SGIP subsidies in order to be cost-effective to the participant.

We direct the utilities to reassess the state's DG program overall using the models and model specifications adopted today. The utilities should conduct this analysis and file the results of the analysis in this proceeding.

Finally, we state our intent to explore other specific applications of the cost-benefit models and model specifications we adopt today.

III. Background on Issues and Policy

A. Overview of Cost-Benefit Approaches

Our inquiry with regard to DG costs and benefits evolves from our wish to promote as much DG as is sensible for California, but to assure that California ratepayers do not pay more for DG than it is worth to them. DG differs somewhat from other generation resources in that it is small and often versatile, that it may be easier on the environment than more traditional energy resources, and that its operation is controlled by the customer rather than the utility. We have elaborated on the value of DG facilities to California utility customers and its economy in several Commission orders and the Energy Action Plan, issued by this Commission, the CEC, and the California Power Authority.

This order proceeds to identify and specify the quantification of all relevant costs and benefits related to DG. The information may then be used to analyze the wisdom of subsidies for DG projects, the allocation of project development costs between project developers and ratepayers, and the benefits of DG relative to other energy resources available to jurisdictional utilities.

The parties to this proceeding identified a variety of possible costs and benefits associated with DG, either in workshops or during the hearings. Among the potential costs of DG projects are:

- Costs to integrate the DG project with the utility's distribution system impacts;
- Utility revenue loss due to displaced usage of transmission and distribution facilities;
- Utility/DWR revenue loss due to avoided commodity purchase—energy, capacity, bonds;
- DG project costs—investment, maintenance, fuel, metering;
- Improved stability and power quality;
- Ancillary services/VAR support;
- Utility loss of revenue due to displaced thermal load, cost of ratepayer incentives for CHP generators;
- Costs of mitigating air and water pollutants, and noise abatement;
- Reduced utility revenues for sales of natural gas;
- Utility administrative costs; and
- Cost of tax and other incentives.

Among the potential benefits of DG identified by the parties are:

- Reduced transmission and distribution line losses;
- Avoided purchases of other energy and capacity;
- Enhanced reliability;
- Improved stability and power quality;
- Provision of Ancillary Services/VAR support;
- Environmental benefits compared to central station facilities, including reduced air and water pollutants, promotion of environmental equity compared to large central station power plants;

- Thermal load provided in Combined Heat & Power applications;
- Increased responsiveness to load growth resulting from DG's modularity and scale;
- Lower market prices for power;
- Increased employment and tax revenue in California;
- National security benefits associated with reduced security risk to grid;
- Conservation of natural gas;
- Avoided utility capital costs; and
- Avoided utility administrative, maintenance, insurance, and installation costs.

Of the costs and benefits identified in this proceeding, some will be easier to quantify than others and some will be extremely difficult to quantify, such as equity impacts. DG costs and benefits vary based on technology, fuel variable, application, size, location, and frequency and duration of the facility's use. Significantly, the value of DG depends on whether the calculation is from the perspective of the DG project owner, the utility's customer base, or society overall. In D.03-02-068, the Commission found that DG can serve different purposes, such as onsite generation or as a distribution system alternative. The value of a DG project may depend on how the power is used, technology, fuel, and application. For this reason, this order evaluates a variety of methodologies that reflect various perspectives and types of DG.

Creating a cost-benefit methodology for DG facilities is a technically complex exercise but is not a novel one. For many years, the Commission has used cost-benefit tests for energy efficiency programs and avoided costs for assessing the value of and setting prices for "qualifying facilities," privatelyowned energy resources that sell power to the utilities under the Public Utilities Regulatory Policies Act of 1981.

In this proceeding, our primary objective is to specify a model or models, that is, to specify variables that would reflect the appropriate costs and benefits to be measured in the model. A secondary but essential objective here is to determine the type of data or information to use to establish values for each of the model's variables.

The parties have used some existing studies and references in advocating for model types and specifications. The Commission has developed and used a cost-benefit model for existing energy efficiency program proposals in the "Standard Practice Manual" (SPM) used to guide energy efficiency program administration. Also providing a foundation for the debate in this proceeding were two reports sponsored by the CEC and the Commission. One, issued by Itron in March 2005, is titled "Framework for Assessing the Cost-Effectiveness of the Self Generation Incentive program" (Itron Report). The other, issued on October 25, 2004, by Energy and Environmental Economics, Inc. (E3), is titled *Methodology and Forecast of Long-Term Avoided Cost(s) for the Evaluation of California Energy Efficiency Programs* (E3 Report) and was presented in R.04-04-025, the Commission's inquiry into energy avoided costs.

The SPM report presents a cost-benefit model. The SPM model was intended to be used for resource assessments generally but has so far been used primarily to evaluate energy efficiency programs. The Itron report uses the SPM methodology as a starting point, and specifies the model inputs that are relevant for DG projects. The E3 Report presents various avoided cost estimates, which were adopted by the Commission in D.05-04-024. Avoided costs are inputs to cost-benefit models. For example, we could specify a cost-benefit model that measures avoided generation costs and avoided transmission line losses. An avoided cost in this context generally refers to a type of cost the utility avoids when the DG facility serves load the utility would otherwise have to serve. The generic avoided cost calculation may accurately reflect a DG facility's value to the system or it may serve as a baseline to which we might include "adders" in the cost-benefit model to reflect an additional value (or cost) that is specific to a DG facility or DG facilities generally compared to other energy resources. For example, we may find that in addition to avoided transmission costs that are common to all resources that reduce load, we may include an adder in the cost-benefit calculation that recognizes the deferral of investment in a transmission line to serve a specific large customer with a DG facility.

B. Development of Avoided Costs in R.04-04-025

The Commission is currently considering avoided costs in a separate docket, R.04-04-025. In that rulemaking, the Commission intends to adopt avoided costs that are consistent, to the extent appropriate, across technologies, programs, and policies. For example, they may be applied to energy efficiency programs, demand response programs, utility resource planning and procurement, energy supply contracts with qualifying facilities, and DG. The Commission already adopted new avoided costs for energy efficiency programs in D.05-04-024, which were derived from the E3 report.

As the scoping memo issued in this proceeding explains, the avoided costs developed in R.04-04-025 may be useful as elements of the cost-benefit models we adopt in this proceeding. Our intent here has been to identify the types of elements appropriate for a cost-benefit model to assess DG projects, which would include an avoided cost and may include other elements. For example, R.04-04-025 may set a value for the avoided capacity cost that applies to a project that defers utility investments in a central station plant. To the extent a DG project avoids capacity, that avoided cost would be included in the DG cost-benefit model. The variables for that cost-benefit model, however, would not necessarily be limited to the avoided cost developed in R.04-04-025. The project may also provide additional benefits to ratepayers or society, or impose additional costs, relative to those that are incorporated in the avoided cost.

Overall, the purpose of our ongoing effort in R.04-04-025 is to promote some consistency in our application of avoided costs across programs and evaluation exercises. We do not pursue consistency, however, in a vacuum. Where it is sensible to distinguish one type of facility or program from another because of costs or benefits associated with the facility or program, we intend to tailor our analysis. This proceeding pursues that objective to specify cost-benefit models in ways that reflect the SGIP and DG facilities in particular.

We do not intend to wait for the adoption of a permanent set of avoided costs in R.04-04-025 before we apply the cost-benefit models we adopt in this order today. Instead, we adopt interim avoided costs that may be incorporated into the methodology we ultimately adopt.

C. Defining DG for Purposes of Modeling Costs and Benefits

In determining how to measure costs and benefits, CAC/EPUC suggests the Commission here adopt a standard definition for DG. DG facilities vary significantly from the standpoint of technologies, applications, size, and use. However, they all serve load in close proximity to the generation. With this in mind, CAC/EPUC proposes the following definition of DG:

"DG is generation located on a customer's site that produces electricity to serve some portion of the customer's load, or nearby load, or both."

CAC/EPUC suggests that this definition includes combined heat and power (CHP) facilities, also called cogeneration plants. CAC/EPUC argues that cogeneration is reliable, efficient, and environmentally beneficial. CAC/EPUC objects to the CEC Working Group's definition of DG as limited to facilities that are connected to the utility's distribution system. CAC/EPUC believes this definition inappropriately imposes size limits on projects that may be identified as DG (because some large cogeneration plants are connected to the grid at the transmission level). Generally, CAC/EPUC believes there should be no requirement that a project to be connected to the utility grid. CCDC agrees with these comments.

No party objected to this definition. The significance of adopting such a definition for purposes of our inquiry here is, however, unclear. The scope of this order is limited to identifying the appropriate cost-benefit models to use when evaluating DG and related matters. We are not changing program parameters or creating new incentives. The way DG is defined should not in any way affect how or whether a project is subject to state or federal regulation. Regulatory jurisdiction is determined on the basis of a project's specific characteristics. To the extent cost-benefit models precisely and accurately incorporate the characteristics of a DG facility, it matters little how DG is defined. In that context, we have no objection to the definition proposed by CAC/EPUC, but do not make any commitments about how DG might be defined for other applications and for other purposes.

D. Assigning Specific Values to Adopted Variables

In addition to determining the types of models we should use to analyze DG projects, we specify the variables for each and identify data that should be used to calculate actual costs and benefits. This latter exercise is likely to be a moving target since many of the values for each cost-benefit model may change. These values may be derived from various information resources depending on the cost or benefit in question. For example, estimates of utility incentives are available in program guidelines and a total would be estimated according to DG facility energy production forecasts. Some model variables would use avoided costs either already in existence or under study in R.04-04-025.

The parties differ to some extent with regard to whether the Commission has the appropriate data to calculate costs and benefits immediately. ASPv would defer the adoption of final values, stating that third parties do not have ready access to much of the data needed for the models. It suggests conducting further proceedings to develop values for each variable. SCE also would await the final avoided costs adopted for DG in R.04-04-025. Other parties propose using what is available today, subject to future adjustments.

The California Legislature directed the Commission to adopt cost-benefit models for DG projects more than four years ago when it added Section 353.9. We see no reason to delay implementation and believe we have adequate data to begin the process of analyzing DG projects immediately. We also state our intent to modify inputs where existing information, data or estimates may be improved upon.

In order to avoid delay in developing reasonable cost-benefit models, we herein assign values to each variable. Where relevant, we use existing tariffs, incentives and tax rates. In some cases, we are able to use values adopted already in D.05-04-024. We will modify them as information becomes available or underlying values change.

IV. Developing Cost-Benefit Models According to Perspective

The costs and benefits of any energy project may vary significantly depending on whose perspective a model reflects. For example, a model that reflects ratepayer concerns will focus primarily on the cost of a project relative to other energy resource options available for purchase by the utility. A model that reflects societal concerns will likely to incorporate environmental impacts and equity concerns. A model that reflects the concerns of the DG owner will emphasize project profitability. The Standard Practices Manual presents three perspectives comparable to these and identifies them as follows:

(1) **The participant test**, which measures the costs and benefits to the customer participating in a program, such as a DG developer receiving a subsidy;

(2) **The non-participant test or "ratepayer impact measure,"** which measures how customer bills change as a result of the program; and

(3) **Societal or "total resource cost" test**, which measures the net costs of the program based on the impacts to participants and non-participants.

Applying all three models would measure how costs and benefits are distributed among various groups or individuals.

The parties generally do not dispute the purpose of each of these models. They do, however, dispute their relative importance, how they should be applied and what the tests should measure. Each is discussed below.

A. The Non-Participant Test or Ratepayer Impact Measure (RIM)

The non-participant test measures the relative costs and benefits of a DG project or program from the standpoint of utility ratepayers. The main difference between this cost-benefit model and the "societal" model discussed below is that the non-participant test measures transfers of wealth between ratepayers and DG facilities are included in this test. Thus, it measures economic benefits as well as the allocation of costs between DG developers and utility ratepayers.

The utilities advocate for the application of the non-participant test in order to evaluate the impact of DG projects on utility customers from cross-subsidies such as exemptions from standby charges and nonbypassable charges. SCE observes that the non-participant test is the only test that quantifies the fairness of the allocation of costs and benefits between customers who install DG and those who do not. SCE observes that this test would measure the cost to ratepayers of such subsidies as exemptions from standby charges and nonbypassable charges, reduced transmission and distribution costs, and SGIP incentives. SCE also states this information is necessary in order for the Commission to comply with Section 353.9, which requires that net costs associated with tariff modifications provided to DG customers be recovered only from the class of the DG customer receiving the tariff modification.

Some DG proponents oppose the use of such a test, viewing it as too narrow to capture the total benefits of DG projects. CCDC does not believe a non-participant test is necessary to evaluate DG, arguing that the Commission need only apply a modified version of the societal test already in use for energy efficiency projects and programs.

Discussion:

Ratepayers (or “non-participants” in this context) support DG programs as part of our policy to promote the development of a more diverse and environmentally sound energy network in California. Among the DG subsidies they support are discounted rates, net metering, exemptions from standby charges, and the cost responsibility surcharge (CRS), and direct financial incentives offered by the SGIP. The cost-benefit test that measures whether ratepayers as a group realize a net benefit from DG development recognizes the subsidies that are offered by ratepayers to DG developers. It differs conceptually from a more traditional cost-benefit test, which does not recognize transfers of wealth between various affected groups. It asks only whether an activity or program provides net benefits to society at large.

Our first concern with regard to whether our DG incentives are worthwhile is whether they provide net benefits to the state at large. If they do, continued funding makes sense from an economic standpoint. This would be true even if DG development would occur without the incentives.

Even if DG subsidies are economically efficient from a societal standpoint, however, the Commission would not be doing its job if it did not at least consider the net cost of the program to those who pay for it. In addition to its duty to promote the interests of the general public and the economy at large, the Commission is charged with the protection of utility ratepayers. For that reason, we intend to specify a non-participant cost-benefit model and to use it to measure ratepayer liabilities. While we may not in every instance use it to disqualify a DG facility from program participation or to modify existing subsidies, we must at least manage ratepayer funds with our eyes open.

We therefore state our intent to measure the costs and benefits of DG facilities and programs from the standpoint of ratepayers. We use the RIM test, as defined in the SPM, as presented in the Itron report, and as modified herein. The RIM test measures ratepayer costs and benefits over 20 years, consistent with how we measure energy efficiency resources. In subsequent sections of this order, we discuss the variables that the non-participant test should include. Where modifications to the Itron approach are not explicitly addressed and adopted, the specifications in the Itron approach are implicitly adopted.

B. Societal Test or Total Resource Cost (TRC) Test

The so-called "societal" test measures the relative costs and benefits of a DG project or program to all Californians. The societal model is the purest form of cost-benefit analysis from an economic standpoint because it is indifferent as to who pays the costs or reaps the benefits of DG. The model merely inquires as to the net benefits accruing to the subject economy or group. The "TRC—Societal Version" (TRC) test is a variation of the societal model that is currently included in the SPM applied to the Commission's energy efficiency programs.

CCDC and ASPv propose the Commission recognize the similarities between DG and energy efficiency projects by adopting the TRC model. They believe this model is appropriate because of the comparability between energy efficiency and DG. CCDC and ASPv recognize that the TRC model should be tailored according to air pollutant emissions of DG projects and suggests the utilities assess the incremental cost of reduced transmission system vulnerability as part of the avoided cost. It would have the Commission use the TRC-Societal Version test to adjust standby rates in utilities' general rate cases.

The TRC-Societal Version measures costs associated with installation, operation and maintenance, fuel costs, removal less salvage value, and administration costs. Among the benefits measured by the TRC test are two external "adders," one for air emissions associated with electricity usage and one for gas usage. It also permits the inclusion of adders to reflect reduced water use and waste generation. In evaluating DG facilities, CCDC believes the Commission should use the standard variables that are applied to energy efficiency programs, such as discount rates, estimates of the effects of "free riders"[2] and useful life. It would apply the six avoided costs included in the TRC-Societal Version, three for electricity savings and three for gas savings. CCDC and ASPv would modify these avoided cost calculations according to the recommendations made in the E3 report issued in January 2004.

ASPv explains its preference for the TRC model in the SPM in part by arguing that the Itron approach fails to include a number of DG benefits because they are considered too general or too difficult to quantify. In light of the state's support for renewable DG, ASPv explicitly advocates for erring on the side of including too many benefits rather than too few even if some of those benefits are quantified at zero for now.

Although SCE does not explicitly object to the application of E3 avoided cost estimates or the TRC test, SCE observes that the E3 report does not present a complete cost-effectiveness methodology, but only addresses avoided costs, which are one element of a cost-benefit test. SCE observes that the variables included in Itron's approach to the Societal Test can be modified to incorporate "market effects," that is, the transformation of the market as DG technologies become more affordable and available to the public.

Discussion:

No party disputes the application of the societal model and we state our intent here to apply it. DG proponents propose to use the TRC model and the E3 findings to measure the cost-effectiveness of DG. SDG&E/SCG and SCE propose using the variables specified in the Itron report. The difference between the societal cost-benefit approach recommended in the Itron report and the SPM

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[2] "Free riders" are beneficiaries of a subsidy designed to motivate certain actions who would have taken that action without the subsidy.

TRC test currently applied to energy efficiency programs is mainly that they include different variables. The TRC test in the SPM includes variables that are not quantified by the Itron model, such as certain environmental adders.

While both DG and energy efficiency programs relieve the utilities of serving some load, in some significant ways they are not alike. The purpose of our inquiry here is to develop a model for DG facilities that best reflects the value of DG to society and ratepayers. Subsequent sections of this order address each variable that presented controversy between the parties. Attachment A lists all of the variables we adopt for each model and the data source for each. While the variables may not measure costs and benefits perfectly, they are reasonable for our purposes and may be modified as better information becomes available.

C. Participant Test

The participant test measures the economic viability of a DG facility to the developer or customer installing the facility. While those who install DG will naturally have their own calculation of whether an investment is worthwhile, the Commission might want to conduct its own participant test to determine the level of incentive needed to promote investment and to help prevent the provision of incentive payments by "free riders." As PG&E observes, it also appears that Section 2827(n) requires the Commission to complete a report on the costs and benefits of net metering from the perspective of "customer-generators." No party opposed the use of a participant test and we state our intent to adopt a participant cost-benefit model here and to use it to evaluate the efficacy of and need for incentives at various levels.

The Itron report identifies as benefits the customer's reduction in electricity bills, the value of displaced fuel with the use of waste heat, tax credits and other government incentives.

We herein state our intent to develop specifications for a participant test and to use that test where appropriate. In subsequent sections, we discuss the variables for that test that were a source of controversy in this proceeding. Attachment A lists all of the variables for the test and the source of data for each variable.

We also state our intent to use the test to eliminate "free-riders." Our purpose is not to penalize a facility for its cost-effective operation but to maximize the use of a limited pool of funds for the development of DG resources. Every dollar spent on a project that would be built without subsidies is a dollar that is not available for a project that might be viable with a subsidy. We will consider changes to the SGIP program and other subsidies consistent with this objective. In future proceedings, we will also consider whether other subsidy programs should be offered only to those facilities requiring them as a way to motivate investment and operation.

V. Variables of Cost-Benefit Models

Each cost-benefit calculation will specify costs and benefits. Most parties agree with the basic list of costs and benefits identified by the Commission and reflected in the Itron report. However, the parties did not agree on some variables proposed for cost-benefit models, as discussed below.

Some costs and benefits may be captured in an avoided cost designed for general application. For example, avoided costs capture the value of reduced natural gas usage. The inclusion of additional costs and benefits—or adders—in the calculation would reflect those impacts of a DG facility that are better (in the case of benefits) or worse (in the case of costs) than central station facilities or which are not captured by the avoided cost calculation at all.

A. Utility Administrative Costs

The utilities and the Itron report include in their cost-benefit tests the costs incurred by the utilities for managing DG programs. No party opposed inclusion of these costs in the RIM and TRC tests and we include them in the models we adopt today. CCDC believes PG&E's interconnection costs are overstated and asks the Commission to inquire as to why those costs exceed the charges to DG customers.

The estimates of administrative costs we include are those presented by the utilities in testimony. With regard to interconnection costs, the CEC is working with parties to develop information about interconnection costs using current and historical data, a matter which has been the subject of inquiry in this proceeding. We agree the CEC's final estimates of interconnection costs should be used as part of the non-participant and societal cost-benefit models adopted today. In the interim, we direct the utilities to use the estimates they provided in the record of this proceeding.

B. Line Losses

DG facilities reduce utility line losses because the energy resource is at the customer's premises and therefore does not need to be transported over transmission lines. There is some debate about how to reflect a project's size in the cost-benefit calculation. SDG&E/SCG observes that the cost-benefit calculation could make simplifying assumptions for small projects. For projects more than 100 kilowatts (kW), SDG&E/SCG suggests that engineering studies are required to calculate avoided transmission and distribution (T&D) costs and line losses.

D.05-04-024 adopted avoided costs for line losses on the basis of estimates presented in the E3 report. We find that those adopted line losses are appropriately used in the cost-benefit models we adopt today. The exception to this would be for large projects where engineering studies may be used to calculate line losses, as SDG&E/SCG proposes. We may update these estimates in R.04-04-025.

C. T&D Investment Deferrals

The Commission has found that DG facilities can reduce the need for new investment in utility T&D facilities. D.03-02-068 adopted several criteria for assessing the extent to which a DG facility might permit the utility to avoid T&D investments, among them the requirements that the facility be operating in time for the utility to avoid system expansion, that it must be of a size that serves the utility's planning needs, and that it provide a "physical assurance" that the customer will not ever require the utility service that would have otherwise been provided over the deferred investment. Thus, transmission and distribution investment deferrals are currently site-specific. There is no recognition of T&D deferral benefits for DG projects overall.

CCDC and ASPv believe cost-benefit models should identify T&D investment deferrals as among the benefits of DG, notwithstanding the specific characteristics of an individual facility. More specifically, CCDC would eliminate the "physical assurance" requirements of DG projects that are not parts of utility resource plans and which are compensated for their inclusion in those plans. CCDC argues that small DG projects together are likely to have very strong reliability benefits because the probability of simultaneous forced outages is very small. ASPv proposes to measure the physical assurance of DG projects at the program or portfolio level, which would recognize the combined value of the state's DG facilities. ASPv believes that even a single DG facility provides value to the system in terms of avoided T&D usage, although it does not estimate that value. CAC/EPUC asks the Commission to assure that large cogeneration plants receive recognition for transmission and distribution investment deferrals.

SDG&E/SCG, PG&E, and SCE argue that the inclusion of this benefit is contrary to the Commission's existing policy and that the DG parties have not justified the automatic inclusion of T&D deferrals in cost-benefit calculations for every DG. PG&E concedes that such a benefit might at some point be included in cost-benefit methodologies when there is sufficient DG in its territory that system planners can rely on their availability.

Overall, SDG&E/SCG believes the Commission should continue to recognize the prospect for DG projects to respond to load growth, recommending that projects be evaluated in the context of the distribution planning process established pursuant to Section 353.5.

Discussion:

Our existing policy is to reflect T&D investment deferrals only in specific circumstances where a facility can demonstrate its location, capacity size and operational characteristics justify an investment deferral. Eliminating these requirements for smaller projects and recognizing a benefit attributable to them would require us to presume that those projects, taken as a whole, permit the utilities to defer T&D investments even in cases where the individual project might not result in short-term deferrals because of size, location or operating characteristics. The potential for DG projects to result in systemwide T&D deferrals will depend largely on the number of projects installed.

This matter was litigated extensively and resolved less than two years ago. We find no compelling reason to change our policy regarding T&D deferrals and intend to measure any potential benefit by applying the existing criteria to specific projects, as set forth in D.03-02-068. We will reconsider this if and when a party can demonstrate that the load served by DG has had an impact—or should have an impact—on the utilities' T&D investment planning. In the meantime, we concur with SDG&E that this is a matter for consideration on a plant-specific basis and consistent with each utility's distribution planning process.

D. Market Price Impacts

Some parties propose that the cost-benefit calculation recognize lower market prices that might occur as a result of a DG project's operation. This effect is also referred to as "price elasticity of demand." The Itron report includes a market price adder in its societal and non-participant tests.

SCE, SDG&E/SCG, and PG&E oppose including a variable for market price impacts in the equation.

It is conceivable that the introduction of many DG projects could reduce a market price by reducing system demand. PG&E argues that a market price adder is inappropriate because a DG facility adds supply as well as reducing demand and therefore the net effect of the facility on the market is zero. PG&E appears to misapply economic theory in this case. Although a DG facility reduces demand by increasing supply, its increased supply is not offered in the relevant market. More relevant to the issue, however, is that additional supplies in a market put downward pressure on prices. We will adopt the market price adder recommended by the Itron report for the societal test and the non-participant test. The tests should reflect any changes to the market price adder that may be adopted in R.04-04-025.

E. Reliability Impacts

Some parties have proposed that the cost-benefit calculation include increased system reliability as a benefit. Conceptually at least, DG may improve system reliability under certain circumstances, for example, by providing a disbursed and versatile source of power supply. On the other hand, those reliability benefits could be offset by the unpredictability of a DG customer's need for power from the utility's system or an operator's decision to shut down the generator when market prices are low.

SDG&E/SCG stated enhanced systemwide reliability is unlikely but concedes that DG has the potential of reducing RS (or RMR) costs for a utility where DG reduces peak load in constrained areas. It believes these benefits will be nearly zero by 2010, however, when new generation is expected to come on-line. SDG&E/SCG also states that DG does not have the control capabilities to provide ancillary services and should therefore be treated as load reduction for purposes of ancillary services and VAR support, as Itron proposes. SDG&E/SCG proposes the Commission use the values presented in the E3 report and adopted in D.05-04-024.

PG&E believes the avoided cost calculation reflects a DG facility's value as a generation resource generally, although it does not assign more or less reliability to the DG facility than a central station facility.

CCDC concurs that quantifying the value of DG to the transmission system will not be possible immediately and proposes the utilities be ordered to conduct a transmission system simulation to determine those potential benefits. The utilities oppose such an effort as time consuming and expensive, and believe this type of task is part of the Independent System Operator's (ISO) transmission system planning process. CCDC also recommends that the Commission adopt E3's estimate for transmission reliability improvements by DG during peak hours.

The extent to which DG projects can improve reliability is unclear. Nevertheless, we believe that, on balance, DG facilities may relieve the strain on some critical elements of the utility system, as SDG&E/SCG observes. We will include a variable for these net benefits using the avoided costs estimated in the E3 report for energy efficiency projects and adopted in D.05-04-024 for energy efficiency cost-benefit measurements. We apply this value for the societal test and the non-participant test. The tests should incorporate any changes to this avoided cost if we adopt new values in R.04-04-025.

DG facilities may also improve the reliability of the DG customer because of its value as back-up power or voltage support. We do not have estimates of the value of a DG facility to the customer who owns it. The utility or the project developer should develop an estimate for each project, which would be incorporated into the participant test.

F. Employment Effects

DG proponents propose the Commission include increased employment as among the benefits of DG. As the utilities argue, we have no evidence in this proceeding to suggest that DG installations would create more jobs than those displaced as a result of the reduced demand for central stations or energy efficiency. We therefore do not include in the cost-benefit model a variable for increased employment.

G. Market Transformation Effects

Some DG Proponents propose the Commission treat DG development as a "market transformation" program and that the cost-benefit calculations include market transformation effects as a benefit. Market transformation in this context refers to development of a self-sustaining market for DG whereby customers have a wealth of potential suppliers of DG and can make independent and freeranging choices about DG installation. We would also expect a transformed market to need minimal or no public subsidies in order to remain competitive and support multiple providers and options for consumers. PV Now explains that the models presented in this proceeding are narrowly defined to promote immediate resource acquisition and do not take into account the more important long-term objectives of assuring that photovoltaic technologies, in particular, are sustainable in competitive markets without subsidies. CalSEIA, the City of San Diego and ASPv offer similar comments.

SCE and SDG&E/SCG object to recognizing market transformation objectives in cost-benefit models, noting that the result would be expensive and unjustified. They also believe the SGIP program has been developed as a resource acquisition program rather than one that is intended to have long-term market impacts. We disagree.

This Commission has stated its strong support for solar photovoltaic generation and other DG projects as part of a larger effort to promote the development of diverse and environmentally sound energy production system. We have expressed our support of such "green" energy production and other DG in the Energy Action Plan, requiring them to be deployed ahead of other energy production technologies. The SGIP program is explicitly designed to promote DG development, as are several tariff exemptions or discounts for DG operators and customers. Recently, the Governor has also publicly endorsed solar technologies in a program we are reviewing in this proceeding and refer to as "the California Solar Initiative."

There is no question that the Commission intends to support the development of a viable market for DG projects, especially those using renewable resource technologies, as alternatives to energy facilities employing fossil fuels, coal and nuclear resources. Notwithstanding the short-term goals of the SGIP program, we believe the program will and should influence the types of energy technologies deployed in California and the structure of the state's energy production and delivery system.

The nature and extent of support required for—or the value of—"market transformation" is neither specified nor quantified in the record of this proceeding. We do not have information to suggest the long-term value of solar technologies, which ones are likely to be most viable and the types of risks that accompany their development. Although we are not prepared to include market transformation benefits in the cost-benefit models we adopt today, we state our interest in quantification of long-term benefits of market transformation of specified green technologies and initiate a process for considering ways to integrate those benefits in cost-benefit models. We intend to review this matter in R.04-04-025.

H. Reduced T&D Revenues

CAC/EPUC objects to including decreased T&D revenues from the non-participant or RIM test, believing the lower revenues are offset by lower costs. CAC/EPUC also believes the Commission should follow the Federal Energy Regulatory Commission (FERC) precedent and assume that such lost revenues are normal business risk.

PG&E responds that T&D costs are generally fixed and ratepayers remit T&D revenues on a volumetric basis. In addition, the RIM test does not measure losses to the utility but to ratepayers. Even if T&D costs fell, ratepayers would not receive the benefits of lower costs between general rate cases.

Under existing ratemaking, when the utility's revenues decline as a result of a DG facility, the utility's ratepayers must ultimately make up all or some portion of the difference. Lost transmission revenues will be made up following subsequent transmission rate cases. Ratepayers assume dollar-for-dollar liability for all distribution and generation revenues that are lost as a result of reduced sales. Accordingly, this is not a case where utility "business risk" is an issue. The risk is ultimately risk to the ratepayer.

In order to assure an accurate assessment of how DG facilities affect ratepayers, the cost-benefit model for non-participants should measure lost T&D revenues. The estimates for these costs to ratepayers would be derived from utility rate tariffs and DG production data. These values would change according to T&D rates and DG output.

I. DG Project Costs

All parties agree that the costs of installing and maintaining DG units should be included in the participant test and the societal test. We agree that this is appropriate.

CalSEIA proposed to measure DG project costs using estimates of future costs at lower levels than that presented in existing databases. SDG&E/SCG believes the Commission should use data collected from the SGIP and the CEC's Emerging Renewables Program (ERP). SDG&E/SCG observes that this data are derived from actual facilities' costs.

We have no basis upon which to forecast future technology costs and we are not convinced that future costs provide an appropriate proxy for current project costs. We intend to use actual data to measure the costs of DG projects. As costs fall, they will be reflected in the data bases. The CEC retains some data tracking such costs associated with solar photovoltaic projects, which should be used. Otherwise estimates available through manufacturers for specific technologies should be included in the analysis.

J. Environmental Values—CO2, NOx, and PM 10 Emissions

The utilities generally support the use of the E3 avoided cost for generation and fuel to recognize air quality improvements from DG. The E3 data incorporates reductions in CO2, NOx and PM 10 emissions. CCDC would modify the E3 environmental adder by reflecting the actual mix of existing and expected power plants and their operating characteristics rather than using futures prices to estimate electricity market prices. The CCDC estimate would affect emission costs for CO2, NOx and PM. CCDC states that the dirtiest power plants are those most likely to be used during peak periods, and these marginal units should be included in the model, at least for the early years of a DG project. CCDC recognizes that emission avoided costs should be tailored by DG technology, time period, and facility location. CCDC also believes the E3 report's use of the NYMEX futures prices does not accurately reflect California conditions and an environmental adder would improve the price estimate in that regard.

PG&E argues that no value should be given to these environmental effects if they are not regulated or their mitigation mandated. PG&E observes that if they are mandated, their impacts will already be included in the cost of avoided generation. PG&E believes that DG facilities may increase CO2 emissions relative to central station plants because modern plants burn fuel at a much higher heat rate. It therefore proposes that this impact be included as a net cost of DG facilities.

PG&E's logic leads to the conclusion that no DG project should be considered any better for the environment than a gas-fired central station plant. Given that this Commission and the California State Legislature have explicitly recognized the environmental benefits of renewable DG facilities, we reject PG&E's position that no environmental value should be ascribed to a DG facility if the impact is not mandated. We wish to capture all benefits attributable to DG facilities and, in particular, to recognize those that improve environmental quality.

We herein adopt CCDC's proposed modification to the E3 avoided costs for electricity and natural gas for the societal and non-participant tests.

K. Combined Heat and Power Applications

CCDC proposes that the E3 avoided cost estimate for fuel and generation be modified to recognize that cogeneration uses a single fuel to produce electricity and production heat. SDG&E/SCG agrees that this benefit would always accrue to the DG customer and may represent a societal benefit if the efficiency of the DG facility is higher than a central station plant. SDG&E suggests these benefits would be plant-specific and believes the Itron report appropriately accounts for them.

We agree that the participant and societal tests should include a value that recognizes more efficient use of cogeneration facilities, where appropriate. We will direct that each project test estimate the related plant-specific characteristics.

L. Standby Charges

The Itron report includes the loss of revenues from exemptions from standby charges as among the costs that should be included in the non-participant test. SDG&E/SCG concurs with this methodology and suggests estimating this cost using data it has collected as part of the SGIP program.

SCE believes that if the revenue shortfall from standby charges is not offset by total DG benefits, Section 353.9 requires that the shortfall be recovered from members of the DG class only.

We agree that this subsidy should be included as a cost in the non-participant test and also as a benefit in the participant test. Estimates would be derived using the utilities' rate tables and according to the DG facilities' production. We also agree in principle with SCE's observation that any revenue shortfall should be recovered from members of the DG class. This latter issue involves revenue allocation, which is outside the scope of this proceeding. We therefore defer this matter to proceedings that allocate revenues among rates and customer classes. For SCE and PG&E, this would be in their respective general rate cases. For SDG&E, this could be in its general rate case or "rate design window" application.

M. Electric and Natural Gas Avoided Costs

The parties generally agree that DG facilities allow the utilities to avoid electric and natural gas costs. SDG&E/SCG proposes that we adopt the E3 values adopted in D.05-04-024. SCE and PG&E would apply those values until the Commission has modified them for DG in a later phase of that proceeding.

We herein adopt the E3 avoided costs for electric and natural gas avoided costs, as adopted in D.05-04-024, subject to modifications in that proceeding and with the modification addressed previously for air quality impacts.

N. Net Metering

Certain renewable DG projects qualify for "net metering," which permits the DG operator to receive bill credits for power sold to the utility. The bill credit amounts to a payment-in-kind that is substantially in excess of the avoided cost the DG facility would otherwise receive for selling wholesale power to the utility. Depending on the type of customer served by the DG facility, the DG customer could avoid all energy and T&D charges or, for large customers who pay fixed T&D charges, energy only.

Because this in-kind payment is a subsidy from ratepayers to DG facilities, SDG&E/SCG proposes to include it as a cost in the non-participant cost-benefit model.

Lost revenues from net metering are a subsidy designed to promote DG development. The reason for permitting net metering rather than tracking production more precisely is to avoid the cost of installing multiple meters to monitor both consumption of the facility and output from the DG unit. Thus, these costs are not readily measured, and we decline to require the installation of a new meter for this purpose, which the utilities' proposal implies. While conceptually this subsidy may be considered a cost, the expense of installing a meter to measure that cost would easily dwarf the benefit derived from knowing the amount of the subsidy. We decline to include these amounts in the cost-benefit calculations.

O. Exemptions From CRS Liabilities

DG projects under 1 megawatt (MW) are exempt from the "cost responsibility surcharge" which permits the collection of power purchase liabilities incurred by the Department of Water Resources (DWR) during the state's energy crisis and which are more expensive than market prices.

The utilities argue that the non-participant test should reflect the loss of CRS revenues when a DG facility goes on-line, as the Itron report recommends.

CAC/EPUC believes the non-participant test should not include reduced CRS liabilities because DWR did not purchase power for DG customers and small DG customers are exempt from CRS charges. CCDC makes similar comments.

CAC/EPUC is correct. Revenues associated with exemptions from CRS revenues should not be accounted for in the non-participant test. In developing its strategy for purchasing power during California's energy crisis, DWR believed that it could rely on a forecasted amount of DG power to meet the state's energy demand and purchased power supplies accordingly. For that reason, we found in D.03-04-030 that certain DG facilities should be exempt from the CRS. D.03-04-030 found that DWR excluded 3000 MW of power for DG from its forecast, and therefore the exemption is not a cost shift. For this reason, we include that CRS revenues should not be considered a cost in the non-participant test.

P. SGIP Subsidies

Currently, both the CEC and this Commission sponsor incentive programs for renewable DG projects. Once we establish that DG facilities should be analyzed using the non-participant test, there is no controversy about whether and how to recognize these subsidies in the models. As the utilities suggest, these subsidies are appropriately considered a cost in the non-participant test and as a benefit in the participant test. The subsidy amounts are available through the program rules and are readily applied according to facility characteristics and performance.

Q. Tax Incentives

Both the state and federal governments provide tax incentives for certain types of DG projects. No party opposes recognizing these subsidies in the models. They should be included as benefits in the participant test. They would not be included in the societal test because they are merely transfers, and would not be included in the non-participant test because ratepayers do not bear these costs.[3]

Tax incentives should be estimated using Internal Revenue Service regulations and State Franchise Tax Board rules, or the information provided by DG vendors.

VI. Program Monitoring, Measurement, and Evaluation

The Commission currently authorizes direct financial incentives, rate exemptions, and special rate discounts that impose a cost on utility ratepayers. Direct subsidies alone could amount to almost $1 billion in the next several years, all of which are supported by utility ratepayers.[4] In many instances, these subsidies may be very worthwhile. In others, ratepayers may be paying more for DG development than it is worth. Although initial evaluations of DG facilities may support the provision of ratepayer subsidies, DG projects should be expected to conform to ongoing performance standards and program guidelines.

In August 2005, Itron published its 4th Year Impact Report, which assesses the state's DG installations using the cost-benefit models which formed the basis for the Itron report considered in this proceeding. Using those cost-benefit models and the avoided costs developed in the E3 Report, Itron's 4th Year Impact Report suggests that more than 70% of Level 3 SGIP projects fail the minimum efficiency requirements to participate in the SGIP program. It points out other

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[3] Of course, the ratepayers of a regulated California electric utility form a subset of California taxpayers and federal taxpayers. The former group, however, do not assume the entire cost of the tax incentive.

[4] Currently, the Commission has committed $875 million for the SGIP, which may be increased for the Solar Roofs Initiative, which is the subject of Senate Bill 1. In addition, the CEC awards about $100 million annually for small DG projects.

problems with DG facilities with regard to reliability and capacity factors. These estimates may change with the methodological refinements we adopt today, but the fact remains that the value of some DG projects is in question, implicating the design of existing programs and tariffs.

One of the explicit purposes of the cost-benefit tests we adopt today is to evaluate the ongoing performance of projects that receive ratepayer support. We intend to use these tests immediately to determine which DG projects should qualify for SGIP funding where the level of funding requested by all applicants exceeds available SGIP funds. Currently, the utilities consistently receive many more requests for funding than SGIP budgets could support. Beginning immediately, the utilities should award SGIP funding to those DG projects on their waiting lists that are most cost-effective, ahead of other projects.

In addition, we direct the utilities to reassess the state's SGIP program overall using the models and variables adopted here and summarized in Attachment A. Because the E3 values adopted in D.05-04-024 are forecasts starting with the year 2006, the utilities should work with the Energy Division to determine whether and how the avoided costs should be modified to reflect gas prices for the periods between 2001 and 2005. The utilities are directed to file the results of the analysis in this proceeding within 45 days.

We also intend to use the cost-benefit models to immediate future in determining whether DG facilities qualify for other subsidies and rate exemptions. Accordingly, we herein direct the utilities and invite other parties to propose specific ways to apply the cost-benefit models we adopt in this order. On the basis of those proposals, we intend to modify our programs to improve their value to ratepayers and California generally in ways that are consistent with our policy to promote DG facilities. Specifically, we seek proposals for the following types of evaluations:

1. **Ongoing subsidies to existing DG projects—**how such projects should be monitored from a technical standpoint, the criteria for evaluating them and the impact on subsidy programs for projects not in compliance with program criteria;
2. **Initial evaluation of DG projects for which subsidies are requested—**how, if at all, the application of each of the three cost-benefit models should affect the grant of incentives, tariff discounts and exemptions, and other subsidies; and
3. **Free ridership—**how the Commission should use the participant test, if at all, to assure ratepayers are not subsidizing projects that would otherwise be viable for the DG customer.

VII. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Kim Malcolm is the assigned Administrative Law Judge (ALJ) in this proceeding.

VIII. Comments on Proposed Decision

The proposed decision was issued for comment on _____________, 2005, in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments were filed on ___________.

Findings of Fact

1. The State Legislature effectively directed the Commission to develop a cost-benefit methodology by enacting Section 353.9, effective May 2001, which requires the Commission to create a “firewall” that protects each group of customer classes from subsidies to DG projects in other customer classes.

2. The Commission has available data and avoided cost estimates to apply to cost-benefit models immediately and during the period before more refined avoided costs are adopted for DG facilities in R.04-04-025.

3. Using the non-participant test to measure the impacts of DG subsidies on utility rates will help the Commission in compliance with Section 353.9 and fulfill its more general obligation to protect ratepayers from unreasonable rates.

4. The societal test would measure the impacts of DG facilities on the state's economy generally and establish the extent to which DG facilities are worthwhile resource additions compared to other energy resource options.

5. The participant test would help identify "free riders," that is, those DG projects that would be profitable for DG customers absent all or some portion of existing subsidies or other incentives.

6. The Standard Practice Manual methodology was developed to measure resource costs and benefits for many types of resources, including energy efficiency, demand response, and distributed generation.

7. The SPM has been used in the past primarily to evaluate energy efficiency programs.

8. The cost-benefit specifications presented in the Itron report were developed specifically to analyze DG facilities.

9. DG facilities and energy efficiency programs and projects are dissimilar in some significant ways.

10. The utilities presented estimates of most administrative costs that reasonably reflect actual costs. The CEC is estimating utility interconnection costs using current and historical data.

11. D.05-04-024 adopted avoided costs for reductions in line losses that are readily applicable to small DG projects. Reductions in line losses attributable to projects greater than 100 kW may be estimated with engineering studies.

12. The requirement that a project demonstrate "physical assurance," a concept adopted in D.03-02-068, assures the DG project is a reliable resource for

utility planning purposes by assessing the DG project's location, capacity, and operational characteristics.

13. DG projects may reduce market prices by reducing customer demand for resources in the state's energy markets. This reduction in demand is not offset by an additional supply because that supply is not offered in the relevant markets. If it were, the impact would be to put downward pressure on prices.

14. The E3 avoided costs for system reliability impacts of energy efficiency programs and projects is readily applicable to DG projects for use in the non-participant and societal tests until and unless the Commission adopts more specific avoided costs for DG facilities.

15. DG facilities may improve reliability of power supplies to DG customers.

16. DG facilities may increase or decrease the level of employment relative to employment at central station plants.

17. The Commission's policy to promote DG as a vital energy resource in the state is consistent with the idea of "market transformation," which assumes the assimilation of DG technologies as an integral part of the state's energy resources. The Commission has no estimates of the value of market transformation in this proceeding.

18. Including reduced T&D revenues in the non-participant test would estimate the losses to ratepayers for financial support of the T&D system.

19. Current and most recent data about the costs of installing, maintaining and operating DG projects would promote a more realistic evaluation of a project's net value than estimates of future costs.

20. Including only those environmental benefits that are attributable to regulatory or other legal requirements would permit the exclusion of tangible and valuable environmental benefits of DG projects.

21. CCDC's proposal to modify the E3 avoided cost estimate for electricity and natural gas by reflecting the air pollutants from the actual mix of power plants, including those that are operated on the margin, would improve the accuracy of those avoided costs where air quality benefits are concerned.

22. Cogeneration plants use a single fuel to produce electricity and production heat, which may be more efficient from an engineering standpoint than electricity production at a central station plant.

23. Exemptions to DG facilities for standby charges represent a subsidy from ratepayers to DG customers.

24. The Commission adopted avoided costs estimated by E3 for electricity and natural gas in D.05-04-024 that may be applied to DG cost-benefit tests until and unless the Commission adopts specific values for DG facilities.

25. The cost of estimating the cost of net metering would itself not be cost-effective.

26. Exemptions for DGs from CRS liabilities do not result in a loss of revenues because DWR did not purchase power for DG customers.

27. SGIP subsidies represent a cost to utility ratepayers and a benefit to DG customers.

28. Tax incentives represent a benefit to DG customers.

29. SCE, SDG&E/SCG, and PG&E have stated in this proceeding that they normally have more requests for SGIP funding than their respective SGIP budgets could support. The cost-benefit models adopted today could help the utilities determine which projects on their waiting lists should receive priority for SGIP funds.

30. Proposed DG projects that would be cost-effective to the DG customer without ratepayer subsidies do not require ratepayer subsidies to motivate project construction and operation.

Conclusions of Law

1. The Commission should immediately implement cost-benefit tests using available data and avoided costs estimates before more refined avoided costs are adopted for DG facilities in R.04-04-025.

2. The Commission should require the use of the non-participant test to measure the impacts of DG subsidies on utility rates to assure compliance with Section 353.9 and fulfill its more general obligation to protect ratepayers from unreasonable rates.

3. The Commission should require the use of the societal test to measure the impacts of DG facilities on the state's economy generally and establish the extent to which DG facilities are worthwhile resource additions compared to other energy resource options.

4. The Commission should require the use of the participant test to help identify "free riders," that is, those DG projects that would be profitable for DG customers absent all or some portion of existing subsidies or other incentives.

5. The cost-benefit models referred to as the participant test, the non-participant test and the societal test should be adopted with the specifications, data and variables set forth herein and as summarized in Attachment A.

6. The utilities' estimates of most administrative costs should be used in societal and non-participant cost-benefit models except that the CEC's estimates of utility interconnection costs should be used.

7. The avoided costs adopted in D.05-04-024 for reductions in line losses should be applied to small DG projects. Reductions in line losses attributable to

projects greater than 100 kW should be estimated with engineering studies. Values for line loss reductions should be included in societal tests and non-participant tests.

8. In estimating the impact of DG facilities on T&D avoided costs, the Commission should not change the requirement for "physical assurance" adopted in D.03-02-068.

9. The impact of DG projects on market prices presented in the Itron report should be used in the non-participant test and the societal test.

10. The Commission should require the use of the E3 avoided costs for system reliability impacts in the non-participant and societal tests until and unless the Commission adopts more specific avoided costs for DG facilities.

11. The Commission should direct the parties to estimate the reliability benefits of DG projects to DG customers and to include those estimates in the participant test.

12. Cost-benefit models should not assume that DG projects improve employment in California.

13. The parties should estimate the value of market transformation effects in R.04-04-025 for inclusion of that variable in the societal test.

14. Reduced T&D revenues should be included in non-participant tests.

15. Current and most recent data about the costs of installing, maintaining, and operating DG projects should be included in the societal test and the participant test.

16. The Commission should require the inclusion in cost-benefit models of all known environmental benefits of DG projects, whether or not they are attributable to regulatory or other legal requirements.

17. The participant test and the societal test for a DG cogeneration plant should estimate the plant's efficiency relative to central station facilities.

18. Exemptions from standby charges should be reflected as a cost in the non-participant test.

19. The avoided costs estimated by E3 for electricity and natural gas and adopted in D.05-04-024 should be applied to DG cost-benefit tests until and unless the Commission adopts specific and more permanent values for DG facilities.

20. Non-participant tests should not include as a cost the reduced revenues attributable to net metering.

21. Reduced CRS revenues should not be included as a cost in the non-participant test.

22. SGIP subsidies should be included in the non-participant test.

23. Tax incentives should be included as a benefit in the participant test.

24. Attachment A, which summarizes costs and benefits for each of the three adopted cost-benefit models, should be adopted to guide cost-benefit calculations for DG facilities, subject to modification in R.04-04-025 and as the Commission determines.

25. The Commission should direct SDG&E/SCG, SCE, and PG&E to apply the cost-benefit models we adopt herein to establish which proposed DG facilities on their waiting lists should receive scarce SGIP funding.

26. Attachment A should be included as part of the program guidelines for SGIP and should be immediately implemented to guide the selection of DG facilities that qualify for SGIP funding.

27. The Commission should develop the record in this proceeding to determine exactly how to use the adopted cost-benefit models in DG programs.

28. The utilities should be ordered to withhold funding for proposed DG projects that are determined to be cost-effective for the DG customer using the participant test adopted herein.

29. SCE, PG&E, and SDG&E/SCG should be ordered to reassess the state's SGIP program using the models, specifications, variables and data adopted herein. The utilities should file the results of the analysis in this proceeding within 45 days.

INTERIM ORDER

IT IS ORDERED that:

1. The cost-benefit models and model specifications described in Attachment A and discussed herein are adopted for the purpose of assessing distributed generation (DG) facilities in California that qualify for subsidies, incentives, and rate exemptions supported by jurisdictional utility ratepayers.

2. Beginning on the effective date of this order, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company/Southern California Gas Company (SDG&E/SCG) shall use the models and specifications summarized in Attachment A to determine which projects qualify for Self-Generation Incentive Program (SGIP) funding. Those projects on the waiting lists that are the most cost-effective investments for ratepayers and society should receive first priority for SGIP funding. Projects that do not require funding in order to be cost-effective for DG customers whose projects are analyzed using the participant test adopted herein shall not receive SGIP funding.

3. PG&E, SCE, and SDG&E/SCG shall collaboratively reassess the state's SGIP program using the models, specifications, and data adopted herein and

summarized in Attachment A. The utilities shall file the results of the analysis in this proceeding within 45 days of the effective date of this order.

4. In order to effectuate the Legislature's intent as set forth in Public Utilities Code Section 353.9, this order is effective today.

Dated ___________________________, at San Francisco, California.