UTILITY-SCALE FLAT-PLATE THIN FILM PHOTOVOLTAICS

1.0 System Description

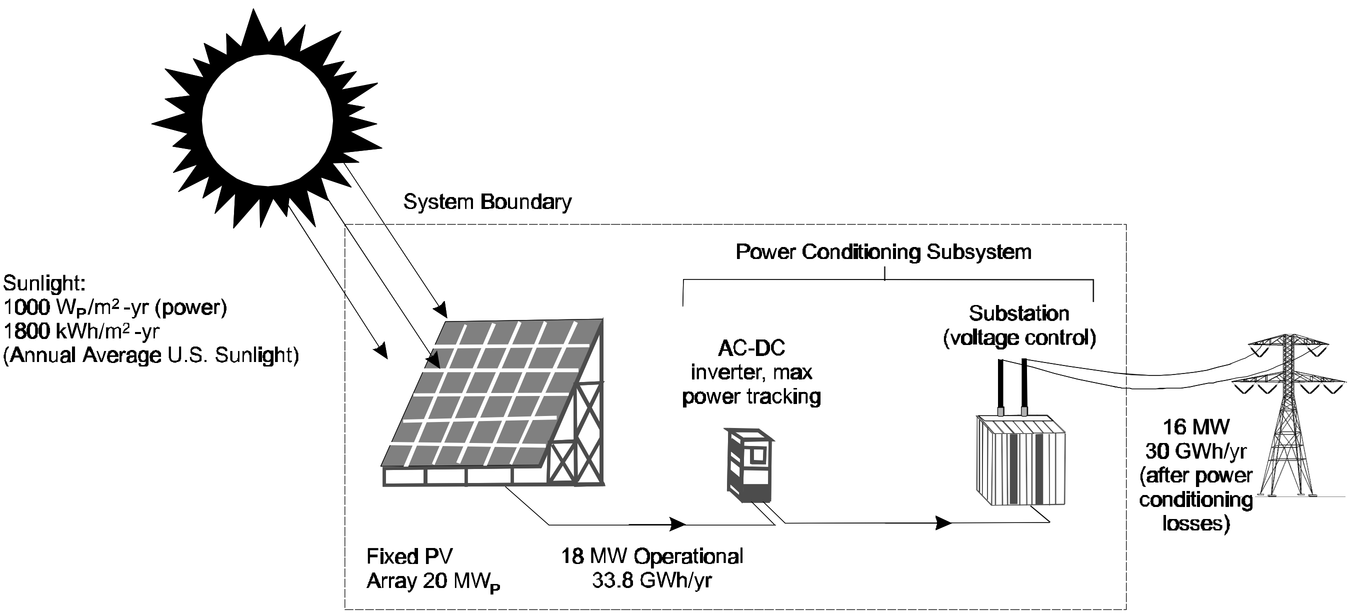

Figure 1. 20 MW_p (DC)/16 MW_p (AC) grid-connected PV system schematic.

Thin film photovoltaic (PV) systems convert sunlight into DC electricity using large-area, solid-state semiconductor devices called thin film PV modules. This section characterizes fixed (nontracking), grid-connected systems in the U.S. producing conditioned, AC electricity (Figure 1). The system in this document is a composite based on the three most mature thin films. In addition to thin film modules, PV systems include other components: support structures, inverters if AC electricity is desired, a solar tracker if needed (not in this study), wiring and transmission, and land. Figure 1 shows the losses between each part of the PV energy delivery system: the amount of sunlight and the power and energy produced at the module level (called the system's 'peak power' when the output of all the modules is summed); and the power-conditioning subsystem (including DC-to-AC inverter) with the losses in wiring and DC-to-AC power conversion. The 'peak power' is only the starting point. By the time the electricity gets to the busbar, losses are about 20% of the initial, peak system total. These losses are taken into account in the energy and cost calculations.

The system input is sunlight. The amount of incident sunlight depends on the latitude and local climate. U.S. average annual solar energy input is about 1800 kWh/m^2-yr for a nontracking array, and varies by about 30% from this amount within the Continental U.S. [1]. For a single-axis tracking array, average output increases to about 2,200 kWh/m^2-yr and to about 2,400 kWh/m^2-yr for a dual-axis system [1]. Despite the higher available energy, trackers are not necessarily preferable, since they add cost, have moving parts, and require maintenance. In this characterization, we describe only fixed (nontracking) systems, and we describe *two* levels of sunlight as input to our PV arrays: a high level (2,300 kWh/m^2-yr) to characterize solar installations in areas of exceptional sunlight; and 1,800 kWh/m^2-yr as an average case, to indicate a more typical level for the U.S.

The use of an *average U.S. solar location* to calculate cost projections for the long-term allows us to generalize conclusions about the impact of the PV characterized here. The economics of a PV system are inversely proportional to the amount of local sunlight. Since sunlight variation in the U.S. is about 30% from an average value, meeting low-cost goals in an average location would qualify PV for consideration in almost all U.S. climates and most global locations. For example, if future PV systems were to produce electricity at 6¢/kWh in Kansas (U.S. average sunlight), the same system would produce electricity at 8¢/kWh in New York State and at 4¢/kWh in the Desert Southwest. These extremes could still provide acceptable costs, given the variation of the cost of conventional electricity (although, of course, such cost variations are unrelated to variations in sunlight). It should also be noted that the first large installations of PV are likely to be in areas of high annual sunlight (or locally high electricity prices). We will capture this by using our 'high sunlight' assumptions to describe pioneering installations by 'early adopters'. Longer-term projections are all based on systems located in areas of average sunlight.

2.0 System Application, Benefits, and Impacts

PV will be used for many, diverse applications, including utility grid power. The system defined here is for future, grid-connected applications. Since such systems will evolve from today's smaller systems, they have been sized at 20 kW_p-10 MW_p in the early years, reaching 20 MW_p (as a typical size) in 2010. Actual size will depend on individual, grid-connected applications. However, since PV systems are highly modular (i.e., modules and partial arrays can be mass produced in the factory), costs are related predominantly to production volume, not to system size.

Two major markets are expected for the kind of multi-use system described in this characterization. In the U.S., distributed systems delivering electricity at peak demand periods would be the main application [2]. Some intermediate daytime loads would also be met. In developing countries, non-grid-connected systems would provide power to the hundreds of thousands of villages that have no electricity grid. Both of these markets would take advantage of significant values that PV electricity can provide. In the U.S., PV output is well-matched to the needs of many utilities for peak power during the daytime for commercial and air-conditioning loads [2]. This is the most costly electricity for utilities to generate. In addition, PV can be used in distributed locations (i.e., closer to the customer) on a utility grid, reducing the need to add capacity to transmission lines to serve growing suburban communities. Modularity provides relative ease of siting and rapid installation. In the developing nations, there are few alternatives to PV for rural use: diesel generators would be the direct competition. However, diesels require a constant supply of fuel and substantial maintenance, while PV has no need for on-site labor during operation, and has very low maintenance requirements.

PV benefits are numerous. Those described here are in terms of the value of using PV generally, as would result once competitive costs are achieved. PV requires no fuel or water, and is low-maintenance during use. It is an energy source that can be used to 'domesticate' (rather than import) energy, reducing import expenditures. Since sunlight is a local fuel that is available globally, national energy security would be enhanced. In addition, since many PV markets are international, production and export of these high-tech products would benefit the U.S. economy. For developing countries, the value of rural electrification is substantial, since it helps stabilize rural-to-urban population shifts while increasing food supplies, improving food storage, and raising the productivity and living-standard of rural economies. PV use by developing countries would help avoid greater dependence on conventional energy sources and their concomitant emissions.

The solar resource base of the Continental U.S. is over 10^{16} kWh/year. U.S. electricity use is about 2.5 x 10^{12} kWh/year. Thus, the U.S., an intense user of energy, has about 4,000 times more solar energy than its annual electricity use. This same number is about 10,000 worldwide. Thus PV could in principle provide all the globe's electricity. In particular, if only 1% of land area were used for PV, more than ten times the global energy could be produced (without impacting water and other important resources). The potential of PV to displace major amounts of conventional energy, ultimately depends on the technical viability of cost-competitive PV technologies, storage, and transmission. After cost reductions are achieved, the biggest barriers to the generalized use of PV beyond an estimated 10% daytime level in developed countries will be the need for electricity storage or advanced transmission schemes that would allow greater dispatchability.

The size of future PV markets will ultimately be determined by the economics of PV systems. Future, lower cost PV systems (such as those based on thin films) have the potential to be used globally on a very large scale. If cost barriers can be overcome, U.S. usage (without storage) of up to 10% of our utility electricity production (more than 200 GW_p PV capacity based on projected future U.S. electric capacity) is feasible. Use in developing countries could be as large or larger.

The environmental impacts of thin film PV are minimal and in general, PV is emission-free. Some impacts may be expected during system manufacture; and issues exist for polycrystalline thin film systems in terms of ultimate disposal/recycling. These issues are very minor compared to fuel-based energy production and are adequately addressed in References 3-13. (Reference 13 is a bibliography of 94 sources on PV environment, safety, and health issues.) There are some issues specific to compound semiconductors such as those found in polycrystalline thin films. Those are also covered in the same references, where 'cradle-to-cradle' recycling schemes have been outlined for key materials (see also below). For example, U.S. cadmium telluride (CdTe) companies have announced recycling and product 'take-back' strategies [14].

In terms of energy use, a PV-based system would radically reduce total fuel-cycle emissions to approximately 5% of conventional, including full energy payback. Calculations show that thin films require much less energy to manufacture than do other PV alternatives (except perhaps concentrator PV). The amount of CO_2 produced during manufacture of thin films is small (about 5%-10% of the amount avoided, [15]). We expect that the mature production of thin films will result in energy paybacks of under three years for the entire system [15]. Since PV systems are expected to have useful lives exceeding thirty years, this implies that the reduction of CO_2 due to using PV is about 90% to 95% in comparison with conventional sources. Based on 0.3 million metric tons (MMT) of avoided CO_2/GW of installed PV/yr (assumes 2,000 GWh/GW_p-yr and 150 MT avoided CO_2/GWh), a scenario in which 230 GW of PV would be installed by 2030 would avoid 70 MMT of CO_2/yr (and would have avoided about 800 MMT CO_2 over the entire 1995-2030 timeframe). Since we expect PV to keep expanding in use beyond 2030, these avoided emissions would be only the beginning of a longer term reduction in CO_2.

3.0 Technology Assumptions and Issues

Thin film PV devices are very different from today's common PV devices made from crystalline silicon. Thin films use 1/20 to 1/100 of the material needed for crystalline silicon PV, and appear to be amenable to more automated, less-expensive production. For a review of thin film PV see References 16-32. There are three thin films that have demonstrated good potential for large-scale PV: amorphous silicon (a-Si), copper indium diselenide (CIS), and cadmium telluride (CdTe). Others are at somewhat earlier levels of maturity (film silicon and dye-sensitized cells). The system in this document is a composite based on the three most mature thin films. It is generally believed that all thin films share similar characteristics: the potential for very low module cost (under $50/m^2$ of module area) and reasonable module efficiencies (13%-15% or more), implying potential module costs *well under* $0.5/$W_p$. See References 22-32 and a cost analysis below for an in-depth discussion of thin film module manufacturing costs. Thus, this assessment is a projection of a 'best, future' grid-connected thin-film PV system such as might be used in the U.S. to produce daytime electricity, after the turn of the 21st century.

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Thin film PV modules currently in production are based on amorphous silicon. Others, based on polycrystalline thin films, are in pilot production. Substantial commercial interest exists in scaling-up production of thin films. As thin films are produced in larger quantity, and as they achieve expected performance gains, they will become more economical for large-scale electrical utility uses and for large-scale non-utility off-grid uses in developing countries. Even though some thin film modules are now commercially available, their real commercial impact is only expected to be significant during the next three to ten years. Beyond that, their general use should occur in the 2005-2015 time frame, depending on investment levels for technology development and manufacture. The 'best future' grid-connected PV system described here requires that thin films continue to make the high-risk transition from lab-scale success to commercial success throughout this same period. As such, the technical and financial risks remain substantial. These affect the uncertainty of the projections.

Although some thin film modules are commercially available, developmental work is ongoing and remains key to their success. Indeed, to meet the economic goals needed for large-scale use, *much more technical development is needed*. Near term (3 to 10 years) commercial products will not be inexpensive enough to compete with conventional systems for volume U.S. utility-connected applications. Important technology development must be carried out to (1) transfer very high thin film PV cell-level efficiencies (up to 18%) to larger-area modules, (2) to optimize processes and manufacturing to achieve high yields, high rates, and excellent materials use, and (3) to assure long-term outdoor reliability. Today's technology base suggests that (with adequate resources) all of these important goals can be achieved [16-32], but each will be challenging.

Funding by the government for technology development has been critical to the thin film technologies described here. Current Federal PV R&D funding is about $40M annually. Federal funding for *thin films* is about half this total ($20M/year). Without it, most people believe that thin film PV would not exist in the U.S. Since almost every PV company is presently losing money, they would not be likely to pursue advanced R&D without public investment. The U.S. Federal investment in thin film R&D is more than half of the total U.S. corporate investment in thin films. Continued government funding of thin film technology development is crucial, and were it to dissipate, none of the projections in this characterization would likely be realized. Secondly, worldwide government spending is now expanding in 'markets', and to some extent we assume that this trend will continue. However, we are not assuming that market subsidies will drive the future of PV, as research funding does. (At current system prices of \$5-\$10/W_p installed, $10 million per year of Federal spending would only buy 1-2 MW of PV. This kind of spending cannot drive down prices.) Instead, the current State and Federal market support is aimed at facilitating PV market entry, not pulling PV costs down a 'learning curve' at an accelerated rate. Future funding is uncertain, and major changes could occur in either direction: critically enhanced or critically reduced PV budgets for technology development or market development. Either would change our picture about the future, *but reductions in R&D investment would invalidate many of the conclusions of this assessment.*

At some point (as PV costs drop), new forms of financing for U.S. and international markets must be developed for PV to become of global significance. We see hints of this future in the World Bank's Global Environment Facility (to fund CO_2 reductions in developing nations). However, as PV becomes a more relevant participant in global markets, developing new financial tools will be critical. Without some stimulus, U.S. utilities (and those in developed countries) are unlikely to press for large-scale use of PV. This is true in the near term (due to high prices) and may even be true in the longer term, especially if commodity energy prices stay low. This utility inertia may occur because even at lower costs (under 6¢/kWh), PV will remain marginally attractive on a purely avoided energy cost' basis. (This is not to discount large-scale use for peak shaving and other specialty markets.)

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4.0 Performance and Cost

Table 1 summarizes the performance and cost indicators for the flat-plate, thin film photovoltaic system being characterized in this report.

4.1 Evolution Overview

In the initial years (prior to 2005), we expect that the only commercial thin film, amorphous silicon, will compete directly with crystalline silicon (the existing PV market leader). Costs should drop steadily. Cost drops will be driven by increased manufacturing volumes, access to more standardized markets, and improvements in process technology (materials use, rates, yields). During the same period (before 2005), at least one other thin film (most likely CdTe) will enter the marketplace in a significant fashion, further adding to competitive pressures for cost reduction. Because CdTe technology appears to have greater near-term potential for higher efficiency and lower cost than amorphous silicon, cost reduction should accelerate. Thus we see fully loaded module manufacturing costs dropping from today's about $\$4/W_p$ to about $\$2.2/W_p$ in 2000 and $\$1.0/W_p$ in 2005. It should be noted, however, that these cost reductions depend strongly on the timing of (1) increases in production volume, (2) the introduction of the CdTe technology to large-scale manufacturing (over 20 MW), and (3) ongoing market growth. If these do not occur, the attainment of $\$1/W_p$ will be delayed up to five years. Module costs are likely to fall by another factor of three by 2030 as (1) the efficiency of commercial modules rises from 10% to 15% and (2) direct manufacturing costs drop from about $\$90/m^2$ to about $\$45/m^2$. Details concerning this progress are in the following sections. They are mostly dependent on technical progress such as improvements in device designs, process rates, process yields, and materials utilization rates. The cost and performance projections made in this section depend on continued steady progress in thin film PV. Although good progress has been made in recent times, ongoing progress can not be assured.

4.2 Performance and Cost Discussion

The AC, grid-connected systems characterized here range in size from 20 kW to 20 MW. All systems are fixed, flat-plate for simplicity of design and use. Actual systems will vary, without major impact on costs. The systems use the best available thin film in any given year (unknown at this time). See References 17-19, 22-33 for details on projected efficiencies and costs. Since 'capacity factor' depends only on tracking and system loss assumptions, capacity factor is assumed constant (21% for average sunlight, 26% for high sunlight) throughout the period. It may improve slightly during the period covered.

The expected economic life of the system is 30 years, although this is somewhat arbitrary. Solid-state devices such as PV modules may eventually last fifty years or more, although other mechanical and electrical aspects of systems may never be as robust. An ongoing outdoor thin film module test at NREL, and parallel accelerated tests [34], form the basis for reliability projections for thin films (see Figure 2). The system construction period is assumed to be less than one year, based on the fact that many such systems are already being built in similar construction times.

Table 1. Performance and cost indicators.

INDICATOR NAME	UNITS	Base Case 1997	+/-%	2000	+/-%	2005	+/-%	2010	+/-%	2020	+/-%	2030	+/-%
Plant Size (DC Rating)	MW_p	0.02		3		10		20		20		20	
Plant Size (AC Rating)	MW	0.016		2.4		8		16		16		16	
Plant Size (module area)	m^2	333		33,500		91,000		143,000		125,000		118,500	
PV Module Performance Parameters													
Efficiency													
- Laboratory Cell (best)	%	18		19	5	20	5	21	6	22	7	23	8
- Submodule (best)	%	13		15	5	17	5	18	6	19	7	20	8
- Power Module (best)	%	10		12	6	15	10	17	10	18	10	19	10
- Commercial Module	%	6		9	10	11	15	14	25	16	25	17	25
- Commercial Module Output	W_p/m^2	60		90	10	110	15	140	20	160	20	170	25
- System Efficiency	%	4.8		7.2		8.8		11.2		12.8		13.6	
System Performance in Average-Insolation Location (global sunlight, in plane, 1800 kWh/m^2-yr)													
AC Capacity Factor	%	20.7		20.7	5	20.7	5	20.7	5	20.7	5	20.7	5
Energy/Area	kWh/m^2-yr	86		130	10	158	15	202	25	230	25	245	25
Energy Produced	GWh/yr	0.029		4.4	15	15	20	29	25	29	25	29	30
System Performance in High-Insolation Location (global sunlight, in plane, 2300 kWh/m^2-yr)													
AC Capacity Factor	%	26.4		26.4	5	26.4	5	26.4	5	26.4	5	26.4	5
Energy/Area	kWh/m^2-yr	110		166	10	202	15	258	20	294	20	313	25
Energy Produced	GWh/yr	0.037		5.6	15	18.6	20	37	25	37	25	37	30

Notes:

1. For each of the six time frames, estimates of uncertainty (+/- %) are provided.
2. Output energy (kWh/m^2-yr) is reduced by 20% to include operational losses as compared with module and system peak watt (W_p) DC ratings. Output energy is used to calculate the busbar energy cost. The system's AC Rating already includes this 20% reduction. The 20% reduction from the peak power of the modules is as follows: 8% for module performance at higher operating temperatures (about 50°C instead of 25°C); 2% for dust accumulation; 5% for wiring and matching modules in array; 5% for DC-to-AC conversion and power conditioning to utility needs. Note that the operating temperature loss is lower than today's array losses because high-band gap materials such as CdTe and amorphous silicon have inherently lower temperature dependencies than crystalline silicon and have half or less losses due to operating at high temperatures.
3. Substantial uncertainties exist in both the magnitude and timing of the projections, since progress in PV depends critically on continued research advances. Long-term projections (2030) are based on reaching cost and performance that look practical, based on today's technologies and understanding. It is likely that actual 2030 achievements will be better than those assumed here because of innovations that are beyond what we can envision today.
4. Energy delivery equals AC Capacity Factor, times plant size (AC Rating), times 8,760 h/yr; it also equals system efficiency, times system area, times available sunlight per unit area, because, for this kind of simple, nontracking system, downtime is negligible.

Table 1. Performance and cost indicators. (cont.)

INDICATOR NAME	UNITS	Base Case 1997	+/-%	2000	+/-%	2005	+/-%	2010	+/-%	2020	+/-%	2030	+/-%
Capital Cost (1997$)													
Direct Module Production Cost	$/m^2	150-200	25	135-185	30	85-105	30	50-80	30	48-62	30	40-50	30
Power-Related BOS (converted from W_p$ to $/m^2)	$/m^2	60	25	54	30	44	30	35	30	32	30	25	30
Area-Related BOS without Land	$/m^2	109	25	100	30	78	30	48	30	42	30	39	30
Land Costs (total system area basis)	$/m^2	0.4		0.6		0.8		0.8		1.2		1.2	
Indirect Cost Factor (on modules and systems)	multiple	1.3	50	1.21	50	1.16	50	1.1	50	1.1	50	1.11	50
Indirect Costs (on modules and systems)	$/m^2	100	50	66	50	35	50	15	50	13	50	11	50
System Total	$/m^2	445	30	380	35	252	35	163	35	142	35	120	35
DC Unit Costs													
Module Cost (w/overhead)	$/W$_p$	3.8	30	2.2	35	1.0	35	0.5	35	0.38	35	0.29	35
BOS Cost (w/overhead & land at $0.02/W$_p$)	$/W$_p$	3.7	30	2.1	35	1.3	35	0.7	35	0.53	35	0.43	35
System Total	$/W$_p$	7.5	30	4.3	35	2.3	35	1.2	35	0.91	35	0.72	35
System Total	$M	0.148	30	12.7	35	23	35	23	35	18	35	14	35
AC Unit Costs													
System Total Capital Cost	$/W$_p$	9.3	30	5.3	35	2.9	35	1.5	35	1.11	35	0.88	35
Operations and Maintenance Cost													
Maintenance (annual)	$/m^2-yr	2	30	1	30	0.5	50	0.4	50	0.3	50	0.3	50
O&M (AC unit costs)	¢/kWh	2.30	30	0.77	30	0.31	50	0.20	50	0.13	50	0.12	50
Total Annual Costs	$/yr	666	30	33,000	30	46,000	50	57,000	50	38,000	50	36,000	50
Total Operating Costs	$/yr	666	30	33,000	30	46,000	50	57,000	50	38,000	50	36,000	50

Notes:

1. For each of the six time frames, estimates of uncertainty (+/- %) are provided.
2. Plant construction is assumed to require less than 1 year.
3. Module manufacturing and BOS costs, when given in units of $/m^2, do not include overhead. However, final costs are fully loaded when given in $/W$_p$ units. The difference is the ‘indirect costs’ given as a separate line. This overhead is used to indicate the fully loaded BOS, module, and installed system costs.
4. Most direct costs are given as $/m^2 because most costs are area-related (e.g., module manufacturing costs). Giving costs in terms of areas is a strong indicator of technical issues and evolutions. For example, critical parameters such as yield, materials use, and process rate are all proportional to module area produced.
5. Substantial uncertainties exist in both the magnitude and timing of the projections, since progress in PV depends critically on continued research advances. Long-term projections (2030) are based on reaching cost and performance that look practical, based on today’s technologies and understanding. It is likely that actual 2030 achievements will be better than those assumed here because of innovations that are beyond what we can envision today.

A key indicator is the projected efficiency of commercial modules. The output of a PV system is nearly proportional to the incident sunlight, and that proportionality is called the 'efficiency' of the system. Efficiency is defined for both energy and power. Power can be used as a measure of the instantaneous amount of sunlight on an array, or the amount of electric power the array produces (units of watts); energy is the power over a period of time (units of kWh). For example, if a PV system produces 180 kWh/m^2-yr in an average U.S. location (with 1,800 kWh/m^2-yr of sunlight), it is said to have an efficiency of 10% (since 180/1,800 is 10%). Similarly, if the instantaneous amount of sunlight is 1,000 W/m^2 (about the solar power at noon on a clear day; part of the definition of standard peak power conditions') and the PV system produces 100 W/m^2 of power, its efficiency is also 10%. Efficiency is the most critical figure of merit for PV, since both output and cost are strongly coupled to efficiency. Cost is inversely proportional to efficiency. A system installed for $1,000 that produces 100 watts has a price of $10/W ($1,000/100 W). One that is twice as efficient in converting sunlight to electricity produces double the power (200 W) for the same $1,000, and thus has half the price (per unit of power), or $5/W.

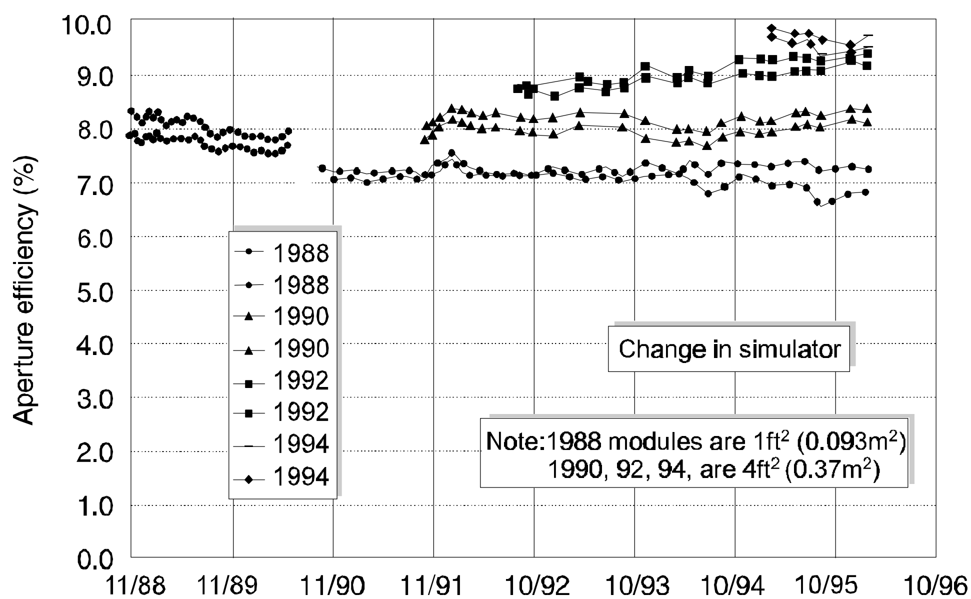

Figure 2. Results from eight years of outdoor thin film module tests.

More than a decade of technology development focused on thin films is beginning to pay off in the form of excellent performance. Table 2 shows the best 'one-of-a-kind', pre-commercial, thin film prototype modules [35,36]. These modules are the basis for our confidence in our cost and performance projections.

The base year (1997) status [18-20, 35-36] of thin films supports these projected levels. For example, cell-level efficiencies have reached 16-18% in two different polycrystalline thin films (copper indium diselenide and cadmium telluride; see Figure 3). Submodule and module efficiencies are closely related to cell efficiencies, with minor losses (about 10%) due to some loss of active area and some electrical resistance losses. Today's best laboratory-level modules are about 8-10% efficient (see Table 2). When the product-level technology (which includes all the process development needed for manufacture) has adopted all the technical capabilities now observed in laboratory experiments, the best lab modules will be about 90% of the efficiency of the best cells. Off-the-shelf commercial modules will be about 90% as efficient as the best prototype modules. The timing of how these R&D advances actually become available in the marketplace is far less certain; projected ranges are used to capture this uncertainty without completely begging the question.

Table 2. The best thin film modules (1997).

Thin Film Material	Size (cm^2)	Efficiency (%)	Power (Watts)	Company & Comments
CdTe	6,728	9.1	61.3	Solar Cells Inc.
a-Si	7,417	7.6	56.0	Solarex (Amoco Enron Solar)
CIS	3,859	10.2	39.3	Siemens Solar Industries
CdTe	3,366	9.2	31.0	Golden Photon Inc.
a-Si	3,906	7.8	30.6	Energy Conversion Devices
a-Si	3,432	7.8	26.9	United Solar Systems (USSC)
a-Si	1,200	8.9	10.7	Fuji (Japan)
CIS	938	11.1	10.4	ARCO Solar (now Siemens Solar)
CdTe	1,200	8.7	10.0	Matsushita (Japan)
a-Si	902	10.2	9.2	USSC

Note: Efficiencies verified independently at NREL.

Submodules not shown in Table 2 have reached 13-14% at about 100 cm^2 in area [36]. Efficiencies are 10% to 11% on square-foot (0.093 m^2) sizes, and 7% to 10% on larger power modules ranging in size from 4 to 8 square feet (0.37-0.74 m^2) in area. A few years ago (1990), no thin film modules larger than four square feet (0.37 m^2) were being made. The transition from laboratory-level cell prototypes to pre-commercial modules is underway. These same modules now form the basis for design and construction of larger-capacity manufacturing facilities, which are in-progress at many U.S. thin film companies. Meanwhile, additional technical progress is in the pipeline [36]. Figure 3 shows the recent progress in polycrystalline thin film laboratory cells. The changes implicit in the best 16-18% efficient cells have not yet been incorporated in the modules of Table 2. When they are, efficiencies will rise commensurately. The progress in thin film cells provides a strong basis for our belief that the ambitious performance goal of 15% for commercial modules will be met, since a reasonable translation of existing cell efficiencies to future module efficiencies would be nearly sufficient to meet the goal. Figure 2 shows outdoor tests of six CIS-based thin film modules at NREL. These modules have been outside for almost eight (8) years. They show no apparent change in performance. Two-year stability data is available for CdTe modules.

Module and system costs are frequently given in $\$/m^2$ as an indication that most PV costs are proportional to module area. (Some costs, such as those for inverters, are proportional to power, but can be converted to $\$/m^2$ using area and a known output per unit area). A module might have a fully loaded cost of $\$400/m^2$ to manufacture. If it produces 100 W/m^2 under 'standard conditions', it is said to have a cost of $\$4/W_p$ (W_p stands for the watts produced under peak sunlight). Today's PV modules sell at about \$3.5 to $\$5/W_p$; and PV systems sell at about \$7 to $\$15/W_p$. Peak power for a system is found by adding up the power of the individual modules, rated at their peak power. System economics are then calculated based on kWh output during real or average conditions at a specific solar location.

The base year (1997) system is modeled after two recent thin film systems: an APS a-Si 400 kW system at PVUSA (\$5/W_p) and a Solar Cells Inc./ 25 kW CdTe system at Edwards Air Force Base (\$6.3/W_p, [37]). Although both of these systems are below the indicated \$7.4/W_p that we assumed (see Table 1), it is probably proper to estimate that the companies installed them for somewhat below true cost.

Today, PV module costs are about half the total system costs for most PV systems and are the primary opportunity for cost reductions. The technology option considered here (thin films) was originally investigated because its potential cost per unit area is significantly lower than existing PV based on wafer silicon [16-20]. In addition to module cost, the module performance defines system output. This combined influence on capital cost and system unit output cost is why modules are the critical cost driver in PV. Structural costs are highly dependent on economies of volume production. They are expected to fall as production increases. But they, too, require some focused developmental work to reach optimal levels. However, module efficiencies and module manufacturing costs are the key areas of focus determining PV system costs. Work on improving PV modules (both in terms of efficiency and cost optimization) is most likely to pay off in reductions in PV prices.

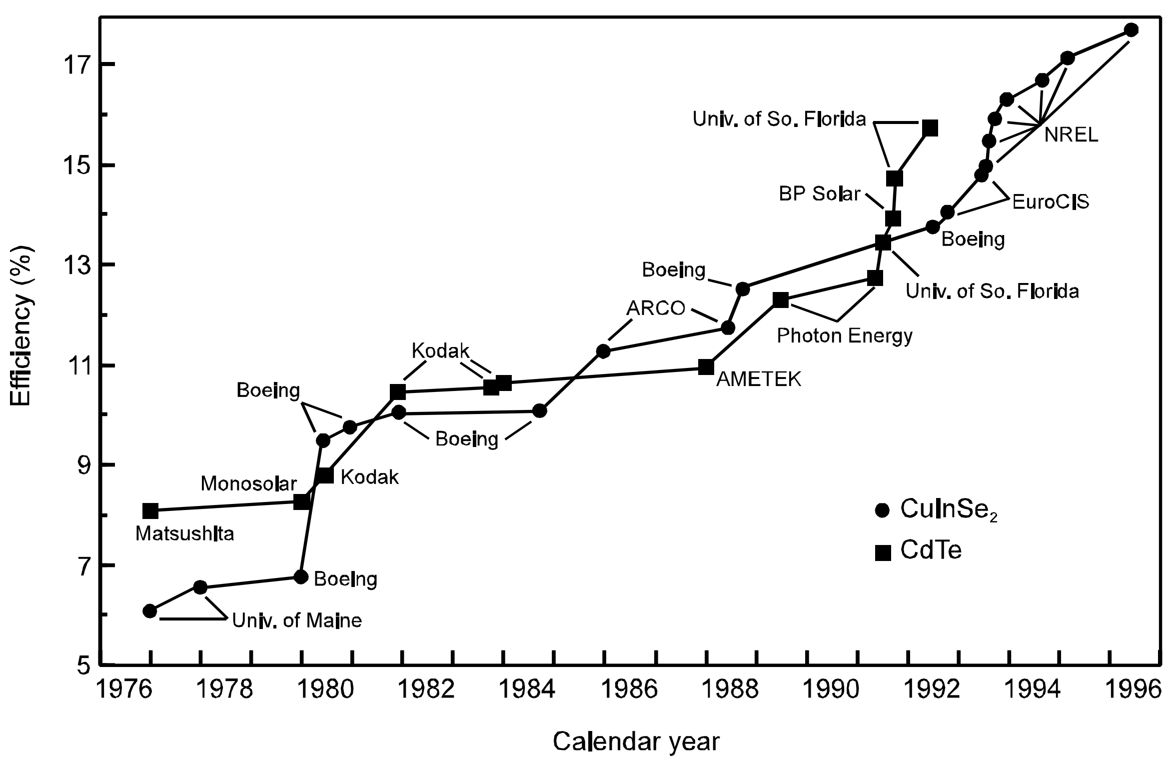

Figure 3. Recent progress in polycrystalline thin film laboratory cell efficiencies.

In terms of module production costs, various studies [22-32, 33] of materials costs, combined with energy inputs, labor, and capital costs, support the cost projections. Data on specific amorphous silicon and polycrystalline thin film technologies were provided by U.S. manufacturers to the DOE/NREL PV Manufacturing Initiative as part of their final reports [27-32]. These provide the most up-to-date information on module cost projections. General analysis of PV system costs can be found in References 38-40. Nearly all of these cost studies agree that ultimate thin-film module manufacturing costs for a future, optimized manufacturing scenario can be as low as $40-$50/m^2. Since the issue of achieving very low module manufacturing costs, $50/m^2 or less, is perhaps the most important of any aspect of these projections, it deserves some special focus. In-depth review of References 22-32 supports this assertion and reveals a few important aspects of cost that are summarized in Table 3.

Table 3. Summary of thin film direct manufacturing costs: projections for practical long-term reductions.

Summary of Thin Film Direct Manufacturing Costs	Cost ($/m^2)
Materials	
Glass (2 sheets @ $5/m^2)	10
Binder (between glass and module)	5
Active Materials (for PV thin film)	5
Subtotal: Materials	20
Capital equipment (manufacturing plant)	10
Energy used in manufacturing	2
Facilities	1
Labor	10
TOTAL	43

Materials: Most thin films use one or two pieces of inexpensive soda lime glass, which is sold in quantity at about $5/m^2. A sheet of binder (between the glass and the module) is about another $5/m^2. The amount of material in a micron thickness across a square meter of area is 1 cm^3. There are about 3-10 g/cm^3 of material in the various films. Film thickness is about 1-10 µm, depending on the design, so a typical amount of material would be about 25 g/m^2. Considering feedstock losses, if only 50% of the feedstock material actually ends up on the module, then 50 g/m^2 of feedstock are needed. Typical materials costs for the various materials used in thin films (at high purity) can vary from $20 to $200/kg, or $0.02-$0.20/g. Fifty grams would cost about $5/m^2. This is the total cost of the active materials in a thin-film module and is a fairly typical number from References 22-32 for all the materials costs outside the glass and encapsulants. The total materials costs are about $20/m^2 (adding the active materials, binder, and two pieces of glass).

Manufacturing Plant: Thin film manufacturing plants are now being built or being planned. Their capital costs tend to fall into the range of $10M to $30M for 10 MW of annual production capacity (about 150,000 m^2 of modules at 6.5% efficiency). That is $1-$3/W$_p$ for first-year module production. If this cost is amortized over 5 years, this becomes $0.3-0.8/W$_p$ for production costs (assuming a discount rate to take into account the time value of money). These costs must be translated into $/m^2 to provide an insight into trends. Since today's module efficiencies are only 5%-8%, these plant costs are about $18 to $52/m^2 (assuming 65 W/m^2 multiplied by $0.3/W or $0.8/W). Today's first-ever manufacturing plants are quite rudimentary, from a technical standpoint. Capital costs can only get lower as processes are optimized for faster throughput and other economies of scale. A 'best' future capital cost of about half of today's lower costs, $10/m^2, seems quite conservative. (For example, tripling the throughput rate would cut the module unit cost attributable to plant capital ($10/m^2) by a factor of three. This kind of improvement is already being investigated at the lab level.)

Energy, Labor and Facilities: The remaining direct manufacturing cost components are energy, labor, and facilities. Various analyses of module energy input costs suggest that modules will pay back their energy output within one year of outdoor operation [41-42]. References 41 and 42 quantify the electrical energy in a thin film module as about 20 kWh/m^2. At a price of $0.1/kWh, this is another $2/m^2.

Adding all of the costs so far, yields $32/m^2. Facilities costs are about $200,000/year for a 10 MW plant, or $0.02/W$_{p,}$ which is $1.3/m^2 (nearly negligible). Labor costs are the last item of significance. We estimate that an operational plant with reasonable automation would require about 10 operators/shift; 30 full time staff. These are technician and operations-level positions. (Management and marketing, as well as other indirect costs, are included in overhead costs.) At direct costs of $50,000/yr, they would cost about $1,500,000/yr, or $0.15/W$_p$, or $10/m^2. Adding together these estimates yields ($20/m^2 for materials; $10/m^2 for capital equipment; $2/m^2 for energy; $1/m^2 for facilities; and $10/m^2 for labor) $43/m^2. This number is both close to estimates of 'best future' manufacturing costs (about $40/m^2) and also without the full value of the following optimizations: thinner semiconductors, improved materials use during deposition, higher-rate deposition processes, better yields, larger-sized or continuous substrates, reduced input energy and substrate costs by either eliminating one sheet of glass or attaching PV production on the end of a glass line, and complete automation of these rather straightforward in-line processing steps. All of these steps are obvious technological improvements that are already underway in various forms, but their potential for improvement is far from being exhausted.

The $/W$_p$ costs in Table 2 are simple restatements of these costs from a $/m^2 basis ($/m^2 divided by W$_p$/m^2 yields $/W$_p$). Total system output is about 20% less than peak power rating due to operational de-rating (operating temperature, resistance and power-conditioning losses) [39,43]. Installed system costs are assumed to be about twice as high as module costs (assuming that increased volume production of systems will result in balance-of-system (BOS) cost reductions that parallel module cost reductions). BOS, or balance of system, costs are the costs associated with everything but the modules and overhead; i.e., land, support structures, module wiring, power conditioning and DC-to-AC inverter, installation, and transportation. Total system cost is the module cost, the BOS cost, plus overheads. Overheads occur at all levels, from overheads on manufacturing the modules and BOS components, to system design and installation overheads.

The overhead and BOS costs are expected to decline because the cost of today's systems is the sum of rather low material costs, fairly high DC-AC inverter costs, and very substantial design, engineering, and installation costs for doing different, small systems one at a time. Improvements in inverters have already been observed in other renewables (e.g., wind) when inverter sizes are large. Inverter costs in-line with those needed for low-cost PV have been achieved in these cases. Similarly, the other aspects of systems costs (design, engineering, installation, overhead) are all likely to fall substantially as volumes and repetition increase. Many PV industry representatives believe that the materials costs in real PV BOS will be compatible with very low ultimate costs like those quoted here.

5.0 Land, Water, and Critical Materials Requirements

Table 4. Resource requirements.

Indicator Name	Units	Base Year 1997	2000	2005	2010	2020	2030
Land	ha/MW	5	4	3	2.5	2.5	2.5
	ha	0.08	9.6	24	40	40	40
Critical elements (e.g., In, Se, Ga, Te)	MT/GW$_p$	NA	50	30	20	10	3
Water	m^3	nil	nil	nil	nil	nil	nil

Land area needs are based on calculating the array area required to produce the desired output, amount of energy per square meter of array and then multiplying this area by a factor of about 2.5 to account for packing the arrays without shadowing. At 10% system efficiency, a PV system produces about 100 W/m^2 of array. Including the packing factor, this is 40 W/m^2 of land area. A MW would thus require 25,000 m^2 of land, or about 0.025 km^2. In the early years, we expect system efficiency to be below 10% (accounting for the larger land requirements), but by 2010, system efficiency of over 10% is assumed (accounting for the lower land-use numbers). In some cases, PV will be used on rooftops or other dual-use applications, thus reducing land use below these estimates.

Certain PV technologies require important elements such as tellurium, indium, selenium, and gallium. The availability of these materials is, in principle, limited by economics and geologic factors. However, thin film PV uses very small amounts. Typical elemental concentrations in PV are about 3 g/m^2 for each micron of layer thickness. Layer thicknesses vary from about 1-3 µm . In early years, little effort will be put into reducing thicknesses, because even at these thicknesses materials costs are not a driver. But as performance increases and other costs are overcome, materials costs will become important, and layers will be thinner. The theoretical limit on how thin layers can be (from today's understanding) is about 0.1-0.3 µm, depending on device subtleties such as light trapping to cause multiple reflections. This evolution of materials needs is captured in Table 4 (above) based on reduced layer thickness (coming down from about 2 µm to about 0.2 µm) and efficiency (output per g of feedstock) rising from 8% to 15%. In no case would the very large-scale use of PV put pressure on the availability of these elements. Indeed, this also means that other materials that are used in compound semiconductors (e.g., cadmium in CdTe) would not be used excessively, obviating most global-level environmental impacts of these materials. For example, cadmium is used today at about 20,000 MT/yr for current uses (rechargeable batteries for entertainment). Using 100 MT/yr for PV (to add over 30 GW$_p$ /yr of PV capacity) would change this usage by less than 0.5%.

Ultimately, as PV reaches a steady-state, recycling of outdated thin film modules would allow for another reduction by half in the amounts of new material needed to make a GW$_p$ per year of PV. In fact, the use of materials is so controlled in PV systems (semiconductors are sealed from the environment for 30 years or more and can then be recycled), that PV may ultimately play a role as a safe and productive 'sink' for numerous materials that are today without any long-term sequestering strategy.

PV systems do not use water during operation.

6.0 References

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