A BENEFIT/COST ANALYSIS OF ACCELERATED DEVELOPMENT OF PHOTOVOLTAIC TECHNOLOGY

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PU/CEES Report No. 281

October 1993

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ABSTRACT

Renewable Energy: Sources for Fuel and Electricity, prepared as an input to the 1992 United Nations Conference on Environment and Development, presents, in the overview chapter by the book's editors, a scenario in which more than half of world primary energy is provided by renewable sources during the second quarter of the 21st century. The editors of ***Renewable Energy*** argue that such a future is consistent with world energy prices that are not much higher than at present. However, bringing about such a future would require very rapid rates of introducing renewable energy technologies.

The present paper follows up this assessment of the prospects for renewables in the long term with a detailed analysis of the economic aspects of developing photovoltaic (pv) technology at a much faster pace than in the current approach, which is focussed on exploiting niche markets where high-priced pv is already cost-competitive. Photovoltaic prices are much further from the levels required for widespread adoption of the technology than are the prices for the other major renewable electric options--wind power, biomass power, and solar thermal-electric power. Without an accelerated development effort, it will not be possible for pv to make substantial contributions to world energy by the end of the first quarter of the next century.

An accelerated pv development strategy is proposed that focuses on grid-connected systems in distributed configurations close to consumers, located in those parts of the world where there is a good correlation between pv output and utility subsystem peak demand. Here pv is much more valuable than in central station applications, and this potential pv market is much larger than the market for stand-alone pv systems for remote areas, a major focus of the niche market development strategy. The accelerated development scenario presented here would lead to 400 GW_p of pv capacity installed in distributed configurations by 2020--half of which would be in the U.S. and most of the rest in developing countries. It is shown that the accelerated development strategy would be far more attractive economically than the conventional niche market development strategy.

Key to the success of the accelerated development strategy is to bring pv prices down quickly via large-scale market development and an accelerated R&D effort. In the accelerated development scenario, pv costs would initially exceed the value of pv to utilities and their customers, so that incentives would be required to stimulate the market development effort. In addition, the pv R&D effort must be expanded to speed up the rate of technological improvement; it is unlikely that pv performance and cost goals for widescale applications can be met with mere refinements of pv technologies now on the market, but there are good prospects for meeting these goals over the next couple of decades with various advanced concepts if there is an adequate R&D effort.

Various scenarios relating to rates of technological progress are explored. It is shown that under a wide range of plausible conditions the direct economic benefits of accelerated development (measured as the reduction in expenditures on electicity by consumers, exclusive of all environmental and energy security benefits) would be several-fold greater than the costs to governments for the increased expenditures on R&D and for the market development incentives. Moreover, the benefit/cost ratio measured this way is found to be much greater than for the niche market development strategy.

A promising approach for implementing an accelerated development strategy would be to require electric utilities to make mass purchases of pv systems in annual auctions in which maximum allowable bid prices would continually decline to reflect expectations that prices will fall as the market expands and the technology improves. To reduce uncertainties about the market, purchase volumes and maximum bid prices could be announced several years in advance. In industrialized countries the required market stimulation subsidy could be administered as a tax credit to the participating utilities. For developing countries the market subsidy could be provided by the home countries from the industrialized world for the vendors seeking these markets in developing countries.

While estimates of future benefits and costs are always uncertain, a plausible outcome for the U. S. of the proposed effort to install grid-connected pv systems in distributed configurations over the period 1995-2020 is that: (*i*) societal benefits in the form of reduced expenditures on electricity in the U. S. would amount to $45

billion (half of the estimated global societal benefits), and (*ii*) U. S. pv manufacturers would be able to sell as much as 60 to 70 GW_p of pv capacity in overseas markets via joint ventures with companies in the purchasing countries. The present worth of the extra cost to the U.S. treasury would be $5.4 billion--consisting of $1.6 billion for domestic market subsidies, $0.5 billion as the U. S. share (1/3 of the total) of the industrialized countries' contributions for the market subsidies in developing co untries, and $3.2 billion for the extra costs of expanding the annual pv R&D budget to six times the current level until early in the second decade of the next century. This cost for launching a major environmentally attractive industry is modest. For comparison the U. S. spent (in 1992 dollars) $56 billion on nuclear fission R&D and $25 billion on fossil fuel R&D over the period 1950 to 1993, and the market value of all subsidies to the nuclear fission and fossil fuel industries in the United States in 1989 amounted to $10.6 billion and $21.1 billion, respectively.

The extra cost to the U. S. treasury for accelerating pv development might be financed by a carbon tax amounting to $1.3 per tonne of carbon on fuel purchases by electric utilities; such a tax would increase the retail price of electricity by 0.3 percent. Alternatively, the cost could be financed from savings associated with a rationalization of the present energy subsidy system to better conform to the environmental, energy security, and competitive challenges the nation faces in the decades ahead.

The expected low cost for accelerating the development of pv technology arises because pv equipment is small and modular. While large conventional energy facilities require extensive construction in the field, where labor is costly and productivity gains difficult to achieve, pv equipment can be constructed in factories, where it is easier to apply modern manufacturing techniques that facilitate cost reduction. The small scale of the equipment also makes the time required from design to operation short, so that needed improvements can be identified by field testing and quickly incorporated into modified designs. In this way many generations of technology can be introduced in short periods.

Because these characteristics are shared by many other renewable energy technologies as well, and because the prices for most other renewable energy technologies are closer to the levels needed to compete in mass energy markets than is the case for pv, it is likely that the accelerated development of a wide range of renewable energy options could be supported at much less cost than historical costs for advancing conventional energy technologies.

While the likely result of a policy aimed at accelerating R&D and market development for pv technology is major direct global economic benefits, complementing the well-known environmental and energy security benefits of this technology, political leadership is needed to seize this opportunity. Sharp departures from historical trends in energy technology are not likely to be realized without it.

INTRODUCTION

Supporting the economies of the already industrialized world and improving the living standards of the rapidly growing populations of the developing world will require substantial increases in the provision of energy services globally. Meeting these energy needs in a sustainable manner, without jeopardizing environmental and security goals, is a formidable challenge.

Oil cannot continue to drive the engines of economic growth without major increases in energy security risks. Despite the present worldwide oil glut, the oil market is likely to tighten substantially before the turn of the century [1]. Because of resource constraints, the U. S. Geological Survey projects that oil production will decline after the year 2000 in all regions outside the Middle East [2]. Holding 65 percent of the world's oil reserves, the politically volatile Middle East could again dominate world markets early in the next century.

Concerns about greenhouse warming are also likely to dictate major changes in energy planning. The U. S. and several other industrialized countries have already agreed to cap CO_2 emissions at 1990 levels over the the next decade or so. Stablization of the emissions level, however, would still imply major climate change risk--including the possibility of a 2.5 °C increase in the mean global temperature by 2100. To prevent any further climate change beyond that inevitable because of past greenhouse gas emissions would require cutting emissions by 60 percent or more, according to the Intergovernmental Panel on Climate Change [3]. This cannot be accomplished without radical changes in our fossil fuel-intensive systems of energy production and use.

While it offers the potential for reduced dependence on Middle East oil without increasing CO_2 emissions, nuclear energy has fallen out of public favor as a result of the Chernobyl accident and unresolved issues associated with radioactive waste disposal. And even if these concerns could be adequately addressed, the nuclear weapons connection to nuclear energy (which has been given little attention to date) would come into focus as a major risk if nuclear energy were resurrected on a large scale [4].

An important strategy for addressing the global energy challenge will be to slow the growth in energy demand by exploiting cost-effective opportunities for making more efficient use of energy, in both industrialized and developing countries [5]. So doing can make the global energy problem far more manageable, but a fossil fuel-intensive energy-efficient world still faces the prospect of major climate change. The only way to slow the pace of climate change substantially is to combine an energy-efficiency strategy with a less greenhouse gas-intensive energy supply strategy.

The primary non-fossil fuel alternative to nuclear energy is renewable energy. Renewable energy attracted a great deal of attention at the time of the oil crises of the 1970s, but public interest in renewables faded with the fall in world prices and the shift to *laissez faire* energy policies in many industrialized countries in the 1980s. Despite the sharp declines in public sector support for renewable energy development, substantial progress in renewable energy technologies occurred in this period. These advances are documented in a major assessment of the prospects for producing and using fuels and electricity derived from renewable energy sources, carried out as an input to the United Nations Conference on Environment and Development [6]. As a part of this assessment, a renewables-intensive global energy scenario (RIGES) was constructed. In this scenario an energy-efficient future for the world is described in which the share of renewables increases from 8 percent of primary commercial energy use in 1985 (mostly hydroelectric power) to 45 percent in 2025, at the same time that global CO_2 emissions from fossil fuel combustion decline 12 percent relative to 1985. While the RIGES is not a forecast of what will happen, its authors argue that: (*i*) the scenario is both technologically and economically feasible at world energy prices that are not much different from at present, but (*ii*) the scenario would not be realized without major changes in public policy encouraging the needed innovations.

The RIGES represents a radical departure from conventional views of the energy future, which typically differ in only modest ways from a continuation of historical trends. In a recent review of alternative strategies proposed for reducing global emissions of greenhouse gases, the RIGES was described as follows [7]:

> ...such a rapid market penetration is without precedent in history. For comparison, it took about 80 years for the market share of oil to grow to 40% of the global primary energy supply...

This review concluded with the following comment on the RIGES and other global energy scenarios characterized by CO_2 emissions levels that are markedly lower than those in most energy forecasts [7]:

> The required acceleration of the rate of decarbonization over the ones achieved historically and projected for the future in most energy scenarios illustrates the difficulty of achieving stabilization of energy-related carbon emissions under the premises of population growth and economic development. Very massive restructuring of future energy systems alongside vigorous efficiency improvement efforts will be required to come close to such a global target.

It is certainly true that the realization of an energy future such as that described by the RIGES would be an ambitious and unprecedented undertaking, requiring much technological and institutional innovation. However, the environmental and security challenges facing the energy sector in the coming decades are also unprecedented. And trend is not destiny. Whether or not the pace of change required for the RIGES is unprecedented matters much less than whether it is technically feasible and affordable.

The present paper addresses such questions quantitatively for the case of accelerated development of photovoltaic (pv) power. It is argued that accelerated development of pv power is not only technically feasible and affordable but probably far more attractive economically than the slow pace of development implied by business-as-usual. The findings presented here for pv power are likely to be applicable to a wide range of renewable energy technologies that offer substantial potential for cost reduction because of shared characteristics that conventional energy technologies do not have.

Conventional energy systems are generally based on large-scale centralized technologies characterized by long lead times. The large plant sizes and long construction times for conventional energy plants are characteristics that make rapid technological progress difficult (*see Box A*). In the 1970s and 1980s production bottlenecks arising from the practical difficulties of standardizing designs for large energy production facilities, toughening environmental regulations, and growing public opposition to the construction of new facilities have often meant that energy produced by new plants is more costly than energy from old plants.

In contrast, because most renewable energy equipment is small, renewable energy technologies can advance at a faster pace than conventional technologies. While large energy facilities require extensive construction in the field, where labor is costly and productivity gains difficult to achieve, most renewable energy equipment can be constructed in factories, where it is easier to apply modern manufacturing techniques that facilitate cost reduction. The small scale of the equipment also makes the time required from design to operation short, so that needed improvements can be identified by field testing and quickly incorporated into modified designs. In this way many generations of technology can be introduced in short periods.

Because of such technological characteristics, it is very likely that, in an energy policy environment that is conducive to technological innovation, the dynamics of renewable energy development would have more in common with the rapid technological progress and sharp price reductions that are characteristic of microprocessor-based technologies, pharmaceuticals, and a wide range of other modern technologies than with the experience for conventional energy technologies.

Such technological characteristics imply that substantial economic benefits may be realized from policies aimed at accelerating the development of renewable energy technologies, in addition to the environmental and energy security benefits. This thesis is argued in the present paper, via an analysis of the dynamics of the costs

Box A: The Roots of Nuclear Power Cost Escalation

A 1974 analysis by John Fisher [8] of the escalation in nuclear power costs in the decade leading up to the first oil crisis provides an important insight relating to power plant construction-related problems that seems relevant for the escalation in electric power costs generally from 1970 to the mid-1980s:

> "When measured in constant dollars per kilowatt of capacity, the cost of constructing a nuclear power plant increased by perhaps 50 percent in the past decade... When power plant costs rise an explanation is required, as we expect all power plant costs to decline through the economies of scale and new technology. The environmental movement was responsible for part of the rise in nuclear plant costs, by causing various procedural delays and by requiring additional expensive safeguards to protect against hypothetical accidents. But there appears to be another cause for increasing construction costs, associated with a growing portion of high-cost field construction and a shrinking proportion of low-cost factory construction for the very large power plants now being built... The costs associated with a shift to field from factory can more than offset anticipated economies of scale..."

Fisher pointed out that for many decades plant construction in the electric power industry followed a pattern in which part of the construction (mainly the building and the boiler) was carried out in the field and part (manufacture of the turbine, generator, and power conditioning equipment) was carried out in large factories serving many utility plants. As electric utility plant capacity doubled every decade, factory capacity also doubled, as did field construction at each site. Manufacturing and construction costs per kW_e declined in the factory and in the field, since each of these increased its scale of operations. As long as both activities grew in proportion, the economies of scale produced similar cost reductions in each, and therefore an overall cost reduction, even though the unit cost of field construction was always higher than the unit cost of factory construction. This pattern held until plant size reached about 200 MW_e and was reflected in a good fit of the average US electricity price to a 75% experience curve during most of the period up to 1970 (*see Figure 1*).

This trend was upset with the introduction of nuclear power. Because of the requirements for shielding and containment and other specifically nuclear features, nuclear plants were expected to be more capital-intensive than fossil fuel plants for the same rating. Since these nuclear-related costs account for a smaller fraction of the total cost at larger plant sizes, it was reasoned that nuclear plants must be built large. Accordingly, nuclear power plant capacities were built in sizes of the order of 1000 MW_e. But building larger plants requires shifting a larger fraction of total construction from the factory to less-efficient field locations, thereby raising costs.

Fisher's important insight is that the widely touted economies of scale in power plant construction are illusory because: (a) field construction is inherently more costly than factory construction, and (b) with field construction it is never possible to move very far along the learning curve, in contrast to the situation with factory production.

and direct economic benefits of pv technology, carried out in the context of two alternative scenarios for the future of photovoltaic (pv) technology: a "Business-As-Usual" scenario that represents a continuation of present trends and an "Accelerated Development" scenario stimulated by a new energy policy that encourages pv development. While no attempt is made to estimate the optimal rate of pv development, it is shown that the present value of the net direct economic benefits (exclusive of any external environmental or energy security benefits) of accelerated pv development--measured as the reductions in society's expenditures on energy in the coming decades--are probably large and far in excess of the costs of pursuing the accelerated development path.

ALTERNATIVE GLOBAL SCENARIOS FOR GRID-CONNECTED, DISTRIBUTED PV SYSTEMS

Because at present the cost of electricity from pv power systems is several times its value in typical grid-connected electric utility applications, the chosen pv technology development strategy involves exploiting niche markets (mainly consumer electronic products and remote off-grid residential and industrial applications) where pv technology is already cost-effective.

While niche market development is important, this strategy by itself will not lead to the high levels of pv development envisaged in the RIGES. Global sales of pv modules increased at an average rate of 70 percent per year, 1976-1983, but growth since then has proceded at a much more modest rate of about 16 percent per year (*see Figure 2)*. In an assessment carried out for the Electric Power Research Institute of the potential global market for pv technology, Arthur D. Little, Inc., estimated that under business-as-usual conditions the global market for pv technology would continue to grow at modest rates, averaging only 19 percent per year, 1991-2010 [9]. If this rate were to persist, pv costs would decline relatively slowly (as discussed below), and global pv electricity generation in 2025 would be only about 2 percent of total global electricity generation.[1]

In the present analysis an alternative strategy is explored in which pv technology is developed much more aggressively. In this alternative development strategy, systems deployed initially are not cost-competitive on a project-by-project basis, but the overall strategy is far more cost-effective than the niche market development strategy, as a result of a much more rapid rate of decline of pv prices and the consequent consumer savings in expenditures on electrical services. The economic importance of aggressive pv development is assessed via benefit/cost analyses of an Accelerated Development scenario and a Business-As-Usual scenario for grid-connected, distributed pv systems installed in sunny regions of the world over the period 1995-2020.

A global rather than a U. S. perspective is taken, because global cumulative production is a good index for tracking costs, and because the effective exploitation of global markets can help bring down costs more quickly than if only domestic markets were exploited. The analysis is focussed on grid-connected applications because only these applications offer a market large enough for the Accelerated Development scenario.[2] The analysis considers only grid-connected systems sited in distributed configurations near consumers (*e.g.*, at utility substations and on residential and commercial building rooftops), because distributed applications offer the most promising initial markets for grid-connected pv systems; electricity produced in distributed pv systems will tend to be worth more to utilities and consumers than electricity produced in central station pv plants. And finally, the scenarios are restricted to those regions that have reasonably good insolation, because of lower pv generation costs and increased pv electricity value, resulting from a good correlation between pv system output and the utility system peak demand.

The scenarios begin with the first additions of distributed pv systems to utility grids in 1995. Annual growth in pv sales is assumed to follow logistics or "S" curves having initial exponential growth rates of 15 and

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[1] In the RIGES, the level of pv power generation is not indicated explicitly, but the total level of power generation by all intermittent renewables (wind power, solar thermal electric power, and pv power) in 2025 is about 4600 TWh/year, or about 1/5 of total electric power generation.

Total global electricity generation rates in the RIGES were adapted from a global electricity demand scenario developed by the Response Strategies Working Group of the Intergovernmental Panel on Climate Change for a world in which energy-efficient end-use technologies are emphasized [10]. In this scenario electricity generation worldwide grows from 9,200 TWh in 1985 to 21,200 TWh in 2020, at an average growth rate of 2.1% per year.

[2] Limiting the analysis to grid-connected systems simplifies the analysis, but ignoring the contributions to pv cost reduction from niche market development leads to an overestimate of the cost of pursuing an accelerated development path.

35 percent per year for the Business-As-Usual and Accelerated Development scenarios, respectively. In both cases annual sales eventually saturate at a rate of 50 GW_p per year (*see Figure 3).* The assumption that sales saturate reflects the expectation that at some point pv costs will be sufficiently low that further growth in sales might come from central station rather than distributed markets. By 2020 cumulative installed distributed pv capacity is 25 GW_p in the Business-As-Usual scenario and 400 GW_p in the Accelerated Develop-ment scenario (*see Figure 3*). The average annual rates of growth in cumulative installed capacity for these two scenarios over the period 1995-2020 are 17 and 30 percent, respectively. While the growth rate for the Accelerated Development scenario is high, it is not unprecedented for new technologies. In particular, it is less than the 37 percent annual rate of growth for worldwide nuclear power capacity between 1957 and 1977 (*see Table 1).*

It is assumed that initially pv systems are installed in areas where insolation averages about 2300 kWh/m^2/year (typical of the Southwest US), and that the insolation at new sites declines with cumulative installed pv capacity, reaching, by 2020, 2100 kWh/m^2/year in the Business-As-Usual scenario and 1500 kWh/m^2/year in the Accelerated Development scenario (*see Figure 4).* At the end of this period in the Accelerated Development scenario, pv systems would be installed in many northern parts of the U. S. (*see Table 2*), but northern parts of Europe would be excluded (*see Table 3*), as would other high latitude sites.

It is assumed that pv systems are installed in the "sunnier" parts of the world that accounted for 2/3 of total world electricity generation in 1985 and where the total electricity supply grows at an annual rate of 2.6 percent per year through 2025 in the RIGES--the growth rate adopted for total electricity supply in these regions for the period 1990 to 2020 in the present analysis. In these regions distributed pv systems would account for 0.5 percent of total electricity generation in the Business-As-Usual scenario and 6 percent of total electricity generation in the Accelerated Development scenario in 2020.

To assess the economics of distributed, grid-connected pv systems, consideration must be given to the cost of pv power generation, the cost of the conventional electricity generation avoided by producing pv electricity instead, and the distributed value of pv power.

USING EXPERIENCE CURVES TO PROJECT FUTURE PV COSTS

A useful tool for estimating future pv costs is the "experience curve," which is based on the phenomenon that for many industries per unit production costs decline as a direct, estimable proportion of cumulative production. The experience curve is a generalization of the more familiar "learning curve."

The learning curve describes, for a given technology, the prospects for near-term cost reductions through organizational learning--in essence, the economies that can be achieved by getting better organized. Cost reductions from organizational learning include improvements in the efficiency or organization of the work force, management, or other variable inputs for a given production process. The learning curve is often formulated to show the dependence of the labor-hours required to produce a unit of a product on the cumulative production of that product by a function of the form:

$$y(x) = ax^b,$$

where:

$y(x)$ = labor hours required to produce the xth unit of output,
x = cumulative production, between the 1st and xth unit,
a = labor hours required to produce the 1st unit,
b = a measure of the rate of reduction in labor hours as cumulative production increases.

Organizational learning was first reported by Wright, who showed that the direct labor required to produce each of a series of airframe orders for a particular plane model diminished 20% for each doubling of cumulative production [11]. Such a trend is said to follow an "80% learning curve," and the "progress ratio" is said to be 80%.[3] Progress ratios in the neighborhood of 80% have been found to characterize a wide number of industries. Figure 5 shows the distribution of progress ratios for more than 100 industries [12].

The experience concept, originated by the Boston Consulting Group, generalizes the learning concept. "The experience...effect...encompasses all costs (including capital, administrative, research, and marketing) and traces them through technological displacement and product evolution" [13]. The Boston Consulting Group found through observations of various industries that "Costs appear to go down...20% to 30% every time total product experience doubles for the industry as a whole, as well as for the individual producers."

As in the case of learning, the experience phenomenon can be described by an experience curve of the form:

$$c(x) = ax^b,$$

where

$c(x)$ = cost of producing the xth unit of output,
x = cumulative production, between the 1st and xth unit,
a = cost of producing the 1st unit,
b = a measure of the rate of cost reduction as cumulative production increases.

As in the case of the learning curve, it is customary to characterize the experience curve by a progress ratio. An 80% progress ratio, for example, implies that cost declines 20% for each cumulative doubling of production.

Unlike the learning concept, which applies to short-term improvements in labor productivity, the experience concept applies to long-term improvements and cost reductions from every conceivable source, including technological improvements, input substitution, economies of scale, new product design, and changing input prices [14], as well as labor productivity improvements for given processes. Cody and Tiedje point out that highly competitive industries that make major investments in research and development are characterized by relatively low progress ratios (*i.e.*, rapid rates of cost reduction), while mature industries that invest little in research and development tend to be characterized by relatively high progress ratios [15].

Whereas there are sound theoretical reasons for using a learning curve to project costs in the near term for a given technology, experience curves should be used cautiously in making long-term projections of future costs, because so many variables are involved and experience is no guarantee that historical trends will persist [14]. However, used in conjunction with independent supporting evidence of the potential for cost reduction, experience curves can be useful in understanding the prospective economics of promising technologies.

Photovoltaic technology is a good candidate for using the experience curve to estimate future prices both because there is a good long-term record showing that pv technology has closely followed an experience curve with a fixed progress ratio [15], and because there is a good basis for estimating future pv cost reductions through technological improvement [16].

Figure 6 shows that between 1976 and 1992 the pv module selling price on the global market followed an 81.6% experience curve. In 1975 Maycock and Wakefield showed that pv module prices followed an experience curve with an 80% progress ratio between 1965 and 1973 [17]. Moreover, Tsuchiya found that the sales of pv modules in Japan followed an 81% experience curve during the period 1979-1988 [18].

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[3] Expressed as a decimal fraction, the progress ratio PR is defined by:

$$PR \equiv 2^b.$$

Thus, for an 80% progress ratio, b = - 0.322.

At present installed costs for grid-connected pv systems (without storage) are in the range \$7,000 to \$8,000 per kW_p, corresponding to electricity generation costs in excess of 25 cents/kWh (*see Figure 7*).[4] Future costs can be expected to be much lower as a result of technological improvements and cost-cutting through organizational learning from market experience. The goals of the U. S. Department of Energy's photovoltaic program are to reduce electricity generation costs to the range 12 to 20 cents per kWh in the mid-term (1995-2000) and to 5 to 6 cents per kWh in the long-term (2010-2030)[19].[5]

There are two broad classes of pv technologies that offer good prospects for realizing dramatic reductions in pv costs [16]: (*i*) thin-film modules [21,22] that would be used in flat-plate pv systems (with fixed or tracking collectors), suitable for use in central station or distributed applications in many areas--even in areas having only moderate insolation, and (*ii*) tracking, concentrating modules [23] suitable for use primarily in central station or sub-station applications in areas with good insolation. Thin-film pv systems will tend to be less efficient than concentrating systems but less capital-intensive. Which of the various pv technologies in each of these categories will end up dominating the market cannot be ascertained at this point. The "winners" may well be technologies that are not yet on the market.

Because the focus here is on distributed applications of pv technology, the present analysis is restricted to pv systems involving flat-plate arrays. For such systems thin-film devices are good candidates for meeting long-term pv cost goals. For such systems to be economically viable in large-scale applications, module efficiencies of the order of 15% will be needed. For amorphous silicon, the only commercially available thin-film pv technology, it is uncertain whether stable efficiencies of this magnitude can be realized in commercial-scale modules. Other thin-film technologies under development show good prospects for meeting this efficiency goal, however. Technical progress has been impressive, especially for copper indium diselenide and cadmium telluride. Stable efficiencies in excess of 15% have already been achieved in the laboratory for small (~ 1 cm^2) cells made of these materials (*see Figure 8*). The challenge for research and development is to make it possible to routinely achieve such efficiencies for mass-produced, commercial-scale modules. Producers must be able to manufacture large-area (~ 1 m^2) modules having extraordinarily thin (~ 1 micron = 10^{-6} m thick--about 1% of the thickness of a human hair) and uniform layers of active materials deposited on substrates such as glass.

Recently a design study for a 50 MW_p power plant based on the use of copper indium diselenide flat-plate modules was carried out for the Electric Power Research Institute [24]. Designed for pv modules based on cell design and performance projected for the 1995 time frame[6] and manufactured in a pv module production facility with a capacity of 100 MW_p/year, the plant would go into operation in 2005 in an area of high insolation (2340 kWh/m^2/year). The study estimated the cost of installed generating capacity to be \$2,340/kW_p and the electricity generation cost to be 10.8 cents/kWh.[7] These cost levels for 2005 are consistent with the

[4] In this paper electricity costs and benefits for pv and alternative electric power systems are calculated on a lifecycle cost basis assuming a 6% real (inflation-corrected) discount rate. Because a societal perspective is adopted, corporate income and property taxes (which are transfer payments, not real costs) are neglected. The procedure for calculating pv elecricity costs is outlined in the appendix. Cost assumptions for fossil fuel power generating systems are summarized in Table 4.

[5] U. S. Department of Energy cost projections are based on the use of standard U. S. electric utility accounting procedutes as recommended by the Electric Power Research Institute in its ***Technical Assessment Guide***, which take into acount corporate income and property taxes [20]. To adjust Department of Energy pv generation cost targets to the accounting rules used in the present analysis (*see footnote 4*), the capital charge components of these targets should be multipled by 0.75.

[6] The 1.1 m^2 modules are 12.7% efficient (based on total module area, at standard test condiitions of 1 kW/m^2 irradiance and 25 °C cell temperature) [24].

[7] This electricity generation cost estimate [24] is based on accounting rules that take into account corporate income and property taxes [20]; under the accounting rules of the present study (*see footnote 4*) the cost would be 8.2 cents/kWh.

technological assumptions of the Accelerated Development scenario with an 80% progress ratio.

It is generally believed in the thin-film pv community that, with adequate R&D, it will be possible by 2010 to produce 15% efficient thin-film modules at a factory-gate price of $\$50/m^2$ (private communication from Ken Zweibel, Manager of the Thin-Film Technology Project, National Renewable Energy Laboratory, Golden, CO, September 1993).[8] These parameters correspond to an installed pv capital cost of about $\$1100/kW_p$ and, for areas having the U. S. average insolation of 1800 $kWh/m^2/year$, an electricity generation cost of less than 5 cents/kWh (*see Table 2 and the appendix*), which is comparable to the cost of electricity from new fossil fuel power plants.

The dynamics of prospective pv cost reductions can be illustrated by the relationship between the cumulative pv capacity CUM_f (in GW_p) that must be built to bring the module cost down to the long-term target level of C_f (in $\$/m^2$) and the progress ratio PR (expressed as a decimal fraction):

$$CUM_f = CUM_o \cdot \left(\frac{C_f}{C_o}\right)^{\left[\frac{\ln 2}{\ln PR}\right]},$$

where C_o is the module cost when cumulative pv production is CUM_o. Assuming 1993 values of $C_o = \$523/m^2$ and $CUM_o = 0.363$ GW_p, the cumulative production needed to reach the cost goal of $\$50/m^2$ would be about 100 GW_p for a 75% progress ratio, 500 GW_p for a 80% progress ratio, 1,000 GW_p for an 81.6% progress ratio (the historical average progress ratio--*see Figure 6)*, and over 8,000 GW_p for an 85% progress ratio.

The CUM_f value of 8,000 GW_e in the last instance indicates that if the progress ratio in the future were as high as 85%, the pv cost goal of $\$50/m^2$ would probably never be reached, because it would require producing pv electricity equivalent to about 1.5 times total global electricity production at present! One situation that could give rise to a high progress ratio is where there is an imbalance in the pv development effort, with market development emphasized at the expense of research and development. A high progress ratio could arise in such circumstances, because mere refinements of pv technologies that are already commercialized are not likely to lead to 15% efficient modules costing $\$50/m^2$.

On the other hand, if a strong research and development effort makes it possible to reduce the progress ratio to 75%, while markets are developed as rapidly as in the Accelerated Development scenario, the goal of 15% efficient modules costing $\$50/m^2$ would be met by the end of the first decade of the next century, when cumulative pv capacity in this scenario would be about 100 GW_p (*see Figure 3)*.

For the scenario analysis it is assumed that costs of pv system components evolve over time following a fixed progress ratio, until long-term cost targets are met, and that subsequently costs remain constant.[9] The progress ratio in the base case is taken to be 80%. With this progress ratio the cost of pv modules falls by 2010 to $\$100/m^2$ (and the corresponding cost of pv electricity from new installations reaches about 6.5 cents/kWh (*see Figure 7)*, in areas where the insolation is 2000 kWh/m^2 (*see Figure 4)*. In this case module costs do not reach the $\$50/m^2$ target until after the end of the second decade of the next century, when cumulative production reaches 500 GW_p (*see Figure 3*).

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[8] Because the active layers of thin-film modules are so thin, estimating future costs per unit area is much easier than for most other pv modules. There is so little active material involved that materials costs are dominated by the costs of glass for encapsulation, wires, and other mundane items whose costs are readily estimated; moreover, manufacturing costs are not expected to vary substantially among the competing candidate thin-film options [16,21,22].

[9] In the present analysis the same progress ratio is applied to both the module costs and the area-related balance-of-system costs, as discussed in the appendix. Assymptotic values for balance-of-system costs would be reached much sooner than for the module costs, however, because the initial values are much closer to the assymptotic values; for power conditioning costs, it is assumed that the assymptotic values are realized by the time the scenarios start in 1995 (*see the appendix*).

While an 80% progress ratio represents an improvement over the historical trend value of 81.6%, an improvement of at least this magnitude is consistent with the spirit of the Accelerated Development scenario, which involves emphasizing research and development as well as stimulating market development. Under such conditions it seems highly unlikely that the cost goal of $50/m^2 for 15% efficient thin-film devices would not be realized until after 2030 (as would be the case if the progress ratio were 81.6%), in light of: *(i)* the remarkable pace of technical progress for both cadmium telluride and copper indium diselenide *(see Figure 8)*, *(ii)* the fact that plans are underway to build commercial capacity for producing cadmium telluride and copper indium diselenide modules in manufacturing facilities that would account for about 5% of the 150 MW_p/year of total new worldwide pv module production capacity planned for 1995 [25], and *(iii)* the fact that there are other potentially very low-cost, thin-film pv technologies, such as dye-sensitized colloidal titanium oxide films [26] that warrant a serious research and development effort.

ESTIMATING THE VALUE OF PHOTOVOLTAIC ELECTRICITY

A cost/benefit analysis of photovoltaic technology requires a comparison of pv costs to benefits. Photovoltaic electricity offers various benefits.

One benefit considered here is the cost avoided by displacing electricity that would otherwise have to be generated from conventional energy sources. Another set of "distributed benefits" considered here arises from the fact that pv electricity generated close to consumers is more valuable than pv electricity generated in central station configurations.

No attempt is made here to quantify or otherwise take credit for environmental benefits such as zero emissions of local air pollutants and greenhouse gases, because the purpose of the present analysis is to highlight the extent of the *direct economic benefits* of accelerated development of pv technology.

The Cost of Conventional Electricity Avoided

In the present analysis only grid-connected applications of pv electricity are considered. The question addressed in this section is: what is the value to the electric utility of avoiding the costs that would otherwise be incurred to generate the same amount of electricity from conventional (*e.g.* fossil fuel) sources? The question is not easily answered. One cannot simply compare the cost of pv electricity to the cost of electricity from a coal or a natural fired power plant, because such comparisons would involve "apples and oranges."

Unlike a conventional fossil fuel plant, a pv power plant (or any power plant involving the production of electricity from an intermittent renewable power source) cannot be dispatched by a utility operator; instead, electricity can be provided only on an as-available basis. This attribute of intermittent renewables, which diminishes its value relative to conventional dispatchable power sources, must be taken into account in assessing their value to the utility. On the other hand, for summer peaking electric utilities, pv electricity is typically generated at the highest rates at the times of the utility system peak demand, which is often determined by the air conditioning load in buildings. This advantageous attribute of solar power sources must also be taken into account in assessing pv value.

To address such questions, an electric utility planning model called SUTIL (for Sustainable UTILity) was developed [27] for the renewable energy study carried out for the UNCED [6]. The costs of generating electricity from alternative electricity supply portfolios for meeting the demand at a specified level of reliability for the generation system can be compared with this model. In particular the model makes it possible to determine the least costly mix of conventional electricity sources that would be required to "back up" a specified level of intermittent renewables on the system and to determine the value of intermittent and other renewable energy systems on electric utility grids as a function of their level of penetration of the utility system.

The SUTIL model requires as inputs hourly load data over a period of at least a year for the utility being modeled. For pv systems it also requires data on insolation available in the utility service area on an hourly basis throughout the year.

Intermittent renewables are treated as "negative demand" in the model (since these power sources are non-dispatchable)--*i.e.*, the output of the available intermittent renewable sources is subtracted from the total load in each hour of the year, and conventional sources are selected and dispatched in the least costly manner to provide the electricity needed to meet the residual demand.

In the modeling exercises for the global scenarios, avoided conventional generation costs are calculated under the assumption that the alternative to pv power generation is the least costly mix of fossil fuel power based on the the use of the most advanced coal and natural gas power-generating technologies now on the market (*see Table 4*).[10] The avoided cost of conventional power generation for the utility system is calculated as follows. For each year t in which new pv capacity in the amount $P(t)$ (in kW) is added to the utility system, the avoided generation cost $AGC(t)$ (in \$ per kWh) is given by:

$$AGC(t) = \frac{TGC[CUM(t)] - TGC[CUM(t)+P(t)]}{CF(t)\cdot P(t)\cdot(8760\,hours/year)},$$

where:

$TGC[CUM(t)]$ = total cost of conventional electricity generation (in \$ per year) for the electric utility system when total installed pv capacity is $CUM(t)$,
$CUM(t)$ = total installed pv capacity at the beginning of year t (in kW),
$CF(t)$ = capacity factor for capacity $P(t)$ added in year t.

A simplifying assumption made in the avoided cost calculations is that the 2/3 of the world's power generation modeled in the scenarios is made up of individual utilities having the same load characteristics and size as the Pacific Gas and Electric (PG&E) Company in California. Given the assumption for the scenario exercise that only summer-peaking utilities are taken into account, this simplification should not distort the findings very much. Figure 9 shows, for the Accelerated Development scenario, that there is very little difference between the avoided costs calculated for the PG&E system and those for a prototypical (synthetic) utility in the United States characterized as a summer peaking utility [29]. (Further investigations would be desirable to see whether the avoided costs would change much if developing country load profiles were used.)

The changing amount and mix of generating capacity and electricity generation over the period 1995 to 2020, with and without pv on the system, calculated with the SUTIL model is shown in Figure 10 for the Accelerated Development scenario.

The total generating capacity on the system is higher with pv than without pv (*see Figure 10*), because the generating capacity value for pv is less than for fossil fuel technology, and this capacity value declines with increasing penetration of pv on the system. A new installed kW of pv capacity is worth 0.83 kW, 0.60 kW, and

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[10] In the calculation of avoided costs, it is assumed that coal and natural gas prices in 1995 are the U. S. average values projected for that year by the U. S. Department of Energy in its National Energy Strategy (NES) study [28]. It is further assumed that coal and natural gas prices escalate (in inflation-corrected terms) at average rates of 1.0 and 1.5 percent per year respectively, 1995-2025, and are constant thereafter. (*See note f, Table* 4.) The assumed growth rate for the coal price is the same as is projected in the NES study, but the the assumed rate of increase in the gas price is only about half of that projected in the NES study. The much slower expected growth in the natural gas price is consistent with the analysis of the renewables-intensive global energy scenario (RIGES) developed in [6], which argued that in an energy economy emphasizing renewables, oil and gas prices would grow much more slowly than under business-as-usual conditions.

0.40 kW of fossil fuel capacity, for the years 1995, 2010, and 2020, respectively.

Initially when pv capacity is added to the system, the conventional electricity it displaces is almost entirely from natural gas-fired combined cycles, reflecting the fact that pv power is displacing mainly electricity produced by such load-following plants at times of high electricity demand. However, over time a larger share of the fossil fuel-based electricity displaced in the least-costly manner is from coal plants (*see Figure 10*). Coal's share of the electricity displaced increases from 0 percent in 2000, to 13 percent in 2010, and to 89 percent in 2015. By 2020 the amount of coal-fired power generation decreases by more than the amount of pv electricity generated, along with a modest increase in the contribution of combined cycle power relative to the case where there is no pv on the system. More coal is displaced during the later periods both because of the growing share of coal in power generation in the absence of pv (*see Figure 10*), as a result of the slower expected growth rate for coal prices than for natural gas prices, and because of the displacement of more baseload generation at higher pv penetration levels.

Avoided generation costs calculated with the SUTIL model for the Accelerated Development scenario (*see Figures 9 and 11 and Table 5*) initially rise slightly from the 1995 value of 6.6 cents/kWh (reflecting the rise in fuel prices) but then decline slowly (reflecting the decline in the marginal value of pv electricity as the pv penetration level increases), reaching 5.7 cents/kWh by 2020.

Benefits of Distributed Pv Systems

The distributed generation concept, involving small-scale, grid-connected generating units sited near consumers, as an alternative to central station power generation, is a hot topic of debate today among electric utility planners in the U. S. [30,31]. Interest in distributed generation is driven by competition in the power generation industry, recent advances in small-scale generating technologies, and growing environmental restrictions that are making it increasingly difficult to site new central-station power-generating facilities. Distributed power-generating systems are often more valuable to the utility (in terms of reduced costs) and to the customer (in terms of increased reliability of service) than electricity generated in large central-station power plants.

Photovoltaic technology in particular has four inherent characteristics that make deployment feasible in dispersed, decentralized configurations where electricity is generated near the consumer:

- Photovoltaic power sources can be deployed at scales of tens and hundreds of kW_p of installed capacity without substantial scale-economy penalties.
- Small-scale pv systems can be designed that do not require operating personnel onsite continuously.
- Maintenance requirements for small-scale pv systems are modest.
- Because pv systems are non-polluting, they can be sited in areas of high population density, where environmental restrictions tend to be the most severe.

There are several factors that contribute to the enhanced value of distributed pv systems.

Major savings in transmission and distribution (T&D) costs are possible with distributed pv power when pv peak output is well-correlated with peak electrical demand on the T&D system.[11] With appropriately sited

[11] The prospect of reducing T&D investment costs via the installation of distributed pv systems should be especially attractive to utilities beset be strong competitive pressures, because investments in T&D equipment have become far more important for electric utilities than they have been historically. In 1982, T&D investments accounted for about 1/5 of total U. S. electric utility expenditures on new construction [32]. Since then, investments in T&D have increased (in inflation-corrected terms) at an annual average rate of 2.4% per year,

distributed pv systems, transmission conductors and substation transformers of lower capacity are needed in serving local distribution grids; installing distributed pv units on existing T&D systems can lead to a deferral of investment in new T&D capacity as a response to growing electrical loads. Distributed systems also make possible savings in the transmission-related costs for the complex switching operations at transformer stations that are necessary to maintain control over voltage.

In addition, power losses in the transmission and distribution network would be reduced if power generating units were located close to consumers. And reactive power losses associated with current and voltage being out of phase that would otherwise have to be corrected by installing shunt capacitors can be reduced as a result of the local voltage support provided by a distributed pv generating facility.

Distributed pv systems can also help reduce electrical service losses to customers that arise from equipment failures in the transmission and distribution system.[12] Customer surveys indicate that lost service is often worth many dollars per kWh for some customers--far in excess of the cost of providing electricity. Some customers (*e.g.*, hospitals, telephone companies, computer-intensive service firms) place such a high value on reliability of service that they are willing to make substantial investments in stand-by generating capacity or batteries on their own premises to safegurard against such outages, even though such equipment is seldom used. Distributed pv systems on the electrical grid can help increase the reliability of electrical service, largely because with these systems on the grid, utilities would have more options for routing power to consumers around a fault in the distribution system during a power outage. Generation equipment located at strategic sites close to consumers would enable the utility to maintain continuous service to more customers while a fault is isolated and being repaired *(see Figure 12)*.

The potential quantitative benefits offered by distributed generation are illustrated by a 500 kW_p one-axis tracking pv array that was installed in May 1993 in the San Joaquin Valley in California, at the Kerman substation of the Pacific Gas and Electric (PG&E) Company. This system was installed as a result of studies carried out at the Pacific Gas and Electric Company indicating that the distributed benefits of such a pv system installed at the Kerman substation would be sufficiently large that it would be cost-effective to install such a system to provide grid support [34,35]. The distributed benefits estimated by PG&E analysts and modified to conform to the cost accounting methodology of the present paper[13] amount to $227 per year per kW of installed capacity *(see Table 6)* or, for a 26% capacity factor, 10 cents/kWh-- which is 50% greater than the avoided generation cost in 1995, as calculated by the SUTIL model.

The extent to which "Kerman-like" opportunities exist elsewhere is not yet known. The Kerman site was selected for careful study because it was known that transmission and distribution capacity upgrades would soon be needed, to avoid overheating of transformers and transmission lines during summer peaking periods. The results cannot be easily extrapolated, because distributed benefits depend on site-specific conditions. A great deal of time and effort went into gathering the data and carrying out the analysis for Kerman. However, methodologies are being developed to reduce the data requirements and standardize and simplify the required

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at the same time total investments in new construction by U. S. electric utilities have declined at an average rate of 9.4% per year. In 1992 total T&D investments were about $16 billion, accounting for about 2/3 of total investments in new construction--a fraction that is expected to persist to the turn of the century [33].

12 Electric utilities commit substantial resources to ensuring the reliability of their electric generating equipment. Typically, utilities in the U. S. strive for a level of reliability for its generating system corresponding to loss of electrical service amounting to 1 day in 10 years--*i.e.*, 2.4 hours per year. But the actual rate of loss of electrical service is often much higher than this because of failures in the transmission and distribution system. For customers served by the Kerman substation of the Pacific Gas and Electrici Company in California, the total outage rate over the last several years has averaged over 20 hours per year *(see note g, Table 6)*.

13 PG&E analysts calculated the distributed benefit to be $382/kW-year, in current dollars, taking taxes into account. This is reduced to $227/kW-year *(see Table 6)* when expressed in constant dollars and taxes are ignored.

analysis in the Distributed Utility Valuation Project, being carried out by the National Renewable Energy Laboratory, Pacific Northwest Laboratories, the Electric Power Research Institute, and the Pacific Gas and Electric Company [36].

The Kerman substation analysis does show, however, that distributed power sources are much more valuable than central station power sources in areas where pv output is strongly correlated with peak electrical demand. Accordingly, it is very likely that in the decades immediately ahead, most grid-connected pv systems installed in such areas will be in distributed configurations.

Initially, distributed pv systems would be installed in areas where the distributed benefits are large, as at the Kerman substation. But as more pv capacity is added to the system, the marginal value of distributed benefits would decline. For example, while the peak electricity output from pv systems installed on rooftops of commercial buildings will often be coincident with the utility subsystem peak demand on summer-peaking electric utility systems, the peak electricity output from systems mounted on residential rooftops will typically preceed the residential peak demand, so that distributed benefits will be reduced unless there are commerical building or other subsystem peaking customers nearby that can be served by these residential rooftoop systems.

In the absence of a good data base on distributed benefits, it is assumed for the global scenario analysis that (*i*) initially (in 1995) the average distributed benefit is much less than the Kerman substation value--\$100/kW-year (or 4.3 cents per kWh for the initial pv capacity factor of 26.6%), and (*ii*) the distributed benefit (measured in \$/kW-year) for new pv capacity varies with the square of the capacity factor for new pv capacity--thus falling to about \$40/kW-year (or 2.8 cents/kWh) by 2020 in the Accelerated Development scenario (*see Table 5).* Under these assumptions the total value of distributed pv electricity (avoided generation cost plus distributed benefit) in the Accelerated Development scenario declines from 10.9 cents/kWh (1.65 times the avoided generation cost) in 1995 to 8.5 cents/kWh (1.48 times the avoided generation cost) in 2020.

GLOBAL BENEFITS AND COSTS

Considering costs and benefits together for distributed, grid-connected pv systems, the trend over time is that pv costs will initially exceed but will eventually fall below benefits in the alternative global scenarios. The crossover point in time depends on the growth rate of pv demand, since it is assumed that future costs are determined by experience curves.

The dynamics of the relationship between costs and benefits per kWh for new distributed pv installations are shown in Figure 11 for alternative scenarios characterized by an 80% progress ratio. Under Business-As-Usual and Accelerated Development conditions, costs fall to the level of total value (avoided generation cost plus distributed benefit) in the years 2009 and 2003, respectively. Moreover, in the Accelerated Development scenario with an 80% progress ratio, the cost falls to near the avoided generation cost level shortly after 2010, so that the end of the first decade of the next century may well be the period when central station pv based on flat-plate collector technology becomes cost-competitive with central station fossil fuel technologies.[14]

[14] If, as indicated in Figure 11, the marginal cost of pv electricity generation reaches but does not fall below the avoided cost of generating electricity from conventional sources, regulations or tax incentives (*e.g.*, a carbon tax) may be needed to tip the balance in favor of pv technology. Incentives may be needed because the propensity of investors will be to stick with the more familiar technology rather than incur the risks of innovation.

In practice, however, flat-plate pv technology may be more attractive for central station applications than is indicated by Figure 11. At modest incremental cost, tracking collectors typically will be able to recover more solar energy per unit of collector area than fixed arrays, and, by providing more electricity later in the day and thereby making a better match to load than is possible for fixed arrays, can often provide electricity that is more valuable to the utility [34].

In addition, Awerbuch has argued that if financial risks are correctly taken into account, pv electricity would be found to be more

If pv concentrating collector technology is also brought to commercial readiness in this period [23], it can be expected that by 2010 there will be many pv technologies competing in central station markets.

Aggregate costs and beneftis for pv development in the global energy economy are determined by considering over time the costs and benefits per kWh (*see Figure 11*) together with the growth in installed global pv capacity (*see Figure 3*). The resulting annual net global benefit (for each year, the avoided generation cost plus the distributed benefit minus the pv generation cost, for the 30-year lifecycle of all new pv capacity added in that year) is shown for the alternative scenarios with an 80% progress ratio in Figure 13 and Table 5 (the notes to which present details of the calculations). Under competitive market conditions these benefits would be realized as reduced expenditures on energy by consumers and could not easily be captured by producers.

Also indicated in Figure 13 is the present worth in 1995 of the net benefits for each scenario. This quantity, the present worth of the positive benefits from the period after breakeven minus the present worth of the dead-weight loss in the years before breakeven, equals $90 billion for the Accelerated Development scenario but only $1.6 billion for the Business-As Usual scenario. The very large difference arises largely as a result of slower rate of decline of costs under Business-As-Usual conditions and the time value of money. Benefits that arise in the distant future are worth little today because of the effect of discounting.

Remarkably, there is little difference between the initial dead-weight losses for these two scenarios: $2.7 billion and $3.3 billion for the Business-As-Usual scenario and the Accelerated Development scenario, respectively; while the annual loss is greater in the early years for the Accelerated Development scenario, the losses occur over a longer period of time in the Business-As-Usual scenario. Of course, a comparison of these initial losses should not be considered too seriously, since the Business-As-Usual scenario presented here is simply a mathematical construct designed to highlight the dependence of the net benefits on the growth rate for pv capacity additions. A true business-as-usual scenario would instead focus on niche market development, for which there would be no initial dead-weight loss. If the cost-cutting potential of niche markets were taken into account, the present worth of global net benefits for the niche-market-exploiting variant of the Business-As-Usual scenario would increase to $4.2 billion, and the initial dead-weight loss for the Accelerated Development scenario would be reduced to some extent.

The sensitive dependence of the present worth of net benefits on the progress ratio is illustrated in Figure 14 for the Accelerated Development scenario: it rises to $132 billion for a 75% progress ratio and falls sharply to - $5 billion for an 85% progress ratio. The 75% progress ratio result illustrates the value of augmenting the R&D effort to the extent that the long-term cost and performance goals for thin films are met by 2010--a goal that the thin-film community generally believes to be feasible. The 85% progress ratio result illustrates the danger of emphasizing market development at the expense of research and development.

PUBLIC POLICY ASPECTS OF ACCELERATED PV DEVELOPMENT

The analysis presented here indicates that under quite plausible conditions, there would be enormous direct economic benefits, as well as environmental and energy security benefits, arising from accelerated development of pv technology. But by definition, accelerated development will not take place without public sector intervention in the marketplace. Pursuing an accelerated development path requires a public policy aimed

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financially attractive in electric utility rate cases than is indicated by the benefit/cost analysis methodology used in this paper, in which all costs and benefits are assessed using a constant 6% real discount rate. He holds that when a shift is made from conventional energy technologies (for which financial rists are very similar) to unconventional technologies such as pv, the discount rates used for financial analyses should be carefully chosen to properly reflect the relative financial risks involved [37]; when risks are properly accounted for, the discount rates involved will tend to vary substantially not only from one technology to another (*e.g.*, natural gas-based and pv-based power generation) but also for different cost components for a given technology. (For example, he argues that fuel expenditures for natural gas should be evaluated with a discount rate that is much less than the risk-free discount rate, in order to reflect properly the large uncertainty in future natural gas prices.)

at creating:

- o Rapidly growing demand for grid-connected, distibuted pv systems worldwide.
- o A mechanism to pay for the initial dead-weight loss associated with early deployment of distributed pv systems.
- o A mechanism to pay for the increased research and development effort needed.

There is no unique formula for carrying out these actions. Here the possibilities are illustrated by showing how public policy might be formulated under two alternative approaches: a fiscally austere strategy and a failure-averse strategy.

A Fiscally Austere Strategy for Accelerated Pv Development

The political climate in most countries is not favorable to making major public sector investments in new energy technologies. The multi-billion-dollar government programs of the 1970s to develop nuclear breeder reactors and to create new synthetic fuels industries were major failures that resulted in no commercial products. Today there is a general cynicism in political circles regarding the ability of government to pick winners in efforts to speed up the rate of technological innovation. In addition, sluggish economic growth in most industrialized countries and large budget deficits in the U. S. make it politically difficult to launch costly new government programs of any kind. In such circumstances it is desirable to explore the prospects for an accelerated pv development program that does not require additional expenditures by governments.[15]

One element of the strategy might involve legislation requiring that utilities make annual purchases of pv systems for distributed applications on their grids, in the amounts required by the Accelerated Development scenario. This initiative might be launched first in the U.S., and the President might call upon other countries to follow the U.S. lead--pointing out that all countries would benefit from a cooperative international effort, which would lead to a more rapid decline in pv prices than otherwise would be possible. An international agreement would be needed to allocate market shares to different countries.

Mass purchases of pv capacity by electric utilities could be done most efficiently via auctions, in which pv vendors compete for sales. The capacity to be purchased in a series of auctions planned over, say, a five-year period might be announced in advance, along with a posting of the maximum allowed bid price for each year. These posted maximum bid prices might, for example, be specified by the historical 81.6% experience curve, if the goal were an 80% experience curve. Maximum bid prices could be adjusted periodically in light of experience.

Since the U.S. accounts for about 40% of total electricity generation for the parts of the world covered by the scenarios developed here, it is reasonable to expect that the U. S. share of annual pv purchases would be at least this percentage of the total. But because the U. S. has such large land areas with good insolation (*see Table 2*), and because its pv industry is much larger than the pv industries in most of the rest of the world covered by the scenarios (mainly developing countries), it is reasonable to expect that half of the pv capacity installed worldwide would be in the U.S., so that annual U. S. purchases would be 70 MW_p in 1995, 290 MW_p

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[15] An accelerated development effort that does not involve additional government expenditures is not necessarily an oxymoron. Sometimes much can be accomplished with a creative stroke of the pen in new legislation or in new administrative procedures. An outstanding success of this kind is the incentive for cogeneration (combined heat and power) provided by the Public Utility Regulatory Policies Act, passed by the U. S. Congress in 1978, which requires that utilities: (*i*) purchase electricity from qualifying cogenerators at a price equal to the avoided cost of not producing the electricity from utility power sources, and (*ii*) provide backup power at fair prices. This law has led to the creation of a powerful new industry of independent power producers in the U. S.

in 1999, and 815 MW_p in 2002, the last year for which installations would be characterized by pv costs in excess of pv value in the Accelerated Development scenario *(see Table 5a).*

The second element of the strategy involves devising private-sector-based, risk-sharing incentive schemes to pay for the pv costs in excess of pv value during the period 1995-2002. The required incentive in the U. S., levelized over the period 1995-2002, would be about $0.26 billion per year. The incentive per unit of pv capacity would be $3,100/$kW_p$ (half the total installed cost of the pv system) in 1995, but the required incentive would be reduced in half by 1998, in half again by 2000, and in half again by 2001 *(see Table 5a).* The incentive scheme must be designed to reward those investors who purchase high-cost units initially; otherwise prospective purchasers of pv equipment will be inclined to delay making purchases until costs come down.

One possible model of a private-sector-based, risk-sharing incentive scheme is the approach being pursued by the Fuel Cell Commercialization Group (FCCG)--a North American organization of potential electric and gas utility buyers of fuel cell power plants. The mission of the FCCG is to commercialize by 1998 the multi-megawatt molten carbonate fuel cell being developed by the Fuel Cell Engineering Corporation (FCE), a subsidiary of Energy Research Corporation (ERC) of Danbury, Connecticut. The basic idea behind the organization is that if an initial 2 MW_e demonstration project meets specified performance criteria, members of the FCCG would be obligated to purchase 35 early production units having a total capacity of 63 MW_e, in exchange for royalties from the sale by FCE of subseqent production units, with royalty payments arranged to give the largest rewards to those who make the initial purchases.[16] In the case of pv, the purchasing utility might form such a joint venture with the winning bidder(s) at the time of an auction.

The third element of the strategy is to increase support for research and development (R&D). Implementing the Accelerated Development scenario will require a diverse and sustained pv R&D effort. At present government expenditures on pv R&D are relatively modest in relation to both overall levels of government support for energy R&D and to the potential benefits of accelerated pv development estimated in this paper. In 1991 total government support for pv R&D in OECD countries was $0.2 billion--about 2 percent of all energy R&D expenditures in OECD countries *(see Table 7).* In the U. S., which accounts for about 1/4 of total government R&D funding for pv in OECD countries *(see Table 7),* cumulative federal funding through 1994, in 1992 dollars, is $1.8 billion *(see Table 8),* some 1.6% of total U. S. government funding for all energy R&D since 1950 [38]. Industry has invested twice as much in pv R&D as the federal government [39]. The facts that some of the most promising technologies for meeting long-tern pv cost and performance goals are not yet on the market and account for a relatively modest fraction of total pv R&D expenditures suggest the need for an expanded R&D effort. For example, total cumulative U. S. Department of Energy support for thin-film pv R&D (1978 through 1994) is about $0.21 billion *(see note d, Table 8),* less than 1/8 of the total for all pv technologies, and in the 1994 Department of Energy budget request for pv R&D, thin-film technology still accounts for less than 1/5 of the total for pv.

Despite the need for more R&D, there would be no increase in government suppport for pv R&D in a fiscally austere strategy to accelerate development. Those who would advocate this approach would argue that the creation of a well-defined market would provide the necessary incentive for industry to expand its R&D effort. They would point to other dynamic industries such as personal computers and pharmaceuticals, where management knows a company must "innovate or die."

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[16] The 2 MW_e demonstration plant is being built for the City of Santa Clara, CA, and is scheduled to go into operation in 1994. If the demonstration project is a success, participants will receive royalties amounting to twice the amount of investment funds that require repayment. Those who purchase the first 22 early production units will receive a royalty premium equal to twice the premium paid above the price of a mature unit. Those who purchase the 23rd through the 35th early production units will receive royalties equal to 1.5 times the premium paid above the mature unit price. The royalty repayment schedule is based on the installation order of the early production units, thus providing an added incentive for early investment.

Would this strategy work? Possibly, but not certainly. If risk-sharing joint ventures could be successfully established between utilities and pv vendors, and if pv costs were to continue declining according to the historical 81.6% experience curve, pv costs would fall below pv value by 2004, the present value in 1995 of net future benefits would be $65 billion (less than for the base case 80% progress ratio but still substantial!), and, if government R&D funding were to persist at the present level for ten years beyond break-even, the societal benefit/cost ratio [(present value of net future benefits)/(present value of future R&D expenditures)] would be about 10 (*see Table 9*).

But it is not certain that risk-sharing joint ventures could be successfully established--especially in the early years. Since the prospects for meeting long-term cost and performance goals for pv technologies suitable for distributed applications are not good for commercially available pv technologies, utilities might feel that the prospects for ever getting acceptable returns on their initial investments from such ventures would not be good, unless that vendors involved had suitably diverse portfolios of pv technologies under development.

If such joint ventures turned out not to be feasible, utilities might still be able to satisfy the legislative mandate for pv purchases by passing on to their customers the pv costs in excess of value. This would not be especially burdensome, because in early years when unit costs are high, the penetration level would be low, and unit costs would fall sharply with the level of penetration. The maximum level of the penalty during the 1995-2002 period would be less than 0.2 percent of the average generation cost for the utilities deploying distributed pv systems. While this is indeed modest, it poses a free-rider problem: future customers of non-participating utilities would benefit from such a strategy.

And there is no guarantee that industry would adequately respond to the R&D challenge without additional government support. The analogy to research and development carried out by personal computer and pharmaceutical manufacturing companies is not a very good one, because such companies compete in large, well-established industries. The pv industry is embryonic. Most companies do not have highly diversified pv technology portfolios but rather are developing one or a small number of alternative concepts. Some of these companies are under-capitalized firms manufacturing pv modules for high-value, low-volume niche markets in remote applications; for them, diversifying to also develop advanced technologies for which costs might be an order of magnitude less poses high risks. There are also small, high technology companies in the industry, each exploring one advanced concept offering long-term promise; with no marketing activity to provide income, such companies are dependent on government R&D support. As noted already, the level of government R&D support for advanced pv concepts is modest.

A plausible outcome of the fiscally austere approach to accelerated development is that costs will fall less rapidly than historically. If, as a result of an inadequate R&D effort, the progress ratio were to increase to 85%, this strategy would be characterized by rapid market demand growth but a negative present worth of future benefits (*see Figure 14).* The heart of the problem lies with the propensity of the private sector to underinvest in R&D--the primary rationale for government support of R&D of any kind. Cohen and Noll point out that the profitability of R&D is higher than for most other investments that industry undertakes, and that the social rate of return is higher still--thus indicating that there is a general tendency in the private sector to underinvest in R&D [40]. The reasons for underinvestment in R&D are well-known, the most important of which in the case of pv are that: (*i*) the information generated is a public good, which makes it difficult if not impossible for innovators to appropriate all the benefits of the spillover effects of their R&D; (*ii*) there is social value (*e.g.*, environmental or energy security benefits) to the technology that are not adequately reflected in market prices. In one attempt to quantify the degree of underinvestment in pv R&D, Richards finds that current R&D funding levels are about 1/6 of the optimal level [39].

Thus, while it might be possible to accelerate the development of pv technology without additional government expenditures, it is just as plausible that the societal returns would be disappointing. There may be no free lunch.

A Risk-Averse Strategy for Accelerated Pv Development

If a high degree of confidence in the outcome of an accelerated development effort is desired, a more active government role may be needed than that associated with the fiscally austere development strategy.

A risk-averse strategy for accelerated pv development could have the same legislative mandate for pv purchases, but additional government expenditures for market development and for R&D would be needed.

For an 80% progress ratio, the present worth of the required market development subsidy is $3.3 billion for the world, half of which would be directed to investments in the U.S. The annualized subsidy levelized over the period 1995-2002 is $0.52 billion per year. The $0.26 billion per year subsidy for U.S. pv investments could be administered as a tax credit for the utilities that purchases pv equipment for distributed applications.

Because initially most companies offering competitive and advanced pv products will have home bases in industrialized countries, and because developing countries (accounting for most of the market outside the U. S.) face pressing development challenges, developing country governments would tend to be reluctant to provide the needed pv market development subsidies. A more plausible scenario is that the subsidies for developing country markets be provided by the governments of those industrialized countries having pv companies seeking export markets in developing countries--mainly several European countries, Japan, and the U.S. These subsidies might be administered so as to nurture the development of joint ventures between domestic and industrialized country companies, to help develop pv industries in developing countries and help ensure a continuing market presence of pv vendors from industrialized countries there, . Various interational agencies (*e.g.* the Global Environment Facility at the World Bank) and bilateral development agencies could help allocate these subsidies and facilitate pv market and industrial development in developing countries.

If the U. S. were to provide 1/3 of the subsidy needed for developing country markets and thereby hope to gain access via joint ventures to as much as 60 to 70 GW_p of potential markets there for American firms, total annualized cost to the U. S. treasury for pv market development, 1995-2002, would be $0.35 billion per year. Suppose, in addition, that the U. S. were to increase its pv R&D support six-fold above the 1992 level, to $0.36 billion per year, so as to provide support at the level suggested as optimal by Richards [39]. The total incremental federal budget requirement for the entire effort, some $0.65 billion per year, might be supported by a carbon tax on electric utility fuel purchases. For the 1992 mix of U. S. electricity sources, the required tax would be $1.33/tC, and its impact would be to raise electricity rates by 0.34 percent--a modest penalty.

For the global effort, societal benefit/cost ratios are listed in Table 9 for R&D support at levels of 3, 6, and 9 times the OECD R&D funding level for pv in 1991, and for 75%, 80%, and 81.6% progress ratio variants of the Accelerated Development scenario. These societal benefit/cost ratios range from 6 to 19 with a three-fold increase in pv R&D support to 3 to 7 for a nine-fold increase in R&D support. Since these ratios are much larger than 1 even with very large increases in R&D support, ascertaining the precise level of R&D support needed to meet pv program goals or the economically optimal amount of pv R&D support (inherently difficult calculations) is not necessary. Very favorable benefit/cost ratios can be realized under a wide range of conditions. Higher levels of R&D support would tend to shift the outcomes to lower progress ratios and to reduce the chances that pv performance and cost goals would not be met. A quantification of the probabilities of alternative outcomes is beyond the scope of the present analysis.

Would not this strategy lead governments into the trap of trying to pick winners and failing in the process--as governments have done so often in the past? There are several ways to address this concern.

First, neither the market-development effort paid for via tax credits nor the enlarged and diversified pv R&D program would involve government choosing the winners among the various pv candidate technologies, although it would require government to make a significant generic commitment to pv technology. The extent to which this commitment limits the possibilities for pursuing other promising alternative energy paths depends on the numbers. For the U. S., the present worth of the incremental cost to the government for this strategy--the market development subsidy for the U. S. plus the U. S. share of the market subsidy for developing countries (1/3 of the total) plus, say, increasing annual pv R&D expenditures to six times the 1992 rate, is some $5.4 billion. This is not a high price for launching a new industry that offers a wide range of economic, environmental, and energy security benefits. For comparison, the U. S. spent on energy R&D between 1950 and 1993, in 1992 dollars, some $56 billion on nuclear fission, $25 billion on fossil fuels, and $15 billion on nuclear fusion (which probably won't be commercialized until late in the second quarter of the next century!)[38].[17]

That the price tag for launching a pv industry is modest is a reflection of the small scale of pv equipment, which makes it easier to realize high rates of progress from both organizational learning and from technological improvement than is feasible with large-scale fossil fuel or nuclear technologies. While the scales involved with pv technology are especially small, the same arguments are likely to hold for many other renewable technologies and also for fuel cells (operated on fossil as well as renewable fuels)--thus making it possible for the government to simultaneously support the development of many such technologies at total costs that are relatively modest. Moreover, the costs to government of helping to establish industries based on other promising renewable technologies are likely to be less in most instances than the costs for pv technologies, because the energy production costs for most of the other promising renewables (*e.g.*, wind power [41], solar thermal-electric power [42], and biomass power [43]) are closer to the levels needed for widespread commerical application. Thus a strong government role in advancing pv technology does not imply that government would be picking the winners. At the levels of public support needed for pv technology, many paths could be pursued simultaneously and government could let a thousand flowers bloom.

Finally, it would be possible to pursue a failure-averse accelerated development strategy for pv (and probably for many other renewable energy and advanced energy-efficiency technologies as well), even in a fiscally austere political climate, if there were a political commitment to rationalize the existing system of energy subsidies. The market value of all U. S. government subsidies to the energy sector is estimated to have been $36 billion in 1989--mostly for fossil fuels ($21.1 billion) and for nuclear fission ($10.6 billion) [38]. Energy policymakers should strive to: (*i*) phase out all subsidies associated with the production and use of established energy technologies, and (*ii*) reorder subsidies for new technologies so as to better reflect priorities with regard to the environmental, energy security, and competitiveness challenges we face in the decades ahead.

The present analysis indicates that major global economic benefits are the likely result of a policy aimed at accelerating R&D and market development for pv technology--complementing the well-known environmental and energy security benefits of this technology. Political leadership is needed to seize this opportunity, as sharp departures from historical trends in energy technology are not likely to be realized without it.

ACKNOWLEDGMENTS

The authors thank Dennis Anderson, Shimon Awerbuch, Roger Booth, Lynn Coles, Avinash Dixit, Harold Feiveson, Jose Goldemberg, Keith Kosloff, Wim Turkenburg, Sigurd Wagner, and Ken Zweibel for helpful comments on early drafts of this paper. This research was supported by the Geraldine R. Dodge Foundation, the Energy Foundation, the W.Alton Jones Foundation, the John Merck Fund, the Rockefeller Foundation, the Macauley and Helen Dow Whiting Foundation, and the U. S. Environmental Protection Agency's Air and Energy Engineering Research Laboratory.

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[17] A fairer comparison would be to the the present worth of these past R&D expenditures, which are much greater. For nuclear fission, fossil fuels, and nuclear fusion, the present worth of such energy R&D investments, 1950-1993, is $222 billion, $77 billion, and $42 billion in 1992 dollars, respectively, assuming a 6% discount rate.

Table 1. Installed Nuclear Electric Generating Capacity (in GW_e)		
Year	United States[a]	Worldwide[b]
1956	-	40
1957	105	181
1958	105	322
1959	105	577
1960	297	859
1961	442	1,019
1962	734	2,009
1963	861	2,406
1964	906	4,160
1965	926	6,440
1966	1,942	8,480
1967	2,887	10,810
1968	2,817	12,214
1969	3,980	15,397
1970	6,493	17,253
1971	8,688	23,355
1972	15,302	35,029
1973	21,118	42,790
1974	31,662	60,992
1975	39,754	75,125
1976	42,918	85,708
1977	49,880	98,145
1978	53,527	117,399
1979	54,593	127,112
1980	56,488	141,475
Average growth rate, 1957-77 (% per year)	36	37

Notes toTable 1

[a] Source: [44].

[b] Source: [45].

Table 2. Insolation[a] and Prospective Costs[b] for PV Power Generation Using Fixed, Flat-Plate Collectors Tilted at the Latitude Angle, at Alternative U. S. Sites

Location	Latitude (° North)	Insolation ($kWh/m^2/year$)	Busbar Cost (cents/kWh)
El Paso, TX	31.81	2563	3.36
Phoenix, AZ	33.43	2430	3.54
Ely, NV	39.28	2372	3.63
Los Angeles, CA	33.93	2197	3.92
Grand Junction, CO	39.12	2174	3.96
Dodge City, KS	37.77	2162	3.98
Miami, FL	25.80	2085	4.13
Fresno, CA	36.77	2083	4.14
Forth Worth, TX	32.83	2079	4.14
Charleston, SC	32.54	1967	4.38
Boise, ID	43.57	1963	4.39
Omaha, NE	41.37	1962	4.39
Bismarck, ND	46.77	1900	4.53
Sterling, VA	39.98	1877	4.59
Great Falls, MT	47.29	1823	4.73
Medford, OR	42.37	1820	4.73
Madison, WI	43.13	1807	4.77
Blue Hill, MA	42.22	1762	4.89
Nashville, TN	36.12	1691	5.09
Seattle, WA	47.45	1526	5.64
Cleveland, OH	41.40	1468	5.87

Notes to Table 2

[a] Data are for the two-year period 1962/63, assuming no shadowing of the illuminated arrays [46].

[b] The busbar cost of photovoltaic electricity is calculated via the procedure described in the appendiix, assuming performance and cost targets for photovoltaic components that are generally thought to be realizable in the year 2010 time-frame as a result of continued R&D and organizational learning through market development.

Table 3. Insolation[a] and Prospective Costs[b] for PV Power Generation Using Fixed, Flat-Plate Collectors Tilted at the Latitude Angle, at Alternative European Sites			
Location	Latitude (° North)	Insolation ($kWh/m^2/year$)	Busbar Cost (cents/kWh)
Faro, Portugal	37° 1'	2049	4.20
Trapani, Italy	37° 55'	1954	4.40
Nice, France	43° 39'	1823	4.73
Madrid, Spain	40° 27'	1804	4.77
Athinai, Greece	37° 58'	1768	4.87
Rome, Italy	41° 48'	1720	5.01
Davos, Switzerland	46° 48'	1574	5.47
Innsbruck, Austria	47° 16'	1432	6.02
Bratislava, Slovakia	48° 10'	1289	6.68
Paris, France	48° 46'	1227	7.02
Stockholm, Sweden	59° 21'	1176	7.32
Kolobrzeg, Poland	54° 11'	1176	7.32
Kilkenny, Ireland	52° 40'	1169	7.37
Oostende, Belgium	51° 12'	1165	7.39
Hojbakkegard, Denmark	55° 40'	1143	7.54
Berlin, Germany	52° 28'	1110	7.76
Groningen, Denmark	53° 8'	1092	7.89
Cambridge, UK	52° 13'	1056	8.16

<u>Notes to Table 3</u>

[a] Source: [47].

[b] The busbar cost of photovoltaic electricity is calculated via the procedure described in the appendix, assuming cost and performance targets for photovoltaic components that are generally thought to be realizable in the year 2010 time-frame as a result of continued R&D and organizational learning through market development.

Table 4. Cost of Electricity Generation (in cents/kWh) by Fossil Fuel Plants[a]			
Cost Component	Base Load: Coal-Integrated Gasification/Combined Cycle[b]	Intermediate Load: Natural Gas-Fired Gas Turbine/Steam Turbine Combined Cycle[c]	Peaking: Natural Gas-Fired Simple-Cycle Gas Turbine[d]
Capital[e]	1.59/CF	0.50/CF	0.39/CF
Fixed O&M	0.30/CF	0.17/CF	0.26/CF
Variable O&M	0.65	0.20	0.40
Fuel[f]	$0.8904*P_c$	$0.8235*P_g$	$1.1095*P$
Total	$0.65 + 1.89/CF + 0.8904*P_c$	$0.20 + 0.67/CF + 0.8235*P_g$	$0.40 + 0.65/CF + 1.1095*P_g$

Notes to Table 4

[a] The performance and cost parameters for these fossil fuel plants were provided by Harvey Wen, Fossil Technology Group, Bechtel Power Corporation, Gaithersburg, Md, October 1991.

[b] A 500 MW_e coal-integrated gasification/combined cycle plant (based on the use of a General Electric Frame 7F gas turbine) for which the overnight construction cost is \$1580/kW_e. It is assumed that the plant is built in 4.5 years, with 10% of the cost expended in the 1st year, 25% in the 2nd year, 42% in the 3rd year, 16% in the 4th year, and 7% in the 5th year, so that the total installed cost (including 6% interest during construction) is \$1794/kW_e. The efficiency at full power is 40.4% (HHV basis).

[c] A 395 MW_e unit (using a General Electric Frame 7F gas turbine), for which the overnight construction cost is \$540/kW_e. It is assumed that the plant is built in 3 years, with 18% of the cost expended in the 1st year, 52% in the 2nd, and 30% in the 3rd, so that the total installed cost is \$569/kW_e. The efficiency at full power is 43.7% (HHV basis).

[d] A 140 MW_e unit (a General Electric Frame 7F gas turbine), for which the overnight construction cost is \$430/kW_e. It is assumed that the plant is built in 2 years, with 40% of the cost expended in the 1st year, and 60% in the 2nd year, so that the total installed cost is \$440/kW_e. The efficiency at full power is 32.5% (HHV basis).

[e] For a 6% real discount rate, a 30-year plant life, an insurance rate of 0.5% per year, and neglecting corporate and property taxes, the annual capital charge rate is 0.07765. Here CF is the annual average capacity factor.

[f] Here P_c and P_g are, respectively, the prices of coal and natural gas, in \$/GJ (HHV basis). It is assumed that coal and natural gas prices escalate in real terms 1% per year and 1.5% per year, respectively, for 30 years from initial values in 1995 of \$1.67/GJ and \$3.15/GJ, respectively. The values for 1995 are the average electric utility prices projected for the US in 1995 by the US Dept. of Energy in its 1991 National Energy Strategy report [23]. It is assumed that fuel prices are constant after 2025. For fossil fuel plants coming on line in 1995 the 30-year levelized fuel prices would be \$1.88/GJ for coal and \$3.76/GJ for natural gas.

Table 5a. Global Accelerated Development Scenario for Photovoltaic Power (*assuming a pv experience curve with an 80% progress ratio*)									
Year	*P(t)*[a] (GW_p)	*CUM(t)*[b] (GW_p)	*INSOL(t)*[c] ($kWh/m^2/y$)	*CF(t)*[d] (%)	*PVC(t)*[e] (cts/kWh)	*AGC(t)*[f] (cts/kWh)	*DB(t)*[g] (cts/kWh)	Unit Incentive Needed[h] ($\$/W_p$)	*GNB(t)*[i] ($\$10^9/y$)
1995	0.14	0.537	2334	26.6	20.22	6.60	4.28	3.10	- 0.434
1996	0.21	0.682	2327	26.6	18.74	6.63	4.27	2.45	- 0.515
1997	0.29	0.887	2319	26.5	17.26	6.66	4.26	2.03	- 0.589
1998	0.41	1.178	2309	26.4	15.83	6.70	4.24	1.56	- 0.640
1999	0.58	1.589	2297	26.2	14.47	6.73	4.22	1.12	- 0.648
2000	0.82	2.171	2283	26.1	13.20	6.72	4.19	0.72	- 0.591
2001	1.16	2.993	2267	25.9	12.03	6.64	4.16	0.38	- 0.443
2002	1.63	4.151	2248	25.7	10.97	6.56	4.13	0.086	- 0.140
2003	2.28	5.779	2227	25.4	10.01	6.49	4.09	0.0	+ 0.391
2004	3.17	8.058	2202	25.1	9.16	6.41	4.04	0.0	+ 1.242
2005	4.39	11.23	2174	24.8	8.41	6.33	3.99	0.0	+ 2.511
2010	17.81	54.54	1979	22.6	6.50	5.99	3.63	0.0	+ 15.14
2015	38.05	185.9	1727	19.7	5.94	5.79	3.17	0.0	+ 27.40
2020	47.41	399.6	1501	17.1	6.04	5.74	2.75	0.0	+ 24.04

Table 5b. Global Business-As-Usual Scenario for Photovoltaic Power (*assuming a pv experience curve with an 80% progress ratio*)									
Year	*P(t)*[a] (GW_p)	*CUM(t)*[b] (GW_p)	*INSOL(t)*[c] ($kWh/m^2/y$)	*CF(t)*[d] (%)	*PVC(t)*[e] (cts/kWh)	*AGC(t)*[f] (cts/kWh)	*DB(t)*[g] (cts/kWh)	Unit Incentive Needed[h] ($\$/W_p$)	*GNB(t)*[i] ($\$10^9/y$)
1995	0.097	0.519	2336	26.7	20.66	6.60	4.28	3.15	- 0.306
1996	0.113	0.616	2332	26.6	19.63	6.63	4.27	2.80	- 0.316
1997	0.131	0.729	2327	26.6	18.67	6.66	4.26	2.48	- 0.325
1998	0.152	0.860	2322	26.5	17.78	6.70	4.25	2.18	- 0.332
1999	0.177	1.012	2317	26.4	16.94	6.73	4.24	1.90	- 0.336
2000	0.205	1.189	2311	26.4	16.16	6.77	4.23	1.64	- 0.337
2001	0.238	1.394	2306	26.3	15.42	6.80	4.22	1.39	- 0.332
2002	0.277	1.63	2299	26.2	14.72	6.83	4.21	1.16	- 0.322
2003	0.321	1.91	2293	26.2	14.07	6.87	4.20	0.95	- 0.304
2004	0.373	2.23	2286	26.1	13.45	6.90	4.19	0.74	- 0.277
2005	0.432	2.60	2279	26.0	12.87	6.93	4.18	0.56	- 0.240
2010	0.907	5.58	2236	25.5	10.40	6.85	4.10	0.0	+ 0.153
2015	1.881	11.78	2179	24.9	8.51	6.76	3.99	0.0	+ 1.264
2020	3.822	24.56	2103	24.0	7.41	6.68	3.85	0.0	+ 3.457

Notes for Table 5

[a] It is assumed that new pv capacity added in year t $[P(t)]$ (in GW_p) follows a logistics curve:

$$P(t) = \frac{P_o \cdot e^{at}}{1-(P_o/P_f)\cdot(1-e^{at})},$$

where P_o = 0.072 GW_p/year in 1993 (t = 0), P_f = 50 GW_p/year, and a = 0.35 in the Accelerated Development scenario and a = 0.15 in the Business-As-Usual scenario.

[b] *CUM(t)* (in GW_p) is the total installed pv capacity at the beginning of year t.

[c] *INSOL(t)* is the annual insolation (in kWh/m²/year) at the sites where new pv capacity is installed in year t. It is assumed that *INSOL(t)* declines with installed capacity according to:

$$INSOL(t) = 2400-80\left[\frac{CUM(t)+CUM(t+1)}{2}\right]^{0.4}.$$

[d] The capacity factor *CF(t)* for new pv capacity *P(t)* in year t is given by *CF(t)* = 100**INSOL(t)*/8760 percent.

[e] The busbar cost *PVC(t)* (in cents/kWh) for pv capacity added in the year t is calculated via the procedure outlined in the appendix, assuming that both the pv module cost and the area-related balance-of-system (*BOS*) cost decline over time according to an 80% progress ratio, until the assymptotic cost levels of \$50/m² for modules and \$40/m² for the area-related BOS are reached.

[f] *AGC(t)* (in cents/kWh) is the 30-year levelized cost of central station power generation avoided via the installation of *P(t)* of pv generation capacity in year t. For each increment of pv capacity a value of *AGC(t)* is calculated using the SUTIL electric utility model described in the text.

[g] *DB(t)* is the distributed benefit (in cents/kWh) of adding distributed pv capacity *P(t)* to the grid. It is assumed that the benefit expressed in \$/kW-year declines as the square of the capacity factor for new pv capacity, from an initial (1995) value of \$100/kW-year.

[h] The unit incentive needed (in $\$/W_p$) is given by the ratio *GNB(t)/P(t)* for the years when *GNB(t)* is negative.

[i] The net global benefit *GNB(t)* (in $\$10^9$/year) is given by:

$$GNB(t) = P(t)\cdot CF(t)\cdot(8760\,hours/year)\cdot\frac{[AGC(t)+DB(t)-PVC(t))}{10^{-5}\cdot CRF(0.06,30)}.$$

Net global benefits for the Business-As-Usual and Accelerated Development scenarios are plotted for the 80% progess ratio case in Figure 13.

Table 6. Distributed Benefits for the 500 kW Photovoltaic Array at the Kerman Substation of the Pacific Gas and Electric Company[a] and Assumed Distributed Benefits for Photovoltaic Modeling Exercise

Distributed Benefit Component	\$ per kW-year (1992 \$)
Reduced line losses[b]	17.1
Reduced reactive power losses[c]	5.1
Avoided transmission capacity investment[d]	25.2
Deferred investment in substation transformer[e]	45.8
Reduced servicing of voltage regulators[f]	4.0
Increased reliability of customer service[g]	130.2
Total distributed benefit at Kerman substation	227.4[h]
Distributed benefit assumed for 1995 in pv modeling analysis	100[i]
Distributed benefit assumed for 2020 in pv modeling analysis (accelerated development scenario)	40[j]

Notes to Table 6

[a] Source: [34].

[b] With distributed generation, transmission and distribution line losses amounting to 10% of central station power generation are avoided. The distributed benefit associated with reduced line losses (DB_{rll}) is estimated as:

$$DB_{rll} = CF \cdot AGC \cdot [8760\ hours/year]\ [1/0.9 - 1] = \$17.1/kW\text{-}year,$$

where:

CF = pv capacity factor (assumed here to be that for pv systems installed in 1995 in the pv modelling exercise) = 0.266,
AGC = incremental cost of electricity generated by conventional sources that is avoided by addition of the pv system (assumed here to be that for pv systems installed in 1995 in the pv modelling exercise) = \$0.066/kWh.

[c] Installing 500 kW of pv capacity at the Kerman substation is estimated to reduce reactive power losses by 545 kVAR (kilovolt-ampere reactive) as a result of local voltage support by the pv generating facility. The value of this voltage support is estimated as the avoided cost of installing shunt capactors on the distribution system, at the substation transformer, and on the transmission system. The distributed benefit associated with reduced reactive power losses (DB_{rrpl}) is estimated as:

$$DB_{rrpl} = [CRF(0.06,30) + INS]\ \frac{SC_{df} \cdot UC_{scdf} + SC_{trf} \cdot UC_{sctrf} + SC_{trm} \cdot UC_{sctrm}}{500\ kW_e} + \frac{OM_{sc}}{500\ kW_e} = 4.2 + 0.9 = \$5.1/kW\text{-}year,$$

where:

$CRF(i, N)$ = capital recovery factor for interest rate i and term N years:

$$CRF(i,N) = \frac{i}{[1-(1+i)^{-N}]},$$

$CRF(0.06,30)$ = 0.0726,
INS = insurance charge rate for capital investment = 0.005,
SC_{df} = avoided shunt capacity for the distribution feeder = 93 kVAR,
SC_{trf} = avoided shunt capacity at the transfomer = 227 kVAR,
SC_{trm} = avoided shunt capacty on the transmission system = 225 kVAR,
UC_{scdf} = unit cost of shunt capacitance for the distribution feeder (at 12 kV) = \$8.9/kVAR,
UC_{sctrf} = unit cost of shunt capacitance for the transformer at the substation (at 70 kV) = \$58/kVAR,
UC_{sctrm} = unit cost of shunt capacitance for the transmission system (at 230 kV) = \$59/kVAR,
OM_{sc} = annual maintenance cost for the shunt capacitors = \$431/year.

Notes to Table 6, cont.

[d] The distributed benefit of the transmission capacity investment avoided by installing 500 kW of pv capacity at the Kerman substation (DB_{atci}) is calculated as:

$$DB_{atci} = [CRF(0.06,30) + INS]\, PPA \cdot LLAF \cdot UC_{tc} + UOM_{tc} = 20.6 + 4.6 = \$25.2/kW\text{-}year,$$

where:

PPA = peak plant availability (fraction of pv capacity that can displace thermal peaking capacity) = 0.87,
$LLAF$ = transmission line loss adjustment factor = 1.08,
UC_{tc} = unit cost of transmission capacity = $282/kW,
UOM_{tc} = unit operation and maintence cost for transmission system = $4.59/kW-year.

[e] Installation of a 500 kW pv array at the Kerman substation makes it possible to defer by 5 years the installation of a larger 16 MVA transformer at the substation. The distributed benefit (DB_{dtrfi}) of this deferral is calculated as:

$$DB_{dtrfi} = [CRF(0.06,30) + INS]\, \frac{C_{trfi}}{500\ kW_e}\left[1 - \frac{1}{(1.06)^5} + \frac{5/30}{(1.06)^{30}}\right] = \$45.8/kW\text{-}year,$$

where:

C_{trfi} = cost of new 16 MVA transfomer, net of salvage value of the present transformer = $1.046 million.

[f] With the installation of a 500 kW pv system at the Kerman substation, the frequency of servicing voltage regulators at the substation and on the distribution system can be reduced from once every 5 years to once every 7 years. The distributed benefit of reduced servicing requirements for voltage regulators (DB_{rsvr}) is calculated as:

$$DB_{rsvr} = CRF(0.06,30)\, \frac{C_{svr}}{500 kW_e}\left[\sum_{i=0}^{5} \frac{1}{(1.06)^{5i}} - \sum_{i=0}^{4} \frac{1}{(1.06)^{7i}} + \frac{5/7}{(1.06)^{30}}\right] = \$4.0/kW\text{-}year,$$

where:

C_{svr} = cost of one servicing of voltage regulators = $34,730.

[g] For strategically placed distributed pv power systems, the reliability of electrical service to consumers can be increased, by reducing sharply the duration of power outages (*see Figure 12).* For customers served by electricity from the Kerman substation the distributed benefit to consumers of increased reliability of service (DB_{ircs}) is estimated as:

$$DB_{ircs} = OF \cdot ADO \cdot AV_{pv} \cdot LF_{fdr} \cdot AVOS = \$130.2/kW\text{-}year,$$

where:

OF = outage frequency = 5.25 outages/year,
ADO = average duration of an outage = 4.29 hours/outage,
AV_{pv} = availability of the pv system = 0.33,
LF_{fdr} = load factor for the feeder = 0.60,
$AVOS$ = average value of service not lost to customers on the Kerman subsystem (weighted average of $5/kWh, residential; $11/kWh, agricultural; and $71/kWh, commercial, industrial, and other; based on customer surveys) = $29.2/kWh.

[h] The total distributed credit shown here ($227 per kW-year) is less than the value ($382 per kW-year) presented in the PG&E report (*see note a*) largely because the present calculation is expressed in constant dollars for a 6% real discount rate, excluding taxes, whereas the PG&E analysis is for nominal future dollars, with taxes included.

[i] Since the capacity factor for new photovoltaic installations averages 26.6% in 1995, this corresponds to a credit of 4.28 cents per kWh.

[j] Since the capacity factor for new photovoltaic installations averages 17.1% in 2020, this corresponds to a credit of 2.75 cents per kWh.

Table 7. Government Energy Research and Development Expenditures in 1991[a] (in US $$10^9$)

	France	Germany	United Kingdom	Japan	United States	OECD Total
Coal	5.3	67.8	5.6	194.6	658.8	989.3
Oil and Gas	37.2	7.0	7.1	90.8	109.4	374.8
Conservation	50.3	21.5	31.2	16.0	217.5	583.2
Renewables						
Solar Heating	2.1	17.8	4.1	3.6	2.6	52.9
Photovoltaics	4.3	59.2	-	52.1	47.1	198.2
Solar Thermal Electric	-	4.1	-	-	20.0	37.6
Wind	0.5	15.1	14.4	4.0	11.5	95.9
Ocean	-	-	4.8	0.8	2.7	11.0
Biomass	4.8	3.5	5.0	4.0	37.0	106.6
Geothermal	3.4	4.9	3.5	38.9	29.3	90.5
Subtotal	15.1	104.7	31.8	103.4	150.1	592.7
Nuclear Fission						
Breeder	45.2	40.1	106.3	480.5	-	675.2
Other	362.9	131.3	36.6	1573.7	538.5	2914.4
Subtotal	408.1	171.4	142.9	2054.2	538.5	3589.6
Nuclear Fusion	48.0	124.4	35.5	221.7	283.9	896.1
Miscellaneous[b]	-	8.1	13.3	167.0	578.4	1267.7
Total	564.3	504.9	267.2	2847.8	2536.7	8293.5

Notes to Table 7

[a] Source: [48].

[b] Includes electricity transmission, electrical storage, energy systems analysis, and other.

Table 8. History of U. S. Government Investment in Pv and Total Solar Energy R&D[a]

Fiscal Year	Pv R&D Expenditures ($$10^6$ per year)		Total Solar R&D Expenditures ($$10^6$ per year)	
	Current Dollars	1992 Dollars[b]	Current Dollars	1992 Dollars[b]
1971	0.0	0.0	1.1	3.58
1972	0.33	1.03	1.9	5.92
1973	0.79	2.31	4.0	11.7
1974	2.4	6.46	16.0	43.1
1975	5.0	12.3	55.0	135.2
1976	28.6	66.1	149.0	344.4
1977	51.9	112.3	290.0	627.2
1978	61.7	123.7	408.0	818.0
1979	118.5	218.7	456.0	841.7
1980	151.1	254.8	550.0	927.4
1981	133.2	204.1	487.0	746.2
1982	74.0	106.8	268.0	386.7
1983	58.0	80.4	202.0	280.1
1984	50.2	66.7	181.0	240.5
1985	56.6	72.5	180.0	230.5
1986	47.8	59.6	145.0	180.9
1987	46.7	56.5	124.0	149.9
1988	35.0	40.7	97.0	112.9
1989	35.15	39.2	92.0	102.5
1990	35.3	37.7	91.0	97.1
1991	46.3	47.6	129.4	132.9
1992	60.4	60.4	142.9	142.9
1993	63.7	62.1	182.8	178.1
1994[c]	78.0	74.1	248.4	235.9
Totals	1240.7	1805.9[d]	4501.5	6975.3

Notes for Table 8

[a] Source: private communication from Tom Surek, Pv Program Manager, National Renewable Energy Laboratory, September 1993.

[b] Expenditures are converted to 1992 dollars using the GDP deflator.

[c] U. S. Department of Energy budget request.

[d] The coreseponding total for R&D expenditures on thin-film pv technologies, 1978-94, is $211 million.

Table 9. Societal Benefit/Cost Ratios for Alternative Scenarios of Distributed, Grid-Connected PV Development[a]					
Annual Government R&D Funding Relative to 1991[b]	Business-As-Usual	Accelerated Development			
	PR = 80%	PR = 75%	PR = 80%	PR = 81.6%	PR = 85%
1	0.30[c]	39	17	10	- 0.35
3	-	19	10	6	-
6	-	10	6	4	-
9	-	7	4	3	-

<u>Notes for Table 9</u>

[a] The societal benefit/cost ratio is the ratio:

$$\frac{C}{B} = \frac{\textit{Present worth of reduced expenditures on electricity}}{\textit{Present worth of } [(\textit{incentives needed until breakeven}) + (\textit{government R\&D expenditures})]} \,.$$

All costs and benefits are discounted to present worth using a 6% real discount rate. The present worth (in 1995) of reduced expenditures on electriicity is $1.57 billion for the Business-As-Usual scenario with an 80% progress ratio, and $132 billion, $90 billion, $65 billion, and - $5 billion for the Accelerated Development scenario with, respectively, 75%, 80%, 81.6%, and 85% progress ratios. The present worth (in 1995) of the incentives needed to make pv competitive before breakeven (when cost = value) is: $2.67 billion for the Business-As-Usual scenario with an 80% progress ratio, and $1.56 billion, $3.26 billion, $4.60 billion, and $11.84 billion for the Accelerated Development scenario with, respectively, 75%, 80%, 81.6%, and 85% progress ratios.

[b] It is assumed that annual government R&D expenditures for pv are constant until ten years after breakeven at a level equal to a multiple of the 1991 expenditures for pv R&D by OECD countries, which amounted to $0.198 billion (*see Table 7*); it is assumed that subsequently government R&D expenditures are zero. For the Business-As-Usual scenario and for the Accelerated Development scenario with an 85% progress ratio it is assumed that this multiple has only the value "1."

[c] For the niche market-focused variant of the Business-As-Usual scenario, in which there is no dead-weight economic loss in the early years, the present worth of reduced expenditures on electricity is ($1.57 + $2.67) billion = $4.24 billion, and the present worth of future R&D is $2.49 billion, so that the societial benefit/cost ratio is 1.7.

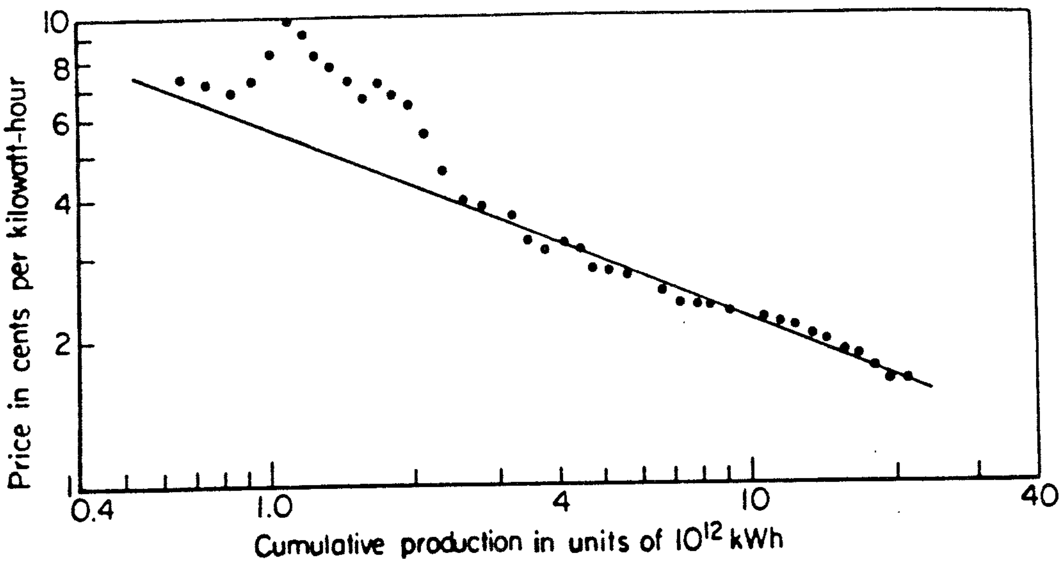


Figure 1: The trend for US electricity prices (in 1970 cents/kWh) from 1926 to 1970.

The trend line corresponds to a 75% experience curve. Prices rose above the trend line during the 1930s largely because of the high fixed charges associated with electricity generation in the face of depression-diminished demand [8].

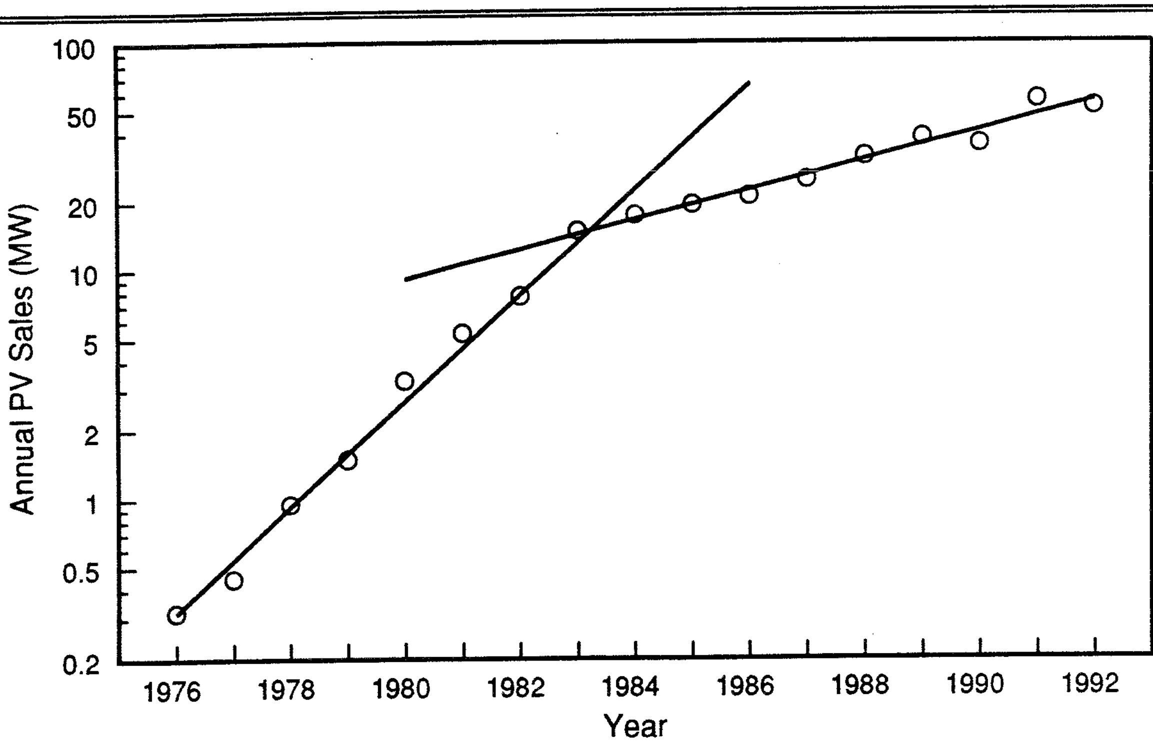


Figure 2: Annual world-wide sales of pv modules from 1976 to 1992.

The solid lines represent growth rates of 70% per year, 1976-1983, and 16% per year, 1983-1992. Data are from Strategies Unlimited, Mountain View, CA, September 1993.

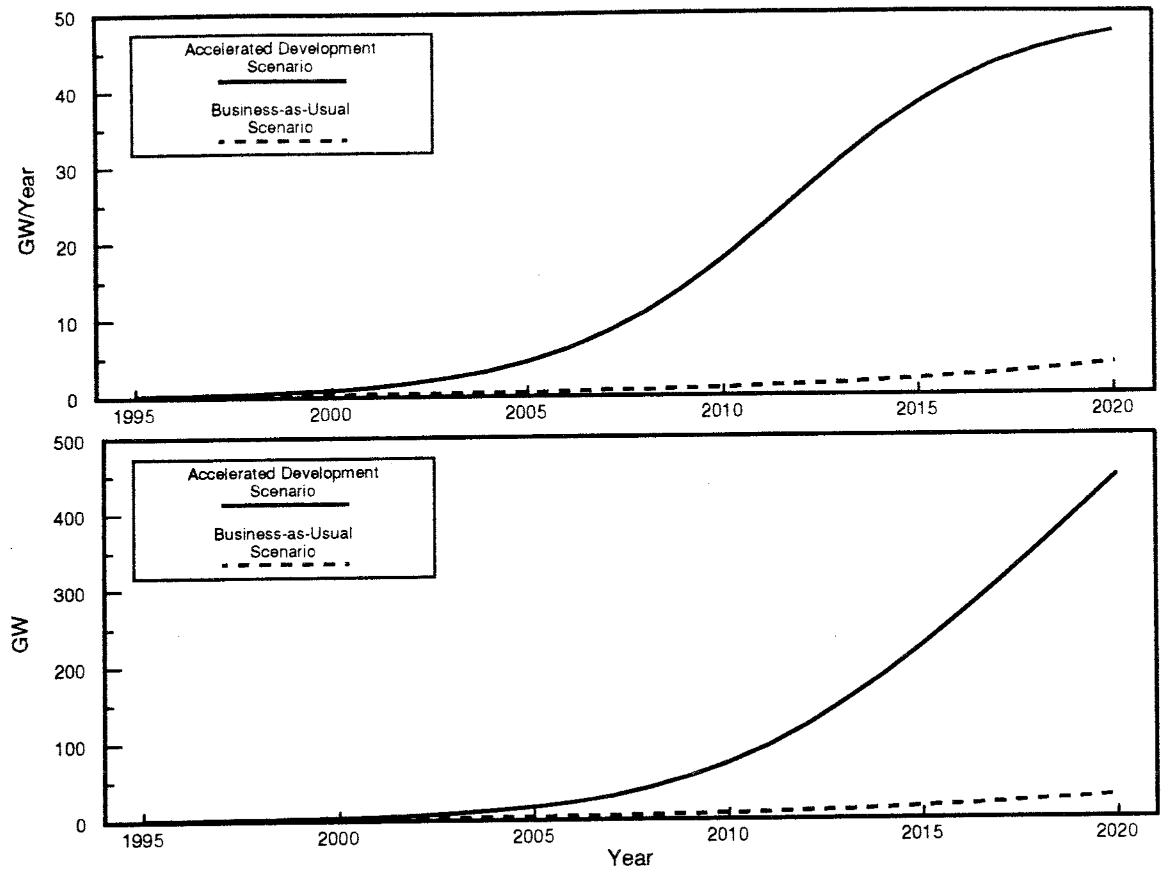


Figure 3: Annual additions of distributed pv generating capacity (*top*) and cumulative pv generating capacity (*bottom*) for the global Accelerated Development and Business-As-Usual scenarios described in the text.

Annual capacity additions are represented by a logistics curve with an assymptotic capacity addition rate in the long term of 50 GW_p per year. (The capacity additions curve saturates because it is expected that thereafter growth in pv capacity additions will be primarily in the form of central station power.) The initial exponential growth rates for these logistics curves are 35% per year for the Accelerated Development scenario and 15% per year for the Business-As-Usual scenario (*see note a, Table 5*).

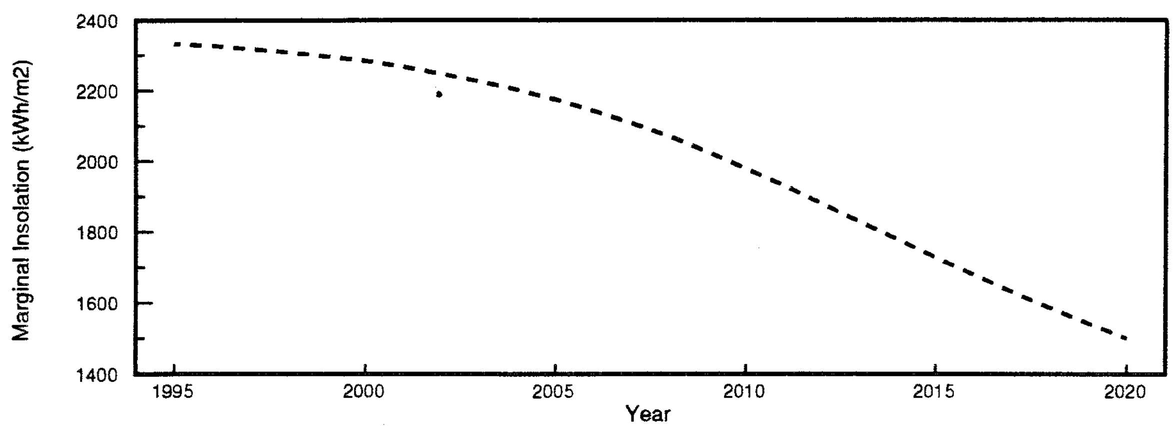


Figure 4: Annual insolation at new sites for pv installations in the Accelerated Development Scenario.

It is assumed that the insolation at new sites declines with cumulative installed pv capacity (*see note c,Table 5*).

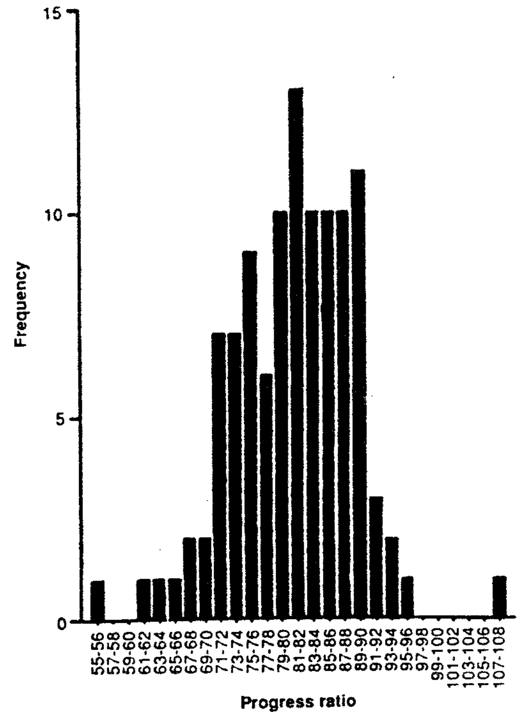


Figure 5: The variation of organizational learning rates among industries is illustrated by this frequency distribution of progress ratios observed for more than 100 industries [12].

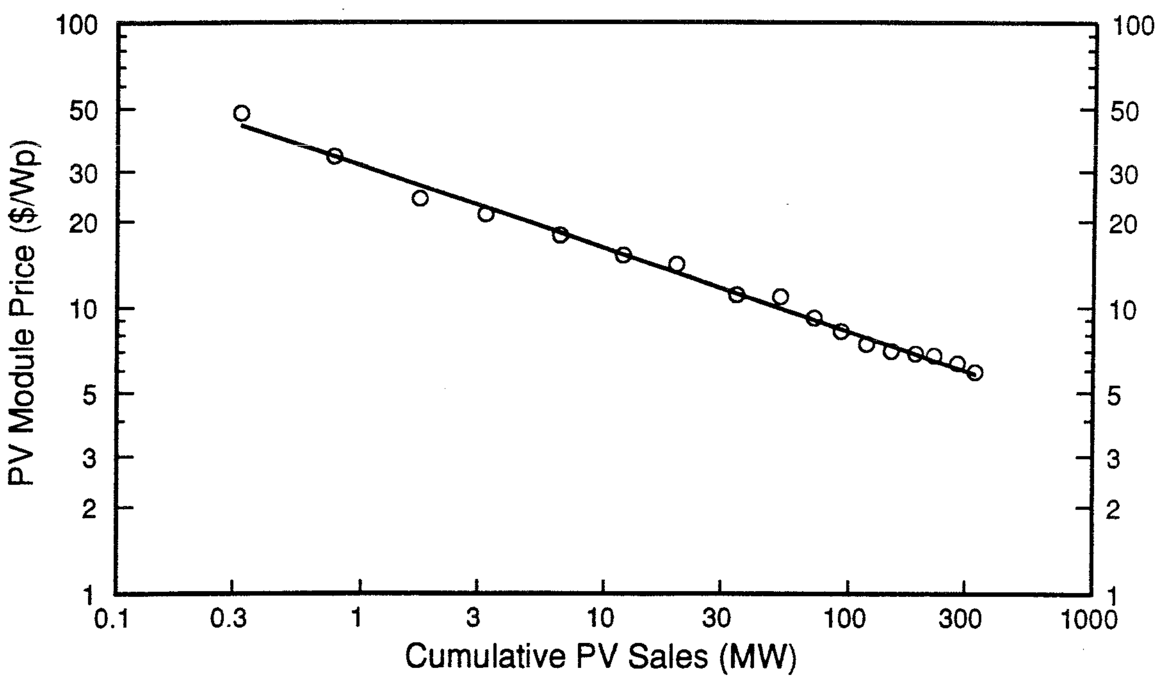


Figure 6: Log-log plot of the selling price of pv modules, 1976-1992.

The pv module selling price follows closely an 81.6% experience curve. Module sales data and prices are from Strategies Unlimited, Mountain View, CA, September 1993. Strategies Unlimited used the Consumer Price Index to convert current prices into 1992 prices.

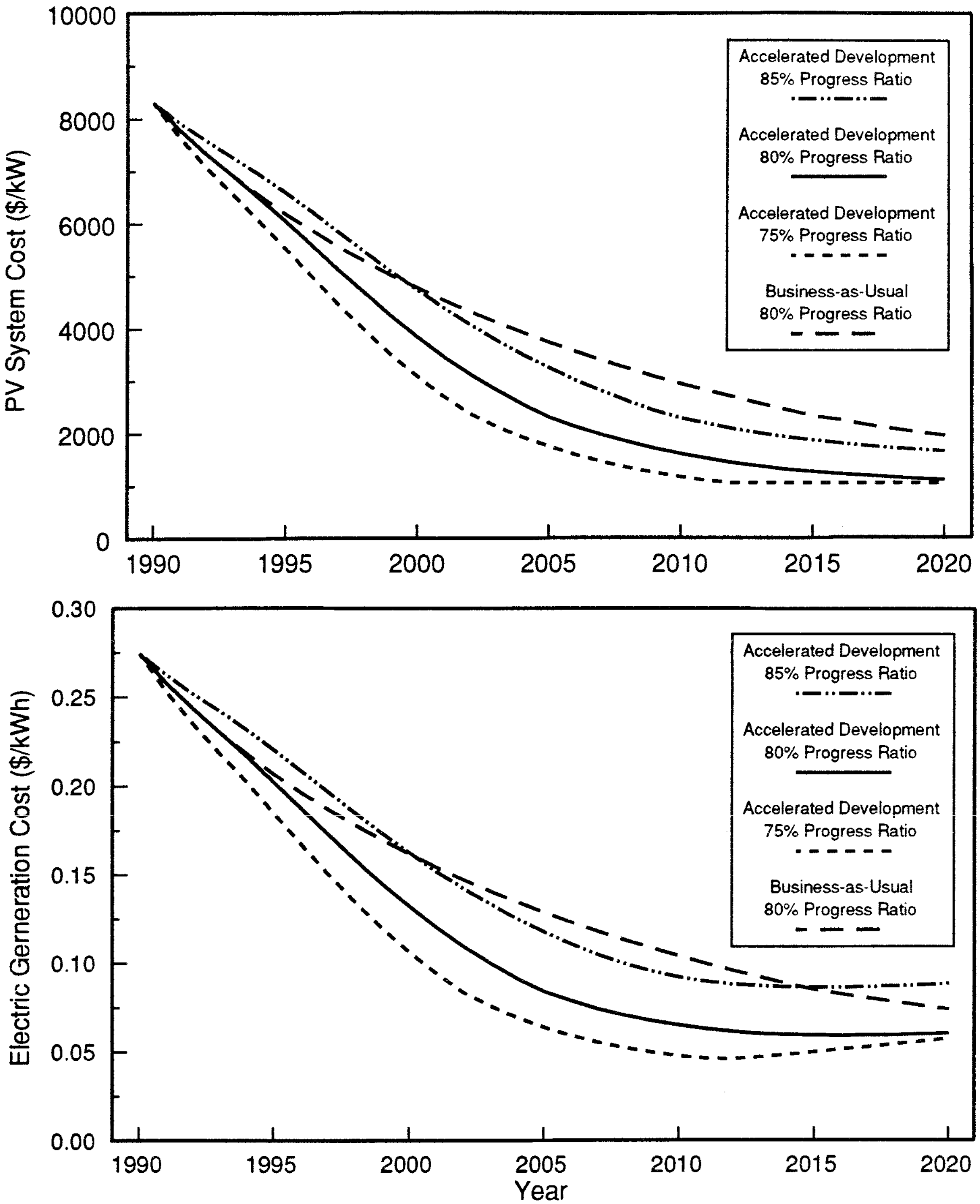


Figure 7: Variation over time of the installed capital cost (*top*) and the cost of electricity generation (*bottom*) for new pv systems in the Business-As-Usual scenario (*80% progress ratio*) and the Accelerated Development scenario (*75%, 80%, and 85% progress ratios*).

Installled capital costs are constant after 2011 in the 75% progress ratio case (*top*), because by that time the assumed assymptotic module price ($50/m^2) is reached. Electric generation costs rise slightly shortly before 2020 in all cases for the Accelerated Development scenario (*bottom*), because the penalty from the shift to areas of lower insolation (*see Figure 4*) outpaces the decline in installed capital costs (*top*) in this period.

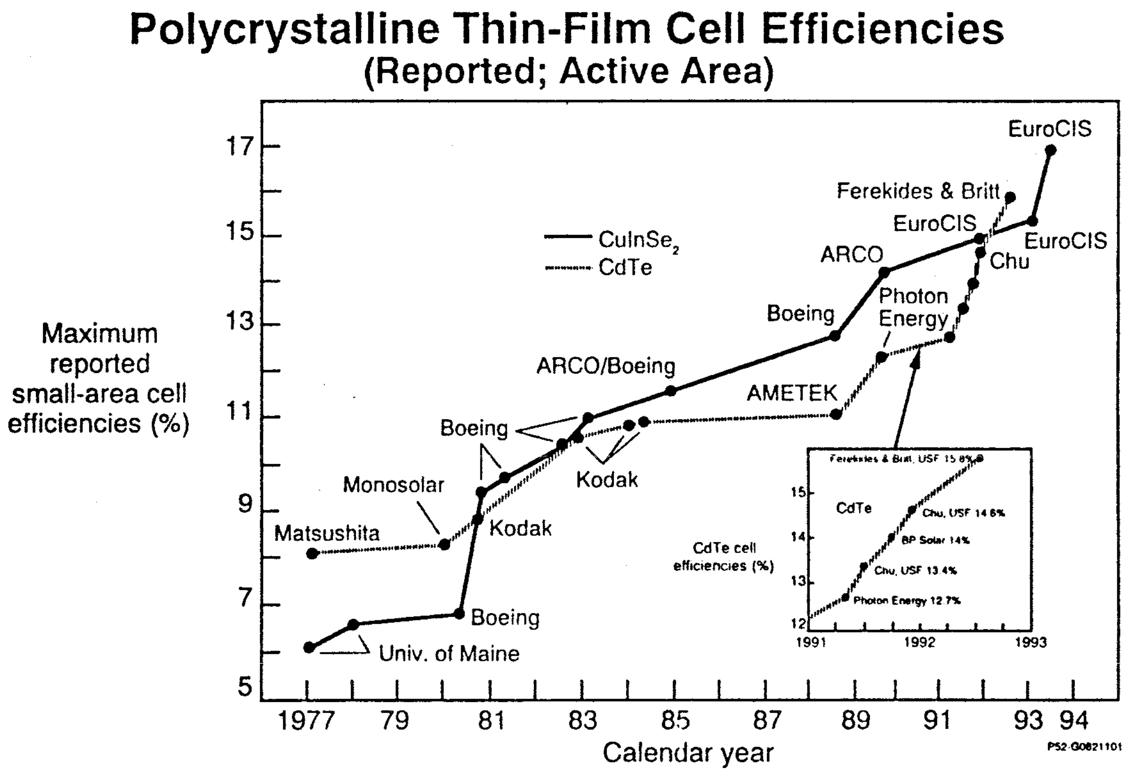


Figure 8: Stabilized efficiencies of small-area polycrystalline thin-film photovoltaic (pv) cells. Values are shown for both copper indium diselenide ($CuInSe_2$) and cadmium telluride (CdTe).

Thin-film pv devices offer the potential for realizing very low unit capital costs at moderate efficiencies. (Other kinds of pv devices have the potential for realizing higher efficiencies but at higher unit capital costs.) The potential for low unit capital cost arises because the active layers of the cells are of the order of one micron thick and thus require very little material. (Note that a typical human hair is about 90-100 microns thick.) Thus the materials cost is dominated by the costs for glass for encapsulation, wires, etc.

The efficiencies shown in this figure are for laboratory cells (areas of the order of 1 cm^2). Further development is needed in order to realize a 15% efficiency in large modules (of the order of 1 m^2 or more per module) and to engineer the processes for mass producing such devices. It is expected that, with an aggressive R&D effort, this could be realized by 2010.

These data, from Ken Zweibel, Manager of the Thin-Film Project, National Renewable Energy Laboratory, September 1993, are based on both NREL measurements and measurements reported in the literature.

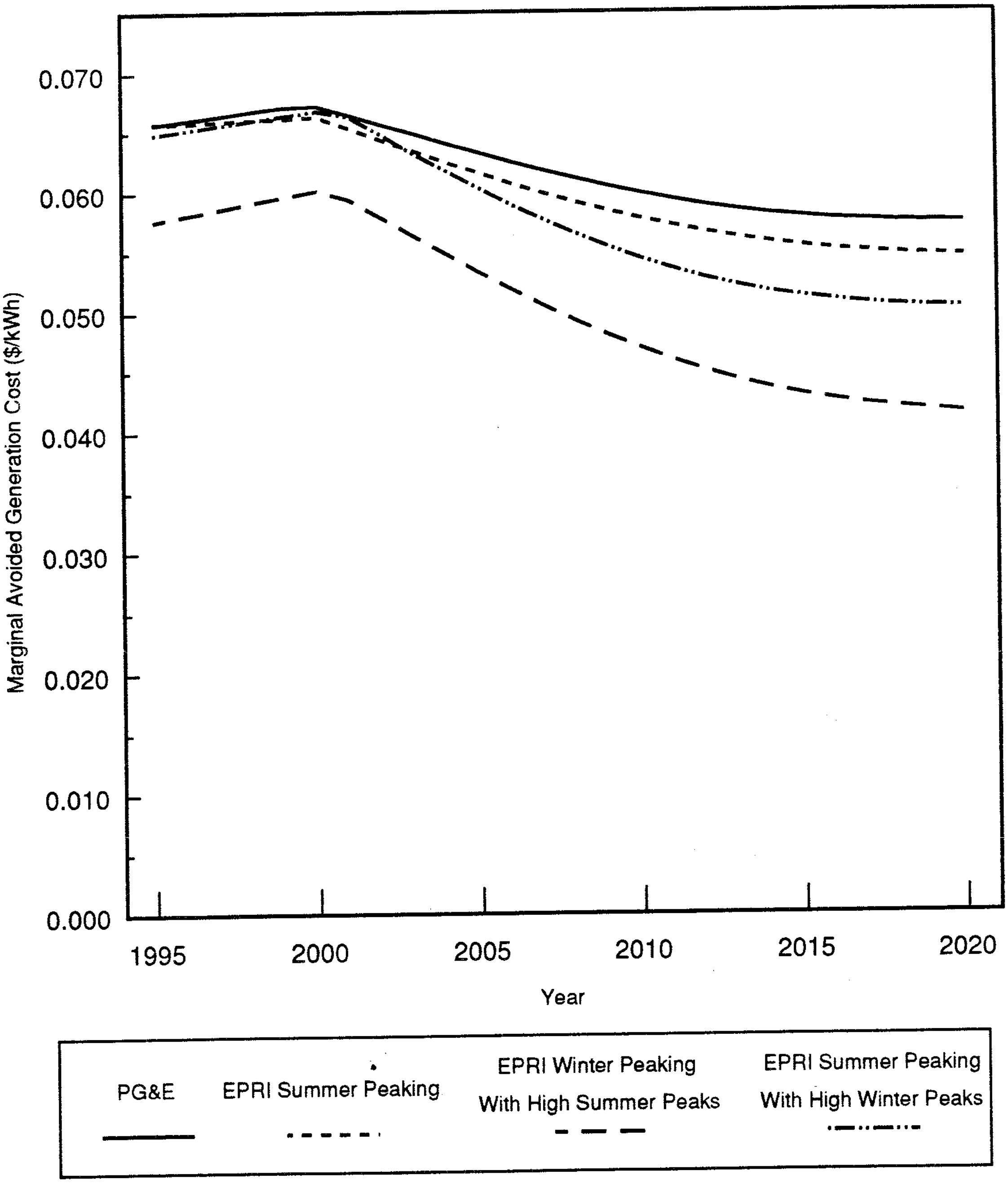


Figure 9: Marginal avoided generation cost for pv systems added to the utility grid in the Accelerated Development scenario, assuming alternative utility load profiles.

The avoided generation cost is calculated for each year, for different levels of pv generation, for different fossil fuel prices, and for alternative utility load profiles using the SUTIL model, as discussed in the text.

The avoided cost calculations presented in other figures and tables are based on the Pacific Gas & Electric electric load profile. This figure shows that the avoided costs for the PG&E systems are essentially the same as for model "synthetic" utilities in the United States that are characterized as "summer peaking" utilities [9].

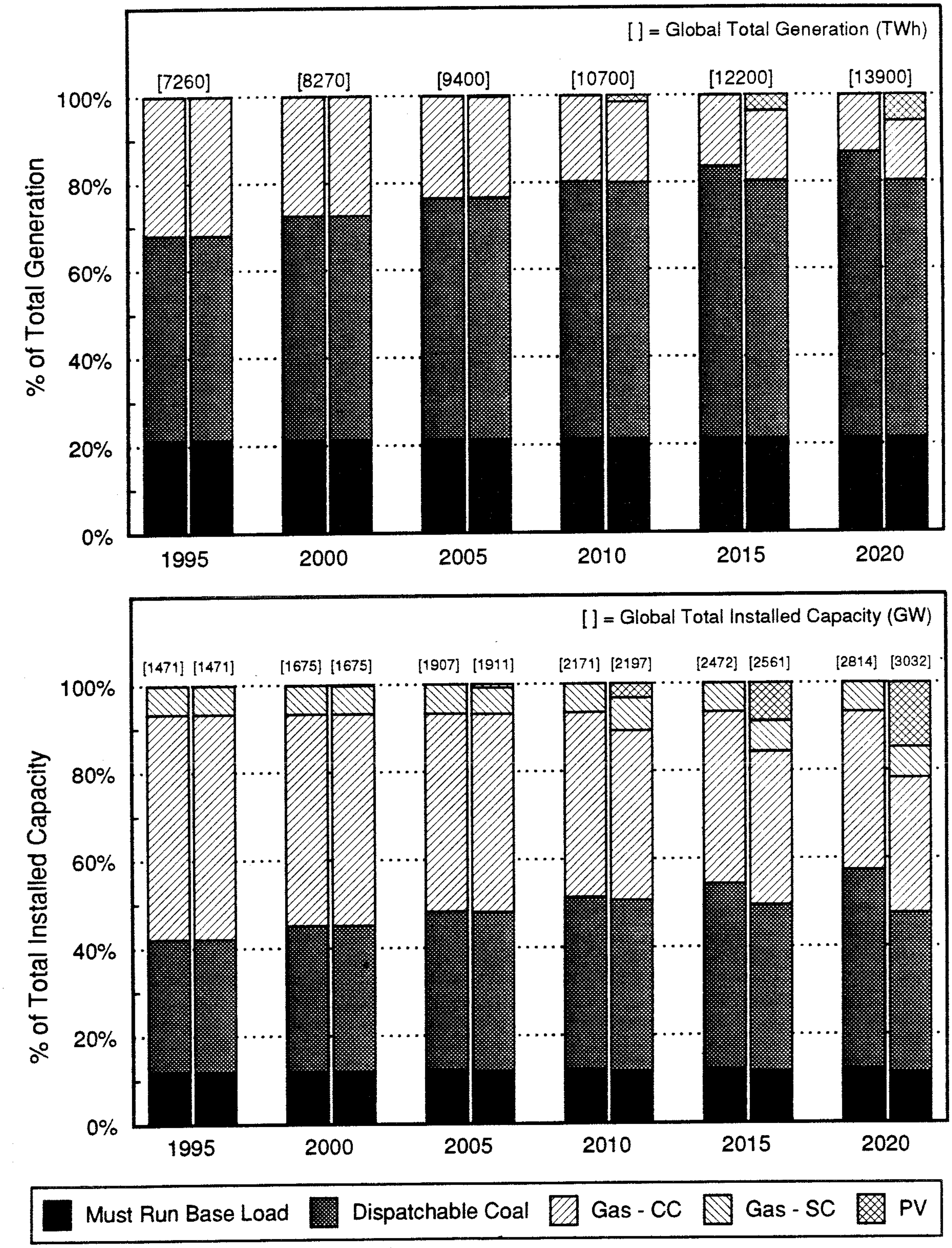


Figure 10: The electricity generation mix (*top*) and the mix of electrical generating capacity (*bottom*) for the global Accelerated Development scenario.

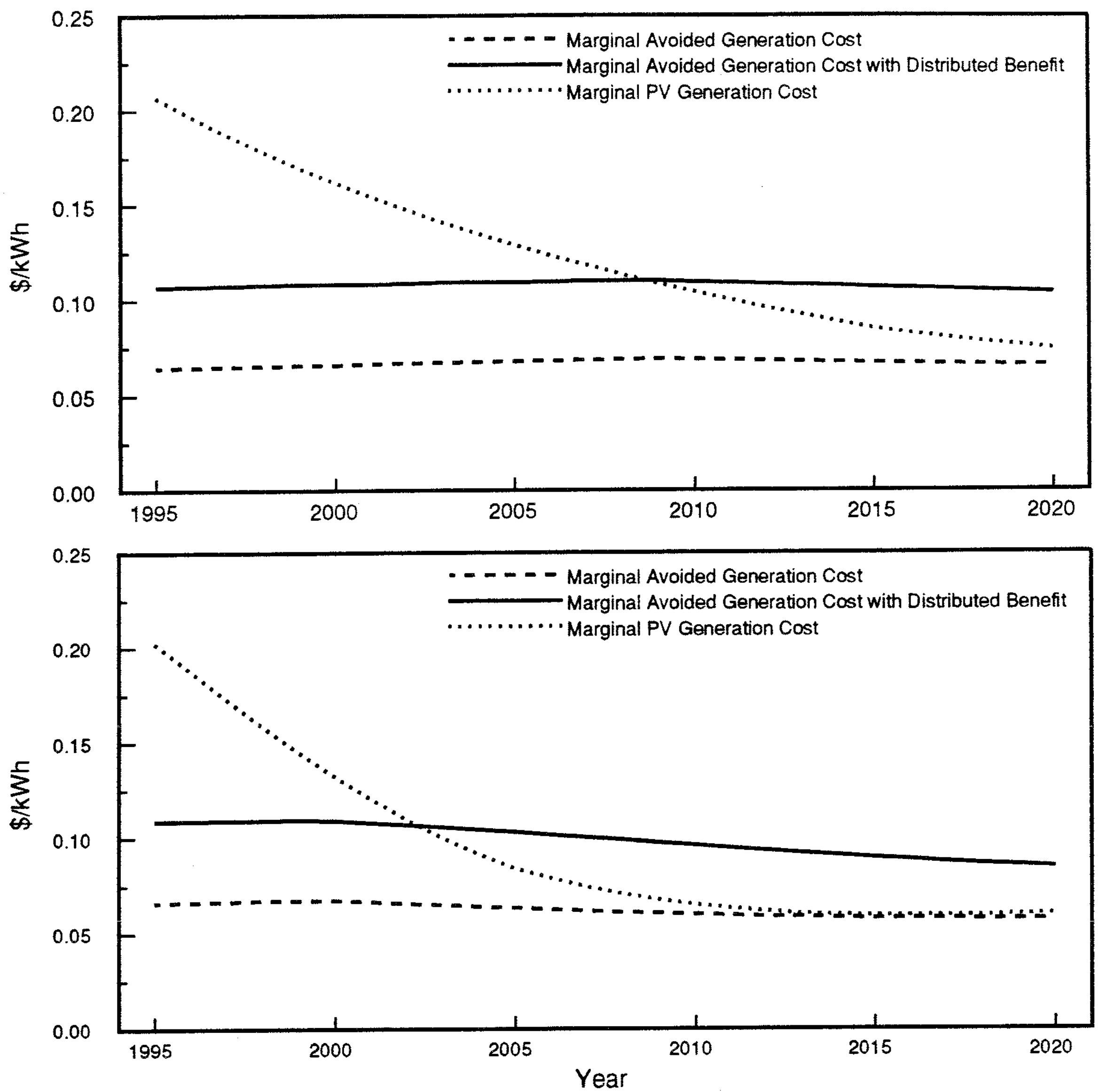


Figure 11: Marginal pv electricity costs and values in the Business-As-Usual *(top)* and Accelerated Development *(bottom)* scenarios, for the base case pv experience curve *(80% progress ratio)*.

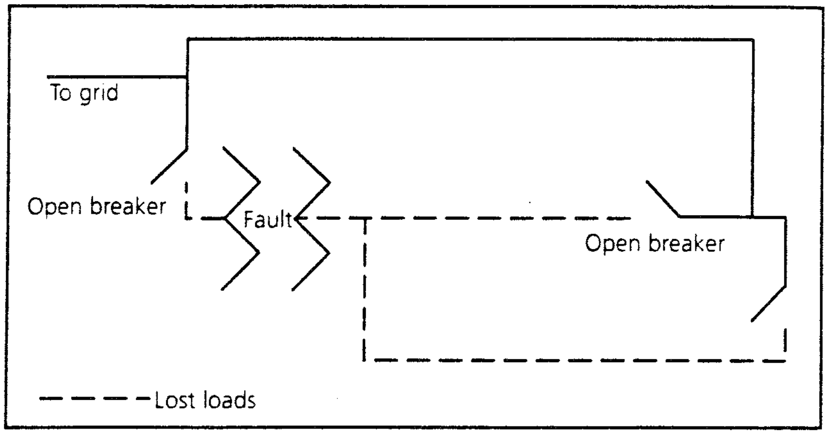
Under Business-As-Usual conditions *(top)* new distributed systems would be competitive by 2010, while under Accelerated Development conditions *(bottom)* they would be competitive by 2003.

The marginal pv generation cost in year t is the 30-year levelized busbar cost for new pv capacity added in that year. The cost of pv modules is assumed to follow an experience curve characterized by an 80% progress ratio. The cost calculations are described in the appendix.

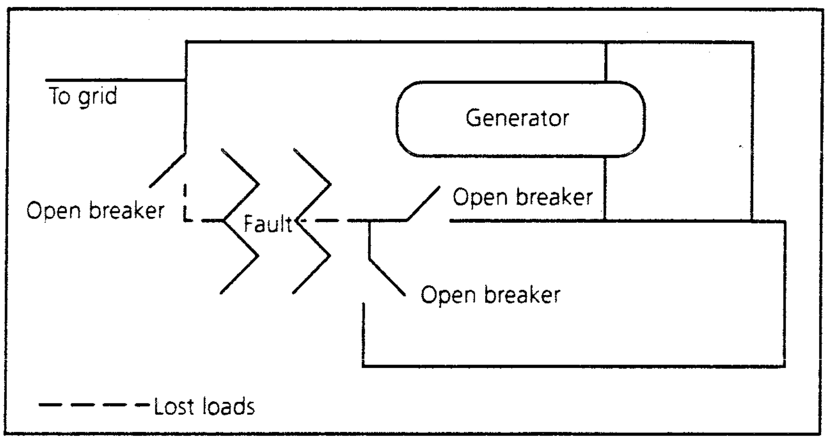
The marginal avoided generation cost in year t is the 30-year levelized cost of generation for the electricity that would otherwise be have to be produced by natural gas and coal-fired power generation in the least-costly configuration, for a given level of penetration of the utility grid with pv power systems. The avoided generation cost is calculated using the SUTIL model, as described in the text.

The marginal avoided cost with distributed benefit adds to the avoided generation cost a credit for the value of a distributed system. It is assumed that the distributed benefit measured in $/kW-year declines with the square of the capacity factor for new pv generation, from an initial value of $100/kW-year in 1995 to about $40/kW-year in 2020. For comparison, the distributed benefit was estimated to be $227/kW-year for the Kerman substation of the Pacific Gas and Electric Company *(see Table 6)*.

Reliablity benefits from distributed generation



A. Loads lost with conventional grid



B. Loads lost with distributed generator support

Figure 12: Distributed generators can increase the reliability of local electric service.

Many utility customers have their power supply cut off when a distribution line is broken, even if there is still a connection between the the utility and these customers. Their service is cut by the utility because continuing to serve them would require rerouting power over lengthy bypass power lines that are already heavily loaded serving other customers.

A typical situation is illustrated in the top figure, where a fault in the distribution system requires the utility to open breakers at the points indicated while repairs are being made, thereby cutting off customers on the lower circuit. If a distributed generator is available at a strategic point in the distribution system, however, as illustrated in the bottom figure, power can be maintained over a much wider area while repairs are underway.

The reliability benefits of strategically placed distributed generators can be quite large, as is illustrated by the analysis of the distributed value of a 500 kW pv array at the Kerman substation of the Pacific Gas and Electric Company, in which it was estimated that increased reliability of customer service accounted for more than half of the total distributed benefit (*see Table 6*).

While utilities normally design their power generation systems to ensure a loss of load probability of no more than about 1 day in ten years (2.4 hours per year), customer service is often disrupted much more frequently as a result of faults in the transmission and distribution system. For example, the annual outage rate for PG&E customers served by the Kerman substation has been over 20 hours per year (*see note g, Table 6*).

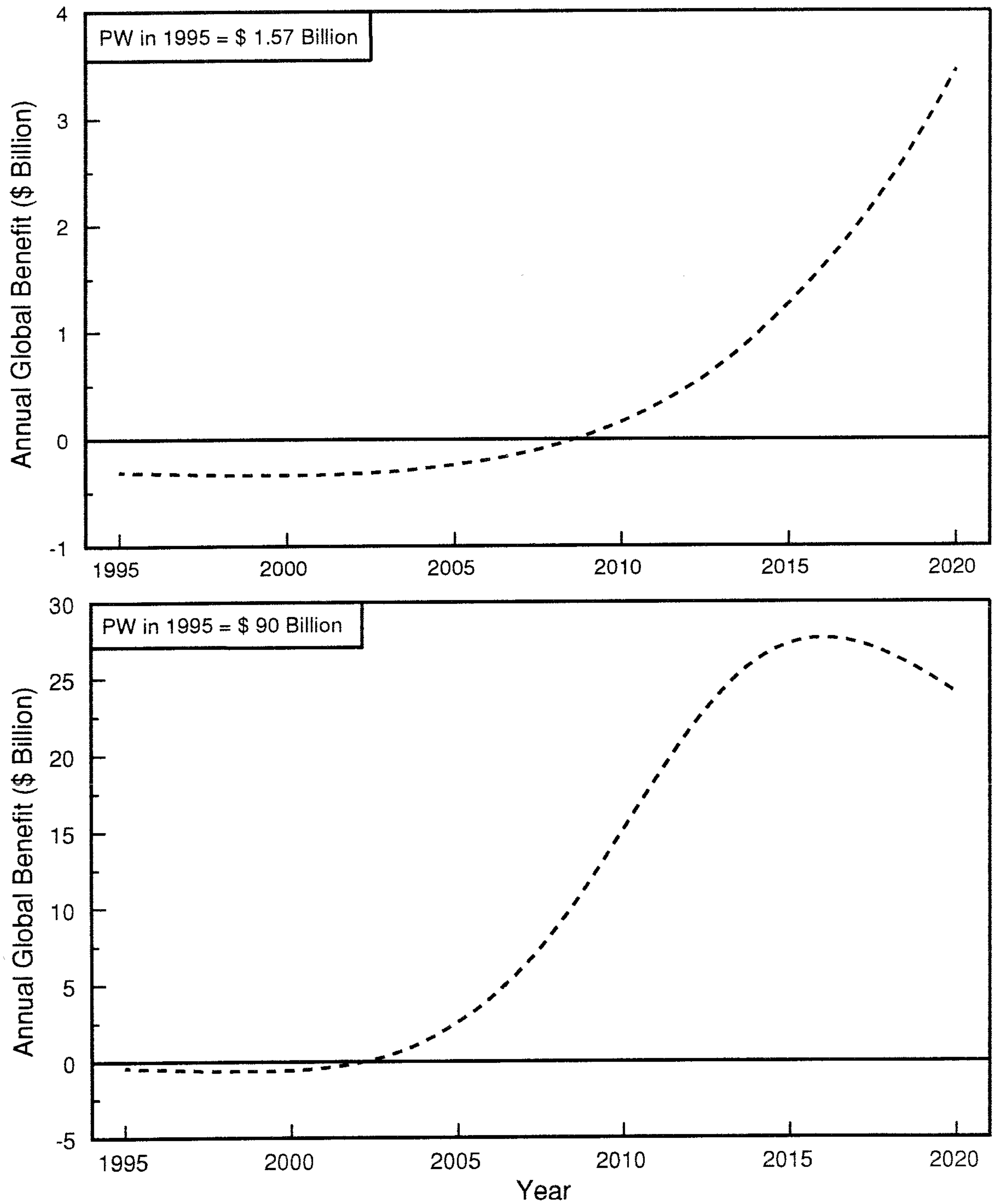


Figure 13: Net global benefits for the Business-As-Usual (*top*) and Accelerated Development (*bottom*) scenarios, assuming the base case experience curve (*80% progress ratio*).

The present value in 1995 of all annual net benefits (defined in note i, Table 5) for the period 1995-2020 is $1.3 billion for the Business-As-Usual scenario and $90 billion for the Accelerated Development scenario. Annual net benefits begin to decline after 2016 in the Accelerated Development scenario largely because in this period the continuing decline in pv module costs is more than offset by the shift to areas of lower insolation and the decline in the distributed benefit.

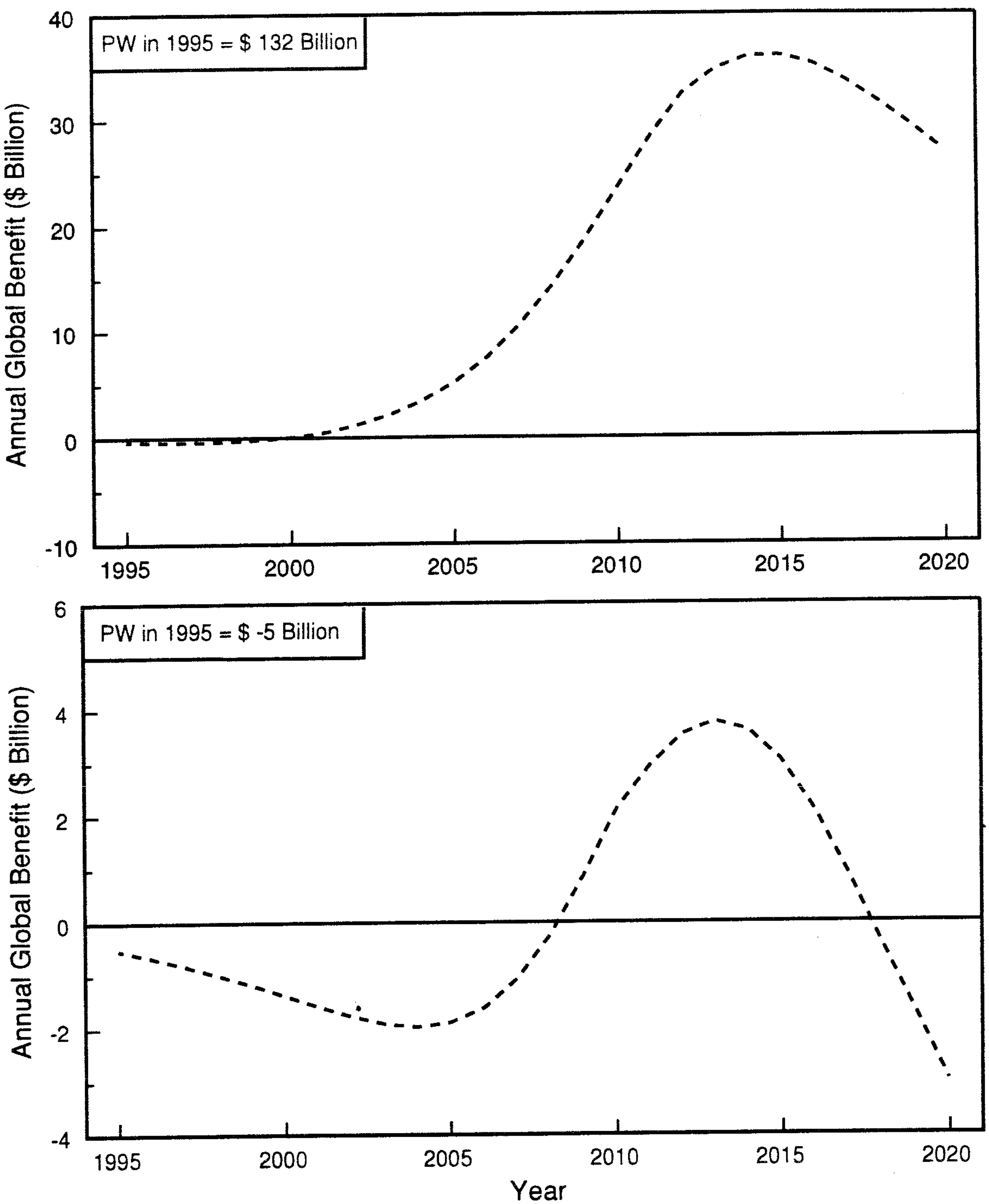


Figure 14: Net global benefits for the 75% (*top*) and 85% (*bottom*) progress ratio variants of the Accelerated Development scenario.

The present value in 1995 of all annual net benefits (defined in note i, Table 5) for the period 1995-2020 is $132 billion for the 75% progress ratio variant and - $5 billion for the 85% progress ratio variant.

Appendix A: The Levelized Cost of Photovoltaic Electricity

Neglecting corporate income and property taxes, the levelized cost of photovoltaic electricity *(in \$/kWh)* is given by [x]:

$$C_{pve} = \frac{\{[CRF(i,N)+INS]\,[1+ID]\,[MOD+BOS+PC\cdot SP\cdot nmod\cdot nbos\cdot nt]+OM\}}{nmod\cdot nbos\cdot nt\cdot INSOL}$$

where:

C_{pve} = levelized production cost of solar electricity (\$/kWh)
i = real discount rate = 0.06
N = pv system lifetime = 30 years
$CRF(i,N)$ = capital recovery factor = 0.0726
INS = insurance cost in \$/year per \$ of capital invested = 0.005
ID = indirect cost factor = 0.25
MOD = capital cost of PV modules (\$/m^2)
BOS = area-related balance-of-system capital cost (\$/m^2)
PC = power-related balance of system capital cost (\$/kW)
OM = annual operation and maintenance cost (\$/m^2/year)
SP = maximum insolation (kW/m^2) = 1.0 kW/m^2
$INSOL$ = annual average insolation on tilted, fixed-flat-plate array (kWh/m^2/yr)
$nmod$ = PV module efficiency (decimal fraction)
$nbos$ = balance of system efficiency (= system effiency/module efficiency)
nt = solar cell average temperature correction (decimal fraction)
pc = power conditioning efficiency (decimal fraction)

In the pv system modeling exercise, only fixed, flat-plate collectors are considered. It is assumed that both the pv module costs and the area-related BOS costs decline with cumulative production according to an experience curve according to the same progress ratio (80% in the base case)[18] until assymptotic values of \$50/m^2 for modules and \$40/m^2 for the area-related BOS are reached[19] Within the thin-film photovoltaic community it is generally thought that by the year 2010 these cost goals could be realized for one or more thin-film photovotaic technologies, with reduced costs arising both from continuing research and development and from organizational learning as a result of market development. [The assumed values for these variables in 1995 (for the accelerated development scenario with an 80% progress ratio) are about \$460/m^2 for modules and \$110/m^2 for the area-related BOS.] The following table lists the other assumed performance and cost parameters for photovoltaic systems [16]:

---

18 For the base case experience curve *(80% progress ratio)*, module costs decline as:

$$MOD = 377.5\cdot(CUM)^{-0.322}\ \$\ per\ m^2,$$

where CUM is the cumulative pv capacity *(in GW_p)*, until the assymptotic value of \$50/m^2 is reached. The area-related balance-of-system costs decline as:

$$BOS = 89.03\cdot(CUM)^{-0.322}\ \$\ per\ m^2,$$

until the assymptotic value of \$40/m^2 is reached.

19 Module costs Y in \$/kW$_p$ are obtained from module costs MOD in \$/m^2 from:

$$Y = \frac{MOD}{nmod\cdot nbos\cdot nt\cdot SP}.$$

The area-related BOS cost can be expressed in \$/kW$_p$ by using the same conversion.

Power-related BOS cost[20] ($/kW)	100
Module efficiency (%)	15
BOS efficiency (%)	90
Power-conditioning efficiency (%)	95
Solar cell average temperature correction (%)	93[21]
Operation and maintenance cost ($/m^2/year)	0.32

[20] It has been estimated that with advanced power semiconductors, improved circuit designs, and increased power production volumes, costs should be reduced to about $100 per kW_p by the mid-1990s, if production volume reaches 50 MW_p per year [49].

[21] This is the current value for CdTe systems.; the current value for a-Si systems is close to 1.0; for CIS the current value is about 0.90 but is expected to be about 0.93 with future wider band-gap materials (private communication from K. Zweibel, National Renewable Energy Laboratory, March 1993).

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