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Project Number: IB0402

45-IB-0402

# A COMPARISON OF DISTRIBUTED GENERATION POLICY IN MASSACHUSETTS AND CALIFORNIA

An Interactive Qualifying Project Report

submitted to the Faculty

of the

WORCESTER POLYTECHNIC INSTITUTE

in partial fulfillment of the requirements for the

Degree of Bachelor of Science

by


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Date: August 12, 2003

Approved:

**1. Distributed Generation**
**2. Electricity**
**3. Interconnection**

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# Acknowledgements

I would like to thank Professor Isa Bar-On for her continued support throughout this project.

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**APPENDICES**

# Abstract

Distributed generation (DG) allows electric company customers to generate their own power. Many states have developed policies and standards regarding interconnection of DG equipment to the electric grid. These policies and standards were examined and compared in Massachusetts and California. This comparison showed that California is encouraging DG use more than Massachusetts. Several factors were identified which may explain these differences. These factors include population growth rates and the current energy crisis in California.

# 1. Introduction

Distributed Generation (hereinafter "DG") allows electric company customers to generate some or all of their power on location, rather than rely on the electric grid.[1] DG has many capabilities that make it a viable alternative power source for customers of the newly restructured electric industry. Technological advances have created DG technologies that have many advantages over conventional grid power. Some of these advantages include lower emissions, higher efficiencies, and reliability, when compared to traditional grid power.

Although there are many benefits to DG, there are still barriers to widespread use. Emerging technologies, such as fuel cells and microturbines, have high initial costs as well as maintenance costs that are relatively unknown. Interconnection of a DG unit to the existing electric grid can act as an obstruction to DG use. However, safe interconnection is necessary for both the electric customer and supplier. It is for this reason that many states are developing, or have developed, standards and policies that govern the interconnection process. These standards and policies address interconnection issues such as: the application process, associated costs, different review paths[2], time frames, equipment testing and reliability, safety, dispute resolution, and related tariffs. However, the content of these standards and policies may affect DG use. Regions that are lenient towards interconnection policy will encourage interconnection more than states with stringent interconnection policies. These differences in policies can be explained through supply and demand. The use of DG, over time, would decrease the demand for power supplied by the electric grid. This becomes critical in regions with limited power supply capabilities and an increasing demand for power.

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[1] This is a general definition of distributed generation. DG can exist as "stand alone" or "hook up." Stand alone DG refers to generators that are not connected to the electric grid, such as those commonly used in construction.
PLEASE NOTE: The term "DG" as used in this report refers mainly to power generating equipment that are interconnected with an electric distribution system.

[2] Review paths are the different means by which interconnection applications are examined, depending on the type, size, etc. of the DG equipment. Review paths are discussed later in the report

California is at the forefront of DG development and implementation in the United States. Their policies and standards had been developed several years before most other states. Here in Massachusetts, policies and standards regarding DG have only recently be put into place. Several stakeholders participated in the development of these policies and standards. These stakeholders include DG equipment providers, governmental agencies, consumer groups, electric utilities, and other public interest groups. Synopses of both states' policies and standards have been given.

These policies and standards were compared in order to determine similarities and differences between the two. These differences can demonstrate how serious each state is about using DG. California's progress in this field will also show where Massachusetts stands in comparison. Programs and policies that exist in California are used to show that they are encouraging DG deployment. These programs and policies will also show where Massachusetts is lacking in comparison.

Finally, different factors that may influence these policies and standards are discussed. A comparison of these factors will show how and why the two states policies and standards towards DG differ. These factors are used to show why, or why not, each state is encouraging DG deployment through their policies, standards, and programs.

## 2. Background of DG

Interest in DG has been growing over the past few years. Several factors have contributed to this. Power consumption will continue rising as the population increases, however some grids are not capable of supplying that power. There is also a demand for high quality power that is reliable in many industries. Investments in large generating facilities have decreased due to governmental restraints. The restructuring of the power industry in the late twentieth century has deterred utilities from constructing new generating facilities. Finally, advancements in technology have created DG devices with larger efficiencies, lower costs, and more environmental benefits when compared to current generation equipment. All of these factors have created a growing interest in the use of DG.[3]

### 2.1 PURPA

The Public Utility Regulatory Policy Act (PURPA) was issued during the energy crises of the 1970s. Congress was attempting to reduce American dependency on foreign oil by encouraging the use of alternative energy sources. Congress was also trying to promote energy efficiency and expand the electric power industry. PURPA allowed non-utility power generators to enter the energy market, and also required the utilities to purchase this power from the independent generators.[4]

PURPA was the first major step towards promoting renewable energy. It is the basis for the electric industry restructuring of the last decade. PURPA marks the beginning of the United State's progress towards the regulated use of DG.

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[3] California Distributed Energy Resource Guide: Market Status and Outlook
www.energy.ca.gov/distgen/markets/status.html

[4] Union of Concerned Scientists, *Backgrounder: PURPA*
*www.ucsusa.org/clean_energy/renewable_energy/page.cfm?pageID=119*

## 2.2 DG Applications

DG has many applications for residential, commercial and industrial use. Nine major customer DG applications have been identified by www.distributed-generation.com. They are:

1) Customer Generation
2) Cogeneration
3) Peak Shaving
4) Selling Power to the Grid Under Net Metering
5) Standby/Emergency Generation
6) Premium Power
7) Green Power
8) Remote Power
9) Residential Fuel Cells

Customers who choose to generate their own power can do so with or without backup power supplied by the grid. This is useful for customers in areas common to power outages.

Cogeneration makes use of the thermal energy contained in the exhaust produced by the system. Cogeneration is also known as combined heat and power (CHP).

Peak shaving is done during peak pricing periods. Electricity is generated onsite in order to reduce the amount of power supplied by the grid, thus reducing costs during peak pricing periods. Peak shaving also reduces the amount of load on the grid.

Net metering permits customers to sell excess power back to the electric company through the grid. This gives a DG customer some incentive for installation. However, net metering is not offered in all parts of the country.

Standby and emergency generation is currently in use at some facilities where it is necessary to have power at all times. It can be used to backup the power supplied by the grid or supply necessary power during outages. This is necessary for facilities such as hospitals, banks, and airports.

Premium power describes both the power quality and reliability. Premium power is useful for industries that require the use of use precision equipment.

Green power is electricity that is produced in an environmentally friendly manner. Wind turbines and photovoltaics are good examples of green power. Green power is an attractive alternative for environmentally conscious electric customers. Green power is also well-suited for use in remote locations, such as farms.

Remote power is suitable for electric company customers located towards the end of a distribution line. These customers can experience more outages and lower quality power than others. DG could eliminate these problems.

Residential fuel cells could be possible if mass production of fuel cells became commonplace. This would decrease initial costs while providing residents with a clean, reliable, and efficient source of power.

## 2.3 DG Technologies

DG is available in many forms. Each type possesses certain characteristics that make it suitable for certain applications. Below is a short description of the different DG technologies that are currently available.

Reciprocating diesel or natural gas engines are a technology that has been available for over 100 years. It is available in many sizes, ranging from small scale generators to 60 MW power plants. Emission outputs of these engines vary depending on the engine. This technology is widely available for continuous or emergency power. Cogeneration systems can be combined with reciprocating engines to recover heat from the exhaust.

Microturbines are an emerging technology that is intended for use in small scale (30-400 kW) applications. They are a technology that is not yet widely available.

Technological improvements on fuel cells in recent years have made them a reliable source of power. Fuel cells are quiet, produce low emissions, and have high efficiencies. However, manufacturing costs are still high and maintenance costs remain relatively unknown.

Photovoltaics, more commonly known as solar panels, are capable of converting light energy into electricity. These systems produce no emissions. They are also reliable and require minimal maintenance. However, photovoltaics have higher initial costs than most other DG technologies. Costs range from about $4500 to $6000 per kW. (See table 2.2)

Wind turbines are a mature technology that utilizes an infinite energy, the wind. Older wind turbines converted this wing energy into mechanical. However, through the use of generators, the wind can be converted into electrical energy.

A comparison of these different DG technologies can be seen in table 2.1.

*Table 2.1 ~ Comparison of DG Technologies*[5]

| Technology | Recip. Engine: Diesel | Recip. Engine: NG | Microturbine | Combustion Gas Turbine | Fuel Cell |
|---|---|---|---|---|---|
| **Size** | 30kW - 6+MW | 30kW - 6+MW | 30-400kW | 0.5 - 30+MW | 100-3000kW |
| **Installed Cost ($/kW)** | 600-1,000 | 700-1,200 | 1,200-1,700 | 400-900 | 4,000-5,000 |
| **Elec. Efficiency (LHV)** | 30-43% | 30-42% | 14-30% | 21-40% | 36-50% |
| **Overall Efficiency** | ~80-85% | ~80-85% | ~80-85% | ~80-90% | ~80-85% |
| **Total Maintenance Costs ($/kWh)** | 0.005 - 0.015 | 0.007-0.020 | 0.008-0.015 | 0.004-0.010 | 0.0019-0.0153 |
| **Footprint ($ft^2$/kW)** | .22-.31 | .28-.37 | .15-.35 | .02-.61 | .9 |
| **Emissions (gm / bhp-hr unless otherwise noted)** | $NO_x$: 7-9<br><br>CO: 0.3-0.7 | $NO_x$: 0.7-13<br><br>CO: 1-2 | $NO_x$: 9-50ppm<br><br>CO: 9-50ppm | $NO_x$: <9-50ppm<br><br>CO:<15-50ppm | $NO_x$: <0.02<br><br>CO: <0.01 |

## 2.4 Problems Associated with DG

Although DG seems to be a qualified technology, several barriers still exist before it will become commonplace.

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[5] www.distributed-generation.com/technologies.htm

High initial costs and relatively unknown maintenance costs may deter customers from interconnecting DG equipment. These costs are expected to decrease with time due to high volume manufacturing. Cost estimates for different DG technologies can be seen in tables 2.2 and 2.3.

*Table 2.2 ~ Predicted Costs for DG Equipment*[6]

| Capital Costs of Selected DER Equipment[7] | |
|---|---|
| | ***Capital Cost ($/kW)*** |
| Microturbine | 700-1100 |
| Combustion Turbine | 300-1000 |
| IC Engine | 300-800 |
| Stirling Engine | 2,000-50,000 |
| Fuel Cell | 3,500-10,000 |
| Photovoltaic | 4,500-6,000 |
| Wind Turbine | 800-3,500 |

*Table 2.3 ~ Operation and Maintenance Costs*

| O&M Costs of Selected DER Equipment | | |
|---|---|---|
| | **Time Until Maintenance Required (hours of operation)** | **Average Maintenance Costs (¢/kWh)** |
| Microturbine | 5,000-8,000 | 0.5-1.6 (estimated) |
| Combustion Turbine | 4,000-8,000 | 0.4-0.5 |
| Internal Combustion Engine | 750-1,000: change oil and oil filter<br>8,000: rebuild engine head<br>16,000: rebuild engine block | 0.7-1.5 (natural gas)<br>0.5-1.0 (diesel) |
| Fuel Cell | Yearly: fuel supply system check<br>Yearly: reformer system check<br>40,000: replace cell stack | 0.5-1.0 (estimated) |
| Photovoltaic | Biyearly maintenance check | 1% of initial investment per year |
| Wind Turbine | Biyearly maintenance check | 1.5-2% of initial investment per year |

[6] California Distributed Energy Resource Guide: Economics of Owning and Operating DER Technologies www.energy.ca.gov/distgen/economics/capital.html

[7] California's *Distributed Energy Resource Guide* refers to DG as DER (Distributed Energy Resources)

Safe interconnection to the existing electric grid is still one of the main challenges for DG. Interconnection must be safe on both sides of the DG equipment. It cannot pose a safety hazard for the DG customer, and it cannot interrupt or alter the power supplied by the grid, which could create a safety hazard in the distribution system. It is for this reason that interconnection standards and policies are necessary.

Interconnecting DG to a secondary networked circuit creates more challenges than interconnecting to a radial circuit. A customer that is connected to a networked circuit has power being delivered by more than one electrical feeder at the point of common coupling[8]. Secondary networks make for tolerable transformer loading in emergencies, and have higher service reliability than radial circuits. Radial circuits have only one electrical feeder, so there is only one path for electrical current[9]. Secondary networks are more common to urban areas, while radial systems are found in less developed regions.

The complexity of networked systems makes for more difficult interconnection. Interconnection applications for DG equipment on networked systems undergo a more costly and intensive review than radial systems. Maintaining the reliability of a networked system is a major technical challenge for interconnection.[10]

Another safety concern is the potential for DG equipment to disrupt the transmission grid. This could occur during regular operation, or malfunctioning of the DG equipment. This also creates the need for standards that ensure safe operation.

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[8] Point of common coupling – transfer point for electricity between Electrical Corporation and Electricity Producer

[9] *California Distributed Energy Resource Guide*

[10] *Proposed Uniform Standards for Interconnecting Distributed Generation in Massachusetts*

## 3. DG in Massachusetts

Massachusetts has just recently taken its first steps towards DG usage. Below is a description of the different orders which eventually led to development of interconnection policy.

### 3.1 History of DG Policy

The Massachusetts Department of Telecommunications and Energy (D.T.E) have issued several orders pertaining to DG. These orders are the foundation for the interconnection standards and policies that were developed over the past few months. Below is a brief summary of each of these orders and their relevance to the development of DG policy.

*DTE 01-54 ~ Investigation by the DTE on its own Motion into Competitive Market Initiatives: Order Opening Investigation into Competitive Market Initiatives*

This 2001 order mainly concerns the progress of Massachusetts' restructured electric industry. There is a small paragraph on page 11 of this document, in a section titled "Other Issues," that deals with DG. It is stated within this paragraph, "[DG] has the potential to be a viable competitive alternative to customers in the restructured industry. It could also be a key contributor to establishing load response capabilities. The lack of uniformity and uncertainty regarding interconnection standards and back-up rates could be inhibiting the installation of [DG] in Massachusetts. The Department will investigate these issues in a separate proceeding." This statement marks the beginning of Massachusetts' progress towards standardizing DG.

*DTE 02-38 ~ Investigation by the DTE on its own Motion into Distributed Generation: Order Opening Investigation into Distributed Generation*
*June 13, 2002*

This order begins by referencing the statements made in DTE 01-54. It also addresses the fact that there are safety and reliability issues concerning the installation of DG. The DTE goes on to identify the three issues as the focus of this investigation:

1. "The development of interconnection standards and practices that do not threaten the reliability or safety of existing distribution systems, but also do not present undue barriers to the installation of DG"

2. "The appropriate method for the calculation of standby or back-up rates and other charges associated with the installation of DG"
3. "The appropriate role of DG in distribution company resource planning"

The investigation focuses on these three issues but does not limit itself to them. The DTE also identifies fuel source and storage, adequacy of natural gas pipeline supply, siting, zoning, and environmental impacts as other issues of concern.

The DTE goes on to address each of the three main issues separately. They identify the fact that safety is a main concern, but also note that unnecessarily restrictive policies and standards can inhibit the use of DG. The DTE also mentions that several states have established state-wide interconnection standards and that IEEE is developing universal interconnection standards for DG.

The DTE acknowledges that DG customers will often rely on distribution companies for standby or back-up power. They also state that DG customers must pay their share of distribution costs, whether they are using grid power or not. The DTE then raises the question of how these rates should be established.

The third issue concerns how DG will affect distribution companies' infrastructure. The DTE states that DG can prevent or delay upgrades and additions to a transmission and distribution system.

*DTE 02-38-A ~ Investigation by the DTE on its own Motion into Distributed Generation: Order Establishing a DG Collaborative Forum*
*October 3, 2002*

This order begins by referring to comments made in the previous orders discussed above. The DTE recognizes the need to address the issues outlined in DTE 02-38. The DTE decided that a collaborative forum would be an appropriate way to establish uniform interconnection standards, policies and procedures for the state of Massachusetts. This forum was to be composed of The Fitchburg Gas and Electric Light Company, Massachusetts Electric Company, Nantucket Electric Company, NSTAR Electric, and Western Massachusetts Electric Company. The standards, policies, and procedures developed by the forum would be applicable to all distribution companies, subject to

DTE approval. The DTE recommends that the content of these interconnection standards be guided by:

1. Simplified, state-wide technical interconnection standards for small DG.
2. Simplified, state-wide technical standards for all remaining DG
3. A state-wide interconnection agreement
4. Interconnection procedures, standardized to the greatest extent possible, including provisions that clarify interconnecting to a network system (compared to a radial system) and equipment pre-approval so that conforming components receive pre-approval by electric distribution companies.
5. A time schedule for responding to interconnection applications
6. A plan to develop and post a generic document describing interconnection procedures
7. An administratively efficient dispute resolution process.

The DTE also notes that interconnection standards are being developed by the Federal Energy Regulatory Commission (FERC). They ask the forum to consider this while developing the proposal.

### 3.2 Summary of Proposed Interconnection Standards for DG

On March 3, 2003, the "Distributed Generation Interconnection Collaborative" (Collaborative) submitted the *Proposed Uniform Standards for Interconnecting Distributed Generation in Massachusetts* to the DTE. The Collaborative was composed of DG providers, government and quasi government agencies, consumers, utilities and public interest groups. Dr Jonathan Raab, the mediator for the Collaborative, states in his cover letter to the DTE:

> *"The report describes a comprehensive starting point for DG interconnection in the Commonwealth covering all sizes of DG on both radial and secondary network systems. It includes a detailed process narrative, timeframes, a fee structure, an alternative dispute resolution (ADR) process, interconnection requirements, a mechanism for tracking interconnections experience over time, and an application form"*

This statement identifies the main focuses of the document. The Collaborative then goes on to identify their seven guidelines as stated in DTE 02-38-A above.

Section 2 of the document identifies eight goals for DG interconnection. The goals, for both radial and network connections, are:

1) Establish uniformity between the Companies where applicable without sacrificing existing efficiencies in current interconnection standards or other customer services.
2) Incorporate the best features of existing interconnection policies and procedures nationally, and take into account the FERC ANOPR[11] process.
3) Maintain or exceed the current level of system reliability.
4) Maintain or exceed the current level of safety to the Company work force and the public.
5) Expedite the timeframes for interconnection approvals.
6) Establish minimal fees appropriate to the scope of work, based upon experience.
7) Develop a cost effective process that allows a Customer/Installer to determine within a predictable timeframe the expected scope and cost of the interconnection process.
8) Establish expeditious and cost-effective approaches for interconnecting on spot and area networks.

In section two, the collaborative also agrees to meet quarterly for the next two years to examine interconnection experiences in Massachusetts as well as the United States.

Section three of the interconnection standards distinguishes between the three review paths that anyone installing DG will fall under. The Collaborative defines these review paths as follows.

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[11] ANOPR stands for Advance Notice Of Proposed Rulemaking. This was issued by the FERC in Oct. 2001 announcing that discussions concerning *Standardizing Interconnection Agreements and Procedures* were underway. Edison Electric Institute, www.eei.org/industry_issues/electricity_policy...

**Simplified** – This is for qualified inverter based facilities[12] with a power rating of 10 kW or less on radial or spot network systems under certain conditions,

**Expedited** – This is for certified facilities that pass certain pre-specified screens on a radial system.

**Standard** – This is for all facilities not qualifying for either the Simplified or Expedited interconnection review processes on radial and spot network systems, and for all facilities on area network systems.

Simplified connection is only applicable to customers using UL 1741 certified inverter-based facilities. The aggregate generating capacity on the circuit must also be less than 7.5% of the annual peak load. This interconnection path will mainly apply to radial systems. Facilities on spot network systems will only qualify under certain conditions. Simplified interconnection is the fastest and least costly of the three. Schematics of the review processes can be seen in the appendix.

If a customer is not likely to enter into simplified or expedited review, they may choose to go directly to standard review. Customers who wish to interconnect on area networks must also go directly to standard review, which is the most costly and time consuming of the three review paths.

If a customer does not qualify for simplified review or does not go directly to standard review, they must pass a series of screens before qualifying for expedited interconnection.

Section four identifies the time frames and fee schedules for the interconnection process. These can be seen in tables 3.1 and 3.2.

[12] Inverter based facilities are DG equipment that use an inverter to convert DC into AC power

*Table 3.1 ~ Interconnection Time Frames*

| | Track | | | |
|---|---|---|---|---|
| Review Process | Simplified | Expedited | Standard Review | Simplified Spot Network |
| Eligible Facilities | Certified Inverter = 10 kW | Qualified DG | Any DG | Certified Inverter < = |
| Acknowledge receipt of Application | (3 days) | (3 days) | (3 days) | (3 days) |
| Review Application for completeness | 10 days | 10 days | 10 days | 10 days |
| Complete Review of all screens | 10 days | 25 days | n/a | Site review 30/90 days (Note 2) |
| Complete Supplemental Review (if needed) | n/a | 20 days | n/a | n/a |
| Complete Standard Interconnection Process Initial Review | n/a | | 20 days | n/a |
| Send Follow-on Studies Cost/Agreement | n/a | | 5 days | n/a |
| Complete Impact Study (if needed) | n/a | | 55 days | n/a |
| Complete Facility Study (if needed) | n/a | | 30 days | n/a |
| Send Executable Agreement (Note 3) | Done | 10 days | 15 days | Done (comparable to simplified radial) |
| Total Maximum Days (Note 4) | 15 days | 40/60 (Note 5) | 125/150 days (note 6) | 40/100 days |
| Notice/ Witness Test | < 1 day with 10 day notice or by mutual agreement | 1-2 days with 10 day notice or by mutual agreement | By mutual agreement | 1 day with 10- day notice or by mutual agreement |

*Table 3.2 ~ Interconnection Fee Schedules*

| | **Track** | | | |
|---|---|---|---|---|
| Review Process | Simplified | Expedited | Standard Interconnection Process Review | Simplified Spot Network |
| Eligible Facilities | Certified Inverter = 10 kW | Qualified DG | Any DG | Certified Inverter = 10 kW |
| Application Fee (covers screens) | 0 (Note 1) | $3/kW with minimum fee $300, maximum fee $2,500 | $3/kW with minimum fee $300, maximum fee $2,500 | $100 for less than or equal to 3kW, $300 if >3kW |
| Supplemental Review or additional review (if applicable) | n/a | Up to 10 engineering hours at $125/hr ($1,250 max) (Note 2) | n/a | n/a |
| Standard Interconnection Initial Review | n/a | n/a | Included in application fee (if applicable) | n/a |
| Impact and Facility Study (if required) | n/a | n/a | Actual cost (Note 3) | n/a |
| Facility Upgrades | n/a (Note 4) | Actual cost | Actual cost | n/a |
| O and M (Note 5) | n/a | TBD | TBD | n/a |
| Witness test | 0 | Actual cost, up to $300 + travel time (Note 6) | Actual cost | 0 (Note 7) |
| ADR costs | TBD | TBD | TBD | TBD |

The notes to accompany these tables can be seen in Appendix A.

# 4. DG in California

California is considered by many to be a leader for promoting DG use. Although most DG policies are fairly recent, California is several years ahead of most other states, including Massachusetts.

## 4.1 Summary of Order Instituting Rulemaking into DG

This decision was filed in December of 2000. The California Energy Commission utilized a workshop process to revise the existing interconnection rules. Several goals were set forth for the workshop. The main goal was to *simplify and standardize* utility interconnection protocols. Development of a proposed tariff rule language to apply to all DG facilities seeking to interconnect was the other objective for the workshop.

This decision also includes an interconnection application that can be seen in Appendix B. The Energy Commission states, "Development of a comprehensive and user-friendly application form was a major goal…" They acknowledge that the application must supply sufficient information to allow accurate evaluation of the interconnection requirements for the DG facility. However, they also recognize that the application should not be burdensome, which would serve as a "barrier to entry."

## 4.2 Summary of California Distributed Energy Resource Guide: Electrical Interconnection Procedures

This (DATE) document begins with the application process for interconnecting Distributed Energy Resources (DER) to the electric grid. This process involves several standardized steps.

The interconnection process begins with the applicant initiating contact with the electrical corporation. The electric company provides the applicant with application forms, documents and technical requirements, as well as a contact person for the interconnection process. Once the application is completed, the utility will acknowledge receiving it and confirm that it has been completed. The electric company will then generate initial cost estimates and interconnection requirements. An initial review will also be completed in order to determine which type of interconnection process will be undertaken.

California defines their two types of interconnection as *Simplified Interconnection* and *Interconnection Subject to Additional Requirements*. Descriptions of the interconnection requirements are provided by the utility if simplified interconnection is applied. The utility will also supply a draft interconnection agreement. All customers not qualifying for simplified connection will undergo a supplemental review, which qualifies for the second type of interconnection. The supplemental review provides customers with one of two things:

1) Interconnection requirements that may include additional requirements beyond simplified interconnection and a draft interconnection agreement.
2) A cost estimate and schedule for an interconnection study. In this case, the applicant and utility shall enter into an interconnection study agreement. After completion of an interconnection study, the utility will provide the applicant with specific requirements, costs, and a schedule for the interconnection of the DER device.

The customer and utility may then enter into a generation interconnection agreement. This may also include a net energy metering agreement or power purchase agreement, depending on the DER device and its mode of operation.

Once the agreements have been completed, installation of the DER device may begin. The applicant is responsible for interconnection in concurrence with the agreement. The DER device can then be tested to make sure it complies with the CPUC[13] regulations for safety and reliability. After completion of all testing, the DER device may begin operating.

[13] California Public Utilities Commission

## 4.3 Incentives to Interconnect

Within the electrical interconnection procedures for California, Public Utilities Code 2827 is mentioned. This code is one of the driving forces behind the widespread use of DG in California. It is intended to remove any "unreasonable barriers" to customer interconnection.[14]

The CPUC is attempting to lower demand for electricity during peak periods by offering incentives to customers of investor owned utilities to install DG. These incentives are offered to customers that install microturbines, small gas turbines, wind turbines, fuel cells and internal combustion engines for all or some of their electrical needs. However, incentives are not provided for customers using DG as back-up power or customers using diesel power. These incentives can be seen in table 4.1.

*Table 4.1 ~ CPUC Incentive Payments*[15]

| Incentive category | Incentive offered | Maximum percentage of project cost | Minimum system size | Maximum system size | Eligible Technologies |
|---|---|---|---|---|---|
| **Level 1** | $4.50/W | 50% | 30 kW | 1 MW | ▪ Photovoltaics<br>▪ Fuel cells operating on renewable fuel<br>▪ Wind turbines |
| **Level 2** | $2.50/W | 40% | None | 1 MW | ▪ Fuel cells operating on non-renewable fuel and utilizing sufficient waste heat recovery |
| **Level 3** | $1.00/W | 30% | None | 1 MW | ▪ Microturbines utilizing sufficient waste heat recovery and meeting reliability criteria<br>▪ Internal combustion engines and small gas turbines, both utilizing sufficient waste heat recovery and meeting reliability criteria |

[14] California State Association of Counties: *CPUC Distributed Generation Policies and Programs* www.csac.counties.org/legislation/energy/distributed_policies.pdf

[15] www.cpuc.ca.gov/published/final_decision/6083.htm#P78_2015

## 4.4 Plans for DG Development in California

In June of 2002, the California Energy Commission issued the *Distributed Generation Strategic Plan.* This document includes recommended policies and strategies for DG in California. It acknowledges that DG use can go one of two paths. DG has the potential to be a major provider to the electric system. However, it could also go overlooked and only be used for remote or emergency power. This plan is intended to push DG towards the first of the two.

## 4.5 California Interconnection Guidebook[16]

This (draft) was prepared for the California Energy Commission and submitted in early July of 2003. The guidebook contains the subtitle "*A Guide to Interconnecting Customer-owned Electric Generation Equipment to the Electric Utility Distribution System Using California Electric Rule 21.*" This document is intended to simplify the Rule 21 (interconnection requirements) language in order to assist the customer in the interconnection process. This 90 page guidebook discusses the electric distribution system, the interconnection application and review process, equipment requirements and installation, along with all other aspects of interconnection.

[16] California Interconnection Guidebook
www.energy.ca.gov/distgen/interconnection/2003-07-10_DRAFTGUIDEBOOK.PDF

# 5. Comparison of Policy

Several differences are present in each state's standards and policies for DG. These differences will later be explained by examining different factors that exist in each state. These factors can both reflect and influence DG standards and policies.

It is clear that California is at a further stage of DG implementation than Massachusetts. This can be illustrated in two ways. The policies that presently exist in Massachusetts can be compared to those of California. Also, policies that exist only in California can demonstrate where Massachusetts is lacking.

## 5.1 The Application Process

Massachusetts' proposed interconnection standards only briefly discuss the application process in the main text of the document. Section three ("Process for DG Interconnection in MA") is mainly concerned with the review paths. However, application fees associated with each review path are discussed briefly. Timeframes regarding the application process are also briefly discussed. The timeframes and fee schedules can be seen in tables 3.1 and 3.2 above.

Appendix A of the Massachusetts interconnection requirements contains the application instructions and form. This form can also be seen in appendix A of this report. Customers that qualify for the simplified review path must complete a relatively short form and attach documentation that their generating equipment is UL 1741[17] listed. However, if expedited or standard interconnection is anticipated, the application form asks for very specific technical data pertaining to the generating equipment. The requested technical data contains no explanation of what it means or where it can be found.

In the CPUC's 2000 *Decision Adopting Interconnection Standards,* it is stated that "Development of a comprehensive and user-friendly application form was a major

[17] UL 1741 is a standard for power supply systems that covers inverters, converters, and controllers.

goal…" The CPUC also acknowledges that the application must contain in information for accurate assessment, but not be "burdensome so as to serve as a barrier to entry." An overview of the application process is given at the beginning of the California Distributed Energy Resource Guide, as discussed in section 4.2. It summarizes each step of the interconnection process and also discusses them in detail later in the document. The California interconnection application form can be found in appendix B.

The application form requests technical data similar to that of Massachusetts'. However, there are notes imbedded within the form that aid the applicant through the process. The *California Interconnection Guidebook (draft)* also contains detailed information about the interconnection application, as well as the interconnection process.

Examination of the application form and process shows that California utilizes a more "customer-friendly" approach than Massachusetts. Information and instructions for the application process is provided in the California interconnection guidebook. There are also instructions for the application imbedded within the form. The application process is one of the first steps towards DG interconnection. Therefore a simpler, user-friendly application will encourage customers to go through with the interconnection process.

### 5.2 Interconnection Review Paths

Both states utilize different review paths in order to simplify the interconnection process. These review paths should allow less complex interconnections to be approved quickly and painlessly. More complicated (i.e. larger systems) must pass supplementary requirements through other review paths.

Massachusetts has distinguished three separate review paths; simplified, expedited, and standard. California chose to use only two review paths; simplified and interconnection subject to additional requirements. However, two classes exist within the second of the two, as discussed in section 4.2.

Simplified interconnection exists in both states. This is the least costly and most efficient review path. Schematics of the simplified review process can be seen in figures A.2 (MA) and B.1 (CA). Examination of the requirements for simplified interconnection shows many similarities. Due to development dates, it is possible that Massachusetts used California's requirements as a starting point.

More complicated interconnections, such as expedited and standard review in Massachusetts and interconnection subject to additional requirements in California, must undergo a more extensive review. Again, the review paths are very similar in both states.

## 5.3 Where Massachusetts is Lacking

It is clear that California's DG standards and policies are at a further stage of development than Massachusetts'. This could be because California began DG legislation several years before Massachusetts. However, some documents and policies that exist in California cannot be compared to anything in Massachusetts. Therefore these documents can be used to show how California is pushing for DG use, while Massachusetts is not.

### 5.3.1 Interconnection Incentives

The CPUC's *Self Generation Incentive Program* is a good example of California encouraging deployment of DG. This program, which was introduced shortly after the interconnection standards, provides monetary incentives to customers of investor-owned utilities who decide to interconnect. This program is designed to reduce load on the distribution system during peak periods. The CPUC's incentive payments can be seen in table 4.1. On the contrary to this program, Massachusetts concentrates on fees associated with interconnection in section three of the proposed interconnection standards.

### 5.3.2 Strategic Planning

The 2002 *Distributed Generation Strategic Plan* issued by the California Energy Commission also shows where Massachusetts has fallen behind. As discussed above, this document outlines strategies and goals, both short and long term, for encouraging DG deployment. A document of this type shows that California is serious about DG use.

### 5.3.3 Interconnection Guidance

Customers who are interested in interconnection may, or may not, be acquainted with the interconnection process. The (draft) interconnection guidebook that was recently developed for Californians is intended to familiarize customers with the interconnection process. A document of this type is nonexistent in Massachusetts. This also shows that California is encouraging the use of DG by attempting to clarify the standards and policies for interested parties.

# 6. Factors that can Influence DG Policy

The differences that are discussed in section 5 can show that California is making more of an effort of encouraging DG use among its residents. This section attempts to explain why this is. Several factors have been identified as possible contributors to the differences that arise in section 5. These factors can influence DG policymakers, causing the outcome to encourage DG use.

## 6.1 Population

It is a common theory that demand for electricity will increase with population. The electric grid must be capable of supplying this power, or else upgrades must be made to the distribution system. If customers choose to generate their own power, the need for costly upgrades can be delayed or eliminated.

*Table 6.1 ~ Estimated Population Projections (in thousands)*[18]

| | July 1, 2000 | July 1, 2005 | July 1, 2015 | July 1, 2025 |
|---|---|---|---|---|
| **Massachusetts** | 6,199 | 6,310 | 6,574 | 6,902 |
| **California** | 32,521 | 34,441 | 41,373 | 49,285 |

It is clear that California has a much larger population. More importantly, California's population is expected to grow at a much faster rate than Massachusetts. Between 2000 and 2005, Massachusetts' population is expected to increase by 1.8%, while California is estimated at 5.9%. Long term increases are estimated to be much larger. Between 2000 and 2025, Massachusetts is projected to have an 11.3% increase, and 51.5% in California.

The U.S. leads the world in total electricity consumption. The U.S. also ranks in the top ten countries for electricity consumption per capita, with an average of about 13,000 kWh

[18] U.S. Census Bureau (www.census.gov/population/projections/state/stpjpop.txt)

per person.[19] In California, the demand for electricity is expected to increase by 2.3% each year until 2004, and 2.0% between 2004 and 2010.[20]

These numbers indicate why population is one of the factors that can influence DG policy. These estimated projections could also be one of the reasons why California began considering DG use several years before Massachusetts. DG use would not immediately eliminate any electricity shortages. However, long term and widespread use could have an impact on the amount of power demanded from the grid.

### 6.2 Power Supply Capabilities

The electric distribution system is capable of supply certain amounts of power depending on the size of its generating facilities. The distribution system consists of large generating facilities and its transmission lines. The electric supply must be greater than the demand for power. Decreasing the demand for grid power will also decrease the amount of power required to be supplied by the grid.

Over the past few years, California has faced a severe energy crisis. This crisis came about because of several factors. A faulty restructuring plan, faulty regulation, environmental regulations, unanticipated reductions in supply, and increases in demand have all been blamed for this situation.[21]

In 1999, California generating facilities produced around 191,000,000 MWh of electricity, while consuming over 260,000,000 MWh. Much of its power had to be imported from surrounding regions at a large expense. Massachusetts generated about 41,000,000 of their 54,000,000 MWh that were consumed. Although the ratios of power

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[19] http://nationmaster.com/country/us/Energy
[20] California Energy Commision, *California Energy Demand: 2000 – 2010* http://www.energy.ca.gov/reports/2000-07-14_200-00-002.PDF
[21] University of California Berkeley: Manifesto on the California Energy Crisis www.haas.berkeley.edu/news/california_electricity_crisis.html

consumed vs. generated are similar, California still had to import over five times as much power as Massachusetts.[22]

The energy situation in California can be simplified by using supply and demand. Demand for electricity in California increased by 11.3 percent between 1990 and 1999, while electric generating capacity decreased by 1.7 percent, creating a shortage.[23] The use of DG could reduce the demand for grid power, which could eliminate the shortage. The energy crisis in California could be a major contributor to California's push towards DG use. This situation does not exist in Massachusetts.

### 6.3 Grid Expansion

Increasing the capability of power supplied by the grid is one way to eliminate power shortages. This is done by adding or expanding generating facilities. This is a multifaceted process that often involves large investments, a complex application process, and, most importantly, approval.

Between 1994 and 1998, no applications for power plants were filed in California. Uncertainty regarding electric industry restructuring prevented interested parties from filing applications. This four year lack of possible expansion eventually contributed to the energy shortage in California. Since restructuring occurred in 1998, 37 applications have been approved for construction.

The application review process is governed by the California Energy Commission. The CEC possesses the authority to certify the construction and operation of generating plants of 50MW or larger. This lengthy review process involves a detailed assessment of all aspects of the project, including; need, public health, environmental impacts, safety, efficiency, and reliability.

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[22] Energy Information Administration
[23] Energy Information Administration
www.eia.doe.gov/cneaf/electricity/california/background.html

## 7. Conclusions

DG has the capability of becoming a practical source of power for electric company customers. However, customers may be deterred from interconnection because of its difficulty. On the other hand, allowing simpler interconnection may encourage customers to interconnect.

Examination of DG standards and policies in Massachusetts and California has shown that California is at a further stage of development. Comparison has also shown that the interconnection process in California is less complex than that of Massachusetts. These factors have lead to the conclusion that California is using less stringent policy to encourage the use of DG.

Several factors have been identified in order to understand why these differences exist. Population has a significant impact on demand for electricity, particularly population growth rate. The electrical crisis in California has a major influence on policy. The supply of power is not qualified to meet the demands of the customers. This situation does not exist in Massachusetts. Widespread DG use would eventually reduce the demand from the distribution system.

Supply and demand is the underlying component behind DG standards and policies. The supply of electricity in Massachusetts is currently sufficient. The demand for electrical power in Massachusetts is increasing at a much lower rate than California. Therefore, DG policy in Massachusetts is aimed at providing safe interconnection for customers who choose to install DG equipment. Encouraging use of DG equipment is not a major objective for Massachusetts at this point in time.

# Appendix A – Massachusetts Documents

*Figure A.1 ~ Schematic of Massachusetts Interconnection Review Processes*

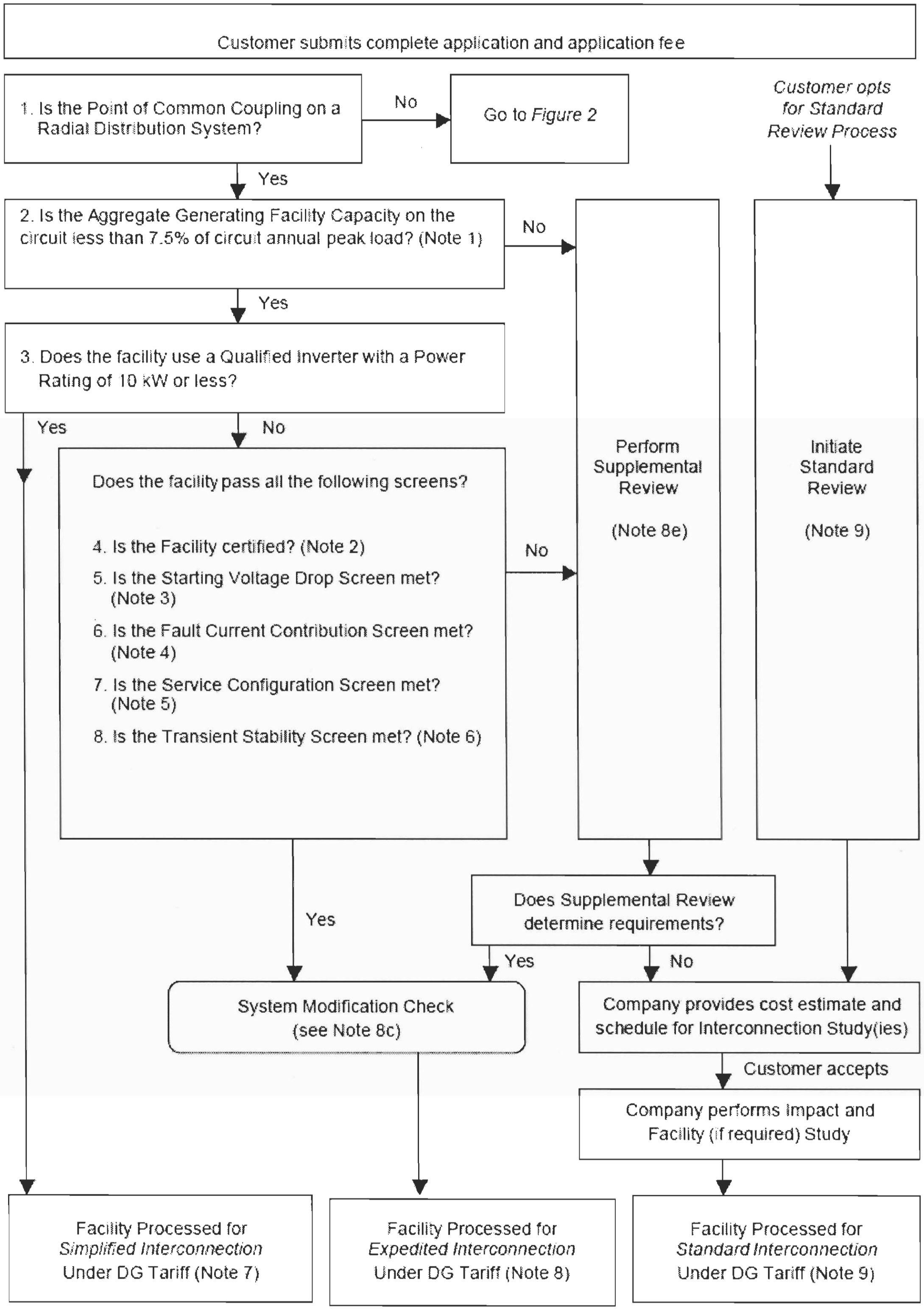
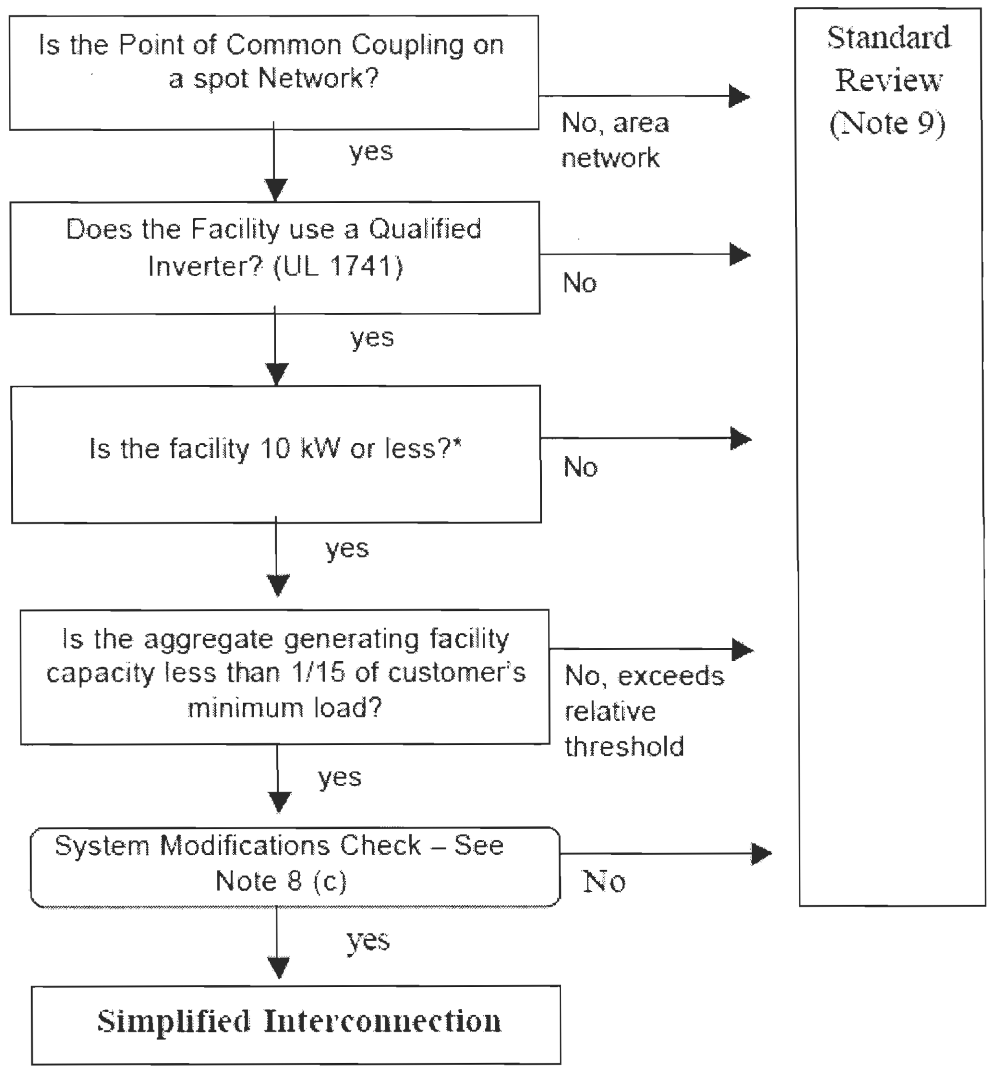


*Figure A.2 ~ MA Simplified Interconnection to Networks Schematic*




*Notes to Accompany Figures A.1 and A.2*

**Note 1.** On a typical radial distribution system circuit ("feeder") the annual peak load is measured at the substation circuit breaker, which corresponds to the supply point of the circuit. A circuit may also be supplied from a tap on a higher-voltage line, sometimes called a subtransmission line. On more complex radial systems, where bidirectional power flow is possible due to alternative circuit supply options ("loop service") the normal supply point is the loop tap.

**Note 2:** California and New York have adopted certification rules for expediting application review and approval of Generating Facility interconnections onto Company electric systems. Generating Facilities in these states must meet commission-approved certification tests and criteria to qualify for expedited review. Since the certification criterion is based on testing results from recognized national testing laboratories, Massachusetts will accept Generators certified in California and New York as candidates for Expedited Review. It is the Customer's responsibility to determine if and submit verification that the proposed Facility has been certified in California or New York.

The above states and Massachusetts have adopted UL 1741, *"Inverters, Converters and Charge Controllers for Use in Independent Power Systems"*, for certifying the electrical protection functionality of independent power systems. UL 1741 compliance is established by nationally recognized testing laboratories. Customers should contact the Facility supplier to determine if it has been listed.

IEEE P1547 Draft Standard includes design specifications and provides technical and test specifications for Facilities rated up to 10MVA. To meet the IEEE standard Customers must provide information or documentation that demonstrates how the Facility is in compliance with the IEEE P1547 Draft Standard. A Generating Facility will be deemed to be in compliance with the IEEE P1547 Draft Standard if the Company previously determined it was in compliance. The Massachusetts Collaborative will identify an appropriate entity to maintain a registry of Generating Facilities previously certified in other states or in compliance with the IEEE standard.

Applicants who can demonstrate Facility compliance with either standard will be eligible for Expedited Review.

**Note 3.** This screen only applies to Generating Facilities that start by motoring the Generating Unit(s) or the act of connecting synchronous generators. The voltage drops should be less than the criteria below. There are two options in determining whether Starting Voltage Drop could be a problem. The option to be used is at the Companies' discretion:

> Option 1: The Company may determine that the Generating Facility's starting Inrush Current is equal to or less than the continuous ampere rating of the Facility's service equipment.
>
> Option 2: The Company may determine the impedances of the service distribution transformer (if present) and the secondary conductors to the Facility's service equipment and perform a voltage drop calculation. Alternatively, the Company may use tables or nomographs to determine the voltage drop. Voltage drops caused by starting a Generating Unit as a motor must be less than 2.5% for primary interconnections and 5% for secondary interconnections.

**Note 4.** The purpose of this screen is to ensure that fault (short-circuit) current contributions from all DG units will have no significant impact on the Company's protective devices and system. All of the following criteria must be met when applicable:

a. The proposed Generating Facility, in aggregation with other generation on the distribution circuit, will not contribute more than 10% to the distribution circuit's maximum fault current under normal operating conditions at the point on the high voltage (primary) level nearest the proposed point of common coupling.
b. The proposed Generating Facility, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts, and line reclosers), or customer equipment on the system to exceed 85% of the short circuit interrupting capability. In addition, the proposed Generating Facility will not be installed on a circuit that already exceeds 85 percent of the short circuit interrupting capability.
c. When measured at the secondary side (low side) of a shared distribution transformer, the short circuit contribution of the proposed Generating Facility must be less than or equal to 2.5% of the interrupting rating of the Companies' Service Equipment.
Coordination of fault-current protection devices and systems will be examined as part of this screen.
**Note 5.** This screen includes a review of the type of electrical service provided to the customer, including line configuration and the transformer connection to limit the potential for creating over voltages on the Company system due to a loss of ground during the operating time of any anti-islanding function.

| Primary Distribution Line Type | Type of Interconnection to Primary Distribution Line | Result/Criteria |
|---|---|---|
| | | |
| Three-phase, three wire | 3-phase or single phase, phase-to-phase | Pass screen |
| Three-phase, four wire | Effectively-grounded 3 phase or Single-phase, line-to-neutral | Pass screen |
| | | |

If the proposed generator is to be interconnected on a single-phase transformer shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generator, will not exceed 20 kVA.

If the proposed generator is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition will not create an imbalance between the two sides of the 240 volt service of more than 20% of nameplate rating of the service transformer.
**Note 6.** The proposed generator, in aggregate with other generation interconnected to the distribution low voltage side of the substation transformer feeding the distribution circuit where the generator proposes to interconnect, will not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., 3 or 4 transmission voltage level buses

from the point of interconnection).

**Note 7. Simplified Interconnection**:

a. Application process:

i. Customer submits an Application filled out properly and completely.

ii. Company acknowledges to the customer receipt of the application within three b usiness days of receipt.

iii. Company evaluates the Application for completeness and notifies the customer within 10 days of receipt that the application is or is not complete.

b. Company verifies Generating Facility equipment passes screens 1, 2, and 3.

c. Company and customer execute agreement (if an agreement is required by the Collaborative). In certain rare circumstances, the Company may require the Customer to pay for minor system modifications.

d. Upon receipt of signed application/agreement and completion of installation, Company may inspect Generating Facility for compliance with standards and may arrange for a witness test.

e. Assuming inspection/test is satisfactory, Company notifies Customer in writing that interconnection is allowed, and approves.

**Note 8. Expedited Interconnection:**

a. Application process:

i. Customer submits an Application filled out properly and completely.

ii. Company acknowledges to the customer receipt of the application within three business days of receipt.

iii. Company evaluates the Application for completeness and notifies the customer within 10 days of receipt that the application is or is not complete.

b. Company then conducts an initial review which includes applying the screening methodology (screens 1 through 8).

c. *Notice: The Company reserves the right to conduct additional studies if deemed necessary and at no additional cost to the Customer, such as but not limited to: protection review, aggregate harmonics analysis review, aggregate power factor review and voltage regulation review. Likewise, when the proposed interconnection may result in reversed load flow through the Company's load tap changing transformer(s), line voltage regulator(s), control modifications necessary to mitigate the effects may be made to these devices by the Company at the Interconnecting Customer's expense or the Facility may be required to limit its output so reverse load flow cannot occur or to provide reverse power relaying that trips the Facility.* As part of the expedited interconnection process, the Company will assess whether any system modifications are required for interconnection, even if the project passes all of the applicable screens. If the needed modifications are minor, that is, the requirement can be determined within the time allotted through the application fee, then the modification requirements, reasoning, and costs for these minor modifications will be identified and included in the executable expedited interconnection agreement. If the requirements cannot be determined within the time and cost alloted in the initial review, the Company may require that

the project undergo additional review to determine those requirements. The time allocated for additional review is a maximum of 10 hours of engineering time. If after these reviews, the Company still cannot determine the requirements, the Company will document the reasons why and will meet with the customer to determine how to move the process forward to the parties' mutual satisfaction. In all cases, the Customer will pay for the cost of modifications that are solely attributable to its proposed project.
d. Assuming all applicable screens are passed, Company sends the Customer an executable agreement and a quote for any required system modifications or reasonable witness test costs.
e. If one or more screens are not passed, the Company will offer to conduct a Supplemental Review. If the Customer agrees to pay the Supplemental Review Fee, the Company will conduct the review. If the Supplemental Review determines the requirements for processing the application through the expedited process including any system modifications, then the modification requirements, reasoning, and costs for these modifications will be identified and included in the executable expedited interconnection agreement. If this is not true, the Supplemental Review will include an estimate of the cost for the studies that are part of the Standard Review process. Even if a proposed project initially fails a particular screen in the Expedited process, if Supplemental Review shows that it can retur n to the Expedited process then it will do so. Supplemental Review includes up to 10 hours of engineering time.
f. Customer returns signed agreement
g. Customer completes installation.
h. Company completes system modification, if required.
i. Company inspects completed installation for compliance with standards and attends witness test, if required.
j. Assuming inspection is satisfactory, Company notifies Customer in writing that interconnection is allowed.

**Note 9. Standard Review Process**

a. Customers may choose to proceed immediately to the Standard Review process. Application process:
i. Customer submits an Application filled out properly and completely.
ii. Company acknowledges to the customer receipt of the application within three business days.
iii. Company evaluates the Application for completeness and notifies the customer within 10 days whether the application is complete.
b. Based upon the results of the initial and Supplemental Reviews, customers may be required to enter the Standard Review process.
i. The Company will conduct a scoping meeting/discussion with the customer (if necessary) to review the application. At the scoping meeting the Company will provide pertinent information such as:
a. The available fault current at the proposed location;
b. The existing peak loading on the lines in the general vicinity of the facility,

c. The configuration of the distribution lines.
ii. Company develops Impact and/or Facility Study Proposal, including a cost estimate.
iii. Customer agrees to pay.
iv. Company performs Impact and/or Facility Studies as agreed to.
v. Company sends the Customer an executable agreement and a quote for any required system modifications or reasonable witness test costs.
iv. Customer returns signed agreement
v. Customer completes installation.
vi. Company completes system modification, if required.
vii. Company inspects completed installation for compliance with standards and attends witness test, if required.
viii. Assuming inspection is satisfactory, Company notifies Customer in writing that interconnection is allowed.

# Massachusetts Application Form

## Contact Information (For all applications)

Legal Name and address of Customer applicant (or, if an Individual, Individual's Name)

Company Name: ______________________ Contact Person: ___________________________

Mailing Address: ____________________________________________________________

City: _______________________________ State: _________________ Zip Code: ________

Telephone (Daytime): _________________ (Evening): ______________________________

Facsimile Number: ____________________ E-Mail Address: __________________________

Alternative Contact Information (if different from Applicant)

Name: ______________________________________________________________________

Mailing Address: ____________________________________________________________

City: _______________________________ State: _________________ Zip Code: ________

Telephone (Daytime): _________________ (Evening): ______________________________

Facsimile Number: ____________________ E-Mail Address: __________________________

Ownership (include % ownership by any electric utility): __________________________

Confidentiality Statement: "I agree to allow information regarding the processing of my application (without my name and address) to be reviewed by the Massachusetts DG Collaborative that is exploring ways to further expedite future interconnections." Yes_____ No_____

## Generating Facility Information (for all applications)

Location (if different from above): ____________________________________________

_____________________________________________________________________________

Electric Service Company: _____________________ Account Number (if available): __________

Type of Generating Unit: Synchronous_______ Induction_______ Inverter________

Manufacturer: _________________________ Model: ___________________________________

Nameplate Rating: _______ (kW) ______ (kVAR) _______ (Volts) Single____ or Three____ Phase

Prime Mover: Fuel Cell___ Recip Engine___ Gas Turb___ Steam Turb___ Microturbine___ PV__ Other___

Energy Source: Solar___ Wind___ Hydro___ Diesel___ Natural Gas___ Fuel Oil___ Other____________ (Specify)

UL1741 Listed? Yes_____ No _____

Does facility need an air quality permit from DEP? Yes___ No ___Not Sure____

Planning to Export Power? Yes____ No____ A Cogeneration Facility? Yes____ No_____

Anticipated Export Power Purchaser: ______________________________________________

Export Form? Simultaneous Purchase/Sale___ Net Purchase/Sale___ Net Metering___ Other__________ (Specify)

Est. Install Date: ___________ Est. In-Service Date: __________ Agreement Needed By: __________

## Application Process (for all applications)

I hereby certify that, to the best of my knowledge, all of the information provided in this application is true:

Customer Signature: ____________________________ Title: _______________ Date: ____________

The information provided in this application is complete:

Company Signature: ____________________________ Title: _______________ Date: ____________

## Simplified Process Only (attach manufacturer's cutsheet showing UL1741 listing & stop here)

Interconnection is approved pursuant to Tariff:

Company Signature: ____________________________ Title: _______________ Date: ____________

## Generating Facility Technical Detail (for Expedited and Standard applications)

List components of the Generating Facility that are currently certified and/or listed to national standards

| | Equipment Type | Manufacturer | Model | National Standard |
|---|---|---|---|---|
| 1. | ________ | ________ | ________ | ________ |
| 2. | ________ | ________ | ________ | ________ |
| 3. | ________ | ________ | ________ | ________ |
| 4. | ________ | ________ | ________ | ________ |
| 5. | ________ | ________ | ________ | ________ |
| 6. | ________ | ________ | ________ | ________ |

Total Number of Generating Units in Facility? ________

Generator Unit Power Factor Rating: ________

Max Adjustable Leading Power Factor? ________ Max Adjustable Lagging Power Factor? ________

Generator Characteristic Data (for all inverter-based machines)

Max Design Fault Contribution Current? ______ Instantaneous ___or RMS? _____

Harmonics Characteristics: ________________________________

Start-up power requirements:____________

Generator Characteristic Data (for all rotating machines)

Rotating Frequency: _______ (rpm) Neutral Grounding Resistor (If Applicable): _______

Additional Information for Synchronous Generating Units

Synchronous Reactance, Xd: _______ (PU) Transient Reactance, X'd: _______ (PU)

Subtransient Reactance, X"d: _______ (PU) Neg Sequence Reactance, X2: _______ (PU)

Zero Sequence Reactance, Xo: _______ (PU) KVA Base: _______

Field Voltage: _______ (Volts) Field Current: _______ (Amps)

Additional information for Induction Generating Units

Rotor Resistance, Rr: _______ Stator Resistance, Rs: _______

Rotor Reactance, Xr: _______ Stator Reactance, Xs: _______

Magnetizing Reactance, Xm: _______ Short Circuit Reactance, Xd": _______

Exciting Current: _______ Temperature Rise: _______

Frame Size: _______

Total Rotating Inertia, H: _______ Per Unit on KVA Base: _______

Reactive Power Required In Vars (No Load): _______

Reactive Power Required In Vars (Full Load): _______

Additional information for Induction Generating Units that are started by motoring

Motoring Power: _______ (kW) Design Letter: _______

X

## Interconnection Facilities Technical Detail (for Expedited and Standard applications)

Will a transformer be used between the generator and the point of interconnection? Yes_____ No_____

Will the transformer be provided by Customer? Yes_____ No_____

Transformer Data (if applicable, for Customer-Owned Transformer):

Nameplate Rating: ________ (kVA) Single ___ or Three ___ Phase

Transformer Impedance: ________ (%) on a _______ KVA Base

If Three Phase:
Transformer Primary: ________ (Volts) ___Delta ____ Wye _____ Wye Grounded ____ Other

Transformer Secondary: ________ (Volts) ___Delta ____ Wye _____ Wye Grounded ____ Other

Transformer Fuse Data (if applicable, for Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt & Total Clearing Time-Current Curves)

Manufacturer: ____________________________ Type:__________ Size: __________ Speed: __________

Interconnecting Circuit Breaker (if applicable):

Manufacturer:_________ Type:_____ Load Rating:______ (Amps) Interrupting Rating:______ (Amps) Trip Speed:_______ (Cycles)

Interconnection Protective Relays (if applicable):

(If microprocessor-controlled)
List of Functions and Adjustable Setpoints for the protective equipment or software:

| | Setpoint Function | Minimum | Maximum |
|---|---|---|---|
| 1. | | | |
| 2. | | | |
| 3. | | | |
| 4. | | | |
| 5. | | | |
| 6. | | | |

(If discrete components)
(Enclose copy of any proposed Time-Overcurrent Coordination Curves)

Manufacturer:__________ Type:__________ Style/Catalog No.:__________ Proposed Setting:__________

Manufacturer:__________ Type:__________ Style/Catalog No.:__________ Proposed Setting:__________

Manufacturer:__________ Type:__________ Style/Catalog No.:__________ Proposed Setting:__________

Manufacturer:__________ Type:__________ Style/Catalog No.:__________ Proposed Setting:__________

Manufacturer:__________ Type:__________ Style/Catalog No.:__________ Proposed Setting:__________

Manufacturer:__________ Type:__________ Style/Catalog No.:__________ Proposed Setting:__________

X

Current Transformer Data (if applicable):

(Enclose copy of Manufacturer's Excitation & Ratio Correction Curves)

Manufacturer:__________ Type:_________ Accuracy Class:________ Proposed Ratio Connection:______

Manufacturer:__________ Type:_________ Accuracy Class:________ Proposed Ratio Connection:______

Potential Transformer Data (if applicable):

Manufacturer:__________ Type:_________ Accuracy Class:________ Proposed Ratio Connection:______

Manufacturer:__________ Type:_________ Accuracy Class:________ Proposed Ratio Connection:______

## General Technical Detail (for Expedited and Standard applications)

Enclose 3 copies of site electrical One-Line Diagram showing the configuration of all generating facility equipment, current and potential circuits, and protection and control schemes with a Massachusetts-registered professional engineer (PE) stamp.

Enclose 3 copies of any applicable site documentation that indicates the precise physical location of the proposed generating facility (e.g., USGS topographic map or other diagram or documentation).

Proposed Location of Protective Interface Equipment on Property:
(Include Address if Different from Application Address)

______________________________________________________________________________

______________________________________________________________________________

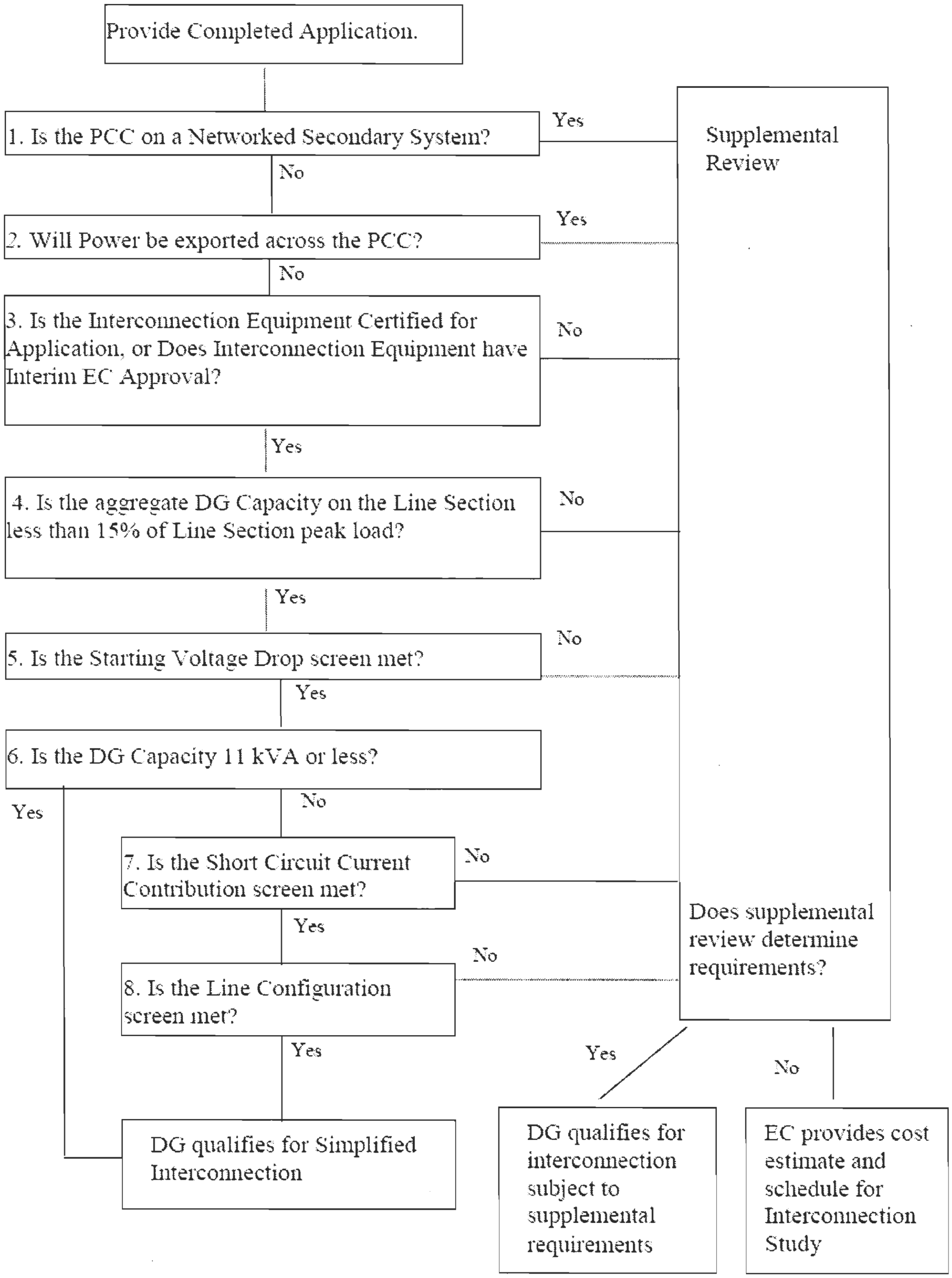
Enclose copy of any applicable site documentation that describes and details the operation of the protection and control schemes.

Enclose copies of applicable schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).

Please enclose any other pertinent information to this installation.

# Appendix B – California Documents

*Figure B.1 ~ Initial Review Process Schematic*



# California 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*

*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? [ ] Yes [ ] No
   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.

   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 [ ] Included
    *Note: A sample Single-line drawing is included with this application.*

    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