WHITE PAPER

ON

DISTRIBUTED GENERATION

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National Rural Electric Cooperative Association

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INTRODUCTION

Distributed generation (DG) is not a new concept. A small number of cooperative consumers have been using DG for decades. Over the last 10 years, the DG market has been somewhat turbulent. In the late 1990s, the creation of competitive retail electric markets, new regulations like net metering, and the development of new DG technologies sparked broader interest in distributed generation. Recently however, higher natural gas prices have slowed the implementation of DG in many areas.

In some cases, properly planned and operated DG can provide consumers and society with a wide variety of benefits, including economic savings, improved environmental performance, and greater reliability. Some cooperatives and other utilities have acted to bring the benefits of DG to their systems and are funding research to develop new technologies.

Nevertheless, the interconnection of DG with the electric grid continues to pose genuine safety and reliability risks. Moreover, because DG could replace or reduce the demand for traditional utility service, DG could also pose an economic risk to some incumbent utilities and their consumers without appropriate rate structures or other cost recovery mechanisms.

This has created a conflict between industry stakeholders and other interest groups. On the one hand, proponents of DG are telling decision makers that utilities and regulators continue to impose technical and economic barriers to the development, installation, and interconnection of DG facilities with the electric grid. They are asking regulators and legislators to act to remove those barriers so that consumers can benefit from DG.

On the other hand, many utilities have insisted that if decision makers adopted the DG proponents' recommendations, it would significantly degrade the safety and stability of electric systems and would require utilities and their residential and small commercial consumers to subsidize uneconomic technology investments by others.

In fact, the truth probably lies somewhere in between. Decision makers should address the legitimate concerns of DG proponents to help attain the potential benefits of DG. But, decision makers must first address a number of real safety, reliability, and economic issues. To accomplish that goal, decision makers should look carefully at different applications of different DG technologies. Separate rules can and should apply to each. The electrical grid is very complex and there are too many variations between the different applications of different DG technologies for any one rule to be universally applicable.

DEFINITION OF "DISTRIBUTED GENERATION"

Almost every participant in discussions about DG defines the term "distributed generation" differently. And, unfortunately, participants in discussions about DG seldom make their definition of the term clear at the outset, making it difficult to evaluate competing proposals.

At one end, DG could include only small-scale, environmentally friendly technologies – such as photovoltaics (PV), fuel cells, small wind turbines, or more conventional technologies like microturbines or reciprocating engines fueled by renewable fuels such as landfill gas – that are installed on and designed primarily to serve a single end-user's site. At the other end, DG could encompass any generation built near to a consumers' load regardless of size or energy source. The latter definition could include diesel-fired generators with significant emissions and large cogeneration facilities capable of exporting hundreds of megawatts of electricity to the grid.

Other definitions of DG include some or all of the following:

- Any qualifying facilities under the Public Utility Regulatory Policies Act of 1978 (PURPA);

- Any generation interconnected with distribution facilities;

- Commercial emergency and standby diesel generators installed, for example, in hospitals and hotels;
- Residential standby generators sold at hardware stores;
- Generators installed by a utility at a substation for voltage support or other reliability purposes;
- Any on-site generation with less than “X” kW or MW of capacity. “X” ranges everywhere from 10 kW to 50 MW;
- Generation facilities located at or near a load center;
- Demand side management (DSM), energy efficiency, and other tools for reducing energy usage on the consumers’ side of the meter. The alternative to this definition would be to abandon the term distributed generation altogether and use instead “distributed resources” (DR) or “distributed energy resources.” (DER)

Why all of these definitions? As discussed below, many decision makers believe that DG is beneficial and are likely to adopt regulations or legislation that removes barriers to or subsidizes the development and installation of DG. Depending on the definition of DG that the decision makers adopt, and the different applications of DG that the decision makers address, different industry participants, or different interest groups will share in the benefits of the new regulatory programs. No industry or interest group wants to be left out.

For the purpose of this paper, it is not necessary to propose yet another competing definition. Instead, the paper will use the term “DG” generically to refer to any or all of the above concepts except DSM. For that reason, the paper will try not to make any categorical statements about DG generally, unless they truly can be said to apply regardless of the reader’s definition. Whenever a comment applies only to a single technology or application, the paper will try to make that clear. Decision makers may benefit from the same approach. They may find much greater consensus in the industry on a range of technical and policy issues if they avoid wide ranging debates about “DG” generally and instead focus on narrow questions about specific applications of particular generation technologies.

DISTRIBUTED GENERATION APPLICATIONS

Distributed generation is currently being used by many customers to provide some or all of their electricity needs. The vast majority of DG units are operated to provide emergency back-up and are unlikely to ever operate in parallel with the distribution system. There are also some customers that use DG to reduce their demand charges, and others that use DG to provide premium power or reduce the environmental emissions from their power supply. In addition, some cooperatives use DG to enhance their distribution systems.

A number of applications for DG technology solutions exist. The following is a list of potential applications of interest to cooperatives and their customers. These applications are not mutually exclusive. In some instances, a specific DG installation can be used for more than one of these applications.

Continuous Power – DG is operated at least 6,000 hours per year to allow a facility to generate some or all of its power on a relatively continuous basis. Important DG characteristics for continuous power include:

- High electric efficiency,
- Low variable maintenance costs, and
- Low emissions.

Continuous power applications could also be used by a cooperative to supply power to some of its customers.

Combined Heat and Power (CHP) – Also referred to as cogeneration or combined heat and power, DG is operated at least 6,000 hours per year to allow a facility to generate some or all of its power, with some or all of the DG waste heat being used for water heating, space heating, or other thermal needs. In some instances this thermal energy also can be used to operate special cooling equipment. Important DG characteristics for combined heat and power include:

- High useable thermal output (leading to high overall efficiency),
- Low variable maintenance costs, and
- Low emissions.

Peaking Power – DG is operated between 50-3000 hours per year to reduce overall electricity costs. In the past, peaking applications only operated a few hundred hours per year. More recently, peaking applications are being used to generated electricity whenever a utility has peak rates. Some utilities have rates with on-peak periods defined as 15 hours per day, 5 days a week for the entire year, leading to as many as 3,000 hours per year of operation for DG operated on-peak[1]. Units can be operated to reduce demand charges, to defer buying electricity during high-price periods, or to allow for lower rates from power providers by smoothing site demand. Important DG characteristics for peaking power include:

- Low installed cost,
- Quick startup, and
- Low fixed maintenance costs.

Peaking power applications could also be used by a cooperative to supply power to customers to reduce the cost to the cooperative of buying electricity during high-price periods.

Green Power – DG is operated by a facility to reduce environmental emissions from its power supply. Important DG characteristics for green power include:

- Low emissions, and
- Low variable maintenance costs.

Green power could also be used by a cooperative to supply power to customers who want to purchase power generated with low emissions.

Premium Power - DG is used to provide electricity service at a higher level of reliability and/or power quality than typically available from the grid. Different customers have different needs, so premium power can be broken down into three sub-categories:

Emergency Power System - An independent system that automatically provides electricity within a specified time frame to replace the normal source if it fails. The system is used to power critical devices whose failure would result in property damage and/or threatened health and safety.

Standby Power System - An independent system that provides electricity to replace the normal source if it fails. The power provided will allow the customer's facility to continue to operate satisfactorily.

[1] New York State Electric and Gas, PSC No. 120 – Electricity Service Classification No. 7, December 2003

True Premium Power System - Uninterrupted power, free of all frequency variations, voltage transients, dips, and surges. Power of this quality is not available directly from the grid – it requires both auxiliary power conditioning equipment and either emergency or standby power. Alternatively, a DG technology can be used as the primary power source and the grid can be used as a backup.

Important DG characteristics for premium power (emergency and standby) include:

- Quick startup,
- Low installed cost,
- Dependability, and
- Low fixed maintenance costs.

Transmission and Distribution Deferral – DG can be used by a cooperative to delay investment in new transmission or distribution facilities or upgrades. In some cases, placing DG units in strategic locations can help delay the purchase of equipment such as distribution lines and substations. A thorough analysis of the life-cycle costs of the various alternatives is important, and contractual issues relating to equipment deferrals need to be examined closely. Important DG characteristics for transmission and distribution deferral (when used as a "peak deferral") include:

- Low installed cost,
- Dispatchability,
- Dependability,
- Appropriate location on a circuit or circuits with the necessary growth characteristics, and
- Low fixed maintenance costs.

Ancillary Service Power – DG is used by a cooperative to provide ancillary services (i.e., interconnected operations necessary to impact the transfer of electricity between purchaser and seller) at the transmission or distribution level. Potential services include spinning reserve (unloaded generation, which is synchronized and ready to serve additional demand) and non-spinning reserve (operating reserve not connected to the system but capable of serving demand within a specific time or interruptible demand that can be removed from the system within a specified time). Among other potential services are reactive supply, voltage control, and local area security. To date, there have been very few DG applications that provide ancillary services in the U.S., although some wholesale power markets are starting to emerge for these services. In markets where the electric industry has been deregulated (the United Kingdom, for example) there is a customer base for larger DG applications for spinning and non-spinning reserve. Important DG characteristics depend on which type of ancillary service is being performed.

Only certain types of DG can be used for some of these ancillary power applications, such as providing reactive power and voltage control. Depending on the type of generation, DG may supply or consume reactive power. Inverter-based DG, typical of microturbines, fuel cells, and solar cells, is required to support the network voltage given appropriate market incentives. Location of the DG is also important when providing ancillary power – these service are usually only needed at in certain areas. Finally, DG that is used to supply ancillary service generally needs sophisticated dispatch hardware, so that the grid operator can coordinate operation of the DG with the grid's needs.

Remote Power - With remote power applications, distributed generation is used to provide electricity to a facility that is isolated from the grid. These applications are typically considered when a facility is being located far from the existing distribution system, or when the terrain in-between poses unique challenges to grid extensions (e.g. mountains, islands, or environmentally sensitive areas). The DG unit is the sole source of power for the facility, so good partial load performance is needed, and high operating hours are common. Important DG characteristics for remote power applications include:

- High electric efficiency,
- Dependability and/or the ability to match the technology with storage, and
- Low variable maintenance costs.

Remote power units are usually run continuously so a quick startup time is not necessary, and it is usually a long-term investment so installed costs are not as much of an issue.

Most DG technology applications in the U.S. have been large industrial and commercial sector CHP, premium power, some peaking power, and, more recently, green power. The most common application in terms of number of units is emergency/standby power.

The following table shows DG application types and important characteristics:

Application	Low Cost	High Efficiency	Thermal Output	Emissions	Start-Up Time	Fixed Maintenance	Variable Maintenance	Dispatch-ability	Dependa-bility
Continuous Power	◒	●	○	◒	○	◒	●	◒	●
CHP	◒	●	●	◒	○	◒	●	●	●
Peaking	●	◒	○	○	◒	●	◒	●	◒
Green	◒	◒	◒	●	○	◒	◒	◒	◒
Emergency	●	○	○	○	●	●	○	●	●
Standby	●	○	○	○	◒	●	○	●	●
True Premium	◒	◒	○	◒	●	◒	◒	●	●
Peaking T&D Deferral	●	○	○	○	◒	●	○	●	●
Baseload T&D Deferral	◒	●	◒	◒	○	◒	●	◒	●
Spinning Reserve	◒	◒	○	○	●	◒	◒	●	●
Reactive Power	◒	◒	○	◒	◒	◒	◒	●	●
Voltage Control	◒	◒	○	◒	◒	◒	◒	●	●
Local Area Security	●	○	○	○	◒	●	○	●	●
Remote Power	◒	●	◒	◒	○	◒	●	○	●

Key:
● Important Characteristic
◒ Moderately Important / Important in Certain Applications
○ Relatively Unimportant

REGULATORY BACKGROUND

CURRENT REGULATORY FRAMEWORK

DG is subject to local, state and federal regulations. Local regulation can include siting and permitting requirements. For example, DG that requires installation of high-pressure natural gas service may require special permits. Moreover, any installation in a home or business will likely require approval from local building inspectors.

State economic and interconnection regulations fall into three categories; 1) those implementing PURPA § 210, 2) regulation having to do with net metering, and 3) more comprehensive activities involving actions like interconnection standards and pre-certification on DG units for interconnection. Many states also have environmental regulations to which DG may be subject.

Most states have adopted rules implementing PURPA § 210.[2] PURPA required utilities to interconnect with "qualifying facilities" (QFs),[3] to sell power to QFs,[4] and to purchase QF power at avoided cost.[5] Those rules, however, do not address the whole spectrum of DG. Under PURPA, QFs include only qualifying solar, wind, waste, or geothermal facilities with a power production capacity of no more than 80 MW and qualifying cogenerating facilities. Until recently, QFs also had to be owned by persons not primarily engaged in the generation or sale of electric power. State rules implementing PURPA § 210 typically included simple rules mandating interconnection with QFs and defining the utility's avoided cost.

In the Energy Policy Act of 2005 (EPAct'05)[6] Congress modified PURPA § 210 to remove limitations on QF ownership. EPAct'05 also permits utilities to apply to FERC for a waiver from the obligation to purchase power from QFs where QFs, have ready access to competitive markets administered by independent systems operators. FERC has issued a final rule implementing this provision in which FERC simplifies the process for obtaining an exemption from the obligation for QFs larger than 20 MW that interconnect to utilities that are members of an established RTO[7]. Utilities that are not members of RTOs would need to make an individual showing to FERC that they are entitled to a waiver. EPAct'05 also eliminated PURPA §210's mandatory "sale" obligation in service territories subject to retail competition pursuant to state law, provided that alternative suppliers are actually present and willing to serve the QF. EPAct'05 also amended Title 1 of PURPA to require state commissions and electric utilities (including co-ops and municipals) of a certain size to consider implementing five new standards including DG interconnection and net metering.

At least 34 states have so called "net metering" rules to date. The purpose of those requirements is to provide a simple means to compensate consumers for certain forms of self generation and/or to promote self generation. Although net metering rules vary widely between states, most cover only fairly small facilities powered with renewable resources: wind, photovoltaics, small hydro, and/or biomass. Most rules require utilities to interconnect with eligible consumer-owned generation and effectively run the consumer's meter backwards every time the consumer's generator exports net energy to the system. If the consumer uses more energy over the course of a billing period than they have generated, they pay only for the net energy that they have imported from the system. State rules vary widely if the consumer generates more than they have used over the course of a billing period. While some states prohibit any payment to consumers for net exports, others require utilities to pay consumers "avoided cost" like with PURPA or credit consumers the full retail price for their excess power. Detailed information on state-level requirements for net metering can be found at www.dsireusa.org.

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[2] Pub. L. No. 95-617, 92 Stat. 3117 (1978).

[3] See PURPA § 202, codified in § 210 of the Federal Power Act (FPA), 16 U.S.C. 824(i).

[4] See PURPA § 210.

[5] See PURPA § 210.

[6] Energy Policy Act of 2005, Signed into law August 8, 2005

[7] 117 FERC, 61,078, 18 CFR Part 292, (Docket No. RM06-10-000; Order No. 688), Issued October 20, 2006

A number of states, including Texas, New York, California, Massachusetts, Connecticut, New Jersey, Illinois, have addressed DG more comprehensively. In some cases states have developed interconnection standards or have pre-certified certain models of DG units for interconnection. The comprehensive interconnection rules typically standardize the interconnection applications, review procedures, interconnection contracts, and interconnection fees. They also establish standardized technical requirements for the DG technologies. Current links to these requirements can also be found at www.dsireusa.org. The National Association of Regulatory Utility Commissioners has issued a model regulation for DG interconnection[8]. Many cooperatives and other utilities have adopted their own interconnection procedures and agreements similar to those the states and NRECA has developed the DG Interconnection Toolkit[9], which is a portfolio of DG resources and tools.

The number of states and utilities considering net metering and interconnection rules is likely to increase significantly during 2005-2008 due to another provision in the recent energy law. EPAct'05 amended Title I of PURPA to require all states, for the covered utilities whose rates they regulate, and all covered nonregulated electric utilities to consider whether to adopt five new Federal standards. These include net metering and DG interconnection standards. Section 1251 pertains to net metering and Section 1254 addresses interconnection. NRECA, NARUC, the Edison Electric Institute (EEI), and American Public Power Association (APPA) have developed an EPAct 2005 implementation manual for utility commissioners and nonregulated electric utilities.[10]

At the Federal level, FERC has adopted two rules on generation interconnection, one for large generators (RM02-1-000) and one for small generators (RM02-12-000). The small generator rulemaking is summarized in these excerpts from a May 2005 FERC press release:

> *The Federal Energy Regulatory Commission today issued standard procedures for the interconnection of generators no larger than 20 megawatts - a move that removes barriers to the development of needed infrastructure by reducing interconnection uncertainty, time and costs.*
>
> *Today's rule will help preserve grid reliability, increase energy supply, and lower wholesale electric costs for customers by increasing the number and types of new generators available in the electric market, including development of non-polluting alternative energy resources, the Commission said.*
>
> *The rule reflects input from a broad-based group of utilities, small generators, state commission representatives, and other interested entities who came together to recommend a unified approach to small generator interconnection. This rule reflects many of these consensus positions as well as those of the National Association of Regulatory Utility Commissioners (NARUC). The rule harmonizes state and federal practices by adopting many of the best interconnection practices recommended by NARUC. It should help promote consistent, nationwide interconnection rules for small generators, the Commission said.*
>
> *The rule directs public utilities to amend their Order No. 888 open access transmission tariffs to offer non-discriminatory, standardized interconnection service for small generators. The amendments should include a Small Generator Interconnection Procedures (SGIP) document and a Small Generator Interconnection Agreement (SGIA).*
>
> *The SGIP contains the technical procedures that the small generator and utility must follow in the course of connecting the generator with the utility's lines. The SGIA contains the contractual provisions for the interconnection and spells out who pays for improvements to the utility's electric system, if needed to complete the interconnection.*
>
> *The rule applies only to interconnections with facilities already subject to the jurisdiction of the Commission; the Commission emphasized that it does not apply to local distribution facilities.*

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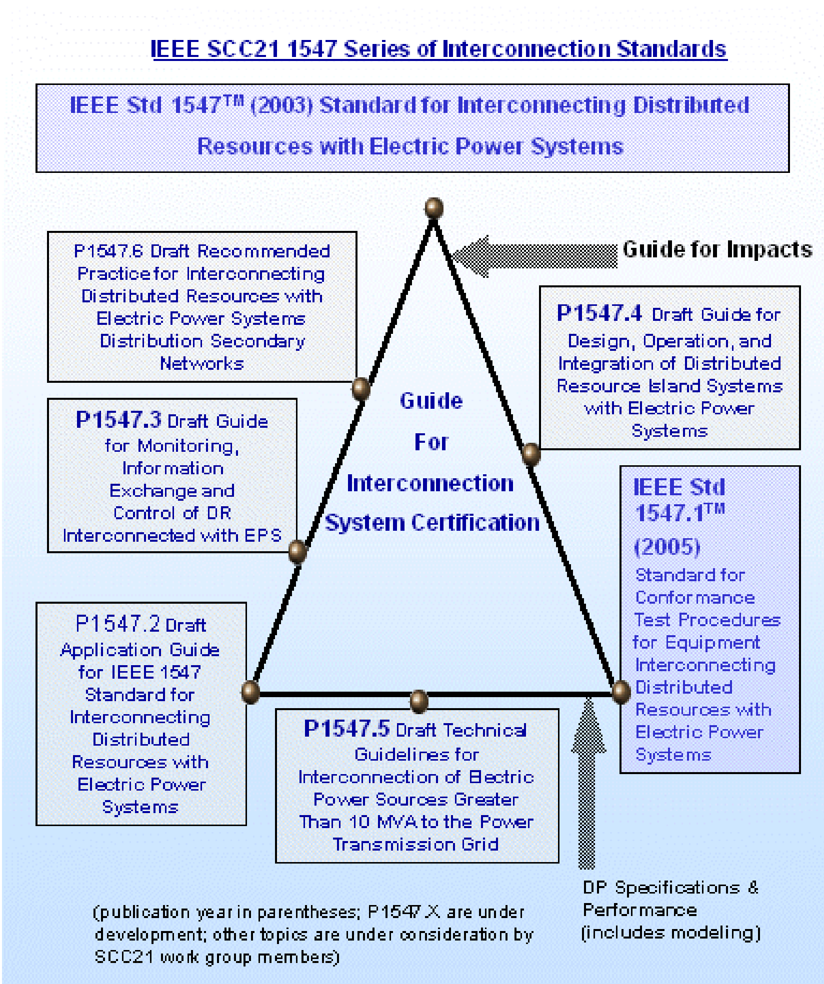
[8] http://www.naruc.org/displaycommon.cfm?an=1&subarticlenbr=103
[9] http://www.nreca.org/publicpolicy/ElectricIndustry/dgtoolkit.htm
[10] http://www.nwppa.org/web/presentations/PP_Fourm_3-06/PURPA%20Manual.pdf

Neither regulation will have a direct impact on most DG installations. The Large Generator rule applies only to generators of 20 MW and over: too large to apply to most DG. The Small Generator rule applies only to those generators that interconnect to Commission-jurisdictional facilities. These include most transmission facilities owned by FERC-jurisdictional utilities and those distribution facilities that are subject to a FERC-jurisdictional utility's Open Access Transmission Tariff. Most DG, on the other hand, is likely to be interconnected to distribution facilities subject exclusively to state or local jurisdiction. FERC's rules, however, could have significant indirect impact as a model to which many states and utilities will look in drafting their own interconnection standards.

OTHER ORGANIZATIONS IMPACTING THE REGULATORY FRAMEWORK

There are also a number of other groups actively involved in looking at DG issues.

The Institute of Electrical and Electronics Engineers (IEEE) is engaged in an ongoing process to develop uniform technical interconnection standards for connecting distributed resources (DR) facilities to the grid. The IEEE definition of DR includes DG as well as energy storage. IEEE is developing a family of standards (IEEE Std. 1547) on DR interconnection. The diagram below shows the different standards in the family.



This first publication in the series of standards is IEEE Std 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems. This standard is an outgrowth of the changes in the environment for production and delivery of electricity and builds on prior IEEE recommended practices.

IEEE Std 1547 focuses on the technical specifications for, and testing of, the interconnection itself, and not on the types of the DR technologies. This standard aims to be technology neutral, although cognizant that the technical attributes of DR and the types of EPSs do have a bearing on the interconnection requirements. This standard provides the minimum functional technical requirements that are universally needed to help assure a technically sound interconnection. Many of the states and federal rules and regulations have incorporated IEEE 1547. As described by the standard itself, its requirements are "universally needed" and "sufficient for most installations," but additional requirements "may be necessary for some limited situations."

The National Association of Regulatory Utility Commissioners (NARUC) is also closely involved with the DG market. NARUC developed a generic Model Procedures and Agreement for interconnection of Distributed Generation (DG) equipment to a distribution-level electric power system. It is intended for consideration, adoption, or adaptation by State regulatory commissions, their counterparts in local units of government, or by rural electric cooperative organizations. Recently, NARUC created and distributed a DG Interconnection CD Resource. NARUC also published final version of DG Interconnection Agreement and Procedures. Information on these documents can be found at http://www.naruc.org/displaycommon.cfm?an=1&subarticlenbr=33.

The Mid-Atlantic Distributed Resources Initiative Working Group (MADRI) seeks to identify and remedy retail barriers to the deployment of distributed generation, demand response and energy efficiency in the Mid-Atlantic region. MADRI was established in 2004 by the public utility commissions of Delaware, District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC) and PJM Interconnection. The guiding principle for MADRI is a belief that distributed resources should compete with generation and transmission to ensure grid reliability and a fully functioning wholesale electric market. MADRI has three goals: 1) Educate stakeholders, especially state officials, on distributed resource opportunities, barriers, and solutions. 2) Develop alternative distributed resource solutions for states and others to implement. 3) Pursue regional consensus on preferred solutions. MADRI developed model small generator interconnection procedures that are being implemented in at least three states.

TECHNICAL BACKGROUND

STATE OF THE TECHNOLOGY

Some DG technologies are mature and have been in use for decades. Others are in different stages of development and commercialization. Each also has very different cost and performance characteristics. Any assumption that all DG technologies can serve any particular policy goal, whether that is efficiency, emissions reductions, or cost reduction, will inevitably prove wrong. For that reason, technical aspects of the different types of DG equipment are described below.

Fuel Cells

Fuel cells are a promising technology. The basic concept of fuel cells is over a century old. Essentially, they behave like batteries. But unlike batteries, they are almost endlessly charged. They run on hydrogen, which can be reformed from natural gas, propane, or any other hydrocarbon source. The hydrogen reacts with oxygen from the air and voltage is generated between two electrodes. Power produced by fuel cells is relatively emission-free.

Fuel cells range in size from around 5 to 2000 kW. A typical single-family home would require a fuel cell around 3 to 8 kilowatts.

Initial installation costs will run high, around \$3,000- \$10,000+ per kW for the actual fuel cell "stack", a "reformer" to strip hydrogen from fuel, an inverter to convert direct current (DC) to alternating current (AC), and equipment for making use of the waste heat. Fuel cell manufacturers have long been predicting that capital costs could decline to as low as $1000 per kW as production volumes increase, and could drop further after that if auto manufacturers successfully develop automotive applications, although timeframes are uncertain. DOE's goal is to lower the cost of fuel cells for stationary applications (i.e. non-transportation) down to $400-$700/kW.

Although costly, the technology can be highly reliable, which makes it appealing for certain commercial operations. In a few cases, fuel cells are used for premium power applications.

Microturbines

Microturbines are also promising. These very small turbines contain essentially one moving part and use either air or oil for lubrication. Units range in size from about 25 kW to 400 kW. Microturbines can run on a variety of fuels, including natural gas, propane, and fuel oil. Microturbines gathered a lot of attention in the late 1990s, but initial sales goals were not met, and the some manufacturers had reliability issues. One of the early leaders in microturbines (Honeywell) dropped out of the market a few years ago.

Microturbines are less expensive than fuel cells. According to current estimates, a microturbine unit costs around $1,500 to $2,500 per installed kW. That could lead to niche applications in areas with high energy costs for power quality, peak shaving or replacement energy.

Microturbines are less efficient than most other existing generation technologies. A microturbine at full load is only around 30 percent efficient. At part load, efficiency drops. Overall efficiency can be increased considerably, however, if consumers can make use of the unit's waste heat.

The technology is proven and has been commercialized for about 5-7 years, and at least one microturbine has been UL listed. They have not, however, gained much market share due to both high cost and continuing technical issues. Most applications are for niche fuels such as landfill, anaerobic digester, and wellhead gas.

Wind and Photovoltaics

Both distributed wind and PV have been around for decades, and both have useful applications in certain settings. But neither one is as economical as central station generation for most consumers who have access to grid power. Smaller wind turbines of 3-100 kW have a capital cost of around $2,000-$5,000/kW. Photovoltaics have a capital cost of approximately $1,500-$6,500/kW with fully installed costs reaching $10,000/kW for smaller residential applications. Also, because they depend on the presence of wind or sun their output is intermittent and less dependable. However, there are many tax benefits and state and local grants that help to pay down some of the high capital cost for the consumer.

Larger wind turbines are available, although most really are not distributed generation. There are some larger DG applications serving communities and larger farms. These turbines range is size from 100 kW to over 2,000 kW.   Installed costs are from $1,800-$2,500/kW.

Both wind and solar energy have been touted as environmentally friendly. But, while they have no emissions, large wind generators do have environmental impacts that have to be considered in site selection and design, including bird kills, noise, interference with radio and television reception, interference with Defense radar, and visual impact. In fact, some proposals to develop wind farms have recently been tabled because of public opposition. Small wind turbines are difficult to site in denser communities due to their visual and noise impacts. Rooftop solar-thermal and photovoltaic arrays have been banned or severely restricted by some homeowners associations.

Internal Combustion Engines

The most commonly installed distributed generation facilities today are small diesel or combustion turbine units ranging from 50 to 5,000 kW. These units typically have a capital cost of between $200 and $1,500/kW. Lower cost units are typically diesel fueled and used for emergency applications. Higher cost units are typically natural gas or biogas-fueled and used for combined heat and power applications. While diesel units emit more air pollutants than gas fired units or central generation, they can be valuable for reliability purposes, load management, and system control purposes. And, because they have much lower capital costs and diesel fuel is readily available, they are used today for far more applications than any other DG technologies. Main applications include diesel-fueled emergency/standby power, peak shaving, and natural-gas fueled engines for combined heat and power applications.

Summary and Discussion

The following tables summarize the present costs and uses of DG facilities.

Characteristics	Internal Combustion Engine	Wind Turbine (small)	Wind Turbine (large)	Microturbine	Fuel Cell	Solar Cell
Size Range (kW)	5-5,000+	3-100	100-2,000+	25-400	5-2,000	1-100+
Current Installed Cost ($/kWh)	$200-$1,500	$2,000-$5,000	$1,800-$2,500	$1,500-$2,500	$3,000-$10,000	$1,500-$10,000
Electricity Cost (¢/kWh)	5.5-10.0	10.0-15.0	5-10	7.5-10.0	10.0-15.0	15.0-20.0
Year Commercial	Available	Available	Available	2000	2005 Limited Availability	Available
Efficiency	25-45%	n/a	n/a	25-30%	40+%	n/a

Application	Internal Combustion Engine	Wind Turbine (small)	Wind Turbine (large)	Microturbine	Fuel Cell	Solar Cell
Continuous Power	✓			✓	✓	
CHP	✓			✓	✓	
Peaking	✓			✓		
Green		✓	✓			✓
Emergency	✓					
Standby	✓					
True Premium	✓			✓	✓	
Peaking T&D Deferral	✓			✓		
Baseload T&D Deferral	✓			✓	✓	
Spinning Reserve	✓			✓		
Reactive Power	✓			✓		
Voltage Control	✓			✓		
Local Area Security	✓			✓		
Remote Power	✓	✓	✓	✓	✓	✓ (with battery)

FUEL COSTS

Recently, higher natural gas costs have slowed the DG market. The table below shows how natural gas costs impact the cost to generate electricity with DG units of varying efficiencies.

Impact on Generation Costs (*cents/kWh*) from Natural Gas Costs for Different Efficiencies of DG

	Natural Gas Cost ($/MMBTU) (HHV)→				
Efficiency (LHV) ↓	**4.00**	**6.00**	**8.00**	**10.00**	**12.00**
25%	*6.07*	*9.10*	*12.13*	*15.16*	*18.20*
30%	*5.05*	*7.58*	*10.11*	*12.64*	*15.16*
35%	*4.33*	*6.50*	*8.67*	*10.83*	*13.00*
40%	*3.79*	*5.69*	*7.58*	*9.48*	*11.37*

Note that in the table above, natural gas costs use higher heating value (HHV), and efficiencies are stated using lower heating value, as is done in the marketplace. There is about a 10% difference between HHV and LHV, and this has been included in the calculations.

A consumer that is considering DG should compare their existing rate to the cost of DG. For example, a typical residential consumer considering a fuel cell would need a generator with a capacity of about 3 to 8 kW for an up-front capital investment of between $9,000 and $32,000 for the fuel cell. They would also have to pay certain other up-front costs to install the unit and interconnect it with the system. Additionally, they would have to pay between 3¢ and 12¢ per kWh for fuel, plus maintenance. And finally, depending on the rules established by the state, the consumer may have to pay certain distribution costs; stand-by service charges; and some fixed charges imposed on all consumers by the state such as taxes, stranded costs, transition costs, or public benefits charges.

Some manufacturers of DG are asking decision makers to compare the cost of DG, summarized above, with costs faced by a utility or independent power supplier considering options for new generation. While this may be a useful exercise for statewide and utility resource management, the comparison is not meaningful for most consumers considering DG. As explained above, those consumers do not have to choose between new central station generation and new DG. They get to choose between new DG and grid power, which includes a number of depreciated, low cost plants. A new DG unit may cost less today than new central station generation, but if the DG power costs more than grid power, it is not an economic choice for most consumers.[11]

Even for the statewide or utility resource manager, the calculation is not as easy as some have suggested. The DG can only reasonably be compared against a new central station generation option if it can reasonably be expected to provide the same benefits. Will it be dispatchable by the utility to operate during system peaks? Will it be able to provide ancillary services such as voltage support? Does it have an equivalent capacity factor? In some cases the answer will be "yes." Several cooperatives have arrangements today with DG owners that allow them to avoid investing in additional peaking capacity. In those cases, the payments to customer-generators proved to be more economical than new central station power. In many other cases, however, the answer will be "no." Small wind and PV is not dispatchable, has low capacity values, and generally cannot provide system support. Many back-up generators have a very poor record of reliability. Because they are not in the business of generation, many owners of back-up generators forget simple necessities such as maintenance and refueling. Each situation, therefore, must be evaluated individually.

CO-OP INVOLVEMENT IN DISTRIBUTED GENERATION

In their continuing efforts to find ways to lower costs for rural electric consumers, electric cooperatives have been actively exploring DG technologies.

[11] Of course, some consumers are interested in investing in DG for reasons other than economics and this issue will not be as important for them.

For example, the cooperatives in Florida have installed more than 125 MW of distributed generation. These are almost totally diesel, or small engine generator sets. These units were added on the customer side of the meter, initially as a reliability device: that is, to support cooperative service at a prison complex, or a chicken farm, where reliable power is a must. Engine-generator sets with years of demonstrated capability were added to ensure that reliability. Once installed, however, this equipment also offered the distinct advantage of serving as a peak shaving device to lower the system peak demand and as an available resource when economically advantageous. The distribution cooperatives worked closely with Seminole Electric Cooperative and the state to be able to take advantage of this peak shaving.

In some cases, the cooperative has distributed generation as part of their generation mix. Basin Electric's largest such project is the Wyoming Distributed Generation (WDG) Project in the Powder River Basin of northeast Wyoming. The project is a response to the coal-bed methane (CBM) development in northeast Wyoming. The project, consisting of nine natural gas fired combustion turbine generators (CTGs), supplies energy and voltage support to Powder River Energy Corporation. The turbines are remotely operated on an as-needed basis. Other cooperative activity includes:

- Dairyland Power Cooperative
    - Purchases methane from dairy farms for generation

    See http://www.dairylandpower.com/energy_resources/animal.php

- Seminole Electric Cooperative
    - Purchases power from consumers with distributed generators

    See http://www.digital50.com/news/items/PR/2007/03/01/CLTH008/seminole-electric-cooperative-inc-seeks-up-to-150-mw-of-renewable-energy-resources-

- Central Virginia Electric Cooperative
    - Sells backup DG units to customers and purchases power from customers with DG

    See http://www.forcvec.com/conservation/generators.htm

- Holy Cross Energy
    - Net meters renewable generators $\leq$ 25 kW
    - Subsidizes up to 50% cost of consumer-owned renewable generation $\leq$ 25 kW
    - Sells green power at premium

    See http://www.holycross.com/.

Moreover, CRN has been working on developing distributed generation issues since the 1980s. CRN helped to fund a large demonstration of emerging technology in the 1980s at Santa Clara, California. A molten carbonate fuel cell apparatus was constructed and operated. This was not a fully integrated system and it had many first generation challenges. ERC, the contractor, has made major strides since then and recently began operation of a new compact design 250 kW molten carbonate fuel cell system in Connecticut. CRN also supported the analysis and tests of phosphoric acid fuel cells, including the operation of five 200-kW fuel cells by Chugach Electric Association to serve a postal facility in Anchorage, AK. Tests demonstrated that the staff of moderate-sized electric co-ops are capable of running a phosphoric acid system. The fuel cell systems proved reliable, but more expensive to purchase and operate, than established distributed generators.

Together with the United States Department of Energy, CRN managed an analysis of a biomass gasifier and fuel cell integrated system. This could be an attractive energy supply in some settings. CRN for several years supported field demonstrations and analysis of PEM fuel cell systems as they might apply to residential service. The PEM technology is improving, but economically feasible stand-alone residential generation has yet to be demonstrated.

CRN conducted two-year field tests of microturbines at seven electric co-ops. The final report incorporates data from a companion study by EPRI. In addition, CRN has cooperated with EPRI and the state of Colorado in studying options to generate power from methane at a Colorado hog farm. An internal combustion generator, a microturbine and a Stirling engine have been tested. CRN is currently studying animal manure to power digester and generation technologies and economics.

CRN has supported investigation into wind and photovoltaic systems as intermittent generation resources that can be used to deliver power to co-op systems and individual consumer-members.

Recent CRN reports of interest include:

- Distributed Generation Resource Guide
- Renewable Power Technology Assessment Guide
- Biopower Toolkit: Analyzing the Economics of Generating Power from Renewable Biofuels
- Microturbine Field Tests: Evaluating Benefits for Cooperatives

DISCUSSION

BENEFITS OF DISTRIBUTED GENERATION

In certain applications, some DG technologies can provide consumers, cooperatives, and society tremendous benefits, including reduced transmission and distribution costs, reduced emissions, and enhanced reliability. Generation located near demand can reduce energy losses; permit utilities to defer upgrades to substations, distribution facilities and transmission facilities; and provide black start capability and spinning reserves. Microturbines, turbines, and internal combustion engine generators can provide voltage support and reduce reactive power losses. Some DG technologies, including fuel cells, microturbines, and internal combustion engines can gain increased efficiency by taking advantage of waste heat. DG powered by renewable resources or fuel cells can substitute for central station generation that could have greater emissions and land-use impacts. DG can also provide some consumers a “self-help” alternative to volatile markets. Finally, because they can be faster to build and easier to move; need less existing infrastructure; and require less total (not per kW) up-front capital investment than large central station generators, some DG technologies could have a tremendous role to play internationally in less developed countries.

There is a risk, however, that the immediate benefits of DG are being oversold to justify aggressive legislative and regulatory proposals to support the development and installation of distributed generation. As discussed above, not all DG technologies have yet proven to be cheap, clean or reliable for broad application. Some of the presumed benefits of DG are speculative. They rely, for example, on the presumption made by manufacturers of fuel cells that their technologies will eventually prove to be as inexpensive and reliable as they have projected they will be. In reality, it will take several years of further development and testing before those projections can be evaluated objectively. Some of the presumed benefits also rely on assumptions about the costs or needs of some model distribution system that may not reflect the realities of any particular system, such as future upgrades to distribution facilities. Potential DG adopters also need to consider the problems associated with attempting to factor future natural gas prices into an economic assessment of developing a DG unit.

Moreover, as discussed below, many of the presumed benefits are highly dependent on the manner in which DG facilities are planned, installed and operated. Policies that encourage DG without taking those factors into account could not only fail to capture any of the presumed benefits, but instead could be extremely costly. As in other areas of electric utility regulation, economic policies ought to take into account the impacts of different technologies and different applications on each distribution system. Good DG policy decisions cannot be made without the input of engineers who understand how specific DG systems and distribution systems really operate.

Finally, it is imperative to ask the question, "benefits for whom?" As discussed below, there are a number of proposed policies under which one group of consumers could be asked to subsidize another. There should be some relation between costs and benefits. One group of consumers should not be asked to pay for policies the benefits of which accrue to others.

For these reasons, decision makers should be careful not to require utilities, consumers, or tax payers to pay for expensive capital investments or subsidies to support DG applications whose benefits may not ultimately outweigh the costs. PURPA's mandatory purchase obligation and the Power Plant and Industrial Fuel Use Act of 1978 provide good reminders of the risks of such policies.

SAFETY

DG imposes a widely recognized risk to public safety that must be and can easily be addressed in any interconnection requirements. On most distribution systems today, generation flows only one way. Even most distribution systems with two-way flows are still fairly simple compared to the interconnected transmission system, and the distribution utility will generally know which way power is flowing. Thus, if a line goes down, the utility will know whether the line is energized and can respond safely. Consumer ownership and operation of generation can change that. Consumer-owned generation could unexpectedly energize a line that the utility believes is cold, with the possibility of injuring or killing a utility worker or a citizen or starting a fire.

Texas and New York have responded to the safety risk by requiring any distributed generator to have a positive disconnect that automatically isolates the generator from the distribution system almost immediately when there is a fault on the system. The generator may not reconnect to the system until the fault is cleared and the system regains its stability.[12] California, Massachusetts, and Connecticut have recognized the need for similar protections. New York and Connecticut have also required all interconnected DG facilities to have a utility accessible manual disconnect switch.[13] Many other interconnection provisions exist to ensure the DG is safely interconnected with the grid system.

Many state-level interconnection rules have requirements for utility accessible, lockable, visible-break disconnect switches, but some states (e.g., Arizona, Colorado, and New Jersey) do not require them for certified, small, inverter-based DR. Most other states require them for all applications, with some states deferring to the utility.

Unfortunately, the cost of ensuring safety sometimes makes this issue more controversial. Some organizations oppose any utility requirement for small residential generators to have utility-accessible disconnect switches. Paying an electrician to run the wires for such a switch can add costs to the interconnection. The absence of such a switch, however, can impose an unnecessary and unreasonable risk to the life and health of utility employees engaged in system maintenance.

RELIABILITY

The electric grid is a complicated "machine" that does not work by itself. If a utility is to provide reliable power, it must have adequate generation, transmission, and distribution capacity and must be able to control the voltage and the frequency of the system. If the utility fails by a small margin – even momentarily – voltage or frequency sags and spikes could ruin expensive

[12] PUCT § 25.212(b) (General Interconnection and Protection Requirements); NYPSC 99-13, Appendix A, pp. 6-7,9,12.
[13] NYPSC 99-13, Appendix A, pp.10-11. See also CPUC 99-10-065, p. 29 (considering whether such a requirement would be necessary) and Connecticut DPUC 03-01-15 p.5.

computer and manufacturing equipment. If the system goes far off balance, it could experience serious failures: transformers and control systems could burn out, lines could sag into trees and start fires, and neighborhoods could black-out. As both Consolidated Edison in New York and Commonwealth Edison in Chicago learned during the summer of 1999, those kinds of failures can be extremely expensive and even dangerous for the utility and its members or consumers. Another large scale system failure hit the Northeast and Midwest in August of 2003 with similar consequences.

That means the operator has to keep generation and demand exactly balanced at all times; has to provide adequate “voltage support” on the lines; has to keep sufficient distribution capacity on all lines to move the power being used; and has to build and maintain sufficient generation, transmission, and distribution capacity to respond to contingencies, including the failure of lines or generators or the sudden addition or loss of large loads.

Moreover, that control process is location sensitive. Where generation and voltage support have to be located depends on the location of load and the design of the distribution system. That means that load, generation, and distribution facilities all have to be planned together. It also means that the addition or removal of a large load or generation source can require the construction of new distribution facilities; the re-engineering of existing distribution facilities; and/or the redispatch of existing generation facilities. The problem is further complicated because no two systems have the same structure or geography. One rule for responding to changes in system architecture may not work for any two systems, or even for any two changes on the same system.

The process is made even more difficult by the interconnected nature of the system. Every connected generation source affects the system and is affected by the system, regardless of whether it exports power. For example, if a small generator operating in parallel with the system cannot keep up with the 60 cycles frequency on the distribution system, it can be damaged. If a large generator operating in parallel with a small system lags behind or leads the system, it can affect the voltage and capacity of the system, even if the generator produces less energy than the consumer at that site is using.

Further every connected load affects and is affected by the system. If an industrial customer that generates its own power drops load without simultaneously dropping generation, it could create a surge that damages utility control equipment as well as any connected electronic equipment operating in the surrounding neighborhood. If the industrial customer instead loses its generator without simultaneously dropping load, it could create a destructive voltage sag.

New generation sources can also change the direction and volume of power flows on the system, possibly causing some wires to be underutilized while overloading others. Those changes may require the distribution company to reinforce its system, build new lines, or install new control equipment.

New generation could also force the system operator to redispatch the rest of the generation on the system. That is, it could require the operator to ramp down lower cost baseload plants and run more expensive peaking plants in order to maintain system reliability.

Obviously, the potential for system harm varies widely according to the type and size of the generator installed, whether the generator is intended to be isolated or operated in parallel with the system, or whether the generator is intended either to meet only a fraction of the consumer’s load or to export significant amounts of power.

An isolated generator may have economic impacts on a distribution system, stranding distribution or generation facilities built for a consumer, but is not going to have reliability impacts. A small interconnected generator (10 kVa or less) serving less than a consumer’s total demand is also likely to have little impact if appropriate control technology is installed between it and the system. At the other end of the spectrum, however, a large interconnected generator with a capacity of a few hundred kVa or more could have both economic and reliability impacts on the system, whether or not it exports power.

Most of the reliability risks discussed here can be addressed with the proper equipment on the grid and customer sides of the meter. The complexity and cost of such equipment varies widely depending on the size, application, location, and technology of the DG facility, the voltage at which it connects, and the size and architecture of the system to which it connects.

Even if a DG application is in compliance with IEEE 1547, in many cases a system impact study is required and changes to the grid will also be required to enable it to interconnect without adverse effects on the system. 1547 provides a uniform standard for interconnection of distributed resources with electric power systems. It provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection, but the standard does not detail potential system impacts and does not fully address power quality concerns.

Ultimately, the technology and engineering skills exist to address reliability problems. But, some of those fixes are complicated and expensive.[14] Therefore, most of these reliability questions come down to several cost-related questions[15]:

Do the costs of integrating a particular DG unit with the grid, while ensuring continued safety and reliability, outweigh the economic and other potential benefits of the unit?[16]

Who will bear the costs of ensuring safety and reliability? Obviously, the answer to this question could impact the answer to the first. If a consumer that is considering installing DG will bear the cost, that consumer will weigh the costs and benefits of the unit very differently than it would if the utility and its other customers would bear the cost.

What actions can decision makers take to lower the costs of protecting reliability so as to make more DG units more economical without adverse system impacts? Some of the proposals have included:

- Government funding for research on interconnection technologies;
- Government support for type testing of DG units;
- Encouraging coordination between consumers and utilities to maximize any possible system benefit from DG.

INTERCONNECTION AGREEMENTS

As discussed in detail elsewhere in this paper, properly planned and coordinated additions of distributed generation can allow a system to postpone expansion of distribution or central station generation plants, provide reliability benefits, and save consumers money. But those benefits can only be achieved when the newly installed generation is planned in coordination with the utility responsible for serving that territory. Because of the nature of the electric grid, the addition of generation to a system is neither simple, nor without cost and risks.

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[14] At the extreme, some large generators simply cannot be integrated reliably with some distribution systems. In such cases, the utility would have to string a radial line from the customer's site to the higher voltage transmission system.

[15] Of course, the risks discussed in this section are only one side of the picture. Distributed generation can provide reliability benefits to distribution systems. If planned with and operated by the distribution utility some DG technologies, including microturbines and combustion turbines,[15] can provide peak shaving, spinning reserves, voltage support, and other ancillary services that improve reliability. The key is coordination. The utility needs to be able to dispatch and control a unit if it is to be able to benefit from the services it can provide.
That is not to suggest that all DG must be owned by utilities. Instead, utilities could contract with consumers for the right to operate consumer-owned generation for the benefit of the system. For example, a utility could enter into an agreement with an industrial consumer with a large cogeneration unit. In exchange for a fee, the utility would have the right to dispatch the generator or adjust its operation to provide voltage support when needed by the system. Such an agreement could turn a unit that would otherwise pose a risk to reliability into a positive asset to the system. The agreement would also share the financial benefit with the consumer that installed the unit.

[16] That question cannot be answered in a vacuum or on a generic basis. It must be made on a unit-by-unit basis. New York was very sensitive to that issue in its Order, requiring utilities to make an independent analysis of the impact of every DG unit on its system, even where the unit was type-tested, NYPSC 99-13, p. 6, and requiring owners of DG units, no matter how small, to pay the costs of integration. Id. at 8.

These types of concerns lie behind the interconnection agreements that many states and utilities are requiring consumers to sign before installing DG. These agreements include provisions addressing, inter alia:

- Certification of the reliability and safety of the proposed DG facility and physical interconnection equipment;
- The conduct and costs of interconnection studies to determine the impact that the proposed facility would have on the distribution system;
- The need for and costs of any distribution system upgrades required to integrate the DG facility;
- Responsibility and requirements for the control, operations, and maintenance of the DG facility and related equipment;
- Metering and payment for any net energy exported to the system;
- Inspection rights;
- Liability and indemnification; and,
- Insurance.

The purpose of interconnection agreements is to ensure that consumers that are installing DG address these issues up front. If properly drafted, the interconnection agreements should ensure appropriate coordination between the utility and the consumer to maximize the benefits of the DG facility and minimize the system costs and risks associated with the facility. Where unavoidable, they should also require consumers to take financial responsibility for any reduced operating efficiencies their DG facility causes, any system improvements their new unit will require ,and for the risk that their new unit will damage property.

Some commentators have expressed concern that utilities are drafting complicated and burdensome interconnection agreements to discourage consumers from installing DG. These agreements, they have suggested, are inappropriate barriers to the development of DG. In fact, most of the requirements complained of have been included in interconnection agreements for years without causing consternation. The problem with those provisions arises from the increasing interconnection of smaller commercial and residential DG units. The large industrial consumers that have been installing cogeneration units with the expectation of saving thousands of dollars per year understandably have been willing to bear much larger up-front costs to interconnect their generation facilities than are small residential consumers whose units may save them little more than $100 per year over their lifetime.[17] The impact of interconnection requirements on the economics of a project differs dramatically depending on the size of the application.

Decision makers should not react to the charges about some interconnection agreements by broadly prohibiting appropriate contractual terms. That would eliminate consumers' obligation to minimize or mitigate the adverse impacts they impose on the system, and require other customers to subsidize those consumers who install distributed generation.

Instead, decision makers, consumers, and utilities should try to adjust interconnection requirements to recognize the different costs and risks that different DG technologies and applications impose on the system. Ultimately, it will be up to decision makers to ensure that interconnection requirements properly assign those costs and risks that are unavoidable to the consumer that is imposing them on the system. If they do, and the distributed generation project is still economical, taking into account the costs it imposes on the system, then it makes sense and will go forward. If the project is no longer economical after internalizing the costs it imposes, then it may not, and perhaps should not go forward. It is a principle of economics that

[17] See, e.g., Starrs, p. 13 (Estimating that a 500 W PV system would save a consumer less than $10/month even before taking into account any interconnection charges or other fees).

uneconomic incentives are created whenever the costs of an investment, such as distributed generation plant, are shifted to others. If a consumer does not bear all of the costs caused by its installation of DG, it is likely to build generation when it would be economically inefficient.

NET METERING

Net metering is one of many techniques available to measure and value the output of customer-owned generation. It is a simple process. It requires only that consumers with their own generation have meters that effectively roll forward when they consume power from the grid and roll backward when the customers export power to the grid. Most existing mechanical meters have this capability. Without more sophisticated meter technology, however, a net meter cannot determine how much total energy the customer's generator produced during any specific period of time or how much energy the customer drew from and exported to the system between meter reads. Rather, the meter measures only the net amount of power that the customer has imported or exported. That is why this technique is called "net metering." The simple meter nets generation exported by the customer at any one time against power the customer drew from the system during any other time over the entire period between meter reads.

The accounting is also simple in most cases. If a consumer uses more energy over the course of a billing period than she has generated, she pays only for the net energy that she imported from the system, plus any fixed monthly charges included in the consumer's rate.

The situation does get a little more complicated if a consumer generates more than she has used over the course of a billing period, i.e., if she has "net excess generation" or "NEG." Some states require credits for NEG to be rolled over to the next billing period. NEG may be rolled over for one year, as in California and Georgia, or indefinitely, as in Indiana and Kentucky. Some states prohibit any cash payment to consumers for NEG. Hawaii and Maryland, for example, grant NEG to the utility at the end of each billing cycle. Maine and Montana require NEG to be rolled forward each month, but grant to the utility any remaining NEG left at the end of the year. Others states such as New York and North Dakota require utilities to pay consumers "avoided cost" (like with PURPA) for NEG. Wisconsin requires all NEG produced by renewable resources to be purchased at the full utility's full retail rate.

The range of technologies and applications entitled to benefit also differ widely in different states. Many states like Illinois, Connecticut and Montana limit net metering only to renewable technologies. Some states have broadened the technologies entitled to net metering to include some combustion technologies. New Mexico and Oklahoma, for example, include municipal solid waste and combined heat and power systems.

All states have size limits on the units that qualify for net metering. For example, Indiana and New Mexico limit qualifying units to no larger than 10 kW. At the other end of the spectrum, California requires net metering for certain generators up to 1 MW in capacity and New Jersey requires net metering for generators up to 2 MW in capacity.

The size of generator eligible for net metering may vary according to the nature of the customer. In Vermont, for example, commercial and residential consumers can qualify for net metering for generators up to 15 kW in capacity, while agricultural consumers can qualify with generators up to 150 kW in capacity. Vermont industrial customers cannot qualify. In Louisiana, agricultural and commercial customers can qualify with generators up to 100 kW in capacity while residential generators cannot qualify if they exceed 25 kW in capacity. Again, industrial customers are ineligible.

Many states have also imposed a limit on the total amount of consumer-owned generation, for which any utility has to provide net metering service. Indiana, Utah, and Virginia all limit net metering to 0.1% of the utility's historic peak load. New Jersey's limit is set at 0.1% of peak capacity or $2 million annual impact, actually setting an explicit dollar cap on the total subsidy cost that can be incurred by each utility. Ohio and Vermont have much higher caps at 1% of a utility's peak demand. Some states have not imposed any cap.

Net metering rules are supported by many proponents of distributed generation and even some utilities – at least as applied to some DG technologies – because they provide a very simple, easily administered way of integrating small consumer-owned generation into the system. Because there are today only a few small units that can benefit from the net metering rules, their cost is limited.

On the other hand, net metering policies unquestionably subsidize consumers with qualifying generation facilities, and could become burdensome as more qualifying facilities are installed. The policies require utilities to pay consumers retail price for wholesale power. Moreover, the policies require utilities to pay high costs for what is often low-value power. Power from distributed wind and photovoltaic systems is intermittent, cannot be scheduled or dispatched reliably to meet system requirements, and may be expensive in some cases to integrate into the system.

Net meters also allow customers to under-pay the distribution, operation and maintenance (O&M), administrative and general (A&G), and other fixed costs they impose on the system. As discussed in detail below, a utility has to install sufficient facilities to meet the peak requirement of the consumer and recover the costs of those facilities through a kWh charge. When the net meter rolls backwards, it understates the total electricity, capacity, and energy used by the consumer, and thus understates the consumer's impact on the fixed costs of the system. It also understates the consumer's total share of other fixed charges borne by all consumers such as taxes, stranded costs, transition costs, and public benefits charges.

Further, net meters can be deliberately or inadvertently gamed. Consumers can take power from the system at peak times when it costs the utility the most to provide it, and then roll their meters backwards by generating power at non-peak times when the utility has little need for it. That is a particular risk, for example, with wind power. During the hottest days when power demand peaks, wind turbines are often becalmed. The turbines do not begin generating power again until the evenings when the cooler air starts to move in and demand for energy falls.

The terms net metering and net billing are sometimes used interchangeably. In FERC's Order 69, for example, FERC uses the term "net billing" to describe the kind of "single-meter" arrangement that this paper has defined as "net metering." The term net billing, however, is more properly used to describe the situation where a consumer generator has two meters, or a more sophisticated bi-directional meter. This arrangement allows the power imported by the consumer generator and the power exported by the consumer-generator to be measured separately. As with net metering, the consumer may interconnect and run in parallel with the utility. The consumer also has the ability to use its generation to reduce the amount of power it would otherwise purchase from the utility. Net billing, however, permits the power imported and exported by the consumer to be more accurately measured and valued.

Under this approach, the utility can determine how much total power the consumer imports over the course of the billing period, and the utility can bill her its regular retail rate for all of that power. The utility can also determine how much total power the consumer exported and can pay her the appropriate wholesale rate for all of the power it exports. The wholesale rate may be the utility's avoided cost, a real-time market price, or any other wholesale rate set by regulation or negotiated by the parties. The customer is not automatically paid a full retail rate for her power exports simply by default due to the limited information available from a single meter.

This approach is called "net billing" because the credits for power exports and debits for power imports are not accounted for separately. The two are netted out in a single bill each month. If the consumer owes more than she is owed, she receives a bill at the end of the month. If the consumer owes less than she is owed, she receives a check at the end of the month. With the support of cooperatives in those states, Colorado and Missouri have adopted legislation requiring cooperatives to offer net billing. Both statutes permit cooperatives to provide net metering if they choose and some cooperatives in each state have elected to do so.

"Dual metering" and "net billing" are also sometimes confused with each other. Typically dual metering means that a consumer and her generator are separately metered. The utility purchases all of the output of the generator at wholesale rates and sells the consumer all of the power the consumer uses at retail rates. The consumer does not use any of the generator's output behind the meter. As with net billing, the wholesale rate may be avoided cost, a real-time market rate, or any other wholesale rate set by regulation or negotiated by the parties. Indiana permits dual metering in conjunction with its DG interconnection requirements. Dual metering is typically used for larger generators installed by consumers for commercial purposes rather than for serving the consumer's own electric needs. Some utilities offer net billing for generators below a certain threshold and dual metering for generators above that threshold.

COST AND COST RECOVERY ISSUES

Presumption of Profit Motive

Investor-Owned Utilities

Several commentators in discussions about DG have expressed concern that utilities will have a built-in bias against DG installed on the consumer side of the meter. They believe that because most utilities charge consumers a fixed rate per kWh, utility revenue – and thus utility profits – are dependent on the volume of sales made. As a result, they say, utilities will oppose any development that tends to reduce total throughput, including consumer-owned generation and demand-side management.[18]

There could be some validity to that concern, particularly as applied to a pure wires company that relies entirely on a unit charge to recover its costs and margin. The more units it sells, the more income it makes. It could also be valid with respect to a vertically integrated investor-owned utility that has a fuel clause that would allow it to pass its power purchase costs through to its consumers when prices spike. Again, the utility's income would be entirely dependent on the number of units sold. The fuel clause makes the utility indifferent to the marginal and variable costs of generation. In response to that concern, some have recommended new ratemaking strategies that would make utilities less sensitive to throughput. These include revenue caps,[19] de-averaging rates,[20] and a number of others.

Unfortunately, the presumption that all utilities will have a bias in favor of throughput misses some complexities with respect to utilities that have an obligation to provide generation at a fixed price per kWh. The presumption could lead decision makers to view utility contributions to DG discussions with unnecessary suspicion and could lead to unnecessarily aggressive efforts to encourage DG over "utility opposition."

First, the presumption fails to take into account the fact that utilities (particularly generation utilities) do experience some savings from reduced volume. If a consumer installs DG or engages in demand side management, the utility does not have to incur some variable costs such as fuel and variable O&M. Thus, there is not a direct one-to-one relationship between reduced sales volumes and reduced profits.[21]

Moreover, there are instances when drops in volume, and thus revenue, significantly lowers costs. That is why utilities seek to shave their peaks. For example, when prices peaked during the summers of 1998 and 1999, cutting a marginal kWh of customer load could cause utilities to lose 7-15¢ in marginal revenues but save the utilities $7.00 or more in marginal power costs. Those utilities with demand side management on the consumer side of their meters who were caught short of power experienced significantly lower losses. Those with demand-side management who had surplus power could make significantly larger profits.

As mentioned, a utility with a fuel clause that permits it to pass through those price spikes may not care about peak shaving. But, as the industry restructures, fewer and fewer utilities have that luxury. Many incumbent utilities are operating under price caps, although these are expiring or have recently expired in a number of states, and new marketers are signing fixed price contracts.

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[18] E.g., RAP Draft Report, *passim*.
[19] See OPUC 98-191; RAP Draft Report, p. 18.
[20] See RAP Draft Report, pp. 19-20.
[21] Compare RAP Draft Report, pp. 15-16 (stating that costs and kWh sales are unrelated, and thus that sales volume bears a direct relationship with utility profits).

Cooperative Difference

The presumption that all utilities have a throughput bias also fails to recognize the differences between cooperatives and investor-owned utilities (IOUs). Unlike IOUs, rural electric cooperatives are not-for-profit entities. They are required by law and by their by-laws to recover only the actual cost of providing service. If income exceeds cost, cooperatives must return the excess to their members.

It is true that cooperatives must recover sufficient revenues to cover all of their costs in order to preserve their fiscal health. But, that is a very different motivation than the IOU's need to maximize profits and returns to their stockholders. First, to maintain their fiscal health, cooperatives need only recover their costs plus a small margin for reserves. Investor-owned utilities, on the other hand, have a fiduciary obligation to earn as large a margin as possible. Second, revenue shortfalls can be eliminated either by lowering costs, or by maximizing revenues. Unlike IOUs, cooperatives are cost minimizers, not profit maximizers. Because a cooperative is owned by its consumers, and the consumers elect the cooperatives's board of directors, the cooperative has a direct obligation to its consumer-owners to minimize costs. That means, among other things, that the cooperative has an obligation to be able to shave peaks so that it can minimize the number of times it has to purchase high price power.

The cooperative difference has been plainly visible in practice. The presumption that utilities must maximize throughput states that distributed resources located on the customer's side of the meter almost always hurt utility profits. Yet, many cooperatives are installing distributed generation on the customer side of the meter because doing it that way can sometimes better preserve reliability and shave peak loads. Profit is not the motivation, reliability and lowered system costs are.

It is important for regulators to recognize the differences between different industry participants. Regulations that may be appropriate to protect IOU customers could harm consumers served by electric cooperatives. For example, IOU customers may not be harmed by regulatory policies that raise utility costs so long as the costs are not recovered in rates. In that case, the utility shareholders have to absorb the costs. That approach, however, does not work for cooperatives. Because cooperatives are owned by their member-consumers, and have no separate shareholders, all costs imposed on cooperatives are paid for by retail consumers.

Moreover, cooperatives are much smaller than most IOUs. Cooperatives average fewer than 57 employees and 10,000 consumers. That compares to IOUs, which average over 2,200 employees and 315,000 consumers. As a result, regulatory costs impose a higher per-capita burden on cooperatives' members. Imagine for example a state rule that bars utilities from requiring consumers with DG to buy insurance or otherwise indemnify the utilities for damage. If an uninsured DG unit causes $100,000 damage to an IOU's distribution system, it will cost each IOU customer only a few pennies on average. An equivalent uninsured accident on a cooperative system could cost each cooperative consumer over $10.00.

On the other hand, regulators ought not presume that rural electric cooperatives are such a small part of the industry that their differences need not be recognized. Although cooperatives are very small individually, taken together cooperatives are a significant segment of the industry. Cooperatives serve over 40 million consumers in 47 states. Cooperatives operate over 45% of the distribution facilities in the nation and serve 75% of the country's total land mass. As a result, any policies that affect distribution system safety, reliability, and costs can have an enormous impact on cooperatives and their members.

<u>Distributed Generation As A Substitute To T&D Investments</u>

In some cases, the installation of DG can lower transmission and distribution costs, or substitute for new transmission and distribution investment. That is one reason why many cooperatives and other utilities are already encouraging such use where economically viable.

Decision makers, however, need to be aware that the availability of cost savings is highly dependent upon the specific needs of a system and the manner in which the distributed generation will be planned and operated. Decision makers should be wary, therefore, of policy proposals that would require utilities to either share presumed cost savings with consumers who install distributed generation or otherwise take those presumed savings into account in determining whether to support or subsidize the development and installation of DG. Any benefit sharing policies should depend on the existence of real cost savings, if any, arising from a particular project proposal.

Remote areas to which the distribution system does not yet reach

In a number of cases, rural electric cooperatives have saved money by installing DG on a customer's property rather than stringing wire out to the customer's remote location. There are also a lot of stock tanks with windmills or photovoltaic arrays powering their pumps and electric fences with photovoltaic battery chargers. Intermittent operation is acceptable for these applications. Moreover, within several years, fuel cells could be able to provide a dependable source of power for entire homes for less than the cost of long distribution extensions. That small scale distributed generation is or could soon be a lot more sensible than running wire into remote areas. But, existing cost incentives are more than sufficient to encourage consumers and utilities to install DG for those applications.

Areas experiencing load growth

In some areas experiencing load growth, particularly large cities with underground distribution systems, it can cost far less to install a generator to serve a neighborhood's load growth than it would to upgrade the distribution system to import the same power. Some incentives that allow utilities and consumers to share in the benefit of DG development could be beneficial for these applications.

But, only a few technologies, such as gas turbines, make economic sense for this purpose. Wind and PV are generally too intermittent to substitute for central station power and fuel cells are unlikely to be economical for most interconnected applications for several more years.

Moreover, for the system to get any benefit, any generator would have to be planned with the distribution utility, properly located, and properly dispatched. A generator located on one distribution trunk could be highly useful, whereas the same generator located on another trunk one block over could be useless to the system or even counter productive.

Similarly, a generator that the utility has the right to dispatch when demand exceeds the distribution system's import capacity could provide enormous system benefits, whereas a generator whose dispatch schedule is unrelated to distribution system needs could be counterproductive.

Moreover, the utility would have to have assurances that the generator would be properly maintained and operated to ensure the greatest possible reliability. And, the generator's maintenance schedule would have to be planned to coincide with the distribution system's low demand periods. If the generator is routinely unavailable due to planned or unplanned outages during the utility's peak, the utility will have to build new generation, transmission, and distribution facilities as well to meet its obligation to provide reliable service. If that were so, there would be no savings, and thus no benefits to share.

Large customers not connected to the grid

A utility can save distribution expansion costs if a new large customer at either a green field location or a location previously occupied by a customer with a low peak demand chooses to build its own generation instead of connecting to the grid. The utility will not have to build new transmission or distribution facilities, or reinforce existing facilities, to meet the customer's large demand. For example, utilities are already installing DG for recreational areas and remotely located resort complexes. These are usually large internal combustion generators.

The system, however, will not get any benefit if the customer is on a site previously occupied by a customer with an equally large peak demand. In that case, the system will experience stranded costs when the customer disconnects. One exception is that if a nearby customer on the same distribution circuit is expanding their load enough to make up for the lost load and otherwise require the utility to expand distribution capacity on that circuit. Either the customer that is disconnecting or the other customers on the system will have to pay for the cost of the distribution facilities that previously served the now disconnected site.

Nor will the system get any benefit if a new large customer builds its own generation to meet its own energy demand but intends to lean on the utility for back up power if its generator is out of service. In that instance, the utility may still have to reinforce its transmission or distribution facilities to serve the customer's peak demand.

De-averaging Rates

In an effort to encourage the development of DG in areas where it will provide distribution cost savings and to discourage development of DG in areas where it will strand distribution costs, some commentators have suggested "de-averaging" prices so that consumers see their actual distribution costs. Those consumers in areas with high distribution costs would then have an incentive to self-generate, while those in areas with low distribution costs would find it more expensive comparatively to build their own generation facilities.

That proposal, however, has two serious flaws. First, there may not be a connection between high distribution costs and the need or ability to obtain savings from deferred distribution investment. Some areas have high distribution costs, for example, because they have recently upgraded their systems to prepare for system growth or to replace worn out facilities. Other areas may have high distribution costs because they are remote and/or rugged, with few consumers per mile of line to divide up the high cost of running conductor.[22] In those instances, de-averaging rates will provide exactly the wrong incentive, because new DG will strand, not save distribution costs.

Second, the de-averaging proposal is inequitable. In many instances, the most expensive areas to serve – including rugged rural areas and urban areas with buried lines – are also the most vulnerable areas with the highest proportion of low income consumers. De-averaging will necessarily raise costs for these low-income consumers.

Moreover, if de-averaging rates is successful in encouraging increased development of DG, it could have the effect of increasing rates for these vulnerable consumers even more. The more consumers who install DG, the fewer consumers are left to pay the cost of these expensive distribution facilities. At the extreme, de-averaging could push electricity beyond the financial reach of many consumers.

Offsetting Costs

DG can strand distribution investments. If a utility reconductors or otherwise expands its system to ensure that it can reliably serve its growing load for the next several decades, one large DG project or several small ones that mask the load growth could strand the investment in new distribution facilities. That stranded cost should be taken into account in analyzing the costs and benefits of a particular DG project as much as any savings would be. Utilities and their consumers should not be penalized for engaging in prudent system upgrades.

Even if there are distribution expansion savings, they may be offset by other costs. For example, in order to permit a large urban apartment building to install its own generation, a utility may need to reconductor the neighborhood or install new control equipment. In calculating the system benefits of the DG project, the costs of that reengineering project must be balanced against any savings that might be gained from deferred distribution expansions.

Moreover, some utilities have large generation reserves that were planned and built to provide for future load growth. If a customer installs its own generation to serve its own load growth, it could strand the utility's investment. Those stranded costs should also be balanced against the savings in distribution investment.

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[22] Rural electric cooperatives average a $2,000 investment, 5.76 consumers, and an annual revenue of $7,038 per mile of line. Investor-owned utilities average a $1,550 investment, 34.85 consumers, and an annual revenue of $59,355 per mile of line. Municipal utilities average a $1,500 investment, 47.76 consumers, and an annual revenue of $72,255 per mile of line.

Distribution System Planning

A related point here is that the increasing use of DG complicates utilities' obligation to plan their distribution systems. Traditionally, utilities have been responsible for predicting load growth and planning distribution system upgrades to address that growth, including the addition of any resources needed to provide voltage support or other distribution ancillary services. The need for facilities was comparatively predictable because with the exception of a few large customers, the utility was the only source of such facilities. With the development of DG, both load growth and the need for support facilities will be less predictable. Whether new or existing consumers install DG is outside the utility's control, and that installation can make long planned, or even recently installed, improvements unnecessary or accelerate the need for improvements that were on the distant horizon.

Several of the pricing proposals, including de-averaging, certain performance-based ratemaking (PBR) proposals, and benefit sharing are intended to align consumer incentives for constructing DG with the utility's need for new facilities, or otherwise to require the utility to take the possibility of DG into account in its planning process. None of these proposals yet can be said to clearly solve the problem.

Stand-by and Fixed Costs

As manufacturers of DG facilities have sought to sell systems, they have complained that utilities are requiring consumers who install DG to pay a variety of fixed charges to cover stand-by or standby service, stranded costs, or other fixed costs of the system. Those new charges, they say, are discouraging consumers from installing DG by making self-generation more costly, and in some cases, uneconomic. Some of these complaints may be valid, as there is a risk that some utilities may deliberately impose barriers to self-generation. Unjustified new fixed charges could unreasonably limit economical uses of DG technologies.

On the other hand, some charges may be necessary both to ensure that utilities continue to earn sufficient revenue to cover their operating costs and to prevent cost shifting between consumers. The incremental rates that utilities have charged under a traditional regime are not well designed for a regime in which consumers will increasingly be able to generate some of their own power requirements.

A retail energy customer is responsible today for a number of different costs. Among the more significant costs are:

- The customer's share of the cost of the physical transmission and distribution facilities over which the utility delivers energy to the customer;
- The customer's share of the cost of the physical generation facilities that were built to serve the customer and/or the customers' share of the capacity costs that the utility pays a generating company to guarantee the utility access to the power its customers may require;
- The customer's share of the costs of operating and maintaining the physical transmission, distribution, and generation facilities (O&M);
- The customer's share of the administrative and general costs required to run its utility (A&G);
- The customer's share of taxes the utility is required to pay and the public benefits the utility is required to provide; and,
- The cost of fuel to generate the power the customer actually consumes.

Few of these costs are directly assigned to individual customers and reflected on the customers' bills. Instead, these costs are generally bundled or rolled in together and collected through an undifferentiated per kWh charge.

There are, of course, some variations. Many utilities, for example, have tiered, or graduated, kWh charges that lower the unit charge for all energy consumed above a certain threshold. Some others have coupled their unit charge with a low fixed monthly fee to collect certain A&G costs, taxes, or other fixed costs. Some others add to their bill a variable unit charge to reflect changes in fuel costs.

Ultimately, however, the goal of most utilities has been to try to ensure that charges on each customer's bills in some way reflect the actual costs for which that customer is responsible. Unfortunately, monthly total kWh is not a very good indicator of cost causation.

Of the costs itemized above, only total fuel costs vary much according to a customer's total monthly energy usage. The more kWh the customer consumes, the more fuel generators have to consume. With limited exceptions, the other costs itemized above vary according to either a customer's peak demand or the customer's contribution to the utility's peak demand.

A utility has an obligation to deliver all the power a consumer wants, when the consumer wants it. If a consumer turns on her air conditioner when the temperature exceeds 100 degrees, the power needs to be there to cool the room. The utility has to have enough generation, or the right to enough generation, to cool that room; the utility has to have enough capacity on its transmission and distribution facilities to get the power from the generator to the customer's meter; and the utility has to have adequately planned and maintained its entire system so that nothing fails when the switch is thrown. If the air conditioner does not turn on, the utility will not be excused because it did not have enough generation, transmission, or distribution capacity available, even on the hottest day of the year, when all of its consumers are turning on their air conditioners. When New York City experienced black outs during the summers of 1999 and 2006, politicians and regulators did not want to hear that Consolidated Edison had not built or maintained enough capacity in their distribution systems to handle the load.[23]

That means that a utility cannot have only just enough generation, transmission, and distribution to handle its <u>average</u> load. It must build its system to be able to handle its <u>peak</u> load, the largest volume of power its customers could possibly use. And, it must either own or have a right to enough generation to meet its system peak plus some reserve for emergencies.

Take for instance a large industrial consumer that has a peak demand of 50 MW that is coincident with the utility's peak demand, that is the industrial customer draws a full 50 MW at the utility's busiest times of day and seasons. To serve that customer, the utility must build strong enough distribution facilities to bring that customer 50 MW of power on top of all of the utility's other obligations. It may need to install particularly heavy gauge wire, large transformers, and other control equipment to handle that large 50 MW distribution load. The utility will also need to make certain that its transmission system has enough capacity. And finally, the utility will have to own or have the right to enough generation capacity to satisfy that 50 MW load at peak times.

Of course, the customer may not be drawing the full 50 MW at all times. At night, the same customer could be drawing less than 1 MW. The customer's average demand may, therefore, be well below its peak of 50 MW. But the utility still has to build to serve the customer's peak load.

As now formulated, the rate structure has been designed to take that fact into account, and the per kWh rate has been set at a high enough level to recover all of the costs of the system based on historical experience. And, in most cases, there is at least a rough approximation between what each customer pays and the burden they place on the system.

Now presume that the same large industrial consumer chooses to install a 50 MW generator on its site to provide its daily energy needs. But, because that generator will need periodic maintenance and could fail unexpectedly, the industrial consumer opts to remain hooked to the grid for standby power. Most of the time, the customer will be drawing no power from the system. But occasionally and with little warning the customer could start drawing a full 50 MW from the system, even during the system peak.

[23] <u>See</u>, <u>e.g.</u>, "Interim Report of the U.S. Department of Energy's Power Outage Study Team: Findings From The Summer Of 1999" (January 2000).

That could have a dramatic impact on the utility's ability to recover its cost of providing service – not profit – just basic cost of service. When the industrial customer builds its generator without disconnecting from the system, the utility does save the marginal cost – generally just the fuel cost – of the generation that the customer is not taking. But, the utility saves little or nothing on the other costs it incurs on that customers' behalf. It must still maintain enough distribution, transmission, and generation capacity to serve the customer's full 50 MW load at any time, just as it would if the customer had never built its own generator. And, it must still incur the O&M and A&G costs associated with those facilities.

On the other hand, however, the utility's revenue drops to practically nothing when the consumer installs its own generation because the consumer is not drawing much total power from the system each month. The unit charge no longer recovers much, if any, of the costs the utility has to incur to guarantee the consumer service on demand.

At that point, the utility has two choices. It can let all of its other consumers pick up the difference, thereby subsidizing the consumer that installs generation and raising costs for other consumers. Or, it can find a new pricing structure that assigns costs more equitably. That is the purpose of stand-by charges and fixed charges. If properly designed, such charges assign to individual customers the costs that those customers actually impose on the system.

Unfortunately, changing the price structure can get an angry response from consumers. Most customers have traditionally received a bundled bill with transmission, distribution, generation, fixed, and variable costs all bundled together into a single unit charge. With competition, more consumers are seeing their bills unbundled with separate charges for generation, transmission, and distribution. But each of those individual charges is still generally assessed by kWh usage. Because it has always been that way, consumers naturally presume that their bill <u>should</u> vary by usage. They think they should pay for the amount of power used, not for the interconnection and the right to draw power on demand. Thus, if they are on vacation for a month, or use their own generation for a month, they presume their bill should be low. If subjected to a fixed charge, they may be surprised and angry that their bill has not dropped much. But, as the industry restructures and new technologies develop, decision makers at least will have to reconsider some of these well settled expectations.

If regulators do not want to change pricing structures for all customer classes, they have several choices. They can allow stand-by power rates that apply only to the individual customers that are causing the utility to incur costs that are not recoverable through per kWh charges. Or, regulators can allow utilities to adopt fixed charges only for certain customer classes, such as large C&I customers. It is the largest customers that impose the largest individual fixed costs on the system. Their large loads can require significant upgrades to physical facilities to stiffen the transmission and distribution system. Their loads can also have a larger impact on a utility's peak demand, and thus on the amount of generation capacity the utility needs to own or have reserved. If a residential customer's 1 kW solar array fails during system peak it has a much smaller impact on system reliability than the failure of an aluminum smelter's 100 MW combustion turbine.

The California Public Utilities Commission has listed a number of options for designing creative stand-by charges. For example, utilities could offer firm and non-firm standby service with different rates. Standby charges could also be adjusted depending on how frequently the consumer used standby power or could be structured with low reservation charges and very high use charges. Charges could also vary depending on the time of use or whether the consumer gave notice before relying on standby service.[24] In 2003, the New York State Public Service Commission approved new standby rates[25] that are based on cost of delivery service and not on energy consumed, and are designed to accurately reflect the size of facilities needed to meet a customers maximum demand for delivery service at any given time. These rates took effect in 2004, and do not apply to customers whose on-site generation is less than 15 percent of their maximum demand. Small combined heat and power systems less than 1 MW have been exempt, although an extension of the exemption past 2006 has not been approved.

Another option includes allowing the customer with DG to take all or part of the risk of outage. If the customer's generation does not operate during peak hours, the customer could be interrupted in whole or in part in lieu of paying stand-by charges.

[24] CPUC, 99-10-065, p. 45.
[25] NY PSC, Case 99-E-1470

Some have argued that stand-by charges are inappropriate because DG actually helps utilities meet the peak needs of their systems. As discussed above, however, the ability of DG to contribute to system needs is extremely case specific. The right kind of generator, operated and maintained pursuant to utility oversight and direction can certainly contribute. And, in such a case, standby charges would not be appropriate. Instead, the contract would probably include a provision for damages in the event the customer-generator fails to operate as directed. On the other hand, the vast majority of DG, which is operated entirely to serve the needs of the customer, not only cannot provide utilities the certainty they need at peak times, but could even be deliberately turned off when the utility most needs it. Predictably, fuel prices and power costs tend to follow very similar patterns. In northern climes, where consumers use both gas and electric as heating fuels, wholesale gas and electric prices are typically very high during the winter months. The costs of both then drop during the spring and early summer. Those customer generators such as hotels and university campuses that can run their operations on either system power or their own generator are likely to engage in arbitrage. When gas (and wholesale power) is inexpensive, they will run their cogenerators at full capacity, exporting power the utilities do not need. When gas (and wholesale power) is expensive – during peak periods – they will turn off their cogenerators and take relatively less expensive power from the system.

The point is, there are as many different ways to design rates as there are accountants, but regulators should allow utilities to adopt a rate structure that requires customers that install DG to continue to pay for the costs that they continue to impose on the system. Regulators should not assume that utilities are merely trying to impose barriers to the deployment of DG.

Subsidies

In each of the issues discussed above, there is a significant risk that policies intended to encourage or "remove barriers to" DG could go too far, instead subsidizing those who install DG at the expense of other consumers. For example:

Interconnection Requirements: Interconnection requirements are intended to ensure that consumers who install DG minimize their impact on the system and pay the costs for which they are responsible. Proposals that would allow consumers who install DG to avoid the costs of necessary interconnection studies, system upgrades, and control equipment, or would insulate consumers from liability for harm to the system, would shift those costs to other consumers;

Net Metering: Net metering requires utilities to pay above-market prices for low-value energy. Other consumers must pay more for their energy to support that program;

Benefit Sharing: Some proposals would require utilities to share the presumed system benefits of DG with the DG owners through rate credits or through exemption from payment of certain fixed costs including stranded costs, transition costs, public benefit funds, backup services charges, and others. If the presumed system benefits of the DG unit are not as great in practice as the benefit given to the DG owner, the utility's other consumers must make up the difference. Even if costs and benefits of the sharing program are equivalent, some of the utility's other consumers may either receive a lesser share of the benefits or bear a heavier share of the costs.

By masking some of the true costs of a DG facility, these subsidies will encourage consumers to install new generation that cannot be justified economically. If a particular DG facility still makes economic sense after a customer pays all of the costs that they impose on the system, then the facility will, and should, be built. If the facility is too expensive to build after all costs are taken into account, then perhaps it should not be built.

Some have argued that it may be worthwhile to build DG that is not otherwise economically efficient, either to encourage the development of new technologies or to achieve environmental benefits. If so, states should recognize that they are deliberately subsidizing an uneconomic investment for other purposes, and then consider carefully the different options for funding that subsidy.

States should not avoid that question simply by asking the utility to bear a share of the costs of an uneconomical project. That policy merely shifts costs from one consumer to the rest of the utility's consumers. True, it is possible that an investor-owned utility's shareholders could absorb part of the cost, but that is not an option for electric cooperatives. Their owners are their consumers, and they must bear all of the cooperatives' operating costs. This is another reason for highlighting the differences between cooperatives and other industry participants.

Moreover, the subsidy in this instance would be decidedly regressive. Until the size and unit cost of new DG technologies drops, most DG facilities will be larger engine or combustion turbine units installed by large industrial or commercial consumers. Another significant portion may be expensive household units installed by higher income consumers.[26] That means that the large or wealthy customers would be shifting costs to smaller, less well off residential customers. Obviously, that is a policy choice that decision makers will need to make. But, at a time when large industrial customers are getting far more benefit than rural and residential customers from retail competition, it does not make much sense to ask the least advantaged consumers to shoulder another burden.

As mentioned above, however, states have a number of options for providing direct subsidies, including up-front capital cost buy-downs, direct payments to consumers who install DG in "DG development zones," tax deductions for consumers who install DG, and others. Each of these options could distribute the cost of subsidies more broadly across the entire tax base. That may not seem critical to decision makers thinking about large investor-owned utilities, which average hundreds or thousands or consumers. With a customer base that large, no consumer needs to bear much burden from a DG subsidy. But, the burden each consumer bears could be much higher in small cooperative and municipal systems. Cooperatives, for example, serve an average of fewer than 10,000 consumers. Spread among so few consumers, any state-required subsidy could have a noticeable impact on each consumer's bill.

ENVIRONMENTAL ISSUES

As mentioned above, one of the most touted benefits of DG is environmental. DG, some proponents have argued, produces less air emissions than most central station generation. While that is certainly true of some technologies, decision makers need to be skeptical of accepting broad environmental claims.

At one end of the spectrum, some technologies are extremely clean. PV and wind energy have no emissions and fuel cells that operate on hydrogen produce no air emissions other than water vapor. Even those fuel cells that operate on natural gas or methanol emit few pollutants.

In the middle, microturbines operating on natural gas may be cleaner than some central station generation. Nevertheless, even some environmental groups are concerned about the possible proliferation of these units. Because they operate on fossil fuels, they do have NO_x, SO_2, and CO_2 emissions. But, they are today subject to much less stringent environmental regulation than central station generators. The thought of tens of thousands of new generating units operating without permits makes some groups very nervous.

And, at the other end of the spectrum, however, by far the largest number of existing DG units today are diesel and combustion turbine units. Some of those units, particularly those that operate intermittently for back-up purposes, can have far greater emissions than central station generation. In fact, this points out one of the areas where some of the touted benefits of DG can conflict. Some DG proponents have suggested that regulators should find a way to encourage the use of existing generators in schools, hospitals, hotels, etc. to provide back-up or supplemental service when there are power shortages or reliability is seriously threatened. But, because most of these small scale consumer-owned units are noisy, high maintenance, diesel generators with significant air emissions, it could be environmentally harmful to encourage increased usage. In fact, most were permitted by state environmental agencies only on the presumption that they would be operated for only a very limited number of hours per year and only for emergencies.

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[26] See "RKS: Yuppies Yearn For On-Site Power," Electricity Daily (September 29, 1999).

CONTINUED UTILITY ROLE

Many State PUC's are still trying to decide if electric distribution company should be permitted to install DG or to sell DG facilities to their consumers. Some commentators have suggested that distribution utilities may have an unfair advantage in the development and installation of distributed generation because independent power producers may not have equal access to the information needed to determine where to place facilities.

Lining up on the other side are a number of utilities, and some manufacturers of DG technologies. The manufacturers are concerned that limitations on utility participation in DG will limit their market for their products. Utilities are concerned both that they could lose the system benefits they can obtain by directly installing DG and the potentially profitable business of selling DG facilities at retail.

In response to that remaining market power concern, others have noted that it should not be difficult or overly burdensome for an independent power producer to figure out where it can find markets for DG. Many of these entities – the large-scale owners of these merchant power plants – are very large and highly sophisticated. Moreover, it does not take a lot of inside knowledge to recognize where in a utility's service territory it is experiencing load growth. One needs only to get the plans for new strip malls or new industrial sites from the city or county planning office to learn that. Moreover, many independent power producers (IPPs) are already working directly with commercial and industrial customers to plan generation plants. Those are the customers that have the interest, the capital, the land, and the large loads now required to justify the installation of DG technology economically. When the cost and technical issues have been addressed to permit a broad spectrum of consumers to benefit from DG, there will be less of an argument that utilities are at an information advantage; IPPs could be well situated to advertise their products to mass audiences.

CONCLUSION

Both existing and developing DG technologies have the potential to bring cooperatives and their members significant benefits. Those benefits, however, cannot be taken for granted. Every application of different DG technologies will need to be examined on its own through the lenses of technological capability, safety, reliability and cost.

Before consumers or utilities install DG, and before decision makers act to support DG, they should ask themselves a series of important questions:

- Has the particular DG technology at issue proven itself to be economically viable, or proven itself to be reliable in commercial operation?
- Has the particular DG technology at issue been properly matched to the particular application for which it will be installed/supported?
- Is the technology capable of providing the required service as a matter of engineering?
- Is the technology economic for the intended application?
- Has the DG installation been planned and coordinated with the local distribution utility?
- As installed, will the DG unit provide the consumer or system any economic benefit?
- As installed, what effect will the DG unit have on system safety and reliability?
- As installed, who will bear the costs and risks of the DG unit: the consumer who installs it? The system? Other consumers on the system? Or society, through a broad-based subsidy?

- Will the operation of the DG be coordinated with the local distribution utility?

- As it will be operated, will the technology provide the consumer or system any benefit?

- As it will be operated, what effect will the DG unit have on system safety and reliability?

- As it will be operated, who will bear the costs and risks of the DG unit: the consumer who installs it? The system? Other consumers on the system? Or society, through a broad-based subsidy?

- If consumers or decision makers choose to install or support a DG technology that is not economic for a particular application to support other goals, they should still ask themselves:

    - Will the DG installation be safe and reliable? That must be the sine qua non of any addition to a distribution system.

    - Has every effort been made to ensure maximum coordination with the local distribution utility to maximize system benefits/minimize system costs?

    - Will the costs of an uneconomic DG unit be fairly allocated to those who receive the non-economic benefits of the unit?

By asking themselves these questions, and working together to find solutions, consumers, utilities, and decision maker should be able to attain the tremendous potential benefits of DG while still addressing the real safety, reliability and economic risks posed by DG.