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DEMONSTRATION OF THE ENVIRONMENTAL AND DEMAND-SIDE MANAGEMENT BENEFITS OF GRID-CONNECTED PHOTOVOLTAIC POWER SYSTEMS

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Abstract This study investigated the pollutant emission reduction and demand-side management potential of 16 photovoltaic (PV) systems installed across the US during 1993 and 1994. The US Environmental Protection Agency (EPA) and 11 electric power companies sponsored the project. This article presents results of analyses of each PV system's ability to offset power plant emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2) and particulates and to provide power during peak demand hours for the individual host buildings and peak load hours for the utility. The analyses indicate a very broad range in the systems' abilities to offset pollutant emissions, due to variation in the solar resource available and the emission rates of the participating utilities' load following generation plants. Each system's ability to reduce building peak demand 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. © 1998 Elsevier Science Ltd. All rights reserved.

1. 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 grid-tied PV power systems 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 probably 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 PV systems remains too expensive to compete with conventional power sources in most grid-connected applications, there is a broad market for 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 has the potential to greatly expand the grid-connected market. Heightened public awareness of the threats to environmental quality posed by the by-products of electricity production has begun to establish a niche market for grid-connected systems. The most notable concern today is the possibility that emission of 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 (Oppenheim, 1995; Farhar, 1996) 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 in the 21st century.

The potential environmental benefits from PV power generation are quite large. If PV systems were installed where possible on the rooftops on the US 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 US account for approximately 34% of the CO_2, 67% of the SO_2 and 37% of the NO_x emissions into the atmosphere from controllable sources within the US. [This estimate is derived from estimates of floor space in residential, commercial and industrial buildings (US Department of Commerce, 1992), assumptions about the ratio of roof space to floor space in each type of building and the assumption that 25, 35 and 45%, respectively, of the available roof area of residential, commercial and industrial buildings would be useable for PV installation.]

2. EPA PV PROJECTS

For grid-connected PV systems, the most immediate opportunity is on the customer side or demand side of the meter, where the customer's peak demand can be partially met using PV systems. For example, in some utility service areas effective summer peaking rates, taking into consideration both an energy and a demand charge, range to over 40 cents per kWh. This implies that demand-side PV used to reduce peak building loads might be cost effective at today's PV prices. Additional PV value can often be found where PV offsets requirements for new investment in electric transmission and distribution equipment.

EPA began a program in August 1992 to demonstrate the technical and economic viability of utility-connected PV systems for demand-side management (DSM) power supply and pollution mitigating energy replacement for fossil fuels. The general objective of the program is to document the electric power production, especially the peak power reduction capability and pollution prevention attained by rooftop PV systems installed on residential, commercial and military buildings located in diverse geographic areas in the US. The installations incorporate improved PV system design to achieve ease of installation, safety and electrical code compliance.

Once installed, the PV systems are monitored for 1 year. Two primary data sets are being recorded at 15 min intervals for each PV system: energy produced by the PV system and energy demanded by the host building. The data are transferred daily from the sites across the country to a central data gathering facility. Each morning the 15 min data files are reviewed for proper system performance and then aggregated into hourly averages and are later merged with additional data provided by utilities. To verify the performance of the PV array and the data acquisition system, both a plane of array irradiance pyranometer and a rotating shadowband pyranometer have been installed to measure global, direct and diffuse irradiance. This allows for crosschecking system performance through the use of array and power conditioner simulation algorithms. It also verifies the translation algorithm from direct normal and diffuse irradiance to plane-of-array irradiance, an essential tool in the translation of the results of the project to other potential PV system designs and to sites with similar solar resource data. Participating utilities provide hourly records indicating which load-following power plants (marginal or "swing" plants) are operating as well as total utility system load. They also supply emissions data for their load-following generating stations. Currently the project tracks CO_2, NO_x, SO_2 and particulate emissions.

Power plant emission rate and system 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.

To date, 30 systems have been installed at various sites throughout the US, including Hawaii. The locations of these systems include all but one of the North American Electric Reliability Council districts (the East Central Reliability Council being the exception). The combined DC capacity of the systems is 368 kW. This article summarizes the results for the first 16 systems; a more detailed description can be found in the project final report (Kern and Greenberg, 1996).

In September 1991, the EPA issued a cost-shared solicitation for the installation of the first 16 grid-tied PV systems with the goal of measuring their environmental and demand-side benefits. The 11 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 up-state 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 north-eastern 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) the 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.

3. PROCEDURE

3.1. System design

Designs were developed for nominal 4 kW "building block" PV systems for this project, capitalizing on Ascension Technology's experience with roof-mounted PV arrays. The majority of the projects sites use either one system (4 kW) or a group of three systems (12 kW nominal total). This project was the first nationwide program to install PV systems of a common design and, as a result of this project, standards for PV ratings and electrical codes have been widely implemented. The nominal system size refers to the inverter AC rating. The actual power output of the 4 kW building block 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 3.5 kW AC.

The PV modules in these systems are Siemens model M55j. Figure 1 shows the schematic of a "nominal" 4 kW PV system in which the PV arrays were configured using 12 PV panel assemblies comprised of seven modules. System design details were developed in close cooperation with Siemens Solar Industries. To expedite field wiring, the PV panel assemblies were prepared with single-pole quick-connectors. Alden Products manufacture these connectors. Alden fabricated connector cables in specified lengths, using 10 AWG type USE-2 cable. The connector cable assemblies were shipped to Siemens for factory rewiring of PV panel assemblies. When shipped, each PV panel assembly had two connector cables: a plug (overall positive) and a receptacle (overall negative). In the field, connecting PV panel assemblies in series simply required mating the connectors from adjacent panels. Source circuits are bi-polar with balanced voltages above and below a neutral or center-tap conductor. The Omnion power conditioner requires this three-wire configuration at approximately ± 250 V DC. The wiring in each bi-polar PV array source circuit terminates at a source circuit protector. A 4 kW array contains three source circuit protectors, one for each row of four PV panel assemblies (see Fig. 1). The source circuit protector performs important electrical safety functions and makes array wiring convenient. The source circuit protector contains two connector cables for interconnection to the array groups that form the bi-polar source circuit, blocking diodes to prevent reverse current flow and a surge suppressor to shunt lighting-induced surges to ground. The source circuit protector was designed and developed specifically for this project and proved to be a convenient wiring interface. Field wiring within the array terminates at the source circuit protectors. To finish the array wiring, each host utility contracted an electrician to provide and install conductors inside conduit between the source circuit protectors. This wiring connects the three source circuits in parallel to form the PV array output. PV array output wiring is placed in conduit and connected to the "power panel" inside the host building, where disconnect switches, the omnion inverter and metering equipment are located. PV panel assembly frames, Roofjacks and ballast trays are bonded together by the equipment ground wiring, which also terminates at the PV source circuit protector.

3.2. Mounting hardware

One of the objectives of the project was to simplify the mechanical attachment of the PV

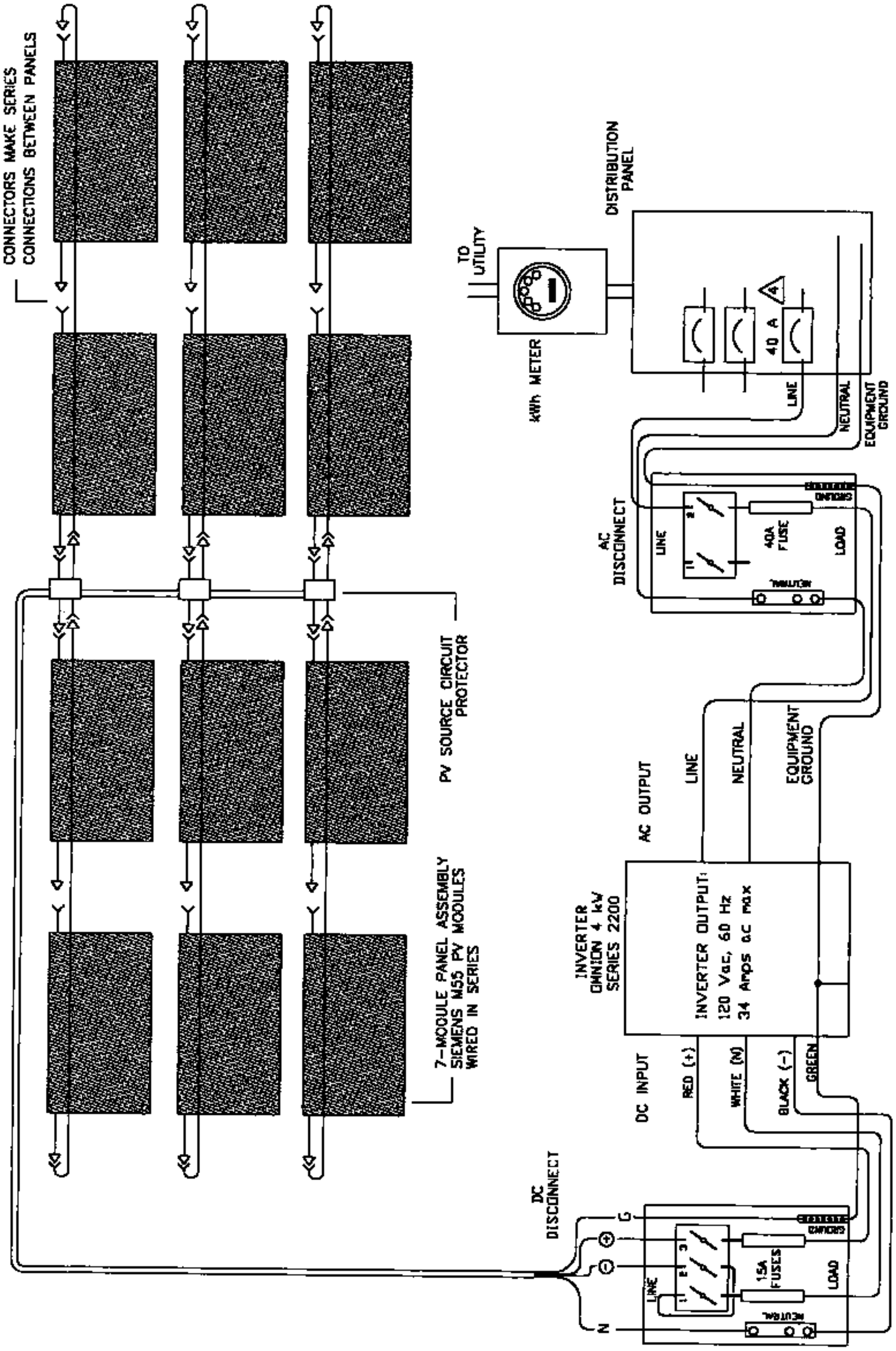

Fig. 1. Schematic of a 4 kW PV system.

arrays to the rooftop surface. To that end, a "RoofJack" (Kern and Greenberg, 1996) mounting system was employed and refined. This mounting system effectively reduces materials and field labor. Roofjacks for a pitched roof are aluminum "L" and "U" shaped brackets, which support PV panel assemblies at four points, keeping the planar PV panels parallel to the existing roof. An air gap of several inches, between the panels and roof, helps promote array cooling (to the benefit of conversion efficiency).

Flat-roof installations use an adaptation of the Roofjacks, designed to work with ballast trays. The flat-roof Roofjacks provide a tilt angle of 15°. Galvanized steel trays, 94.5 by 46 in. (240 × 117 cm), were designed to be placed end-to-end in rows. Prior to placement, a Roofjack was bolted to the tray. When laid out, the spacing of the Roofjacks was precisely as required to match the pin spacing of the PV panels. The overall design allows reasonable tolerances to accommodate variations in all dimensions. Crews shoveled gravel or placed other ballast in the trays to prevent them from moving. With the ballast in place, the PV panel assemblies were installed. Preparations for flat roofs varied and depended upon a roof's specific composition and type. In all cases, roofers were consulted regarding flat-roof array installation procedures.

3.3. *Power conditioning equipment*

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. Electricians mounted the inverters) on 3/4 in. (1.9 cm) plywood attached to a convenient wall space near the point of interconnection to the building electrical service. Output from the inverter passes through a kilowatt-hour meter, equipped with a pulse initiator tied into the datalogger for the site. The AC output of the PV system ties into the building electrical service through a 40 A 120 V circuit breaker, in a convenient distribution panel. At sites with three systems, a three-phase system is formed. The separate 120 V AC outputs from the three PV systems feed into a single 120/208 V AC three-phase circuit breaker, providing a balanced interconnection.

3.4. *Monitoring instrumentation*

Standardized instrumentation was included with each of the 16 PV system sites, to measure meteorological and PV system performance variables. A Campbell Scientific CR10 datalogger lies at the heart of the instrumentation systems. The baseline instrumentation is described in Table 1. A rotating shadowband pyranometer (RSP) simplifies the measurement of the components of sunlight: direct beam irradiance (coming from the solar disk), diffuse horizontal (coming from rest of the sky, excluding the solar disk) and global horizontal (all irradiance on a surface of any orientation, fixed or tracking). Irradiance and temperature measurements are made once per second, averaged over a 15 min period. Electric power production was measured with pulse initiating watt-hour meters. The datalogger was used to count pulses over the 15 min intervals, convert the pulse counts to their energy values and store them along with the irradiance and temperature for retrieval later. The accuracy of the irradiance measurements is limited by the pyranometer's 3–5% uncertainty. Typical watt-hour meters have 0.3% uncertainty.

Wisconsin Public Service Company and Southern California Edison Company purchased additional instrumentation to monitor their PV arrays. At these sites, transducers were added to measure PV array DC current and voltage. This extra instrumentation allows calculation of PV array and inverter efficiencies. More importantly, it has been useful for developing PV system models and troubleshooting PV systems.

3.5. *System costs*

The installations in this project are based on a nominal 4 kW [3895 WDC at PVUSA Test Conditions (PTC) of 1000 W/m^2 irradiance and 20°C ambient temperature] system consisting of 12 PV panels, one inverter and balance-of-system components including Roofjacks, ballast trays (flat roofs only), panel-to-panel wiring, row junction boxes and DC disconnects. The 12 kW systems are made using three identical 4 kW rated systems. The major part of the cost consists of the hardware costs presented in Table 2, which are constant for all installations.

In addition, each system has installation costs that are specific to the individual site. These costs include permits, transport of the materials to the roof, preparation of the roof to receive the trays, buffer materials used between the trays and the roof, installation of the trays, panels, electrical connections, wiring, meters, miscellaneous electrical materials and shipping of the PV panels, the power conditioners, the

Table 1. Instrumentation of the PV systems

Variable	Sensor
AC kilowatt-hours produced by the PV system	Pulse-initiating kWh meter (supplied by utility)
AC kilowatt-hours used in the host building	Pulse-initiating kWh meter (supplied by utility)
Plane-of-array irradiance	LiCor 200 Sz pyranometer mounted in plane of array
Direct normal irradiance	Ascension Technology Rotating Shadowband Pyranometer
Global horizontal irradiance	Ascension Technology Rotating Shadowband Pyranometer
Horizontal diffuse irradiance	Ascension Technology Rotating Shadowband Pyranometer
Ambient air temperature	Thermistor housed in a radiation shield

Table 2. Hardware component costs

	Flat roof	Pitched roof
PV panels	$22 698	$22 698
Power conditioner	$3456	$3 456
BOS (includes trays/roofjacks)	$2200	$820
Total hardware cost	$28 354	$26 974

ballast trays, RoofJacks and PV source circuit protectors. To determine total cost, the hardware costs in Table 2 are combined with the site-specific costs. The total costs for each system are summarized in Table 3. The cost of the data acquisition equipment, site specific engineering and testing fees and any untypical construction work associated with the installation (for example, removal of a skylight, addition of a roof hatch) are not included in the total system cost. Salaries for utility personnel time attributed to project administration are not included. However, when utility electricians and other personnel directly participated in the installation, the cost of their services is included in the total cost.

4. PV SYSTEM PERFORMANCE HISTORY

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.

Of the 16 PV systems installed by this project, all but two experienced problems during the study period that temporarily limited system output or prevented generation altogether (Kern and Greenberg, 1996). Inverter-related problems were the most vexing of the generation-limiting events. In all, 27 inverter-related problems resulted in an estimated generation loss of 12 740 kWh, approximately 9% of the combined generation of those systems over the relevant time periods.

This first nationwide program to install distributed rooftop PV systems identified many areas for improvement in subsequent efforts to develop similar systems. As a result of the inverter-related outages experienced in this project, the inverter manufacturer (Omnion) 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 systems located in northern locations or at high altitudes. Of the systems in such locations, the estimated energy loss as a result of snow cover ranged from less than 1–16% of measured annual generation. This snow accumulation and retention for extended periods on flat-roof installations in the northeast and Great Lakes regions was due to the low profile and shallow tilt angle of the PV arrays. The "roof-hugging", 15° tilt-angle design was primarily prompted by consideration for wind loading of the ballast-mounted arrays. Snow shedding can be improved by increasing the tilt angle and raising the arrays, but at the expense of increased wind loads. In subsequent projects the angle has been raised to 25°.

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 have failed.

5. RESULTS

5.1. Pollutant emission offset

Models of marginal emission rates (i.e. emission rates of load following units) were devel-

Table 3. System cost summary

Site	Roof Type	Hardware cost	Instalation cost	Shipping cost	Total cost	Cost/AC Watt[a]
1. NYSEG Plattsburgh, NY 12 kW	Ballasted flat, protected membrane	\$85 062	\$15 351	\$1500	\$101 913	\$9.69
2. NU Berlin, CT 4 kW	Ballasted flat	\$28 354	\$7113	\$500	\$35 967	\$10.26
3. ACE Pleasantville, NJ 12 kW	Flat, modified bitumen	\$85 063	\$18 755	\$1180	\$104 997	\$9.98
4. ACE Brigantine, NJ 4 kw	Pitched asphalt shingle	\$26 974	\$3804	\$320	\$31 098	\$8.87
5. NYPA White plains, NY 4 kW	Ballasted flat, protected membrane	\$28 354	\$6280	\$560	\$35 194	\$10.04
6.APS Scottsdale, AZ 8 kW	Flat, lightweight concrete	\$56 708	\$6177	\$1302	\$64 187	\$9.16
7. APS Peoria, AZ 4 kW	Pitched asphalt shingle	\$26 974	\$4069	\$301	\$31 344	\$8.94
8. APS Flagstaff, AZ 4 kW	Ballasted flat	\$28 354	\$3526	\$318	\$32 198	\$9.19
9.WPS Ashwaubenon, WI 12 kW	Ballasted flat	\$85 062	\$14 616	\$1359	\$101 037	\$9.61
10. WPS Denmark, WI 4 kW	Pitched asphalt shingle	\$26 974	\$4001	\$257	\$31 232	\$8.91
11.NSP Minnetonka, MN 4 kW	Flat, modified bitumen	\$28 354	\$9007	\$600	\$37 961	\$10.83
12. PG and E San Ramon, CA 12 kW PV mechanically attached	Flat, lightweight concrete with mineral cap	\$85 062	\$17 800 (\$10 800–11 800 without tether)	\$2024	\$104 886	\$9.98 (\$9.31–9.40 without tether)
13. COA Austin, TX 12 kw	Flat, modified bitumen	\$85 062	\$10 890	\$1566	\$97 518	\$9.27
14. SCE Barstow, CA 4 kW	Pitched asphalt shingle	\$26 974	\$3788	\$102	\$30 864	\$8.81
15. SCE Edwards AFB, CA 4 kw	Pitched asphalt shingle	\$26 974	\$4100	\$92	\$31 166	\$8.89
16. SCE Palm Desert, CA 12 kw	Flat, Butler system, no ballast trays	\$81 651	\$14 825	\$220	\$96 696	\$9.20

[a]Cost/AC watt is based on each system's AC rating at standard operating conditions (SOC), which is calculated as follows: plane of array irradiance, 1000 W/m^2; ambient temperature, 20°C; cell temperature, 50°C; efficiency degradation coefficient, 0.417%/°C; inverter full-load efficiency, 90%; 4 kW (nominal) DC array rating at SOC, $4452\times[1-(50-20)\times0.00417]=3895$ W DC; 4 kW (nominal) system AC rating at SOC, $3895\times0.90=3505$ WAC.

oped 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 to determine hourly emission offsets. These results take into account an enhancement that results from utility specific savings in transmission and distribution losses. A kilowatt hour generated on site will probably displace 1.05 to 1.10 kWh at a power plant.

Annual emission mitigation values are presented in Figs 2 5. More detailed monthly emission offsets for each site can be found in Kern and Greenberg (1996). Annual SO_2 offsets ranged from 4 g to 16 kg per kilowatt of PV system capacity, rated at standard operating conditions (SOC) of 1000 W/m^2 irradiance and 20°C ambient temperature. (Note: throughout the remainder of this paper, annual emission mitigation by PV systems is reported in terms of grams or kilograms per kilowatt of PV capacity, g/kW or kg/kW.) NO_x offsets ranged from 110 g/kW to 8.7 kg/kW. The range in annual CO_2 emission offsets was from 700 g/kW to 2300 kg/kW of system rating and that for particulates was 20 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 insulation, using average US emission rates based on data collected by the Energy Information Administration for 1993 (Office of Air Quality Planning and Standards, 1994).

The high 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

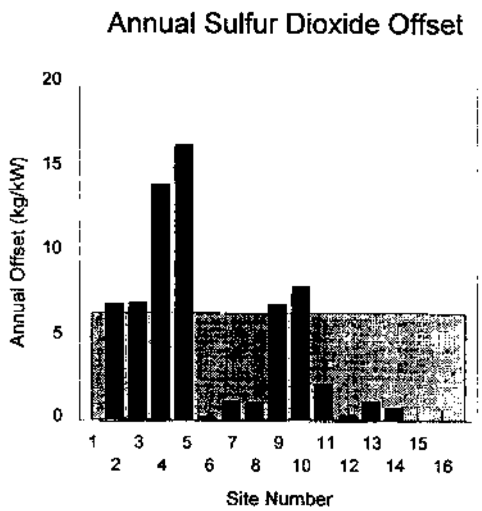

Fig. 2. Annual sulfur dioxide offset.

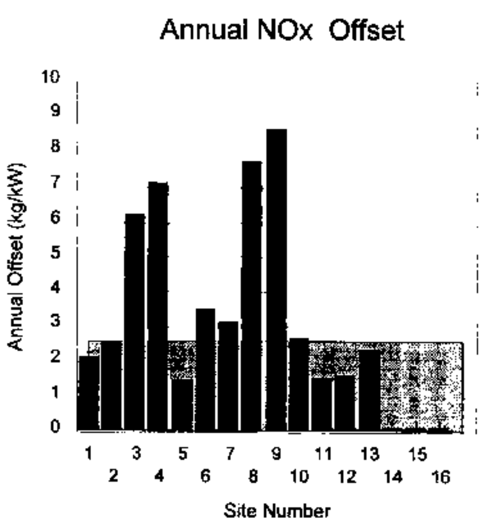

Fig. 3. Annual NO_x offset.

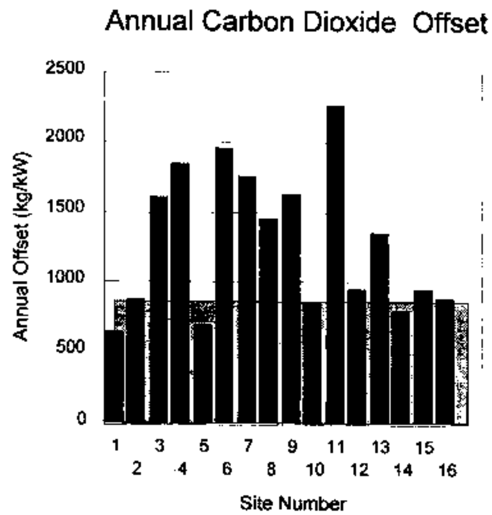

Fig. 4. Annual carbon dioxide offset.

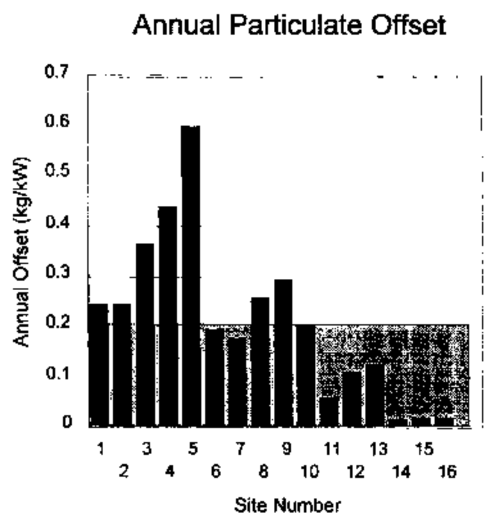

Fig. 5. Annual particulate offset.

than (1), as can be seen by comparing the range for CO_2 to those for the other pollutants. Since there are currently no mitigation measures for CO_2, variation in utility CO_2 emission rates is due only to relatively small (about 2:1) variation in the carbon content of fuels used and variation in the heat rates of the power plants. The ratio of the highest to lowest annual offset is relatively small (3.3:1). For the other pollutants, variations in the pollutant content of the fuel as well as interutility 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.

5.2. *Building-level load reduction*

The monthly peak impact investigation was straightforward: for each of the 15 months in the study period, the date and time of the peak gross load for each of the host buildings were determined. The average power generation by the PV system during that hour was determined, both in kilowatts and as a percentage of each PV system's capability under standard operating conditions (SOC). The results of this analysis are illustrated by bar charts such as the examples for the Brigantine, NJ, site in Figs 6 and 7 (see Kern and Greenberg, 1996 for detailed results for all sites).

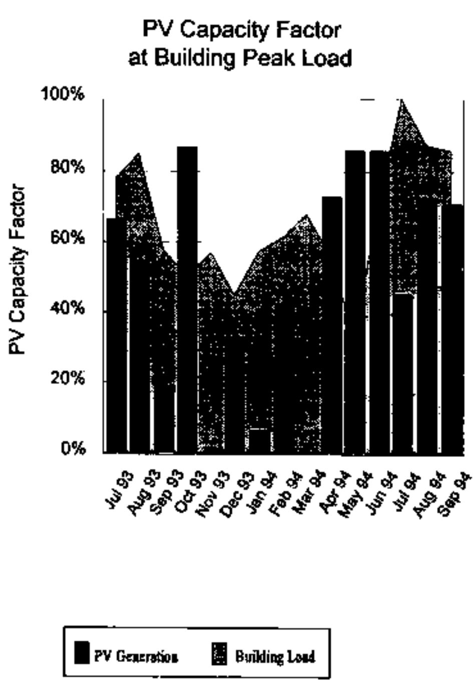

Fig. 6. PV capacity factor at building peak load (example is for Brigantine, NJ).

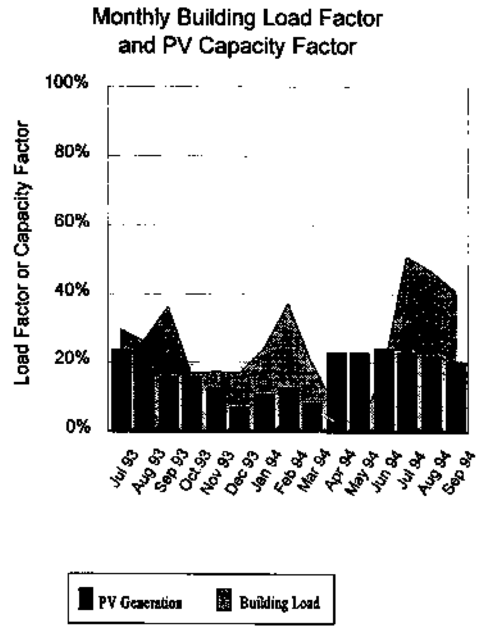

Fig. 7. Monthly building load factor and PV capacity factor (example is for Brigantine, NJ).

It is important to note that the amount of power delivered by a PV system during a building's monthly peak load hour will not, in most cases, provide an accurate indication of the amount by which the monthly peak load is reduced. The reason is that the PV system will not be operating at the same power level during all of the highest load hours in a month. If there are hours for which the gross load level is close to the monthly peak, but during which the PV output is less that during the peak hour, net load for these hours may exceed net load during the hour at which the gross load attains its monthly peak level. In this case, the reduction of peak load will not be the system's output during the peak gross-load hour, but the differences between the peak gross load and the peak net load for the month. This difference will usually be less than the PV system's output during the peak gross-load hour. The data collected for this project provide several examples.

A more comprehensive and accurate understanding of the effect of the PV systems on peak building loads can, therefore, be gained by observing the effect of the systems on building load duration curves (LDC). LDCs are constructed by sorting load values for the period of interest in descending order. The sorted hourly load values are then plotted with the load level on the ordinate and the rank order of each load value on the abscissa. The chronological continuity of the data is lost in the sorting process, but by plotting load data in this way, one can easily focus on how PV system operation affects building load during the highest building load hours.

As illustrated by Fig. 8 (data for Brigantine,

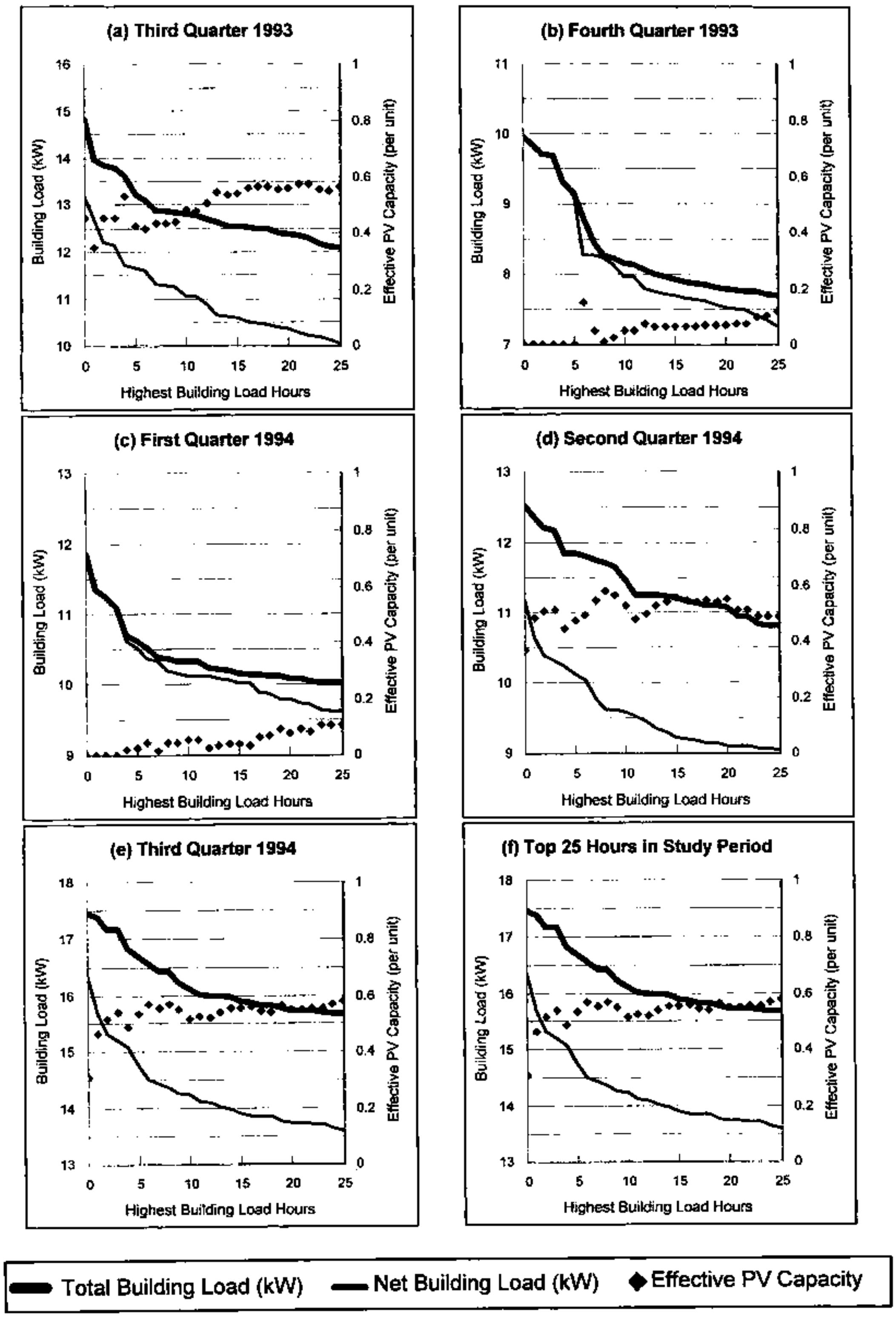

Fig. 8. Building load duration curves with and without PV (example is for Brigantine, NJ).

NJ), the PV system's effect on a building's LDC can be determined by comparing an LDC produced from gross load values to one produced from net load values, or in other words, comparing the building LDC with and without the PV system. The absolute magnitude of the difference between the gross and net LDC can be read off the scale on the left side of the figure. The diamond-shaped data points represent the PV system's effect on the building's LDC per kilowatt (SOC) of installed PV capacity. Where a difference exists between a LDC based on gross load values and one based on net load values, the PV system can be said to have reduced building load for the period in question. Unlike Fig. 6, which indicates the amount by which gross building load is reduced only at the peak load hour of each month, Fig. 8 indicates the impact of PV system operation at all hours (although only the highest load hours are shown). It is important to note that any point along the net LDC will not necessarily represent the same hour as the point immediately above it on the gross LDC. The reason for this is that gross load values must be sorted independently of net load values in the construction of these curves. Again, the goal is to compare each building's LDC with and without the PV system. The hours at which peak gross loads occur may well be very different from the hours at which peak net loads occur.

For each site there is a set of these charts for the entire study period (Kern and Greenberg, 1996). However, to present the data in their entirety in this article would be prohibitive due to the amount of data involved. Therefore, a brief analysis of the data is provided and Kern and Greenberg (1996) should be consulted for more in-depth coverage.

As would be expected, 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. Those in Ashwaubenon, WI and Scottsdale, AZ, are examples of PV systems that reduced host building LCD's 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 residential sites occurred near or after sunset.

The second general conclusion no be drawn for the data is that the generation by a PV system during an individual building's peak load hour provided 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 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.

5.3. *Utility coincident peak load reduction*

Each PV system's ability to provide power during utility peak load hours was analyzed by 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 data for the Brigantine, NY site illustrates the PV system's average capacity factor for the highest n load hours, where n is read off the ordinate.

By plotting the CACF curve on the same axes as the normalized utility 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 Fig. 9(a) for the Brigantine, NJ, site indicates that the PV system's average capacity factor during the utility's 10 highest load hours was about 40%.

Figures displaying the utility LDC and the PV system's CACF curves were created for each calendar quarter for the other sites during the study period (Kern and Greenberg, 1996). These data provide a measure of each PV system's peak shaving capacity. 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.

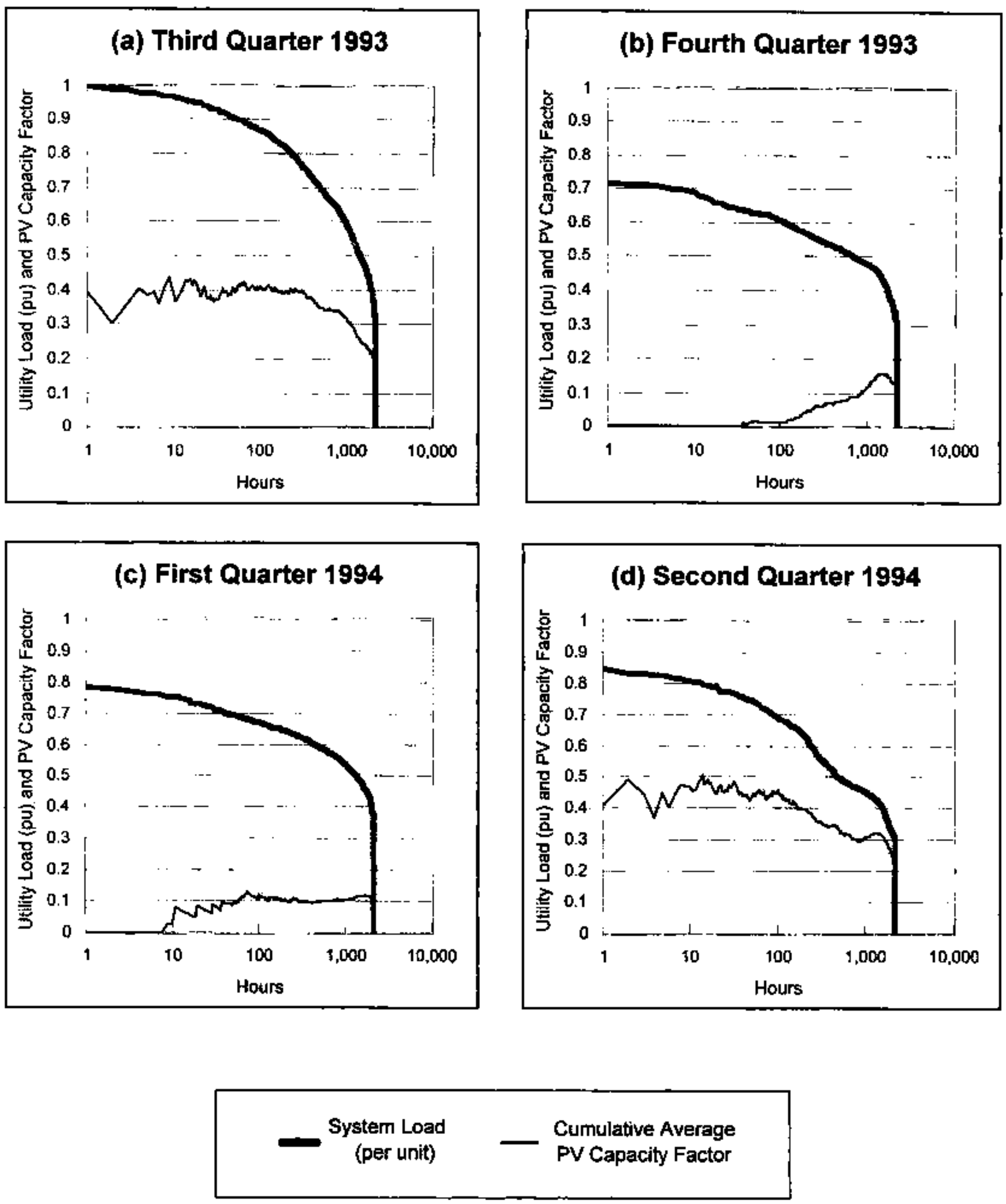

Fig. 9. Utility load and cumulative average PV capacity factor (example is for Brigantine, NJ).

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 US 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 Arizona Public Service (APS) system in Flagstaff, AZ, which operated at only about 30% capacity factor during the APS peak load hour. This low result is most likely explained by the fact that the weather patterns in Flagstaff are quite different from those in Phoenix, which is about 1 mile (1.6 km) lower in elevation and 140 miles (224 km) south, where APS has a majority of its 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 zero capacity factor during peak hours in the first quarter of the year.

6. 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 subtler and less well recognized advantages over central-station generators.

The final report (Kern and Greenberg, 1996) 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. 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, along with transmission and distribution losses.

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 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 nonpolluting, 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 article documents are an essential component of that effort.

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