Decision **PROPOSED DECISION OF COMMISSIONER LYNCH**
(Mailed 1/10/2003)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking into Distributed Generation.	Rulemaking 99-10-025 (Filed October 21, 1999)

O P I N I O N

(See Appendix A for List of Appearances.)

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Appendix A - List of Appearances

OPINION

1. Summary

This decision completes our rulemaking and establishes policies for ownership and operation of distributed generation and their integration into utility planning and operation of the distribution grid. We find that there is no need to place restrictions on ownership of distributed generation units. The technology of electricity distribution, however, necessitates that a distributed generation owner will only be eligible for compensation for deferring distribution system upgrades in limited circumstances, described herein, and only if the distributed generator offers physical assurance. Similarly, since almost every retail sale will utilize both the distribution and transmission networks (even those that appear to stay within a single circuit), we do not adopt a distribution-only tariff.

The nature of this new technology and its likely uses obviates the need to make any changes to rate design to accommodate distributed generation at this time. Nevertheless, we do allow the utilities to establish memorandum accounts to track distributed generation implementation costs that cannot be attributed to specific distributed generation projects and are not part of the utilities' existing budgets.

We do not adopt a mass marketing information campaign about distributed generation, but rather a multi-pronged education effort directed to those considering a distributed generation installation.

To allow us to consider ongoing issues, we state our intent to open a new rulemaking – related to distributed generation.

2. Background

The purpose of this rulemaking is to develop policies and rules to facilitate deployment of distributed generation in California. As part of this process, we are reviewing our regulatory framework to ensure that unnecessary barriers to deployment of distributed generation are removed. In Decision (D.) 00-12-037 we adopted improved interconnection tariff rules for Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE).

This decision is the result of our review of the April 17, 2000 System Planning and Operation Workshop Report and comments on that report, prepared testimony, cross examination during 9 days of hearings on Phase 1 issues and 7 days of hearings on Phase 2 issues, and post-hearing briefs on Phase 1 and 2 issues. In this decision we address all outstanding issues from Phases 1 and 2, including valuation of distributed generation benefits, distribution system operation and planning, ownership and control of distributed generation, the need for distribution-only tariffs, net metering, rate design as it relates to distributed generation, and educational and consumer protection efforts.

Commissioner Bilas presided at two days of hearings in Phase 1 and three days of hearings in Phase 2. Upon the departure of Commissioner Bilas from the Commission, Commissioner Lynch assumed direction of this rulemaking.

3. Outstanding Procedural Matters

Throughout the course of this proceeding, the Assigned Commission or the assigned Administrative Law Judge (ALJ) have ruled on numerous motions. We affirm those rulings at this time. On January 21, 2003, an organization calling itself Joint Parties Interested In Distributed Generation / Distributed Energy Resources (JPIDG) filed a motion to intervene. Several of the member organizations have participated during the course of the proceeding. On January 28, 2003, Clarus Energy Partners, L.P. (Clarus) filed a motion to intervene. Clarus installs, owns, and operates combined heat and power generation systems. The motions are granted. To the extent that any motions remain outstanding, the motions are denied.

4. Potential Benefits of Distributed Generation

Parties identified potential benefits that could result from wide-spread deployment of distributed generation, including: peak demand reduction; deferral of distribution system equipment and upgrades; increased life of distribution equipment; reduction of utility capital risk; power quality improvements; voltage support; line-loss reductions; increase in reliability; environmental benefits; customer satisfaction; and fuel diversity. Benefits listed in parties' testimony echo those discussed by workshop participants in workshops facilitated by the Energy Division, which resulted in the Distribution System Operations and Planning Workshop Report, issued April 17, 2000. Parties do not agree on whether these benefits do occur.

Parties linked valuation of distributed generation benefits to the utilities' distribution system planning process, citing potential opportunities to provide distribution support services. Several parties submitted testimony on the need for a system to assign value to the perceived benefits. No party submitted a detailed methodology, although Utility Consumers' Action Network (UCAN), Natural Resources Defense Council (NRDC), PG&E, SDG&E and The Utility Reform Network (TURN) each provided principles that could be considered in developing a valuation methodology.

SCE distinguishes potential benefits of distributed generation depending on the parties that stand to receive the benefits. SCE asserts that only distributed generation designed to support the distribution system benefits should be considered by utility in its grid planning decisions. PG&E and SCE contend that many benefits from customer-side distributed generation accrue directly to the customer, without necessarily avoiding any utility costs. SDG&E's discussion of benefits includes only those benefits it considers of value to the utility distribution system.

UCAN and NRDC argue that there is a role for distributed generation to address the peak capacity shortage predicted to face California over the next several years. UCAN acknowledges that pending utility projects to expand transmission import capacity are underway to address system peak demand needs, but points out the long-term nature of completing such construction projects. Besides the capacity strain and reliability implications that excessive peak demand presents on the system, UCAN discusses the relationship of large peak demands on the cost of energy purchased by utilities. UCAN points out that the current availability and flexibility of distributed generation peak shaving technologies such as microturbines, photovoltaics, and wind turbines present potential value both to individual customers and the system by addressing peak demand needs. UCAN states that end users may prefer to make individual investments in onsite distributed generation rather than pay higher distribution tariffs to achieve added reliability. Individual distributed generation customers, by meeting their own needs through self-generation, would at the same time alleviate the demand on the system infrastructure. In addition to customer use, UCAN indicates substation capacity and feeder support as particularly viable areas where distributed generation can reduce system demand and benefit the overall system.

In comments on the predecessor rulemaking, PG&E stated "import constraints and high prices for power over the summer of 1998 sent peak price signals to the market that could, especially if repeated in 1999, provide the economic incentives for the installation of DG as a large 'customer-side' peaking resource." (Rulemaking (R.) 98-12-015, Response of PG&E, March 17, 1999, Attachment A, p. 4.) SCE indicates that distributed generation is a solution to the peak demand problem only when high peak demand prices make distributed generation cost-effective. We take official notice of the prices listed on the website of the California Independent System Operator (ISO) which indicate that peak prices in 2000 generally met or exceeded those of 1998, indicating that conditions do support consideration of distributed generation as a customer-side peaking resource.[1]

NRDC asserts that distributed generation increases the life of distribution equipment. SDG&E argues that NRDC's assertion is unsupported by any data. SDG&E maintained that it does not benefit from reactive support or from line loss reductions due to distributed generation, as system line losses were accounted for in Power Exchange rates. PG&E, SDG&E, and SCE state that distributed generation alone cannot ensure added value to system reliability, without a form of operational guarantee, or physical assurance. SCE states that the low level of distributed generation deployment to date has not resulted in any avoided distribution capacity costs. PG&E also states that reliability is a customer-specific benefit.

NRDC cites the minimal environmental impact of photovoltaics and wind turbines, and supports the use of fuel cells over central generation. NRDC points out that potential benefits expand beyond the direct value to the utility to include public goods and public interest benefits such as lower environmental impacts,

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[1] See http://www.caiso.com/surveillance/pricedata/index.cgi.

insurance against uncertainties in load growth, and increased power available for sale. In testimony, NRDC identified technologies that are beneficial for the environment as zero emission renewables and "clean" fuel cells. NRDC argues that wind, solar photovoltaic, and fuel cell technologies emit lower amounts of NOx, SO2 , and particulates, making them environmentally preferable to standard combined-cycle central generation plants. SCE recommends that valuation of environmental benefits be performed outside of the Commission, for example, under similar mechanisms to that of the South Coast Air Quality Management District's emission trading market.

PG&E considers distributed generation as an additional support to distribution investments in areas where local loads are estimated to exceed wires capacity for a number of hours per year. SDG&E and PG&E state that grid benefits from distributed generation occur when distributed generation provides a substitute or defers distribution system and equipment investments by meeting utility-specific planning requirements. SDG&E identifies four specific conditions that are required if grid benefits from distributed generation are to be realized: (1) distributed generation must be located where SDG&E's planning indicate a need; (2) distributed generation must be installed and operational within the window of time needed by SDG&E; (3) distributed generation must be of appropriate size to accommodate SDG&E's planning needs; and (4) distributed generation must provide physical assurance.[2] (See SDG&E, Ex. 54, p. 20. See also, PG&E, Ex. 53, pp. 1-5 to 1-6.)

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[2] SDG&E's Opening Brief defines physical assurance as "The application of devices and equipment that interrupts a distributed generation customer's normal load when distributed generation does not perform as contracted. An equal amount of customer load to the distributed generation capacity would be interrupted to prevent adverse

Footnote continued on next page

4.1. Discussion

Although the utilities dispute many of these perceived benefits as being unsubstantiated at this time, most parties agree that distributed generation has the potential to reduce system demand in areas experiencing load growth, and that it should be considered as an option to defer distribution investments. PG&E indicates that solicited distributed generation may also benefit the distribution system by providing voltage support, power factor improvement, and emergency back-up functions. PG&E defines solicited distributed generation as a distributed generation installation based on a utility-identified need. SCE indicates that if the Commission adopts SCE's recommendation for utility-only ownership for distribution capacity distributed generation, there is no need to determine distributed generation value beyond SCE's authorized ratemaking mechanisms.

Based on the record developed in this case, we conclude that distributed generation has the potential to improve, and therefore benefit, system reliability in two primary ways. First, distributed generation has significant potential to reduce system peak demand by serving onsite load. As noted by UCAN, installation of customer side distributed generation has the potential to release existing generating capacity to meet peak demand requirements of other customers. We take official notice of the fact that California's consumption of electricity grew by 4.0% per year (on average) between 1998 and 2000.[3] During a period of strong demand growth and tighter supply, distributed generation

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consequences to the distribution system and to other customers." We use this definition of physical assurance herein.

[3] See http://www.energy.ca.gov/electricity/silicon_valley_consumption.html, Statewide Consumption column.

provides an alternative source of supply to large central station generators to meet a given customer's onsite load. By serving onsite loads, especially during peak demand periods, installation of customer side distributed generation not only can free up generating capacity to serve other loads, but can provide a stabilizing force for peak period prices. These benefits will flow through to all customers without this agency specifically "valuing" such benefits. In particular, these benefits can be captured by incorporating distributed generation into long-term procurement plans. In addition, R.02-01-011 raises the issue of whether departing load customers who utilize onsite distributed generation provide value to the system that should result in a reduction to their cost responsibility surcharge. This proceeding does not provide us with sufficient record to resolve this issue, but deserves further exploration in a successor rulemaking

Second, distributed generation has some potential to defer distribution system upgrades, however such deferrals are time and location limited. The record does not support a finding that distributed generation provides for long-term distribution upgrade deferrals, regardless of ownership of the distributed generation asset, because distribution circuits have a limited capacity to connect additional generation units. In other words, distributed generation, as a substitute for distribution system upgrades is likely to have limited application and be time limited because of long-term growth on the distribution system.

The primary purpose of attempting to identify and value benefits of distributed generation is to ensure that the utility distribution planning process fairly evaluates potential distributed generation solutions relative to traditional wires investments. Most parties agree that the Commission should not establish an administratively determined valuation scheme. In the System Planning section below, we will discuss how utilities should incorporate distributed generation into their distribution system planning. In our opinion, it is not necessary to establish a "valuation" system in order to ensure that distributed generation is properly incorporated into utility distribution system planning.

Identifying unique benefits of distributed generation solutions could help us design appropriate price signals or other incentive mechanisms to encourage installation of distributed generation, if desired. Although we find that distributed generation does have potential benefits, we do not find that these benefits are unique to distributed generation. Rather, we find that potential benefits, such as deferral of distribution upgrades or costs, reduced capital risk, extended service life of existing plant, improved power quality, reduced line losses, var or reactive support, are all benefits which the utility should evaluate in its planning process, regardless of whether the proposed solution is a distribution asset or distributed generation.

As NRDC demonstrated, wind, solar photovoltaic, and fuel cell technologies emit lower amounts of NOx, SO2, and particulates, making them environmentally preferable to standard combined cycle central generation plants. It is unclear, however, that renewable distributed generation offers unique benefits when compared to distribution system upgrades that do not have emissions. Renewable distributed generation does offer unique environmental benefits over fossil-fueled distributed generation for serving onsite loads. However, because the choice of a given customer for its onsite use is not within the jurisdiction of this Commission, we decline to establish a "valuation" process for those benefits. This is not to say that this Commission should not establish policies to promote more environmentally responsible investment choices, only to say that we do not at this time establish a specific valuation process to accomplish our environmental objectives as it relates to distribution system investments. In other forums, for example, R.01-10-024, we are incorporating environmental criteria into our electricity procurement policies.[4]

5. Distribution System Operations and Planning

In D.99-10-065, the Commission confirmed the utilities' responsibility to plan, operate and maintain their respective distribution systems. We recognized that significant deployment of both grid-side and customer-side distributed generation would likely affect distribution system planning, operations and maintenance, and indicated that R.99-10-025 should study the impacts on these functions.

The Commission directed the Energy Division to hold a workshop to consider these specific distribution system planning and operations issues:

- How distributed generation impacts distribution system operations;
- What changes in operating practices may be needed;
- How the utilities can identify the level of future deployment of distributed generation; and
- How this forecast of deployment can be incorporated into the distribution system planning process.

A Workshop Report was filed by the Energy Division on April 17, 2000, followed by a round of comments and reply comments. Parties were also asked to provide written testimony on potential revisions to existing ratemaking mechanisms to facilitate cost effective distribution system planning. Some

[4] JPIDG does not distinguish throughout its comments on the proposed decision that distributed generation can play very different roles, for example, as an onsite generation source or as a distribution system alternative. In playing these different roles, distributed generation can have very different value to ratepayers as a whole or a particular ratepayer.

parties discussed these and other issues related to distribution system planning and operational issues in both phases of their testimony.

5.1. System Operations

The utilities operate the distribution system to ensure employee and public safety and system reliability. Although operations vary among the utilities, certain basic operating principles and distribution system characteristics apply to all utilities. Several factors could influence how distributed generation impacts the utilities' operation of the distribution system. These factors include customer load, the size, technology, location and operational mode of the distributed generation, the number of distributed generation units on a circuit, the controlling entity, and the applicable tariff structure.

Parties identified how distributed generation impacts distribution system operations, and made recommendations as to the operational changes likely needed to accommodate distributed generation. Most operations system impacts, such as voltage levels, flicker, coordination of protection schemes, unintentional islanding, and remote monitoring were identified through the Interconnection Workshop process, and appropriate technical requirements were specified within the interconnection standards approved in D.00-11-001 and D.00-12-037. The utilities express concern over unintentional exporting of power during a system outage. As established in the interconnection standards approved in D.00-11-001 and D.00-12-037, this problem can be prevented with protection device coordination, conductor upgrades, and other automatic means.

From an operations standpoint, distributed generation raises few operational issues that are not covered by well thought out interconnection standards. Distributed generation that exports energy to the grid has a system planning impact because of the potential need for system upgrades to accommodate exported power. Distributed generation that provides grid support also raises system planning issues.

5.2. System Planning

NRDC agrees that the utility should compare the relative costs and benefits of potential distributed generation[5] solutions and wires alternatives, and select the most cost effective solution, but expresses concern that current planning models do not thoroughly consider the "public good" nature of certain environmental, customer acceptance, system stability and power quality differences. NRDC does not propose any specific valuation methodologies, but identifies the need to analyze distributed generation options and apply them to the utility planning process.

The utilities indicate that if the utility is responsible for the safety, reliability and operation of the distribution system, it must have control over the planning and operation of the system. We reaffirm this today. Parties also agree that the utilities should continue their current responsibility of managing and planning the distribution system, but urge the Commission to clarify how distributed generation can be incorporated into the utilities' planning process.

5.2.1 Physical vs. Contractual Assurance

In considering how to incorporate distributed generation into the utility distribution system planning process, we must determine whether a non-utility distributed generation could provide sufficient reliability to substitute for a

[5] NRDC refers to distributed energy resources, rather than distributed generation, in its system planning discussions.

distribution system upgrade.[6] New Energy, Inc. (New Energy) observes that the utility does not need to own all or any grid side distributed generation to fulfill its obligation to provide a safe and reliable distribution system, but the utility would need to have a certain level of control over grid side distributed generation. New Energy further states that sufficient control can be achieved through contractual relationships, coupled with severe economic penalties for failure to perform.

SDG&E believes there are no economic penalties strong enough to ensure distributed generation operates when needed. According to SDG&E, only physical assurance can ensure system safety and reliability, and is necessary if distributed generation is to be incorporated into the planning process as an alternative to distribution upgrades. SCE concurs, adding that its negative experience with RMR contracts reinforces its view that contracts for grid services are not an adequate substitute for grid ownership, and would interfere with SCE's ability to fulfill its obligation to provide safe and reliable distribution service. If the Commission orders the utilities to contract with third parties for distributed generation capacity, control and dispatch must be retained by the utility.

If we allow third-party owned distributed generation to contract for distribution capacity deferrals, or other services, it must operate when needed, and that load must be automatically curtailed if contracted distributed generation fails to operate. Physical assurance accomplishes these objectives, and addresses the utilities' concerns about the need for sequential restoration.

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[6] There is no dispute that utility control is not required when distributed generation serves a customer's onsite load.

The Interconnection Standards requirements approved in D.00-12-037 pre-certify, standardize and track the performance of distributed generation, which, paired with increasing distributed generation reliability, may make distributed generation an increasingly attractive option to enhance reliability of the distribution system. The option to provide distribution support (for a fee) may factor into a customer's decision to purchase distributed generation. Requiring physical assurance will increase confidence in contracting for distributed generation, thus enhancing opportunities for distributed generation in lieu of distribution capacity upgrades.

We agree with parties who make the distinction between ownership and control of distributed generation. As New Energy observes, "the key to ensuring safe and reliable distribution services is not ownership, but the ability to control the distributed generation unit. There are tools available to ensure that a third party owned distributed generation grid side unit performs its intended function – distribution system reliability." (New Energy Phase 1 Reply Brief, p. 9.) Utility ownership of grid-side distributed generation units is not necessary to ensure the safe operation and reliability of the utility operated grid.

5.2.2 Incorporating Distributed Generation into System Planning

NRDC, Enron North America Corp. and Enron Energy Services, Inc. (Enron), and New Energy recommend use of appropriate incentives to minimize the total cost of delivering electricity services, and to encourage development and use of new technologies. NRDC emphasizes the importance of coordinating grid planning with existing or planned non-utility distributed generation, pointing out that without coordination, the utilities may build distribution capability to serve loads that could disappear from the grid within a few years due to use of onsite distributed generation.

Very few parties provide specific recommendations on how the utilities might design a process to procure distributed generation used to defer capacity upgrades. PG&E and SDG&E indicate a willingness to consider distributed generation as an alternative to traditional wires solutions, and each provides similar broad selection criteria using existing procurement methods to obtain distributed generation. The Workshop Report observes that "[u]sing a solicitation process that provides functional or performance specifications (e.g., amount, time, duration, etc.) rather than a prescriptive solicitation could allow a wider range of possible solutions and a better chance that an innovative solution will surface" (pp. 42-43.)

TURN submits a more detailed approach similar to the alternative principles proposed by Capstone Turbine Corporation (Capstone) in the Workshop Report. TURN's model requires the utilities to develop a transparent planning process subject to Commission review and approval. TURN believes its model creates a fair and transparent process that balances flexibility with accountability.

SCE does not favor solicitation of third party distributed generation used as an alternative to wires upgrades, citing its position that only the utilities should be allowed to own distributed generation used to provide distribution support. SCE urges the Commission to use caution in creating policy regarding this type of distributed generation, citing the QF experience of relying on untested third-party contracts to promote development of new technologies. SCE further notes that utility-owned distributed generation would not require contract administration, an extensive mandatory bid process, or other coordination costs. Lastly, SCE indicates that distributed generation is not currently a cost-effective alternative to distribution investments.

Although PG&E agrees with SCE that distributed generation does not appear to be a cost effective alternative, PG&E offers a proposal to value distributed generation used for distribution support. PG&E's suggested criteria includes four requirements: the distributed generation unit must be identified by PG&E as an alternative to a distribution capacity upgrade; the distributed generation capacity must defer or alleviate an actual investment; compensation to the distributed generation must be cost-effective relative to the utility's alternative wires solution; and the distributed generation unit must provide the required distribution capacity. Although New Energy supports these criteria, it observes that industry participants must be provided more specific information in order to meet the "cost effective" criteria. SDG&E asserts that a formal solicitation process would hinder its planning efforts, and recommends adoption of approach described in its testimony as the most efficient method of implementing a cost effective capacity solution.

Proposals made by a number of parties for procedures to solicit grid side distributed generation, and how to utilize third party owned distributed generation deployed as a substitute for distribution system upgrades, are similar to previous regulatory schemes, and the utilities are wary of them. Some parties regard the process of soliciting for third party distributed generation as similar to the Biennial Resource Plan Update (BRPU) process.

The key utility responsibility is system planning. System planning must consider distributed generation alternatives (both on the grid side and customer side of the meter) to wires upgrades as part of the normal planning process. Non-utility solutions should be actively solicited through the planning process. The level of utility control/physical assurance should be weighed in evaluating/selecting options.

We do not wish to re-create a BRPU-type process for determining whether wires or distributed generation should be used to satisfy demand for electricity in distribution constrained areas. As part of each utility's planning process, each utility shall determine when a distribution system upgrade is necessary to ensure reliability and safe operation of the system. As a part of this determination, the utilities shall determine if a grid-side distributed generation unit could be a reasonable means of providing the electricity demanded in the identified constrained area.

SDG&E outlines the criteria distributed generation must meet to allow the utility to defer capacity additions and avoid future cost. The distributed generation must be located where the utility's planning studies identify substations and feeder circuits where capacity needs will not be met by existing facilities, given the forecasted load growth. The unit must be installed and operational in time for the utility to avoid or delay expansion or modification. Distributed generation must provide sufficient capacity to accommodate SDG&E's planning needs. Finally, distributed generation must provide appropriate physical assurance to ensure a real load reduction on the facilities where expansion is deferred. There is potential that distributed generation installed to serve an onsite use will also provide some distribution system benefit, however, unless it meets the four planning criteria describe by SDG&E, such benefits will be incidental in nature.

We adopt the approach to distributed generation procurement proposed by SDG&E in its Phase 1 testimony and developed in subsequent briefs and Phase 2 testimony. SDG&E describes a method that enables the utility to retain control of its distribution system planning process, maintain reliability at a reasonable cost, yet provides the flexibility required to evaluate various distributed generation options and technologies as an alternative to a wires solution. To accommodate distributed generation in the planning process, SDG&E suggests the utility be allowed to establish performance criteria for determining when a distributed generation solution is a viable distribution alternative. The distributed generation community would be made aware of these criteria and would be contacted in advance regarding specific locations where the utility is considering procuring a distributed generation option. When the utility determines that distributed generation is a potential alternative for the distribution system requirements, the utility would procure the distributed generation solution.

In comments on the proposed decision, TURN proposes that we require the utilities to file advice letters for approval of their implementation process. SDG&E suggests in reply comments that the utilities be required to file a compliance filing describing the methodology used for evaluating distributed generation as a distribution alternative. Both approaches are designed to ensure an understanding of the distribution planning process and distributed generation's role in it. The specific language proposed by SDG&E meets these needs with sufficient flexibility and has been incorporated into an ordering paragraph.

The compensation paid to the distributed generation solution would be no greater than that calculated for the deferral of a planned capital addition. Compensation for this deferral would be paid in the form of a bill credit or direct payment, to the distributed generation provider 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.[7] This process is consistent with the Operations and Planning Workshop Report, which states that the utilities should be responsible for determining the threshold at which distributed generation is considered as an option for distribution services. Because the distributed generation provider would only be compensated when its costs are less than distribution upgrade costs, and because the utility will control whether a credit is offered, the costs of any credits are absorbable within the existing distribution budgets. Credits shall be treated as distribution expenses.

The selection criteria established by the utility shall include a balanced consideration of reliability and cost. The utility is charged with selecting the proposal that would provide the adequate level of reliability and safety to the affected circuit at a reasonable cost to consumers. All decisions made by the utility must be documented and defensible should any third party challenge the utility's selection.

Payment to the distributed generator providing distribution support services to the utility should be governed by a contract mutually acceptable to the parties. We encourage the utilities to develop sample contracts that can be used as a starting point for negotiations between the parties, like the Form Contracts proposed by SDG&E in Exhibit 72, but we will not mandate or adopt specific terms.

6. Ownership of Distributed Generation

In the prior section we have established that with sufficient utility control, or physical assurance, over distributed generation installed in lieu of a

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[7] If the deferral lasts more than one year, the credit for future years should reflect the present value of the deferral.

distribution system upgrade, utility ownership of distributed generation is not required. When distributed generation serves a customer's onsite load, parties do not dispute that utility ownership or control is not necessary. In this section we decide, whether as a matter of policy, we should limit ownership of distributed generation installed either to serve onsite load or to defer distribution upgrades. For ownership purposes, when a distributed generation serves onsite load but also sells excess energy into the market, we will consider such unit as if it were supplying onsite load, unless it has participated in the utility system planning process.

In setting policy regarding the ownership of distributed generation, including the role of the utilities in the distributed generation marketplace, most parties recommend that policies be tailored to whether distributed generation will be used to supply customer needs or to support the distribution system. In testimony, briefs, and workshop report comments, parties focused on how different ownership and control rules could affect the market. From the input received from parties throughout this proceeding, it is apparent that there are a number of real concerns about who should be allowed to own distributed generation units.

6.1 Positions of Parties

One of the main concerns of consumer representatives was that utilities should not be allowed to own grid side distributed generation because they would be able to cross subsidize their distributed generation operations with earnings from rates on services provided through their regulated monopoly. The Office of Ratepayer Advocates (ORA) and TURN are concerned that without careful limitations on utility's activity in the distributed generation marketplace, the utilities may be able to use their position as monopoly providers of distribution services to gain an unfair advantage. Particularly, these consumer advocates are concerned about utilities having incentives to behave anti-competitively if they own and operate distributed generation units.

TURN notes that it believes utility and utility-affiliates should be prohibited from owning distributed generation on either side of the meter because it would present "undue competitive advantage" in the distributed generation market to the utility and utility-affiliate. ORA focused its comments on the utility, and noted that utilities should be barred from owning distributed generation on customer locations, and should utilities be able to own grid-side distributed generation, a utility would have the incentive to act in an anti-competitive manner.

TURN and ORA are worried about a utility's ability to cross-subsidize its distributed generation operations with its protected monopoly distribution services. In the case of grid-side distributed generation, the consumer advocate groups warn against possible attempts by the utilities to roll their distributed generation operation expenses into their distribution rates.

Parties agree that any prohibition on utility ownership and operation of distributed generation should be exempted in cases where an emergency exists and temporary deployment of distributed generation on a limited basis could restore reliability and ensure safe operation of the distribution grid. In addition, ORA and TURN suggest that in locations where distribution upgrades may be necessary, the utility solicit distributed generation installations by third parties. TURN and ORA warn of possible conflict of interest if the utility is put in a position of deciding between a third party bid and a utility or utility affiliate proposal.

Utilities focus on their responsibility to maintain system safety and reliability, although PG&E, SDG&E, and SCE had different positions regarding the question of ownership of distributed generation. All agree that because of their responsibility to maintain and operate the grid, the utility needs some form of control over all types of distributed generation, with the greatest level of control for distributed generation units installed in lieu of a wires upgrade. Utilities note that their main requirement is that they be given sufficient control over the distributed generation resources, regardless of what side of the meter they are installed on to ensure the system's safe and reliable operation.

SDG&E does not share the other utilities views that the utilities should be allowed to own and operate distributed generation. SDG&E supports utility ownership of distributed generation in only limited emergency circumstances. The other utilities, most notably SCE, argue that utility ownership would provide the most efficient means of bringing the benefits of distributed generation to electric customers.

The ISO focused on the control needed to ensure reliability of the transmission system. The ISO states that it needs to have information regarding the amount of distributed generation that is online and supplying power to either side of the meter, to ensure it understands what causes fluctuations in load detected in the ISO control room.

NRDC, the only environmental advocacy group to provide testimony on Phase I issues, notes that utility ownership is not necessary for benefits to occur when distributed generation substitutes for distribution upgrades.

Energy service providers Enron and NewEnergy are concerned that the utility may engage in preferential treatment of utility owned distributed generation units within their service territory, and suggest that the utility not be allowed to own or operate distributed generation units for that reason.

The marketers of distributed generation technologies feel that development of distributed generation will be maximized if regulated utilities are not allowed to compete, especially on the customer side of the meter. Similar to many other parties, the distributed generation marketers expressed the opinion that the utilities should put grid-side distributed generation out for public bid. The distributed generation marketers that commented on Phase I issues noted many of the same concerns as the consumer advocates, specifically those concerns about utility cross-subsidization of distributed generation activities with revenues from it's protected monopoly activities.

6.2 Criteria for Evaluating Options

The parties have provided several options for ownership of distributed generation resources. In evaluating the possible alternative for ownership of distributed generation assets we kept the following criteria in mind: grid-side distributed generation applications should maintain or enhance grid reliability and safety; regulations promulgated by the Commission should be designed to minimize complexity – thereby minimizing the cost of regulatory burden, in addition to providing clear rules for market participants; this decision should promote the most efficient allocation of resources – in other words, the cost of grid-side distributed generation deployment versus distribution system upgrades should be considered; and the selected policy should protect consumers and minimize the costs borne by ratepayers.

6.2.1 Customer Side

Customers with specific power reliability or quality needs may look to onsite generation to meet all, or a portion of their generation needs. Customer side power is not a new idea; customers that operate critical electrical devices (such as hospitals) have had onsite backup generation available for decades. However, new, lower-priced, more efficient distributed generation technologies, in conjunction with the high energy prices faced by some California consumers, has caused some consumers to consider producing their own energy onsite full time, not only as a means of emergency backup power.

None of the utilities that participated in this proceeding plan to market distributed generation to customers and SDG&E explicitly argues against utility ownership of customer side distributed generation. We agree with SDG&E that utilities are responsible for "the safe and reliable delivery of power at reasonable prices." (See SDG&E, Phase 1 Opening Brief, p. 3.) SCE and PG&E however argue that despite the fact that they do not intend to market distributed generation to customers, they should not be precluded from doing so if they later change their mind.

Customer-side distributed generation represents a new market in California's electric industry. The investor-owned utilities have a franchise, which grants them sole rights to provide electric distribution services within specific service territories in return for being subject to state regulation. Sections 330(e), (f), (g), and (r) all demonstrate that regulated utilities should be focusing on their delivery, safety, and reliability responsibilities. Pub. Util. Code § 377, as effective in 1999 and 2000, directed the Commission to regulate utility owned generation to ensure that utility ownership does not confer undue competitive advantage on the utility.[8] SCE relied on § 377, as previously adopted, to argue that the Commission has the authority to allow utilities to own customer side distributed generation. TURN argues on brief that the reverse is also true, that the Commission has the authority to limit utility ownership of distributed generation under § 377.

[8] All statutory references are to the Pub. Util. Code, unless otherwise noted. We note also that while this proceeding was pending, § 377 was modified.

Although we might have considered not allowing the regulated utilities or their affiliates to sell, own, or operate, distributed generation units on the customer's side of the meter based on the record developed in this proceeding, circumstances in the electric industry have changed and we choose not to limit ownership at this time. We note that the utilities and their affiliates do not appear to offer any sort of specialized expertise in the manufacture, sale, or operation of distributed generation on the customer side of the meter, so we do not encourage them to enter this new business line within the regulated utility. However, utilities and affiliates of the utilities, as independent agents, remain free to enter the customer side distributed generation market along with independent third parties. From a ratemaking standpoint, utility owned customer side distributed generation should be treated as a generation asset and revenues associated with utility ownership or operation of customer side distributed generation should offset the utility's costs of ownership or operation.

6.2.2 Grid Side

In the system planning section we concluded that sufficient control and physical assurance is possible for distributed generation units such that utility ownership is not necessary for units that are developed in order to defer distribution upgrades. Only SCE argues that utility ownership is the surest way to provide for physical assurance and therefore we should not allow other ownership for distributed generation designed to defer a distribution upgrade. All other parties agree that if a distributed generation unit is sized, located, and installed consistent with the utility's planning process, and provides physical assurance, ownership by the utility is not required in order to provide distribution system benefits. We agree with TURN who states that:

> "While it may be necessary for a non-UDC distributed generation unit to provide some form of physical assurance, it is also clear

> that any so-called 'Distribution DG' unit owned by SCE would also need to provide that same guarantee. Therefore, any SCE-owned distributed generation unit providing reliability services would be required to identify load that can be shed if the unit fails to perform at a time of peak demand. Given that this requirement would apply equally to any distributed generation performing this function, it is not clear that utility ownership would offer any greater guarantees than a non-UDC alternative." (TURN, Phase 1 Opening Brief, p. 30.)

For these reasons, we will not limit ownership of distributed generation on the grid-side to utilities. Third-party ownership should be allowed, subject to appropriate physical assurances and participation in the utility planning process. Because it is unlikely that distributed generation will permanently defer distribution system upgrades, we expect that contracts for third party owned distributed generation would be relatively short term in nature and renewed or dissolved based on the results of the utility distribution system planning process.

The question then becomes, should utilities be allowed to own distributed generation installed for grid support purposes at all. SDG&E recommends that grid-side ownership by utilities be limited to "portable generators used to provide operational support on a temporary and short-term basis, generation used for emergency purposes to support the distribution system on a temporary basis, pending more permanent consideration during the annual planning process, and research development and demonstration." (SDG&E, Phase 1 Opening Brief, p. 2.) The record reflects that these are the only capacities in which utilities have owned or utilized distributed generation in the recent past. TURN supports SDG&E's proposal and would limit temporary use to no longer than one year. Other parties similarly support utility ownership of distributed generation for temporary, emergency, or research applications to support the reliability of the distribution system. There is clearly a public interest in allowing utilities the flexibility to respond to distribution system emergencies and temporary situations through ownership of distributed generation for these limited applications. Utility ownership of distributed generation used for these limited purposes is appropriate and we will allow this continued ownership by utilities.

Should utilities be allowed to own distributed generation that is designed to defer distribution upgrades on a more permanent basis? Because we have found that benefits from installation of distributed generation for distribution support purposes are likely to be time and location limited, regardless of ownership, any distributed generation installed for distribution support purposes will be unlikely to serve that function indefinitely. Distributed generation installed on a permanent basis will soon become simply a power generator, rather than a distribution deferral project. As a general rule, we encourage utilities to limit their ownership of distributed generation to portable generators used to provide operational support on a temporary basis, generation used for emergency purposes to support the distribution system on a temporary basis, pending more permanent consideration in the annual planning process, and research, development and demonstration purposes relating to delivery service operation. This preference is not intended to prejudge any potential utility role in the generation market that may be considered as part of the utilities long-term procurement planning process.

We will not specify how long "temporary" lasts as recommended by TURN, but we expect that utility owned distributed generation will be utilized in truly temporary situations with permanent solutions being implemented through the distribution system planning process that occurs within one year after implementation of a temporary distributed generation solution. For utility-owned distributed generation solutions that are temporary in nature, we will not require the same type of metering associated with permanent generating facilities. We adopt the proposal of SDG&E, which is supported by ORA, to treat output of such facilities as Unaccounted for Energy. We agree with SDG&E that such output should be relatively insignificant in nature and ensures that the utility utilizes its own distributed generation only when it provides distribution value, not based on any perceived value of generation output. (See generally, SDG&E, Ex. 54, p. 3.)

If a grid-side distributed generation solution is identified as part of the utility's annual planning process and the utility distributed generation solution is the least cost investment, the utility should be allowed to make the investment. Like third-party distributed generation providers, the utility should be eligible to receive a credit based on the deferral value of the distributed generation unit. The credit would be paid out of the distribution budget. The distributed generation capital cost and operations and maintenance costs should be treated as a generation cost. Any distribution credit will be treated as an expense and would serve to reduce the capital and O&M costs of the generation asset.

7. Need for a Distribution-Only Tariff

In *Tennessee Power Company*, 90 FERC ¶ 62,238 (March 15, 2000), the Federal Energy Regulatory Commission (FERC) clarified that generators have a right to interconnect to a utility distribution facility under open access tariffs on file with FERC. When a generator connected at distribution wishes to sell its output at wholesale, Order 888 provides guidance. "A public utility's facilities used to deliver electric energy to a wholesale purchase, whether labeled 'transmission', 'distribution,' or 'local distribution' are subject to [FERC's] exclusive jurisdiction ...." *Order 888*, FERC Stats. & Regs. ¶ 31,036, at pp. 31,969, 31,980 (Appendix G). There is no dispute that when a distributed generator sells its output in the wholesale market or at retail to a customer on a different distribution circuit that the transaction is FERC-jurisdictional. At issue in this proceeding is whether a generator connected at distribution who makes a retail sale to a customer on the same distribution circuit (1) utilizes the transmission system, (2) should be eligible for a distribution-only tariff, and (3) is subject to state or federal jurisdiction.

7.1 Does a Retail Sale within a Distribution Circuit Utilize the Transmission System?

PG&E, SDG&E, SCE, and Edison Electric Institute (EEI) argue that, from an engineering perspective, distribution-only transactions are infeasible. For example, SDG&E describes the dependence of the distribution system upon services originating from the transmission grid as follows:

> "From a technical viewpoint, the distribution system and the customers on the distribution system depend upon the products and services delivered by the transmission system. By separating the two systems, the products and services from the transmission system would cease to flow to distribution customers, and the distribution system would cease to function (de-energize). . . . In certain instances, a distribution customer's energy requirements may be served by DG, however, the ancillary services that an end-use customer pays are supplied by the transmission system because these products cannot be provided by DG or the distribution system apart from transmission." (SDG&E, Ex. 62, p. 16.)

SDG&E further notes that:

> "The transmission system and the ISO grid are influenced by energy imbalances associated with distributed generation. If distributed generation is forced out of service, or its output varies in an unscheduled manner, the resulting energy schedule imbalance will be evident on the transmission system and the ISO grid." (SDG&E, Ex. 54, pp. 17-18.)

In testimony, some parties argue that transactions that utilize only distribution facilities can occur.[9] Parties arguing that distribution-only transactions can occur provided no engineering support for their position. In fact, under cross-examination, witnesses for these parties acknowledged that, in virtually all circumstances, distribution wheeling involves the use of the transmission system and the ISO. For example, Witness Townley for New Energy stated that rather than making <u>no</u> use of the transmission system, distribution wheeling did not involve the "full services" of the California ISO. (Townley, New Energy, RT 732.)

Parties generally agreed that the ISO has the responsibility to balance load and generation within its control area and to provide reserves for load located in the control area. Parties also agreed that utilities do not have the ability or resources to provide load balancing or reserves for load connected with the distribution system and, if a distributed generation either ceases to operate or

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[9] New Energy, Ex. 108, pp.17-19; Enron, Ex. 106, pp. 5, 6; Distributed Power Coalition of America & California Manufacturers' and Technology Association (DPCA/CMTA), Ex.105, pp. 5-6; and Honeywell Power Systems, Inc. (Honeywell), Ex. 107, pp. 16-17; and ORA, Ex. 3, pp. 2-14, 2-15, 2-24.

operates at a lower level, the load is automatically served by the interconnected grid.[10]

The ISO explains that since ancillary services and reserves originate from transmission-connected generation sources (i.e., generators and imports) and loads are connected primarily at the distribution level, the ISO relies on the interconnected transmission and distribution grid to deliver imbalance energy from capacity reserves, when required. Hence, the ISO concludes that provision of ancillary services and delivery of imbalance energy to maintain system balance requires the use of both transmission and distribution facilities. Likewise, the ISO argues that "almost every transaction" on a utility distribution system affects ISO operations and thereby imposes costs on the transmission grid. (ISO, Ex. 150, p. 8.)

The ISO acknowledges that, under certain unique circumstances, a transaction can occur that does not affect ISO operations. If a sale occurs "on a Distribution System that is electrically isolated from the ISO Controlled Grid…." it would not rely on the transmission system. (Ibid., p. 9.) If "the energy transmitted from a distribution-connected Generator to a distribution-connected Load does not alter in any way the energy flowing on the ISO Controlled Grid <u>and</u> the Demand of the Load is subject to an automatic curtailment scheme that would disconnect or curtail the Load simultaneously with the disconnection or curtailment of the Generator" then the ISO agrees that use of transmission would be limited. (Ibid.) Under both scenarios, the ISO indicates it would neither arrange for Ancillary Services for the Load nor provide Imbalance Energy.

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[10] Mara, Enron, RT:818-825; Skowronski, Honeywell, RT:771-772, 803-804; Townley, New Energy, RT:741-743; Mazy, ORA, RT:549-552.

Under the second scenario, the ISO states that its operations would "still be affected inasmuch as the ISO would have to: (1) account for the amount of Demand that is connected to the system but that is controlled by an automated curtailment scheme. . . ; and (2) be able to monitor the status of the automated curtailment scheme. . ." (Ibid.) Therefore, despite its proclamation that ISO operations would not be affected, the ISO nevertheless asserts that it "should be involved" in these situations in order to track the availability/operable status of any load curtailment scheme. (ISO, Phase 1 Opening Brief. p. 21.)

7.2 Should We Establish a Distribution-Only Tariff for Distributed Generators that Sell within a Single Distribution Circuit?

The record makes clear that in all but limited circumstances, a retail sale within a distribution circuit will utilize transmission facilities. If a sale of excess energy occurs on a distribution system that is electrically isolated from the ISO controlled grid it clearly does not rely on the transmission system and imposes no cost on the transmission system. ORA identifies Mountain Utilities and Santa Catalina Island as two examples of islanded distribution systems. (See ORA Phase 1 Opening Brief, p. 34.) However, rates for SCE customers in Santa Catalina include a transmission component.[11]

[11] In D.99-10-057, we declined to adopt a Catalina Island Diesel Fuel Balancing Account proposed by SCE. Adoption of the account implied creation of an associated new rate to be imposed on Catalina Island customers, different from rates in effect for other SCE customers. If adopted, Catalina Island rates would have been based on the cost of serving the local area, rather than on the average cost of SCE's entire system. SCE proposed the rate to permit it to recover fuel costs that it could not recover through the market because Catalina Island is not connected to the grid. Its power is generated locally and can only be sold locally because of the Island's physical isolation. In that case, SCE had not notified its Catalina Island customers of its proposal to increase their rates. Section 454 provides that a utility proposing a rate change must notify affected

Footnote continued on next page

Mountain Utilities is not connected to the transmission system and does not have a transmission component to its rates, as it has no transmission costs.[12] Thus, Mountain Utilities already has a distribution only tariff. If an electrically isolated distribution system is located within one state, no interstate commerce occurs, and no FERC jurisdiction attaches. (See generally, Federal Power Act, §201(b)(1), 16 USC §824(b)(1).) When a distribution system is electrically isolated from the transmission grid, it makes sense to consider development of a distribution only tariff, and such tariff would be subject to exclusive Commission jurisdiction.

The ISO cautions that the proliferation of islanded distribution systems would conflict with current regulatory policies to consolidate control areas by exacerbating "seams" at the boundaries of interconnected systems, ultimately leading to increased transaction costs. As a policy matter, we agree that electrically isolated distribution systems should not be encouraged. Stand-alone distribution systems could lead to reduced reliability, establishment of new utilities and the attendant regulatory costs. However, from a cost causation standpoint, if a distribution system is not interconnected to the grid and

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customers of its proposal. Because SCE had not provided that customer notice, we declined to authorize a rate increase or the associated balancing account.

[12] Mountain Utilities provides electrical services to the small and geographically isolated community of Kirkwood, California. Mountain Utilities differs significantly from PG&E, SDG&E, and SCE in the number and types of customers, seasonal electricity usage patterns, isolation from the California electrical grid, and limited generation options. Mountain Utilities' service territory is approximately 26 miles from the nearest transmission grid facilities of any other utility. Mountain Utilities serves its customer load with six utility grade diesel generators with a combined normal operating capacity of 4,200 kilowatts. Mountain Utilities delivers electricity to its retail customers through a 12 kV distribution network. (See D.99-12-006.)

therefore imposes no costs on the transmission system, customers on that system should not be required to pay transmission charges.

To the extent that the distribution system is not electrically isolated from the grid, as a general rule, the ISO must provide ancillary services and imbalance energy for retail transactions, even if such transactions occur within a single distribution circuit. The ISO's services rely on the transmission system, and therefore a retail transaction within a distribution circuit utilizes the transmission system. Transmission services are required for that transaction to be completed; therefore, compensation for those services should be provided and a distribution-only tariff is not appropriate. Establishment of a distribution-only tariff would "unjustly permit a customer to avoid responsibility for its share of the costs associated with the construction, maintenance, and operation of the [Cal] ISO Control Grid without which the transactions in question would not be possible." *PG&E*, 88 FERC ¶ 63,007 at page 65,073 (1999). As PG&E points out, "(t)hese transmission and grid management costs will not go away; instead, they will be unfairly shifted to other utility ratepayers." (PG&E Phase 1 Opening Brief, p. 13.)

TURN also voices strong concern over cost shifting impacts associated with adoption of a distribution-only tariff. TURN observes that "[a]t its core, this proposal seeks to allow some customers to pay marginal transmission costs while requiring all others to share the remaining embedded costs of ISO operations." (TURN, Phase 1 Opening Brief, p. 57.) According to TURN, implementation of distribution-only tariffs would "encourage large customers to avail themselves of opportunities to decrease their purchases of transmission services while likely doing little to reduce the overall costs incurred by the ISO. In fact, the practice of distribution wheeling could potentially increase ISO costs by forcing more costly monitoring of smaller DG units and more precise balancing of loads in particular control areas." (Ibid.) TURN then indicates that the amount of ISO fixed costs to be collected from customers continuing to receive bundled service "is almost certain to increase despite the fact that these customers would not be altering their behavior at all." (Ibid.) With respect to adverse impacts on particular customer classes, TURN adds that "[s]ince it is clear that residential customers are extremely unlikely to take advantage of unbundled distribution wheeling service, the consequences for this class are all but certain." (TURN, Ex. 10, p. 15.) TURN strongly recommends the Commission reject proposals for distribution-only tariffs.

In general, we concur with TURN's analysis. However, the ISO has identified at least one situation in which it would not provide ancillary services or deliver imbalance energy. In that situation, the full services of the ISO-controlled grid are not utilized and it would be appropriate to remove certain ISO related costs (i.e., costs associated with ancillary services and imbalance energy) from transmission charges when transactions meet the criteria laid out by the ISO. We agree with the ISO that the transmission system is still implicated even under these transactions because of monitoring requirements. Because rate design should be consistent with cost causation principles, we concur that if the full services of the ISO controlled grid are not utilized, a customer should not pay for those services. We do not agree with parties who argue that we should adopt a distribution-only tariff because any remaining costs are *de minimus.*

FERC, not this Commission, sets transmission rates for customers purchasing energy from third parties. In *Order 888*, FERC addressed "what facilities are jurisdictional to [FERC] in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to an end user." *Order 888* at p. 31,780. FERC concluded, and the

Court of Appeals upheld, that it has jurisdiction over the transmission component of an unbundled interstate retail wheeling transaction, including the rates, terms, and conditions for the use of transmission facilities. See *Transmission Access Policy Study Group v. FERC*, 2000 U.S. App. Lexis 15362 (D.C. Cir. June 30, 2000). The decision of whether and how to establish a tariff for the limited circumstance described by the ISO is within FERC's jurisdiction.

The evidence demonstrates that, as long as the distribution system is not electrically isolated from the transmission grid, a distribution-only transaction cannot occur and therefore a distribution-only tariff is inappropriate. Therefore, we decline to adopt a distribution-only tariff at this time. However in some very limited circumstances, as defined by the ISO, transactions may not rely on the full menu of transmission services and in those circumstances, a tariff removing ancillary services and imbalance energy costs would be appropriate. Not only would such a tariff be consistent with cost causation principles, but it would also encourage generators and users to develop innovative arrangements designed to maximize efficient and reliable use of the distribution infrastructure. We encourage the utilities, the ISO, and FERC to explore whether existing tariffs properly reflect cost causation for the narrow set of transactions identified by the ISO as not relying on the full menu of transmission services. If distribution systems are electrically isolated from the transmission system, cost causation principles dictate that distribution-only tariffs should be developed under the jurisdiction of this Commission.

7.3 Jurisdiction over Distributed Generation Interconnections when Sales of Excess Energy Occur

When a distributed generator interconnects to the distribution system for backup or standby service in order to serve its own load, the Commission has jurisdiction over the interconnection. In D.00-11-001 and D.00-12-037, we adopted standardized requirements for interconnections where the generator does not sell its excess energy or capacity into the grid. As FERC held in *Order 888*, "states have authority over the service of delivering electric energy to end-users."(at p. 31,782). Jurisdiction over qualifying facility (QF) interconnection arrangements made for the purpose of selling to the utility was explicitly given to the states. *Western Massachusetts Electric Company*, 61 FERC ¶ 61,182 at p. 61,662 (1992), *aff'd, Western Massachusetts Electric v. FERC*, 165 F.3d 922 (D.C. Cir. 1999). Thus, this Commission has had jurisdiction over rates, terms, and conditions of the majority of distributed generation installations to date.

In R.99-10-025, we sought comments on whether the FERC or this Commission will have jurisdiction over the rates, terms, and conditions of interconnection when the interconnecting entity sells energy. We postulated that jurisdiction would depend on whether the sale was at retail or wholesale. PG&E points out that "if generators wish to deliver to the grid, they are seldom going to be in a position to make an exclusive marketing determination at the time of interconnection whether they will be selling at wholesale or retail. They can, in fact, switch back and forth on an hourly basis." (PG&E Phase 1 Opening Brief, p. 21, Ex. 53, p. 1-12.) PG&E argues that when facilities can be used for both state jurisdictional and FERC jurisdictional services, FERC has jurisdiction. FERC and the courts have taken the position that when facilities are of mixed use, in other words, that they might be used for both transmission and distribution, FERC has exclusive jurisdiction to regulate those facilities. *Western*, 61 FERC at 61,662 n. 20 and *Order 888* at p. 31,369 n. 13.

Our objective in exploring this question is to ensure that the significant work parties have undertaken, and continue to undertake, to develop and refine statewide interconnection protocols that address the technical aspects of interconnection is not lost in a debate over jurisdictional responsibilities at the state or federal level. As PG&E points out:

> "Most interconnection details by their nature are relatively stable; addressing such issues as what safety equipment is needed, what process will the utility go through in evaluating new interconnection proposals, and who will bear cost responsibility for upgrades. It makes no sense for such rules to change from hour to hour depending on the generator's choice of customer. Accordingly, it is important that either the question of interconnection jurisdiction be clearly resolved in a way that provides stable rules for given situations from one authority, ..., or makes FERC and CPUC rules on interconnection requirements the same." (PG&E Phase 1 Opening Brief, p. 22.)

In accord with our position before the FERC in Docket No. RM02-1-000, it is the Commission's position that California's interconnection rules and guidelines should apply to distributed generation that falls within the definition of a QF.[13] In cases where the distributed generation unit does not meet the

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[13] (17) (A) "small power production facility" means a facility which is an eligible solar, wind, waste, or geothermal facility, or a facility which—

(i) produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, geothermal resources or any combination thereof; and

(ii) has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts …

(C) "qualifying small power production facility" means a small power production facility--

(i) which the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliability) as the Commission may, by rule, prescribe; and

(ii) which is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities) … 16 USCS § 796(17), definition of a QF, California's interconnection procedures should apply so long as the distributed generator's sale of or unintentional export of energy into the system is incidental.[14] When power sources operate in parallel with the grid there is no technological difference between the interconnection of a QF or distributed generator. Nor is there a need for different technical interconnection requirements for incidental energy sales versus incidental energy exports because the interconnection does not know whether or not a sale has occurred.

We consider this an analogous situation to the FERC's handling of transmission siting. The FERC has stated numerous times that transmission siting clearly falls within the state's purview, in part because it is a matter of inherent local concern.[15] The FERC has limited its review to the ratemaking that flows from state siting decisions. As with transmission siting, interconnection of generators on the distribution system presents issues of local safety, reliability,

[14] Incidental export of energy without compensation is already possible under Rule 21, assuming all technical interconnection requirements have been met.

[15] "[FERC] does not have jurisdiction over transmission siting." *Removing Obstacles to Increased Electric Generation And Natural Gas Supply In The Western United States*, 96 FERC p.61, 155; 2001 FERC Lexis, 1859. "The existence of RTOs has not and will not in the future, interfere with traditional state and local regulatory responsibilities such as transmission siting, local reliability matters, and regulation of retail sales of generation and local distribution." *Notice of Proposed Rulemaking*, 87 FERC p.61 173; 1999 FERC Lexis 1015. "[FERC] recognize[s] the exclusive authority of state and local governments and regulatory agencies over the siting of transmission facilities." *Regional Transmission Organizations*, 89 FERC p.61, 285; 1999 FERC Lexis 2692. Certification by FERC "does not relieve a facility of any other requirements of local, state or federal law, including those regarding siting, construction, operation, licensing, and pollution abatement. Certification does not . . . authorize construction." *Oxbow Geothermal Corporation*, 43 FERC p.61, 286; 1988 FERC Lexis 1203.

and environmental concern where the state has primary jurisdiction. Consequently, because this is a local resource issue and not a ratemaking issue, technical interconnection rules and procedures for distributed generation are state jurisdictional, regardless of whether incidental sales of energy occur.

8. Rate Design

Phase 2 focused on rate design issues and the interrelationship of distributed generation to stranded costs (if any), bypass/exit fess, various types of customer charges, standby rates, performance based ratemaking (PBR) and flexible pricing mechanisms, and distribution wheeling rates. D.01-07-027 established policies for standby rate design for distributed generation. Because of the standby rate design policies adopted, in which distributed generation customers pay their fair allocation of the costs they impose on the system, stranded distribution costs will be minimized. (See D.01-07-027, p. 56.) Therefore, we need not further address whether stranded costs will occur or develop any cost recovery mechanisms at this time. Because we have adopted a standby rate policy which minimizes stranded distribution costs, we also need not consider imposition of any exit or bypass fees associated with distribution costs on customers pursuing distributed generation. Issues surrounding responsibility of departing load customers for going forward electricity procurement costs is being handled in R.02-01-011 and will not be addressed here. These conclusions need not be modified today but should continue to be evaluated over time, perhaps in a successor rulemaking.

8.1 PBR Incentives/Pricing Flexibility

The regulation of utility distribution networks in California currently varies widely. PG&E's distribution system is regulated under cost-of-service rate-of-return regulation. SCE's is subject to "revenue cap" regulation, which sets a revenue requirement based on a formula and makes the utility indifferent to changes in electric consumption. SDG&E remains subject to price cap regulation. Our rulemaking asked whether current PBR mechanisms contain proper incentives for the use of distributed generation and in particular, whether the Commission should create special PBR mechanisms for distributed generation, or modify existing PBR mechanisms because of the introduction of distributed generation.

8.1.1 Position of Parties

PG&E notes that it does "not now have an electric PBR in place, and does not recommend that one be designed specifically for DG."(PG&E, Phase 2 Opening Brief, p. 37.) In this area, PG&E recommends a comprehensive approach, stating:

> "The design of a PBR has implications that go far beyond DG. The Commission should evaluate different PBR mechanisms in the context of a PBR that would apply to all customers, not just DG, before making a decision on the appropriate methodology or whether changes in the methodology are needed for existing PBRs." (Ibid., p. 39.)

In this particular proceeding, SCE argues that the Commission should not consider revisions to existing PBR structures except in a proceeding related to PBR's. SCE notes that "no party in this proceeding has submitted a proposal for a DG-related PBR." (SCE, Phase 2 Opening Brief, p. 30.) SDG&E argues against the adoption of a revenue cap PBR in this proceeding. SDG&E states that:

> "The facilitation of the deployment of DG would be just one of many factors that the Commission might want to take into consideration in adopting the form of indexing selected for a <u>future</u> PBR mechanism. The Commission should not attempt to prejudge this issue in this proceeding, particularly when DG is

> being considered in isolation from other potential factors." (SDG&E, Ex. 76, pp. 9-10.)[16]

Aglet Consumer Alliance (Aglet) opposes authorization of a separate PBR or incentive mechanism dedicated to distributed generation. Aglet states "The Commission's objective should be a fair market test of DG economics and technology." (Aglet, Phase 2 Opening Brief, p. 10.) FEA states that it "strongly believes that Performance Based Ratemaking (PBR) should not be applied either to encourage the installation of DG or to deal with revenue consequences resulting from alterations in the level of use of the system as a result of the installation of DG resources." (FEA, Phase 2 Opening Brief, p. 12.)

ORA states on brief that it "has not offered any testimony on this subject [PBR], and notes that PBR proceedings themselves will discuss this issue." (ORA, Phase 2 Opening Brief, p. 15.)

TURN, UCAN, and NRDC presented Phase 2 testimony supporting a revenue cap PBR. TURN supports this position in its opening brief, noting "Rate policies that tie a utility distribution company's earnings to kilowatt-hour sales create an incentive to maximize kilowatt-hour sales." (TURN, Phase 2 Opening Brief, p. 35.) TURN also supports the adoption of an "anti-padding mechanism," to prevent the growth of ratebase through investments in either a distribution system upgrade or a distributed generation facility. NRDC supports a revenue cap form of PBR. NRDC claims that such a mechanism "breaks the link between the revenues of a distribution company and kWh sales." (NRDC, Phase 2 Opening Brief, p. 10.) In comments on the proposed decision, NRDC clarifies

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[16] SDG&E's PBR mechanism will be in effect until December 31, 2002.

that it does not per se recommend a PBR mechanism but rather a mechanism that ensures that utility revenue is not tied to throughput.

California Solar Energy Industry Association (CALSEIA) opposes any restructuring of utility rates unless and until market penetration of solar electric generation reaches a significant level. When a significant level is reached, CALSEIA believes that the Commission should "consider adoption of a rate design that makes distribution utilities indifferent to the amount of throughput on their systems." (CALSEIA, Phase 2 Opening Brief, p. 17.) CALSEIA states that such rate designs "may include" PBR "based on revenue caps." (Ibid.)

The Solar Development Cooperative calls for incentives to "incorporate DG renewables" deployment onto the electricity network. (Solar Development Cooperative, Phase 2 Opening Brief, p. 20.)

8.1.2 Discussion – No Actions Needed at this Time

Regulation of utilities is in a state of flux due to instability in wholesale electric markets during 2000 and 2001. In the wake of this crisis, other Commission actions have obviated the need to adopt distributed generation specific PBR mechanisms. For example, D.02-04-055 has replaced SCE's price cap PBR with a revenue cap PBR making SCE indifferent to lost electric sales arising from either customer conservation or through the use of electricity produced by distributed generation. PG&E has never had PBR regulation, thus, while the electricity market was unstable, with the cost of procuring electricity exceeding the prices PG&E could charge for electricity, there was no incentive pushing PG&E to promote the consumption of electricity.

Only SDG&E is currently under price cap regulation. Concerning SDG&E, we agree with SDG&E that the effects of distributed generation are likely small at this time, and there is no need to change its PBR program now. Moreover, since

SDG&E's PBR is scheduled to expire at the end of 2002, there is no need to change this program for the few months that remain.

The TURN / ORA / UCAN proposal of establishing "project caps" for each proposed distributed generation project is not needed at this time, because each project undertaken by the utilities will be subject to review in the next GRC. For these reasons, we see no reason to modify existing PBR programs or to implement a program specific to distributed generation investment.

This conclusion does not prejudge how or if distributed generation is incorporated into any renewable incentive mechanism considered in R.01-10-024.

8.2 Public Purpose Program Funding

Public purpose programs are activities not directly required to provide utility service, like funding for renewable power sources, research and development, and low-income assistance, that the Legislature or the Commission have determined to be socially desirable and in the public interest. Funding for these programs is part of the rates charged to all customers.

California law dictates that exiting the public electric network does not end a customer's responsibility to provide financial support for public purpose programs. In particular, Cal. Pub. Util. Code §§ 381-382 makes low-income and certain other public interest programs "nonbypassable." As implemented, customers departing for distributed generation must continue to pay for these programs, thereby avoiding unwarranted cost shifts to other ratepayers.

8.2.1 Positions of Parties

PG&E supports the "nonbypassability" of public purpose program charges and urges the Commission to reconfirm this policy. (PG&E, Phase 2 Opening Brief, p. 40.) SCE similarly states that "it is permissible and appropriate to require DG customers to pay the full amount of non-bypassable charges based on their total energy consumption." (SCE, Phase 2 Opening Brief, p. 30.) SCE points out that it currently collects these charges from standby customers through its tariffs. SDG&E believes that "deployment of DG should have little or no impact on public purpose program funding assuming current laws and Commission-approved tariffs remain in effect." (SDG&E, Phase 2 Opening Brief, p. 35.) SDG&E notes that current tariffs provide for the recovery of public purpose program funds associated with customers choosing to self generate.

ORA's position is that distributed generation might have an impact on public purpose funding, but it should not. ORA supports decoupling public purpose program funding from energy "throughput." (ORA, Phase 2 Opening Brief, p. 15.)

NRDC notes the legislative support for a nonbypassable surcharge for the public purpose programs, and states that it is "appropriate to continue to apply this charge to all new on-site generators (based on output) located on the customer side of the meter that provide power to offset the customer's consumption." (NRDC, Phase 2 Opening Brief, p. 11.) On the other hand, NRDC recommends that an "exception should be made for building-integrated PV systems and projects operating under the net metering tariff." (Ibid.)

Aglet supports the inclusion of a "fair share of public purpose program funding" in standby rates. (Aglet, Phase 2 Opening Brief, p. 10.) Aglet, however, recommends that the Commission support the recovery of these program costs in the long run through taxes, and notes that Aglet "does not support imposition of public purpose bypass charges on customers solely because they depart the utility service." (Ibid., citing RT 1632:13-22.)

Latino Issues Forum and Greenlining Institute (jointly, LIF) state that the "Commission should seek to codify utility tariffs that authorize the collection of public purpose program funds from departed customers." (LIF, Phase 2

Opening Brief, p. 5.) LIF opposes the use of a tax to finance public purpose programs, and opposes the collection of the costs of public purpose programs through a one time "exit fee." (Ibid., p. 7.)

CALSEIA, in contrast, does not support the use of a nonbypassable surcharge to fund public purpose programs. Instead, CALSEIA supports public purpose program funding through "usage based electricity charges." (CALSEIA, Phase 2 Opening Brief, p. 17.) It notes that solar customers "typically draw a significant percentage of their total demand from the grid." (Ibid.) Thus, it sees no threat to public purpose program funding by any "foreseeable increase in the deployment of distributed solar generation." (Ibid.) In short, CALSEIA sees no problem at this time, and therefore no need to collect public purpose program charges through a nonbypassable surcharge.

Similarly, the United States Department of the Navy and All Other Federal Executive Agencies (FEA) states that "customers should not be required to pay public purpose funding surcharges on services that they do not take from the utility." (FEA, Phase 2 Opening Brief, p. 13.) Instead, FEA recommends "adjusting the rate used to collect these charges" in order to ensure funding. (Ibid., p. 14.)

8.2.2 Discussion

Pub. Util. Code §§ 381-382 make low-income and certain research and development programs "nonbypassable" and consequently shape our policy on this matter. In particular, we agree with the commenters that, pursuant to statute, the public purpose program surcharge should be nonbypassable. As SDG&E notes, current tariffs already provide for the recovery of these surcharges from any customer who self-generates, whether in conjunction with distributed generation or simply for economic purposes.

Beyond affirming our support for the legislatively-mandated nonbypassable public purpose program surcharge, we conclude that there is no need to take further action at this time. In particular, we decline to take a position supporting tax legislation as Aglet requests. Similarly, we also note that we have no intention at this time of converting our ongoing surcharge to a one-time exit fee, but instead plan to continue our current tariff arrangements, a policy supported by LIF.

8.3 Localized/Deaveraged Rates

This rulemaking posed the question of whether distribution rate components should be deaveraged to reflect localized differences in costs. Traditionally, average rates provide all consumers in a rate class with an equal cost structure for distribution services, regardless of the varying costs of serving a specific location.

8.3.1 Positions of Parties

PG&E, SCE, and SDG&E oppose area-specific distribution rates. In particular, PG&E states "a change to area rates for all customers could have extraordinarily far-reaching implications, above and beyond the effects of the limited changes sought by participants in this proceeding." (PG&E, Phase 2 Opening Brief, p. 44.) PG&E believes that following the "TURN / UCAN / NRDC suggestion regarding project-specific solicitations" offers a reasonable approach to solving the problem of geographic divergent costs. (Ibid.)

SCE believes that "implementation of geographically deaveraged distribution rates is fraught with practical problems and implicates many fundamental policy questions." (SCE, Phase 2 Opening Brief, p. 31.) SCE notes that deaveraged rates are generally unstable, can be viewed as discriminatory by customers, and would require significant expenditures to change current billing systems. SCE further notes that the Commission "has previously determined" that "it would be inefficient to offer a geographically deaveraged credit when underlying rates are still averaged." (Ibid., p. 32, citing D.98-09-070 (mimeo.) p. 25.)

SDG&E opposes deaveraging distribution rates, which it states "would accomplish relatively little . . . at a great administrative burden." (SDG&E, Phase 2 Opening Brief, p. 36.) SDG&E, however, views the provision of credits to distributed generation "at the right time, in the right location, of the right size and with physical assurance" in a contract as a valid policy approach for solving the locational problems associated with distributed generation. (Ibid., p. 37.)

Similarly, TURN, ORA, Aglet, and FEA oppose deaveraging rates. TURN notes that the locational credit proposal submitted by TURN, UCAN and NRDC "is not equivalent to deaveraged ratemaking." (TURN, Phase 2 Opening Brief, p. 47.) On the other hand, TURN supports a "locational credit" that "would provide for a location- and time-specific sharing of cost-savings associated with distributed generation that serves a distribution function and avoids certain distribution costs." (Ibid., p. 44.) TURN believes implementing a credit in an effective way requires "a fair and transparent distribution planning process." (Ibid., p. 41.) ORA states that "[d]istribution rate components should not be deaveraged at this time to reflect localized differences in costs." (ORA, Phase 2 Opening Brief, p. 16.) ORA believes that deaveraged rates are "contrary to long-standing policy." (Ibid.) Like TURN, ORA supports offering credits to specific customers or third parties if the incentives can defer the need for localized distribution expenditures. FEA opposes deaveraging rates, but, states that "to the extent that there are areas of the system where the utility would find it uneconomical, or expensive, to expand the distribution system to accommodate load requirements, these areas could be specifically targeted for incentives to install DG." (FEA, Phase 2 Opening Brief, p. 14.) Aglet opposes localized or deaveraged rates as "contrary to the important societal objective of universal service." (Aglet, Phase 2 Opening Brief, p. 10.)

Those supporting localized deaveraged rates generally argue that they will prove more efficient. The supporters of this position include the City and County of San Francisco (CCSF), State Consumers,[17] New Energy/Capstone,[18] CALSEIA and NRDC. CCSF supports the development of "localized/deaveraged rates and credits to provide for a locational sharing of benefits associated with DG when it helps to avoid or delay distribution costs." (CCSF, Phase 2 Opening Brief, p. 8.) State Consumers state that "standby pricing for distribution should be based on the area-specific marginal costs, capped at existing distribution costs." (State Consumers, Phase 2 Opening Brief, p. 9.) State Consumers believe that such a policy will lead to lower standby rates because "standby customers drive minimal distribution resource additions." (Ibid., p. 10.) Similarly, State Consumers support the use of credits and incentives based on location.

New Energy/Capstone support deaveraged rates, stating that "distribution costs vary significantly by location, and those variation should be clearly signaled to incentivize customers to help minimize UDC costs where they can." (New Energy/Capstone, Phase 2 Opening Brief, p. 21.) However, noting that full geographic deaveraging presents challenges, they support a tariff

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[17] State Consumers is made up of University of California, California State University, and the California Department of General Services (DGS).

[18] New Energy and Capstone participated individually in other phases of the proceeding but were joined in their Phase 2 Brief by Caterpillar, Inc., Elektryon, and Honeywell. Their joint position is referred to as New Energy/Capstone.

approach with "rate riders or credits" to "signal the cost of local distribution expansion, and opportunities to reduce them." (Ibid., p. 22.)

CALSEIA "recommends that the Commission consider the adoption of financial incentives in the form of geographically de-averaged buyback rates to reward the installation and operation of on-site solar facilities in designated areas with high distribution costs." (CALSEIA, Phase 2 Opening Brief, p. 17.) NRDC "supports the development of a locational credit mechanism that would provide for a location- and time-specific sharing of benefits. . ." (NRDC, Phase 2 Opening Brief, p. 11.) In addition, NRDC supports the "exploration and identification of distribution development zones." (Ibid., p. 12.) In comments on the proposed decision NRDC clarifies that they do not support deaveraged rates.

8.3.2 Discussion: Contracting for Distributed Generation Obviates Need for Deaveraged Tariffs or Incentive Programs at This Time

Since we are permitting utilities to enter into contracts with customers or third parties that install distributed generation at the right time, in the right location, of the right size and with the physical assurances needed to enable a utility to defer a distribution capacity addition, we see no need for deaveraged tariffs or other incentive programs. We retain most of the efficiencies that deaveraged tariffs promise, yet avoid the complications of reversing the long-standing policy of uniform pricing.

Our administrative experience and the comments of parties makes it clear that geographically-deaveraged distribution rates are fraught with practical implementation problems. Similarly, administering a localized incentive or credit program while maintaining geographically averaged rates offers a piecemeal approach that invites tariff arbitrage and other regulatory problems. Finally, we note the Commission has long used average rates as an equitable means of providing universal and non-discriminatory service. We see no reason to change our current policy.

8.4 Implementation Costs

Implementation costs are those costs associated with implementing a new program. The question then becomes, what costs are implementation costs associated with distributed generation, and which are costs already covered under current distribution system planning budgets.

8.4.1 Position of Parties

The three utilities express particular concerns with implementation costs. PG&E states that "[a]ny implementation costs incurred to accommodate DG should be tracked in a separate balancing account." (PG&E, Phase 2 Opening Brief, p. 13.) These costs, in PG&E's view, should be recovered "through a general charge assessed on the beneficiaries of the particular programs." (Ibid.) SDG&E argues that "if implementation costs are attributable to individual customers deploying DG, the costs should be recovered from those individual customers. . ." (SDG&E, Phase 2 Opening Brief, p. 10.) On the other hand, "if implementation costs are not directly attributable to any one customer or group of customers, SDG&E would propose to collect such costs from all distribution customers." (Ibid.) SCE proposes that implementation costs "should only refer to those costs that the UDC incurs due to activities mandated by this Commission." (SCE, Phase 2 Opening Brief, p. 10.) SCE cautions the Commission against mandating any particular costs, such as requiring SCE to provide educational or engineering advice to prospective distributed generation customers. Further, SCE argues that implementation costs "should not refer to physical plant additions for a specific customer to utilize DG." (Ibid, p. 10.) SCE believes that these facility costs should continue to be administered through tariffs, but if the costs from mandated changes become large, SCE argues that the Commission should establish a separate recovery mechanism for these costs.

Enron states that "costs incurred to interconnect a specific DG installation should be assigned to that customer." (Enron, Phase 2 Opening Brief, p. 2.) On the other hand, Enron argues that implementation costs "that cannot be ascribed to a specific (or group of) customer(s) should be recovered through general distribution rates." (Ibid., pp. 2-3.) FEA states that "[a]ny implementation costs that are not appropriately chargeable to individual customers should be considered network costs and be recovered in charges for secondary service, primary service, subtransmission service, and/or transmission voltage level service as applicable." (FEA, Phase 2 Opening Brief, p. 5.) FEA, however, considers these costs as "no different than how other general network expansion, upgrade, or replacement costs are handled." (Ibid.)

In contrast to these positions, TURN and Aglet express skepticism that any distributed generation implementation costs warrant recovery. TURN "strongly opposes proposals for establishing a balancing account to track implementation costs as suggested by PG&E and SCE." (TURN, Phase 2 Opening Brief, p. 14.) TURN notes that no utility has identified specific implementation costs that are not already covered in existing charges. It further states that "[i]f costs are associated with particular system investments, then they should be recovered through rates and interconnection charges." (Ibid., p. 13.) Aglet states that the "Commission should reject any special recovery of DG costs." (Aglet, Phase 2 Opening Brief, p. 3.) Aglet argues that costs associated with a program like this are among those that are typically covered under the overall cost umbrella of a GRC. Aglet further notes that the "low level of DG market penetration forecast for the near future also supports denial of utility requests for special implementation funding." (Ibid., p. 4.) In addition, Aglet argues that these costs are related to competition, and that the Commission has frequently rejected utility requests for additional revenues to reflect the effects of competition. In the long term, Aglet concludes that "the Commission should consider DG implementation costs in general rate cases, as it considers other distribution costs." (Ibid., p. 5.)

8.4.2 Discussion

Since the purpose of this rulemaking is "is to develop policies and rules to facilitate deployment of distributed generation in California," (D.02-03-057) we authorize the creation of memorandum accounts to track distributed generation implementation costs that cannot be attributed to a specific distributed generation projects. These could include, for example, the costs of a distributed generation education program, major changes in the utility planning process necessitated by this decision, or some other subsidy to a general distributed generation program.

As TURN, Aglet and FEA have indicated, the costs of implementing the distributed generation policies adopted herein will likely be small. In addition, to ensure the eventual incorporation of distributed generation into routine utility operations, we will set these memorandum accounts to expire unless continued at the next GRC for each company. At that point the Commission can consider whether to incorporate a special revenue requirement into the distribution system to finance distributed generation or continue with a memorandum account system.

9. Net Energy Metering

The net energy metering program established in Pub. Util. Code § 2827 allows eligible residential and small commercial customers relying on small photovoltaic and wind generators, with a meter capable of registering two-way electricity flow, to offset future retail electricity purchases with their excess generation at anytime during an annual billing cycle. The current rules prescribed by Pub. Util. Code § 2827 limits program eligibility to customer generating units up to 1 MW maximum capacity.[19] Utilities must, and energy service providers may, offer net energy metering. Utilities may not impose costs on net energy metering customers that are not also assigned to customers in the rate class to which that customer would otherwise be assigned.

Net energy metering has been promoted as an effective way to encourage renewable generation by small-scale generators. Some parties state that net energy metering provides a reasonable proxy for benefits from renewable generation that are difficult to measure, particularly environmental benefits. They argue that without the economic incentives provided by the flexible billing provisions of the program, many small, renewable self-generation units would not be financially feasible. Parties supporting the net energy metering program also argue that in addition to environmental benefits, other system benefits exist from the energy commodity delivered to the grid from net-metered distributed generation.

Because net energy metering encourages the use of small, non-polluting technologies, this proceeding considered options to expand the net energy metering program. Parties identified four areas for potential amendment of the program: 1) increasing the size of eligible units from the 10 kW limit in place at the time parties were filing testimony; 2) expanding eligibility to

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[19] The maximum limit at the time testimony was filed in this proceeding was 10 kW. The limit was raised to 1 MW by passage of ABX1 29, signed into law April 11, 2001, a provision which expires December 31, 2002.

environmentally beneficial or emerging technologies such as fuel cells and microturbines that are not currently eligible under current rules in §2827; 3) expanding eligibility to other customer classes; or 4) increasing the 0.1% aggregate demand program limit in place at the time parties were filing testimony. CALSEIA believes any of these changes would necessarily require legislative action.

PG&E, SDG&E, SCE, and EEI oppose any expansion of the existing net energy metering program. FEA joins these parties, arguing that subsidies that may occur from net energy metering should not be increased by expansion of the program. They argue that allowing net energy metering customers to offset energy consumption with energy produced during a different time-of-use period gives rise to a mismatch in pricing signals. These parties also state that a subsidy arises because customers are credited for energy produced at the full retail price, which includes nonbypassable charge components for public purchase programs, CTC, nuclear decommissioning, and ancillary services. LIF is concerned that funding of public purpose programs may be jeopardized by expansion of net energy metering. PG&E states that it incurs costs from the banking service required by annual billing under the net energy metering program.

CalSEIA believes the subsidy arguments to be overstated and based on inaccurate assumptions. CALSEIA believes that net energy metering customers who produce energy primarily for their own needs are subject to different economics than larger generation plants. Eligible net energy metering customers are small residential and commercial customers who would generally not take time-of-use service to begin with and therefore would not necessarily respond to time-differentiated pricing. CALSEIA also testifies that it is possible that the UDC receives excess energy from net energy metering customers at high cost and peak load periods during which solar photovoltaic and wind energy systems are most likely to generate, which benefits the system. Further, CALSEIA asserts that net energy metering customers do not have the incentive to generate more than they consume over an annual billing period as they do not receive credit for any excess generation at the end of the billing period.[20]

The ISO states that although net energy metering is inconsistent with ISO rules, the current program limits do not adversely affect the ISO's reliability or ancillary markets functions. The ISO cautions that net energy metering expansion, particularly of the allowable aggregate demand limit above the current level, may impair the ISO's ability to account for load in planning for reserve requirements and reliability. For this purpose, the ISO requests monitoring measures to ensure that the size limit is not exceeded.

9.1 Discussion

The net energy metering program was established to "encourage private investment in renewable energy resources, stimulate in-state economic growth, enhance the continued diversification of California's energy resource mix, and reduce interconnection and administrative costs for electricity suppliers." (Pub. Util. Code § 2827.) The Legislature's statement of intent demonstrates its emphasis on developing diverse, environmentally sensitive electricity resources.

The original net metering law was established in 1995, and has been amended three times by the Legislature: in 1998, in 2000 by Assembly Bill (AB)

[20] CalSEIA also introduced a proposal for the Independent Clean Energy Tariff (ICE-T) to provide incentives for generators up to 1 MW to install clean distributed generation by eliminating standby/backup charges or interconnection fees. CalSEIA states that standby charges make little sense for facilities that would be eligible for its tariff proposal in light of the size and relative output, whereas standby charges would impose a substantial economic barrier to installation. We adopted ICE-T in D.01-07-027.

918 (Chapter 1043, Statutes of 2000), and in 2001 by ABX1 29. Most utility net energy metering customers requested this service only after the amendments to § 2827 in 1998.

Energy from renewable self-generation may be more economic to customers than in the past due to current retail electricity prices throughout the state. Peak demand concerns may promote installation of photovoltaic units that generate energy on-peak, when system demand is most critical. Various buy-down and financing incentives are offered by the Commission, CEC, and other state agencies for purchases of renewable and super clean generators. This trend could result in additional programs or incentives being developed that might impact participation in net energy metering programs. Together these influences may result in increased participation in the current program that was not reflected in parties' recommendations during Phase 1 of this proceeding.

Prior to passage of ABX1 29 (Chapter 8, Section 11, Statutes of 2001), the net energy metering program had a low program limit of 0.1% of aggregate demand, in part, to minimize potential financial impacts from the program.[21] Participation in the net metering program historically has been well below this limit. ABX1 29 removed the percent limit, making it unnecessary for us to consider modifications to the limit in this decision. AB 58 (Chapter 836, Stats. 2002) reinstates a program limit of one-half of one percent, which is five times the prior limit.

[21] Under former section §2827(c)(3), 0.1% of aggregate demand was a cap on what the utility <u>must</u> offer but the statute provided the utility with discretion to offer net energy metering to more than 0.1% of aggregate demand.

This proceeding considered whether to increase the maximum capacity of eligible units from the 10 kW limit in place at the time parties were filing testimony. ABX1 29 statutorily raised the limit from 10 kilowatts to one megawatt. Therefore, we decline to make further changes to the limit in this decision.

We also considered whether to expand net metering eligibility to other customer classes. ABX1 29 expanded eligibility to large commercial, industrial, and agricultural customers and AB 58 retains this eligibility. Therefore, there is no current need to expand eligibility.

While DPCA and New Energy have suggested extending eligibility to environmentally beneficial and emerging technologies not currently eligible under the current program, they fail to identify specific technologies would meet such a definition. Besides solar and wind technologies, it is uncertain which types of fuel cell technologies can be considered "environmentally beneficial". The experimental nature of many fuel cells shows that it is premature to define fuel cells in a generic sense, as providing environmental benefits, without further information. Therefore, we do not propose that the Legislature consider modifying § 2827 to expand eligibility to additional technologies at this time.

For the foregoing reasons, we conclude that it is not necessary at this time to modify the current program eligibility criteria established by § 2827.

9.2 Eligibility of Integrated Renewable and Nonrenewable Technology Configurations for Net Metering

Resolution E-3764 recommended that this proceeding consider the applicability of net energy metering to system configurations that use both eligible renewable generation (solar and/or wind turbines) and nonrenewable generation, such as microturbines. We agree, and address the issue in this decision.

SCE's Schedule NEM-Net Energy Metering Service, revised pursuant to ABX1 29 and approved by the Commission in Resolution E-3764, defines "Eligible Customer-Generator" as a customer "who uses a solar or wind turbine electrical generating facility, or a hybrid system of both, *without the support of fossil fuel or other non-wind or non-solar energy source,…that is the sole source of generation located on the eligible customer's premises*" (emphasis added). This language excludes otherwise eligible renewable technologies from participating in net energy metering if an ineligible technology (i.e. fueled neither by solar nor wind and excluded from net metering eligibility) is also installed on the customer's premises.

SDG&E and PG&E describe net energy metering as available to "residential, small commercial…, commercial, industrial, or agricultural customers who use a solar or wind turbine electrical generating facility, or a hybrid system of both, with a capacity of not more than 1000 kilowatts that is located on the customer's owned, leased, or rented premises, is interconnected and operates in parallel with the Utility's transmission and distribution facilities, and is intended primarily to offset part or all of the customer's own electrical requirements." This definition does not preclude otherwise eligible renewable technologies from participating in net energy metering if they also have an ineligible technology installed on the premises.

The City of Santa Monica and Helios International protested SCE's new definition of a customer-generator in the proposed tariff, stating that it would exclude new, "smart" designs to integrate high efficiency combined heat and power microturbine systems with photovoltaic installations. SCE responded that the language was justified in the stated definition from AB X1 29, Chapter 8, Section 11.b.2 and, additionally, that the City of Santa Monica did not indicate how nonrenewable energy would be prevented from supplementing renewable energy exports to the grid on the net energy metered tariff.

Section 2827 of the Public Utilities Code defines an Eligible Customer-Generator as a customer "who uses a solar or wind turbine electrical generating facility, or a hybrid system of both…that is located on the customer's owned, leased or rented premises." We do not interpret this language as disallowing a non-wind or non-solar energy source from also being installed on the customer's premises, nor do we believe integrated use of nonrenewable energy sources excludes eligible renewable generation connected to the same service account from net metering. We note, however, that the ineligible generator does not become eligible for net metering due to the combined configuration. This decision does not expand the scope of technologies eligible for net energy metering.

Standard, simplified interconnection procedures were developed by a working committee including representatives from the regulated electric utilities and other parties, and were adopted in this Rulemaking. The subsequent Rule 21 interconnection tariffs specify standard interconnection, operating, and metering requirements for distributed generation.

Rule 21 requires one of four options to ensure that excess power will not be exported to the grid from an approved, grid-connected system. Option 1 utilizes a reverse power Protective Function to ensure that power is not fed back into the utility grid. We believe this provides adequate assurance that a nonrenewable generation system, even when connected to the same service account as the eligible renewable generator, will not export electricity. Such export to the utility grid from the generator would interfere with accurate registration of net energy metering for the eligible renewable generation system. The nonrenewable generator also would be required to meet all other Rule 21 interconnection standards. In such a renewable/nonrenewable configuration, a separate meter may only be required by the utility if necessary to ensure accurate accounting of net metered energy. The cost of this meter would be borne by the customer.

We order SCE to modify its Net Energy Metering tariff to remove the exclusionary language, and be consistent with approved language used by PG&E and SDG&E.

10. Consumer Education

Some parties in R.98-12-015 indicated that a program should be undertaken to inform end-use customers about distributed generation. In R.99-10-025, we asked parties to discuss possible approaches to educate consumers about distributed generation and how such a program might be funded. In testimony, parties presented positions on whether consumer education is necessary, which consumers should be educated, the scope of information consumers will need, and who should oversee an education program. Some parties indicated the Commission should also consider developing consumer protection standards, and provide recommendations on specific program elements.

Few see a need for consumer education about distributed generation at this time. To the extent parties believe consumer education is necessary, they generally indicate the Commission should take the lead role in ensuring that consumers are provided with neutral, unbiased information about distributed generation. UCAN is the strongest proponent for proactive consumer education. According to UCAN, meaningful consumer education provides customers with an understanding of industry changes and tools so they can fully evaluate distributed generation. UCAN encourages us to recognize the importance of education as a means of accelerating distributed generation deployment. UCAN recommends we be proactive to ensure the availability of unbiased information, emphasizes that customers should be educated in simple terms, and the importance of educational information reaching customers at the time they make a purchase.

FEA believes that educational material about distributed generation options should be made available to consumers from an unbiased source. LIF believes that consumers should be informed about emerging distributed generation technologies and their potential benefit to system reliability. LIF wants consumers to know how to obtain information about distributed generation and how to protect themselves from unethical marketers. Both LIF and UCAN agree the program must be multi-lingual and multi-cultural.

SCE believes the Commission should be responsible for providing information to consumers but also notes that the California Energy Commission (CEC) currently conducts consumer education programs regarding renewable technologies, and might assume a similar role with distributed generation. SCE is not clear about which customer should be educated about distributed generation but it identified four general categories of information it believes consumers will seek:

- Technical/Economic – information about technical characteristics (such as fuel consumption, performance, consumption availability), initial cost, operating cost, available financing
- Safety Issues of distributed generation – hazards to persons and property
- Interconnection requirements – what are the required equipment and procedures to interconnect a distributed generation unit with the utility grid

- Consumer Protection – what if any consumer protections will be provided above and beyond existing law and status for electrical devices

PG&E opposes the idea of a utility-funded or sponsored program, although PG&E appears to agree that information regarding economic, safety, and reliability should be available to consumers. In rebuttal testimony, SCE retreated from its original view, to support PG&E's position that there is little need for a Commission-sponsored education program at this time.

SDG&E and DGS contend that given today's technologies, distributed generation applications will most likely be grid-side or installed at larger customer sites. Large customers are sophisticated users with sufficient informational resources to make informed choices about distributed generation. SDG&E states it would like to facilitate distributed generation deployment, but expresses uncertainty over who needs education and what they would be educated about. According to SDG&E, small customers do not need education on distributed generation, because the size and complexity of distributed generation, other than photovoltaics, make it impractical for small users to consider. SDG&E points out that photovoltaics have been available for years, and there is nothing new requiring an extensive education program. If distributed generation becomes more economic for residential and small commercial customers, then SDG&E and DGS agree that consumer education and consumer protection efforts may be required. SCE indicates that distributed generation would not be relevant to all its customers, and would be particularly cost prohibitive for low-income customers and those who move frequently.

PG&E states distributed generation developers should be responsible for public outreach and advertising associated with marketing their products. SCE asserts that as the distributed generation market develops, customers will have questions and will need information to assist them in making decisions about whether to install distributed generation, types of distributed generation to consider, installation and operation requirements, and distributed generation costs. Four likely sources of information are the Commission, the CEC, energy service providers and/or energy service companies, and the utilities.

SCE envisions the utilities' consumer education role focusing primarily on health and safety information, citing its statutory obligation under Section 119085 of the California Health and Safety Code to inform customers of electrical backfeed hazards of connected generators. A secondary role is to provide information on interconnection standards and procedures. SCE states that the utilities will inevitably be involved in consumer education, as consumers traditionally look to the utility to provide information about electric products in general, and their impacts to the customer's bill or facilities.

UCAN is doubtful of any efforts that rely upon incumbent utilities to provide objective and useful information about competitive services. UCAN recommends that the Commission require independent consumer education, either by a non-aligned entity or by the Commission. LIF and UCAN believe the Commission should not rely on distributed generation marketers to educate customers because marketing performed by service providers is not education. Customer education allows customers to make informed decisions through understanding their options. Distributed generation providers can offer customers insight only for the option the provider is selling.

UCAN recommends the Commission encourage the use of a stakeholder group to develop and review the educational messages and themes. Both LIF and UCAN support the use of community based organizations (CBOs) and non-traditional modes of education: community colleges, social service agencies, and other entities who have relationships with targeted customers. UCAN recommends use of the internet as a low-cost means of disseminating up to date information to the public and to CBOs. SCE agrees that the internet is low cost, but based on its work with CBOs participating through the Electric Education Trust grant program, believes that technology does not reach most CBOs or customers identified as vulnerable. DGS suggests that when appropriate, distributed generation education take a form similar to energy conservation programs.

10.1 Discussion

At this point in time, it appears that most distributed generation installations will be pursued by larger customers because size and economics will not support most residential applications.[22] There is no question that residential and small commercial customers (as a whole) are less sophisticated in their energy decisions than large energy consumers. Therefore, to the extent that we decide to pursue a distributed generation education program, we should target such a program to residential and small commercial customers. However, because many smaller customers are unlikely to be approached to install distributed generation, a broad-based mass marketing campaign does not appear appropriate.

UCAN believes an education program should target customers not likely to be attractive to the market, or who are subject to higher levels of victimization. Because distributed generation requires significant up front investment by the customer, we think targeting educational materials to customers who are not likely to be attractive to the market is not a good use of resources. No matter

[22] As SDG&E points out, the exception is photovoltaics which have been available for residential applications for many years.

how well educated they are, if the economics do not support a customer's investment in distributed generation, they will not make that investment. In our opinion, residential and small commercial customers will be best served if they are educated regarding what distributed generation options are available, what, if any, incentives or rebates are available if distributed generation is installed, how to determine the payback of a distributed generation investment, and the safety issues associated with interconnection. We intend to accomplish these objectives using a multi-pronged effort.

First, every year, we will require the utilities to include an insert in customer bills discussing distributed generation options, available incentives and rebates, and other sources of information on distributed generation. The utilities should place information on the bill face in English and Spanish, directing customers to the bill insert. The information for the bill insert will be prepared jointly by this Commission and the CEC, after consulting the parties, and supplied to the utilities for printing and distribution. Whenever possible, the information provided should be coordinated with the efforts authorized by D.01-03-073, through the Commission's self-generation incentive program. The utilities should employ a court-certified interpreter to translate the bill insert into multiple languages appropriate to their service territory after consultation with the Commission's Public Advisor. The bill insert is designed to make basic information about distributed generation available to all consumers and to let them know where to go to obtain more information.

In comments on the proposed decision, LIF suggested that in lieu of bill inserts we pursue an informational campaign using radio and television to target different language communities. As we described above, we do not believe this type of mass market approach will be useful at this point, but as the market for distributed generation grows we may consider these approaches.

Second, whenever a residential or small commercial customer, or their agent, request an interconnection application, the utility should be required to transmit directly to the customer detailed information about how to access: (1) a payback tool; (2) emissions information on various distributed generation technologies; and (3) information regarding permitting requirements for distributed generation. Each of these items will be developed and prepared by the CEC and this Commission. Consistent with their commitment set forth in the October 25, 2000 Supplemental Recommendation, we envision that the CEC will take the lead and serve as a central clearinghouse for information regarding distributed generation, emissions and permitting requirements, rebates, incentives and economics of distributed generation investments.

The payback tool we envision should allow a customer to input simple information (e.g. zip code, customer type, historic electricity usage, and the specific type of distributed generation unit being considered) into a web-based model. The model should produce a results sheet that allows the customer to see the costs and savings associated with the potential distributed generation investment. The results sheet should identify any rebates or incentives available for that specific distributed generation unit and how to apply for such rebates or incentives. In addition, the results sheet should identify the permitting and interconnection requirements for the distributed generation unit. These items should also be transmitted to residential and small commercial new construction accounts at the time a service connection is requested.

Third, in D.00-11-001 and D.00-12-037 we adopted streamlined interconnection standards applicable to all interconnected distributed generators. These interconnection standards lay out the technical requirements for interconnecting to the grid. We agree that customers that decide to pursue a distributed generation installation need to fully comprehend the safety and reliability implications of interconnection to the grid. By completing the interconnection process, we are confident that they will be fully apprised of these implications by utilities.

UCAN was the only party to submit recommendations on how a consumer education program might be funded. UCAN suggests four possible funding approaches. PG&E, SDG&E, and Sierra Pacific Power Company (Sierra) take the position there should be no utility funded customer education program. PG&E and SCE indicate there should be no publicly funded or sponsored effort. We believe that the responsibilities assigned to utilities are relatively low cost and should generally absorbable within their existing budgets. The responsibilities the CEC and we will handle should also be absorbable within our existing budgets. We note that the CEC's website already contains much of this information and in many cases, fulfilling these responsibilities will simply be a matter of tailoring this information for this particular purpose. Because we do not adopt a costly education campaign, we do not take up the funding options raised by UCAN, but we will revisit them in the event that costs associated with the program we have adopted exceed an absorbable level.

10.2 Consumer Protection

LIF and PG&E recommend the Commission consider consumer protection standards similar to those established for energy service providers in D.98-03-072 and D.99-05-034. LIF recommends that the Commission put these standards in place prior to extensive distributed generation proliferation. PG&E indicates that customers should be made aware of the economic, safety, and reliability aspects of distributed generation prior to committing to distributed generation installation. PG&E provides examples of specific consumer protection components the Commission might consider, such as a requirement for distributed generation developers to disclose price information in a standardized format similar to energy service providers, and a registration requirement for distributed generation vendors. Customers should be made aware of the economic, safety and reliability aspects of distributed generation before committing to having distributed generation installed. Economic aspects relate to the costs of deploying distributed generation, and include disclosure of all developer/vendor, operator and utility charges. Safety and reliability aspects include interconnection standards, and the operational responsibilities and features of customer-side distributed generation.

Consumer protection of residential customers, especially those with limited English skills, was necessary when direct access was launched, in order to ensure that customers were protected in the event that marketers engaged in deceptive marketing resulting in prohibitively high electricity rates. Switching direct access providers carried with it no or low up-front costs to customers. Unlike choosing an electric service provider, the decision to install distributed generation carries with it a significant up front cost to purchase the unit and pay for interconnection. In addition, any customer that wants to install distributed generation must complete a detailed interconnection application that is reviewed by the utility prior to interconnection taking place. The interconnection rules specify the safety and reliability responsibilities of the customer who installs distributed generation. For these reasons, we find that, coupled with our education plan, sufficient protection exists for residential and small commercial customers that renders additional consumer protection requirements unnecessary at this time. We will revisit this issue on our own motion or if deployment of residential and small commercial customer distributed generation reaches 0.1% of peak demand for those classes.

11. Applicability of the California Environmental Quality Act to this Decision

CEQA applies to discretionary government activities, which are defined as "projects." The statutory definition of "project" is "the whole of an action, which has the potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect change in the environment, and that is any of the following:

1. An activity that is directly undertaken by any public agency.
2. An activity undertaken by a person which is supported in whole or in part through public agency contracts, grants, subsidies, loans, or other forms of assistance from one or more agencies.
3. An activity involving the issuance to a person of a lease, permit, license, certificate, or other entitlement for use by one or more public agencies."[23]

The pertinent inquiry here is whether, in rendering a policy determination regarding distributed generation, the Commission possesses any discretion to require changes that would mitigate, in whole or part, one or more of the environmental consequences of installation of distributed generation that an environmental review might uncover. The distributed generation facilities under consideration in this proceeding are not within the Commission's permitting jurisdiction. These facilities are subject to CEQA review and permit issuance by local governmental agencies. Thus, it reasonably follows that the discretionary authority to require changes to mitigate potential environmental impacts of a proposal for distributed generation construction would occur at the local level,

[23] CEQA Guideline 15378.

and is not a function of the Commission’s policy determination regarding distributed generation. Accordingly, adoption of this policy decision is not a “project” and does not require CEQA review.

12. Governmental Efforts Regarding Distributed Generation

Although we determine that no environmental review is required of our adoption of policies surrounding distributed generation, we recognize that because of its nature, distributed generation has numerous impacts to local governments, in terms of siting and permitting responsibilities. In addition, we recognize that because electric customers in California are served by municipal and regulated utilities, consistency in interconnection requirements between regulated and local utilities was desirable. This section summarizes statewide efforts to assist local governments and municipal utilities in facilitating installation of distributed generation resources.

12.1 Local Government Outreach Regarding Interconnection Standards

The CEC held two meetings with municipal utilities on November 28, 2001 and April 10, 2002 regarding the interconnection standards adopted in D.00-11-001 and D.00-12-037. In addition, representatives of municipal utilities regularly participate in the Rule 21 Working Group, a collaborative effort designed to continuously refine and improve the interconnection standards. These efforts have also included the smaller Commission-jurisdictional utilities, in order to ensure consistency.

Riverside Public Utilities has already adopted interconnection standards in response to these efforts, which have been ratified by the Riverside City Council on June 4, 2002. The Sacramento Municipal Utilities District has indicated that it may adopt interconnection standards by the end of 2002 and the Los Angeles

Department of Water and Power has also expressed interest in adopting the standards.

12.2 Identification of Permit Streamlining Opportunities

In R.98-12-015, we requested that the CEC "hold a workshop…to discuss whether local government agencies can use a streamlined CEQA process for the siting of certain types of distributed generation facilities." After a workshop and a public hearing, the CEC issued the report *Distributed Generation: CEQA Review and Permit Streamlining* (December 2000). The report recommended several CEC efforts to improve siting of distributed generation facilities, including:

1. Provision of technical assistance to local jurisdictions conducting CEQA review and land-use approval for peaker projects. CEC staff would provide training and technical assistance to city and county building department staffs to facilitate permitting and inspection of distributed generation technologies.

2. Development of the scope, definition, and criteria for categorical exemptions of certain distributed generation facilities. The report recommends that CEQA guidelines should be amended to provide categorical exemptions for certain types of distributed generation projects. CEC staff would work with local government planning departments to develop:

   - Lists of distributed generation projects exempt from CEQA and land-use approval;
   - Thresholds of significance in key environmental issues; and
   - Standard mitigation measures for types of distributed generation projects that have the potential to cause significant impacts to air quality, noise, aesthetics and other environmental areas.

3. Providing assistance to the California Air Resources Board (CARB) in developing distributed generation emissions standards and certification program.

In 2002, the CEC undertook a separate initiative to define a strategic plan for distributed generation. CEC held a public workshop to gain input and then drafted its *Strategic Plan for Distributed Generation* (June 2002). Several of the goals of the Strategic Plan also will assist in improving local government siting efforts, including:

1. Assessment of the technical and economic potentials for distributed generation and the drafting of model ordinances for distributed generation facilities; and

2. Raising consumer and public awareness about distributed generation by creating and maintaining a central repository of distributed generation information. The CEC would:

   - Develop a database of all distributed generation installations in the state; and

   - Publish up-to-date information on distributed generation technologies, such as: environmental factors such as emissions and noise; efficiency and reliability; commercial availability; installation and operational costs; and control aspects.

These efforts will assist local jurisdictions in permitting decisions regarding distributed generation. As highlighted in the 2000 CEQA workshop report, local governments need information on distributed generation technologies, an inventory of current distributed generation installations, and identification of public health and environmental impacts, to accurately and efficiently assess projects that seek to locate in their communities.

Additionally, to enable expedited environmental review of proposed projects and to address cumulative impacts of increasing numbers of distributed generation sources, the *CEQA Review and Permit Streamlining* report recommends that public agencies undertake program or master Environmental Impact Reports (EIR). Project EIRs, prepared for individual projects, must include analysis of the potential cumulative impacts of the proposed activity. Rather than addressing cumulative impacts on a project-by-project basis, CEQA allows public agencies to address them in master EIR or program EIR, allowing future project EIRs to avoid conducting further cumulative impact analysis. This step could more efficiently and effectively allow local or regional public agencies to consider cumulative impacts from distributed generation projects and ensure that worthwhile mitigation measures were adopted on a program-wide basis.

We encourage the CEC to proceed with the education efforts it has identified. We realize that California's budget situation may impact the ability of state agencies to undertake new program activities such as these but we encourage the CEC and this Commission to leverage federal program funds (e.g. U.S. Department of Energy) to undertake these efforts.

12.3 Air Quality Standards Established for Distributed Generation

Senate Bill 1298, Chapter 741, Stats. 2000, required CARB to adopt uniform emission standards for distributed generation technologies, which have historically been exempt from air pollution control or air quality management district permit requirements. The statute also directed CARB to establish a certification program for distributed generation. CARB has also been developing guidance to local air districts and permitting authorities who may have oversight over distributed generation siting.

CARB approved a staff proposal for the distributed generation certification program (with certain modifications) and the district guidance document at its November 15, 2001 Board Hearing. These documents are available on CARB's website at http://www.arb.ca.gov/energy/dg/dg.htm. Adoption of these regulations will help to ensure that distributed generation in California is on the leading edge of emissions control technology and the cleanest in the country.

12.4 Evaluation of Efficiency, Emissions, and Reliability of DER

Section 353.15 calls for the Commission, in consultation with the CARB and the CEC, to evaluate efficiency, emissions, and reliability of distributed generators over 10kW capacity that receives the rate treatment prescribed by SBX1 B. We intend to pursue this evaluation within this or a successor rulemaking.

13. Comments on Proposed Decision

The proposed decision in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Commission's Rules of Practice and Procedure. Comments were filed by PG&E, SCE, SDG&E, ISO, LIF, TURN, NRDC, State Consumers, JPIDG, Clarus, and CEC.[24] Reply comments were filed by PG&E, SCE, SDG&E, TURN, State Consumers, and jointly by Cogeneration Association of California and the Energy Producers and Users Coalition. Revisions have been made throughout the decision in response to the comments and further review of the record.

Several parties recommend that the record be reopened to consider changes in the electricity market since hearings on these issues were held. Other parties oppose reopening the record. Because this decision deals primarily with distributed generation and its integration with the distribution planning process and its impact on the distribution system rather than its role as an energy provider, we see no need to reopen the record to consider these issues.

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[24] The CEC has not previously participated in this proceeding as a party.

However, we intend to open a new rulemaking to allow us to consider ongoing issues with respect to distributed generation and the outstanding issues we identified in today's decision.

14. Assignment of Proceeding

Loretta M. Lynch is the assigned Commissioner and Michelle Cooke and Timothy Sullivan are the ALJs assigned in this proceeding.

Findings of Fact

1. Distributed generation has the potential to reduce system peak demand in areas experiencing load growth.

2. Distributed generation has some potential to defer distribution system upgrades but this potential is time and location limited.

3. Distributed generation does not raise operational issues for the distribution system that are not addressed by interconnection standards.

4. The key to ensuring safe and reliable distribution services is not utility ownership of distributed generation, but the ability of the utility to control the distributed generation unit.

5. Utility ownership of a distributed generation unit designed to defer distribution system upgrades is not necessary to ensure the safe operation and reliability of the utility operated grid, provided physical assurance of the unit is provided.

6. The value of a distributed generation alternative is the value of deferral of a planned distribution upgrade for the time period of the deferral.

7. Physical assurance is required if distributed generation is to be considered as an alternative to distribution system upgrades.

8. Distribution system planning must consider distributed generation alternatives to wires upgrades as part of the normal planning process and non-

utility distributed generation solutions should be actively solicited through the distribution planning process.

9. None of the utilities plan to market distributed generation to customers, and they do not offer specialized expertise in the manufacture, sale, or operation of distributed generation.

10. If a distributed generation unit is sized, located, and installed consistent with the utility's planning process, and provides physical assurance, ownership by the utility is not required in order to provide distribution system benefits.

11. Utilities have only owned or utilized distributed generation to provide operational support on a short-term or temporary basis or for emergency generation purposes.

12. In all but limited circumstances, as retail sale within a distribution circuit will utilize transmission facilities.

13. Adoption of a distribution-only tariff is inappropriate because a distribution only transaction cannot occur unless the distribution system is electrically isolated from the transmission grid.

14. Because of changes in the electric industry and the current status of utility PBR mechanisms, there is no need to implement a PBR program specific to distributed generation investment.

15. Current tariffs provide for recovery of public purpose program charges from any customer who self-generates.

16. Allowing utilities to enter into contracts with distributed generators who defer a distribution system upgrade eliminates the need for deaveraged tariffs or other incentive programs.

17. Costs of implementing the distributed generation policies adopted herein will likely be small and able to be incorporated into routine utility operations.

18. Section 2827 was modified in 2001 to expand eligibility for net energy metering to larger units and other customer classes.

19. Rule 21 interconnection tariffs specify standard interconnection, operating, and metering requirements for distributed generation that provide adequate assurance that a nonrenewable generation system, even when connected to the same service account as an eligible renewable generator, will not export electricity.

20. Installing a distributed generation unit carries with it a significant up front investment.

21. The Commission does not possess any discretion to require changes that would mitigate, in whole or part, one or more of the environmental consequences of installation of distributed generation that an environmental review might uncover.

Conclusions of Law

1. It is not necessary to establish a "valuation" system in order to ensure that distributed generation is properly incorporated into utility distribution system planning.

2. The utilities are responsible for the safety, reliability, and operation of the distribution system and therefore must have control over the planning and operation of the distribution system.

3. Third party ownership of distributed generation designed to defer distribution system upgrades should be allowed, subject to appropriate physical assurances and participation in the utility distribution planning process.

4. SDG&E's distributed generation procurement approach should be adopted for all utilities because it allows the utility to retain control of its distribution

system planning process, maintain reliability at reasonable cost, while providing flexibility to evaluate distributed generation alternatives to a wires solution.

5. Utilities should develop model contracts for distributed generation designed to defer distribution system upgrades.

6. Compensation paid to a distributed generator that is selected as a wires alternative should not exceed the cost of the planned addition multiplied by the utility's short-term carrying cost of capital and the number of years of deferral and should be made as a bill credit or direct payment and be paid out of the distribution budget.

7. Like third-party distributed generation providers, the utility should be eligible to receive a credit based on the deferral value of the distributed generation unit. The credit would be paid out of the distribution budget. In other respects, utility-owned distributed generation should be treated as a generation asset, with revenues associated with ownership or operation of customer side distributed generation offsetting the costs of ownership or operation.

8. Public purpose program costs are nonbypassable by law.

9. If utilities incur implementation costs to implement these policies, it is reasonable to allow them to establish memorandum accounts to track these costs.

10. Because of the changes to Pub. Util. § 2827 made in 2001, no modifications to the current eligibility standards are necessary.

11. SCE should modify its Net Energy Metering tariff to be consistent with approved tariffs of PG&E and SDG&E and to remove language excluding integrated renewable/nonrenewable distributed generation technologies from eligibility for net energy metering.

12. A broad-based mass marketing campaign is not appropriate at this time to educate customers about distributed generation.

13. The Commission and the CEC should prepare information for a bill insert discussing distributed generation options, available incentives and rebates, and other sources of information on distributed generation.

14. The Commission and the CEC should develop a distributed generation payback tool, emission information on distributed generation technologies, and information regarding permitting requirements for distributed generation.

15. Adoption of this policy decision is not a "project" and does not require CEQA review.

16. The Commission should open a new rulemaking to allow for consideration of ongoing issues with respect to distributed generation.

O R D E R

Therefore**, IT IS ORDERED** that:

1. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) shall ensure that their distribution planning processes incorporate SDG&E's distributed generation procurement approach to evaluate alternatives to distribution system upgrades.

2. Within 75 days of the effective date of this decision, PG&E, SDG&E and SCE shall file a compliance filing describing the methodology each will use for evaluating distributed generation as a distribution alternative. The methodology shall be specific enough to provide the distributed generation community with information on when distributed generation may be an alternative for a distribution system modification or upgrade, while giving the utility flexibility to react to changes in the distributed generation marketplace.

3. PG&E, SDG&E, and SCE shall develop model contracts for distributed generation designed to defer distribution system upgrades.

4. PG&E, SDG&E, and SCE shall pay compensation to distributed generators selected through their distribution planning process, by a bill credit or direct payment, no higher than the utility's short-term carrying cost of capital multiplied by the cost of the planned distribution addition and the number of years of deferral.

5. PG&E, SDG&E, and SCE shall pay compensation to distributed generators selected through the distribution planning process from their distribution budget.

6. Except for the credit for deferral value described in Conclusion of Law 7, PG&E, SDG&E, and SCE shall treat utility owned distributed generation as a generation asset, with costs and revenues being booked to generation accounts.

7. The utilities shall submit quarterly reports specifying any activities the utility or their affiliates have in the manufacturing, ownership, sale, or operation of distributed generation within the utilities' service territory.

8. PG&E, SDG&E, and SCE may propose a memorandum account via Advice Letter to track costs for implementation of these distributed generation policies that are not already part of existing budgets or recovered from customers installing distributed generation.

9. SCE shall modify its Net Energy Metering tariff to be consistent with approved tariffs of PG&E and SDG&E and to remove language excluding integrated renewable/nonrenewable distributed generation technologies from eligibility for net energy metering.

10. PG&E, SDG&E, and SCE shall include an insert in customers bills every year discussing distributed generation options, available incentives and rebates, and other sources of information on distributed generation. PG&E, SDG&E, and SCE shall include information on the bill face in English and Spanish directing customers to the bill insert. The bill insert will be developed by this Commission

and the California Energy Commission (CEC) after consultation with the parties. PG&E, SDG&E, and SCE shall translate the bill insert into multiple languages after consultation with the Commission's Public Advisor.

11. PG&E, SDG&E, and SCE shall provide every residential or small commercial customer that requests an interconnection application (or makes a request through as agent) with detailed information about where to access (1) a payback tool; (2) emissions information on distributed generation technologies; and (3) permitting information developed by the CEC and this Commission.

12. Energy Division and the Public Advisor shall work with staff identified by the CEC to develop the materials and tools described in Ordering Paragraphs 7 and 8 to ensure that the utilities shall be able to implement these provisions within 75 days of the issuance of this decision.

This order is effective today.

Dated ________________________, at San Francisco, California

APPENDIX A
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