

**Comparison of Distributed Generation  
Interconnection Rules in California,  
Delaware, Michigan, New York, Ohio, Texas  
and Wisconsin**

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## SECTION 1: INTRODUCTION

This is the latest in a series of reports that the State Utility Forecasting Group (SUFG) has written examining the state of the distributed generation (DG) industry. This report is separate from the Indiana renewables study, which will be available in the fall. In the first of the DG reports appearing as a section in the 2001 forecast<sup>1</sup>, SUFG presented the characteristics of the various DG technologies including their cost characteristics in comparison with the conventional central station generation technologies. That report also included a discussion of the various barriers to interconnection to DG interconnection reported in literature. The second report, written in July 2003<sup>2</sup>, contained a comparison of the cost to a residential and a commercial customer of supplying all their electricity needs from various DG technologies assuming the full range of cost and efficiency reported. This was compared to the energy weighted residential and commercial tariff in Indiana. This July 2003 report also contained a discussion of the net metering rules in place in some 34 states at that time.

The focus of this report is the DG interconnection rules that have been adopted in some seven states since 1999. The states that have issued DG interconnection rules in order of dates they adopted the rules are: Texas<sup>3</sup> and New York<sup>4</sup> in 1999; Delaware<sup>5,6</sup> and Ohio<sup>7,8</sup> in 2000, California<sup>9</sup> in 2001, Wisconsin<sup>10,11</sup> in January 2004 and Michigan<sup>12</sup> in March 2004. The report compares how the rules treat the various issues related to DG interconnection to the grid. The issues that arise when a significant number of DG are connected to the grid are articulated in the in the January 2002 IURC DG white paper<sup>13</sup>. The issues include the maximum size of generator that is allowed, buy-back of excess electricity fed back to the grid by the DG, cost recovery for distribution system upgrade, insurance and liability requirements, application fees and time frames, provisions for fast track interconnection review, stranded cost recovery standby charges etc.

The report is laid out as follows.

- In section 2, a brief review of the net metering rules that have typically preceded the more generalized DG interconnection rule is given.
- In section 3, a comparison of the treatment of the various issues by the states of California, Delaware, New York, Ohio, Texas and Wisconsin is presented.
- A separate section, section 4, is dedicated to the Michigan interconnection rule. This being the most recent rule, there is not as much information available on it as for the other six states.
- Section 5 presents the enabling legislation behind the interconnection rules and the tax and other incentives in place in the seven states with DG interconnection rules.
- Section 6 presents an analysis of DG installation patterns by technology, fuel types and customer groups installing them. This analysis is based primarily on the state of California where the relevant data was more complete.

### 1.1 What is Distributed Generation?

Distributed generators are relatively small electricity generators located in close proximity to the load, mostly at the low voltage distribution system. This is in contrast to the traditional large central station generators located remote to the load and connected to

the load centers by a system of high voltage transmission lines. The size of DG units can vary from a few kilowatt (kW) units powering a residential property to tens of megawatt (MW) units supplying an industrial facility. The technologies used in distributed generation include such traditional technologies as internal combustion turbines, gas turbines, wind turbines and also newer technologies such as micro-turbines and fuel cells. Also included in the mix are generators using renewable resources such as photovoltaic panels and small wind turbines. Although DG can be owned and operated by the distribution utility or the customer, the challenging scenario is where the DG is owned and operated by the customer and located on the customer side of the meter. Another distinguishing feature of DG is that, unlike the traditional emergency back-up generators, DG units are intended to operate in parallel with the grid. That is, an electrical connection is maintained between the DG unit and distribution grid while the DG unit is running and the customer has the option to meet all or part of their load from either the grid or their DG unit. In such a parallel connection electricity is free to flow back and forth between the DG owning customer's facility and the distribution grid.

It is widely recognized that distributed generators have the potential to bring significant economic, reliability and environmental benefits to the electricity system. Due to their proximity to the load, distributed generators avoid transmission and distribution costs and losses. Some distributed generation technologies such as fuel cells have efficiencies much higher than conventional central station technologies, and because they are close to the load, the total energy conversion efficiency can be further enhanced by utilizing the waste heat to supply the customer's heating and cooling needs. When connected in parallel to the grid, distributed generators add to the reliability associated with the load they supply and with appropriate controls can be used to enhance the reliability and power quality of the distribution system to which they are connected. Distributed generators powered by renewable energy sources such as photovoltaic panels and wind turbines improve the environmental impact of the energy supply system.

## **1.2 The Need for Standardized Interconnection Rules**

Connecting a significant number of these customer-owned generators across the distribution system presents a non-trivial technical and regulatory challenge. On the technical side, the challenge arises due to the electricity delivery system generally not being designed to handle electricity generating devices at the distribution level. Therefore, technical interconnection standards are needed to ensure that the DG unit does not compromise the distribution systems ability to safely deliver electricity at the required reliability and quality. For example, a major concern in this respect is the potential for a DG unit to continue energizing a distribution feeder when the rest of the distribution system is down (inadvertent islanding). This has the potential to harm utility workers and other customer equipment on the feeder. Significant progress has been made in addressing these technical interconnection issues; a major landmark in this respect was the adoption in July 2003 of the Institute of Electrical and Electronic Engineers standard on interconnection of DG, IEEE 1547<sup>14</sup>. The states that have issued their interconnection rules since the adoption of this IEEE 1547 have included the standard in their interconnection rules.

## SECTION 2: NET METERING: A FIRST STEP TOWARDS DG INTERCONNECTION RULES

As explained in the IURC white paper<sup>13</sup>, net metering rules have preceded the more generalized DG interconnection rules in most states. The net metering rules were primarily designed to encourage technologies utilizing renewable energy sources and emerging technologies such as fuel cells. At the heart of the net metering rules is the arrangement where a reversible meter nets out the power exchange between the utility and the DG-owning customer. This implies that the power exported to the utility is valued at the utility's retail rate. The single meter arrangement is simple to administer and the valuation of the energy at the utility retail rate is generally considered an incentive to encourage these desirable technologies.

In addition to being restricted to renewables and emerging technologies, the amount of DG that can be connected to the grid under most states net metering rules is restricted to a small fraction of the of the utility's or the state's total demand (less than 1% in most states). For example the net metering rule adopted in Texas in 1986 provided for the interconnection of customer owned DG up to 50kW running on renewables. The Texas DG interconnection rule adopted in 1999 expands the provision for DG to include all generating technologies and raised the allowed maximum size of the individual DG unit to 10 MW. Table 1 shows some characteristics of the net metering rules of the six states that have implemented DG interconnection rules.

**Table 1. Net Metering Rules for Texas, Wisconsin, California, New York, Delaware and Ohio**

State	Allowable Technology and Size	Allowable Customer	Statewide Limit	Treatment of Net Excess Generation (NEG)	Authority	Enacted
Texas	Renewables only ≤50 kW	All customer classes	None	Monthly NEG purchased at avoided cost	Public Utility Commission	1986
Wisconsin	All technologies ≤20 kW	All retail customers	None	Monthly NEG purchased at retail rate for renewables, avoided cost for non-renewables	Public Service Commission	1993
California	Solar and wind ≤1000 kW	All customer classes	0.5% of utilities peak demand	Annual NEG granted to utilities	Legislature	2002; 2001; 1995
New York	Solar only residential ≤10 kW; Farm biogas systems <400 kW	Residential; farm systems	0.1% 1996 peak demand	Annualized NEG purchased at avoided cost	Legislature	2002; 1997
Delaware	Renewables ≤25 kW	All customer classes	None	Not specified	Legislature	1999
Ohio	Renewables, micro-turbines, and fuel cells (no limit per system)	All customer classes	1.0% of aggregate customer demand	NEG credited to next month	Legislature	1999

Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Green Power Network<sup>18</sup>.

In these six states incentive provisions for renewables and emerging technologies that were written into the initial net metering rules were retained in the DG interconnection rules. According to the U.S. Department of Energy (DOE) Green Power Network<sup>18</sup>, some 38 states in the U.S. have some form of net metering program in place. This includes laws, regulatory orders and utility voluntary programs. Indiana is listed in this DOE list as having had a net metering program since 1985.

Another method of valuing the excess energy from a customer owned generator is the utility “avoided cost” as prescribed by the 1978 Public Utilities Regulatory Policies Act (PURPA). Under this federal statute energy efficient generators that qualify can sell their excess energy to the utility at the cost that the utility saves by not producing that energy themselves. The avoided cost is typically lower than the utility retail rate.

## SECTION 3: COMPARING DG INTERCONNECTION RULES

In this section a comparison of the treatment of various issues by the DG interconnection rule in the states of California, Delaware, New York, Ohio, Texas and Wisconsin is presented. To enable the comparison, the issues selected are set in table format in Tables 2(a) and 2(b). The issues presented include maximum DG size allowed; the feeder configuration allowed at the point of interconnected, buy-back of excess generation, system upgrade cost recovery, minimum insurance requirements, application fees, study fees and time frame for application review. The Michigan interconnection rule is presented as a stand alone part in section 4 of the report. Michigan is the latest state to adopt a DG interconnection rule, and little information was available about how they treat many of the issues. The rule was adopted in September 2003 amid protests by the Michigan utilities; the deadline for utilities to file their standardized interconnection requirements and procedures was set for March 22, 2004. SUFG did not find any Commission approved utility filings at the time of writing this report.

### 3.1 Maximum DG Size and Feeder Configurations

The second column of Table 2(a) shows the maximum generator size that is allowed to interconnect to the grid under the DG interconnection rules in each state. In addition it shows the distribution feeder rating and configuration onto which customer owned DG is allowed.

The maximum DG size rating in most states is specified in units of real power, kW and MW, except for New York where the kilovolt-ampere (kVA) is used. The volt-ampere is a measure of electric power that includes both the real and reactive element of an AC power system. In the absence of reactive power, kVA and kW are equal. Holding kVA constant, as reactive power supplied increases, kW supplied must decrease. The range of maximum DG sizes allowed varies from a low in Ohio of 300kW to Wisconsin's 15MW. In addition, California does not have an explicit DG size limit; the rules depend on other feeder characteristics, such as short circuit capacity to limit the DG size. Ohio and Texas specify two maximum DG size limits, one for single phase distribution feeder and one for three phase distribution feeders. The single phase feeder limits are 25kW for Ohio and 50kW for Texas. New York has two size limits; 400kW for farm waste generators and 300 kVA for all other DGs. Proposed revisions to the New York rules raise the DG size limit to 2MW and remove the restriction of interconnection on secondary network systems<sup>20</sup>.

Another feeder configuration issue is whether to allow DG interconnection on network secondary distribution systems. Most electricity distribution systems are radial: that is, power flows on a single line from the source to the various loads along the line. Flow normally occurs in only one direction, from source to load, as illustrated in Figure 1. In such a system, flow in the reverse direction is an indication of a problem, such as a short circuit. In densely populated urban systems it is common to have the distribution system

configured in what is referred to as network secondary distribution systems. In these network distribution systems electricity is supplied from multiple sources using multiple paths and unlike radial systems bi-directional flow of electricity is anticipated, as illustrated in Figure 2. However, power feedback into the radial systems feeding the network is prohibited, and fast acting circuit elements known as network protectors are put in place to stop this reverse flow<sup>3</sup>. A generator connected to run in parallel within such a network stands the potential of tripping these network protectors and hence reducing the reliability of supply to customers served by this secondary distribution network.

Figure 1 Illustration of a Radial Distribution System

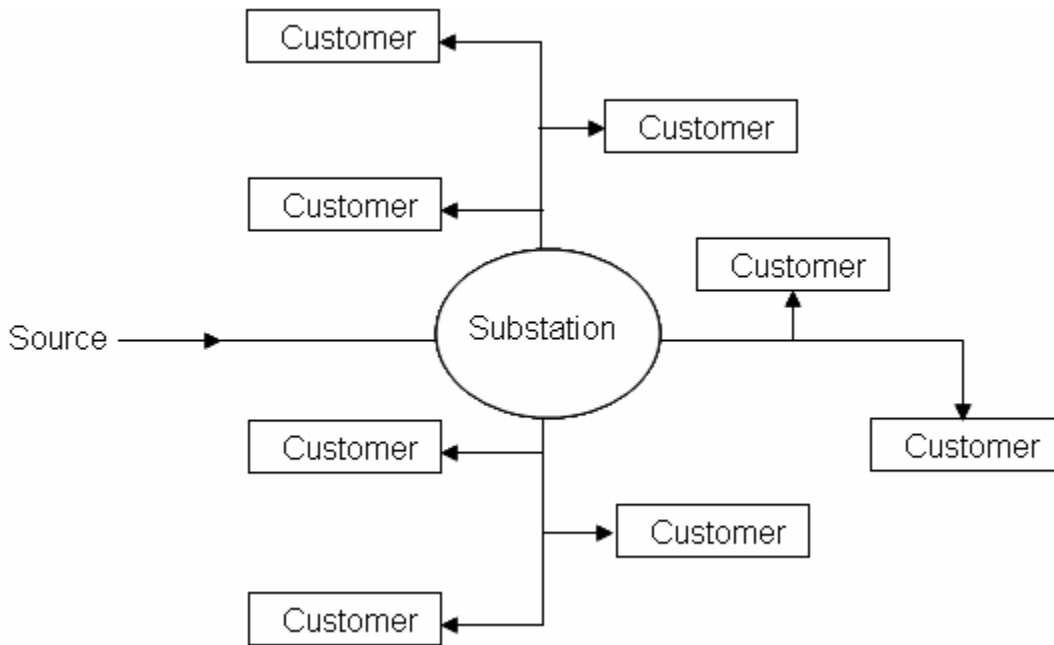
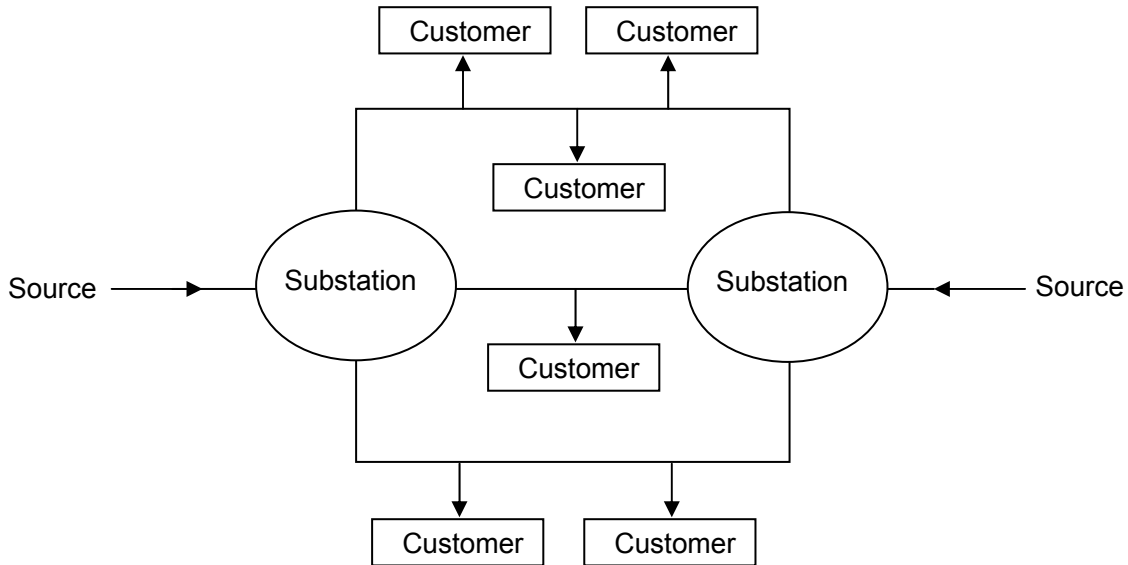




Figure 2 Illustration of a Network Distribution System



New York and Ohio explicitly forbid interconnecting customer-owned generators to network secondary systems. In California a customer seeking interconnection onto a network subsystem is disqualified from the simplified interconnection classification. Therefore the customer is responsible for the costs of the supplemental studies and the modifications necessary to accommodate the DG into the network. This is similar to the rules in Wisconsin, which recognize that interconnecting into networked subsystems requires system modifications and holds the customer responsible for the cost of such modifications. In this respect the Texas interconnection rules are unique in that they require the utility to make every reasonable effort to interconnect DG, even on secondary network systems. The utility is expected to absorb the network upgrade costs except where the costs are deemed substantial. The Texas rules provide that no fees can be charged when the aggregate DG interconnecting to the secondary network is less than 25% of the peak load on the network and the DG unit has a capacity less than the customer load or its protection circuit is inverter-based. The rules also require the utility to consider the possibility of switching the DG-owning customer to a radial feeder if that is a practical option. Delaware prohibits DG interconnections at voltages above 34.5kV and Ohio has a similar limit of 35kV. The other four states do not impose constraints on interconnection voltages.

Table 2 (a) Comparing DG Interconnection Rules (Size and Cost Allocation)

	<b>Max DG Size and Feeder Configurations</b>	<b>Excess Generation Buy-Back</b>	<b>System Upgrade Cost Recovery</b>	<b>Minimum Insurance</b>
<b>Texas Nov 1999</b>	1-phase 50kW 3-phase 10 MW	Utility not obliged to buy.  Customer expected to market their output in deregulated market.	Utility absorbs all except "substantial" upgrades on secondary network systems.	None specified.
<b>New York Dec 1999</b>	300 kVA,  400kW for farm waste generators,  Radial feeders only	Utility not obliged to buy or deliver the excess generation.	Customer pays in advance estimated costs above typical and customary.  Residential net meter photovoltaic max \$350 for transformer only; farm waste max \$3,000.	Not required; only recommended, but disclosure required.
<b>Delaware Jan 2000</b>	1MW ≤ 34.5 kV feeder	Non-exporting implied except for renewables qualifying for net metering.	Customer pays all costs above "typical and customary".	No minimum given.
<b>Ohio 2000</b>	1-phase 25kW  3-phase 300 kW, non-networked, ≤ 35kV feeder	Net metering for small renewables. For non-renewables implies customer negotiates rates with retail service providers.	Customer pays costs caused by DG presence.	Proof of insurance required.  No minimum specification.
<b>California 2001</b>	No size limit.	Standard agreement is non-exporting. 4 types provided for: 1. No- or low-export. 2. Non-compensated intermittent export. 3. PURPA 1978 QF, and 4. Net metered renewables.	Customer pays costs caused by DG presence.  Utility financing arrangements allowed.	DG ≤10kW: ≥ \$200,000  DG ≤ 20kW: ≥ \$500,000  DG ≤ 100kW: ≥ \$1,000,000  DG > 100kW: \$2,000,000
<b>Wisconsin Jan 2004</b>	15MW.	≤ 20kW - net metering, no distinction for renewables.  > 20kW avoided cost (as per PURPA 1978) or some other negotiated rate. This system existed before PSC 119.	Customer pays costs caused by DG presence.	DG ≤20kW: ≥\$300,000  20kW<DG ≤200kW: ≥\$1,000,000  200kW<DG ≤1MW: ≥\$2,000,000  DG >1MW: negotiate

PURPA - Public Utilities Regulatory Policy Act 1978; QF – Qualifying Facilities as defined by PURPA

Table 2 (b) Comparing DG Interconnection Rules (Application Review)

	Application and Study Fees	Time Frame for Application Review	Factors That Qualify for Fast-track Review
<p><b>Texas</b></p> <p><b>PUC rule 25.211, 25.212</b></p> <p><b>Nov 1999</b></p>	<p>No application fee</p> <p>Study fee allowed except for following: on radial feeder if DG pre-certified, <math>\leq 500\text{kW}</math>, <math>\text{SCCR} \leq 25\%</math>, DG export <math>\leq 15\%</math> feeder load;</p> <p>On network if unit pre-certified; total DG <math>\leq 25\%</math> feeder load and either DG has inverter-based protection or and DG <math>\leq</math> customer load</p>	<p>Non-network – 4wks pre-certified / 6 weeks others,</p> <p>plus 6 wks if network and DG <math>&gt; 25\%</math> load, and agreed construction time if required <math>+ \leq 2\text{wks}</math>.</p>	<p>Two fast track paths:</p> <p>1) non-network PCC – pre-certified, <math>\leq 500\text{kW}</math>, export <math>\leq 15\%</math> feeder load, <math>\text{SCCR} \leq 25\%</math>, and</p> <p>2) network – pre-certified, total DG <math>\leq 25\%</math> feeder load or DG <math>\leq 20\text{kW}</math> and inverter-based protection or DG <math>&lt;</math> customer load.</p>
<p><b>New York</b></p> <p><b>Dec 1999, Nov 2000, Aug 2003</b></p>	<p>Non-refundable application fee of \$0 for DG <math>\leq 15\text{kVA}</math> \$350 for DG <math>&gt; 15\text{kVA}</math></p> <p>Excess above cost of transformer refundable for net metered customers.</p> <p>Customer pays study fees except DG <math>\leq 15\text{kVA}</math> exempted.</p>	<p><math>\leq 15\text{kVA}</math> 33 days, <math>&gt; 15\text{kVA}</math> 52 days</p> <p>and 60 days after interconnection to reconcile and issue formal letter.</p>	<p>No formal simplified interconnection process, but DG <math>\leq 15\text{kVA}</math> less system impact study time,</p> <p>And recognition that type-tested systems will likely take less review time.</p>
<p><b>Delaware</b></p> <p><b>2000</b></p>	<p>No application fee mentioned.</p> <p>Customer responsible for study costs above “typical and customary.”</p>	<p>4 weeks with more time allowed for exporting DG on networked secondary.</p>	<p>DG <math>\leq 25\text{kW}</math> and non-exporting renewables that qualify for the net metering tariff.</p>
<p><b>Ohio</b></p> <p><b>2000</b></p>	<p>\$100: 1-phase <math>\leq 25\text{kW}</math> \$500: 1-phase <math>&gt; 25\text{kW}</math> and all 3-phase.</p> <p>and full cost of system impact study if required with deposit at various levels (500/1,000/3,000/5,000) required,</p> <p>and \$115 per inspection of some inverter-based DG.</p>	<p>3 days acknowledge receipt, and 10 days to report on whether application is complete.</p> <p>To be negotiated w/ utility if networked.</p>	<p>PCC not on networked subsystem Aggregate DG <math>&lt; 15\%</math> peak load, <math>\text{SCCR} \leq 2.5\%</math> and total <math>\text{SCCR} \leq 10\%</math>.</p> <p>No utility side construction.</p>
<p><b>California</b></p> <p><b>Rule 21</b></p> <p><b>2001</b></p>	<p>\$800 for simplified interconnection, \$600 supplemental review, and cost of any other study necessary with fees waived for net metering customers and non-exporting solar facilities <math>\leq 1\text{ MW}</math> up to \$5,000.</p>	<p>10 business days for initial. 20 business days for supplemental, and to be negotiated for networked subsystems</p>	<p>PCC not on network subsystem. DG <math>\leq 11\text{kVA}</math> Aggregate DG <math>&lt; 15\%</math> peak load No LDC construction required.</p>
<p><b>Wisconsin</b></p> <p><b>PSC Rule 119</b></p> <p><b>Jan 2004</b></p>	<p>Application plus engineering review plus distribution system review; DG <math>\leq 20\text{kW}</math>: \$0 + 0 + 0 20 <math>&lt;</math> DG <math>\leq 200</math>: \$250 + <math>\leq 500</math> + <math>\leq 500</math> DG <math>&gt; 200\text{kW}</math>: \$500 + cost based + cost based.</p>	<p>25 working days for application review Engineering review 10/15/20/40 working days by DG category Distribution system study. 10/15/20/40 working days by DG category</p>	<p><math>\leq 20\text{kW}</math></p>

SCCR – short circuit current contribution ratio; PCC – point of common coupling; LDC – local distribution company

### **3.2 Buy-Back of Net Excess Generation from Customer-Owned Generator**

The rules under which a utility buys back excess generation from a DG unit can vary from one unit to another. DG units can be classified into three categories: combined heat and power (CHP) generators covered by the Public Utilities Regulatory Policy Act (PURPA) of 1978, renewables and emerging technologies covered by the net metering rules, and the rest of the DG that are neither PURPA qualifying facilities nor eligible for net metering. The power exported from a PURPA qualifying facility is purchased by the host utility at the utility's avoided cost as prescribed by that federal statute. Similarly the power exported by a DG that qualifies under net metering rules is purchased by the host utility at the utility's retail rate using the netting out mechanism that is central to the net metering rules.

The treatment of the excess electricity from DG units that do not qualify either as PURPA qualifying facilities or under each state's net metering rules can be divided into two broad categories based on the structure of the electricity market in the state. In states with retail competition such as Delaware, New York, Ohio and Texas, the price of the power exchanged between a customer and the utility is set by the competitive market and there is no need to prescribe a buy-back value. The host transmission and distribution utility is no longer the sole provider of energy services and the customer has the freedom to negotiate terms with the competitive services provider of their choice.

On the other hand, in the states where the DG interconnecting rules are being implemented in a regulated market, the host utility is the sole provider of all electrical service to the DG-owning customer. Therefore, there is need to provide, within the DG interconnection rule, a value to the power the DG unit feeds back to the system. The two states in this report having DG interconnection rules in a regulated environment are California and Wisconsin. In California the standard interconnection agreements are either for non-exporting DG or for low intermittent export DG. In these standard agreements the power exported to the system is not compensated, the DG unit is expected to make sure it does not feed power into the system beyond the allowed technical limits. In Wisconsin any generator that does not qualify under PURPA or under the net metering rules is expected to negotiate a purchase with the host utility. If a DG-owning customer in Wisconsin wishes to export the excess power to a third party, the transaction is treated as a wholesale transaction falling under the jurisdiction of the FERC and the rules of the Midwest Independent System Operator (MISO).

### **3.3 Distribution System Modification Cost Recovery**

Except for Texas, the six states listed in this report allocate the cost of system modification to the DG owning customer. The Texas rules require the host utility to absorb those costs and treat them the same way it treats other distribution system modifications for non-DG owning customers. New York limits the charges to residential

net metered customers owning a photovoltaic system to \$350 and only for the cost of adding a dedicated transformer where such a transformer is necessary. New York also limits the total system upgrade cost that can be recovered from farmers with a farm-waste DG to \$3,000.

### 3.4 Stranded Costs Recovery

In a traditional, vertically integrated utility system, fixed costs are recovered in an averaged manner across all customers. If a significant number of customers self-generate, their contribution to the recovery of capital costs is lost, resulting in what is commonly referred to as stranded assets. Historically, as markets move toward deregulation and unbundling of vertically integrated services, there have been provisions for some mechanism to recover the cost of these utility assets no longer being covered by the rate-base. These mechanisms vary from state to state and have such names as exit fees, competitive transition charges, etc.

In markets with retail competition, the issue of cost recovery for stranded assets, and the mechanism for paying for distribution services have been dealt with as part of the restructuring process. The states with retail competition have no need to make extra provisions for exit in their DG interconnection rules. The billing mechanisms in these markets are also already unbundled to differentiate between the fixed costs, such as distribution and the variable energy cost. The DG-owning customer will continue to pay their fixed charges to their local distribution utility and to negotiate their stand-by power needs with their competitive energy provider.

Two states in Table 2, California and Wisconsin, have regulated vertically integrated electricity markets. SUFG did not find any reference to exit fees or competitive transition charges in the Wisconsin DG interconnection rules. In California a DG customer is expected to pay the exit fees that apply to their tariff class. California provides a temporary waiver of exit fees for DG units of 5MW or less as follows: for “ultra clean” generators until December 31, 2005 and for renewable and combined heat and power facilities until December 31, 2004<sup>21</sup>. “Ultra clean” technologies are defined as technologies that meet or exceed the low emissions and high levels of waste heat recovery associated with state-of-the art combined cycle power plants<sup>22</sup>.

### 3.5 Standby Charges

Standby charges are designed to compensate the utility for the cost of the assets necessary to serve the DG-owning customer’s load whenever the DG unit is not available. A significant proportion of a utility’s cost of providing standby service is associated with the fixed cost of the transmission and distribution system (T&D). As articulated in the IURC DG white paper<sup>13</sup> setting of optimal standby charges is at once a very important issue but also a very complex one. From the DG-owning customer’s side, high monthly standby charges have been cited as one of the significant barriers to the competitiveness

of DG. On the other hand, utilities are concerned that undercharging the DG customer will shift the burden to other non-DG customers or to the shareholders.

As in the case of stranded costs discussed previously in section 3.4, the issue of bill unbundling into a fixed T&D charge and a per kWh energy charge will already have been dealt with as part of the deregulation process in the states with retail competition. There will be less need therefore for a detailed treatment of standby charges in the DG interconnection rule in these states. SUFG did not find any references to standby charges in the DG interconnection rules in the four states in this report that have retail competition (Delaware, New York, Ohio and Texas).

In the two states with a regulated electricity market, California<sup>9</sup> and Wisconsin<sup>10</sup>, DG-owning customers are expected to pay the standby charges that apply to their tariff class. In California, a temporary exemption from standby charges is provided for DG below 5 MW until December 31, 2004 for renewable and combined heat and power DG and until December 31, 2005 for “ultra clean” for DG utilizing “ultra clean” technologies. “Ultra clean” technologies are as defined in section 3.4.

## SECTION 4: MICHIGAN INTERCONNECTION RULE

Although the order adopting the Michigan interconnection rule was issued in September 2003, the Michigan rule appears to be very much a work in progress. The formation of the rule can be traced back to the Michigan restructuring act of June 2000<sup>24</sup>. Section 10e(3) of this law (Public Act 141) required that the Michigan Public Service Commission “*establish standards for the interconnection of merchant plants with the transmission and distribution systems of electric utilities. The standards shall not require an electric utility to interconnect with generating facilities with a capacity of less than 100 kilowatts for parallel operations.*” As can be seen from the above statement, the legislative act exempts the utilities from being required to interconnect generators below 100kW, which is the capacity range where most of the DG considered in this report would lie. So when the Public Service Commission in its subsequent orders required the utilities to write interconnection standards for all non-utility generators, including those below 100 kW, it elicited a lot of discussion and requests for rehearing by the utilities in Michigan<sup>25</sup>. The Commission eventually denied the requests for rehearing and issued an order adopting the DG interconnection rule on September 11, 2003. The deadline for utilities to file the interconnection standards was at first set for December 2003, but was later postponed to March 22 at the request of the utilities<sup>12</sup>. At the time of writing this report the process of filing and approving of the interconnection rules by the Michigan utilities did not appear to be complete. No approved procedures were posted on the Michigan Public Commission website yet.

By virtue of the Michigan interconnection rule being designed to include merchant plants, there is no maximum generator capacity designated for interconnection, rather, the rule classifies non-utility generators into five categories by capacity as follows:

1. less than 30 kW,
2. equal to or greater than 30 kW but less than 150 kW,
3. equal to or greater than 150 kW but less than 750 kW,
4. equal to or greater than 750 kW but less than 2 MW,
5. and greater than 2 MW.

The Michigan rule allows the utility to charge for engineering studies up to the lower of 5% of estimated total DG project cost or \$10,000. However generators with export capacity less than 15 percent line section peak load and short current contribution ratio no more than 25 percent are exempted from charges for engineering studies. If the distribution system requires modification, the utility is required to charge no more than the actual cost of the modification. A unique provision in the Michigan rules is that if the utility does not meet the deadlines to make the needed modifications on the distribution system, the generator owner is allowed to hire a contractor to complete the modifications from a certified contractor list maintained by the utility.

Application processing deadlines are provided for as follows:

- The utility is required to respond to the initial application within three working days.
- After the client has paid an application fee that varies from \$100 to \$500, the utility is required to provide a two hour consultation. This consultation is required to include a “good faith” estimate of the utility’s charges to complete the interconnection.
- The rules require that each utility set in its DG interconnection filings a reasonable deadline to make an initial response to the application. If the application is rejected, the utility is to provide a written explanation of the reasons for rejection. The reason must be based solely on demonstrably valid technical, reliability or safety criteria.
- If the application is complete and satisfactory, the Michigan rules provide the following deadline for the utility to complete all it’s obligations for interconnection.
  - generators less than 30 kW capacity – 2 weeks
  - equal to or greater than 30 kW but less than 150 kW – 4 weeks
  - equal to or greater than 150 kW but less than 750 kW – 6 weeks
  - equal to or greater than 750 kW but less than 2 MW – 12 weeks
  - equal to or greater than 2 MW – 18 weeks.

The details of how the interconnection standards deal with the other issues discussed in this report will only be clear when the process of filing of utility interconnection standards and procedures acceptable to the Michigan Public Service Commission is complete.



## SECTION 5: ENABLING LEGISLATION AND INCENTIVE PROGRAMS

In this section, the enabling legislation and incentive programs that encourage distributed generators are provided. The incentive programs are targeted primarily towards renewables and energy efficiency. The list and the description given here is extracted from the Database of State Incentives for Renewable Energy (DSIRE). DSIRE is a project of the Interstate Renewable Energy Council, funded by the U.S. Department of Energy and managed by the North Carolina Solar Center<sup>26</sup>.

### 5.1 Enabling Legislation

#### Texas

The Texas interconnection rule can be traced back to the Texas restructuring legislation (SB 7) of June 1999<sup>27</sup> that included, among its list of customer rights, a customer's right to have access to on-site distributed generation in section 39.101. The Public Utility Commission of Texas followed up in October 1999 with the interconnection rule 25.

#### New York and Delaware

SUFG has found no reference to enabling legislation in New York and Delaware. However, it is instructive to note that the DG interconnection rules in both states were issued immediately after the implementation of electricity retail competition. The New York Public Service Commission finished approving the restructuring orders of the six utilities in New York in 1998<sup>27</sup> while the DG interconnection rules were issued in 1999<sup>26</sup>. Similarly in Delaware, the DG interconnection rules were adopted in 2000 while the electricity retail competition was implemented in 1999<sup>26</sup>.

#### Ohio

The Public Utilities Commission of Ohio issued the interconnection service rule 4901:1-22<sup>28</sup> in September 2000. The rule is authorized by the 1999 Ohio competitive electric services law, and in particular section 4928.11 that requires the commission to “*establish uniform interconnection standards to ensure transmission and distribution system safety and reliability and shall otherwise provide for high quality, safe, and reliable electric service*” and that the interconnection rules “*shall seek to prevent barriers to new technology and shall not make compliance unduly burdensome or expensive.*”<sup>29</sup>

#### California

The California DG interconnection initiative can be traced back to the launch of competitive markets in California with Assembly Bill 1890<sup>30</sup>. This bill also established the self-generation incentive rebate program discussed later in the report. A multi-agency collaborative effort was launched in 1999 involving the California Energy Commission, the California Public Utilities Commission, the California Air Resources Board and others to develop common standards for interconnection and issuing of air permits. The process culminated in the adoption of the resulting interconnection standards by the California Public Utilities Commission in December 2000. Assembly Bill 970 of September 2000 gave further incentives to the rule making process by requiring the

Public Utilities Commission and the Electricity Oversight Board to “*to investigate Independent System Operator policies to determine if they discourage cogeneration and self-generation, and to take actions to revise those policies should they be found to discourage such practices.*”<sup>31</sup>. Other legislation providing incentives for DG and renewables are presented in section 5.2 below.

### **Wisconsin**

The Wisconsin distributed generation interconnection rule (Administrative Code Chapter PSC 119) was developed in response to section 196.496 of Wisconsin legislative act 16 of 2001. The legislation required that the Wisconsin Public Service Commission “*shall promulgate rules establishing standards for the connection of distributed generation facilities to electric distribution facilities. To the extent technically feasible and cost effective, the standards shall be uniform and shall promote the development of distributed generation facilities.*”<sup>10</sup>

### **Michigan**

The Michigan rule adopting DG interconnection standards, Case U-13745, was issued in response to the requirement of Public Act 141<sup>24</sup>, the Michigan Customer Choice and Electricity Reliability Act. Section 10e(3) of the act stated among other things that the Michigan Public Commission “*establish standards for the interconnection of merchant plants with the transmission and distribution systems of electric utilities.*” This act also contained the statement that “*the standards shall not require an electric utility to interconnect with generating facilities with a capacity of less than 100 kilowatts for parallel operations.*” This has resulted in disagreements among the stakeholders on the whether DG below 100 kW should be included in the Michigan utilities interconnection rules. The final order adopting the interconnection rule was issued in September 2003, and the utilities had until March 22, 2004 to file their interconnection standards consistent with the rule<sup>12</sup>.

## 5.2 Incentive Programs

### Texas

1. The solar energy device franchise tax deduction – This statute allows a corporation to deduct the cost of a solar energy device in one of two ways: (1) the total cost of the system may be deducted from the company's taxable capital; or, (2) 10% of the system's cost may be deducted from the company's income. Both taxable capital and a company's income are taxed under the franchise tax. Texas also offers a franchise tax exemption for manufacturers of photovoltaic systems.
2. The solar and wind-powered energy systems exemption – This incentive allows a property tax exemption of the amount of the appraised value of the property that arises from the installation or construction of a solar or wind-powered energy device that is primarily for the production and distribution of energy for on-site use. The definition of solar energy device includes energy imparted to plants through photosynthesis employing the bioconversion processes of anaerobic digestion, gasification, pyrolysis, or fermentation.
3. The solar energy system manufacturer's franchise tax exemption – This exempts any corporation that is engaged solely in the business of manufacturing, selling, or installing solar energy devices from franchise tax.
4. Mainstay Energy Rewards Program – green tag purchase program – This is a privately funded incentive by the company Mainstay Energy. It offers customers who install grid connected renewable energy systems the opportunity to sell the renewable energy credits, associated with the energy generated by these systems. Through the Mainstay Energy Rewards Program, participating customers receive regular, recurring payments depending on the type of renewable technology as follows. Photovoltaic: 2¢/kWh - 5¢/kWh, Wind: 0.2¢/kWh - 1.5¢/kWh, Biomass/biofuel electric: 0.1¢/kWh - 1¢/kWh, Geothermal/Low-impact hydro: 0.2¢/kWh - 1¢/kWh.
5. Austin Energy – solar rebate program – In this program, funded by the Austin City Council, residential and commercial customers who install photovoltaics on their homes or businesses will be eligible for the rebate. The rebate is \$5 per watt, increasing to \$6.25 per watt for solar installations that use PV equipment manufactured in Austin. For residential customers, the rebate program will pay 80% of customer invoiced cost or \$15,000, whichever is less. For commercial customers, the rebate program will pay 80% of customer invoiced cost or \$100,000, whichever is less.

### New York

1. The Energy Smart new construction program – This program provides for opportunities to implement permanent energy efficiency and load management improvements in building envelopes and major systems (e.g., HVAC, lighting, controls, building envelope) at the time of new construction or substantial renovation.

Incentives to install building-integrated photovoltaics are also included.

2. The Energy Smart loan fund – This is a loan program providing reduced-interest loans through participating lenders to finance renovation or construction projects that improve a facility’s energy efficiency or incorporate renewable energy systems. To qualify for the loan program, the facility must be an electric distribution customer of one of the State’s six investor-owned utilities.
3. Photovoltaic incentive program – The New York State Energy Research and Development Authority (NYSERDA) provides incentives of \$4 to \$5 per Watt to eligible installers for the installation of approved, grid-connected, photovoltaic systems up to 15kW. Incentives are only available to eligible installers and incentives must be passed on to customers. Once eligible, installers reserve incentives for approved systems, for specific customers, on a first-come, first-served basis, for as long as funds (~\$2.5 million) are available. The goal is to increase the network of eligible installers across the State, offering customers a choice of qualified or certified installers in their area.
4. Wind incentive program –NYSERDA has at least \$2.5 million in incentives to encourage wind technology deployment and infrastructure development in New York. The goal of the program is to encourage the development of a network of eligible installers who will install end-use wind energy turbines for all sectors including, but not limited to, residential, commercial, industrial, agricultural, institutional, educational, not-for-profit, and government-owned facilities. The incentives, of up to \$100,000 per installation, will be paid to eligible installers who meet NYSEDA's requirements for education, training, experience, insurance, and other criteria. The installers, in turn, pass through incentives directly to end-use customers.
5. Solar and wind energy systems property tax exemption – This provides a 15-year real property tax exemption for solar and wind energy systems constructed in New York State. It was later expanded to include farm waste electric generating equipment up to 400 kW.
6. The solar and fuel cell generating equipment personal tax credit – This personal income tax credit applies to expenditures on solar electric equipment used on residential property. This tax credit provision was passed as part of a bill that includes provisions for the net metering of the same equipment. The credit is for 25 percent of the cost of equipment and installation of photovoltaic systems.
7. Mainstay Energy Rewards Program – green tag purchase program – This is a privately funded incentive by the company Mainstay Energy. It offers customers who install grid connected renewable energy systems the opportunity to sell the renewable energy credits, associated with the energy generated by these systems. Through the Mainstay Energy Rewards Program, participating customers receive regular, recurring payments depending on the type of renewable technology as follows. Photovoltaic: 2¢/kWh - 5¢/kWh, Wind: 0.2¢/kWh - 1.5¢/kWh, Biomass/biofuel

electric: 0.1¢/kWh - \$1¢/kWh, Geothermal/Low-impact hydro: 0.2¢/kWh - 1¢/kWh.

8. Long Island Power Authority (LIPA) Solar Pioneer Program – This program by LIPA is designed to encourage the use of solar energy among Long Island homeowners and businesses and to help make the installation of a PV system more affordable.

### **Delaware**

1. The green energy program rebates – This program was established as part of The Electric Utility Restructuring Act of 1999. Under the program, energy alternatives rebates are available for the installation of qualifying photovoltaic, solar water heating, wind turbine, and geothermal heat pump systems. The maximum rebate amount is 50% of installation costs for photovoltaic, solar water heating, and wind turbine systems up to the maximum as follows: nonresidential - \$250,000, residential photovoltaic systems - \$22,500, residential wind turbine - \$5,000.
2. Mainstay Energy Rewards Program – green tag purchase program – This is a privately funded incentive by the company Mainstay Energy. It offers customers who install grid connected renewable energy systems the opportunity to sell the renewable energy credits, associated with the energy generated by these systems. Through the Mainstay Energy Rewards Program, participating customers receive regular, recurring payments depending on the type of renewable technology as follows. Photovoltaic: 2¢/kWh - 5¢/kWh, Wind: 0.2¢/kWh - 1.5¢/kWh, Biomass/biofuel electric: 0.1¢/kWh - \$1¢/kWh, Geothermal/Low-impact hydro: 0.2¢/kWh - 1¢/kWh.

### **Ohio**

1. Distributed energy resources grant program – This program is managed by the Ohio Department of Development's Office of Energy Efficiency Eligible projects include but are not limited to industrial heat recovery, combined heat and power, landfill or biomass methane, PV and wind up to a maximum of 25 MW. Project support is provided by Ohio's Energy Loan Fund, the state's public benefits fund.
2. Renewable energy loans – The incentive was created by the Ohio's 1999 electric restructuring act. It reduces interest rate -- by approximately half -- on standard bank loans for those qualifying Ohio residents and businesses who borrow money to implement energy efficiency or renewable energy projects.
3. Conversion facilities tax exemption (corporate and personal) – This statute, originally enacted in 1978, exempts certain equipment from property taxation, Ohio's sales and use tax, and Ohio's franchise tax where applicable. Eligible technologies include solar thermal systems, photovoltaic systems, wind, biomass and waste recovery systems.
4. Mainstay Energy Rewards Program – green tag purchase program – This is a privately funded incentive by the company Mainstay Energy. It offers customers who install grid connected renewable energy systems the opportunity to sell the renewable energy credits, associated with the energy generated by these systems. Through the

Mainstay Energy Rewards Program, participating customers receive regular, recurring payments depending on the type of renewable technology as follows. Photovoltaic: 2¢/kWh - 5¢/kWh, Wind: 0.2¢/kWh - 1.5¢/kWh, Biomass/biofuel electric: 0.1¢/kWh - \$1¢/kWh, Geothermal/Low-impact hydro: 0.2¢/kWh - 1¢/kWh.

## **California**

1. Self-Generation Incentive Program (SGIP) - SGIP provides incentives to encourage customers to produce energy using microturbines, small gas turbines, wind turbines, photovoltaics, fuel cells, and internal combustion engines. The incentives include payments of \$1 to \$4.50 per watt, depending on the technology used, and will be funded through the end of 2007. AB 1685 of 2003 extended the program expiration date from 12/31/04 to 1/1/08, as well as providing funding of approximately \$500 million.
2. The emerging renewable rebate program – This program of the California Energy Commission, provides rebates for the following types of systems: solar photovoltaic, solar thermal electric, fuel cells using renewable energy, and wind turbines. The initial incentive was \$4.00 per watt for photovoltaic systems and \$2.50 per watt for small wind systems. Incentives were set to decline by \$0.20 per watt every six months, with the first decline beginning July 1, 2003. An incentive of \$4.75 per watt for affordable housing projects for photovoltaic systems was available until 12/31/03, after which the incentive was to decline by \$0.25 per watt every six months. Owners of self-installed systems receive a 15 percent lower rebate than contracted installations.
3. Statewide solar schools program – This program managed by the California Energy Commission and the California Power Authority provides rebates for photovoltaic systems for public and charter schools that meet certain eligibility requirements. It is part of the emerging renewable rebate program presented above.
4. State loan program - Under the program titled Energy Financing Industrial Bond Program, the California Power Authority offers below-market rate loans to manufacturing companies that will use the loan for the purchase and installation of renewable energy systems, energy-efficient equipment, or clean distributed generation systems on their own facilities, or manufacturers of renewable energy and/or clean distributed generation systems or components establishing or expanding the manufacturer's California production facilities. Eligible renewable energy technologies include photovoltaics, solar thermal electric, fuel cells, small and large wind turbines, biogas, landfill gas, biomass, and geothermal electric technologies.
5. Statewide property exemption for solar systems - According to the California Revenue and Taxation Code, section 73, when assessing property for property tax purposes, active solar energy systems installed between January 1, 1999 and January 1, 2006 are not subject to property taxes. Active solar energy systems may be used for any of the following: domestic, recreational, therapeutic, or service water heating; space conditioning; production of electricity; process heat; and solar mechanical

energy.

6. Statewide personal and corporate tax credit for solar and wind energy - California's Solar or Wind Energy System Credit (SB17x2) provides personal and corporate income tax credits for the purchase and installation of solar energy systems no more than 200kW.
7. More localized incentive programs are maintained by cities and utilities in their jurisdictions. They include.
  - a. San Diego residential solar electric incentive for homes destroyed in wildfires.
  - b. Anaheim Public Utility photovoltaic buy-down program.
  - c. Burbank Water and Power residential and commercial solar support
  - d. City of Palo Alto Utilities – Photovoltaics partners program.
  - e. Los Angeles Department of Water and Power solar incentive program.
  - f. Redding Electric – “Vantage renewable energy rebate program.”

### **Wisconsin**

1. Solar and wind energy equipment property tax exemption – Any value added by a solar or wind energy system is exempted from general property taxes.
2. Focus on Energy state rebate program - Focus on Energy offers Cash-Back Rewards for installing or expanding renewable energy systems on businesses and homes. Payments are based on an estimate of the amount of electricity or therms produced annually. Non-residential projects include wind, photovoltaics, solar hot water and solar space heating. Eligible residential systems include wind, photovoltaics, and solar hot water.
  - a. Residential
    - Wind energy systems (20 kW or less): 25% of project cost or \$35,000
    - Photovoltaic systems (20 kW or less): 25% of project cost or \$35,000
    - Solar hot water systems: 30% of project cost or \$3,000.
  - b. Non-Residential
    - Wind energy systems (20 kW or less): 25% of project cost or \$35,000
    - Photovoltaic systems (20 kW or less): 25% of project cost or \$35,000
    - Solar hot water systems (5,000 or fewer therms per year): 25% of project cost or \$35,000
    - Solar space heating systems (5,000 or fewer therms per year): 25% of project cost or \$35,000
3. Focus on Energy state loan program – Focus on Energy offers low-interest loans to finance renewable energy projects on existing owner-occupied single-family and duplex homes. Eligible technologies include photovoltaics, solar water heat and wind. Homeowners can borrow \$2,500 - \$20,000 at an interest rate of 1.99%. Loan terms vary from three to 10 years.

4. Wisconsin municipal utility solar energy cash allowance – Many of Wisconsin's municipal utilities support customer use of solar energy by providing cash incentives for qualifying projects. The incentives vary by community but may include:
  - \$1/watt for photovoltaic installations (maximum incentive of \$1,000)
  - \$15/square foot of collector area for new solar hot water systems (maximum incentive of \$1,000)
  - 50% of the cost of repair for existing solar hot water systems (maximum incentive of \$500)
  
5. Mainstay Energy Rewards Program – green tag purchase program – This is a privately funded incentive by the company Mainstay Energy. It offers customers who install grid connected renewable energy systems the opportunity to sell the renewable energy credits, associated with the energy generated by these systems. Through the Mainstay Energy Rewards Program, participating customers receive regular, recurring payments depending on the type of renewable technology as follows. Photovoltaic: 2¢/kWh - 5¢/kWh, Wind: 0.2¢/kWh - 1.5¢/kWh, Biomass/biofuel electric: 0.1¢/kWh - 1¢/kWh, Geothermal/Low-impact hydro: 0.2¢/kWh - 1¢/kWh.

### **Michigan**

1. Energy efficiency grants – Michigan offers grants to support energy efficiency projects, including fuel cell installations, through the state's Low-Income and Energy Efficiency Fund, which was authorized by the Customer Choice and Electricity Reliability Act of 2000.
  
2. Large-scale photovoltaic demonstration project grants – Photovoltaic demonstration grants are available to public and non-profit organizations to help fund the purchase and demonstration of new photovoltaic systems with a minimum capacity of 10 kW. A total of \$180,000 is available for three \$60,000 projects. Grants should not exceed 90% of the cost of photovoltaic equipment, materials, and supplies. Grant recipients must pay for labor, installation and some equipment costs.
  
3. Mainstay Energy Rewards Program – green tag purchase program – This is a privately funded incentive by the company Mainstay Energy. It offers customers who install grid connected renewable energy systems the opportunity to sell the renewable energy credits, associated with the energy generated by these systems. Through the Mainstay Energy Rewards Program, participating customers receive regular, recurring payments depending on the type of renewable technology as follows. Photovoltaic: 2¢/kWh - 5¢/kWh, Wind: 0.2¢/kWh - 1.5¢/kWh, Biomass/biofuel electric: 0.1¢/kWh - 1¢/kWh, Geothermal/Low-impact hydro: 0.2¢/kWh - 1¢/kWh.



## SECTION 6: DG PENETRATION

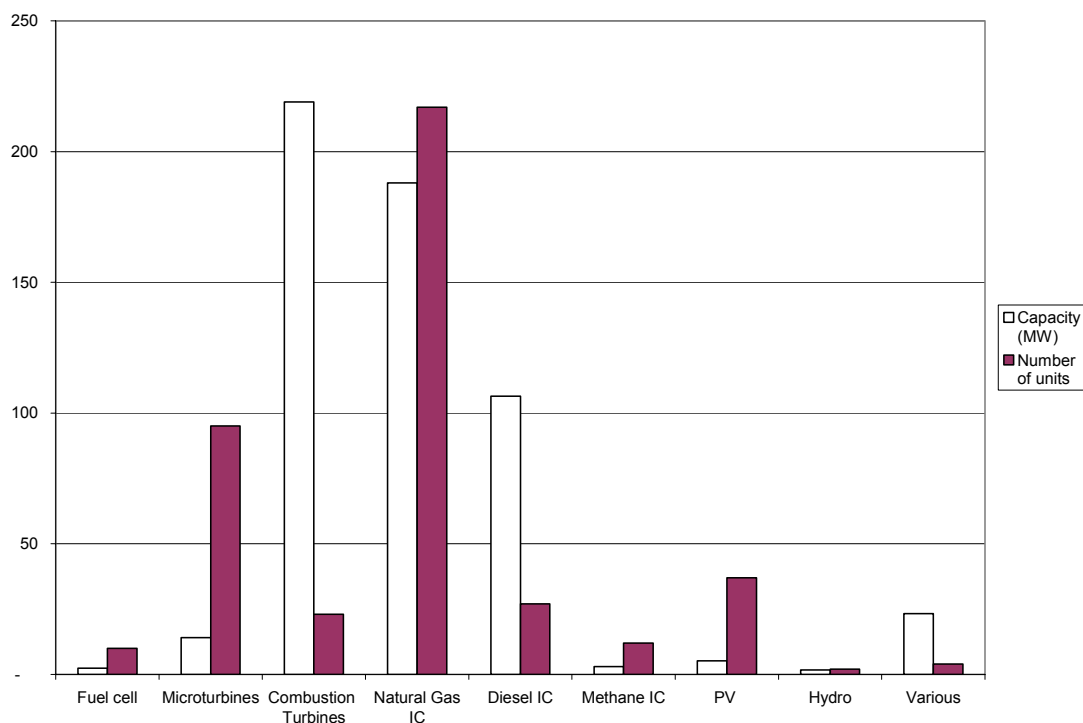
This section examines DG penetration by technology, fuel source and customer group. It focuses primarily on California since it has the most complete data available.

### 6.1 Technology and Fuel Mix

As of December 2003, 372 MW of DG capacity had been interconnected under the California DG interconnection Rule 21<sup>32</sup>. A further 191 MW were waiting for authorization to interconnect. Figure 3 shows the distribution of the DG installed in California by technology types. The technologies installed or awaiting authorization in order of the amount of capacity are as follows:

- i. Internal combustion turbines whose 297 MW make up 53% of the capacity
- ii. Combustion turbines using natural gas at 219 MW or 39%
- iii. Micro-turbines at 14 MW or 2.5%
- iv. Solar photovoltaics at 5.3 MW or 0.9%
- v. Fuel cells at 2.4 MW or 0.4%
- vi. Hydro at 1.8 MW or 0.3%
- vii. Approximately 23 MW (4%) comprised of combined technologies.

Figure 3 Distribution of DG Installations by Technology Types in California



*IC – Internal combustion engine; PV – photovoltaic*

Source: Chart drawn from data on California Rule 21 Statistics web page<sup>32</sup>.

Among the 297 MW of internal combustion engine capacity, 188 MW (63%) of the internal combustion engines use natural gas as their fuel, 106 MW (36%) use diesel and 3 MW (1%) use methane for fuel. Among the 14 MW of micro-turbine capacity, 77% (10.8 MW) uses natural fuel, 15% (2.2 MW) uses methane fuel and 1.1 MW is classified as using other fuels.

This predominance of natural gas and diesel-fired combustion technologies is confirmed by the statistics collected on the DG interconnection in Texas. A total of 212 MW of DG capacity installed in Texas. Out of the 155 MW interconnected in the Oncor (TXU) service territory the most common fuel in use was diesel and out of the 58 MW connected in the rest of Texas the most common source of fuel was natural gas.

## 6.2 DG Distribution Among Customer Groups

Looking at the distribution of DG among customer groups provides an additional perspective. Figure 4 shows the amount of DG in California by customer groups as of December 2003. The installations in order of capacity are as follows:

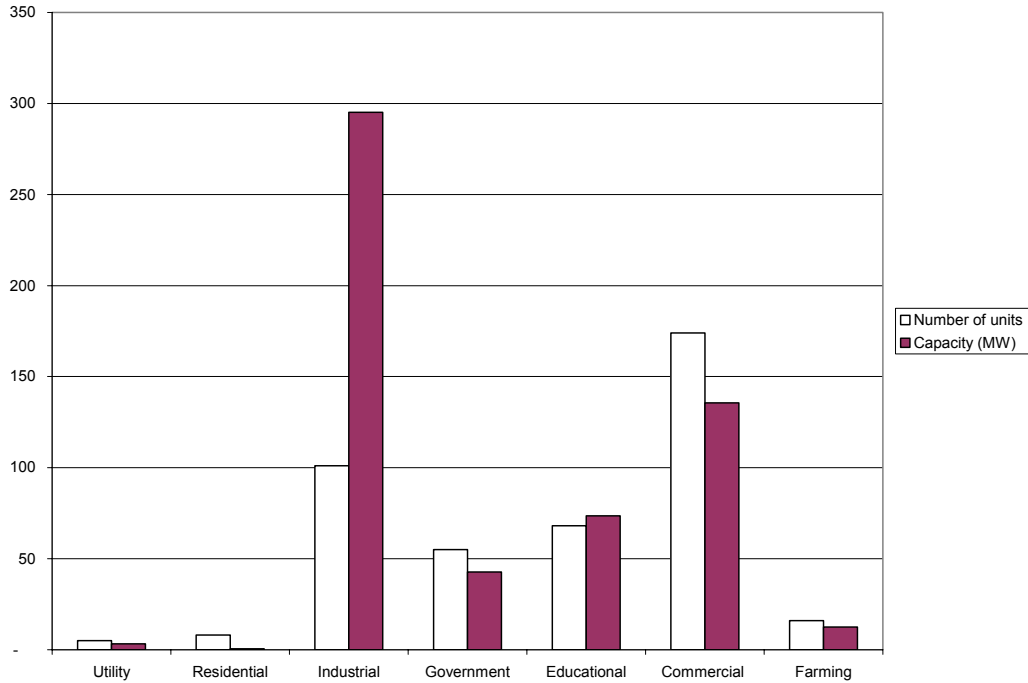
- i. Industrial – 295 MW or 52% of the capacity
- ii. Commercial – 136 MW or 24%
- iii. Educational institution – 74 MW or 13%
- iv. Government installations – 43 MW or 7.6%
- v. Farming – 12 MW or 2.2%
- vi. Utilities – 3.2 MW or 0.6%
- vii. Residential – 484 kW or 0.1 %

The average size of units in each customer group is as follows:

- i. Industrial – 2.9 MW
- ii. Educational – 1.1 MW
- iii. Commercial – 779 kW
- iv. Farming – 778 kW
- v. Government – 776 kW
- vi. Utility – 642 kW
- vii. Residential – 61 kW

The largest unit interconnected to operate in parallel under California's interconnection Rule 21 is a 47 MW generator in an oil refinery in the Southern California Edison service territory. This gas turbine was interconnected in 2002 to serve as the primary power source for the refinery. The smallest unit is a 1.8 kW PV at a commercial facility in Pacific Gas & Electric Company service territory.

Figure 4 DG Distribution among Customer Groups in California



Source: Chart drawn from data on California Rule 21 Statistics web page<sup>32</sup>.

### 6.3 Impact of Interconnection Rules on Penetration

The 563 MW of existing and proposed DG installations in California represent roughly one percent of total electricity generating capacity for the state. In Texas, DG represents approximately one quarter of a percent of all generation capacity. Unfortunately, capacity numbers are not available for other states or for the U.S. as a whole. However, it is likely that California has achieved a higher than average level of DG penetration. While California's interconnection and net metering rules have facilitated DG installations, the high level of DG penetration cannot be attributed solely to those rules. The high electricity prices and rolling blackouts that characterized the recent California energy crisis provided a powerful incentive for DG.

The adoption of standardized interconnection and net metering rules should result in an increased amount of DG. Due to the unique circumstances in California and a lack of data elsewhere, it is not possible to accurately quantify the effects of such rules.

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