CALIFORNIA
ENERGY
COMMISSION

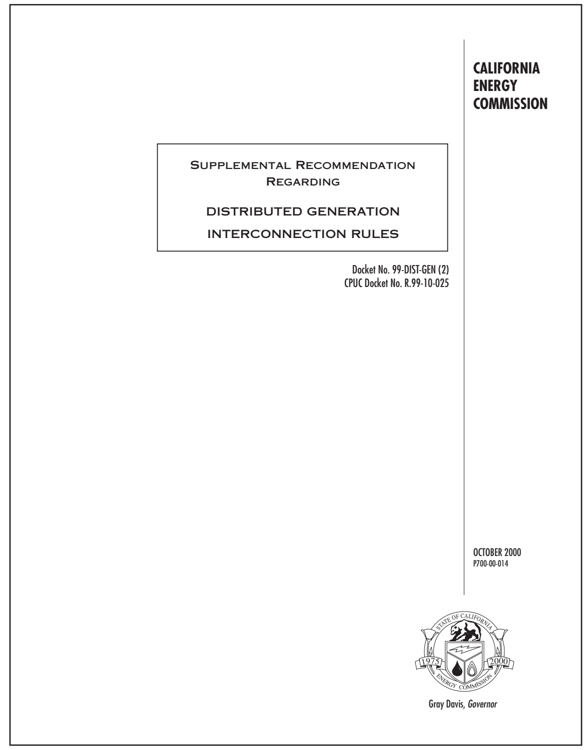
Supplemental Recommendation Regarding

DISTRIBUTED GENERATION INTERCONNECTION RULES

Docket No. 99-DIST-GEN (2)
CPUC Docket No. R.99-10-025

OCTOBER 2000
P700-00-014

Gray Davis, *Governor*



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ACKNOWLEDGEMENTS

The Energy Commission wishes to thank the parties that have continued to participate in this rulemaking effort. In particular, we express our deepest appreciation for the dedicated efforts of the Energy Commission staff, including Scott Tomashefsky, Jeff Ogata, Jon Edwards, Joe Diamond, and Evelyn Beevers. We also wish to thank the members of the FOCUS team for their continuing efforts under contract with the Energy Commission: Bill Brooks, Cris Cooley, Mike Edds, Edan Prabhu, and Chuck Whitaker.

Companies actively participating in the summer working group process are listed below with asterisks noted for those parties filing comments. We wish to thank PG&E, SCE, SDG&E, and Capstone Turbine for hosting at least one working group meeting during the summer.

California Air Resources Board
California Manufacturers and Technology Association (CMTA) *
California Municipal Utilities Association (CMUA)
California Independent System Operator (ISO)
Capstone Turbine
CPUC – Office of Ratepayer Advocates
Cogeneration Association of California/Energy Producers and Users Coalition (CAC/EPUC) *
Enron
Elektryon
Honeywell *
Los Angeles Department of Water and Power
New Energy Inc.
Pacific Gas and Electric *
Polaris Group (The)
Real Energy
Riverside Public Utilities
Southern California Edison *
San Diego Gas and Electric *
Sacramento Municipal Utilities District
Sempra Energy
Southern California Gas Company
VFL Energy Technologies

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I. Introduction

The California Energy Commission (Energy Commission) hereby submits this final report to the California Public Utilities Commission (CPUC) in support of Docket 99-DIST-GEN(2) and CPUC Docket R.99-10-025. The purpose of the report is to set forth a formal supplemental recommendation regarding the development of Distributed Generation rules. The Energy Commission adopted its initial set of recommendations in June 2000 and forwarded it to the CPUC for further consideration. A proposed decision by the CPUC on the initial set of recommendations is scheduled to be considered for adoption on November 2nd.

As the June report suggested, several areas required additional work to complete the development of standardized interconnection rules. A total of six additional working group meetings were held between late June and mid-August to address the following issues:

- DG Interconnection Fees – Initial and Supplemental Reviews
- DG Interconnection Database and ISO Needs
- Certification and Testing Procedures for Non-certified Equipment
- Changes to Initial Review Screens
- Uniqueness of Utility Tariffs
- Interconnection Agreement
- Interconnection Application Form
- Miscellaneous Issues Raised at June 14th Business Meeting
- Forum for Additional Work

Section II of this report discusses each of the above-mentioned issues in greater detail and incorporates many of the issues raised by the parties at a September 7th Siting Committee hearing and in written comments submitted on September 15th, October 16th, 17th, and 25th. The report concludes with a discussion about the next steps required in this process. Attachment A contains the full version of the Rule 21 language, including language from the June 2000 recommendation. Changes stemming from the supplemental working group activity are indicated in strikeout mode. Attachments B and C provide the sample Agreement and Application, respectively.

II. Issues Addressed During Supplemental Working Group Meetings

DG Interconnection Fees – Initial and Supplemental Reviews

The calculation of the Interconnection Study fee for DG Applications outlined in Section 3.1.2 of the proposed Rule language is a key issue that was not resolved during the development of the Energy Commission's formal recommendation to the CPUC in June. The Energy Commission directed the working groups to develop a full record on this issue during the summer working group meetings. In doing so, the working groups decided to focus on the total cost of the review, leaving the issue of actual fees and cost allocation to the CPUC.

To initiate discussions, PG&E prepared an estimate of the various activities and approximate costs associated with reviewing and processing the applications. As Table 1 indicates, a range of 9-17 hours was identified as the amount of time needed to review the application, perform requisite engineering analysis, and process the contract paperwork once the application is approved by the Electrical Corporation. Assuming a $100 hourly rate for Electrical Corporation personnel time, the total cost of the initial review suggested by PG&E ranges between $900 and $1700.

TABLE 1
ACTIVITIES AND TIME ASSOCIATED WITH INITIAL REVIEW

	Activity	Estimated Time
Account Services	Check for completed application Check for Screen 2 Check for Screen 6 Coordinate all review activity Coordinate with mapping department Site Visit (If Needed)	2-4 Hours
Planning	Check for completed technical info Check for Screen 1 Check for Screen 3 Check for Screen 4 Check for Screen 7 Check for Screen 8	4-8 Hours
Customer Services	Modify Billing Records	1 Hour
Pre-Parallel Inspection	Ensure equipment and protection system operate correctly Site Visit	2 to 4 Hours
Total		9-17 Hours

During discussions, parties generally agreed that the activities identified in the above table represent the full range of activities associated with the initial review process. Various parties, however, questioned the appropriate allocation of hours to each of the activities. Additional discussions lead to an agreement that 3-5 hours should be allocated to review and evaluation of the Application, with an additional 3-5 hours for pre-commissioning and inspection. Recognizing efficiencies of Application review, the group agreed that eight hours should apply to the Initial Review process. The total initial cost in this instance would be $800, assuming the Application is approved and processed. In the event the Application is rejected, half of that amount ($400) would be returned, accounting for account and customer service activities that would not be incurred by the Applicant.

It is important to note that the $800 minimum charge is equal to the full cost of reviewing and processing the Application. We do not provide any suggestions about how much of the cost should be borne by the DG Applicant and how much should be borne by the Electrical Corporation as part of its "everyday operations." The Energy Commission leaves that issue to be resolved by the CPUC based on the results of its Phase 2 investigation stemming from R.99-10-025. Proposed language for Section 3.1.2 follows:

3.1.2 **Applicant Completes an Application Document.** All Applicants shall be required to complete and file an Application document and supply any additional information requested by the Electrical Corporation. The filing must include the completed standardized Application, which may be either in paper or electronic form, and a fee for processing the application and performing the Initial Review to be completed by the Electrical Corporation pursuant to Section 3.1.3. The application fee shall vary with the nature of the proposed Generating Facility as follows:

Type of Generating Facility	Initial Review	Supplemental Review
Net Energy Metering (per Public Utilities Code Section 2827)	None	None
All others	$800	$600

Note: Allocation of cost between DG Applicant and Electrical Corporation to be determined by CPUC in Phase 2 of R.99-10-025. The total cost borne by the Applicant should be reduced by the cost allocated to the utility's distribution function.

Fifty percent of the fees associated with the Initial Review will be returned to the Applicant if the Electric Corporation rejects the Application or the Applicant retracts the Application.

The Applicant may propose and the Electrical Corporation may negotiate specific costs for processing non-standard installations such as multi-units, multi-sites, or otherwise as conditions warrant. The costs for the Initial Review and the supplemental review contained in this Section, as well as the language provided in Sections 3.1.3 and 3.1.4 do not apply under these circumstances.

Within ten (10) business days of receiving an Application, the Electrical Corporation shall normally acknowledge its receipt and whether the Application has been completed adequately. If defects are noted, the Electrical Corporation and Applicant shall cooperate in a timely manner to establish a satisfactory Application.

The group also addressed the maximum charge that would be appropriately assessed to a DG applicant seeking to interconnect with the Electric Corporation. The criteria for the charge was based on the notion of providing the Electrical Corporation with an opportunity to resolve issues not addressed in the Initial Review without making the review cost prohibitive to those not interested in a full-blown Interconnection Study. Initial discussions suggest that a maximum of six additional hours will provide a firm understanding whether a full-blown study would be needed before an Application would be processed. Thus, the total cost of the initial and supplemental cost would not exceed $1,400.

For larger scale projects, the likelihood of passing the initial or the supplemental review is inversely related to the size of the project. In other words, larger scale projects will require more review and likely lead to a full-blown Interconnection Study. In order to more expeditiously process Applications, Question 11 of the interconnection application form contains a box in which an applicant can waive the initial and supplemental review and ask the Electrical Corporation to immediately proceed towards an Interconnection Study. The minimum fee would then equal the $1,400 fee associated with the initial and supplemental review process. The actual bill would be reconciled once the Electrical Corporation completes its work.

Comments Filed by Stakeholders and Discussion

PG&E's comments include a request to modify Section 3.1.3.3 of the proposed Rule 21, enabling the Electrical Corporation to collect $600 in advance of performing a supplemental review. According to PG&E, this would "make more explicit that the 20-day timeline for conducting supplemental review is tolled until the $600 supplemental review fee is received." Alternatively, the applicant could pay the additional supplemental review fee at the initiation of the initial review, for an up front total of $1,400, subject to refund if a supplemental review is not needed.

Energy Commission Recommendation – DG Interconnection Fees

We sincerely appreciate the willingness of the parties to fully debate the fee issue as requested in the Energy Commission's initial recommendation adopted in June. We agree that the issue of cost allocation is one that will need to be resolved at the CPUC and can best serve our sister agency's needs by addressing these fees on a total cost basis. While the $1,400 total cost provides a viable starting point for the initial implementation of these rules, we strongly suggest revisiting the cost issue two years after implementation to determine whether adjustments will be needed. As mentioned in previous reports, the Energy Commission is prepared to lead a post implementation phase of this investigation.

Regarding PG&E's request described in its comments, we are not amenable to requiring an up front payment for supplemental review. In our opinion, the up-front fee for application review should not represent a barrier to entry by deterring DG applicants from interconnecting. As a compromise measure, we will add language to Section 3.1.3.3 that requires DG applicants to remit payment to the Electrical Corporation within 10 calendar days after the results of the review are provided to the DG applicant. Section 3.1.3.3 now reads as follows:

3.1.3.3 If the Application does not qualify for Simplified Interconnection as submitted, the Initial Review will include a Supplemental Review as described in Appendix A. The Supplemental Review provides either (a) Interconnection Requirements that may include requirements beyond those for Simple Interconnection, and a draft Interconnection Agreement, or (b) a cost estimate and schedule for an Interconnection Study. The supplemental review shall be completed, absent any extraordinary circumstances, within 20 business days of receipt of a completed Application. Payment for the Supplemental Review shall be submitted to the Electrical Corporation within 10 calendar days after the results of the Supplemental Review is provided to the Applicant.

DG Interconnection Database and ISO Needs

The purpose of the DG interconnection database is to provide a readily accessible source of information for those entities seeking a current inventory of distributed generators operating in California. This information was first requested by the California Independent System Operator (ISO) to help in the planning and operating functions of the electrical transmission system. As discussed at the working group meeting on August 1st, the ISO requested operational information on Generating Facilities (GF) above one megawatt in size with more general information for units below one megawatt.

<u>Data Needs for GF Greater Than or Equal to One Megawatt</u>

The ability to obtain data for larger DG systems is consistent with ongoing data collection activities at the Energy Commission. Recognizing the changes in the electricity market, the Energy Commission initiated an investigation in 1997 (Docket 97-DC&CR-1) to redefine what types of data should still be collected and who should be required to report. Proposed regulations were initially submitted with the Office of Administrative Law in June 2000. The current 15-day regulations, which was approved by the Energy Commission on October 11th and expected to become effective on January 1, 2001, propose the following:

> Each UDC should report semiannually the following data for each electric power plant located in the UDC's electric service area. Notwithstanding Section 1303(e), the report shall be submitted on January 31 and July 31 each year.
>
> (1) name;
> (2) facility code assigned by the EIA (Energy Information Administration);
> (3) nameplate capacity in megawatts;
> (4) voltage at which the electric power plant is interconnected with the UDC system or transmission grid;
> (5) address where the electric power plant is physically located, including the street address, city, state, and zip code;
> (6) power plant owner's full legal name and address of principal place of business, including the street address, city, state, and zip code; and
> (7) longitude and latitude, expressed to the nearest degree, if available.
>
> See Express Terms for Proposed Amendments To California Code Of Regulations, Title 20, Division 2: Chapter 3, Article 1 (Quarterly Fuel And Energy Reports) and Chapter 7, Article 2 (Disclosure Of Commission Records), September 2000, pages 21-22.

These data regulations cover the full range of concerns, including confidentiality. The Energy Commission will work with the ISO and other stakeholders to determine a procedure for accessing data fields that are not protected under the confidentiality agreement.

Data Needs for GF Less Than One Megawatt

For Generating Facilities less than one megawatt, the working group suggested relying on a variation of the periodic Qualifying Facility (QF) report currently prepared by the utilities pursuant to CPUC Decision 82-01-103, modified by Decision 97-05-021. The 1997 decision requires the investor-owned utilities to file a *Cogenerator and Small Power Producer Report* on an annual basis with a semi-annual update if there is new information to report. The fields needed to populate a "small" DG database are: 1) location (generalized to city or town); 2) fuel type (natural gas, biomass, diesel, wind, solar); 3) Generating Facility total nameplate rating in kW; and, 4) expected type of operation (peaking, base load, emergency). This level of data is already supplied by each utility with respect to QFs connected to the utility system.

According to representatives from each utility, expanding this reporting activity to include Distributed Generators would not provide an undue hardship to the Electrical Corporation. Since this information is needed for all Generating Facilities regardless of whether or not it is registered as a QF, the Electrical Corporation would not need to differentiate whether or not the unit is a QF in their data reports. It is the Energy Commission's understanding that these four pieces of information will satisfy the ISO's need for data for Generating Facilities less than one megawatt.

Comments Filed by Stakeholders and Discussion

CAC/EPUC and PG&E filed comments with respect to the interconnection database issue. CAC/EPUC responded to an ISO request in the data collection proceeding that Distributed Generators over one megawatt provide longitude and latitude data in addition to plant address, and change the utility reporting requirement from annual to quarterly filing. CAC/EPUC argues that the information be requested "on a voluntary basis only" and only if the information is available at little or no cost. No comment was made with respect to the change in the reporting requirement.

The Energy Commission already responded to this concern in the data collection proceeding. The regulatory language proposed in June 2000 had two broad sections regarding generator data. Section 1340(a) requires owners of power plants one megawatt or greater to provide data on the operations of the plant. Section 1340(b) requires the investor-owned utilities only to provide a list of locational data (as shown on the previous page) about each power plant in its service territory. In response to the ISO request, Section 1340(b) was modified in the adopted regulations to call for geographical coordinates if available and change the reporting requirement to a semi-annual basis.

In its comments, PG&E expressed concern about the compatibility of the existing QF report with that of a modified QF/DG report. The utility argues that reporting generator status "is not directly compatible with the QF report which is based on the contracts QFs have with the utility, not interconnection or operating status." PG&E proposes having the option of providing a separate report as an alternative.

Energy Commission Recommendation – Interconnection Database

We endorse the development of an interconnection database and expect that each utility's contribution to a statewide database will be located at the Energy Commission. Since the elements of the database involve individual end-user information, certain data can be expected to be deemed confidential. Future working group meetings will resolve the details of what data is made available publicly, what data would be provided to the ISO, and what data is reserved solely for Energy Commission usage recognizing our commitment to honor confidentiality designations. As such, no additional Rule changes are required at this time.

In response to PG&E's concerns, the recent adoption of new data collection regulations obviates the need for the utilities to modify its QF report. For all facilities *regardless* of size, the Energy Commission's data collection regulations will require that basic information about each facility be submitted directly from the utilities. As such, there will be no need for the CPUC to extend the utility QF reports to include DG units for units below one megawatt.[1]

Testing and Certification Procedures

In its initial recommendation to the CPUC, the Energy Commission endorsed the development of an Initial Review screening process to create a path for quickly considering Applications not requiring an Interconnection Study. The third review screen assesses whether specific interconnection equipment is deemed Certified for use without further testing. The June report indicated that the certification and testing work was originally set aside by the technical group to focus on completing Section 4 of the proposed Rule 21 language. The working group undertook a considerable effort during the past few months to provide the Testing and Certification appendices contained in this report.

Appendix B of the proposed Rule 21 language details the testing procedures and requirements for equipment used to interconnect a Distributed Generator to the Electrical Corporation's Distribution System. Included are procedures for the following tests:

Type Testing	Tests performed on a particular model of a device to verify specific aspects of its design/construction and establish its performance.

[1] As a result of the adopted data collection regulations all operating data concerning electricity production and fuel use will be submitted to the Energy Commission directly by each facility owner for any facility one megawatt and larger. The Energy Commission itself will estimate or collect any needed operating data for facilities less than that threshold.

Production Testing	Tests performed on each device coming off the production line to verify certain aspects of its performance.
Commissioning Testing	Tests performed during or at the completion of the DG installation to verify specific aspects of its performance and post-installation settings.
Periodic Testing	Tests performed over the life of the DG unit to verify certain aspects of the unit's performance.

The above-mentioned procedures rely heavily on those described in appropriate documents developed by Underwriter's Laboratories (UL), the Institute of Electrical and Electronics Engineers (IEEE), and the International Electrotechnical Commission (IEC).[2]

Equipment tested and approved by an accredited, nationally recognized testing laboratory will be considered certified for interconnection purposes. Certification may apply to either a pre-packaged system or an assembly of components that address the necessary functions. Type Testing may be done in the factory/test lab or in the field. At the discretion of the testing laboratory, field-certification may apply only to the particular installation tested. In such cases, some or all of the tests may need to be repeated at other installations.

For non-certified equipment, the Electrical Corporation may require some or all of the tests described in Appendix B. The tests are intended to provide assurance that the DG equipment will not adversely affect the Distribution System of the Electrical Corporation and that it will cease providing power to the grid under abnormal conditions. Equally important to note is that these tests were developed assuming a low level of DG penetration. At high levels of DG penetration, other requirements and corresponding test procedures may need to be defined.

The manufacturer or other entity acceptable to the Electrical Corporation may perform these tests. Test results must be submitted to the Electrical Corporation with the Interconnection Application for review and approval under the supplemental review. Approval by one Electrical Corporation for use in a particular application does not guarantee approval for use in other applications or by other Electrical Corporations.

Changes Required to Definitions Section

The completion of the certification language produced the need to add five definitions to the list of definitions contained in Section 8. The following list was suggested by the working group:

[2] The most notable documents include UL1741 and IEEE929—as well as the testing described in May 1999 New York Standardized Interconnection Requirements. These procedures and requirements were developed prior to the completion of IEEE P1547 *Standard for Distributed Resources Interconnected with Electric Power Systems*, and may need to be revised once that standard is published.

Non-Exporting	Designed to prevent the transfer of electrical energy from the Electrical Producer to the Electrical Corporation.
Non-Islanding	Designed to detect and disconnect from a stable Unintended Island with matched load and generation. Reliance solely on under/over voltage and frequency trip is not considered sufficient to qualify as Non-Islanding.
In-rush Current	Current drawn by the Distributed Generator during startup.
Nationally Recognized Testing Laboratory	A laboratory approved to perform the necessary certification testing requirements.
Starting Voltage Drop	The percentage voltage drop at a specified point resulting from In-rush Current.

Energy Commission Recommendation – Certification Issues

The Energy Commission closely relied on the technical expertise of the working groups in its general support of the proposed certification language. Based on the results of the September Siting Committee hearing and the lack of critical comments on the certification language, we fully endorse the certification language contained in Appendix B of this report. While accepting the language at this time, however, we recognize the need to closely monitor the development of IEEE standards and modify the language in the future. We look to the working groups for that support in the post-implementation phase.

Changes to Initial Review Screens

The completion of the certification work raised the need to evaluate whether any of the screens previously endorsed by the Energy Commission should be revised. Two notable changes are being proposed in this report. The first is the removal of the Net Metering screen. The group determined that, since an Electrical Corporation already has an established procedure for processing net-metered systems, the screen is not necessary. This action has no impact on the technical evaluation of a DG Application.

The second change calls for a new technical screen that addresses Electrical Corporation concerns regarding customer power quality. The "Starting Voltage Drop" screen addresses potential voltage fluctuation problems caused by generators that start using Electrical Corporation motor power.[3] Units that could use Electrical Corporation-powered motor starting include microturbines, induction generators, and possibly some synchronous generators.

[3] Some technologies do not need a motor to start operation of the generator. Examples include photovoltaics and fuel cells.

The screen considers two options, either of which can be used by the Electrical Corporation to evaluate the Starting Voltage Drop. In Option 1, the unit passes the screen if the magnitude of current drawn by the Distributed Generator during startup (also referred to as In-rush Current) does not exceed the current rating of the customer's service equipment (as defined by the 1999 National Electric Code.) Option 2 relates to the Electrical Corporation evaluating starting voltage drop based on its present method of evaluating motor loads. This method can be either an actual calculation (based on the EC's knowledge of the service equipment) or pre-calculated values taken from a look-up table or nomograph. In using this method, the Electrical Corporation will determine if the voltage drop is within 2.5 percent for primary interconnection or five percent for secondary interconnection. The Distributed Generator passes the screen if these criteria are met.

Even though an applicant may pass the screen, the DG will still need to comply with the flicker requirements contained in Section 4.2.2 of the proposed Rule 21. Flicker refers to a situation where voltage fluctuations result in perceptible light "flickering." During working group meetings, the technical group determined that certification for meeting flicker requirements through Type Testing was not feasible. Flicker is a site-specific phenomenon based on the stiffness of the distribution line, equipment impedance at a given location, and the In-rush Current. This last parameter can be Type Tested and is included in the Testing and Certification section (Appendix B).

Energy Commission Recommendation – Changes to Initial Screens

The Energy Commission endorses the changes to the screens proposed by the working group. With respect to the Starting Voltage Drop screen, we recognize that it is better to address potential issues with respect to a DG application prior to the installation of the Generating Facility.

Uniqueness of Utility Tariffs

In the development of the June report, SDG&E indicated a desire to keep utility-specific provisions of Rule 21 intact rather than being required to move them to other areas of the utility tariff rules. PG&E also submitted information that suggested that some aspects of the tariffs remain unique. SCE was generally comfortable with the proposed language contained in the draft report.

Through discussions this summer, SDG&E reversed its position and no longer has concerns about tariff specific language. SCE stands ready to accept standardized tariffs as well.

PG&E has two proposals regarding the need to include missing provisions from its existing Rule 21. The first refers to language which specifies that the Electricity Producer is responsible for future Distribution System alterations if the additions are due to the interconnection. PG&E maintains that, in the event of circuit changes (voltage upgrades, undergrounding, and changes in load on the distribution circuit), there could be additional expense to the Electrical Corporation as a result of the Generating Facility being connected to the distribution system. The utility argues that Distributed Generators should pay for these additional costs, similar to existing rules which applies to load customers with Special Facilities. As such, PG&E proposes that Section B.6 of its existing Rule 21 be included as Section 5.4 of the proposed Rule 21 language that applies to PG&E:

> 5.4 **COSTS OF FUTURE UTILITY SYSTEM ALTERATIONS.** The Producer shall be responsible for the costs of only those future Utility system alterations which are directly related to the Producer's presence or necessary to maintain the Producer's interconnection in accordance with PG&E's applicable operating, metering and equipment publication in effect at the time of interconnection. Such alterations may include, but are not limited to, relocation or undergrounding of PG&E's distribution or transmission facilities as may be ordered by a governmental authority having jurisdiction. Alterations made at the Producer's expense shall specifically exclude increase of existing line capacity necessary to accommodate other Producers or PG&E customers.

The second proposal addresses Operation and Communication language from PG&E's existing rule. PG&E recommends that Operation and Communication language from its existing interconnection agreement be included in the Draft Rule 21 in Section 2.9 or in Section 4. This issue was not fully debated in the working groups since little time was spent on operational requirements during the working group meetings. The language from the utility's existing Rule 21 follows:

a. If the Generation Customer [EP] wishes to perform work on its own facilities which would normally be energized by PG&E-controlled source(s) of energy, the Generation Customer may request that PG&E open, lock and tag PG&E's associated disconnect device to isolate the Generation Customer's facilities from PG&E source(s) of energy. PG&E will also establish the disconnect device(s) as an open <u>Clearance Point(s)</u> and install "Man on Line" tags (see PG&E's General Operating Instructions).

b. The Generation Customer agrees to the following conditions regarding a <u>Non-Test</u> requested by PG&E:

   1. The Generation Customer shall not re-energize the affected circuits, whether manually or automatically, without first receiving the approval of the Designated PG&E Switching Center.

   2. The Generation Customer agrees to install and maintain permanent warning signs on the Facility's main control panel and at each remote operating location where the Generation Customer has remote closing capability. The warning signs shall instruct personnel to contact PG&E before re-closing the circuit.

<u>Clearance Point:</u> The points that isolate equipment from possible sources of energy. PG&E may from time to time request that the Generation Customer provide a Clearance Point so that work can be safely performed on the PG&E electric system

<u>Non-Test:</u> A procedure used by PG&E in connection with work on a live line or near an energized circuit. In a Non-Test, PG&E will request that the Generation Customer contact the Designated PG&E Switching Center before re-energizing a circuit following an automatic trip

Comments Filed by Stakeholders and Discussion

PG&E, SDG&E, CMTA, and Honeywell submitted comments on the PG&E proposals. PG&E's comments essentially restate its proposals as discussed above. With respect to the proposed Section 5.4, SDG&E agrees with PG&E's concern that a DG owner should be only responsible for future costs incurred due to changes in the operation of the DG. Honeywell believes the proposed arrangement would impose an "open-ended financial commitment" on the Electricity Producer since the Electrical Corporations are "financially indifferent to added construction or modifications." Regarding the second proposal, SDG&E suggests a need to follow the operating of the rules of the Electrical Corporation but notes that the issue has not been fully addressed at this point. Honeywell contends that the Electricity Producer not be held responsible for a disconnect switch, as suggested by PG&E.

In a general statement applicable to both proposals, CMTA urges the Energy Commission to be "skeptical" of calls for uniqueness at this time and prefers to have these issues debated as part of the future working group process.

Energy Commission Recommendation – PG&E Language Proposals

We are committed to our goal of developing standardized rule language unless there is a compelling reason not to do so. As such, we see no reason to adopt the PG&E language changes at this time. In our opinion, Section 5.2.2 of the proposed Rule 21 language addresses PG&E's concern about future utility system alterations. Section 2.4 of the proposed Rule 21 language provides uniform assurance that an Electricity Producer will comply with all utility operating practices.

While rejecting the PG&E proposals at this time, the Energy Commission believes that the working groups, in its post-implementation work, consider whether stronger language is needed in Rule 21 to mitigate the concerns of PG&E and the other utilities at this time. After additional debate by the working groups, we will consider the issue again if the group believes it will improve the quality of the Rule 21 language.

Interconnection Agreement

While not part of the formal Rule 21 language, the Interconnection Agreement is a critical component to the success of Rule 21. During the first half of this year, parties began developing a proposed Interconnection Application and Agreement for Energy Commission consideration. In its June report, the Energy Commission identified three areas that needed further debate before a formal recommendation could be forwarded to the CPUC for adoption: 1) liability and insurance coverage; 2) actions to be taken when an Electricity Producer consumes energy when it has been forced to curtail or interrupt its generation; and 3) a party's right to control the maintenance outages taken by the other party. Each of these issues will be addressed in this section after a brief overview regarding the contents of the standardized application. The complete draft Interconnection Agreement can be found in Attachment B.

It is important to note that the proposed agreement does not apply to QFs or other parties seeking to export loads. The ultimate goal of this process is develop a family of standardized agreements that would accommodate export and non-export arrangements. These other agreements will be developed by the working groups during the post-implementation phase of this proceeding.

Agreement Overview

The proposed agreement contains 16 sections in its present form (Table 2). Working group discussions about the contents of the agreement focused on several areas, including Sections 2, 4, 5, 7, and 8. Sections 2, 4, and 5 are addressed in the non-controversial part of this section. Sections 7 and 8 focus on controversial issues. The other sections, while reviewed by the group, did not generate any significant discussion and will therefore not be addressed in this report.

TABLE 2 Components of Proposed Interconnection Agreement by Section
1. Scope and Purpose
2. Summary and Description of Electricity Producer's Generating Facility
3. Documents Included; Defined Terms
4. Term and Termination
5. Generating Facility Operation and Certification Requirements
6. Interconnection Facilities
7. Indemnity and Liability
8. Insurance
9. Notices
10. Review of Records and Data
11. Assignment
12. Non-Waiver
13. Governing Law, Jurisdiction of CPUC, Inclusion of Electrical Corporation Tariffs and Rules
14. Amendment and Notification
15. Entire Agreement
16. Signatures

Non-Controversial Agreement Issues

a. Summary and Description of Electricity Producer's Generating Facility (Section 2)

Section 2 of the agreement provides the basic information pertaining to the Generating Facility. Included in the section is information about the facility's physical location, Gross and Net Nameplate Ratings, expected annual energy production, date of Initial Operation. Also included are the Electrical Corporation-specified identification numbers for the Generating Facility, as well as an indication whether the Customer is a cogeneration customer.[4]

b. Term and Termination (Section 4)

Section 4 of the application describes the manners by which either party of an interconnection agreement can terminate the agreement. The language allows the Electrical Producer to terminate the agreement for any reason approximately two months after giving notice to the Electrical Corporation. The Electrical Corporation can also terminate the agreement but only under certain conditions. For example, an Electrical Corporation can terminate the agreement if substantial regulatory or legal changes preclude the utility from performing its obligations under the agreement. Other reasons allowing for termination of the agreement include: 1) if the Electrical Producer fails to take any corrective action if the Electrical Corporation specifies that the Generating Facility is out of compliance with the terms and conditions of the agreement; 2) if the Electrical Producer fails to interconnect and operate within 120 days of the initial start-up date specified in the agreement; and 3) if the Electrical Producer abandons the facility.

c. Generating Facility Operation and Certification Requirements (Section 5)

Section 5 describes the need for an Electricity Producer to regulate the flow of power from a Generating Facility to prevent the flow of electricity from the Generating Facility to the Distribution System. It also describes the need to ensure that Electrical Producers classified as cogenerators are actually functioning, and if not, provides measure for either ensuring compliance or terminating the agreement.

Verification of cogenerator power generation is critical to the collection of competition transition cost (CTC) charges associated with the transition to a more competitive market. As of July 1, 2000, CTC charges are no longer collected from cogenerators. The working group prepared language in Section 5.2 that allows for annual verification and back-billing potential if it is determined that an Electricity Producer is knowingly claiming to be a cogenerator to avoid the CTC charge.

Controversial Application Issues

a. Indemnity (Section 7)

For purposes of this proceeding, indemnity is defined to be a contract between two parties whereby one undertakes and agrees to indemnify the other against loss or damage arising from

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4 Section 218.5 of the Public Utilities Code defines cogeneration to mean the sequential use of energy for the production of electrical and useful thermal energy. The sequence can be thermal use followed by power production or the reverse, as long as: a) at least five percent of the facility's total annual energy output shall be in the form of useful thermal energy; b) where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output equals not less than 42.5 percent of any natural gas and oil energy input.

some contemplated act on the part of the indemnitor, or from some responsibility assumed by the indemnitee, or from the claim or demand of a third person, that is, to make good to him such pecuniary damage as he may suffer.[5] The issue of which parties, if any, are indemnified in an interconnection agreement was one of the more controversial issues addressed by the working groups. In general, three indemnification alternatives exist: mutual, unilateral, and none.

Under an agreement with mutual indemnity language, each party is held harmless from any damages, losses, and liabilities resulting from the other party's performance under the contract, except in the case of gross negligence or intentional misconduct. Unilateral indemnity extends the same protections from one party to the actions of the second party, but does not apply in reverse. A third alternative, no indemnity, eliminates the need for an indemnity clause in the agreement.

A wide range of viewpoints were expressed on this issue. From the utility perspective, unilateral indemnity is appropriate for several reasons. The main justification is that the activities of the Electricity Producer expose the utility and its ratepayers to additional risks and liability. The utility is required to perform the activities related to interconnecting the Electricity Producer at its request for its benefit. The utilities believe that each utility and its ratepayers should be insulated from the risks that accompany utility activities in support of distributed generation, since neither the utility nor its ratepayers benefit or profit from DG. In essence, it is arguably counter to the principle of keeping the utility and its ratepayers risk neutral to potentially burden the utility and its ratepayers with an indemnity obligation (an additional liability) to the Electricity Producer.

Support for mutual indemnity was led by Honeywell with other manufacturers generally endorsing this position. The manufacturers maintain that Distributed Generation provides substantial benefits to the Electrical Corporation and its ratepayers, in direct contrast to the utility viewpoint.[6] In addition to the benefits argument, manufacturers claim that unilateral indemnity in the direction of the Electrical Corporation is unfair. In a contractual agreement, the manufacturers assert that both parties should have equal rights and representation under the law. Unilateral indemnity arguably provides preferential treatment to the Electrical Corporation. The utilities have stated in subsequent discussions that it is misleading to characterize the manufacturer proposal as mutual because the language does not provide the same protections to both parties.

It should be noted that all parties agreed that the indemnity clause should be eliminated in the event that the Commission does not accept their respective indemnity positions. The two sets of language are displayed directly below for comparison purposes. The major distinctions between the two alternatives are found by comparing Section 7.1 of the utility alternative to Sections 7.1-

[5] See Black's Law Dictionary, Abridged Fifth Edition.

[6] A recent white paper submitted by Honeywell in the CPUC's DG rulemaking delineates a series of benefits, including a deferred need to build distribution feeders and generation facilities, improved system reliability, and peak shaving opportunities for the grid. See: Skowronski, Mark. *Proposed Methodologies for Evaluating Grid Benefits of Distributed Generation*, as part of Honeywell testimony submitted in Phase I of CPUC Rulemaking, R.99-10-025.

7.4 of the manufacturer alternative. Sections 7.2 of the utility alternative and 7.5 of the manufacturer alternative are essentially the same.

<table>
<tr><th>Alternative A – Utility Position
(Unilateral Indemnity)</th><th>Alternative B – Manufacturer Position
(Mutual Indemnity)</th></tr>
<tr><td>7.1 EP shall, at all times, indemnify, defend, and save EC harmless from and against any and all damages, losses, claims (including claims and actions relating to injury to or death of any person or damage to property), demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from EC's performance of its obligations under this Agreement on EP's behalf, except in cases of EC's gross negligence or intentional wrongdoing.

7.2 If EP fails to comply with the provisions of Section 8 to provide liability insurance, EP agrees to, at EP's own cost, defend, save harmless and indemnify EC, its directors, officers, employees, and agents, assigns, and successors in interest from and against any and all loss, liability, damage, claim, cost, charge, demand, or expense of any kind or nature resulting from injury or death to any person or damage to any property, including EC's personnel or property, to the extent that EC would have been protected had EP complied with all of the provisions of Section 8. The inclusion of this Section 7.2 is not intended to create any express or implied right for EP to elect not to provide the insurance required under Section 8.</td><td>7.1 Each Party as indemnitor shall defend, save harmless and indemnify the other Party and the directors, officers, employees, and agents of such Party against and from any and all loss, liability, damage, claim, cost, charge, demand, or expense (including any reasonable fees, costs or disbursements of outside and/or inside counsel) for injury or death to persons, including employees of any Party, and damage to property including property of any Party arising out of or in connection with (a) the engineering, design, construction, maintenance, repair, operation, supervision, inspection, testing, protection or ownership of, or (b) the making of replacements, additions, betterments to, or reconstruction of, the indemnitor's facilities; provided, however, Electricity Producer's duty to indemnify EC hereunder shall not extend to loss, liability, damage, claim, cost, charge, demand, or expense resulting from interruptions in electrical service to EC's customers other than Electricity Producer. This indemnity shall apply notwithstanding the active or passive negligence of the indemnitee. However, no Party shall be indemnified hereunder for its loss, liability, damage, claim, cost, charge, demand or expense resulting from its sole negligence or willful misconduct.

7.2 Notwithstanding the indemnity of Section 7.1 and except for a Party's willful misconduct or sole negligence, each Party shall be responsible for any loss, including, but not limited to, damage to its facilities resulting from electrical disturbances or faults.

7.3 The provisions of this Section 7 shall not be construed to relieve any insurer of its obligations to pay any insurance claims in accordance with the provisions of any valid insurance policy.

7.4 Except as otherwise provided in Section 7.1, no Party shall be liable to another Party for consequential damages incurred by that Party.

7.5 If Electricity Producer fails to comply with the provisions of Section 8, Electricity Producer shall, at its own cost, defend, save harmless and indemnify EC, its directors, officers, employees, and agents, assignees, and successors in interest from and against any and all loss, liability, damage, claim, cost, charge, demand, or expense of any kind or nature (including any reasonable fees, costs or disbursements of outside and/or inside counsel), resulting from injury or death to any person or damage to any property, including the personnel or property of EC, to the extent that EC would have been protected had Electricity Producer complied with all of the provisions of Section 8. The inclusion of this Section 7.5 is not intended to create any express or implied right in Electricity Producer to elect not to provide the insurance required under Section 8.</td></tr>
</table>

Comments filed by Stakeholders and Discussion

Comments on the draft recommendation restated the same general party lines. Mutual indemnity was offered by the DG community with utility representatives offering unilateral indemnity in response.

Energy Commission Recommendation – Indemnity Issues

Given the level of impasse on this issue and the desire to have a workable standardized agreement, the Energy Commission concludes that no indemnification language be referenced in the standard interconnection agreements at this time. As mentioned above, this "fallback" position is the alternative position desired by all parties.

PG&E and SCE voiced strong opposition to a proposal to substitute a "Standard Attorney Fee" provision for indemnification language contained in the Siting Committee recommendation. SCE argues that these types of provisions do not discourage litigation, as the Siting Committee suggested, but rather "encourage litigation because they serve to incent attorneys to encourage the filing of complaints on the hope that their fees will be recovered from a deep-pocket third-party… Leaving each party responsible for its own attorney fees serves to motivate each party to avoid litigation and control litigation costs." PG&E adds that attorney fee provisions actually "discourage settlements once litigation has commenced."

Based on the justifiable concerns of PG&E and SCE, the Energy Commission has removed the "Standard Attorney Fee" provision proposed by the Siting Committee and have replaced it with the Limitation of Liability cause proposed by PG&E, with minor word changes. The recommended language reads as follows:

> **7. Limitation of Liability**
>
> Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages of any kind whatsoever.

b. Minimum Insurance Liability (Section 8)

The issue of the appropriate minimum level of liability insurance required by an Electricity Producer was debated during the summer working group meetings. The starting point for the debate was a 1983 CPUC decision (D.83-10-093) that established Interconnection requirements as well as terms and conditions for QFs connecting to the Distribution System. In that decision, the CPUC set the following minimum liability requirements based on the size of the Generating Facility: 1) $1,000,000 for QFs over 100 kW; 2) $500,000 for QFs from 21 kW -100 kW; and $100,000 for QFs 20 kW or less. In directing the utilities to require that level of insurance, the CPUC argued that "the utilities should be assured that any costs incurred by the utility resulting from liability exposure greater than $1 million shall be recovered through rates" (CPUC D.83-10-093, Section B, Discussion Paragraph 11).

Some parties during the working group meetings suggested that the minimum liability threshold is too low and should be increased no less than the rate of inflation. PG&E representatives, in speaking with their insurance department, suggested that the thresholds be raised to $5,000,000 for QFs above 100 kW, $2,000,000 for QFs between 21 kW and 100 kW, and $1,000,000 for QFs 20 kW and less. DG manufacturers argued that the minimum level remain at the same levels endorsed in the CPUC decision, at least for facilities less than 10 kW.

As a compromise to both positions, the group agreed on the appropriateness of doubling the minimum liability level for facilities greater than 20 kW. The minimum liability of facilities 20 kW and less is proposed to increase from $100,000 to $500,000 although a $200,000 minimum is allowed if the unit is less than 10 kW and connected to an account receiving residential service. The proposed language is now contained in Section 8.1 of the proposed agreement and reads as follows:

> 8.1 In connection with EP's performance of its duties and obligations under this Agreement, EP shall maintain, during the term of the Agreement, general liability insurance with a combined single limit of not less than:
>
> (a) Two million dollars ($2,000,000) for each occurrence if the Gross Nameplate Rating of EP's Generating Facility is greater than one hundred (100) kW;
>
> (b) One million dollars ($1,000,000) for each occurrence if the Gross Nameplate Rating of EP's Generating Facility is greater than twenty (20) kW and less than or equal to one hundred (100) kW; and
>
> (c) Five hundred thousand dollars ($500,000) for each occurrence if the Gross Nameplate Rating of EP's Generating Facility is twenty (20) kW or less.
>
> (d) Two hundred thousand dollars ($200,000) for each occurrence if the Gross Nameplate Rating of EP's Generating Facility is ten (10) kW or less and EP's Generating Facility is connected to an account receiving residential service from EC.
>
> Such general liability insurance shall include coverage for "Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations."

Energy Commission Recommendation – Liability Issues

We agree with the working group that some adjustment is appropriate to minimum thresholds set almost 20 years. At the same time, we do not intend to create a new barrier to market entry by requiring small DG units to pay insurance costs that are prohibitive. Similar to the approach the CPUC took in 1983 when it adopted liability minimums for QFs, we recommend some adjustment to the minimum thresholds to at least account for inflation. Assuming three percent inflation on average since 1983, the total increase would be 65 percent (1.03^17). As such, it seems appropriate to double the minimum thresholds for larger scale facilities. For smaller ones, increasing the minimum threshold to $200,000 is not unreasonable compared to the levels of liability insurance held by homeowners. Although there is no legal requirement for homeowner's insurance in California, most lenders will not make home loans unless the home buyer holds a minimum of $100,000 of coverage.[7] As such, the working group recommendations are acceptable.

PG&E Suggested Changes to the Interconnection Agreement

PG&E requested one additional change with respect to Section 10 of the agreement that specifies some of the information that is required to be kept in a generator log. The present language is contained in Section D.4 of its existing Rule 21 and reads as follows:

> The Producer shall at all times keep and maintain a detailed generator operations log. Such log shall include, but not be limited to, information on unit availability, maintenance outages, circuit breaker trip operations requiring manual reset and unusual events. PG&E shall have the right to review the Producer's log.

PG&E believes that revising Section 10 of the Interconnection Agreement to read as follows is appropriate to capture this existing provision:

> REVIEW OF RECORDS AND DATA
>
> EC shall have the right to review and obtain copies of EP's operations and maintenance records, logs, or other information such as, unit availability, maintenance outages, circuit breaker operation requiring manual reset, relay targets and unusual events pertaining to EP's Generating Facility or its interconnection with EC's Distribution System.

Energy Commission Recommendation – PG&E Requested Addition to Section 10

We are comfortable with PG&E's proposal to modify Section 10 as it provides specific definition to some of the information contained in the generator log. Section 10 of the proposed agreement will be adjusted accordingly.

Interconnection Application Form

Equally important to the success of the revised Rule 21 effort is the development of a comprehensive and user-friendly Application form. The Application form is in essence the interface through which an Applicant interacts with the utilities by formally requesting the Interconnection and providing necessary information to process the request. Much effort was spent ensuring that the Application did not ask for the same information in different sections of the Application form. In its proposed form, the Application holds a place for all the information necessary for the simplest to the most complex Distribution System Interconnection.[8]

[7] Insurance Information Institute, August 2000, Jeanne Salvatore, private conversation with Cris Cooley.

[8] Although the Application contains all information that will be required under normal circumstances, the EC reserves the right to ask for more information in cases where the DG requires a detailed study.

The Application includes three parts and appears to be quite complex at first order. Part 1 requires general information from every Applicant. Part 2 calls for information associated with non-certified DG systems or system components. Part 3 provides questions pertaining only to the Electrical Corporation's internal review and is never visible to the Applicant.

The process for completing the Application works in the following manner. The Applicant first completes Parts 1 and 2, although the latter will not need to be completed if the Generating Facility is certified. Next, the Applicant sends the Application along with the required Application fee to the Electrical Corporation for evaluation. Upon review, the Electrical Corporation will either 1) approve the Application as a Simplified Interconnection or a non-simplified interconnection; 2) reject the Application as incomplete, or 3) provide a cost estimate for a detailed Interconnection Study.

If the Application is approved, the information in the Application is used to fill out the Interconnection Agreement. If and when the Applicant approves the terms of the Agreement, the DG installation can proceed. The Electrical Corporation will log the information from the Application for its own internal purposes.

Discussion about the Application form focused on tradeoffs between keeping the Application simple and providing enough technical detail to simplify the evaluation from a Application reviewer's perspective. Manufacturers remain concerned that the form could make things difficult for the DG community by complicating the application that once was viewed as a relatively simple process. The vision of the group early in the process called for a two-page document with the intent of not complicating documents and establishing unnecessary or unreasonable fees. Others have argued that the extensive amount of information required on the Application is designed to ensure that the applicant understands what information is required to process the Application and the EC does not have to hunt the information down. The group generally agreed that in order to minimize the cost of the Application review, it was a more cost effective option for the applicant to supply the information.

Comments filed by Stakeholders and Discussion

CAC/EPUC suggested at the September Siting Committee hearing and in its comments to eliminate the following text from Section 3.1.1 of the application: "You must execute a Service Agreement under the EC's Wholesale Distribution Access Tariff (WDAT) filed with the Federal Energy Regulatory Commission." The Energy Commission agrees with this suggestion.

SDG&E raised two comments regarding Section 7 of the application form. Regarding Section 7.1, the utility believes that a DG applicant may not know whether a proposed system is connected to the distribution system through a transformer shared by other customers. The suggested addition to the Section is the following: "It may be necessary to contact the Electrical Corporation to obtain this information." In the Energy Commission's opinion, the SDG&E recommendation on Section 7.1 adds clarity to the application form and should be incorporated into the final application form.

In Section 7.2, SDG&E suggests removing the word "other" from the following question contained in the application form: "What is the interruptible rating of the other customer's service panel?" We do not agree to the SDG&E changes at this time. For shared systems, it is important to determine the interrupt rating of the other customers on a shared system to determine how much current can go through the breakers and operate properly.

Energy Commission Recommendation – Application Form

We remain concerned about whether the level of detail in an application form will create a barrier to market entry. Clearly, reviewing each section of the application form requires a wealth of technical competence that most parties cannot be expected to fully understand. On the other hand, we recognize that much of the information is required in order for the Electrical Corporation to promptly evaluate an application.

With the modifications addressed in the previous section, we are willing to endorse the proposed application form. We look to the working group in subsequent meetings to carefully monitor the use of the form and be ready to report back to the Energy Commission if additional changes are required. We also endorse the development of an electronic application form although place no timeframe on the completion of that work product.

Miscellaneous Issues Raised at June 14th Business Meeting

Section 3.1.9 of the proposed rule language focuses on a process whereby an Electrical Producer may opt to have an Electrical Corporation reconcile any advance payments it made to an Electrical Corporation based on the actual cost of completing the Interconnection. Under the proposed rule language, an Electrical Producer can agree to either: 1) a fixed cost calculation with no reconciliation once the work is complete; or 2) actual cost billing, with a cost reconciliation performed by the Electrical Corporation.

In comments submitted earlier this year, PG&E argued that the costs of conducting a cost reconciliation "can be a sizeable fraction of the study cost. Smaller units (under 1 MW) should pay an estimated cost without true-up." As such, the Electrical Corporation requests further consideration of this issue by the Energy Commission.

In addressing the issue during the summer working group meetings, additional clarification was provided regarding the intent of Section 3.1.9. As a result, PG&E withdrew its concerns and no longer requests future consideration of this issue.

Responses to Other Comments on Draft Report

In addition to the above recommendations, parties provided one additional suggestion to improve or clarify certain elements of the proposed Rule 21 language. The following provides a brief summary of the issue raised and the action recommended by the Energy Commission.

Section 6.3 (Net Generation Metering)

In its comments, Edison raised a concern about Section 6.3 which calls for the Electrical Corporation to "report to the CPUC on a quarterly basis, the rationale for requiring net generation equipment in each instance along with the size and location of the facility." Edison claims that the reporting requirement is burdensome and is the same for each installation: to require "an accurate means of measuring generator output."

We reject the Edison request for three specific reasons. First, in the early stages of monitoring market development and the effectiveness of Rule 21, more information for evaluation purposes is preferred to less. Furthermore, the reporting requirement will clearly be revisited and could be modified. As Section 6.6 indicates, the provisions of Section 6.3 are interim and sunset at the end of 2002. Second, it is not clear that the rationale for requiring net generation metering is the same in all cases. In Section 6.3, for example, specific language references seven factors for requiring Net Generation metering. Even if Edison believes that providing an accurate means of measuring generator output is the only reason it would consider as justification, that reason was not voiced by PG&E or SDG&E. Lastly, discussion of net generation metering was held during the initial work leading to the initial recommendation and the working group activity during the development of the supplemental work did not focus on this issue. As such, no party was made aware of Edison's concern until the filing was made.

We restate our concern from the initial report that the Electrical Corporation retains considerable discretion regarding whether net generation metering and telemetering equipment is required. There must be a mechanism in place to track how these provisions are being applied, especially in the early stages of using new Rule 21 language.

Forum for Additional Work

Once the supplemental rules are adopted by the Energy Commission and forwarded to the CPUC, the future role of the Energy Commission with respect to interconnection rule shifts to the post-implementation phase. The Energy Commission offers a unique opportunity to ensure that Rule 21 best serves the California market in the future. In doing so, the Siting Committee is prepared to recommend that the Energy Commission oversee a working group process similar to the Rule 22 Direct Access working group to review future changes to the rule. We are willing to lead that process under the direction of the Committee. Once the CPUC issues a decision adopting Rule 21 tariff language, the Energy Commission will open a new proceeding as a home for addressing issues and recommending change.

The Energy Commission also expects to play an outreach role throughout the state to further increase the likelihood of statewide, standardized rules. We expect to work with municipalities, irrigation districts, and local governments to adopt Rule 21-type rules that could further encourage standardized interconnection rules across the entire state.

In its desire to remove market barriers, the Energy Commission is prepared to become the central point of reference for stakeholders participating in the Distributed Generation industry. We expect to provide detailed information about Distributed Generation on our website, support the information needs of parties submitting and reviewing Interconnection Application requests, seeking information on permitting, seeking standardized contracts, as well as other things not yet defined. The Siting Committee will oversee the development of these details and coordinate efforts to ensure consistency with CPUC regulations adopted in R.99-10-025.

III. Next Steps

The next step in this proceeding is for the CPUC to receive this recommendation, which will occur around November 1st. CPUC Administrative Law Judge Cooke will then prepare a proposed decision for CPUC consideration.

Attachment A - Full Text of Proposed Rule 21 Tariff Language

(Including Formal Recommendations Adopted by the Energy Commission in June 2000)

1. APPLICABILITY AND INTRODUCTION

1.1 **Applicability.** This Rule describes the interconnection, operating and metering requirements for Generating Facilities that are intended to be connected to the Distribution System over which the California Public Utilities Commission (CPUC) has jurisdiction. Subject to the requirements of this Rule, Electrical Corporation will allow the interconnection of Generating Facilities with its Distribution System.

1.2 **Definitions.** Capitalized terms used in this Rule, and not otherwise defined, shall have the meaning ascribed to such terms in Section 8.

1.3 **Enabling Documents.** It is contemplated that the Applicant will be required to execute various enabling documents, such as the Application and Interconnection Agreement. Such documents shall be in the form on file with the CPUC, as may be amended from time to time.

2. GENERAL RULES, RIGHTS AND OBLIGATIONS

2.1 **Authorization Required to Interconnect.** An Electricity Producer must comply with this Rule, form an Interconnection Agreement with Electrical Corporation, and receive Electrical Corporation's express written permission to interconnect before connecting or operating a Generating Facility in parallel with the Electrical Corporation's Distribution System. Electrical Corporation shall apply this Rule in a non-discriminatory manner and shall not unreasonably withhold its permission to interconnect an Electric Producer's Generating Facility.

2.2 **Separate Arrangements Required for Other Services.** An Electricity Producer requiring other electric services from the Electrical Corporation including, but not limited to, Distribution Service provided by the Electrical Corporation during periods of curtailment or interruption of a Generating Facility, must enter into separate arrangements with Electrical Corporation for such services in accordance with CPUC-approved tariffs.

2.3 **Transmission Service Not Provided with Interconnection.** Interconnection with the Electrical Corporation's Distribution System under this Rule does not provide an Electricity

Producer any rights to utilize Electrical Corporation's Distribution System for the transmission or distribution of electric power, nor does it limit those rights.

2.4 **Compliance with Laws, Rules, and Tariffs.** An Electricity Producer shall ascertain and comply with applicable CPUC-approved rules, tariffs, and regulations of the Electrical Corporation; applicable FERC-approved rules, tariffs, and regulations; and any local, state or federal law, statute or regulation which applies to the design, siting, construction, installation, operation, or any other aspect of the Electricity Producer's Generating Facility and Interconnection Facilities.

2.5 **Design Reviews and Inspections.** Electrical Corporation shall have the right to review the design of an Electricity Producer's Generating Facility and Interconnection Facilities and to inspect an Electricity Producer's Generating and/or Interconnection Facilities prior to the commencement of Parallel Operation with Electrical Corporation's Distribution System. Electrical Corporation may require an Electricity Producer to make modifications as necessary to comply with the requirements of this Rule. Electrical Corporation's review and authorization for Parallel Operation shall not be construed as confirming or endorsing the Electricity Producer's design or as warranting the Generating and/or Interconnection Facility's safety, durability or reliability. Electrical Corporation shall not, by reason of such review or lack of review, be responsible for the strength, adequacy, or capacity of such equipment.

2.6 **Right to Access.** An Electricity Producer's Generating Facilities and Interconnection Facilities shall be reasonably accessible to Electrical Corporation personnel as necessary for Electrical Corporation to perform its duties and exercise its rights under its tariffs and rules filed with and approved by the CPUC, and any agreement between Electrical Corporation and the Electricity Producer.

2.7 **Confidentiality of Information.** Any information pertaining to Generating and/or Interconnection Facilities provided to an Electrical Corporation by an Electricity Producer shall be treated by Electrical Corporation in a confidential manner. Electrical Corporation shall not use or disclose information provided by an Applicant, nor propose discounted tariffs based on that information.

2.8 **Prudent Operation and Maintenance Required.** An Electricity Producer shall operate and maintain its Generating Facility and Interconnection Facilities in accordance with Prudent Electrical Practices and shall maintain compliance with CPUC adopted standards for the Electricity Producer's particular Generation and Interconnection Facilities. Said standards shall be those in effect at the time an Electricity Producer executes an Interconnection Agreement with Electrical Corporation.

2.9 **Curtailment and Disconnection.** Electrical Corporation may limit the operation and/or disconnect or require the disconnection of an Electricity Producer's Generating Facility from Electrical Corporation's Distribution System at any time, with or without notice, in the event of an Emergency, or to correct Unsafe Operating Conditions. Electrical Corporation may also limit the operation and/or disconnect or require the disconnection of an Electricity Producer's Generating Facility from Electrical Corporation's Distribution System upon the provision of reasonable notice: 1) to allow for routine maintenance, repairs or modifications to Electrical Corporation's Distribution System; 2) upon Electrical Corporation's determination that an Electricity Producer's Generating Facility is not in compliance with this Rule; or, 3) upon termination of the Interconnection Agreement.

3. APPLICATION AND INTERCONNECTION PROCESS

3.1 Application Process

3.1.1 **Applicant Initiates Contact with the Electrical Corporation.** Upon request, the Electrical Corporation will provide information and documents (such as an application form, contract and technical requirements, specifications, listing of Certified Equipment, application fee information, applicable rate schedules and metering requirements) in response to the potential Applicant's inquiry. Unless otherwise agreed upon, all such information and a copy of the Electrical Corporation's standardized interconnection requirements shall normally be sent to the Applicant within three (3) business days following the initial request from the Applicant. The Electrical Corporation will establish an individual representative as the single point of contact for the Applicant, but may allocate responsibilities among its staff to best coordinate the Interconnection of a Applicant's Generating Facility.

3.1.2 **Applicant Completes an Application Document.** All Applicants shall be required to complete and file an Application document and supply any additional information requested by the Electrical Corporation. The filing must include the completed standardized Application, which may be either in paper or electronic form, and a fee for processing the application and performing the Initial Review to be completed by the Electrical Corporation pursuant to Section 3.1.3. The application fee shall~~be non-refundable and shall~~ vary with the nature of the proposed Generating Facility as follows:

Type of Generating Facility	Initial Review	Supplemental Review
Net Energy Metering *(per Public Utilities Code Section 2827)*	None	None

All others	$800	$600
	~~$(Fixed; amount TBD)~~	

Note: Allocation of cost between DG Applicant and Electrical Corporation to be determined by CPUC in Phase 2 of R.99-10-025. The total cost borne by the Applicant should be reduced by the cost allocated to the utility's distribution function.

Fifty percent of the fees associated with the Initial Review will be returned to the Applicant if the application is rejected by the utility or the Applicant retracts the application.

The Applicant may propose and the Electrical Corporation may negotiate specific costs for processing non-standard installations such as multi-units, multi-sites, or otherwise as conditions warrant. The costs for the Initial Review and the Supplemental Review contained in this Section, as well as the language provided in Sections 3.1.3 and 3.1.4 do not apply under these circumstances.

Within ten (10) business days of receiving an Application, the Electrical Corporation shall normally acknowledge its receipt and whether the Application has been completed adequately. If defects are noted, the Electrical Corporation and Applicant shall cooperate in a timely manner to establish a satisfactory Application.

3.1.3 **Electrical Corporation Performs an Initial Review and Develops Preliminary Cost Estimates and Interconnection Requirements.**

3.1.3.1 Upon receipt of a satisfactorily completed Application and any additional information necessary to evaluate the Interconnection of a Generating Facility, the Electrical Corporation shall perform an Initial Review using the process defined in Appendix A. The Initial Review determines if the Application qualifies for Simplified Interconnection, if the Application can qualify for Interconnection subject to additional requirements, or if it will be necessary for Electrical Corporation to perform an Interconnection Study to determine Interconnection Requirements.

3.1.3.2 The Electrical Corporation shall complete its Initial Review, absent any extraordinary circumstances, within 10 business days if the Application qualifies for Simplified Interconnection. If the Initial Review determines that the proposed facility can be interconnected by means of a Simplified Interconnection, the Electrical Corporation will provide the Applicant with a written description of the requirements for interconnection and a draft Interconnection Agreement pursuant to Section 3.1.5.

3.1.3.3 If the Application does not qualify for Simplified Interconnection as submitted, the Initial Review will include a Supplemental Review as described in Appendix A. The Supplemental Review provides either (a) Interconnection Requirements that may include requirements beyond those for Simple Interconnection, and a draft Interconnection Agreement, or (b) a cost estimate and schedule for an Interconnection Study. The supplemental review shall be completed, absent any extraordinary circumstances, within 20 business days of receipt of a completed Application. Payment for the Supplemental Review shall be submitted to the Electrical Corporation within 10 calendar days after the results of the Supplemental Review are provided to the Applicant.

3.1.4. **When Required, Applicant and Electrical Corporation Commit to Additional Interconnection Study Steps.** When an Initial Review reveals that the proposed facility cannot be interconnected to the Electrical Corporation's system by means of a Simplified Interconnection pursuant to Section 4 and Appendix B, and that significant Electrical Corporation Interconnection Facilities or Distribution System Improvements must be installed or made to the Electrical Corporation's electric system to accommodate the interconnection of an Applicant's G~~g~~enerating F~~f~~acility, the Electrical Corporation and Applicant shall enter into an agreement that provides for the Electrical Corporation to perform such additional studies, facility design, and engineering and to provide detailed cost estimates for fixed price or actual cost billing, to the Applicant at the Applicant's expense. The Interconnection Study Agreement shall set forth the Electrical Corporation's schedule for completing such work and the estimated or fixed price costs of such studies and engineering. Upon completion of an Interconnection Study, the Electrical Corporation shall provide the Applicant with the specific requirements, costs and schedule for interconnecting the Generating Facility to accommodate execution of agreements pursuant to Section 3.1.5.

3.1.5 **Applicant and Electrical Corporation Enter Into a Generation Interconnection Agreement and, Where Required, a Financing and Ownership Agreement for Interconnection Facilities or Electric System Modifications.** The Electrical Corporation shall provide the Applicant with an executable version of the Interconnection Agreement, Net Energy Metering Agreement, or Power Purchase

Agreement appropriate for the Applicant's Generating Facility and desired mode of operation. Where the Initial Review or Interconnection Study performed by the Electrical Corporation has determined that modifications or additions are required to be made to its Electric System, or that additional metering, monitoring, or protection devices will be necessary to accommodate a Applicant's Generating Facility, the Electrical Corporation shall also provide the Applicant with an Interconnection Facilities Financing and Ownership Agreement (IFFOA). The IFFOA shall set forth the respective parties' responsibilities, completion schedules, and estimated or fixed price costs for the required work.

3.1.6 **Electricity Producer Installs or Constructs the Generating Facility; Where Applicable, Electrical Corporation or Electricity Producer Installs Required Interconnection Facilities or Modifies Electrical Corporation's Electric System.** After executing the appropriate Generation Interconnection or Power Purchase Agreement, and where required, the IFFOA, the Electricity Producer may install or construct its Generating Facility in accordance with the provisions of this rule and the terms of the specific agreements formed between the Electricity Producer and the Electrical Corporation. Where appropriate, the Electrical Corporation will commence construction/installation of the system modifications and/or metering and monitoring requirements identified in the IFFOA. The parties will use good faith efforts to meet the schedules and fixed costs or estimated costs in the IFFOA.

3.1.7 **Electricity Producer Arranges for and Completes Testing of Generating Facility and, Where Applicable, Electricity Producer Installed Interconnection Facilities.** New Generating Facilities and associated Interconnection Facilities must be tested to ensure compliance with the safety and reliability provisions of the CPUC-approved rules and regulations prior to being operated in parallel with the Electrical Corporation's electric system. Certified Equipment will be subject to the tests specified in Section 4. For non-Certified Equipment, the Electricity Producer will develop a written testing plan to be submitted to the Electrical Corporation for its review and acceptance. Alternatively, the Electricity Producer and Electrical Corporation may agree to have the Electrical Corporation conduct the required testing at the Electricity Producer's expense. Where applicable, the test plan shall include the installation test procedure(s) published by the manufacturer(s) of the generation or interconnection equipment. Facility testing shall be conducted at a mutually agreeable time, and depending on who conducts the tests, the Electrical Corporation or Electricity Producer shall be given the opportunity to witness the tests.

3.1.8 **Electrical Corporation Authorizes Interconnection.** The Electricity Producer's Generating Facility shall be allowed to commence parallel operation with the Electrical Corporation's electric system upon satisfactory compliance with the terms of the Generation Interconnection Agreement, Power Purchase Agreement or Net Energy Metering Agreement. Compliance may include, but not be limited to, provision of any required documentation and satisfactorily completing any required inspections or tests as described herein or in the agreements formed between the Electricity Producer and the Electrical Corporation. An Electricity Producer shall not interconnect a Generating Facility unless it has received the Electrical Corporation's express written permission to do so.

3.1.9 **Electrical Corporation Reconciles Costs and Payments.** If the Electricity Producer selected a fixed price cost for the Interconnection Facilities or Electric System Modifications, no reconciliation will be necessary. If the Electricity Producer selected actual cost billing, a true-up will be required. Within a reasonable time after the interconnection of a Electricity Producer's Generating Facility, the Electrical Corporation will reconcile its actual costs related to the Electricity Producer's facility against the application fee and any other advance payments made by the Electricity Producer. The Electricity Producer will receive either a bill for any balance due or a reimbursement for overpayment as determined by the Electrical Corporation's reconciliation. The Electricity Producer shall be entitled to a reasonably detailed and understandable report detailing the Electrical Corporation's reconciliation process.

4. GENERATING FACILITY DESIGN AND OPERATING REQUIREMENTS

4.1 General Interconnection and protection requirements

4.1.1 Protective Functions shall be equipped with automatic means to prevent the Generating Facility from re-energizing a de-energized Distribution System circuit.

4.1.2 The Protective Functions of a Generating Facility must include an over/under voltage trip function, an over/under frequency trip function, and a means for disconnecting the DG from the EC when a protective function initiates a trip.

~~4.1.2~~4.1.3 The Generating Facility and associated Protective Functions shall not contribute to the formation of an Unintended Island.

~~4.1.3~~4.1.4 The Electricity Producer's protection and control diagrams for the interconnection shall be approved by the Electrical Corporation prior to completion of the Generating Facility Interconnection, unless the Electricity Producer uses a protection and control scheme previously approved by the Electrical Corporation for system-wide application or uses only Certified Equipment.

~~4.1.4~~4.1.5 Protective Functions shall be equipped with automatic means to prevent reconnection of the Generating Facility with the Distribution System unless the Distribution System service voltage and frequency is of specified settings and is stable for 60 seconds.

~~4.1.5~~4.1.6 Certified Equipment contains certified functions that are accepted by all California Electrical Corporations. This equipment may be installed on a Distribution System in accordance with an Interconnection control and protection scheme approved by the Electrical Corporation.

~~4.1.6~~4.1.7 These requirements are designed to protect the Electrical Corporation's Distribution System and not the Generating Facility. An Electricity Producer shall be solely responsible for providing adequate protection for the Electricity Producer's Generating Facility and Interconnection Facilities connected to the Electrical Corporation's Distribution System. The Electricity Producer's protective equipment shall not impact the operation of other protective devices utilized on the Distribution System in a manner that would affect the Electrical Corporation's capability of providing reliable service to Customers.

~~4.1.7~~4.1.8 Circuit breakers or other interrupting devices at the Point of Common Coupling must be Certified or "Listed" (as defined in Article 100, the Definitions Section of the National Electrical Code) as suitable for the application. This includes being capable of interrupting maximum available fault current. The Generating Facility shall be designed so that the failure of any one device shall not potentially compromise the safety and reliability of the Distribution System.

~~4.1.8~~4.1.9 The Electricity Producer will furnish and install a manual disconnect device that has a visual break to isolate the Generating Facility from the Distribution System. The device must be accessible to Electrical Corporation personnel and be capable of being locked in the open position. Generating Facilities with non-islanding inverters totaling 1kVA or less are exempt from this provision.

4.1.10 This section is not intended to address the requirements for generators that parallel momentarily or generators that operate independently of the Electrical Corporation.

4.2 **Prevention of interference.** The Electricity Producer shall not operate equipment that superimposes upon the Distribution System a voltage or current that interferes with Electrical Corporation operations, service to Electrical Corporation customers, or Electrical Corporation communication facilities. If such interference occurs, the Electricity Producer must diligently pursue and take corrective action at its own expense after being given notice and reasonable time to do so by the Electrical Corporation. If the Electricity

Producer does not take timely corrective action, or continues to operate the equipment causing interference without restriction or limit, the Electrical Corporation may, without liability, disconnect the Electricity Producer's equipment from the Distribution System, in accordance with Section 2.9 of this rule.

To eliminate undesirable interference caused by operation of the Generating Facility, each Distributed Generator in a Generating Facility shall meet the following criteria:

4.2.1 **Normal voltage operating range.** The voltage operating range for Distributed Generators shall be selected as a protection function that responds to abnormal Distribution System conditions and not as a voltage regulation function.

4.2.1.1 **Small systems (11 kVA or less).** Distributed Generator systems of 11 kVA capacity or less shall be capable of operating within the limits normally experienced on the Distribution System. The operating window shall be selected in a manner that minimizes nuisance tripping and range between 106 volts and 132 volts (88-110% of nominal voltage) on a 120-volt base. Generating Facilities shall cease to energize the Electrical Corporation lines whenever the voltage at the PCC deviates from the allowable voltage operating range.

4.2.1.2 **Systems larger than 11 kVA.** Electrical Corporations may have specific operating voltage ranges for larger Distributed Generator units, and may require adjustable operating voltage settings for these larger systems. In the absence of such requirements, the above principles of operating between 88% and 110% of the appropriate interconnection voltage should be followed.

4.2.1.3 **Voltage Disturbances.** System voltage assumes a nominal 120 V base. For the convenience of those wishing to translate these guidelines to voltage bases other than 120 volts, the limits will also be provided as approximate percentages. The Distributed Generator should sense abnormal voltage and respond. The following conditions should be met, with voltages in RMS ~~and measured~~ at the Point of Common Coupling:

Voltage at Point of Common Coupling	Maximum Trip Time (Assuming 60 Cycles per Second)
Less than 60 Volts	**10 Cycles**
Greater than 60 volts but less than 106 volts	**120 Cycles**
Greater than 106 volts but less than 132 volts	**Normal Operation**

Greater than 132 volts but less than 165 volts	**120 Cycles (30 cycles for facilities greater than 11kVA)**
Greater than 165 volts	**6 Cycles**

***"Trip time" refers to the time between the abnormal condition being applied and the Distributed Generator unit ceasing to energize the Distribution System. Certain circuits will actually remain connected to the Distribution System to allow sensing of electrical conditions for use by the "reconnect" feature. The purpose of the allowed time delay is to ride through short-term disturbances to avoid excessive nuisance tripping. For systems of 11 kVA peak capacity or less, the above set points are to be non-user adjustable. For Distributed Generator units larger than 11 kVA, different voltage set points and trip times from those in Table 4.1 may be negotiated with the interconnecting Electrical Corporation.*

4.2.2 **Flicker.** Any voltage flicker at the Point of Common Coupling caused by the Generating Facility should not exceed the limits defined by the "Maximum Borderline of Irritation Curve" identified in IEEE 519 (*IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems*, IEEE STD 519-1992, Institute of Electrical and Electronic Engineers, Piscataway, NJ. April 1992. This requirement is necessary to minimize the adverse voltage effects to other customers on the Distribution System. Induction generators may be connected and brought up to synchronous speed (as an induction motor) provided these flicker limits are not exceeded.

4.2.3 **Frequency.** The Electrical Corporation controls system frequency, and the Distributed Generator unit shall operate in synchronism with the Distribution System. Small Distributed Generators should have a fixed operating frequency range of 59.3-60.5 Hertz. The DG must cease to energize the system in a maximum of ten cycles should the EC remain outside of the frequency limits. The purpose of the time delay is to allow the DG to ride through short-term disturbances to avoid excessive nuisance tripping. Electrical Corporations may require adjustable operating frequency settings for systems larger than 11 kVA to assist the system during serious capacity shortages. ~~For systems larger than 11 kVA, low frequency settings of 59.3 Hz and 58.0 Hz may be used with the consent of the Electrical Corporation.~~

4.2.4 **Harmonics.** Harmonic distortion shall be in compliance with IEEE 519. Exception: The harmonic distortion of a Distributed Generator at a Customer's site shall be evaluated using the same criteria as the loads at that site.

4.2.5 **Direct Current Injection.** The Distributed Generator should not inject Direct Current greater than 0.5% of rated output current into the Distribution System under either normal or abnormal operating conditions.

4.2.6 **Power Factor.** Each Distributed Generator in a Generating Facility shall be capable of operating at some point within a range of a power factor of 0.9 (either leading or lagging). Operation outside this range is acceptable provided the reactive power of the Generating Facility is used to meet the reactive power needs of on-site loads or that reactive power is otherwise provided under tariff by the Electrical Corporation. The Electricity Producer shall notify the Electrical Corporation if it is using the Generating Facility for power factor correction.

4.3 Control, protection and safety equipment requirements

~~4.3.1 Basic Requirements~~

~~4.3.1.1 **Protective function requirements.** The Protective Functions of a Generating Facility must include a visual open disconnect device (except as exempted in Section 4.1.8), a fault-interrupting device, an over/under voltage trip function, and an over/under frequency trip function.~~

~~4.3.1.2~~4.3.1 **Limits specific to single-phase generators** For single-phase generators connected to a shared single-phase secondary, the maximum capacity shall be 20 kVA. Distributed Generators applied on a center-tap neutral 240-volt service must be installed such that no more than 6 kVA of imbalance in capacity exists between the two sides of the 240-volt service. For dedicated distribution transformer services, the limit of a single-phase Distributed Generator shall be the transformer nameplate rating.

4.3.2 Technology Specific Requirements

4.3.2.1 **Three-phase synchronous generators.** The Distributed Generator circuit breakers shall be three-phase devices with electronic or electromechanical control. The Electricity Producer shall be responsible for properly synchronizing its Generating Facility with the Distribution System by means of either a manual or automatic synchronizing function. Automatic synchronizing is required for all synchronous generators, which have a Short Circuit Contribution Ratio (SCCR) exceeding 0.05. A Generating Facility whose SCCR exceeds 0.05 shall be equipped with Protective Functions suitable for detecting loss of synchronism and rapidly disconnecting the Generating Facility from the Distribution System. Unless otherwise agreed to between the Electricity Producer and the Electrical Corporation, synchronous generators shall automatically regulate power factor, not voltage, while operating in parallel with the Distribution System. Power system stabilization is specifically not required for Generating Facilities under 10 MW.

Synchronization: At the time of connection, the frequency difference shall be less than 0.2 Hz, the voltage difference shall be less than 10%, and the phase angle difference shall be less than 10 degrees.

4.3.2.2 **Induction Generators.** Induction Generators do not require separate synchronizing equipment. Starting or rapid load fluctuations on induction generators can adversely impact the Distribution System's voltage. Corrective step-switched capacitors or other techniques may be necessary and may cause undesirable ferroresonance. When these counter measures (e.g. additional capacitors) are installed on the Electricity Producer's side of the Point of Common Coupling, the Electrical Corporation must review these measures. Additional equipment may be required to resolve this problem as a result of an Interconnection Study.

4.3.2.3 **Inverter Systems.** Utility-interactive inverters do not require separate synchronizing equipment. Non-utility-interactive stand-alone inverters shall not be used for parallel operation with the Distribution System.

4.3.3 Initial Review process

Appendix A of this Rule defines the Initial Review process. The Initial Review process evaluates the specific characteristics of the Interconnection, including those specific to the location of the Generating Facility, and whether additional requirements are necessary.

4.3.4 Supplemental DG Requirements

4.3.4.1 **Unintended Islanding For DG that fail the Export Screen.** Generating Facilities must mitigate their potential contribution to an Unintended Island. This can be accomplished by one of the following options:

(1) incorporating certified non-islanding control functions into the Protective Functions, or

(2) verifying that local loads sufficiently exceed the load carrying capability of the Generating Facility, or

(3) transfer trip or equivalent function.

4.3.4.2 **Fault Detection.** A Generating Facility with an SCCR exceeding 0.1 or that does not meet any one of the options for detecting Unintended Islands in 4.4.4.1 shall be equipped with Protective Functions designed to detect Distribution System faults, both line-to-line and line-to-ground, and promptly remove the Generating Facility from the Distribution System in the event of a fault. For a Generating Facility that cannot detect these faults within two seconds, transfer trip or equivalent function may be required. Reclose-blocking of the Electrical Corporation's affected recloser(s) may also be required by the Electrical Corporation for generators that exceed 15% of the peak load on the Line Section.

4.3.5 **Generating Facility types and conditions not identified.** In the event that Section 4 of this rule does not address the interconnection requirements of a Generating Facility, the Electrical Corporation and Electricity Producer may interconnect a Generating Facility using mutually agreed upon technical requirements.

5. INTERCONNECTION FACILITY OWNERSHIP AND FINANCING

5.1 Scope and Ownership of Interconnection Facilities

5.1.1 **Scope.** The interconnection of an Electricity Producer's Generating Facility with Electrical Corporation's Distribution System is made through the use of Interconnection Facilities. Such interconnection may also require Distribution System Improvements. The nature, extent and costs of Interconnection Facilities and Distribution System Improvements shall be consistent with this Rule and determined through the Initial Review and/or Interconnection Studies described in Section 3.

5.1.2 **Ownership.** Subject to the limitations set forth in this Rule, Interconnection Facilities which may be installed on Electricity Producer's side of the Point of Common Coupling may be owned, operated and maintained by the Electricity Producer or Electrical Corporation. Interconnection Facilities installed on Electrical Corporation's side of the Point of Common Coupling and Distribution System Improvements may be owned operated and maintained only by Electrical Corporation.

5.2 Responsibility for Costs of Interconnecting a Generating Facility

5.2.1 **Study and Review Costs.** An Electricity Producer shall be responsible for the reasonably incurred costs of the Initial Review and any Interconnection Studies conducted pursuant to Section 3.2 of this Rule solely to explore the feasibility and determine the requirements of interconnecting a Generating Facility with Electric Corporation's Distribution System.

5.2.2 **Facility Costs.** An Electricity Producer shall be responsible for all costs associated with Interconnection Facilities owned by the Electricity Producer. The Electricity Producer shall also be responsible for any costs reasonably incurred by Electrical Corporation in providing, operating, or maintaining Interconnection Facilities and Distribution System Improvements required solely for the interconnection of the Electricity Producer's Generating Facility with Electrical Corporation's Distribution System.

5.2.3 **Separation of Costs.** Should Electrical Corporation combine the installation of Interconnection Facilities, or Distribution System Improvements with modifications or additions to the Electrical Corporation's Distribution System to serve other Customers or Electricity Producers, Electricity Corporation shall not include the costs of such separate or incremental facilities in the amounts billed to the Electricity Producer for the Interconnection Facilities or Distribution System Improvements required pursuant to this Rule.

5.3 Installation and Financing of Interconnection Facilities Owned and Operated by Electrical Corporation

5.3.1 **Agreement Required.** Costs for Special Facilities shall be paid by Electricity Producer pursuant to the provisions contained in the Interconnection Agreement or, where the nature and extent of the Interconnection Facilities and Distribution System Improvements warrant additional detail, in a separate Interconnection Facility Financing and Operating Agreement between the Electricity Producer and Electrical Corporation, and Electrical Corporation's applicable tariffs and rules for Special Facilities.

5.3.2 **Attachments and Modifications to Distribution System.** Except as provided for in Section 5.3.3 of this Rule, Interconnection Facilities connected directly to Electrical Corporation's Distribution System and Distribution System Improvements shall be provided, installed, owned and maintained by Electrical Corporation as Special Facilities.

5.3.3 **Third-Party Installations.** Subject to the approval of Electrical Corporation, an Electricity Producer may, at its option, employ a qualified contractor to provide and install Interconnection Facilities or Distribution System Improvements to be owned and operated by Electrical Corporation. Such Interconnection Facilities and Distribution System Improvements shall be installed in accordance with Electrical Corporation's design and specifications. Upon final inspection and acceptance by Electrical Corporation, the Electricity Producer shall transfer ownership of such Electricity Producer installed Interconnection Facilities or Distribution System Improvements to Electrical Corporation and such facilities shall thereafter be owned and maintained by Electrical Corporation at Electricity Producer's expense as Special Facilities. The Electricity Producer shall pay the Electrical Corporation's reasonable costs of design, administration, and monitoring the installation of such facilities to ensure compliance with Electrical Corporation's requirements. Electricity Producer shall also be responsible for all costs, including any income tax liability, associated with the transfer of Electricity Producer installed Interconnection Facilities and Distribution System Improvements to Electrical Corporation.

5.3.4 **Reservation of Unused Facilities.** When a Electricity Producer wishes to reserve Electrical Corporation-owned Interconnection Facilities or Distribution System

Improvements installed and financed as Special Facilities for the Electricity Producer, but idled by a change in the operation of the Electricity Producer's Generating Facility or otherwise, Electricity Producer may elect to abandon or reserve such facilities consistent with the terms of its Interconnection Facility Financing and Operating Agreement with Electrical Corporation. If Electricity Producer elects to reserve idled Interconnection Facilities or Distribution System Improvements, Electrical Corporation shall be entitled to continue to charge Electrical Producer for the costs related to the ongoing operation and maintenance of the Special Facilities.

5.3.5 **Refund of Salvage Value.** When a Electricity Producer elects to abandon the Special Facilities for which it has either advanced the installed costs or constructed and transferred to the Electrical Corporation, the Electricity Producer shall, at a minimum, receive from the Electrical Corporation a credit for the net salvage value of the Special Facilities.

6. METERING, MONITORING and TELEMETRY

6.1 **General Requirements.** All Generating Facilities shall be metered in accordance with this Section 6 and shall meet all applicable standards of the Electrical Corporation contained in the Electrical Corporation's applicable tariffs and published Electrical Corporation manuals dealing with metering specifications. The requirements in this Section 6 do not apply to metering of Generating Facilities operating under the Electrical Corporation's net metering tariff pursuant to California Public Utilities Code Section 2827.

6.2 **Metering by non-Electrical Corporation Parties.** The ownership, installation, operation, reading, and testing of metering for Generating Facilities shall be by the Electrical Corporation except to the extent that the CPUC has determined that all these functions, or any of them, may be performed by a non-Electrical Corporation as authorized by the CPUC.

6.3 **Net Generation Metering.** For purposes of monitoring Generating Facility operation for determination of standby charges and applicable non-bypassable charges as defined in Electrical Corporation's tariffs, and for Distribution System planning and operations, consistent with Section 2.4 of these Rules, the Electrical Corporation shall have the right to specify the type, and require the installation of, Net Generation Metering. The Electrical Corporation shall require the provision of generator output data to the extent reasonably necessary to provide information for the utility to administer its tariffs or to operate and plan its system. The Electrical Corporation shall only require Net Generation Metering to the extent that less intrusive and/or more cost effective options for providing the necessary generator output data are not available. In exercising its discretion to require Net Generation Metering, the Electrical Corporation shall consider all relevant factors, including but not limited to:

1. Data requirements in proportion to need for information;
2. Customer election to install equipment that adequately addresses the Electrical Corporation's operational requirements;
3. Accuracy and type of required metering consistent with purposes of collecting data;
4. Cost of metering relative to the need for and accuracy of the data;
5. The project's size relative to the cost of the metering/monitoring;
6. Other means of obtaining the data (e.g. generator logs, proxy data etc.);
7. Requirements under any power purchase agreement with the customer.

The Electrical Corporation will report to the CPUC or designated authority, on a quarterly basis, the rationale for requiring net generation equipment in each instance along with the size and location of the facility.

6.4 Point of Common Coupling Metering. For purposes of assessing Electrical Corporation charges for retail service, the Electricity Producer's Point of Common Coupling Metering shall be a bi-directional meter so that power deliveries to and from the Electricity Producer's site can be separately recorded. Alternately, the Electricity Producer may, at its sole option and cost, require the Electrical Corporation to install multi-metering equipment to separately record power deliveries to the Distribution System and retail purchases from the Electric Corporation. Such Point of Common Coupling Metering shall be equipped with detents to prevent reverse registration.

6.5 Telemetering. If the nameplate rating of the Generating Facility is 1 MW or greater, Telemetering equipment at the Net Generator Metering location may be required at the Electricity Producer's (and Customer's) expense. If the Generating Facility is interconnected to a Distribution System operating at a voltage below 10kV, then Telemetering equipment may be required on Generating Facilities 250 kW or greater. The Electrical Corporation shall only require Telemetering to the extent that less intrusive and/or more cost effective options for providing the necessary data in real time are not available. The Electrical Corporation will report to the CPUC or designated authority, on a quarterly basis, the rationale for requiring telemetering equipment in each instance along with the size and location of the facility.

6.6 **Sunset Provision.** Sections 6.3 and 6.5 are interim provisions only. The Electrical Corporation shall file permanent metering requirements with the CPUC on or by December 31, 2002. At that time, the Electrical Corporation shall serve its application for approval of permanent metering requirements on the service list in Rulemaking 99-10-025.

6.7 **Location.** Where Electrical Corporation-owned metering equipment is located on the Electricity Producer's (or Customer's) premises, Electricity Producer (and Customer) shall provide, at no expense to the Electrical Corporation, a suitable location for all such metering equipment.

6.8 **Costs of metering.** The Electricity Producer (and Customer) will bear all costs of the metering required by this Rule 21, including the incremental costs of operating and maintaining the Metering.

7. DISPUTE RESOLUTION PROCESS

7.1 The CPUC shall have initial jurisdiction to interpret, add, delete or modify any provision of this Rule or of any agreements entered into between the Electrical Corporation and the Electricity Producer to implement this tariff ("the implementing agreements") and to resolve disputes regarding the Electrical Corporation's performance of its obligations under its electric rules and tariffs, the implementing agreements, and requirements related to the interconnection of the Electricity Producer's Facilities pursuant to this Rule .

7.2 Any dispute arising between the Electrical Corporation and the Electricity Producer (individually "Party" and collectively "the Parties") regarding the Electrical Corporation's performance of its obligations under its electric rules and tariffs, the implementing agreements, and requirements related to the interconnection of Producer's Facilities pursuant to this Rule shall be resolved according to the following procedures.

7.2.1 The dispute shall be reduced to writing by the aggrieved Party in a letter ("the dispute letter") to the other Party containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the aggrieved Party that it is invoking the procedures under Section 7.2. Within 45 calendar days of the date of the dispute letter, the Parties' authorized representatives will be required to meet and confer to try to resolve the dispute.

7.2.2 If the Parties do not resolve their dispute within 45 calendar days after the date of the dispute letter, the dispute shall, upon demand of either party, be submitted to resolution before the Commission in accordance with the Commission's rules, regulations and procedures applicable to the resolution of such disputes.

7.3 Pending resolution of any dispute under this section, the Parties shall proceed diligently with the performance of their respective obligations under this Rule and the implementing agreements, unless the implementing agreements have been terminated.

a. Disputes as to the application and implementation of this section shall be subject to resolution pursuant to the procedures set forth in this section.

8. DEFINITIONS

Accredited, Nationally Recognized Testing Laboratory (NRTL): A laboratory approved to perform the certification testing requirements.

Active Anti-Islanding Scheme: A control scheme installed with the Generating Facility that senses and prevents the formation of an Unintended Island.

Applicant: The entity submitting an Application for Interconnection.

Application: The standard form CPUC-approved document submitted to the Electrical Corporation for electrical interconnection of a Generator with the Electrical Corporation**.**

Certification Test: A test adopted by an Electrical Corporation that verifies conformance of certain equipment with CPUC-approved performance standards in order to be classified as Certified Equipment. Certification Tests are~~normally~~ performed by ~~approved laboratories such as the Underwriter's Lab (UL)~~ NRTLs.

Certification; Certified; Certificate: The documented results of a successful Certification Testing. ~~(Note: The details about the certification process will be part of a Supplemental Report.)~~

Certified Equipment: Equipment that has passed the Certification Test.

CPUC: The Public Utilities Commission of the State of California.

Commissioning Test: A test performed during the commissioning of all or part of a DG system to achieve one or more of the following:

- Verify specific aspects of its performance;
- Calibrate its instrumentation;
- Establish instrument or Protective Function set-points.

Customer: The entity that receives or is entitled to receive Distribution Service through the Distribution System.

Dedicated Transformer; Dedicated Distribution Transformer: A transformer that provides Electricity Service to a single Customer. The Customer may or may not have a Generating Facility.

Distributed Generation: Electrical power generation by any means, including from stored electricity, that is interconnected to an Electrical Corporation at a Point of Common Coupling under the jurisdiction of the CPUC.

Distributed Generator; Generator (DG): An individual electrical power plant (including required equipment, appurtenances, protective equipment and structures) that is capable of Distributed Generation.

Distribution Service: All services required by, or provided to, a Customer pursuant to the approved tariffs and rules of the Electrical Corporation.

Distribution System: All electrical wires, equipment, and other facilities owned or provided by the Electrical Corporation by which an Electrical Corporation provides Distribution Service to its Customers.

~~**Distribution System Island:** A condition on the Distribution System in which one or more Distributed Generator(s), over which the utility has no direct control, and a portion of the Distribution System operate while isolated from the remainder of the Distribution System.~~

Electrical Corporation (EC): The entity that, under the jurisdiction of the CPUC, is charged with providing Electricity Distribution Service to the Customer.

Electricity Producer (EP): The entity that executes an Interconnection Agreement with the Electrical Corporation. The Electricity Producer may or may not own or operate the Generating Facility, but is responsible for the rights and obligations related to the Interconnection Agreement.

Emergency: An actual or imminent condition or situation, which jeopardizes the Distribution System Integrity.

Field Testing: Testing performed in the field to determine whether equipment meets the Electrical Corporation's requirements for safe and reliable Interconnection
Generating Facility: All Distributed Generators that are included in an Interconnection Agreement.

Gross Nameplate Rating: The total gross generating capacity of the Distributed Generator as designated by the manufacturer of the Distributed Generator.

Host Load: Electrical power that is consumed by the Customer at the property on which the Generating Facility is located.

Initial Operation: The first time the Generating Facility is in Parallel Operation.

Initial Review: The review by the Electrical Corporation, following receipt of an Application, to determine the following:

If an Application qualifies for Simplified Interconnection, or

If an Application can be made to qualify for Interconnection with supplemental review determining any potential additional requirements, or

If an Interconnection Study is required, the cost estimate and schedule for performing the Interconnection Study

In-rush Current: The current drawn by the DG during startup.

Interconnection Agreement: An agreement between the Electrical Corporation and the Electricity Producer that gives each the certain rights and obligations to effect or end Interconnection.

Interconnection Study: A study to establish the requirements for Interconnection of an Electricity Producer.

Interconnection; (Interconnected): The physical connection of Distributed Generation in accordance with the requirements of these rules so that Parallel Operation with the utility system can occur (has occurred).

Interconnection Facilities: The electrical wires, switches and related equipment that interconnect a Generating Facility to the Distribution System.

Island; Islanding: A condition on the Distribution System in which one or more Generating Facilities deliver power to Customers using a portion of the Distribution System that is electrically isolated from the remainder of the Distribution System.

ISO: The California Independent System Operator, responsible for the management of electrical power flow through California's electrical transmission network.

Line Section: That portion of the Distribution System connected to a Customer bounded by automatic sectionalizing devices or the end of the line.

Metering Equipment: All equipment, hardware, software including meter cabinets, conduit, etc. that is necessary for Metering.

Metering: The measurement of electrical power flow in kW and/or kWh, and, if necessary, kVAR at a point, and its display to the Electrical Corporation, as required by this rule.

Net Energy Metering: Metering for the mutual purchase and sale of electricity between the Electricity Producer and the Electrical Corporation pursuant to the net metering tariff approved by the CPUC.

Net Generation Metering: The Metering of the net electrical energy output in kW and kWh from a given Generating Facility. This may also be the measurement of the difference between the total electrical energy produced by a Distributed Generator and the electrical energy consumed by the auxiliary equipment necessary to operate the Distributed Generator. For a Distributed Generator with no Host Load and/or Section 218 Load, Metering that is located at the point of Common Coupling. For a Distributed Generator with Host Load and/or Section 218 Load, Metering that is located at the Distributed Generator bus after the point of auxiliary load(s) and prior to serving Host Load and/or Section 218 Load.

Net Metering: Where electricity at a point may flow in both directions, the measurement of the net, or the algebraic sum, of electrical energy in kWh, that flows through that point in a given time-interval. Net Metering typically uses two meters, or in some cases a single meter with two or more registers, to individually measure a Customer's electric deliveries to, and consumption of retail service from, the Distribution System. Over a given time frame (typically a month) the difference between these two values yield either net consumption or net surplus. The meter registers are ratcheted to prevent reverse registration. If available, a single meter may be allowed spin backward to yield the same effect as a two meter (or register) arrangement.

Net Nameplate Rating: The Gross Nameplate Rating minus the consumption of electrical power of the Distributed Generator as designated by the manufacturer(s) of the Distributed Generator.

Network Service: More than one electrical feeder providing Distribution Service at a Point of Common Coupling.

Non-Exporting : Designed to prevent the transfer of electrical energy from the EP to the EC.

Non-Islanding: Designed to detect and disconnect from a stable Unintended Island with matched load and generation. Reliance solely on under/over voltage and frequency trip is not considered sufficient to qualify as Non-Islanding.

Parallel Operation: The simultaneous operation of a Distributed Generator with power delivered or received by the Electrical Corporation while Interconnected. For the purpose of this rule, Parallel Operation includes only those generators that are so interconnected with the Distribution System for more than 60 cycles.

Periodic Test: A test performed on part or all of a DG system at pre-determined time or operational intervals to achieve one or more or the following:

- Verify specific aspects of its performance;
- Calibrate instrumentation;
- Verify and re-establish instrument or Protective Function set-points.

Point of Common Coupling Metering: Metering located at the Point of Common Coupling. This is the same Metering as Net Generation Metering for Generating Facilities with no Host Load and/or Section 218 Load.

Point of Common Coupling (PCC): The transfer point for electricity between the electrical conductors of the Electrical Corporation and the electrical conductors of the Electricity Producer.

Point of Interconnection: The electrical transfer point between an electrical power plant and the electrical distribution system. This may or may not be coincident with the Point of Common Coupling.

Power Purchase Agreement(PPA): An agreement for the sale of electricity by the Electricity Producer to the Electrical Corporation.

Production Test: A test performed on each device coming off the production line to verify certain aspects of its performance.

Protective Function(s): The equipment, hardware and/or software in a Generating Facility (whether discrete or integrated with other functions) whose purpose is to protect against Unsafe Operating Conditions.

Prudent Electrical Practices: Those practices, methods, and equipment, as changed from time to time, that are commonly used in prudent electrical engineering and operations to design and operate electric equipment lawfully and with safety, dependability, efficiency, and economy.

Rule 2: A CPUC rule specific to each Electrical Corporation that describes the conditions of Distribution Service to Customers and includes provisions for charges related to Special Facilities and Interconnection Facilities.

Scheduled Operation Date: The date specified in the Interconnection Agreement when the Generating Facility is, by the Electricity Producer's estimate, expected to begin Initial Operation.

Secondary Network: A network supplied by several primary feeders suitably interlaced through the area in order to achieve acceptable loading of the transformers under emergency conditions and to provide a system of extremely high service reliability. Secondary networks usually operate at 600 V or lower.

Section 218 Load: Electrical power that is supplied in compliance with California Public Utilities Code (PU Code) section 218. PU Code 218 defines an "Electric Corporation" and provides conditions under which a generator transaction would not classify a generating entity as an Electric Corporation. These conditions relate to "over-the-fence" sale of electricity from a generator without using the Distribution System.

Simplified Interconnection: Interconnection conforming to the minimum requirements under these rules, as determined by Appendix A.

Short Circuit Contribution Ratio (SCCR): The ratio of the Generating Facility's short circuit contribution to the Electrical Corporation's short circuit contribution for a three-phase fault at the high voltage side of the distribution transformer connecting the Generating Facility to the Electrical Corporation's system.

Special Facilities: Those facilities installed at the Electricity Producer's request, which the Electrical Corporation does not normally furnish under its tariff schedule; or a pro rata portion of existing facilities requested by the Electricity Producer, allocated for the sole use of such an Electricity Producer, which would not normally be allocated for such sole use.

Stabilization; Stability: The return to normalcy of an Electrical Corporation Distribution System, following a disturbance. Stabilization is usually measured as a time period during which voltage and frequency are within acceptable ranges.

Starting Voltage Drop: The percentage voltage drop at a specified point resulting from In-rush current. The SVD can also be expressed in volts on a particular base voltage, (eg. 6 volts on a 120-volt base, yielding a 5% drop).

System Integrity: The condition under which a Distribution System is deemed safe and can reliably perform its intended functions in accordance with the safety and reliability rules of the Electrical Corporation.

Telemetering: The electrical or electronic transmittal of Metering data on a real-time basis to the Electrical Corporation.

Type Test: A test performed on a sample of a particular model of a device to verify specific aspects of its design, construction and performance.

Unintended Island: The creation of an island, usually following a loss of a portion of the Distribution System, without the approval of the Electrical Corporation.

Unsafe Operating Conditions: Conditions that, if left uncorrected, could result in harm to personnel, damage to equipment, loss of System Integrity or operation outside pre-established parameters required by the Interconnection Agreement.

Appendix A - Initial Review Process for Applications to Interconnect Distributed Generation

Introduction:

This Initial Review Process was developed to create a path for selection and rapid approval of those Applications for Interconnection that do not require an Interconnection Study. The capitalized phrases used in this Appendix A have the same meanings as those in Section 8 of the proposed Rule 21.

Purpose:

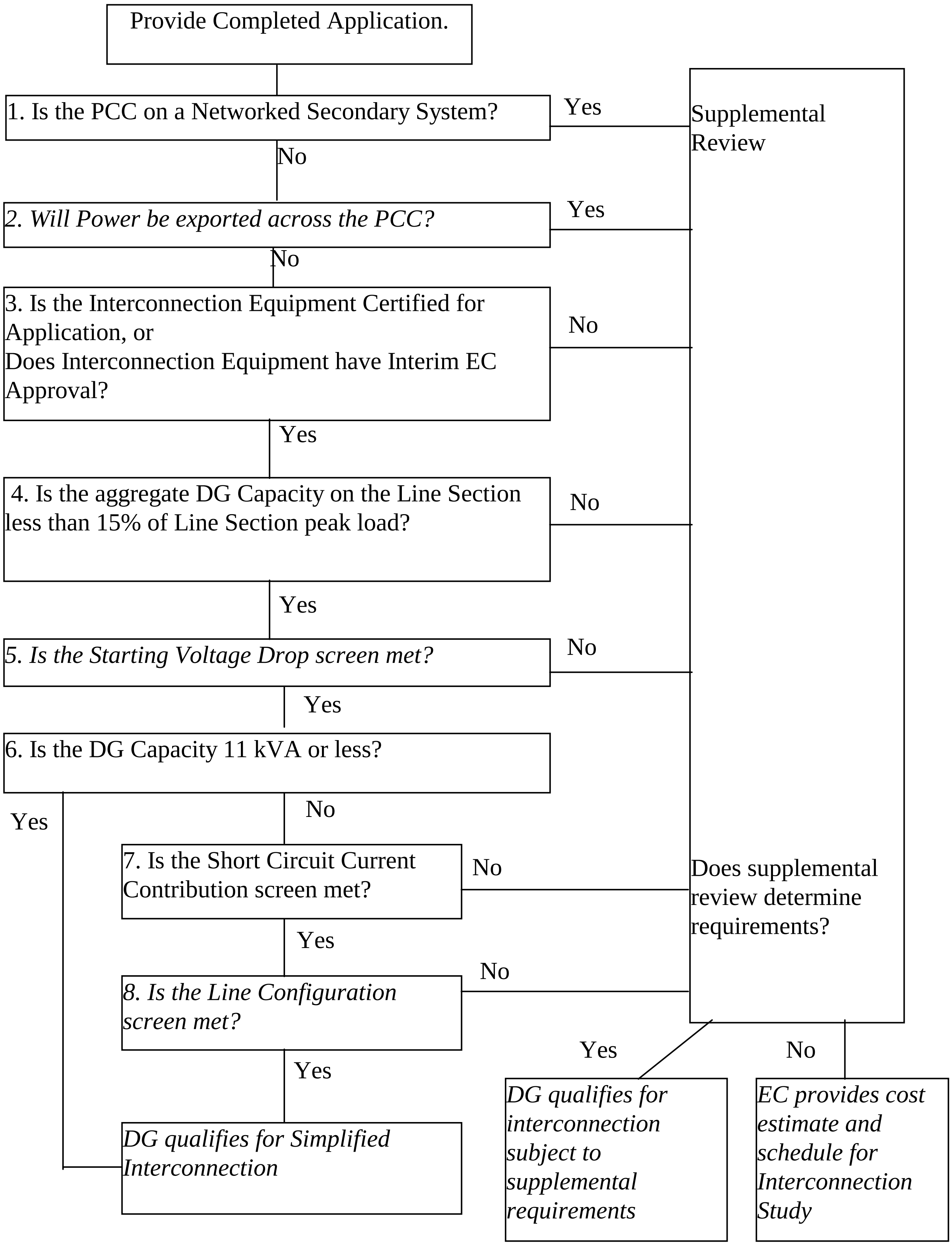
The Initial Review determines:

a. If an Application qualifies for Simplified Interconnection;
b. If an Application can be made to qualify for Interconnection with supplemental review determining any potential additional requirements, or
c. If an Interconnection Study is required, the cost estimate and schedule for performing the Interconnection Study.

Note:

Failure to pass any screen means that further review, and/or studies, are required before the DG project will be approved for interconnection with the Electrical Corporation. It does not mean that the DG cannot interconnect.

Initial Review Process Flow Chart



Initial Review Process Details:

1. Is the PCC on a Networked Secondary System?

If No, continue to next screen.
If Yes, DG does not qualify for Simplified Interconnection.
Perform supplemental review.

Significance:

1. Special considerations must be given to DG on networked secondary distribution systems because of the design and operational aspects of network protectors. There are no such considerations for radial distribution systems.

2. Will power be exported across the PCC?

If Yes, DG does not qualify for Simplified Interconnection.
Perform supplemental review.

If No, DG must incorporate one of the following four options:

Option 1:
To insure power is never exported, a reverse power Protective Function must be implemented at the PCC.
Default setting shall be 0.1% (export) of transformer rating, with a maximum 2.0 second time delay.

Option 2:
To insure at least a minimum import of power, an under-power Protective Function must implemented at the PCC.
Default setting shall be 5% (import) of DG Gross Nameplate Rating, with maximum 2.0 second time delay.

Option 3:
To limit the incidental export of power, all of the following conditions must be met:

- The aggregate DG capacity of the Generating Facility must be no more than 25% of the nominal ampere rating of the Customer's Service Equipment;
- The total aggregate DG capacity must be no more than 50% of the service transformer rating (This capacity requirement does not apply to customers taking primary service without an intervening transformer);
- The DG must be certified as Non-Islanding.

Option 4:
To insure that the relative size (capacity) of the DG compared to facility load results in no export of power without the use of additional devices, the DG capacity must be no greater than 50% of the Customer's verifiable minimum annual load.

Significance:

1. EC's Distribution System does not need to be studied for load-carrying capability or DG power flow effects on EC voltage regulators since on-site DG reduces EC load.
2. Permits use of reverse-power relaying at the PCC as positive anti-islanding protection.

3. Is the Interconnection Equipment Certified for the Application or does the Interconnection Equipment have Interim EC Approval?

If No, DG does not qualify for Simplified Interconnection.
Perform supplemental review.

If Yes, continue to next screen.

Significance:

The Electrical Corporation does not need to review, or test, the DG's protective function scheme. Site Commissioning Testing may still be required to insure that the system is connected properly and that the protective functions are working properly.

- Basic protective function requirements met.
- Harmonic distortion limits met.
- Synchronizing requirements met.
- Pf regulation requirements met.
- Non-islanding requirements met.
- If used, reverse power function requirement met.
- If used, under-power function requirement met.

4. Is the aggregate DG Capacity on the Line Section less than 15% of Line Section Peak Load?

If Yes, continue to next screen.
If No, perform supplemental review to determine cumulative impact on Line Section.

Significance:

1. Low penetration of DG will have a minimal impact on operation and load restoration.

2. The operating requirements for a high penetration of DG may be different since the system impact will no longer be minimal, therefore requiring additional study or controls.

5. Is the Starting Voltage Drop screen met?

If Yes, continue to next screen.
If No, perform supplemental review.

NOTICE: This screen only applies to Generating Facilities that start by motoring the DG.

The EC has two options in determining whether Starting Voltage Drop could be a problem; which option to use is at the EC's discretion.

Option 1: The DG starting Inrush Current must be equal to or less than the continuous ampere rating of the Customer's Service Equipment.

Option 2: Determine the impedances of service distribution transformer (if present) and secondary conductors, from primary to Customer's Service Equipment. Perform voltage drop calculation, or alternately use EC's tables or nomographs. Voltage drop must be less than 2.5% for primary interconnection and 5% for secondary interconnection.

Significance:

1. This screen addresses potential voltage fluctuation problems for generators that start by motoring.
2. When starting, DG should have minimal impact on the service voltage to other EC Customers.
3. Passing this screen does not relieve the DG from compliance with the flicker requirements of Rule 21, Section 4.

6. Is the DG Capacity 11 kVA or less?

If Yes, DG qualifies for Simplified Interconnection.
If No, continue to next screen.

Significance:

1. DG has minimal impact on fault current levels and any potential line overvoltages from loss of system neutral grounding.

7. Is Short Circuit Current Contribution screen met?

If No, DG does not qualify for Simplified Interconnection.
Perform supplemental review.

If Yes, continue to next screen.

<u>Short Circuit Current Contribution Screen:</u>

A. *At primary side (high side) of the Dedicated Distribution Transformer, for the specified feeder, the sum of the Short Circuit Contribution Ratios (SCCR) of all DG's on the feeder must be less than or equal to 0.1.*
B. *At secondary (low side) of a shared distribution transformer, the short circuit contribution of the proposed DG must be less than or equal to 2.5% of the interrupting rating of the Customer's Service Equipment.*

<u>Significance</u>:

No significant DG impact on:

- Distribution System's short circuit duty
- Distribution System fault detection sensitivity
- Distribution System relay coordination
- Distribution System fuse-saving schemes

8. Is the Line Configuration screen met?

If No, then DG does not qualify for Simplified Interconnection.
Perform supplemental review.

If Yes, then DG qualifies for Simplified Interconnection.

<u>Line Configuration Screen:</u>

Identify primary distribution line configuration. Based on proposed interconnection type, determine from table whether DG passes screen.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	Any	Pass screen
Three-phase, four wire	Single-phase, line-to-neutral	Pass screen
Three-phase, four wire (For any line that has such a section OR mixed 3 wire & 4 wire)	All others	To pass, aggregate DG Capacity must be less than or equal to 10% of Line Section Peak Load.

Significance:

1. If the Electrical Corporation's primary system is three-wire or the DG interconnection transformer is single-phase (line-to-neutral), then there is no concern about overvoltages to the Electrical Corporation's, or Customer, equipment caused by loss of system neutral grounding during the operating time of anti-islanding protection.

Appendix B - Testing and Certification Criteria

B1 Introduction

This Appendix describes the test procedures and requirements for equipment used for the Interconnection of Distributed Generation to the Electric Corporation's Distribution System. Included are Type Testing, Production Testing, Commissioning Testing, and Periodic Testing. The procedures listed rely heavily on those described in appropriate Underwriters Laboratory (UL), Institute of Electrical and Electronic Engineers (IEEE), and International Electrotechnical Commission (IEC) documents—most notably UL 1741 and IEEE 929—as well as the testing described in May 1999 New York Standardized Interconnection Requirements. These procedures and requirements were developed prior to the completion of IEEE P1547 *Standard for Distributed Resources Interconnected with Electric Power Systems*, and should be revisited once that standard is published.

The tests described here, together with the technical requirements in Section 4 of Rule 21, are intended to provide assurance that the DG equipment will not adversely affect the EC Distribution System and that it will cease providing power to the grid under abnormal conditions. The tests were developed assuming a low level of DG penetration. At high levels of DG penetration, other requirements and corresponding test procedures may need to be defined.

This test specification also provides a means of certifying equipment. The Electric Corporation does not need to review the design or test Protective Functions of Certified Equipment. The use of non-certified equipment may be acceptable subject to testing and approval by the EC as discussed below.

B2 Certification Criteria

Equipment tested and approved (e.g. listed) by an accredited, nationally recognized testing laboratory (NRTL) as having met both the Type Testing and Production Testing requirements is considered Certified Equipment for purposes of Interconnection. Certification may apply to either a pre-packaged system or an assembly of components that address the necessary functions. Type Testing may be done in the factory/test lab or in the field. At the discretion of the testing laboratory, field-certification may apply only to the particular installation tested. In such cases, some or all of the tests may need to be repeated at other installations.

For non-certified equipment, some or all of the tests described in this document may be required by the EC. The manufacturer or other lab acceptable to the EC may perform these tests. Test results must be submitted to the EC with the Interconnection Application for review and approval under the supplemental review. Approval by one EC for use in a particular application does not guarantee approval for use in other applications or by other ECs.

The NRTL shall provide to the manufacturer, at a minimum, a Certificate with the following information for each device certified:

Administrative:

- Effective date of certification or applicable serial number (range or first in series), other
  proof that certification is current
- Equipment model number (s)
- Software version, if applicable
- Test procedures specified (including date or revision number)
- Laboratory accreditation (by whom and to what standard)

Technical (As appropriate):

- Device rating (kW, kVA, V, A, etc.)
- Maximum available fault current, A
- In-rush current, A
- Trip points, if factory set (trip value and timing)
- Trip point and timing ranges for adjustable settings
- Nominal power factor or range if adjustable
- If the device/system is certified for non-export and the method used (reverse power or under power)
- If the device/system is certified non-islanding

It is the responsibility of the equipment manufacturer to ensure that certification information is made publicly available by the manufacturer, the testing laboratory, or by a third party.

B3 Type Testing

B3.1 Inverters

Static power inverters shall meet all of the Type Tests and requirements appropriate for a utility interactive inverter as specified in UL 1741 *Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems*, and listed below. These requirements may be applied to inverters used with DG sources other than PV. The specific section number from the May 1999 version of UL1741 is provided for each test and requirement. The titles for some sections were added for clarity. These section numbers are subject to change by UL. A revised version of 1741 is expected to be published around Nov 2000. The utility interconnection-related procedures and requirements of that version will need to be reviewed to determine if they should be adopted into these testing and certification rules. The requirements described below cover only issues related to Interconnection and are not intended to address device safety and other issues outside the need and relationship between the EC and EP..

39.1 Utility Disconnect Switch
39.2 Field Adjustable Trip-points
39.3 Field Adjustable Trip-points
39.4 Field Adjustable Trip-points

39.5 Field Adjustable Trip-points, Marking
40.1 DC Isolation
41.2 Simulated PV Array (Input Source) requirements
44 Dielectric Voltage Withstand Test
45.2.2 Power Factor
45.4 Harmonic Distortion
45.5 DC Injection
46.2 Utility Voltage and Frequency Variation Test
46.2.3 Reset Delay
46.4 Loss of Control circuit
47.3 Short Circuit Test
47.7 Load Transfer Test

A description of key aspects of these procedures is provided in the testing procedures section of this Appendix.

Separate test procedures are provided to certify non-islanding function (B3.4) and non-export function (B3.5), to determine the in-rush current B3.6, to subject the device to voltage surge conditions B3.7, and to verify the inverter's ability to synchronize with the Distribution System (B3.8).

B3.2 Synchronous Generators

Until a standardized test procedure, written specifically for synchronous generators, is identified, an EC or NRTL shall determine which of the tests described in this Appendix are appropriate and necessary to certify the performance of the control and protection system functions of the synchronous machine, and how to perform them. The following tests, defined in UL 1741, shall be performed as applicable to a synchronous generator.

39.1 Utility Disconnect Switch
39.2 Field Adjustable Trip-points
39.3 Field Adjustable Trip-points
39.4 Field Adjustable Trip-points
39.5 Field Adjustable Trip-points, Marking
44 Dielectric Voltage Withstand Test
45.2.2 Power Factor
45.4 Harmonic Distortion
46.2 Utility Voltage and Frequency Variation Test
46.2.3 Reset Delay
46.4 Loss of Control circuit
47.3 Short Circuit Test

Separate test procedures are provided to certify non-islanding function and non-export function, to determine in-rush current, to subject the device to voltage surge conditions, and to verify the generator's ability to synchronize with the Distribution System.

B3.3 Induction Generators

Until a standardized test procedure, written specifically for induction generators is identified, an EC or NRTL shall determine which of the tests described in this Appendix are appropriate and necessary to certify the performance of the control and protection system functions of the induction generator, and how to perform them. The following tests, defined in UL 1741, shall be performed as applicable to a induction generator.

39.1	Utility Disconnect Switch
39.2	Field Adjustable Trip-points
39.3	Field Adjustable Trip-points
39.4	Field Adjustable Trip-points
39.5	Field Adjustable Trip-points, Marking
44	Dielectric Voltage Withstand Test
45.2.2	Power Factor
45.4	Harmonic Distortion
46.2	Utility Voltage and Frequency Variation Test
46.2.3	Reset Delay
46.4	Loss of Control circuit
47.3	Short Circuit Test
47.7	Load Transfer Test

Separate test procedures are provided to certify non-islanding function and non-export function, to determine the in-rush current, and to subject the device to voltage surge conditions.

B3.4 Anti-Islanding Test

In addition to the above Type Tests, devices that pass the Anti-Islanding test procedure described in this Appendix will be considered Non-Islanding for the purposes of these interconnection requirements.

B3.5 Non-Export Test

In addition to the above Type Tests, devices that pass the Non-Export test procedure described in Section C1.1 will be considered Non-Exporting for the purposes of these interconnection requirements.

B3.6 In-rush Current Test

Generation equipment that utilizes EC power to motor up to speed will be tested using the procedure defined in Section C1.2 to determine the maximum current drawn during this startup process. The resulting in-rush current is used to estimate the starting voltage drop.

B3.7 Surge Withstand Capability Test

Interconnection equipment shall tested for surge withstand capability (SWC), both oscillatory and fast transient, in accordance with the test procedure defined in IEEE/ANSI C62.45 using the peak values defined in IEEE/ANSI C62.41 Tables 1 and 2 for location category B3. An acceptable result occurs even if the device is damaged by the surge, but is unable to operate or energize the EC. If the device remains operable after being subject to the surge conditions, previous type tests related to EC protection and power quality will need to be repeated to ensure the unit will still pass those tests following the surge test.

B3.8 Synchronization Test

This test verifies that the unit synchronizes within the specified voltage/frequency/phase angle requirements. It is applied to synchronous generators and inverters capable of operating as voltage-source while connected to the EC. This test is not necessary for induction generators or current-source inverters.

The test will start with only one of the three parameters--voltage difference between DG and EC, frequency difference, or phase angle--outside of the synchronization specification. Initiate the synchronization routine and verify that the DG is brought within specification prior to synchronization. Repeat the test five times for each of the three parameters.

For manual synchronization with synch check or manual control with auto synchronization, the test must verify that paralleling does not occur until the parameters are brought within spec.

B4 Production Testing

As a minimum, the Utility Voltage and Frequency Variation Test procedure described in UL1741 under Manufacturing and Production Tests, Section 68 shall be performed as part of routine production (100 percent) on all equipment used to interconnect DG to EC. This testing may be performed in the factory or as part of a Commissioning Test (B5.1).

B5 Commissioning Testing

Commissioning Testing, where required, will be performed on-site to verify protective settings and functionality. Upon initial Parallel Operation of a generating system, or any time interface hardware or software is changed that may affect the functions listed below, a Commissioning Test must be performed. An individual qualified in testing protective equipment (professional engineer, factory-certified technician, or licensed electrician with experience in testing protective equipment) must perform commissioning testing in accordance with the manufacturer's recommended test procedure to prove the settings and requirements of this document.

The EC has the right to witness Commissioning Tests as described below, or to require written certification by the installer describing which tests were performed and their results.

Functions to be tested during commissioning, particularly with respect to non-certified equipment, may consist of the following:

1. Over- and under-voltage
2. Over- and under-frequency
3. Anti-Islanding function (if applicable)
4. Non-Export function (if applicable)
5. Inability to energize dead line
6. Time delay restart after utility source is stable
7. Utility system fault detection (if used)
8. Synchronizing controls (if applicable)
9. Other interconnection protective functions that may be required as part of the Interconnection Agreement

Other checks and tests that may need to be performed include:

1. Verifying final protective settings
2. Trip test
3. In-service test

B5.1 Certified Equipment

Systems qualifying for Simplified Interconnection incorporate Certified Equipment that have, at a minimum, passed the Type and Production Tests described in this document, and are judged to have little or no potential impact on the EC distribution system. For such systems, it is necessary to perform only the following tests:

1. Protection settings that have been changed after factory testing will require field verification. Tests will be performed using injected secondary quantities, applied waveforms, a test connection using a generator to simulate abnormal utility voltage or frequency, or varying the set points to show that the device trips at the measured (actual) utility voltage or frequency.
2. Non-Islanding function will be checked by operating a load break disconnect switch to verify the interconnection equipment ceases to energize the line and does not re-energize for the required time delay after the switch is closed
3. Non-Export function will be checked using secondary injection techniques. This function may also be tested by adjusting the DG output and local loads to verify that the applicable non-export criteria (i.e., reverse power or under power) are met.

The supplemental review or an Interconnection Study may impose additional components or additional testing.

B5.2 Non-Certified Equipment

Non-certified equipment shall be subjected to the appropriate tests described in Type Testing (Section B3) as well as those described in Certified Equipment Commissioning Test (Section B5.1). With EC approval, these tests may be performed in the factory, in the field as part of commissioning, or a combination of both. The EC, at its discretion, may also approve a reduced set of tests for a particular application or, for example, if they have sufficient experience with the equipment.

B5.3 Verifying final protective settings

If the testing is part of the commissioning process, then, at the completion of such testing, the EP shall confirm all devices are set to EC-approved settings . This step shall be documented in the Commissioning Test Certification.

B5.4 Trip test

Interconnection protective devices (e.g. reverse power relay) that have not previously been tested as part of the interconnection system with their associated interrupting devices (e.g. contactor or circuit breaker) shall be trip tested during commissioning. The trip test shall be adequate to prove that the associated interrupting devices open when the protective devices operate.

Interlocking circuits between protective devices or between interrupting devices shall be similarly tested unless they are part of a system that has been tested and approved during manufacture.

B5.5 In-service test

Interconnection protective devices that have not previously been tested as part of the interconnection system with their associated instrument transformers or that are wired in the field shall be given an in-service test during commissioning. This test will verify proper wiring, polarity, CT/PT ratios, and proper operation of the measuring circuits. The in-service test shall be made with the power system energized and carrying a known level of current. A measurement shall be made of the magnitude and phase angle of each ac voltage and current connected to the protective device and the results compared to expected values.

For protective devices with built-in metering functions that report current and voltage magnitudes and phase angles, or magnitudes of current, voltage, and real and reactive power, the metered values may be used for in-service testing. Otherwise, portable ammeters, voltmeters, and phase-angle meters shall be used.

B6 Periodic Testing

Periodic Testing of Interconnection-related Protective Functions shall be performed as specified by the manufacturer, or at least every four years. All periodic tests prescribed by the manufacturer shall be performed. The EP shall maintain periodic test reports or a log for inspection by the Electrical Corporation. Periodic Testing conforming to EC test intervals for the particular line section may be specified by the EC under special circumstances, such as high fire hazard areas.

A system that depends upon a battery for trip power shall be checked and logged once per month for proper voltage. Once every four years, the battery must be either replaced or a discharge test performed.

Testing Procedures

C1 Type Test and Requirements

This section describes the Type Tests necessary to qualify a device as Certified, which are not contained in Underwriters Laboratories UL 1741 Standard *Inverters, Converters and Controllers for Use in Independent Power Systems,* or other referenced standards.

C1.1 Non-Export Test Procedure

The non-export test is intended to verify the operation of relays, controllers and inverters designed to limit the export of power and certify the equipment as meeting the requirements of Step 2, Options 1 and 2, of the Initial Review Process. Tests are provided for discrete relay packages and for controllers and inverters that include the intended function.

C1.1.1 *Reverse Power Relay Test*

This version of the Non-Export test procedure is intended for stand-alone reverse power and under power relay packages provided to meet the requirements of Options 1 and 2 of the Export Screen. It should be understood that in the reverse power application, the relay will provide a trip output with power in the export (toward the EC system) direction.

Step 1: Power Flow Test at Minimum, Midpoint and Maximum Pickup Level Settings

Determine the appropriate secondary pickup current for the desired export power flow of 0.5 secondary watts (the agreed-upon minimum pickup setting, assumes 5Amp and 120V CT/PT secondary). Apply nominal voltage with minimum current setting at 0 degrees in the trip direction. Increase the current to pickup level. Observe the relay's (LCD or computer display) indication of power values. Note the indicated power level at which the relay. trips. The power indication should be within 2 percent of the expected power. For relays with adjustable settings, repeat this test at the midpoint, and maximum settings.

Repeat at phase angles of 90, 180 and 270 degrees and verify that the relay does NOT operate (measured watts will be zero or negative).

Step 2: Leading Power Factor Test

Apply rated voltage with a minimum pickup current setting (calculated value for system application) and apply a leading power factor load current in the non-trip direction (current lagging voltage by 135 degrees). Increase the current to relay rated current and verify that the relay does NOT operate. For relay's with adjustable settings, this test should be repeated at the minimum, midpoint, and maximum settings.

Step 3: Minimum Power Factor Test

At nominal voltage and with the minimum pickup (or ranges) determined in Step 1, adjust the current phase angle to 84 or 276 degrees. Increase the current level to pickup (about 10 times higher than at 0 degrees) and verify that the relay operates. Repeat for angles 90, 180 and 270 degrees and verify that the relay does NOT operate.

Step 4: Negative Sequence Voltage Test

Using the pickup settings determined in Step 1, apply rated relay voltage and current at 180 degrees from tripping direction, to simulate normal load conditions (for 3-phase relays, use Ia at 180, Ib at 60 and Ic and 300 degrees). Remove Phase-1 voltage and observe that the relay does not operate. Repeat for phase-2 and 3.

Step 5: Load Current Test

Using the pickup settings determined in Step 1, apply rated voltage and current at 180 degrees from the tripping direction, to simulate normal load conditions (use Ia at 180, Ib at 300 and Ic at 60 degrees). Observe that the relay does NOT operate.

Step 6: Unbalanced Fault Test

Using the pickup settings determined in Step 1, apply rated voltage and 2 times rated current, to simulate an unbalanced fault in the non-trip direction (use Va at 0 degrees, Vb and Vc at 180 degrees, Ia at 180 degrees, Ib at 0 degrees, and Ic at 180 degrees). Observe that the relay, especially single phase, does not misoperate.

Step 7: Time Delay Settings Test

Apply Step 1 settings and set time delay to minimum setting. Adjust the current source to the appropriate level to determine operating time, and compare against calculated values. Verify that the timer stops when the relay trips. Repeat at midpoint and maximum delay settings

Step 8: Dielectric Test

Perform the test described in IEC 414 using 2 kV RMS for 1 minute.

Step 9: Surge withstand

Perform the surge withstand test described in IEEE C37.90.1.1989 or the surge withstand test described in B.3.7.

C1.1.2 *Under Power Relay Test*

In the underpower application, the relay will provide a trip output when import power (toward the EP) drops below the specified power level.

Note: For an underpower relay, pickup is defined as the highest power level at which the relay indicates that the power is *less* than the set setting.

Step 1: Power Flow Test at Minimum, Midpoint and Maximum Pickup Level Settings

Determine the appropriate secondary pickup current for the desired power flow pickup level of 5% of peak load (the agreed-upon minimum pickup setting). Apply rated voltage and current setting at 0 degrees in the direction of normal load current. Decrease the current to pickup level. Observe the relay's (LCD or computer display) indication of power values. Note the indicated power level at which the relay. trips. The power indication should be within 2 percent of the expected power. For relays with adjustable settings, repeat the test at the midpoint, and maximum settings.

Repeat at phase angles of 90, 180 and 270 degrees and verify that the relay operates (measured watts will be zero or negative).

Step 2: Leading Power Factor Test

Using the pickup current setting determined in step 1, apply rated voltage and rated leading power factor load current in the normal load direction (current leading voltage by 45 degrees). Decrease the current to 145% of the pickup level determined in Step 1 and verify that the relay does NOT operate. For relays with adjustable settings, repeat the test at the minimum, midpoint, and maximum settings.

Step 3: Minimum Power Factor Test

At nominal voltage and with the minimum pickup (or ranges) determined in Step 1, adjust the current phase angle to 84 or 276 degrees. Decrease the current level to pickup (about 10% of the value at 0 degrees) and verify that the relay operates. Repeat for angles 90, 180 and 270 degrees and verify that the relay operates for any current less than rated current.

Step 4: Negative Sequence Voltage Test

Using the pickup settings determined in Step 1, apply rated relay voltage and 25% of rated current in the normal load direction, to simulate light load conditions. Remove Phase-1 voltage and observe that the relay does not operate, repeat for phase-2 and 3.

Step 5: Unbalanced Fault Test

Using the pickup settings determined in Step 1, apply rated voltage and 2 times rated current, to simulate an unbalanced fault in the normal load direction (use Va at 0 degrees, Vb and Vc at 180 degrees, Ia at 0 degrees, Ib at 180 degrees, and Ic at 0 degrees). Observe that the relay, especially single phase, operates properly.

Step 6: Time Delay Settings Test

Apply Step 1 settings and set time delay to minimum setting. Adjust the current source to the appropriate level to determine operating time, and compare against calculated values. Verify that the timer stops when the relay trips. Repeat at midpoint and maximum delay settings.

Step 7: Dielectric Test

Perform the test described in IEC 414 using 2 kV RMS for 1 minute.

Step 8: Surge withstand

Perform the surge withstand test described in IEEE C37.90.1.1989 or the surge withstand test described in B.3.7

C1.1.3 *Functional Test for Inverters and Controllers*

Inverters and controllers designed to provide reverse or under power functions shall be tested to certify the intended operation of this function. Two methods are provided.

Method 1: If the controller utilizes external current/voltage measurement to determine the reverse or underpower condition, then the controller shall be functionally tested by application of appropriate secondary currents and potentials as described in the Relay Test C1.1.1.

Method 2: If external secondary current or potential signals are not used, then unit-specific tests must be conducted to verify that power cannot be exported across the PCC for a period exceeding two seconds. These tests may be factory tests, if the measurement and control points are part of a single unit, or may be provided for in the field.

C1.2 In-rush Current Test

This test will determine the maximum in-rush current drawn by the unit.

C1.2.1 *Locked-Rotor Method*
Use the test procedure defined in NEMA MG-1 (manufacturer's data is acceptable if available).
C1.2.2 *Start-up Method*
Install and setup the DG equipment as specified by the manufacturer. Using a calibrated oscilloscope or data acquisition equipment with appropriate speed and accuracy, measure the current draw at the Point of Interconnection as the DG starts up and parallels to the EC. Startup shall follow the normal, manufacturer-specified procedure.

Sufficient time and current resolution and accuracy shall be used to capture the maximum current draw within five percent. In-rush current is defined as the maximum current draw from the EC during the startup process, using a 10-cycle moving average. During the test, the utility source, real or simulated, must be capable of maintaining voltage within +/- five percent of rated at the connection to the unit under test. Repeat this test five times. Report the highest 10-cycle current as the in-rush current

A graphical representation of the time-current characteristic along with the certified in-rush current will be included in the test report and will be made available to the EC.

Attachment B – Interconnection Application Agreement

This Generating Facility Interconnection Agreement ("Agreement") is entered into by and between Electrical Producer's Name ("Electricity Producer" or "EP "), and Electric Corporation's Name ("EC"). EP and EC are sometimes also referred to in this Agreement jointly as "Parties" or individually as "Party."

In consideration of the mutual promises and obligations stated in this Agreement and its attachments, the Parties agree as follows:

1. SCOPE AND PURPOSE

This Agreement provides for EP to interconnect and operate a Generating Facility in parallel with EC's Distribution System to serve the electrical loads connected to the electric service account that EC uses to interconnect EP's Generating Facility (or, where permitted under Section 218 of the California Public Utilities Code, the electric loads of an on-site or neighboring party lawfully connected to EP's Generating Facility through EP's circuits).

2. SUMMARY AND DESCRIPTION OF EP's GENERATING FACILITY

2.1 A description of the Generating Facility, including a summary of its significant components and a single-line diagram showing the general arrangement of how EP's Generating Facility and loads are interconnected with EC's Distribution System, is attached to and made a part of this Agreement as Appendix A.

2.2 Generating Facility identification number: ___________________ (Assigned by EC)

2.3 EC's customer electric service account number: ______________ (Assigned by EC)

2.4 Name and address used by EC to locate the electric service account used to interconnect the Generating Facility with EC's Distribution System:

____

____

____

2.5 The Gross Nameplate Rating of the Generating Facility is: _____ kW.

2.6 The Net Nameplate Rating of the Generating Facility is _____ kW.

2.7 The expected annual energy production of the Generating Facility is ______ kWh.

2.8 For the purpose of securing the Competition Transition Charge exemption available under Section 372 of the California Public Utilities Code ("PUC"), EP hereby declares that the Generating Facility ❑ does / ❑ does not meet the requirements for "Cogeneration" as such term is used in Section 218.5 of the California Public Utilities Code.

2.9 The Generating Facility's expected date of Initial Operation is ____________.
The expected date of Initial Operation shall be within two years of the date of this Agreement.

3. DOCUMENTS INCLUDED; DEFINED TERMS

3.1 This Agreement includes the following exhibits which are specifically incorporated herein and made a part of this Agreement by this reference:

Appendix A- Description of Generating Facility and Single-Line Diagram

Appendix B- Copies of Rules 2 and 21 and other selected rules and tariffs of EC

Appendix C (When applicable) Copy of Interconnection Facility Financing and Ownership Agreement

3.2 When initially capitalized, whether in the singular or in the plural, the terms used herein shall have the meanings assigned to them either in this Agreement or in Rule 21 of EC's tariffs.

4. TERM AND TERMINATION

4.1 This Agreement shall become effective as of the last date entered in Section 16, below. The Agreement shall continue in full force and effect until the earliest date that one of the following events occurs:

(a) The Parties agree in writing to terminate the Agreement; or

(b) At 12:01 A.M. on the 61^{st} day after EP or EC provides written Notice (pursuant to Section 9, below) to the other Party of EP's or EC's intent to terminate this Agreement.

4.2 EP may elect to terminate this Agreement pursuant to the terms of Section 4.1(b) for any reason. EC may elect to terminate this Agreement pursuant to the terms of Section 4.1(b) for one or more of the following reasons:

(a) A change in applicable rules, tariffs, and regulations, as approved or directed by the CPUC, or a change in any local, state or federal law, statute or regulation, either of which materially alters or otherwise affects EC's ability or obligation to perform EC's duties under this Agreement; or,

(b) EP fails to take all corrective actions specified in EC's Notice that EP's Generating Facility is out of compliance with the terms of this Agreement within the time frame set forth in such Notice; or,

(c) EP fails to interconnect and operate the Generating Facility per the terms of this Agreement prior to 120 days after the date set forth in

Section 2.9, above, as the Generating Facility's expected date of Initial Operation; or,

(d) EP abandons the Generating Facility. EC shall deem the Generating Facility to be abandoned if EC determines, in its sole opinion, the Generating Facility is non-operational and EP does not provide a substantive response to EC's Notice of intent to terminate this Agreement as a result of EP's apparent abandonment of the Generating Facility affirming EP's intent and ability to continue to operate the Generating Facility.

4.3 Notwithstanding any other provisions of this Agreement, EC shall have the right to unilaterally file with the CPUC, pursuant to the CPUC's rules and regulations, an application to terminate this Agreement.

4.4 Any agreement attached to and incorporated into this Agreement shall terminate concurrently with this Agreement unless the Parties have agreed otherwise in writing.

5. GENERATING FACILITY OPERATION AND CERTIFICATION REQUIREMENTS

5.1 The electric power produced by EP's Generating Facility shall be used solely to serve electrical loads connected to the electric service account that EC uses to interconnect EP's Generating Facility (or, where permitted under Section 218 of the PUC, the electric loads of an on-site or neighboring party lawfully connected to EP's Generating Facility through EP's circuits). EP shall attempt in good faith to regulate the electric power output of EP's Generating Facility so as to prevent the flow of electric energy from the Generating Facility to EC's electric system. Unless otherwise agreed upon in writing by the Parties, this Agreement does not provide for, nor otherwise require EC to receive, purchase, transmit, distribute, or store the electrical power produced by EP's Generating Facility.

5.2 If EP declares that its Generating Facility meets the requirements for "Cogeneration" as such term is used in Section 218.5 of the PUC (or any successor definition of "Cogeneration") ("Cogeneration Requirements"), EP warrants that, beginning on the date of Initial Operation and continuing throughout the term of this Agreement, its Generating Facility shall continue to meet such Cogeneration Requirements. If EP becomes aware that its Generating Facility has ceased to meet the Cogeneration Requirements, EP shall promptly provide EC with Notice of such change pursuant to Section 9.1 below. If at any time during the term of this Agreement EC determines in its sole discretion that EP's Generating Facility may no longer meet the Cogeneration Requirements, EC may require EP to provide evidence that its Generating Facility continues to meet the Cogeneration Requirements within 15 business days of EC's request for such evidence. Additionally, EC may periodically (typically, once per year) inspect EP's Generating Facility and/or require documentation from EP to monitor the Generating Facility's compliance with Section 218.5 of the PUC. If EC determines in its sole judgment that EP either failed to provide evidence in a timely manner or that it provided insufficient evidence that its Generating Facility continues to meet the Cogeneration Requirements, then the Cogeneration status of the Generating Facility shall be deemed ineffective until such time as EP again demonstrates to EC's reasonable satisfaction that the Generating Facility meets the requirements for a Cogeneration facility (the "Status Change").

5.2.1 EC shall revise its records and the administration of this Agreement to reflect the Status Change and provide Notice to EP of the Status Change pursuant to Section 9.1 below. This Notice shall specify the effective date of the Status Change. This date shall be the first day of the calendar year for which EC determines in its sole discretion that the Generating Facility first ceased to meet the Cogeneration Requirements. EC's Notice shall include an invoice for Competition Transition Charges ("CTCs") that were not previously billed during the period between the effective date of the Status Change and the date of the Notice in reliance upon EP's representations that the Generating Facility complied with the Cogeneration Requirements and therefore was eligible for the exemption from CTCs available under Section 372 of the PUC.

5.2.2 Any amounts to be paid or refunded by EP, as may be invoiced by EC pursuant to the terms of this Section 5.9, shall be paid to EC within 30 days of EP's receipt of such invoice.

6. INTERCONNECTION FACILITIES

6.1 EP and/or EC, as appropriate, shall provide Interconnection Facilities that adequately protect EC's Distribution System, personnel, and other persons from damage or injury, which may be caused by the operation of EP's Generating Facility.

6.2 EP shall be solely responsible for the costs, design, purchase, construction, operation, and maintenance of the Interconnection Facilities that EP owns.

6.3 If the provisions of EC's Rule 21, or any other tariff or rule approved by the CPUC, requires EC to own and operate a portion of the Interconnection Facilities, EP and EC shall promptly execute an *Interconnection Facilities Financing and Operation Agreement* that establishes and allocates responsibility for the design, installation, operation, maintenance, and ownership of the Interconnection Facilities.

This *Interconnection Facilities Financing and Operation Agreement* shall be attached to and made a part of this Agreement as Appendix C.

7. LIMITATION OF LIABILITY

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages of any kind whatsoever.

8. INSURANCE

8.1 In connection with EP's performance of its duties and obligations under this Agreement, EP shall maintain, during the term of the Agreement, general liability insurance with a combined single limit of not less than:

(a) Two million dollars ($2,000,000) for each occurrence if the Gross Nameplate Rating of EP's Generating Facility is greater than one hundred (100) kW;

(b) One million dollars ($1,000,000) for each occurrence if the Gross Nameplate Rating of EP's Generating Facility is greater than twenty (20) kW and less than or equal to one hundred (100) kW; and

(c) Five hundred thousand dollars ($500,000) for each occurrence if the Gross Nameplate Rating of EP's Generating Facility is twenty (20) kW or less.

(d) Two hundred thousand dollars ($200,000) for each occurrence if the Gross Nameplate Rating of EP's Generating Facility is ten (10) kW or less and EP's Generating Facility is connected to an account receiving residential service from EC.

Such general liability insurance shall include coverage for "Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations."

8.2 The general liability insurance required in Section 8.1 shall, by endorsement to the policy or policies, (a) include EC as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that EC shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to EC prior to cancellation, termination, alteration, or material change of such insurance.

8.3 If EP's Generating Facility is connected to an account receiving residential service from EC and the requirement of Section 8.2(a) prevents EP from obtaining the insurance required in Section 8.1, then upon EP's written Notice to EC in accordance with Section 9.1, the requirements of Section 8.2(a) shall be waived.

8.4 Evidence of the insurance required in Section 8.2 shall state that coverage provided is primary and is not in excess to or contributing with any insurance or self-insurance maintained by EC.

8.5 EP shall furnish the required insurance certificates and endorsements to EC prior to Initial Operation of the Generating Facility. Thereafter, EC shall have the right to periodically inspect or obtain a copy of the original policy or policies of insurance.

8.6 If EP is self-insured with an established record of self-insurance, EP may comply with the following in lieu of Sections 8.1 through 8.4:

(a) EP shall provide to EC, at least thirty (30) calendar days prior to the date of Initial Operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under Section 8.1.

(b) If EP ceases to self-insure to the level required hereunder, or if EP are unable to provide continuing evidence of EP's ability to self-insure, EP agrees to immediately obtain the coverage required under Section 8.1.

8.7 All insurance certificates, statements of self insurance, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

EC Name
Attention: ______________
____
____
____

9. NOTICES

9.1 Any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person or sent by first class mail, postage prepaid, to the person specified below:

If to EC: EC Name
Attention: ______________
____
____
____

Phone: (   ) ________
FAX: (   ) ________

If to EP :   EP Name
Address: __________________
City: ___________________
Phone: (   ) ________
FAX: (   ) ________

9.2 A Party may change its address for Notices at any time by providing the other Party Notice of the change in accordance with Section 9.1.

9.3 The Parties may also designate operating representatives to conduct the daily communications, which may be necessary or convenient for the administration of this Agreement. Such designations, including names, addresses, and phone numbers may be communicated or revised by one Party's Notice to the other.

10. REVIEW OF RECORDS AND DATA

EC shall have the right to review and obtain copies of EP's operations and maintenance records, logs, or other information such as, unit availability, maintenance outages, circuit breaker operation requiring manual reset, relay targets and unusual events pertaining to EP's Generating Facility or its interconnection with EC's Distribution System.

11. ASSIGNMENT

EP shall not voluntarily assign its rights nor delegate its duties under this Agreement without EC's written consent. Any assignment or delegation EP makes without EC's written consent shall not be valid. EC shall not unreasonably withhold its consent to EP's assignment of this Agreement.

12. NON-WAIVER

None of the provisions of this Agreement shall be considered waived by a Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

13. GOVERNING LAW, JURISDICTION OF CPUC, INCLUSION OF EC's TARIFFS AND RULES

13.1 This Agreement shall be interpreted, governed, and construed under the laws of the State of California as if executed and to be performed wholly within the State of California without giving effect to choice of law provisions that might apply to the law of a different jurisdiction.

13.2 This Agreement shall, at all times, be subject to such changes or modifications by the CPUC as it may from time to time direct in the exercise of its jurisdiction.

13.3 The interconnection and services provided under this Agreement shall at all times be subject to the terms and conditions set forth in the tariff schedules and rules applicable to the electric service provided by EC, which tariff schedules and rules are hereby incorporated into this Agreement by this reference.

13.4 Notwithstanding any other provisions of this Agreement, EC shall have the right to unilaterally file with the CPUC, pursuant to the CPUC's rules and regulations, an application for change in rates, charges, classification, service, tariff or rule or any agreement relating thereto.

14. AMENDMENT AND MODIFICATION

This Agreement can only be amended or modified by a writing signed by both Parties.

15. ENTIRE AGREEMENT

This Agreement, including any incorporated tariff schedules and rules, contains the entire agreement and understanding between the Parties, their agents, and employees as to the subject matter of this Agreement. Each party also represents that in entering into this Agreement, it has not relied on any promise, inducement, representation, warranty, agreement or other statement not set forth in this Agreement or in the incorporated tariff schedules and rules.

16. SIGNATURES

IN WITNESS WHEREOF, the Parties hereto have caused two originals of this Agreement to be executed by their duly authorized representatives. This Agreement is effective as of the last date set forth below.

EP NAME		**EC NAME**	
By:	*SAMPLE* ____________________	By:	*SAMPLE* ____________________
Nam	____________________	Name:	____________________
Title	____________________	Title:	____________________
Date	____________________	Date:	____________________

APPENDIX A

DESCRIPTION OF GENERATING FACILITY
AND SINGLE-LINE DIAGRAM,
(Provided by EP)

APPENDIX B

RULES: “2” and “21”
TARIFF SCHEDULE: “S”- Standby
TARIFF SCHEDULES: ………

(Note: EC’s tariffs are included for reference only and shall at all times be subject to such changes or modifications by the CPUC as the CPUC may, from time to time, direct in the exercise of its jurisdiction.)

APPENDIX C

(When Applicable)

INTERCONNECTION FACILITIES FINANCING AND OWNERSHIP AGREEMENT

Attachment C – Interconnection Application Form

PART 1 To be filled out by all Applicants

Note: This Application must be filled out in accordance with Rule 21 of the CPUC Tarriff, "Interconnection Requirements", including Appendices A and B

Facility Information (Where will the Generating Facility be installed?)

Contact Person	Phone	Fax	Email Address

Company Name	EC Meter Number

Street Address	City	State	Zip Code

Mailing Address (if different from above)	City	State	Zip Code

Contractor / Installer Information (If different from above.)

Contact Person	Phone	Fax	Email Address

Company Name

Street Address	City	State	Zip Code

Mailing Address (if different from above)	City	State	Zip Code

Applicant Information (Who will be contractually obligated for this Generating Facility?)

Contact Person	Phone	Fax	Email Address

Company Name

Street Address	City	State	Zip Code

Mailing Address (if different from above)	City	State	Zip Code

Installation Questions

1. How many Generators do you intend to install behind the single meter covered by this Application for this Generating Facility?

   Number of Generators

Note:
Multiple Generators connected through a single interface and controlled as one generating set count as one Generating Facility.
Examples: photovoltaic panels connected through a single inverter or multiple micro-turbines connected through a single interface and controlled as one generating set count as one Generating Facility. If you plan to use more than one type of Generator, please provide the information for each type and specify how many of each type you plan to use.

2. Is any piece of generation equipment you are using Certified? (Appendix B, Rule 21)

   Yes No

If you answered "yes" to question #2, please attach your generation equipment certificate for each certified generation package. If every piece of equipment you are using is certified, go to question 3.
Note: If you want to check for certification, please contact the manufacturer of your Product.

2.1. Has any non-certified piece of generation equipment you are using received Electric Corporation Interim Certification (ECIC) approval?

Yes	No

If you answered "yes" to question #2.1, please enter the approval letter date for each piece of equipment that has received interim EC approval.

Approval date	Equipment Type	Approval date	Equipment Type

Note: Add additional sheets if necessary.

2.2. Is any piece of generation equipment you are using not Certified?

Yes	No

If you answered "yes" to question #2.2, please complete Part 2 for each non-certified or non-ECIC approved piece of generation equipment.

Note: You will need to fill out one Part 2 form for each non-certified Generator

Note: The following questions refer to Appendix A of Rule

3. Do you plan to export to the Distribution System?

If you answered "yes" to question 3, please continue to question 3.1.
If you answered "no" to question 3, please continue to question 3.2.

3.1 Is DG system a Qualifying Facility (QF) ?

Yes	No

If you answered "no" to question 3.1, STOP! You cannot apply with this form.

If you answered "yes" to question 3.1, please continue to question 3.1.1

3.1.1 Is the DG system < 100kW?

Yes	No

If you answered "yes" to question 3.1.1, please continue to question 3.1.1.1.
If you answered "no" to question 3.1.1, STOP! You cannot apply with this form.

3.1.1.1 What is the estimated net annual export in kWh?

Net Export kWh

3.2 Which if the four options do you choose as your non-export condition?

Note: See Appendix A of Rule 21

Option 1: Reverse power protection — Yes

Option 2: Underpower (always import) — Yes

Option 3: Limit incidental export of power* — Yes

*If you select this option, you must meet all the following conditions:

a. Aggregate DG capacity of the generating facility must be <=25% of nominal ampere rating of the Customer's Service Equipment.

b. Total Aggregate DG capacity of the generating facility must be <=50% of the transformer rating. *Note: Does not apply to customers taking primary service.*

c. DG must be certified as Non-Islanding.

Option 4: Operate at <50% of minimum load [ ] Yes

What is the minimum load at your facility? [ ] Minimum Load kW

4. Operational Information

4.1 What mode of operation do you plan?

As available [ ] Yes Peak shaving [ ] Yes Demand management [ ] Yes

Prime power (base load) [ ] Yes Combined Heat and Power [ ] Yes Load Following [ ] Yes

Other:Describe [ ]

4.2 What is your total estimated annual kilowatt-hr_production? [ ] Annual kWh Production

5. Does your DG start by using grid power (motoring)? [ ] Yes [ ] No

If you answered "no" to question 5, please skip to question 6.
If you answered "yes" to question 5, please answer the following questions.

5.1 What is your inrush current? [ ] Inrush

Note: If you don't know, call your DG manufacturer.

5.2 What is the continuous ampere rating of your Service Equipment? [ ] Ampere rating

6. Is the nameplate rating of this DG system 11kVA or less? [ ] Yes [ ] No

If the answer to question 6 is "yes", please skip to question 8.

Note: The DG system include all units interconnected behind the point of interconnection with the utility.

7. What is the short circuit contribution of the proposed DG system:

At the Generator terminals? [ ] Amps

Note: If the DG system is not Certified or if this information is not in the Certificate, you must answer Part 2, Question 6

At the point of common coupling? [ ] Amps

Note: adjustment for site/facility impedance to point ofcommmon coupling

7.1 Is the proposed DG system connected to the Distribution System through a transformer shared by other Customers? [ ] Yes [ ] No

Note: It may be necessary to contact the EC to obtain this information.

If the answer to question 7.1 is "yes", please answer question 7.2.
If the answer to question 7.1 is "no", please continue to question 8.

7.2 What is the interrupting rating of the other Customer's service panel?

Amps

8. Will you install a Dedicated Transformer?

If the answer to question 8. is "yes", please answer question 8.1.

If the answer to question 8. is "no", please continue to question 9.

Yes No

8.1 If you are adding a transformer, please provide:

Rating KVA Primary volts

Secondary Volts Impedance

9. What is your estimated date of initial operation?

Date of Operation

10. The following attachments must accompany Part 1 of the application when you submit it.

Single-line Drawing

Note: A sample Single-line drawing is included with this application.

Included

Site plan showing the location and arrangement of the major equipment (facility layout).

Note: This plan should include any customer-owned transformers.

Included

11. Please check this box if you wish the EC to bypass Initial Review and to provide you with a cost-estimate for the Interconnection Study:

Provide Cost Estimate

When you have completed this application, you may mail, express mail, email it to:
EC Name
EC address (for express mail)
P.O. Box
City, CA Zip Code
Phone:
Fax: E-Mail:

All completed applications must be accompanied by the Application Fee: A check in the amount of _________ payable to EC Name must accompany all completed Applications prior to EC commencing the Initial Review.

Note: If you choose to Fax, please contact EC to notify the date and time your successful Fax transmission occurred. It is the DG Customer's responsibility to ensure Application and Application Fee have been received by EC.

Part 2 To be filled out for all non-certified DG units or component types.

Note: Please fill out one Part 2 form for each non-certified Generator. multiple Generators connected through a single interface and controlled as one generating set count as one Generating Facility. Examples: photovoltaic panels connected through a single inverter or multiple micro-turbines connected through a single interface and controlled as one generating set count as one Generating Facility.

1. Is the unit a Pre-packaged prime mover/generator/inverter/controller system? [ ] Yes [ ] No

   If the answer is "no", please skip to question 2.
   If the answer is "yes", please answer the following questions:

   1.1 Who is the manufacturer? ______ Manufacturer Name

   1.2 What is the model number? ______ Model

2. What is the Gross and Net Nameplate Rating in kVA? ______ Gross kVA ______ Net kVA

   Note: Net kVA is net of auxiliary loads.

3. Prime Mover Information

   What is the prime mover technology? (Please check all appropriate boxes.)

   [ ] IC Engine [ ] Microturbine [ ] PV [ ] Fuel Cell [ ] Hydro [ ] Wind [ ] Comb. Turbine [ ] Steam Turbine

   ______ Other (please describe)

   Who is the prime mover manufacturer? ______ Manufacturer Name

   What is the prime mover model number? ______ Model

4. Generator/Inverter Information

   What is the generator/inverter technology? (check all appropriate boxes)

   [ ] Inverter [ ] Induction [ ] Synchronous [ ] Single phase [ ] Three phase

   Who is the generator/inverter manufacturer? ______ Manufacturer Name

   What is the generator/inverter model #? ______ Model

5. What is the power factor range? ______ Min ______ Max

   Is the range adjustable? [ ] Yes [ ] No

   Note: When paralleled with the distribution system, the unit is required to operate in power factor regulation mode (not in voltage regulation mode).

6. Short Circuit Current Capability

6.1 What is the short circuit current capability of the proposed DG system at the Generating Facility terminals? [ ] Amps [ ] Nominal Voltage

6.2 If you intend to have only one generating set behind the single meter covered by this application, please go to question 6.3.

If you intend to have more than one generating unit behind the meter:

What is the maximum number of units operating simultaneously? [ ] Number of Units

6.3 During a distribution system fault, what is your short circuit contribution, in amps? [ ] Amps

Note: To answer this question, you may need to gather the following from the Generator manufacturer:

> *Fault duration curve and fault current interrupt time of the interrupting device*
Or:

> *(Synchronous only) Fault current interrupt time of the interrupting device;*
Direct axis synchronous reactance (Xd) – contact Generating Facility mfr
Direct axis transient reactance (X'd)
Direct axis subtransient reactance (X"d)
Or:

> *(Synchronous only) Inertia constant of prime mover or Generator, whichever is greater.*
Direct axis synchronous reactance (Xd) – contact Generating Facility mfr
Direct axis transient reactance (X'd)
Direct axis subtransient reactance (X"d)

7. The following attachments must accompany Part 2 of the application when you submit it:

7.1 Complete and accurate protection diagrams including single-line meter relay and logic diagrams. [ ] Included

7.2 A description of the proposed protection schemes and description of operations. [ ] Included

7.3 Maintenance plans for the interconnection protective devices and interconnection interrupting devices. [ ] Included

7.4 All available results from testing and certification that may assist in obtaining interim approval [ ] Included

Part 3 For Electric Corporation's Use Only

1. Is this DG on a network system?

2. When installed, will total DG capacity exceed 15% of peak load of the line section to which this DG system is connected?

3. What is the distribution line configuration?

4. What is the Interconnection Voltage?

5 EC assigns an Application ID number in the following format:
MMYY-0000-AAA
MonthYear-Four digit number-EC Acronym

6 EC assigns Generating Facility IDs to each Generating Facility Set.