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The Potential Market for Photovoltaics and Other Distributed Resources in Rural Electric Cooperatives[+]

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Abstract

Rural electric cooperatives have an aging distribution system (1 million miles of distribution wires were originally installed over 40 years ago) and a load density that is about one-tenth of the load density at other utilities. The result is that there may soon be a large market opportunity for photovoltaics (PV) and other distributed resources. This paper calculates the cost of replacing portions of the distribution system as it wears out with hybrid-PV systems, compares it to the cost of replacing the system with equivalent distribution system equipment, and selects the alternative with the lowest cost. Results suggest that there is a potential market of 500 MW to 950 MW of PV at a price of $3,000/kW and a corresponding fossil-based generation market size of 280 MW to 555 MW at a price of $1,000/kW. The hybrid-PV systems could replace 7 percent to 16 percent of the miles of distribution system and could save co-ops $1.0 Billion to $2.5 Billion (present value).

Introduction

The nation's 900 rural electric co-ops sell 8 percent of the total electricity sold and own nearly half the electric distribution lines in the U.S. (NRECA 1998). This is enough wire to circle the earth 80 times.

Despite their low customer density and high percentage of residential customers (their average load density is about one-tenth that of investor-owned and public utilities), their 1995 average revenue of $0.070/kWh is comparable to the national average rate of $0.071/kWh (RUS 1996, Table 3; EIA 1996, Table A8).

This situation, however, may be changing. As much as half of the co-ops' infrastructure was originally installed over 40 years ago (Shultz 1998); the result is that the aging distribution system may soon need replacing. When this is combined with low customer density, rural co-ops may be on the verge of an important opportunity of using photovoltaics (PV) and other distributed resources to provide electric service to their customers rather than replacing their aging distribution facilities.

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Objective

One alternative to replacing the distribution system when it wears out is to satisfy demand using distributed resources. One use of distributed resources is to support the transmission and distribution system in areas that are experiencing load growth by providing generation where the loads are occurring (Hoff 1996 and 1997). Another use is to totally replace the distribution system with the distributed resources (Hoff et. al., 1997 and 1998). This second use is the one considered in this paper.[1]

This paper addresses two specific questions. First, what is the potential market for PV and other distributed resources in rural co-op applications? Second, how much could co-ops save by investing in hybrid-PV systems rather than new distribution facilities?

Model Description

Two economic models are developed in this section to assess the market for PV and the cost savings for co-ops. The first model determines how much it will cost to serve customers by replacing the distribution system as it wears out. The second model determines how much it will cost to serve customers using a hybrid-PV system composed of PV, generators, and batteries. The models are developed in terms of the annual cost and then converted to the cost per kWh. The alternative with the lowest cost per kWh is the least cost alternative.

Distribution System Replacement Cost of Service

The annual cost of serving customers by replacing the distribution system equals the sum of:

- ***distribution system finance charge***: capital cost (includes cost of removing old equipment) in \$/mile (C_{dist}) times the number of miles of distribution system (M) times the capital recovery factor that converts the initial capital cost to an annual cost (i_{dist})
- ***distribution system O&M cost***: O&M cost in \$/mile (O_{dist}) times the number of miles of distribution system (M)
- ***electricity cost***: electricity price (P_{elec}) times electricity sold (E) times the distribution system loss factor ($1+L_{dist}$)
- ***administrative and other costs***: administrative and other costs (A) times electricity sold (E); transmission costs are included in this term because the average transmission cost is less than \$0.001/kWh and is negligible from the perspective of this analysis

$$Cost_{dist} = \overbrace{C_{dist} M_{dist} i_{dist}}^{\text{Distribution Capital Cost}} + \overbrace{O_{dist} M_{dist}}^{\text{Distribution O\&M Cost}} + \overbrace{P_{elec} E\left(1 + L_{dist}\right)}^{\text{Electricity Cost with Losses}} + \overbrace{A E}^{\text{Admin. \& Other Costs}} \tag{1}$$

[1] The distributed resources could totally replace the distribution system by either: (1) using self-contained distributed resource systems to serve each isolated load (e.g., farm, house, well, etc.); or (2) using isolated micro-grids to serve small communities (e.g., Hoff and Herig 2000). The implementation depends upon the distance between the various loads and which alternative is most cost-effective.

The capital recovery factor, $i_{dist} = \frac{(1+i)^{Life_{dist-years}} i}{(1+i)^{Life_{dist-years}} - 1}$, where i is the discount rate and $Life_{dist-years}$ is the life of the distribution system in years.

The annual cost is converted to a cost per kWh by dividing by the amount of electricity sold annually.

$$\frac{Cost_{dist}}{kWh} = \frac{\overbrace{C_{dist} i_{dist} + O_{dist}}^{\text{Distribution Capital and O\&M Cost}}}{D_{dist}} + \overbrace{P_{elec}(1+L_{dist})}^{\text{Electricity Cost with Losses}} + \overbrace{A}^{\text{Admin. \& Other Costs}} \tag{2}$$

where the load density equals the electricity sold divided by the miles of distribution system ($D_{dist} = \frac{E}{M_{dist}}$).

Hybrid-PV System Cost of Service

The annual cost of serving customers using a hybrid-PV system equals the sum of:

- ***PV finance charge***: installed capital cost in \$/kW (C_{PV}) times the PV size in kW (S_{PV}) times the PV capital recovery factor (i_{PV})
- ***generator finance charge***: installed capital cost in \$/kW (C_{gen}) times the generator size in kW (S_{gen}) times the generator capital recovery factor (i_{gen})
- ***battery finance charge***: installed capital cost in \$/kWh (C_{bat}) times the number of kWh of battery storage in hours (S_{bat}) times the battery capital recovery factor (i_{bat})
- ***PV O&M cost***: O&M cost in \$/kWh (O_{PV}) times the amount of electricity produced by the PV; the electricity produced by the PV equals the total electricity sold in kWh/year (E) times the fraction of total electricity sold that is provided by the PV (B) adjusted for the amount of energy that goes through storage (1+ Z_{PV} L_{sys}), where Z_{PV} is the percent of PV produced electricity that goes into storage and L_{sys} are round trip storage losses
- ***generator fuel and O&M cost***: fuel cost in \$/kWh (P_{fuel}) times generator efficiency (η) plus O&M cost in \$/kWh (O_{PV}) times the amount of electricity produced by the generator; the electricity produced by the generator equals the total electricity sold in kWh/year (E) times the fraction of total electricity sold that is provided by the generator (1-B) adjusted for the amount of energy that goes through storage (1+ Z_{gen} L_{sys})
- ***battery O&M cost***: O&M cost in \$/kWh (O_{bat}) times the amount of electricity produced by the PV and generator that go through storage, or $E[Z_{PV} B + Z_{gen} (1-B)]$
- ***administrative and other costs***: administrative costs in \$/kWh (A) times the electricity sold (E)

$$
\begin{aligned}
Cost_{sys} = & \overbrace{C_{PV} S_{PV} i_{PV}}^{\substack{\text{PV}\\ \text{Capital Cost}}} + \overbrace{O_{PV} E\left(1 + Z_{PV} L_{sys}\right) B}^{\substack{\text{PV}\\ \text{O\&M Cost}}} \\
& + \overbrace{C_{gen} S_{gen} i_{gen}}^{\substack{\text{Generator}\\ \text{Capital Cost}}} + \overbrace{\left(P_{fuel}\eta + O_{gen}\right) E\left(1 + Z_{gen} L_{sys}\right)\left(1 - B\right)}^{\substack{\text{Generator}\\ \text{Fuel and O\&M Cost}}} \\
& + \overbrace{C_{bat} S_{bat} i_{bat}}^{\substack{\text{Battery}\\ \text{Capital Cost}}} + \overbrace{O_{bat} E\left[Z_{PV} B + Z_{gen}\left(1 - B\right)\right]}^{\substack{\text{Battery}\\ \text{O\&M Cost}}} + \overbrace{A E}^{\substack{\text{Admin. \& Other}\\ \text{Costs}}}
\end{aligned}
\tag{3}
$$

Table 1 presents the constraints to which Equation (3) is subject. The constraints are that the PV/generator system delivers enough electricity to satisfy the annual demand and the storage losses. All variables are non-negative and the result must be greater than or equal to 0 (i.e., *B* is between 0 and 1); *F* is the annual capacity factor.

Table 1. System constraints.

Electricity from PV	Electricity from Generator
$\overbrace{S_{PV} F_{PV} 8{,}760}^{\text{Electricity from PV}} = E\left(1 + Z_{PV} L_{sys}\right) B \geq 0$	$\overbrace{S_{gen} F_{gen} 8{,}760}^{\text{Electricity from Generator}} = E\left(1 + Z_{gen} L_{sys}\right)\left(1 - B\right) \geq 0$

The capital recovery factors (*i*) are a function of the discount rate and technology life. The discount rate is the same for all technologies but the life can vary. PV system life is fixed because it is non-dispatchable while the generator and battery lives depend upon how they are operated. $\overline{S}_{bat}$ is defined to be the hours of storage at average load. The life calculations (in years) are presented in Table 2.

Table 2. Component life.

PV	Generator	Battery
$Life_{PV}$	$Life_{gen-years} = \dfrac{Life_{gen-hours}}{F_{gen} 8{,}760}$	$Life_{bat-years} = \dfrac{\overline{S}_{bat} Life_{bat-hours}}{\left[Z_{PV} B + Z_{gen}\left(1 - B\right)\right] 8{,}760}$

The hybrid-PV system cost in $/kWh is obtained by substituting the constraints, capital recovery factors, and component lives into Equation (3) and then dividing by the energy sold (*E*).

$$\frac{Cost_{sys}}{kWh} = \overbrace{\left(\left[\frac{C_{PV}}{F_{PV}8{,}760}\right]\left[\frac{i(1+i)^{Life_{PV}}}{(1+i)^{Life_{PV}}-1}\right]+O_{PV}\right)\left(1+Z_{PV}L_{sys}\right)B}^{\text{PV Cost}}$$
$$+\overbrace{\left(\left[\frac{C_{gen}}{F_{gen}8{,}760}\right]\left[\frac{i(1+i)^{\left(\frac{Life_{gen-hours}}{F_{gen}8{,}760}\right)}}{(1+i)^{\left(\frac{Life_{gen-hours}}{F_{gen}8{,}760}\right)}-1}\right]+P_{fuel}\eta+O_{gen}\right)\left(1+Z_{gen}L_{sys}\right)(1-B)}^{\text{Generator Cost}} \tag{4}$$
$$+\overbrace{\left[\frac{C_{bat}\overline{S}_{bat}}{8{,}760}\right]\left[\frac{i(1+i)^{\left(\frac{\overline{S}_{bat}Life_{bat-hours}}{\left[Z_{PV}B+Z_{gen}(1-B)\right]8{,}760}\right)}}{(1+i)^{\left(\frac{\overline{S}_{bat}Life_{bat-hours}}{\left[Z_{PV}B+Z_{gen}(1-B)\right]8{,}760}\right)}-1}\right]+O_{bat}\left[Z_{PV}B+Z_{gen}(1-B)\right]}^{\text{Battery Cost}}+\overbrace{A}^{\text{Admin. \& O Costs}}$$

There are two importing things to notice about Equation (4). First, the hybrid system can be optimized for the least-cost PV/generator mix simply by varying B from 0 to 1. Second, the generator's capacity factor (F_{gen}) affects both the generator's initial capital cost as well as the generator's capital recovery factor so that the two operate together as a pair. Thus, generator life (and thus the capital recovery factor) is not arbitrarily chosen but instead depends upon how the generator is operated. The same is true for the battery.

Data

This section describes the data used to perform the analysis.

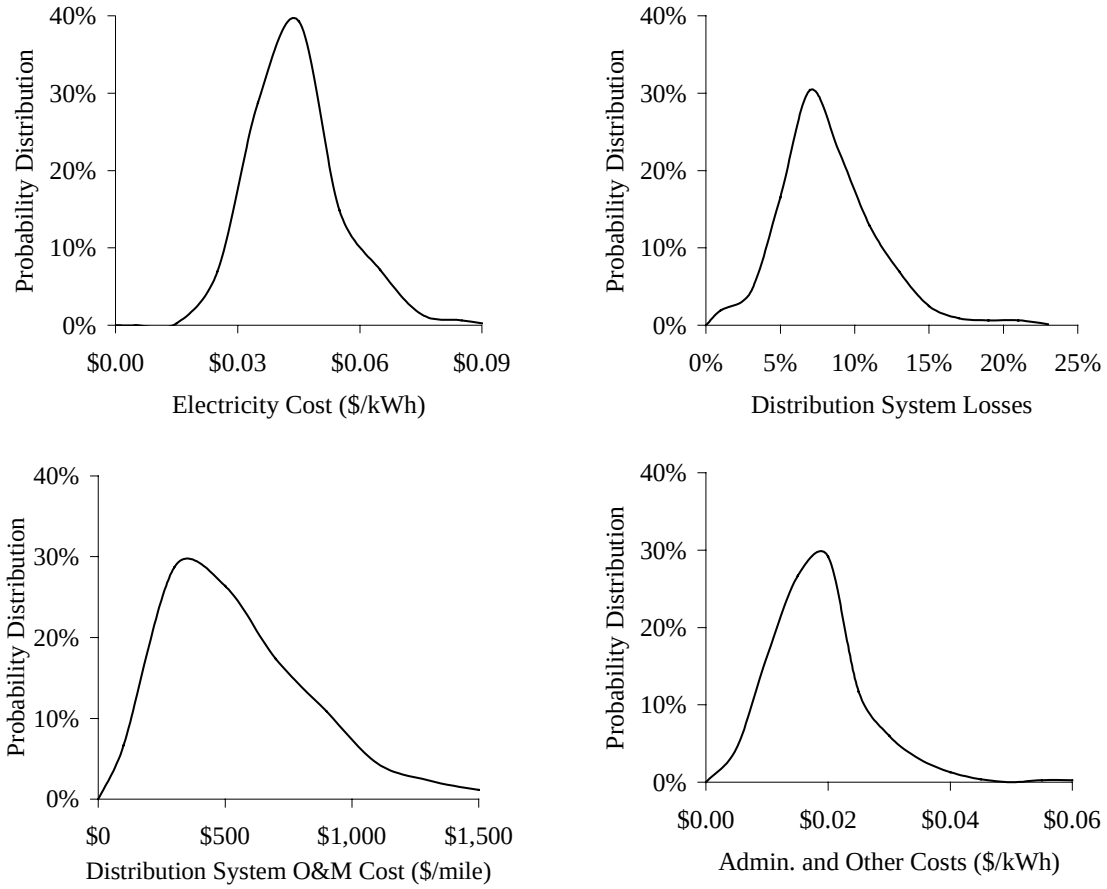
Discount rate

The discount rate is 7 percent. This is approximately the rate at which a co-op would borrow money from a private finance company, such as the Cooperative Finance Corporation, to finance new long-term projects.

RUS Data Set

The Department of Agriculture's Rural Utility Service (RUS) collects detailed operating and financial statistics on about 90 percent of all rural co-ops (the 1994 data set covers the most co-ops: it includes 837 co-ops that deliver 190,000 GWhs using 1.8 Million miles of distribution line). This paper is based on operating and financial data for 1994-1996 (data collected by the RUS using RUS Form 7 (RUS 1998a)) and on the RUS's 1995 Annual Statistical Report (RUS 1996). Data for all of the variables in Equation (2), except for the capital cost of new distribution facilities and the distribution system life, are the specific data that the co-ops reported to the RUS. Figure 1 presents the probability distributions that summarize the data (the calculations in the next section are performed one at a time).

Figure 1. Probability distributions of various costs and other parameters for all co-ops.



Distribution System Capital Cost

The cost of replacing distribution systems is estimated to be $15,000 per mile for overhead, single phase lines (Norris 1999). It is assumed that the system life is 30 years. Using a 7 percent discount rate, this translates to an annual capital cost of $1,208/mile/year. (Note: a distribution system with an infinite life would have an annual cost of $1,050/mile/year.)

Load Density

Two variables that have a major impact on distribution system cost are the distribution system capital cost and the load density. In fact, as indicated in Equation (2), reducing the load density by 50 percent has an even greater effect on cost than doubling the distribution system capital cost because the load density impacts both the capital cost and the O&M cost.

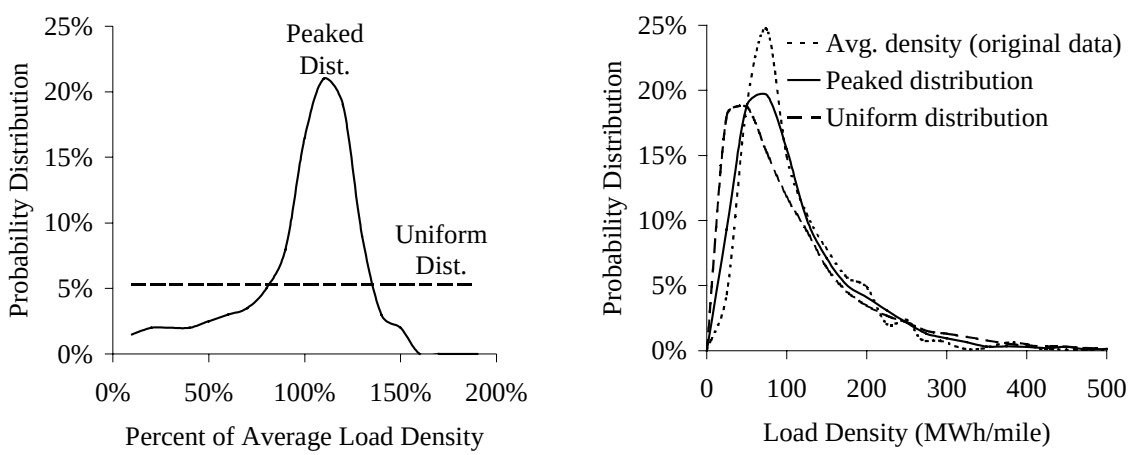
While each co-op's average load density is well documented, very little data exists on the load density distribution within each co-op. It is known, however, that load densities can range widely within a given co-op. For example, Norris (1999) recently evaluated the load densities at six study areas that accounted for four percent of the total miles in a

Nebraska co-op. Each area examined had a load density significantly lower than the co-op average. In fact, one area that accounted for one percent of the co-op's total miles of line had a load density that was less than one-twentieth of the co-op's average load density. Hoff and Cheney (1999) found a similarly wide distribution of load densities at an Arizona co-op.

Due to the importance of this variable, the work by Norris (1999) and Hoff and Cheney (1999) were used to estimate a probability distribution of load density within a given co-op (labeled peaked distribution in the left side of Figure 2). A uniform distribution is also included in order to provide a range of results. Both distributions sum to 100 percent and have a weighted average load density of 100 percent; this leave the co-op's average load density unchanged.

The average load density number for each co-op in the RUS data set was converted to load density probability distributions using the distributions in the left side of Figure 2. This was done for all 837 co-ops. The right side of Figure 2 summarizes the resulting load density probability distributions for the for all co-ops for three cases: (1) the average load density is used (i.e., the load density is considered as a single point for each co-op); (2) there is a peaked load density distribution at each co-op; and (3) there is a uniform load density distribution at each co-op.

Figure 2. Load density distribution for each co-op; resulting load density distribution for all co-ops.



PV

The PV system price is allowed to vary since the first objective of the analysis is to determine the size of the market for PV as a function of PV price. The system has a 30-year life. The capacity factor ranges from 12 percent to 25 percent based on the location in the U.S. O&M cost is $0.01/kWh.

The amount of PV generated electricity that goes into storage depends upon the PV system size and the load match. Based on an evaluation of a PV/ load data set for Arizona, a linear approximation of the amount of electricity going into storage is that electricity in excess of 30 percent of the system load first goes to storage before satisfying the load. Mathematically, this means that $Z_{PV} = Max[B - 0.3, 0]$.

Cogeneration

Pfeifenberger, Hanser, and Ammann (1997) suggest that distributed generation's close proximity to customers greatly increases the potential for cogeneration since most customers consume both electric and thermal energy over the course of a year. Hoff and Herig (1999) take this one step further and demonstrate that there is a great potential to use a system composed of cogeneration, PV, and energy efficiency in the residential sector. A cogeneration unit sized to satisfy all of a customer's thermal needs will provide about half of the customer's electrical needs. If the unit produces electricity when it is needed (i.e., it is a load following unit) and then stores the heat for use at a later time, only a minimal amount of electricity needs to go into storage.

This paper assumes that: cogeneration capital cost is $1,000/kW; the generator runs on propane that costs $1.25/gallon and has an electrical efficiency of 35 percent; the unit can run at full load for 40,000 hours before being replaced; the unit follows the load with an annual capacity factor of 50 percent and with 90 percent of the electricity produced going directly to the load (the rest goes into storage and then the storage satisfies the load); and O&M cost is $0.02/kWh.

The cogeneration effectively reduces the generator's fuel cost since the fuel would have had to been burned anyway to generate heat. When the cogeneration's thermal efficiency equals the thermal efficiency of the units that would have been installed to satisfy the thermal load, the effective fuel price is calculated by multiplying the fuel price (P_{fuel}) times $\max\left(1 - \frac{cogen}{1-B}, 0\right)$ if B <1, or by 0 if B = 1; *cogen* is the amount of electricity supplied by the generating unit when run in a cogeneration mode. Hoff, et. al (1998) discuss the cogeneration aspect in more detail.

Battery Storage

The battery capital cost is $100/kWh; the battery will operate for 2,000 hours at full dispatch (thus, storage use affects battery life); the battery will provide 6 hours of storage at average load; it has an O&M cost of $0.02/kWh; and it has round trip losses of 20 percent.

Results

The data from the preceding section were input into Equations (2) and (4) at each different load density in the distribution using increments of 10 percent of average load within the co-op for each of the 837 co-ops in the RUS data set. Four cases were considered: optimal system configuration (i.e., least-cost PV/generator combination)

using peaked load density distribution (case 1) and using uniform load density distribution (case 2); and half PV/half generation using peaked load density distribution (case 3) and using uniform load density (case 4).

Figure 3 presents the potential number of MWs of economic applications of PV. The actual number of MWs may vary from the projected number because some of the distribution lines may have already been replaced. Given that half the lines were installed more than 40 years ago and that the lowest density lines tend to be the oldest (this was the case with the Nebraska co-op in Norris, 1999), however, the potential number of MWs should be representative of the actual number of MWs.

Table 3 summarizes the results when the PV/generator mix is optimized (cases 1 and 2). Results suggest that there is a potential market of 500 MW to 950 MW of PV at a price of $3,000/kW.[2] The corresponding fossil-based generation market size is 280 MW to 555 MW (50 percent capacity factor, $1,000/kW price). These PV/generator systems represent 7 percent to 16 percent of the miles of distribution system and could save co-ops $1.0 Billion to $2.5 Billion (present value).

[2] According to Don Osborne, Manager of Photovoltaics and Distributed Generation at the Sacramento Municipal Utility District (SMUD), the total installed cost for PV systems at SMUD is currently less than $5,000/kW and will decrease to less than $3,000/kW by mid-2003. (Phone conversation on April 3, 2000). SMUD has one of the more aggressive PV programs in the U.S. The current cost for individual PV systems ranges from about $6,000/kW to $10,000/kW.

Figure 3. Potential market for PV (837 co-ops, all time).

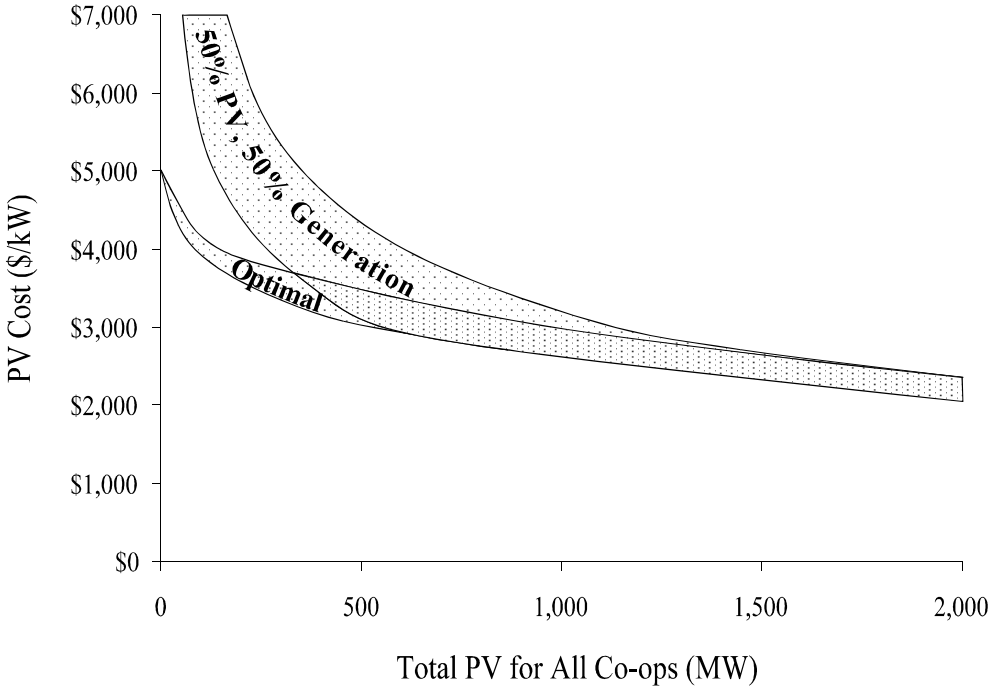


Table 3. Results for optimized system.

PV Price	PV Generation	Other Generation	Miles of Lines Replaced	30-year Present Value Savings
$2,000/kW	2,100 to 2,825 MW	850 to 1,100 MW	280,000 to 460,000 miles	$2.2 to $4.3 Billion
$3,000/kW	500 to 950 MW	280 to 555 MW	135,000 to 290,000 miles	$1.0 to $2.5 Billion
$5,000/kW	1 to 3 MW	275 to 625 MW	95,000 to 230,000 miles	$0.7 to $1.9 Billion

Two key factors that affect these results are: (1) the generator output follows the load so most of the output goes directly to the load without going through storage; and (2) the generator is operated in a cogeneration mode. A sensitivity analysis was performed to determine the effect of changes in these two assumptions. The results of this sensitivity analysis are that, at a PV price of $3,000/kW, the PV market and co-op cost savings are reduced by half if (1) all of the generation's output first goes into storage; the PV market and co-op cost savings are reduced by about four-fifths if (1) all of the generation's output first goes into storage and (2) there is no cogeneration.

An important implication of these results (Figure 3 and Table 3) and sensitivities is that both the PV and generation technologies need each other in order to achieve their largest market size.

Conclusions and Further Research

Rural electric cooperatives have an aging distribution system (1 million miles of distribution wires were originally installed over 40 years ago) and a load density that is about one-tenth of the load density at other utilities. The result is that there may soon be a large market opportunity for photovoltaics (PV) and other distributed resources. This paper calculated the cost of replacing portions of the distribution system as it wears out with hybrid-PV systems (systems that use PV, generators, and batteries to satisfy demand where it occurs), compared it to the cost of replacing the system with equivalent distribution system equipment, and selected the alternative with the lowest cost. Results suggest that there is a potential market of 500 MW to 950 MW of PV at a price of $3,000/kW and a corresponding fossil-based generation market size of 280 MW to 555 MW at a price of $1,000/kW. The hybrid-PV systems could replace 7 percent to 16 percent of the miles of distribution system and could save co-ops $1.0 Billion to $2.5 Billion (present value).

It is important to emphasize that the exact timing of when the systems would be installed is not known. While major portions of the distribution system are old, the rate at which distribution systems will be replaced is not well documented.

There are several areas for further research. The factor with the greatest influence on the market size estimated in this paper is load density. Load densities within individual co-ops need to be better characterized. A better understanding is also needed to determine the rate at which old distribution lines will be replaced and how the replacement will occur (e.g., a pole at a time over several years or an entire line at one time). These factors could be addressed by performing targeted case studies similar to Norris (1999) at co-ops in different geographic and population density areas. These case studies would provide valuable insight into the economics of distributed generation in rural electric co-ops.

Factors that could increase the size of the market include: incorporating non-grid-connected remote loads (these were not included in this analysis), and accounting for the potential added reliability associated with hybrid-PV systems and consumer preferences for green power.

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