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Project Summary

Demonstration of the Environmental and Demand-side Management Benefits of Grid-connected Photovoltaic Power Systems

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This project investigated the pollutant emission reduction and demand-side management potential of 16 photovoltaic (PV) systems installed across the country in 1993 and 1994. The project was sponsored by the U.S. EPA and 11 electric utilities. This report presents analyses of each system's ability to offset emissions of sulfur dioxide, nitrogen oxides, carbon dioxide, and particulates, and to provide power during peak load hours for the individual host building and the utility. Results of simulations of battery storage systems powered by each PV system are also presented.

The analysis indicates a very broad range in the systems' abilities to offset pollutant emissions, due to variation in the solar resource available and the marginal emission rates of the participating utilities. Use of dispatchable storage would reduce emission offsets due to energy losses in charging and discharging the batteries. Each system's ability to reduce building peak loads was dependent on the correlation of that load to the available solar resource. Most systems operated in excess of 50% of their capacity during building peak load hours in the summer months, but well below that level during winter peak hours. Similarly, many systems operated above 50% of their capacity during utility peak load hours in the summer months, but at a very low level during winter peak hours. The addition of dispatchable energy storage significantly increases each system's peak load matching ability, raising capacity factors to 100% for most systems during the utility's highest load hours.

This Project Summary was developed by the National Risk Management Research Laboratory's Air Pollution Prevention and Control Division, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

Photovoltaic (PV) conversion of sunlight to electricity has become substantially less costly and more efficient in recent years. Since its first application in the space program in the 1950s, the cost of PV modules has fallen approximately 70% per decade, and module manufacturers continue to make progress in reducing costs further. Although technological innovation has been responsible for much of the decline in costs, an international market for remote, off-grid power, growing at the rate of 20 to 30% annually, has resulted in expansion of module production capacity. This, in turn, has led to production economies which have driven module prices down still further.

Despite these cost reductions, modules remain the dominant factor in the cost of a grid-tied PV power system accounting for approximately 70% of the total. The power converter (inverter), necessary for transforming the direct-current (DC) power output from a PV array to grid-synchronous alternating-current (AC) power, is another significant component of system cost, accounting for about 15% of total cost. Because the market for grid-tied AC power from PV systems has been relatively small, there has been little progress in reducing the cost of the inverter.

However this project and other similar projects are increasing the demand for inverters, and will likely result in technological improvement and cost reduction. The remaining cost components of PV systems are the array mounting structure, wiring, and switchgear, collectively referred to as the balance of system (BOS).

Although electricity generated by PVs remains too expensive to compete with conventional power sources in most grid-connected applications, there is a growing niche of cost-effective applications (most of them remote from the power grid) which will expand as the cost of PV power falls. A 50% drop in module prices is expected within the decade which has the potential to greatly expand the grid-connected market. Against this background of falling costs is a heightened public awareness of the threats to environmental quality posed by the by-products of electricity production. The most notable concern today is the possibility that emission of carbon dioxide (CO_2) resulting from the combustion of fossil fuels may lead to climatic changes on a global scale. As a result of this heightened concern regarding environmental quality, many consumers have shifted their consumption patterns, and some are willing to pay premiums for products that have lower environmental impacts. Several recent surveys suggest that about half of electric utility customers would be willing to pay a $10 monthly premium for electricity generated by renewable resources. Given this context, it is very likely that the domestic market for grid-tied PV power systems will expand substantially within the next decade, and continue to grow rapidly.

The potential environmental benefits from PV power generation are quite large. If PV systems were installed where possible on the rooftops of the U.S. inventory of residential, commercial, and industrial buildings, they could produce roughly 20% of the Nation's electricity. Currently, fossil fuels used for electric power generation in the U.S. account for approximately 34% of the CO_2, 67% of the sulfur dioxide (SO_2), and 37% of the nitrogen oxide (NO_x) emissions into the atmosphere from controllable sources within the U.S.

In September 1991 the EPA issued a solicitation for the installation of grid-tied PV systems with the goal of measuring their environmental and demand-side benefits. Ascension Technology developed a proposal in response to this solicitation, with the support and participation of utilities across the nation. Eleven utilities supporting the proposal to EPA were (1) New England Electric System (NEES) with service areas in Rhode Island, Massachusetts, and New Hampshire; (2) New York State Electric and Gas (NYSEG) in upstate New York; (3) Northeast Utilities (NU) with service areas in Connecticut, Massachusetts, and New Hampshire; (4) Atlantic City Electric (ACE) in southern New Jersey; (5) New York Power Authority (NYPA) with customers throughout New York State; (6) Arizona Public Service (APS) in central and northern Arizona; (7) Wisconsin Public Service (WPS) in southeastern Wisconsin; (8) Northern States Power (NSP) with service areas in Minnesota, Wisconsin, Michigan, and the Dakotas; (9) Pacific Gas and Electric (PG&E), serving most of northern California; (10) the City of Austin Municipal Utility (COA); and (11) Southern California Edison (SCE) serving much of southern California. In addition to the geographic diversity of the service areas represented by these utilities, their pollutant emission characteristics also proved to be quite divergent. Ascension Technology's partners from the PV industry were Siemens Solar Industries, which provided PV modules, and Omnion Power Engineering Corporation, which provided the inverters.

EPA awarded the contract for this project to Ascension Technology in the third quarter of 1992. The final system design effort began shortly thereafter, and the first system was installed and operating in April 1993. Ten of the systems were operating by the end of August 1993, and the last was completed by mid-January 1994.

Monitoring of each system began concurrently with initial system operation, although the "official data start date" was delayed where there were initial technical problems with either instrumentation or PV system hardware. At each site, 15-minute average values of solar irradiance, ambient temperature, PV system power output, and building load were recorded and stored for subsequent retrieval by modem. Monitoring of each site (for the purposes of this study) continued through September 1994.

Emission rate and load data provided by each participating utility were used in conjunction with the data collected from each system to conduct analyses of (1) the emission offsets resulting from operation of the PV systems; (2) the ability of each PV system to reduce the peak power demand of the building on which it was installed; and (3) the chronological correlation of each PV system's power output to the respective utility's peak loads. In addition, a model was developed to simulate the operation of each system in conjunction with dispatchable battery storage. This simulation shifted each system's daily generation to the utility's daily peak load hour(s), thus increasing the peak load correlation and reducing emission offsets (due to battery charging and discharging losses).

Chapter 1 of the full report is a general introduction to the project. Chapter describes the design, installation, and cost of each system. Chapter describes the data acquisition system and presents data collection and review procedures. System performance history is described generally in Chapter (details are provided in appendix D). Chapter discusses the model used to simulate the behavior of the PV systems with dispatchable battery storage. The marginal emission rate models developed for each participating utility are described in Chapter 8, as are the site-by-site emission offset estimates. Chapter 6 discusses each system's impact on the load of the building it is installed on, and utility-level load matching results are presented in Chapter 7. Conclusions from this project are summarized in Chapter .

Procedure

System Design

Designs were developed for nominal 4-kW "building block" PV systems for this project, capitalizing on the project staff's experience with roofmounted PV arrays in prior projects. The majority of the project's sites use either one system (4 kW) or a group of three systems (12 kW total). Note that the nominal system size refers to the inverter AC rating. The actual power output of the PV systems under standard operating conditions (1000 W/m^2 irradiance (full sunlight) and an ambient temperature of 20°C) is limited by the PV array to multiples of 3.5 kW AC.

PV arrays were configured using 12 PV panel assemblies. Each PV panel assembly contains seven modules, electrically wired in series. A PV source circuit is formed with four PV panel assemblies, wired in series. A 4-kW PV array consists of three PV source circuits.

Both pitched- and flat-roof installations utilize Ascension Technology RoofJack PV array supports, which have been used to install more than 1 MW of PV systems. PV arrays are held in place by ballast on flat roofs; this approach requires no roof penetrations to hold down of the PV arrays. System design details were developed in close cooperation with Siemens Solar Industries of Camarillo, CA, the PV module supplier. Omnion Power Engineering was selected as the supplier of power conditioners. The PV systems were designed to accommodate the specifications of the 4 kW-rated Omnion Series 2200 unit.

System Installation

System installation began in April 1993, and was complete by the end of January 1994, although instrumentation and hardware problems delayed the initiation of monitoring at some sites. The systems were installed on a variety of residential, commercial, and industrial buildings. Installation costs for each system varied by system size (4-, 8-, or 12-kW) and a number of site-specific factors. Table 1 summarizes the size and cost of each system.

PV System Performance History

Of the 16 PV systems installed by this project, all but two suffered events during the study period which temporarily limited system output or prevented generation altogether. Inverter-related problems were the most vexing of the generation-limiting events. In all, 27 inverter-related events resulted in a generation loss of 12,740 kWh, approximately 9% of the combined generation of these systems over the relevant time periods.

As a result of the inverter-related outages experienced in this project, the inverter manufacturer made several design changes and increased product testing across their full line of inverters. In addition, they extended the product warrantee for the EPA project installations.

Snow cover was also a frequent cause of PV system outages for those systems located in northern locations or at high altitude. Of the systems in such locations, the estimated energy loss as a result of snow cover ranged from less than 1% to 16% of measured annual generation.

A variety of other outages occurred during the study period, not all of which have identified causes. Of those "other" outages for which a cause was identified, the most frequent was, by far, fuse failure in the DC disconnect switch. Such failures occurred 17 times at 11 sites. It was determined that the original fuses in the DC disconnect switches did not have the proper surge rating. As they failed, they were replaced by "slow-blow" fuses which were rated for 600 V DC. None of the replacement fuses has failed to date.

Table 1. *System Size and Cost*

Site	*Utility*	*Size kW*	*Total Cost**	*Cost* per AC Watt*
1	*NYSEG*	*12*	*101.9*	*9.69*
2	*NU*	*4*	*36.0*	*10.26*
3	*ACE*	*12*	*105.0*	*9.98*
4	*ACE*	*4*	*31.1*	*8.87*
5	*NYPA*	*4*	*35.2*	*10.04*
6	*APS*	*8*	*64.2*	*9*
7	*APS*	*4*	*31.3*	*8.94*
8	*WPS*	*12*	*101.0*	*9.61*
9	*WPS*	*4*	*31.2*	*8.91*
10	*NSP*	*4*	*38.0*	*10.83*
11	*PG&E*	*12*	*104.9*	*9.40*
12	*COA*	*12*	*97.5*	*9.27*
13	*APS*	*4*	*32.2*	*9.19*
14	*SCE*	*4*	*30.9*	*8.81*
15	*SCE*	*4*	*31.1*	*8.89*
16	*SCE*	*12*	*96.7*	*9.20*

* Costs are in $1,000s

Battery Storage Model

Where peak loads do not coincide with peaks in the available solar resource, the value provided by a PV system can sometimes be greatly enhanced by the addition of dispatchable battery storage. Although some energy is lost both in charging and discharging a battery array, the ability to dispatch energy generated by the PV system during utility peak loads (or, for that matter, the peak loads of a transmission line or distribution feeder) allows the PV generation to be used to reduce generation by a utility's highest operating cost units, which are typically used only during peak periods.

To investigate the degree to which dispatchable battery storage would improve the ability of each PV system to offset load during utility peak load hours, a simple model was developed to simulate battery charging, discharging, and dispatch. The approach taken was to maximize the contribution of each PV system during the highest utility load hours of each day, by simulating the daily operation of each system's inverter(s) at its (their) peak capacity for as long as possible. The duration of operation each day was determined by the amount of energy actually generated each day and the AC rating of the inverter. The addition of dispatchable battery storage affects both pollutant emission offsets (due to battery charging and discharging losses) and the system's operation during utility peak load hours.

Results

Pollutant Emission Offsets

Models of marginal emission rates (i.e., emission rates of load following units) were developed for each utility based on utility provided data. The hourly emission rates of SO_2, NO_x, CO_2, and particulates were then combined with hourly PV system generation data (and simulated PV/storage dispatch data) to determine hourly emission offsets.

Annual emission offsets are presented in Figures 1 through 4. Annual SO_2 offsets ranged from 4 g/kW to 16 kg/kW of system rating under standard operating conditions (SOC) (1000 W/m^2 irradiance and 20° C ambient temperature). NO_x offsets ranged from 110 g/kW to 8.7 kg/kW. The range in annual CO_2 emission offsets was from 700 to 2,300 kg/kW of system rating, and that for particulates was 20 g/kW to 600 g/kW annually. The lighter shaded area in each figure is an estimate of the pollutant offset achievable by a PV system with average insolation, using average U.S. emission rates based on data collected by the Energy Information Administration for 1993.

The extreme variability in these results is due to two factors: (1) variability in the local solar resource and (2) variability in utility marginal emission rates. Factor (2) is far more influential than (1), as can be seen by comparing the range for CO_2 to those of the other pollutants. Since there are currently no mitigation measures in place for CO_2, variation in utility CO_2 emission rates is due only to the relatively small (about 2:1) variation in the carbon content of fuels used and variation in the heat rates of the power plants. The range of the highest to lowest annual offset is relatively small (3.3). For the other pollutants, variations in the pollutant content of the fuel as well as inter-utility differences in installed pollution mitigation equipment give rise to the tremendous differences between utility emission rates which underlie the differences in emission offsets described above.

The results of the PV-powered dispatchable storage system simulations indicate that pollutant offsets would be reduced by at least 25% were storage added to these systems. This is largely due to energy losses in charging and discharging batteries, but is also influenced by marginal emission rates which are typically lower during utility peak load hours when cleaner, more efficient power plants are often used to follow load.

Building-Level Load Reduction

Each PV system's ability to provide power during building peak load hours was analyzed by comparing each building's net (of PV generation) and gross load duration curve (LDC). The LDC is constructed by sorting all load values for a given period in descending order, and plotting each value against its rank in the sort. Differences in a building's net and gross LDC for the highest load values

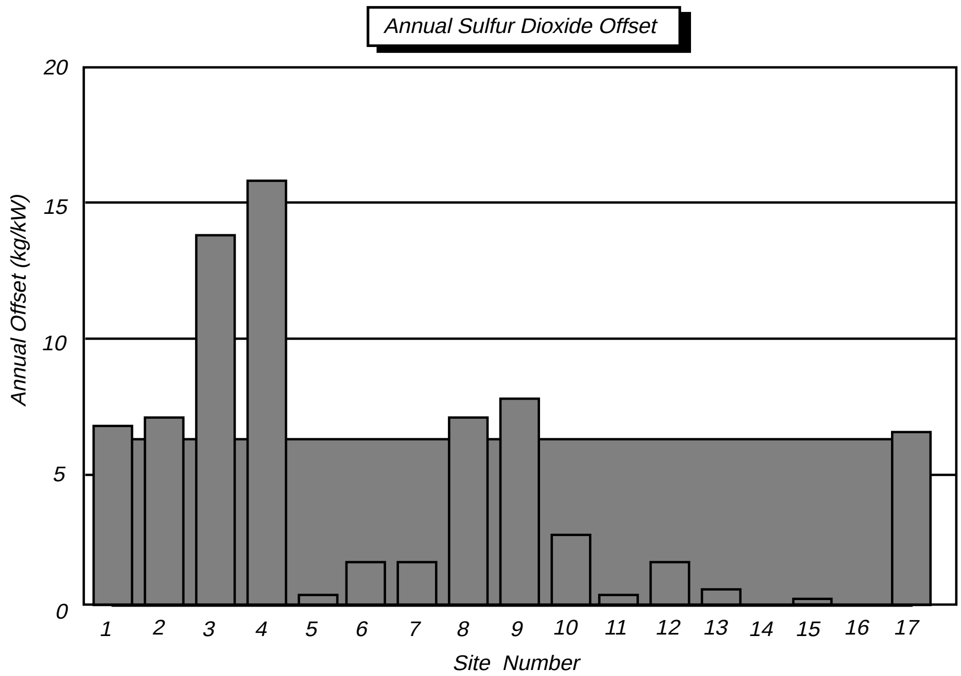

Figure 1. *Annual SO_2 offsets.*

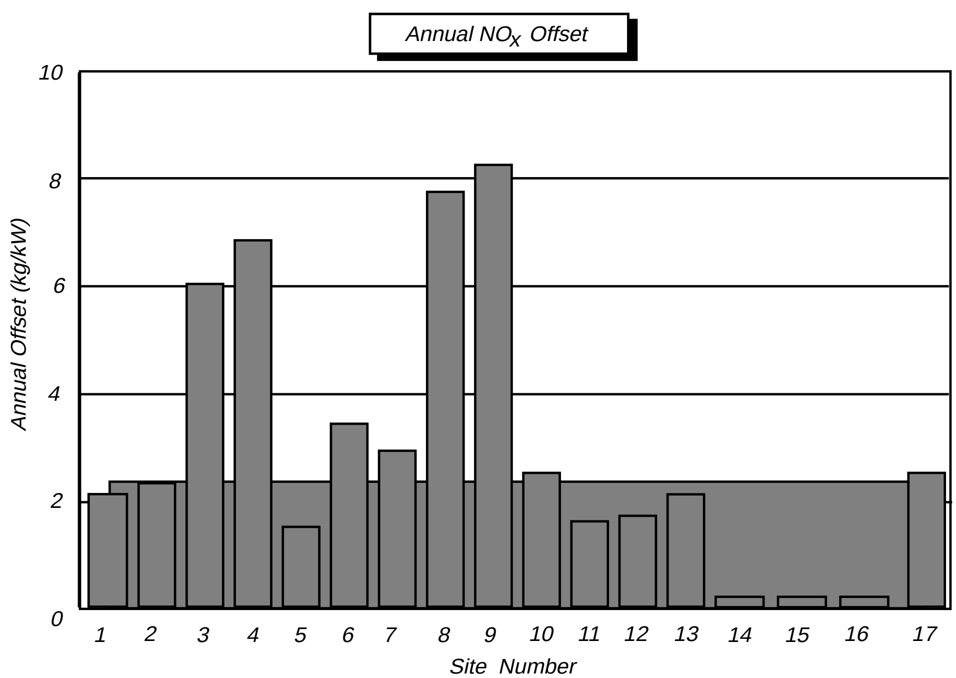

Figure 2. *Annual NO_x offsets.*

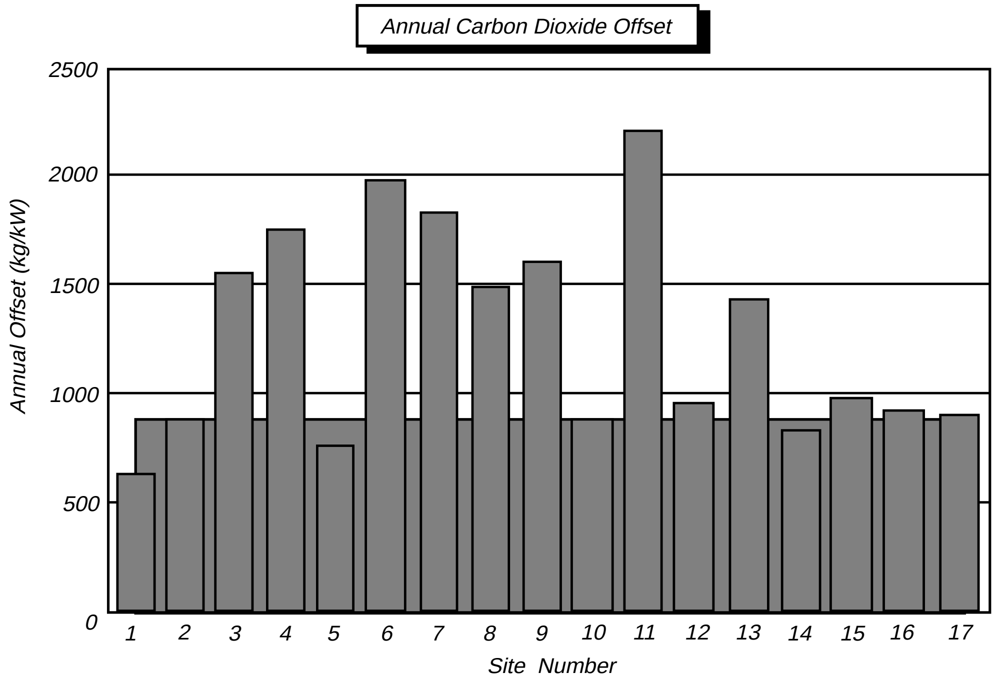

Figure 3. *Annual CO_2 offsets.*

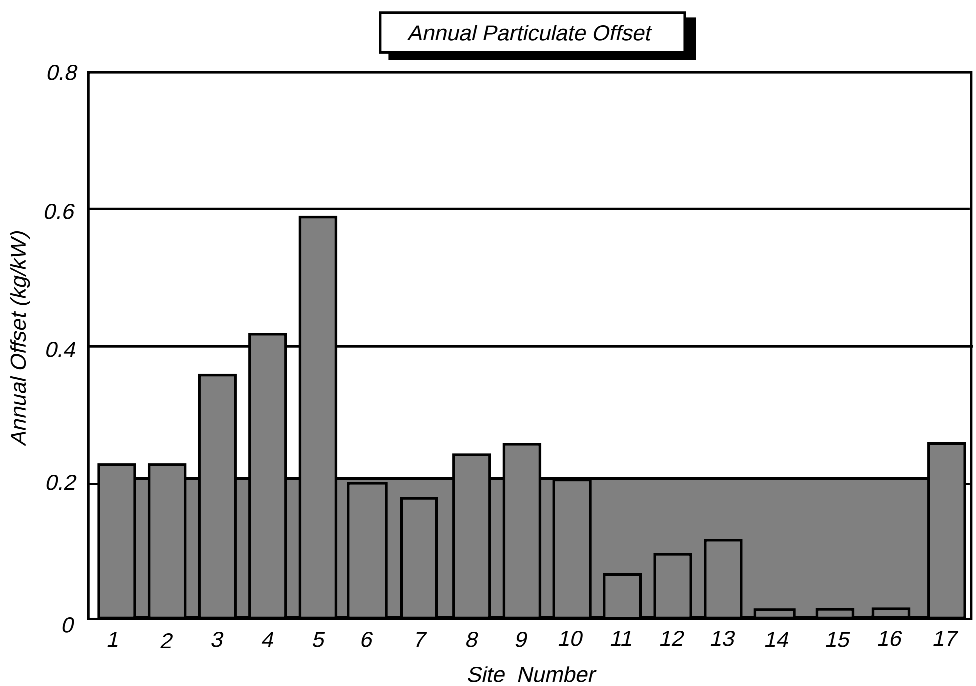

Figure 4. *Annual particulate offsets.*

indicate the PV system's ability to reduce building peak loads.

As one would expect, reductions in net building load were generally higher in the summer months and lower in the winter months, with the difference being particularly pronounced for systems installed in northern states. Most systems reduced the building's LDC by more than 50% of system AC rating during the highest load hours in the second and third quarters of the year. In the winter months, PV output during building peak load hours dropped below 10% of rating for some systems, although many systems in the southern and western states performed as well or even better during winter peak load hours.

Two general conclusions may be drawn from the analysis. The first is the relatively self-evident conclusion that, if reduction of customer net demand is the primary motivation for the installation of a PV system, it is critical to investigate the correlation of building peak loads to solar irradiance. The set of host buildings participating in this project included some with loads which were very well matched to the solar resource as well as some for which the match was very poor. The systems in Ashwaubenon, WI, and Scottsdale, AZ, are examples of systems which reduced host building LDCs by a substantial fraction of their SOC rating. The highest loads in these buildings occurred during midday hours, when the solar resource peaks. The systems in Barstow, CA, and Denmark, WI, on the other hand had very little effect on the host building's LDC, despite ample solar resource. Many of the highest building loads at these sites occurred near or after sunset.

The second general conclusion to be drawn from the data is that the generation by a PV system during an individual building's peak load hour provides little information regarding that system's ability to reduce the building's peak monthly load, or to reduce demand charges. Even if the system generates at full power during the monthly peak, there may be hours during which building load is slightly below the monthly peak and during which the PV system operates at a much lower level. In such cases there may be very little change in the building's net LDC and correspondingly small changes in demand charges. The monthly peak load will have simply been shifted to another hour.

Utility Coincident Peak Load Reduction

Each PV system's ability to provide power during utility peak load hours was analyzed by simultaneously sorting hourly PV generation data and hourly utility load data in descending order, with utility load level determining the sort order. The result was a utility load duration curve with a value of PV generation for each corresponding hour on the LDC. A "cumulative average PV capacity factor curve" (CACF curve) was then created by dividing each hourly PV generation value by the system's capacity rating (resulting in hourly capacity factors) and then averaging each hour's capacity factor with the capacity factors of all hours higher in the sort-order (i.e., all hours in which utility load was higher). The resulting curve illustrates the PV system's average capacity factor for the highest n load hours, where n is read off the ordinate.

By plotting this curve on the same axes as the normalized LDC, one can determine for each point on the LDC, the average PV system capacity factor for all hours up to and including that hour. For example, the CACF curve in Figure 5 indicates that the PV system's average capacity factor during the utility's 10 highest load hours was about 40%. CACF curves were calculated using both measured PV system performance data and the performance data generated by the dispatchable storage simulation.

Charts displaying the utility LDC and the PV system's CACF curves (both with and without storage) were created for each calendar quarter during the study period. An additional chart showing the same data for the 100 highest load hours encountered during the study period was also created. These charts provide a measure of each PV system's peak shaving capacity.

Load Reduction Without Storage

Not surprisingly, load matching for PV systems installed in northern states is greatest in the spring and summer months, with the capacity factor during the highest load hours typically averaging above 40%. Several of these sites achieved capacity factors well in excess of 60% of their SOC rating during the highest load hours in these months. The northern systems invariably generated little or no power during winter peak hours, most or all of which occurred at night.

Utility peak loads in the southern and western parts of the U.S. invariably occurred during the summer months when the solar resource is greatest, although these peaks consistently occurred in the mid- to late-afternoon. Most of the systems installed in these regions operated at capacity factors in excess of 40% during the highest load hours in the summer months. Some systems consistently operated at capacity factors above 60% during these hours. The one exception to this is the system in Flagstaff, AZ, which operated at only about 30% capacity factor during the peak load hour. This low result is most likely explained by the fact that the load and weather patterns in Flagstaff

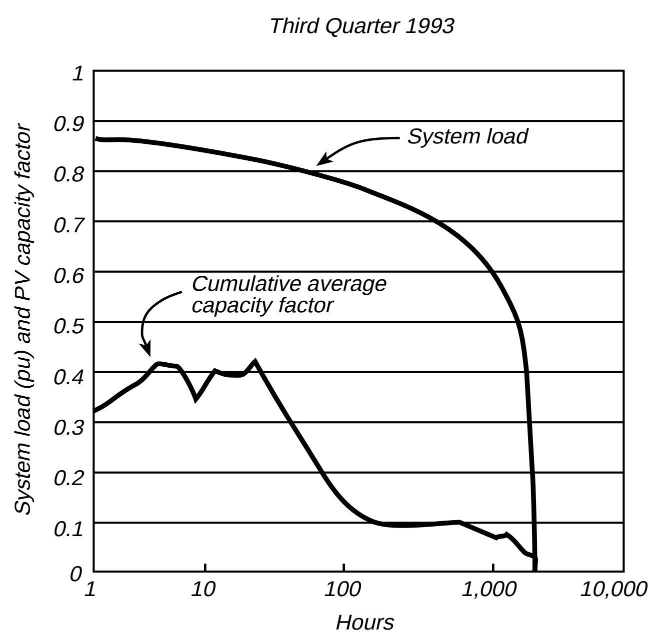

Figure 5. *Example utility load duration and cumulative average capacity factor curves.*

are quite different from those in Phoenix which is about 1 mi (1.6 km) lower in elevation and 140 mi (225 km) south. Loads in the Phoenix area probably dominate the APS system load.

As did their counterparts in the Midwest and Northeast, systems in the southern and western states typically operated at a lower level during winter peak hours. Except for systems in southern California, systems in the West operated at or near a zero % capacity factor during peak hours in the first quarter of the year.

Load Reduction With Storage

Except where the power output was limited by a system outage, results from the storage simulation indicate that storage can provide system operation at the full inverter rating during the peak load hours in the summer months at all sites. In regions (such as the NU service area) where peak utility loads are highly correlated to the solar resource, the addition of a dispatchable storage system may do little to improve the PV system's load matching capability, since it will already be quite good. Systems in northern states are much less able to provide power during peak load hours in winter due to their limited solar resource and snow cover. Even with storage, some of these systems were unable to provide power at more than a few percent of inverter rating during winter peak load hours. However, daytime generation at other northern sites was sufficient to allow inverter operation well in excess of 50% of inverter rating during winter peak hours.

Unlike many systems installed in northern climates, the addition of dispatchable storage to systems installed in the southern and western states would allow them to operate at high capacity factors during winter peak hours. The results of the simulation indicate that most of the systems installed in this part of the U.S. would operate at or near 100% of inverter rating during the highest winter load hours.

It is important to recognize that these results are substantially determined by the storage charging/dispatch algorithm. An algorithm which stores generation from 1 or more days and dispatches only when load exceeds a predetermined threshold (as opposed to dispatching during the peak hours of each day) might substantially improve the load matching characteristics of all systems.

Conclusions

This project has provided an initial demonstration of the effectiveness of grid-connected PV energy systems in reducing the pollutant emissions of electric utilities. The broad range of emission offsets achieved by these systems reflects differences in both the available solar resource at each site and differences in emission rates among utilities. The results demonstrate that the latter factor is far more important in determining the pollution mitigating potential of a PV system than is the former. Given current and projected costs of PV systems, it is unlikely that this technology will be employed solely for its pollution mitigating potential. While there is certainly substantial value in this potential, PV's environmental benefits must be considered in conjunction with the other benefits provided by the technology for grid-connected applications to be considered cost-effective. These benefits include conventional energy and power benefits as well as more subtle and less well-recognized advantages over central-station generators.

The report documents case studies of the peak load reduction benefits, for utilities and for individual customers at sites across the country. While PV will not provide substantial power during peak load periods at every location, it will at many, with or without storage. If a PV system is interconnected on the customer side of the meter, this translates into energy- and demand-charge savings. On the utility side of the meter, distributed generating resources such as PV which provide power during peak load hours can defer costly and under-utilized additions to generation and transmission capacity. In addition, every kilowatt-hour generated by a PV system reduces utility fuel and variable operation and maintenance costs.

As the electric utility industry enters the world of retail competition, the high cost of providing power during peak hours is likely to be much more clearly reflected in the prices paid by consumers. The value provided by resources such as PV that generate power during such times is therefore likely to increase substantially for customers that cannot alter their consumption patterns, and for utilities hoping to retain such customers.

Retail competition at the generation level will also bring the costs of maintaining the transmission and distribution (T&D) system under closer scrutiny. Already, several studies have demonstrated that such costs are not homogeneous across a service area, but are typically highly differentiated. Communities in which load growth necessitates an increase in the power delivery capacity of local distribution resources may have T&D costs many times the average for the utility service area. In such areas distributed generating resources such as PV might defer or eliminate the need for T&D capacity additions, to the degree that they are able to provide power at the time when the existing distribution system is stressed.

In addition to its environmental, energy, and capacity benefits, PV technology possesses a variety of characteristics which, although less easily quantifiable, contribute additional real value. Among these are (1) its reliance on a limitless, indigenous resource, which could reduce growing dependence on imported oil; (2) its modularity and speed of installation, allowing generating capacity to be added as needed rather than tying up large amounts of capital in conventional power plants, the need for which may not materialize; (3) the relative ease of siting PV power plants, as opposed to the permitting hurdles and public opposition that utilities typically encounter in attempting to site conventional power plants and transmission lines; and (4) its ability to fulfill consumers' desire for non-polluting, renewable resources, which may have strategic value to utilities in addition to environmental benefits.

Taken collectively, the benefits of grid-connected PV power may already outweigh its costs in some applications. As PV costs continue to decline, the range of such applications is certain to grow, but much work remains in the effort to fully quantify the benefits of the technology. Projects such as the one this report documents are an essential component of that effort.

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The complete report, entitled "Demonstration of the Environmental and Demand-side Management Benefits of Grid-connected Photovoltaic Power Systems," (Order No. PB97-117618; Cost: $41.00, subject to change) will be available only from:

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