Chapter 6

The Impact of Dispersed Generation Technologies on Utility System Operations and Planning

CONTENTS

List of Tables

List of Figures

Chapter 6

The Impact of Dispersed Generation Technologies on Utility System Operations and Planning

INTRODUCTION

As the penetration of dispersed generating sources increases in U,S. electric power systems, the implications for system planning, operation, performance, and reliability are receiving increased attention by the industry. [1] The interest in dispersed generating technologies has been stimulated by new Federal laws that have increased the economic attractiveness of such systems. As discussed in chapter 3, the Public Utility Regulatory Policies Act of 1978 (PURPA) opened the way for customer-owned generation mandating interconnection with existing electric systems.

The characteristics of many alternative generating technologies pose both potential benefits and problems for electric system planning and operation. The benefits of dispersed generation generally stem from the potential of substituting plentiful, environmentally acceptable and renewable sources of energy for conventional fuels. Due to the modularity of many of these alternative technologies, deployment on an incremental basis is possible, offering the potential for a more economic expansion of the generation supply. (Other benefits are discussed in chapter 3.)

The nonconventional aspects of dispersed sources of generation concern electric utilities largely because of the industry's lack of knowledge regarding performance of these systems. There is concern, for example, about the lack of utility control over generating resources. in addition, where alternative generation supplies are weather dependent, production is intermittent. Similarly, many cogeneration supplies are highly dependent on the process to which they are linked. Finally, increasing production at the distribution level poses new questions regarding reliability because the delivery system is less reliable at the distribution level than at the transmission or bulk level, i.e. a kilowatt of production at the distribution level is less reliable than one generated at the bulk level.

[1] For example, in 1984 the Electric Power Research Institute initiated two major studies entitled, respectively, "Integration of Dispersed Storage and Generation Into Power System Control During Normal System Operations" and "Integration of Load Management Into Power System Control During Normal System Operations."

INTERCONNECTION OF DISPERSED GENERATING SOURCES

Overview

The concept of a dispersed source of generation (DSG) has a variety of meanings, often resulting in some confusion. In this document, a DSG is any generating device (irrespective of size) that introduces power into an electric delivery system, but not at the bulk power level or at the traditional point where a particular utility's conventional generation injects power. By and large, this means electric power production linked to the distribution system of the utility, such as most non utility power producers that are qualifying facilities (QFs) under PURPA.

While present day electric systems have been structured (in capacity, protection, and configuration) to allow safe and reliable operation without the presence of a DSG device, most researchers agree that with proper modification of the electric network configuration and operation practice, a DSG device can be compatible with the electric system.

Current Industry Issues

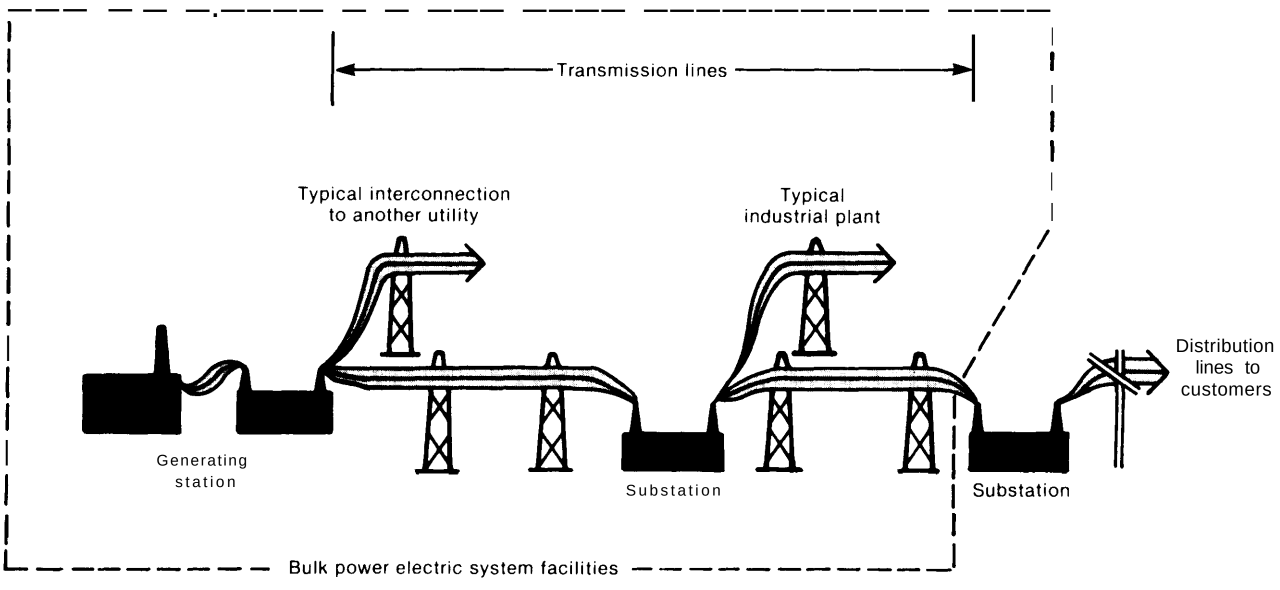
Traditionally, utilities and the agencies that regulate them have primarily been concerned with power flows in electric systems in one direction:[2] either from utility-owned central station powerplants to customers through the transmission and distribution network, or from one utility to another. More recently, however, the incentives offered under PURPA and other Federal and State laws have promoted addition to the electric grid of DSGs which are often nondispatchable and predominantly nonutility-owned. Management of these "two-way" power flows has introduced a new element of complexity into the operation of electric utilities. As a result, utilities and DSG customers have begun to focus some attention on the nature, quality, and cost of the interconnection equipment, and regulators have begun to examine their role in managing the integration of DSGs into the utility grid.

The issues associated with interconnection have their roots in the way power is generated and transmitted through the utility grid. A typical grid (shown in figure 6-1) is composed of several large central generating plants, connected to bulk power transmission lines. These lines typically are maintained at the highest voltages in the grid. Power is then transported through a network of transformers and lower voltage lines until it reaches the customer. Depending on the type of end use, an industrial customer with large process needs may connect directly to primary distribution circuits, while most residential customers connect to secondary distribution circuits at lower voltages.

In addition to power lines and transformers, the grid also includes protection equipment such as circuit breakers, relays, and switches as well as control equipment such as voltage regulators, capacitors, and tap-changing transformers. In powerplants, control of turbine, frequency, and excitation systems is performed. While, a central

[2]Utilities have always had some form of dispersed generators on their systems. For example, descending elevators can act as generators and feed power back into the grid (Self Reliance, Inc., *A Guide to Interconnection Requirements in New York State*, prepared for New York State Energy Research and Development Authority (NYSERDA) (Albany, NY: NYSERDA, May 1985), Report No. 85-2. However, the amount of power generated by these dispersed sources has traditionally been a very small proportion of the power generated by the centralized sources.

Figure 6-1.—Layout of an Electric Power System



SOURCE: North American Electric Reliability Council (NERC), *Reliability Concepts* (Princeton, NJ: NERC, February 1985).

control center manages, dispatches, and directs the overall operation of the electric grid. Power requirements of the system vary, depending on the time of day and season because the demand for power is changing over time. The protection equipment is used to prevent damage to the grid and its customers from abnormal circumstances or faults and to maintain a highly reliable and dependable supply of electricity. The control equipment provides a high quality of electric power and determines the system's performance standards under normal operation.

Utility customers expect electric power to meet quality and performance standards so that appliances, lights, and motors will operate efficiently and not be damaged under normal conditions. While there is no general agreement among utilities as to the definition of "acceptable" power quality, typically a utility supplies ac power at 120/240 volts (single-phase[3]) for residential and 240/480 volts or higher (three-phase) for industrial customers (with the voltage ranging between 95 to 106 percent). The frequency of the delivered power is 60 Hz (*0.002 Hz).

The types of generating devices used in a DSG can significantly influence its impact on the electric system. The generating equipment can be of many varieties; table 6-1 categorizes different generating types. Rotating machines (most traditional generating equipment) produce ac voltage as either synchronous or induction generators (see box 6A for definitions), while inverters, through the use of power conditioning equipment, change the current from DC sources (such as a photovoltaic array) into AC current. Inverters may be either li ne-commutated or self-commutated, i.e., either dependent on the utility's voltage and frequency power signal or independent of the utility line.

[3]See box 6A for defi n It Ions of interconnection terms.

Table 6-1 .—Classification of Dispersed Generating Types

Line independent:
- Synchronous generator
- Forced-commutated converter
- Double output induction with a forced-commutated converter
- DC source with a forced-commutated converter
- Permanent magnet reach ine
- Field-modulated generators

Line dependent:
- Induction generator
- Line-commutated inverter
- Double output induction with a line-commutated converter
- DC source with a Iine-commutated converter
- AC commutator generator

SOURCE Office of Technology Assessment

Both induction generators and line-commutated inverters consume reactive power (see box 6A for the definition of reactive power) in normal operation and, therefore, one issue for these types of nonutility-owned DSGs is how to compensate for or charge costs of the reactive power consumed. Usually, synchronous generators and self-commutated inverters do not consume any reactive power, i.e., they produce their own, and can operate independently of the utility.

The power conditioning equipment used by inverters produces harmonic frequencies of 60 Hz in the voltage and current signals in the grid. These harmonics, which appear at frequencies that are multiples of 60 Hz, combine to form a complex waveform. The resulting levels of so-called total harmonic distortion (THD) can lead to deterioration in customer appliances and motors. The presence of harmonics can shorten the life of electrical devices by 5 to 32 *percent* through thermal aging.[4]

Since harmonic voltages affect loads, it is important to understand how they are generated at various parts of the electrical network. Many systems inject current harmonics into the network; these current harmonics are conducted in the various lines and transformers and into the loads, inducing harmonic voltages within the electric system. The location and amplitude of these induced harmonic voltages are largely cletermined by the electrical parameters of the network. The point of injection and the amplitude of current harmonics, however, are *not* likely to determine the potential impacts; rather problems and their location are determined by network characteristics where harmonic voltages are in-

[4]E, Fuchs, U n iversit y of Colorado, *Impact of* Harmonics *on* Home *Appliances,* draft contractor report to the U.S. Department of Energy, June 1982, DOE-RA-50150-9.

Box 6A.—Definitions of Interconnection Terms

Single phase: The type of power carried by most secondary distribution lines supplying residential users. Single-phase power consists of one power signal.

Three phase: Consists of three single-phase signals, each one out of phase with the other two by 120°. Three-phase power is used by larger commercial appliances and industrial customers and is usually found in transmission and primary distribution lines.

Power factor: Refers to the difference in phase between the current and voltage signals in a given power line. This difference is measured as the cosine of the fraction (measured in degrees) of the full 360° cycle between the voltage and current maximums. Therefore, a power factor of 1.00 indicates that the two signals are in phase. Power factors less than 1.00 indicate that the voltage and current are out of phase and can either be "leading" if the voltage maximum occurs before the current maximum, or "lagging" if it occurs after. Because power is most efficiently delivered when voltage and current are in phase, it is important that the power factor be as close to 1.00 as possible.

Reactive power: The product of the level of real power and tangent of the phase angle between the voltage and current signals is the value of reactive power, which is measured in volt-amperes-reactive (Var's). Reactive power indicates (along with power factor) the magnitude of the phase difference in the power signal.

Utility-grade relays: Usually refers to relays that have been approved for use in utility power systems and generally have higher quality and cost than standard industrial-grade relays.

Rotating generators: Electric power is produced by the action of a rotating magnetic field that induces a voltage in the windings of the stationary part of the generator. The rotation is caused by mechanical means, such as a steam turbine, and the magnetic field is created by a current flowing in the windings of the rotor. There are two types of rotating generators, based on the way the rotor current is supplied:

Synchronous generators: A rotating machine generator in which the rotor current comes from a separate DC source or the generator itself—thus, the synchronous generator can operate independently from the electric grid.

Induction generators: A rotating machine generator in which the rotor current is supplied by an external AC source, usually the electric grid itself.

Area control error: In an interconnected power system (two or more independent systems—called areas—linked by power interchange tie lines), the change required each area's generation to restore the frequency and net interchange (power flow between the areas) values to their desired levels.

duced. As a consequence, *harmonic voltage problems typically will result in a location remote from the* point of *injections*

While there seems to be no general agreement concerning the precise acceptable level of distortion, typically utilities limit THD at the point of injection to less than 5 percent of the current signal with any single harmonic less than 3 percent, and 2 percent of the voltage signal with any single harmonic less than 1 percent. Filtering out this distortion may be expensive for smaller sized DSGs. Therefore, another issue that has surfaced is whether or not all interconnected harmonic sources should be required to meet specified THD standards, or whether these standards should vary according to DSG size and type.

In addition to power quality issues, utilities are concerned with the proper measurement of net power generated by DSG customers. Should all DSG customers be required, and therefore charged, for extra metering equipment? Utilities are also concerned with the liability of DSG customers for utility employee accidents or equipment damage that may result from improper interconnection.

[5] "Computer Simulation Study, " ORNL/SUB/81-95011/1, Oak Ridge National Laboratory, Oak Ridge, TN, August 1983.

As larger proportions of DSGs are installed across the country, another concern is the effect of DSG operation on system dispatching, control, short-term transmission and distribution (T&D) operations, and long-term, central-station capacity planning. [6] As more utilities gain experience with interconnecting customers, guidelines for interconnection are evolving. Efforts are underway to standardize these guidelines (discussed later).

in general, most researchers agree that the technical aspects of interconnection and integration with the grid seem to be relatively well understood; they are discussed in an earlier OTA report. [7] The primary unresolved issue is determining appropriate cost-effective interconnection requirements, i.e., how to balance the utilities' technical risks with interconnection against the non utility power producers' desire to keep front-end costs of interconnection down. The resolution of this issue will depend on the costs of interconnection equipment, the requirements associated with the utilities' legal obligation to interconnect, and the availability of new hardware and operating practices for DSGs to lower interconnection costs.

[6] H. Chestnut, et al., "Monitoring and Control Requirements for Dispersed Storage and Generation," *Institute of Electrical and Electronics Engineers (IEEE) Transactions on Power Apparatus and Systems,* vol, PAS-101, July 1982, pp. 2355-2363; in 1984 the Electric Power Research Institute Initiated a major field study on the impact of DSGs on power system operation; see "Integration of Dispersed Storage and Generation Into Power System Control During Normal System Operations," EPRI RFP 2.? 36-1

[7] U. S. Congress, Office of Technology Assessment, *Industrial and Commercial Cogeneration* (Washington, DC: U .S. Go\ ernment Printing Office February 1983), OTA-E-192.

INTERCONNECTION PERFORMANCE

Overview

Interconnection equipment generally consists of four major functional subsystems: 1) a *protection and control* subsystem for monitoring DSG power quality and disconnecting the DSG from the grid in case of abnormal conditions on the grid or in the generator itself; 2) a *power conditioning* subsystem PCS) for converting DC to AC if necessary); 3) a *metering* subsystem for measuring: a) power flowing from and to the customer, and b) perhaps time of day; and 4) *other hardware* associated with various types of electrical converters chosen for the DSG. Synch ionization equipment is required with many rotary converters; capacitors, power factor correction, transformers, and other equipment can also be required. Each DSG technology may require a somewhat different configuration of subsystems, with the precise configuration depending on current utility guidelines, existing distribution equipment, the type of DSG customer, and other factors,

For example, induction machines and line-commutated inverters may continue to operate after being disconnected from the utility grid, presenting a potential safety problem. Even though these types of equipment require some kind of external power supply to provide reactive current, there may be sufficient reactive power available in that part of the distribution grid near the point of interconnection. This could occur when a utility installs extra capacitors to compensate for the reactive power drain of the DSG. This type of equ ipment may need extra protective devices to prevent problems associated with unscheduled operation.

Another example is conventional cogeneration equipment. While not requiring extensive investment in power conditioning equipment (these systems typically produce ac power), a conventional cogeneration system requires additional hardware such as: 1) a synchronizer to match its frequency and phase with that of the grid and 2) a transformer for isolation and voltage match. Most inverters have synchronization logic included in the PCS.

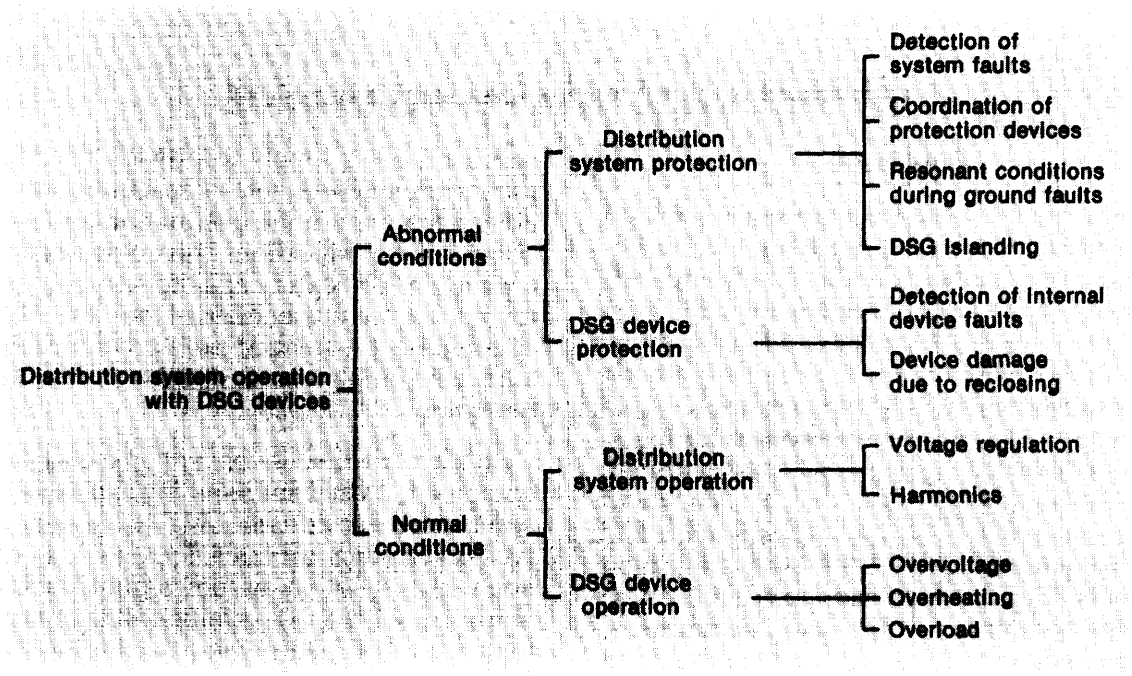
Protection and Control Subsystems

Perhaps the most heated debate concerning utility interconnection equipment has centered around the use of protective devices for each DSG configuration. Typically, these devices are: 1) relays designed to detect over- and under-current, over- and under-voltage, and over- and under-frequency of the power produced from the DSG; and 2) filters to eliminate excessive harmonics and electromagnetic interference. A major issue is the setting of these relays to provide an appropriate level of protection, yet avoid "nuisance tripping" of the DSG off-line whenever system power quality conditions vary over the normal course of the day. Of related concern are the cost implications of the tolerance range—the costs for more sensitive protection equipment are higher. These issues are discussed later.

Protection philosophy covers both the normal and abnormal operating conditions of the electric system. The problem of protecting the electric system involves protection of the distribution system, loads, and other customers as well as protection of the DSG.[8] The most concern arises during abnormal operation when potential damage to the electric system, its customers, and the DSG couid occur. The overall protection philosophy and problems are presented in figure 6-2.

[8] D.T. Rizy, *Personnel Safety Requirements for Electric Distribution Systems With Dispersed Storage and Generation* (Oak Ridge, TN: Oak Ridge National Laboratory, November 1982), ORNL/TM-8455.

Figure 6-2.—Distribution System and DSG Device Protection Problem Areas



SOURCE: Electrotek Concepts, Inc., *Impact of Decentralized Generating Sources on Utility System Operations*, contractor report to the Office of Technology Assessment, 1985.

DISTRIBUTION SYSTEM AND DSG DEVICE PROTECTION PROBLEM AREAS

Potential safety problems for electric utility personnel are also of concern to the electric utility industry. Attention is focused on the adequacy of present maintenance practices and hardware to ensure a safe working environment. Work procedures[9] have been developed for both energized (live line) and de-energized (dead line) maintenance practices.

For de-energized line work, there are six basic safety steps: notification, certification, switching, tagging, testing, and grounding. When work is performed on energized systems, insulating devices such as rubber gloves and mats, insulating stools and platforms, and/or insulated tools such as hotsticks are used by utility personnel. Guidelines of the Occupational Safety and Health Administration (OSHA) require that utility personnel may not approach or take a conductive object without suitable insulation. The addition of a DSG device has the potential of converting a dead line to a live line without knowledge of the maintenance person. The easiest way to prevent this situation is to either place a manual disconnect at the DSG or use live line maintenance practices where DSGs are present.

Power Conditioning

For wind and photovoltaic generators, the PCS is perhaps the most crucial link in the interconnection apparatus. Early PCS and many low cost systems consisted of inverters which often produced many harmonics and operated at low conversion efficiencies. However, recently there have been a number of important advances in development of PCS technologies. These new technologies use a method called high-frequency modulation (H FM) to chop the dc output into the sine wave pattern of ac power, using solid-state switching devices.[10] Such equipment generally produces fewer harmonics; has higher efficiencies and power factors; increased fault and reclosing detection; and improved voltage regu lation compared to earlier, line-commutated designs.[11]

Working with utilities, private PCS manufacturers and government researchers at Sandia Laboratory have developed and improved upon residential-sized (<20 kW) "advanced-design" PCS. A prototype Sandia-designed HFM-PCS performed well in utility simulator tests.[12] Further research is underway at several utilities, such as at Georgia Power (see box 6B). Most engineers agree that the H FM-PC has superior performance compared to earlier line-commutated inverters in terms of power quality. For example, current HFM devices in production (for 2 to 4 kW generators) produce harmonics similar to those of hair blowdryers, and have power factors between 0.97 and 1.00. The new equipment has fast and reliable reclosing and fau lt detection capabilities, accomplished through electronic sensing and control. I n the case where a fau lt (e. g., precipitated by a thunderstorm) disconnects the PCS from a utility, logic and control circuits turn off the PCS, thus preventing any danger to the utility and any reconnection of the DSG if the utility quickly returns on-line.[13]

[9] D.T. Rizy, et al., *Operational and Design Considerations for Electric Distribution Systems With Dispersed Storage and Generation (DSG)* (Oak Ridge, TN: Oak Ridge National Laboratory, September 1984), ORNL/CON-1 34.

[10] J. Stevens and and T. Key, *Draft Report: The Utility Interface—Can State-of-the-Art Power Conditioners Alleviate Our Concerns* (Albuquerque, NM: Sandia National Laboratories, 1984),

[11] Critics, however, argue that the new technology isn't necessary. For example, simulation models at the University of Texas using the Gemini inverter, a line-commutated device, show that a high penetration of photovoltaic arrays on two different types of distribution feeders does not significantly influence power quality. With 20 percent penetration of a particular feeder, there is less than 1 percent of total harmonic distortion of voltage, the power factor remains between 0.7 and 1.0. The models indicate that there is no problem with DC injection into the AC circuits since the amount of time required for DC to be injected (after the failure of the Gemini inverter) into the grid is much greater than the amount of time needed to detect the DC injected and isolate the fault. Voltage drops experienced were less than 0.3 percent with 30 percent PV penetration; see J. Fitzer, et al., University of Texas at Arlington, *Impact of Residential Utility Interactive Photovoltaic Power Systems on the Utility*, contractor report to Sandia National Laboratories, Albuquerque, NM, March 1984.

[12] Stevens and Key, op. cit., 1984; and W. I. Bower, et al., "Photovoltaic Power-Conditioning Performance Evaluation: Lessons Learned," paper presented at IEEE Photovoltaic Specialists Conference, May 1984.

[13] T.S. Key, "Evaluation of Grid-Connected Inverter Power Systems: The Utility Interface," *IEEE Transactions on Industrial Appli-*

Box 6B.—Georgia Power & Light Co.

Encouraged by the provisions of PURPA, entrepreneurs in Georgia are renovating many of the small textile mills which were abandoned over the past several decades. The renovation has been spurred on just for the sake of producing power from the under 5-MW hydroelectric plants that were once part of the mills. Over 35 mills have been refurbished, and Georgia Power & Light receives at least two applications a month for new ones.

The utility has over 600 MW of DSG capacity, which represents about 5 percent of its system peak load. The units are all fairly large and use conventional technology, ranging in size from a 750-kW hydro plant to a large 70-MW wood-waste steam turbine cogenerator. Even with this profile of DSGs, the utility has not experienced any reduction in power quality or other problems with the units, and has had no complaints from non-DSG customers.

However, Georgia Power is continuing to push the interconnection technology forward and it is one of the four participating utilities in the Sandia Laboratories project to test the new high-frequency PCSs in "real world" situations. Using an instrumented test facility in Florida, the utility will test the high-frequency modulation PCS technology on a series of three residences with 5-kW photovoltaic arrays. The homes are on a standard 13.8 kV distribution line. Georgia Power will test the power quality of the PCS with and without conventional generation on the line as well as with and without extra capacitors to boost power factors.

Sandia has also asked Georgia Power to test the injection of DC current directly into the transformers, thus simulating the failure of a PCS as closely as possible.

SOURCE: Clayton Griffith, Georgia Power & Light Co., personal communication, July 1984.

This increased PC performance, however, comes at a premium price. If HFM devices were required by utilities, the increase in price would burden the smallest generating customer. (See figure 6-3 in next section for cost comparisons of different sized interconnection equipment.) One suggested alternative is to institute varying requirements for different sizes and types of generators. Utilities have begun to use this idea in their own guidelines for interconnection (as discussed in the next section) by having different sections of the guidelines apply toward a particular size of generator.

Some utilities are still concerned about the so-called "pollution" of their power systems, while others consider this concern as overly restrictive. Some researchers believe that if non-DSG customers cannot distinguish differences in power quality, the utility should not penalize DSG customers with overly stringent and costly requirements.[14] This would shift the issue of "how high a power quality is appropriate" to the question "what are customers willing to pay to receive higher power quality?" These issues are being debated in the technical community.

Metering

The third and last component of interconnection is the metering equipment used to measure power consumed by the customer. In general, the three types of meters available today are the single watt-hour, double watt-hour with rachets, and advanced meters.[15] The single watt-hour meter is in common use in most homes and costs about $30 (1 984$). If a DSG is producing power, the meter simply runs backward. This configuration only measures net power use and assumes that there is no difference between the utility's retail rates and its rate for purchasing power from DSGs. If these rates are different, which is usually the case, then two meters are routinely used, one of which runs in the reverse direction to measure power produced; both meters have rachets that prevent any reverse rotation. Another configuration uses more advanced meters to

cation, July/August 1984' and R.S. Das, et al., "Utility-Interactive Photovoltaic Power Conditioners: Effects of Transformerless Design and DC Inject ion," paper presented at Intersociety Energy Conversion Engineering Conference, No. 849413, August 1984.

[14] Martin Schlect, General Electric Co., personal Commun ication, July 1984.

[15] Discussed in more detail in OTA, *Industrial and Commercial Cogeneration*, op. cit., 1983.

measure such quantities as power factor, energy, and time of use.

One metering issue is the incremental expense of additional metering for DSG customers: should the DSG customer be required to purchase meters that a non-DSG customer is not required to have? For example, Wisconsin Power & Light does not require those customers who did not previously use time-of-day meters to install them when interconnecting their DSGs.[16] Another metering issue centers around when and how DSGs should be charged for consuming reactive power.

[16] Wisconsin Power & Light Co., "Various Guidelines for Parallel Generation, Madison WI, September 1983; and B. Bauman and D. Fimreite, "Parallel Generation in Southern Wisconsin," paper presented at the Summer Meeting of the American Society of Agricultural Engineers, No. 80-3041, June 1980.

Summary

The current evidence suggests that the technical issues of interconnection can be resolved and that state-of-the-art power conditioners can alleviate many utility concerns about the quality of interconnection subsystems. Advances in automation in electric systems will tend to mitigate many problems associated with DSGs.[17]

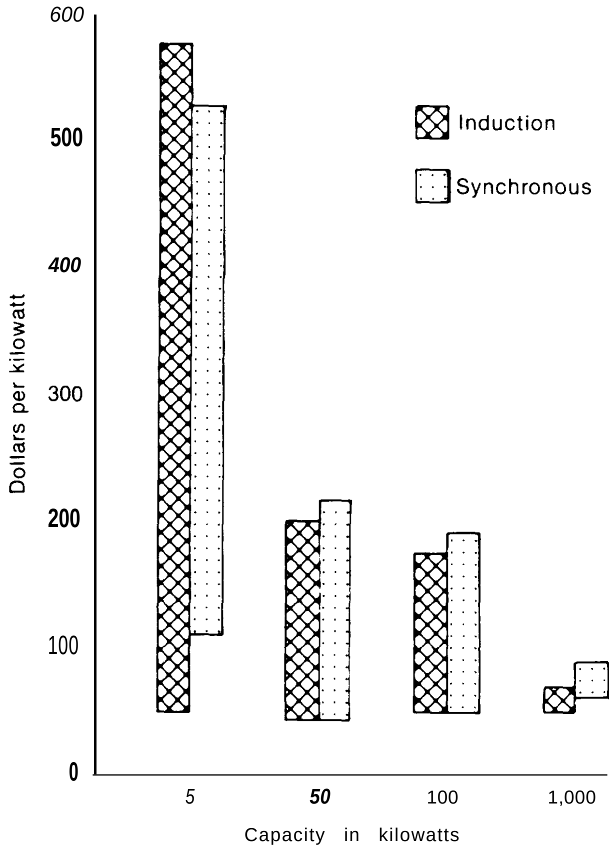
[17] D.T. Rizy et al., *Operational and Design Considerations for Electric Distribution Systems with Dispersed Storage and Generation (DSG)*, 1984.

INTERCONNECTION COSTS

Recent research demonstrates that costs for interconnection per kilowatt decrease rapidly as generator size increases. Moreover, costs have come down dramatically[18] for the smaller generators in recent years and are now within $600/kW for the 5 kW (residential) size and $200/kW for 50 kW size.[19] (In 1983, OTA reported costs of interconnection equipment vary between $12/kW for larger generators to $1,300/kW for smaller generators.[20])

Figure 6-3 shows the range of costs for both induction and synchronous DSGs, based on typical configurations for seven generator sizes and

Fiaure 6.3.—Costs for Interconnection of Qualifying Facilities



SOURCE' Office of Technology Assessment

[18] For example, Janice Hamrin (Executive Director, Independent Power Producers Association) inculcates that Pacific Gas & Electric opened its bidding process for interconnection equipment in mid-1984 and this has tended to drive down the costs of interconnection (OTA Electric Utility Advisory Panel, August 1984).

[19] H. Geller, Self-Reliance, Inc., ' 'The Interconnection of Cogenerdto rs and Sma l l Pow e r Prod ucers to a Util it y System, cent ractor report to the District of Columbia Off Ice of the People's Counsel, Washington, DC, February 1982; T S. Key, "Power Conditioning tor Grid-Connected PV Systems Less Than 250 kW, " paper presented at Intersociety Energy Conversion Engineeri ng Conference, No. 849407, August 1984; P. Wood, "Central Station Advanced Power Conditioning: Technology, Utility Interface, and Performance "paper presented at Intersociety Energy Conversion Engineering Conference, No. 849411, August 1984; D. Curtice and J.B. Patton, Systems Control Inc., *Interconnecting DC Energy Systems: Responses to Technical Issues*, contractor report (Palo Alto, CA: Electric Power Research Institute, June 1983), EPRI AP/EM-31 24,

[20] OTA, *Industrial and Commercial Cogeneration*, op. cit., 1983.

two levels of protection, using manufacturers information and price catalogs currently available. For the higher level of protection, additional interconnection equipment is used, such as dedicated transformers, more expensive "utility grade" (see box 6A) relays, and more protection devices.

interconnection costs include engineering labor and the equipment cost of switchgear, power transformers, instrument transformers. For installations under 50 kW, these costs can be prohibitive when using utility-grade equipment and providing the typical level of protection for generating equipment. (Many of the details of interconnecting DSGs have been tabulated elsewhere. [21]) These costs are still much higher than the Department of Energy's (DOE) suggested price of $200 to $300/kW for "economical" interconnection equipment for residential generators.[22] While future technological advances such as microprocessor controls, less costly nonmetallic construction, and integration of different components could bring prices down, "the major cost decrease is expected to come from volume production" of interconnection equipment.[23]

For systems using inverters, perhaps the most costly component for interconnection is the power conditioning subsystem (PCS). In 1981, Sandia Laboratories asked four potential PCS manufacturers to estimate their selling price for these units, assuming they would be sold in quantity lots of 1,000. The prices ranged from $109 to $254/kW for 100 kW-sized units. Since receiving these estimates, Sandia reports that the cost of solid-state power devices has fallen dramatically and predicts that prices will drop substantially in the future.[24]

Interconnection costs have continued to decline during the past 5 years. However, the cost of interconnection for smaller units remains a high proportion of the cost of the generation equipment ($600/kW). The cost for intercon nection for larger units is about 5 to 10 percent of the capital cost of these units.

[21] D. T. Rizy, *Protection and Safety Requirements for Electric Distribution Systems With Dispersed Storage and Generation (DSG)* (Oak Ridge, TN; Oak Ridge National Laboratory, August 1984), ORNL/CON-143.

[22] Stevens and Key, op. cit., 1984.

[23] T. S. Key, "Power Conditioning for Grid-Connected PV Systems Less Than 250 kW, "op. cit., 1984.

[24] D. Chu and T.S. Key, "Assessment of Power Conditioning for Photovoltaic Central Power Stations, "paper presented at IEEE Photovoltaic Specialist Conference, May 1984.

UTILITY INTERCONNECTION STANDARDS

In the first years since the enactment of PURPA, few utilities had any published guidelines dealing with interconnection requirements. In 1983, OTA reported that most interconnection configurations were custom-fitted and no general patterns for utility standards had emerged.[25] Since 1983, the number of applications from dispersed generating customers to interconnect to utilities has increased. As a result, more utilities have standardized their interconnection requirements in the form of published guidelines. The guidelines, approved by the Public Service Commission, usually require data and drawings on the type of generator and PC equipment as well as anticipated customer loads.

It is important that such requirements be sensitive to the needs of both the utility and DSG customers. The customer should know exactly what equipment is necessary so that costs can be predicted with some certainty, and the utility should be able to reduce design review approval time and costs so that its power quality and operations can be maintained. Knowing probable interconnection costs ahead of time may be as important as the actual cost itself.[26]

interconnection guidelines should also stimulate the exchange of information between the utility and the DSG customer. Ideally, the DSG

[25] OTA, *Industrial and Commercial Cogeneration*, op. cit., 1983.

[26] F.V. Strnisa, et al., New York State Energy Research dnd Development Administration, "Interconnection Requirements in New York State, "paper presented at Tenth Energy Technology Conference, Washington, DC, 1983.

customer should have access to necessary information regarding technical characteristics of the utility system's power circuits, such as relay tolerance settings, the short circuit capacity at the point of interconnection, and the speed and operation of reclosers after detecting faults.

Utilities currently use two different philosophies in preparing guidelines: they either prescribe functional performance requirements that must be met by the interconnection equipment, or nonfunctional, equipment-specific requirements. For example, a utility might require equipment to detect when the DSG generates power with a frequency outside a certain range (a functional requirement) or require specifically an under-frequency relay (technology-specific).

While a combined approach may be used by a utility in preparing its guidelines, research to date suggests that performance-based standards appear preferable since they allow cogenerators to meet functional criteria rather than requiring them to install particular types of equipment that might later be found unnecessary. New interconnection equipment is being introduced continually with better performance and reduced cost. Perhaps in response to the fast pace of technological change and improvements in the dispersed generation industry, many utilities are instituting function-based interconnection guidelines.

Typically, utilities have different requirements for different sized DSGs, with fewer and less stringent protective functions for the smaller generators. While the precise definition of "smaller" versus "larger" is not agreed upon by all utilities, usually, generators less than 20 kW are considered small DSGs and have fewer functional requirements imposed *on* them than generators larger than 100 kW. The rationale behind this scaling is, as mentioned earlier, to relate the level of protection and cost of the interconnection equipment to the size of the generator. In spite of this, the per-kilowatt cost of even the least stringent interconnection requirements is much higher for smaller generators (see figure 6-3.)

There are other variations in the exact requirements specified by utility guidelines (see box 6C). Even within a particular State, such as New York, requirements differ among utilities for particular kinds of equipment, compliance with specific electrical codes, etc.[27] (see table 6-2 and box 6D).

In addition to these changes, there are the ongoing efforts by standard-setting committees of the Institute of Electrical and Electronics Engineers (IEEE) and the National Electric Code (NEC) as well as research sponsored by DOE, and the Electric Power Research Institute (EPRI) to develop national "model" guidelines. While all of these organizations have published draft standards or suggestions for model guidelines, none has as yet released final versions.[28] One of the more influential of such efforts is the preparation of revisions to the NEC. Working groups meet periodically to suggest revisions, and the overall committee publishes the consensus every 3 years, with the next revision planned for 1987. Once the revisions are published, they are usually circulated to all local city, county, and other municipal bodies, which then incorporate the changes into their own local building and inspection codes. This process of incorporation, however, may take a decade or longer.

The delays inherent in this process work against the fast-changing nature of interconnection technology. Even with the adoption of NEC or other national standards, utilities are reluctant to accept equipment which is unknown to their own experience, even if it is in wide use in some other utility's service territory. For example, New York State Electric & Gas requires that interconnection equipment meet American National Standards institute standard C37.90 (for power quality) but stipulates the utility must have already tested the equipment, surveyed users by telephone, and collected successful performance histories in other utilities.[29]

Another example is the requirement that DSG customers use "utility-grade" relays, which cost

---

[27] Ibid.

[28] %. Chalmers, "Status Report of Standards Development tor Photovoltaic Systems Utility Interface," paper presented at Intersociety Energy Conversion Engineering Conference, No. 849406, August 1984; IEEE Standards Coordinating Committee for Photovoltaics, "Terrestrial Photovoltaic System Utility Interface *for Residential* and Intermediate Applications," Standard 929 (Draft), November 1983; and D. Curtlce and J. B. Patton, *Interconnecting DC Energy Systems: Responses to Technical Issues*, op. cit., 1983.

[29] F.V. Strnisa, et al., "Interconnection Requirements in New York State," op. cit., 1983.

Box 6C.—The Evolution of Utility Guidelines

Interconnection guidelines have been evolving for two reasons: the increase in number of customers applying for interconnection, and the increase in utility engineering experience. However, this evolution has not been consistent across utilities: some utilities have made their guidelines more restrictive, while others have become more liberal. The final implications are that guidelines are vastly different among utilities.

An example of one utility that has liberalized its guidelines is Southern California Edison (SCE). SCE was one of the first utilities to publish interconnection guidelines. Since then over 400 MW of dispersed generation has been installed on its system. The original set of guidelines was the product of the utility's own experience and research and has not changed significantly since its inception. However, recent experience has shown that underfrequency detection has been too stringent when the operation of the interconnection equipment is compared to the normal variations in the centralized power supply for large industrial customers. As a consequence of this frequency range, the present interconnection devices have tripped these customers off-line when small disturbances or short circuits have reduced overall system frequency. SCE has revised its guidelines to allow a greater underfrequency operating range so that the interconnection devices will continue to keep these larger customers on-line.[1]

By contrast, another utility, Wisconsin Power & Light (WP&L), has recently made its guidelines more stringent. Between 1980 and 1983, WP&L's guidelines underwent substantial revision based on analysis of both interconnection economics and experience. The 1980 guidelines split DSG customers into two classes by generator size: those with generation under and those exceeding 200 kW, respectively. The 200 kW threshold was lowered in 1983 to 20 kW.

Originally, the 1980 buy-back rates for less than 200 kW customers were 4.8 cents/kWh on-peak and 1.75 cents/kWh off-peak. Larger generating customers were required to negotiate their rates on an individual basis with WP&L. In 1983 this requirement was revised: customers with generation less than 20 kW are billed on a net-energy basis, thereby eliminating the need for time-of-day metering (if the customer did not originally use one) and providing a higher buy-back rate. Customers with generation greater than 20 kW are paid depending on the location of their interconnection to the WP&L system—either at the transmission, distribution, or secondary distribution level—but the on-peak rate is less than 4 cents/kWh and the off-peak rate is more than 2 cents/kWh.

In 1983 a liability clause was added requiring all generating customers to maintain $100,000 of insurance "or demonstrate financial responsibility satisfactory to [WP&L]." This clause is unusual, as many utility guidelines do not even mention any special liability coverage.[2]

[1] A. Dawson, Southern California Edison, personal communication, May 1984.
[2] Guidelines provided to OTA by Virginia Electric Power Co., Wisconsin Power & Light Co., and Carolina Power & Light Co.; Carl DeWinkel, Wisconsin Power & Light Co., personal communication, June 1984.

more and have supposedly better reliability than ordinary commercial-grade relays. There is no general agreement as to what relays are of which grade. For example, Central Hudson Electric & Gas defines relays as "utility-grade" if the utility has had experience with it and can predict its performance.[30] As yet, however, no utility has published any assessments linking reliability with the level of equipment grade. Thus, the requirement of and definition of "utility-grade" equipment may be largely attributed to general utility conservatism towards equipment performance, rather than towards specific groups of interconnection apparatus.

Equipment grade stipulations can present an awkward situation for DSG customers wishing to interconnect. For example, a utility refuses to approve an interconnection unless the eauipment has undergone prior safety inspection', yet the

[30] Ibid.

Table 6.2.—New York Utility Interconnection Requirements

	Utility						
Requirement	A	B	C	D	E	F	G
Utility approval prior to operation	X	X	X	X	X	X	X
Utility inspection	X	X	X	X	X	X	X
On premise maintenance log	X	X	X	X		X	X
Lockable manual disconnect switch	X	X	X	X	X	X	X
DSG shall not energize a dead circuit	X	X	X	X	X	X	X
Harmonic content limit	X	X	X	X	X	X	X
Reactive power meter			X				
Protective equipment including:							
Main circuit breaker	X		X	X		X	
Power transformers for isolation	X		X				
Automatic fault detection and shutdown equipment		X	X	X	X	X	X
Dead circuit detection equipment		X	X		X	X	
Over/under frequency and voltage relays		X	X				
Directional overcurrent relays		X					
Ground overcurrent relays		X		X			
Synchronizing equipment				X		X	
Conform to the applicable codes including:							
National Electric Code		X	X		X		X
National Electric Safety Code			X				
Fire Underwriters			X		X		
UL approval						X	
DSG may not backfeed power to secondary networks	X						

KEY TO UTILITIES:
A. Consolidated Edison Co.
B. Central Hudson Gas & Electric Corp.
C. Long Island Lighting Co.
D. New York State Electric & Gas Corp.
E. Niagara Mohawk Power Corp.
F. Orange & Rockland Utilities
G. Rochester Gas & Electric Co.

SOURCE: D. Wolcott and F. Strnisa, *New York State Interconnection Issues Manual* (Albany, NY New York State Energy Research and Development Authority, March 1984)

safety inspectors have refused to approve the installation of interconnection equipment unless they have prior utility consent. An example of this dilemma is the case of a wind generator control panel, which several utilities insist must have Underwriter's Laboratories (UL) approval. UL, however, does not test assembled control panels, although they do test the components used in the panels. Such subtleties can create significant delays in granting interconnection approval, increase the cost both to the utility and the customer, In such instances, some experts argue that:

> the burden of proof for refusing to accept a "relay that has passed the standard tests [should] be placed on the utilities. [The utility should ei-

Box 6D.—Consolidated Edison Co. (ConEd)

The service area for ConEd contains all of New York City and parts of Westchester County. The combination of high cost for electricity, many older plants, and dense population have made the area ripe for potential DSG opportunities. Yet, the difference between opportunity and installed DSG capacity is large—so far only one 40 MW cogenerator has been allowed to interconnect to ConEd's network, while 30 applications are still pending. The chief cause of this disparity is due to the different expectations and interpretations of responsibility between potential DSG customers and the utility.

ConEd's interconnection guidelines delineate the precise responsibility of the potential DSG customer in obtaining an interconnection, the engineering considerations, and the data that the customer must supply to Con Ed with the application. Some DSG applicants claim that these guidelines are too stringent for any economical interconnection, while the utility counters these criticisms by saying that the cost for interconnection is higher due to the network configuration of its transmission and distribution (T&D) system within Manhattan, and that the detailed guidelines are necessary for the proper operation of its T&D system.

ConEd argues that Manhattan network has a different topology from that of other utilities around the country. Rather than a radial, hub-and-spoke type of pattern (as shown in figure 6-1), the Manhattan-network is a criss-cross grid with many intersecting nodes between dktribution lines. In a radial system each customer has one centralized source of electricity supply, and if that source goes out of service, the customer is without power. In the network system, each customer has multiple sources of centralized supply. At many places in ConEd's Manhattan network certain types of protective devices are placed to allow power to flow from source to customer and not in the reverse direction. Because of this, if DSGs were placed at the customer site, power could not be fed back into the grid and a critical benefit, that of sales of power back to the utility, would not be possible.

SOURCE: Roch Cappelli, Consolidated Edison Co., personal communication, August 19B4; and Bill Wagers, Consolidated Edison Co., personal communication, May and August 1984.

ther be required to] show negative operating system experience, or they must develop a testing program . . . rapidly and systematically. . . . If one utility tests relays and finds them acceptable the results should [constitute compelling evidence for other utilities].[31]

Therefore, due to a combination of utility conservatism, jurisdictional issues, marked differences in individual utility's guidelines, and the lack of model national standards, DSG customers are likely to face a confusing array of interconnection guidelines well into the next decade. The extreme diversity among utility guidelines may also make it difficult to produce high volumes of standardized equipment and to achieve accompanying economies of scale. All of these factors may slow the deployment of DSGs.

[31]Strnisa, et al., op. cit., 1983.

UTILITY SYSTEM PLANNING AND OPERATING ISSUES

Overview

The process of planning and operating an electric utility system is a very complex one. *P/arming* focuses on the selection of technology requirements (generation, transmission, and distribution) to satisfy predicted demand by the most financially attractive means. *Operations management* refers to the day-to-day, hour-to-hour, and second-to-second deployment of existing facilities to meet the demand on the electric system. Both processes have an overriding goal: to provide the production and delivery capabilities to meet electricity demand in a safe, reliable, and economic manner.

The addition of DSGs to the utility network complicates both planning and operations. In the short-term, if utility system controllers do not correctly anticipate load changes, network elements (transformer, lines, generators, etc.) may become overloaded and circuit breakers may open, possibly causing power reductions or interruptions for customers. In the medium-term, insufficient transmission and distribution capacity may cause poor quality of service. And over the long term, if utility planners underestimate or overestimate future demands, the utility may be placed in financial jeopardy by having to purchase power from its neighbors at high rates (for underbuilding) or by having too much idle capacity (for overbuilding). This section discusses the effect of increasing DSG capacity on utility operations and planning.

Electric System Planning

Good planning of electric systems is the key to controlling costs since the timing and type of additions will likely determine overall costs. There are two components in the electric supply cost equation: fixed or capital costs, and variable costs, e.g., fuel, operation, and maintenance. Although the overall cost tends to be dominated by generation costs, on the order 60 to 65 percent, transmission and distribution costs can not be ignored. The greatest impact of DSGs is likely to be on the distribution system itself.

Determining DSG's impact on the overall electric system involves: 1) estimating the performance of the DSG, 2) establishing the relationship between system load and DSG performance, and 3) calculating the change in the utility's performance resulting from the DSG.[32]

Generation System Planning.–As discussed in chapter 3, utilities perform fundamental economic studies of their systems so that the most financially attractive generation option can be chosen to meet predicted demand and so that they can determine when to retire existing units. The basic calculation involves the estimation of the value resulting from the installation of a power source—defined as the savings in conventional fuel, operation, maintenance, and capacity costs.

[32]T. Flaim, et al., *Economic Assessments of Intermittent, Grid-Connected Solar Electric Technologies: A Review of Methods* (Golden, CO: Solar Energy Research Institute, September 1981), sERI/TR-353-474.

A number of value studies of incorporating solar energy generating sources into utility resource plans have been performed on a variety of specific utility systems since 1975.33 Typically, these studies analyze a base case (without solar technologies) and then a case with solar. The value assigned to the solar energy is the cost difference between the two study cases.

These studies[34] generally incorporate the following steps in evaluating the value of DSGs in a utility's resource plan. First, a base case analysis of an expansion plan without solar technology establishes a benchmark against which solar technologies are evaluated. Next, a second case is analyzed with solar technologies in three steps: 1) estimating the power output of the solar technologies, 2) modification of the hourly loads by the solar production to determine the residual hourly loads on the nonsolar technologies generation, and 3) recalculating production costs and the reliability impacts. Typically, generation planning studies for the 20- to 30-year planning horizon do not use detailed, hourly data, but the intermittent nature of solar energy requires this type of representation. The difference in reliability between the base case and the solar alternative can be used to compute the solar technologies' capacity credit in the utility's generation plan. As a final step in the process, the cost difference between the cases with and without solar technologies are examined to obtain the single year savings. Using the single year savings, the present value of the total savings is accumulated over the expected lifetime of the solar facility under study.

The most important factor affecting the breakeven energy cost is the utility's present and planned future generation mix, which determines the type and quantity of fuel and capacity displaced. Evidence strongly suggests that while solar technologies may displace some conventional production capacity, the greatest value of solar rests with the displacement of energy, i.e., fuel savi rigs.

Key areas of future work include the development and validation of models that accurately characterize the dynamic behavior of solar technologies. Capacity potential will be measured in part by the effectiveness of solar technologies to participate in short-term load following process, i.e., load frequency control.

Transmission Planning.—Electric transmission systems are studied in terms of network capacity and reliability requirements. Criteria for sizing the transmission system vary from utility to utility; however, the basic purpose of all transmission system design studies is to establish when and where new lines should be added and at what voltage level.

A transmission plan consists of three major components: 1) a generation dispatch strategy and the projected load profile for the system are used to determine the expected transmission line loading levels over the planning period; 2) a minimum cost transmission expansion plan for the horizon year which meets the reliability criteria; and 3) and a "through-time plan, " i.e., the sequence of changes in the transmission system in transition to the horizon year.[35] Key parameters for comparing alternative expansion plans are the number of line additions required per unit of time and the present worth cost of those additions.

Studies sponsored by EPRI[36] estimate transmission "credits," i.e., capital cost savings, associated with DSG siting close to load centers of $66 to $133/kW, for a variety of transmission system configurations. If more expensive underground cables are involved, the savings were estimated to be as high as $250/kw. The simulations showed that an optimal DSG market penetration, from the point of view of transmission system planning, appeared to be about 20 percent of metropolitan load growth. Below or above that level, the transmission credits per kilowatt decreased.

Distribution Planning.–The effect of DSGs on the distribution system (typically 13 kilovolts and

[33] Ibid.; and T. Flaim and S, Hock, *Wind Energy Systems for Electric Utilities: A Synthesis of Value Studies* (Golden, CO: Solar Energy Research Institute, May 1984), SERI/TR-211 -2318

[34] T. Flaim and S. Hock, *Wind Energy Systems for Electric Utilities: A Synthesis of' Value Studies*, op. cit., 1984.

[35] B.M. Kaupang, Assessment *of Distributed Wind Power Systems* (Palo Alto, CA: Electric Power Research Institute, February 1983), EPRI AP-2882.

16 Systems Control, Inc., *Impact on Transmission Requirements of Dispersed Storage and Generation* (Palo Alto, CA: Electric Power Research Institute, December 1979), EPRI EM-1 192.

below) is determined by the deployment strategy of the equipment. Clusters of generating equipment, irrespective of individual unit size, that are placed on feeders or in substations, affect the system very differently than small generators distributed throughout the electric system.

In substations, the primary element for concern is the transformer. The addition of DSGs has the potential for changing significantly the operating conditions of the transformer. Deferring additional substation capacity is the desirable attribute. For small additions of DSGs up to some minimum level, no deferral of transformer capacity results because the substation is largely responsible for serving all the load. Above this minimum up to some maximum level, deferrals will result; above the maximum, additional transformer capacity is required for the generator itself. In sum, the effect of deferral is captured by the particular sizing policy of the utility, but DSGs can defer the addition of both transformer and feeder capacity.[37]

The addition of DSGs to the substation has no influence on distribution system losses, but placing generating equipment on the feeder can reduce losses because the production will be closer to the load. When generation is placed closer to the load, less power is transported through the system, thereby reducing losses. DSG installation must be well planned so that existing circuits are not a limitation. Again, the amount of loss reduction depends on the utility.

Excessive voltage fluctuations offer greater potential concern when DSGs are placed in the distribution system, especially since they are nearer the loads. Under wind gust or cloud cover conditions, solar technologies can cause large voltage swings due to current surges from the electrical converter. Voltage regulators and tap-changing transformers in the power system are very slow to respond (on the order of a minute) resulting in no influence on the short-term problem.

Electric Power Systems Operations

Overall management of power system operation consist of two phases—operation planning and real-time operation. Operation planning consists of the scheduling of generation and transmission facilities for use during a 1- to 3-day period; it is the so called "redispatch problem." Real-time operation involves the on-line management and control of all facities on a second-to-second basis. In most utilities, daily operations are directed from a central control center.[38]

Operations Planning.–A strategy is formulated to deploy the system's available resources to meet the anticipated load of the next day economically and reliably. First a load forecast of hourly loads and load ramp rates (minute to minute changes in load) is made to determine the generation and transmission requirements. Subsequently, a "unit commitment" strategy is determined based on available facilities as determined by any scheduled or unscheduled down-time of equipment. The resulting plan is the guideline to daily operations.[39]

Real-Time Operations.— Utilities must continually adjust electricity production to follow the constantly changing electric demand. Production and demand are maintained in balance by the combined actions of speed governors on individual generating units (frequency regulation) and a closed loop automatic generation control system which performs load frequency control (regulation) and economic dispatch functions.[40] In addition, the instantaneous balance of load and demand is known as stability. A configuration is chosen which assures a stable system under a credible list of potential system component failures (faults, equipment trips, etc.).

Automatic Generation Control.–There remains much uncertainty and debate over what DSG penetration level will negatively affect utility system performance. An earlier OTA report[41] discusses concerns about the effects of a high penetration of DSGs. A common definition of "high penetration" is a DSG capacity over 25 percent of the capacity of the particular distribution

[37] Ibid.

[38] T. W. Reddoch, et al., "Strategies for Minimizing Operational Impacts of Large Wind Turbine Arrays on Automatic Generation Control Systems," *Journal of Solar Engineering,* vol. *104,* May *1982.*

[39] Ibid.

[40] Ibid.

[41] OTA, *Industrial and Commercial Cogeneration,* op. cit., 1983.

feeder or over 25 percent of overall utility system capacity.

There are no utilities today approaching this definition of high penetration of DSG equipment on particular distribution feeders—even the utilities with the most DSG installations have less than one-tenth of 1 percent penetration. Yet, for most utilities, the penetration level is increasing and some, such as Houston Lighting & Power, are planning for the possibility of penetrations as high as 30 percent by the year 2000.[42] One utility in Hawaii currently has 10 percent DSG penetration (see box 6E).

The effect DSGs have on an electrical system's area control error (ACE) is of particular interest. ACE measures a combination of frequency deviation and net tie-line power flow (see box 6A). North American utilities have agreed on certain minimum standards for ACE values: ACE must equal zero at least once and must not vary beyond a certain range during each 10-minute interval.[43]

Analysts measuring utility system performance with high penetrations of DSGs must measure the increase in ACE caused by the DSGs, rather than by other influences unrelated to DSGs. These measurements are difficult to make in the field, since ACE often results from the demand shifts caused by fast-changing, unpredictable conditions such as a quickly moving thunderstorm, a fast drop in temperature, or a drop in power coming from a neighboring utility across a high-voltage tie-line.

Most researchers agree that at the present low levels and continuing up to at least 5 percent of DSG penetration, there are no ill effects on system operations as measured by ACE. However, there is no general agreement on what increase in penetration of DSGs beyond 5 percent will increase ACE.

Curtice and Patton[44] used data on wind generators and estimated ACE for four different generator penetration levels. Their results indicated that ACE increases only 1 percent when total wind capacity is at 20 percent of the overall utility system. When penetration reaches 50 percent, ACE increases to 10 percent. While these changes in ACE were not significant, the authors noted, with 5 percent penetration, wind output variations

> ,.. did not cause a significant change in the control process. . . . However, increased energy flow over the tie-lines connected to neighboring utilities compensated for generator/load mismatches occurring too fast for the utility's generators to follow. If the utility's control process is designed to minimize tie-line flow deviations, . . . then generator/load mismatches show up as increased ACE and decreased system performance.

These results suggest that, although measured ACE was not large, there is a potential problem with installing wind machines. *If* there is a high enough fluctuation in wind speed, *if* there is a high proportion of wind generation on a particular feeder, and *if* the utility optimizes its control procedures for minimizing tie-line variations (an electric industry standard), a decrease in system performance could occur. Moreover, there is a potential for overloading the distribution feeder. (Other research notes the need to develop alternative generation control algorithms to better accommodate DSGs.[45])

A Sandia Laboratories study[46] also supports the view that DSGs have a limited effect on system

[42] Henry Vadie, Houston Lighting & Power, OTA workshop on Cost and Performance of New Generating Technologies, June 1984.

[43] M. G. Thomas, et al., Arizona State University, *Draft Report: The Effect of Photovoltaic Systems on Utility Operations,* contractor report (Albuquerque, NM: Sandia National Laboratories, February 1984), SAND84-7000.

[44] D. Curtice and J. B. Patton, *Interconnecting DC Energy Systems: Responses to Technical Issues,* op. cit., 1983.

[45] S. H. Javid, et al., "A Method for Determining How to Operate and Control Wind Turbine Arrays in Utility Systems," *IEEE Transaction on Power Apparatus and Systems,* IEEE Summer Power Meeting, Seattle, WA, 1984; F. S. Ma and D. H. Curtice, "Distribution Planning and Operations With Intermittent Power Production," *IEEE Transactions on Power Apparatus and Systems,* August 1982; Systems Control, Inc., *The Effect of Distributed Power Systems on Customer Service Reliability,* contractor report (Palo Alto, CA: Electric Power Research Institute, August 1982), No. EPRI 3L-2549; and T. W. Reddoch, et al., "Strategies for Minimizing Operational Impacts of Large Wind Turbine Arrays on Automatic Generation Control Systems," op. cit., May 1982. Another recent study examined how to efficiently operate and control wind turbine arrays; see Stevens and Key, op. cit., 1984.

*Thomas, et al., op. cit., 1984, SAN D84-7000; and M. G. Thomas and G. J. Jones, *Draft Report: Grid-Connected PV Systems: How and Where They Fit* (Albuquerque, NM: Sandia National Laboratories, 1984).

Box 6E.—Hawaii Electric Light Co. (HELCo)

The Island of Hawaii may soon have the highest proportion of dispersed electric generation capacity in the United States. Hawaii, the largest island in the State, is mostly rural and sparsely populated. The island's utility, Hawaii Electric Light Co. (HELCo), has a system peak of about 100 MW during the evening hours and a minimum off-peak demand of 40 MW. The island is not connected electrically to the other islands and has a residential electricity rate of 12 cents/kWh. The company presently has a mix of both conventional and new generation capacity: 56 MW of oil-fired steam base load generation, a 10 MW gas turbine, 24.6 MW of diesel generation, 3.3 MW of hydropower, 2.5 MW of geothermal, and 32 MW of biomass generation obtained through contracts with local sugar plantations. Finally, HELCo has signed contracts with wind developers in excess of 20 MW. This will bring the total capacity of wind turbines at HELCo to over 20 percent of the system peak load.

Due to the large number of wind machines on HELCo's system, the island utility is concerned about possible system stability problems that may result from wind farms connected at the end of long distribution feeders. During off-peak hours (11 p.m. to 4 a.m.), base load generation must be reduced to minimum levels. During these hours, wind-generated electricity fed into the grid could result in shut down of base load generation. Hence, HELCo has required all wind farms in excess of 300 kW to be equipped with supervisory controls to enable the utility to disconnect the wind farms from the system should the need arise. With many wind machines using line-commutated inverter systems, utility engineers are also concerned about excessive harmonic distortion; excessive harmonic content on the grid may create problems in other operations such as revenue metering, system losses, relaying, and quality of service.

Engineers express concern about the future operations of their utility. There is no consensus, however, about the influence of the high proportion of dispersed capacity on generation mix, power quality, and the cost and reliability of providing service. Yet, to date, there have not been any complaints from non-DSG customers about power quality, which utility personnel also feel is adequate.[1]

[1]Alva Nakamura, Hawaii Electric Light Co., personal correspondence with OTA staff, July 11, 1985; and R.M. Belt, Hawaii Electric Light Co., personal correspondence with OTA staff, June 1984.

performance. The researchers modeled photovoltaic (PV) arrays on a long rural distribution line with 30 percent of the homes on the line using small (1 O to 20 kW) PVs. In order to observe any significant increase in ACE, "a solid cloud cover would engulf all 10 miles of the distribution feeder simultaneously masking every PV home . . . and this scenario would be repeated every 6 minutes. " The study maintains this is a very unlikely situation and in any event represents the worst possible condition for PV interconnection equipment.

The sudden and unpredicted loss of a large generator can drastically unbalance the supply system of a utility, especially when this generator represents a large proportion of the entire system capacity. Two modelers have studied such a situation:

Researchers from Arizona State University simulated the effects of larger PVs with a three region model (the regions are the service areas of Arizona Public Service and The Salt River Project as well as a third region representing the remainder of the Western United States and Canadian grid). A PV generator was placed in each area and its output changed in response to predetermined cloud movement and wind velocity. Five different-sized PVs were used, ranging from 50 to 250 MW. The researchers found no significant increase in ACE as long as: 1) any single central-station PV unit was less than 5 percent of total system capacity or less than 5 percent of any particular distribution feeder; and 2) a combination of smaller, home-sized PVs was less than 50 percent of total system capacity or particular feeders.[47]

Dynamics and Transient Stability.—Most concerns with stability have focused on wind turbines. The special characteristics of wind turbine generators which cause their dynamic behavior to be different from that of conventional units can be traced to the large turbine rotor diameter and slow turbine speed necessary to capture sufficient quantities of power from the relatively low power density of the wind. The electrical generators for large wind turbine applications are generally four or six pole designs and a high ratio gear box is essential to step up the low turbine speed to the synchronous speed of the generator (] **,800** or 1,200 rpm). The high ratio gear box causes wind turbine drive trains to have torsional properties which are not characteristic of conventional turbine generators. But the dynamics of large wind turbines are compatible with conventional power systems and pose no apparent barrier to their application. The same could be said of the transient stability properties of wind turbines during electrical or mechanical disturbances.[48]

[47] R. M. Belt, "Ut]lity Scale Application of Wind Turbines, " paper presented at V1'inter Power Meeting of the IEEE, No. CH 1664, February 1981,

[48] E N H i n ric hsen a nd P. J. Nola n, *Dynamics ot Single- and* A'fu/f/-*Unit Wind Energy Conversion Plants Supplying Electric Utility Sys-ferns*, contractor report, US, Department of Energy (Washington, DC: National Technical Information Service, August 1981), DOE/ ET/20466-78/ 1.