The Basic Economics of Photovoltaics for Vacuum Coaters

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ABSTRACT

With widespread deployment of photovoltaic (PV) power imminent, it is useful for members of the Society of Vacuum Coaters to have at least a basic knowledge of the economic principles that govern PV modules and systems. A simplified framework is presented that illustrates that minimum PV efficiency and lifetime values exist even for low-cost deposition processes.

INTRODUCTION AND BACKGROUND

According to industry analysts, shipments of photovoltaic (PV) modules worldwide in 2008 were over 5 GW, with a module cost of 3-4 dollars per peak watt ($\$/W_p$) [1]. It is expected that the Levelized Cost of Electricity (LCOE) for solar generated electricity will reach 8 cents per kWh by 2015 [2]. This will lead to rapid and widespread economic deployment of PV. It is therefore useful for those who make or repair vacuum coating equipment to be familiar with the economic principles that govern PV module production and installation. This paper presents a brief review of this type of analysis.

Before proceeding with a description of PV economics, it is useful to briefly describe the types of PV technologies currently deployed. Most commercial PV panels are made from individual solar cells made of crystalline (c-Si) [3] or multicrystalline silicon (mc-Si). These wafer-based Si solar cells are currently produced by growing single crystal ingots or by casting multicrystalline blocks. The silicon is then sliced into 200-300 micron thick wafers and processed with dopants using methods similar to those used for making integrated circuits. Less developed thin film PV technologies are based on materials such as amorphous silicon (a-Si) or on polycrystalline CdTe or $CuInGaSe_2$ (CIGS) [4]. These thin film light absorber materials can be directly deposited on glass and interconnected using laser-based scribing or photolithography. Concentrator PV (CPV) solar cells, in contrast, cover only a tiny fraction of a whole PV system and are typically made from Si or III/V materials. Such CPV cells can reach solar conversion efficiencies of over 40%. Any viable PV production process, be it thin film, wafer-based or for concentrators, must be conducive to high throughput production rates (e.g. large areas per unit time) and high yields so that Gigawatt per year (GW/y) capacities are possible.

The history of PV economics is as long as the industry itself. In the field of thin film PV, the work of Zwiebel [5] is among those that are most quoted. This is in part because it is easy to follow and it relates the cost per square meter of the module to its cost per peak watt and the cost of electricity in a installed PV system. More recently, this work has been extended to map out a plan that would allow solar energy to supply all of the electricity needs of the U.S. [6]. Several recent papers have updated the field of PV economics [7] for both organic and silicon-based technologies [8]. These studies highlight the need to consider the manufacturing equipment, throughput and process yields.

THE BASICS OF PV MODULE ECONOMICS

The economics of PV devices is related to their conversion efficiency as well as to the solar irradiance at the Earth's surface. The cost of photovoltaic materials is expressed on a per-unit-area basis, but the modules are often sold based on cost per watt that is potentially generated under peak solar illumination conditions. To convert the cost per square meter to this cost per peak watt ($\$/W_p$), the following equation can be employed [9]:

$$\$/W_P = \frac{\$/m^2}{\eta \cdot 1000\ W_P/m^2} \tag{1}$$

The peak solar irradiance is 1000 W/m^2. A 12% efficient module with a cost of \$400/m^2 thus yields a cost per peak watt of \$3.33. For a PV module operating at a solar conversion efficiency of 16%, power could be produced at 2.5 $\$/W_p$ if the module cost is 400 \$/m^2. For a 10% efficient module, the $\$/W_p$ cost would be the same for 250 \$/m^2.

For the analysis that follows, an average daily insolation of 5 kWh/m^2 day will be used. This corresponds to a location such as San José, California with an annual insolation on a horizontal surface of 1820 kWh/m^2/year and an insolation on a south-facing solar array, tilted at an angle approximately equal to the latitude, of 1980 kWh/m^2/year. For the month of May, for example, the same surface and location would receive about 200 kWh/m^2 of energy for either orientation. For comparison, a properly tilted array at that location would have an average annual *irradiance* on it of 270 - 300 W/m^2.

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In a simplified economic analysis, it is desirable to estimate the return on the investment made for a particular material used as part of the photovoltaic system. For example, the payback time for the PV module is related to its efficiency, the location it is installed and the cost at which electricity is sold on the market (in \$/kWh). The payback time is given by

$$\text{Payback time} = \frac{\text{Cost \$/m}^2}{\eta \cdot \frac{5\,\text{kWh}}{\text{day} \cdot \text{m}^2} \cdot \frac{365\,\text{day}}{\text{y}} \cdot \frac{\text{electricity \$}}{\text{kWh}}} \tag{2}$$

As an example, the payback time for a 150 \$/m^2 module of 20% efficiency at an electricity selling price of 0.08 \$/kWh is approximately 5 years.

ESTIMATED SOLAR MODULE COST

To estimate its \$/m^2 costs, one can consider a hypothetical thin film PV module for which several steps are made with vacuum coating equipment. To calculate the area-related costs, one considers both the materials and fabrication costs. If we assume that a single piece of glass is used as the substrate, we also must include costs of sealing and encapsulation. The costs for a hypothetical [5, 7, 10] thin film PV module is outlined in the Table 1 below and is found to be \$155 (2009) dollars per square meter.

Table 1: Module Cost Breakdown.

	Cost (*\$/m²*)
Solar cell materials (e.g. absorber layers) [5, 10]	50
TCO-coated low Fe glass	20
Encapsulant or Sealant (e.g. EVA, Silicone)	10
Additional moisture barrier and backing (e.g. Tedlar, PVF)	10
Frame, junction box and electrical inter-connects	20
Labor (Direct)	10
Production Overhead:	
Equipment Depreciation	20
Indirect Materials	5
Labor (Indirect)	5
Profit, Interest due on loans	5
Total module cost	*155 \$/m²*

The direct costs such as tools and labor are related to the actual production of the module, while the indirect costs, such as accountants, rent and computers, are volume insensitive. Labor costs include assembly and testing. This calculation assumes a 20 MW_p/year factory with 100 employees and a capital cost of equipment of \$20 million housed in a 2,000 m^2 facility. The transparent conductive oxide (TCO) coated glass is, for example, low iron content tempered glass coated with SnO_2:F such that its transmission is above 80% and its sheet resistance is between 7-15 ohms/square. For most PV technologies, the module costs are determined primarily by the cost of the glass, absorber materials and the production overhead. Overhead expenses are costs other than direct labor and direct materials and includes items such as accounting fees, advertising, insurance, interest, legal fees, rent, repairs, supplies, taxes, telephone bills, travel, utilities costs and depreciation.

To calculate the equipment depreciation that should be applied to a square meter of product, one first divides the size of the factory (in MW_p/year) by the product of the peak solar irradiance (1000 W_p/m^2) and panel efficiency, η. This yields the throughput, the area produced by the factory in a year. Separately, one amortizes the initial capital cost, P, of the necessary equipment using a formula for the annual worth,

$$\text{Annual worth} = \frac{i \cdot P}{\left[1-(1+i)^{-N}\right]} \; or \; \frac{P \cdot i(1+i)^N}{\left[(1+i)^N - 1\right]} \tag{3}$$

where "i" is the depreciation rate and N is the time over which it is depreciated. The values for "i" and N in this equation are obtained via the Modified Accelerated Cost Recovery System (MACRS). For the semiconductor industry, values of i = 10% and N = 7-10 years are appropriate. One can then estimate the equipment depreciation via

$$\text{Equipment cost/m}^2 = \frac{\text{Annual worth}}{\frac{\text{MW}_\text{P}}{\text{year}} \Big/ (\eta \cdot 1000\ \text{W}_\text{P}/\text{m}^2)} \tag{4}$$

For example, for 20 million dollars worth of equipment (P), and using the values: i = 10%, N = 7 and an annual module production of 20 MW_p, the appropriate depreciated equipment cost is approximately 20 \$/m^2 for modules of 10% conversion efficiency. This was used in the estimate given in Table 1. From this, one sees that if the process yield decreases, the effective equipment cost per unit area increases. Note that if the resulting module efficiency drops, the annual output should be reduced in proportion.

As a comparison, the cost of a c-Si or mc-Si module would differ considerably in the cost of the absorber materials. For wafer-based cell technologies, these costs are currently 400-500 \$/m^2, but this is decreasing over time because the grams per watt (g/W_p) is being decreased via the use of thinner wafers and advanced light trapping schemes [3, 4]. Both thin film and c-Si PV modules require an encapsulant and moisture barrier. Some designs, such as solar shingles, can do away with the expensive metal frame [4, 5]. To estimate the cost per peak watt, one relates the cost per unit area above with the power produced, which depends on the solar conversion efficiency and the peak solar illumination as described in Equation 1.

ECONOMICS OF PHOTOVOLTAIC SYSTEMS

The essential economic concept for all PV installations is that its cost should be recovered by the useful energy that is produced over its lifetime. To begin with, one realizes that there is more to a PV system than just the module. To produce useful power in a commercial power generating application, one must consider the average illumination, instead of the peak irradiance, and the finite lifetime of the PV panels. Area-related Balance of Systems (BOS) costs such as the mounting, wiring, installation, and land must be added to the cost of the module itself. Power conditioning (PC) by control circuitry and inverters must be included, as well as operating and maintenance (O&M) costs. When all of these factors are included, the levelized cost of electricity (LCOE) can be estimated from the ratio of the total life cycle cost to the total lifetime energy production, or

$$\mathrm{LCOE}\ \frac{\$}{\mathrm{kWh}} = \frac{\left(\text{Cost of system } \$/\mathrm{m}^2\right)\cdot \text{amortization}}{\mathrm{kWh/m}^2 \text{ produced each year}} + \mathrm{O\&M} \qquad (5a)$$

Inserting the relevant terms, Eqn. 3a becomes [10]

$$\frac{\$}{\mathrm{kWh}} = \frac{\text{Module } \$/\mathrm{m}^2 + \text{BOS } \$/\mathrm{m}^2 + \left(\text{PC } \$/\mathrm{kW}\right)\cdot \eta\, I_P}{\eta \cdot \frac{5\,\mathrm{kWh}}{\mathrm{day}\cdot \mathrm{m}^2}\cdot \frac{365\,\mathrm{day}}{\mathrm{y}}}\cdot \mathrm{CRF}\left(1+\mathrm{IND}\right) + \mathrm{O\&M} \qquad (5b)$$

Here, I_p is the peak solar irradiance (1 kW/m^2) and an average daily insolation of 5 kWh/m^2 day has again been used. In some studies, the denominator of equation 5b is replaced by a capacity factor and costs in the numerator are in \$/W_p [5]. The amortization is taken as the so-called Capital Recovery Factor (CRF). It is calculated from the real discount rate, *i*, and the PV module lifetime, N, from

$$\mathrm{CRF} = \frac{i}{\left[1-\left(1+i\right)^{-N}\right]}\ or\ \frac{i\left(1+i\right)^N}{\left[\left(1+i\right)^N - 1\right]} \qquad (6)$$

This factor depends on current interest rates and the availability of capital. For utility-scale power, i = 6% and for investor-funded projects, i = 10% is appropriate. For residential systems and projects on commercial buildings, a low interest loan might be secured. For these, a more generous i = 5% is used below.

Table 2: Cost (\$/kWh) of a photovoltaic system for i = 5% and a 200 \$/m^2 module.

PV Module Efficiency, η	8 %	15 %	20 %
N = 20 Years	0.21	0.12	0.09
N = 10 years	0.34	0.19	0.15

Using an O&M value of \$0.005/kWh, the electricity costs can be estimated from the simplified equations above. For illustrative purposes, the following values [5, 10] were used: module cost of 200 \$/m^2, area-related BOS costs of 75 \$/m^2, inverter costs of \$170 per peak kW (e.g. power conditioning), and an indirect cost (IND) of 30% of direct costs for architect and engineer fees, along with interest during construction. The cost of energy (LCOE) produced with this hypothetical PV is 0.12 \$/kWh, assuming a 15% efficient module which lasts at least 20 years under the irradiance levels found in the sunnier regions of the western United States.

Note that our cost estimate falls within the range of electricity prices for conventional fossil fuel-based systems (between 0.06 and 0.13 \$/kWh and this depends on location and time of day). The above analysis therefore outlines one scenario where solar cells could represent a viable energy option. The results of this kind of simplified economic analysis also indicate that although solar cells of 15% efficiency that last for 20 years can be competitive with fossil fuels, solar cells of less than 8% efficiency with lifetimes less than 10 years will probably not be economical or competitive. Even a panel with free absorber materials must have a minimum lifetime and efficiency.

The cost of the PV module is often the largest cost in a photovoltaic system. It, of course, depends on the nature of the technology and the processes used to make it. For concentrator PV systems, the area-related module cost is reduced, because optics can be much less expensive than semiconductors. In equations 5a and 5b above, it can be split into two \$/m^2 costs: one for the cells and one for the optics [4, 10]. For CPV, the PV cell's cost can be reduced by the concentration ratio.

The simplified analysis presented herein can be used to illustrate the areas for further research and discussion. It updates the previously published version [9]. The results are summarized in Tables 1-3. The calculations above do not consider the effects of non-optimal arrangement of the panels or the fact that power conditioning system failures can lead to downtimes. For a full cost assessment, other factors should also be considered.

Table 3: Present and future PV system cost breakdown.

Aspect of PV System Cost	Now	Needed
Module cost	150 - 450 $/m^2$	60 - 200 $/m^2$
Module Cost per W_p	3 - 4 $/W_p$	1 - 3 $/W_p$
Module efficiency	10 - 18 %	10 - 20 %
Power-conditioning	500 – 800 $/kW	200 – 300 $/kW
Area-related BOS	75 - 150 $/m^2$	50 - 75 $/m^2$
Cost of PV generated AC electricity	0.20-0.30 $/kWh	0.07-0.20 $/kWh

CRITIQUE OF THE ANALYSIS

One should point out that the market cost (selling price) of PV modules is often different, by as much as 1 $/$W_p$, than their manufacturing cost and that this depends on supply and demand. The simplified equations presented herein did not consider the cost savings from larger economies of scale [3, 12]. This has yielded useful insights by considering the flow of materials through a PV factory. The total yearly needs for a 20 MW PV manufacturing plant represent only a few days of production for a sheet glass factory. To make low-iron glass, the manufacturer has to shut down the line, clean the oven and re-start with low iron feedstock. The low-iron glass would then have to be stored for a year or shipped to where it is needed. This suggests that a cluster of PV factories might be located close to a glass company, which itself might be situated near suitable deposits of silica or quartz used as raw materials. One should also note that the inverter costs used for the calculation above are optimistic. For large residential systems, PC can have values of $500-600/kW and DOE targets are approximately $300/kW by 2020 [11]. Clearly, further work needs to be done to lower both BOS and PC costs and to consider solar module design from a systems and supply chain approach.

One also needs to consider the availability of the materials used to absorb the light in solar cells as well as the other components that complete the full PV module or panel. The analysis above does not include the costs of securing contracts for materials, or the availability of non-abundant crustal elements such as In, Ga, Ge or Te. This aspect has been explored by Anderson [14] and, more recently, by Freundlich [15] and Fthenakis [16]. For example, indium is primarily obtained from the mining of zinc. It is used in the transparent conductive oxide (TCO) coatings of Indium Tin Oxide (ITO) for flat panel displays and thin film PV technologies. It is also part of the absorber layer itself in CIGS-based and some III-V CPV-based cells. Molybdenum, selenium, and tellurium are obtained primarily from the by-products of copper mining. Gallium is a scarce element and 95% of its global supply is obtained as a by-product of aluminium production from bauxite. The above-mentioned studies indicate that the availability and yearly production of these materials may limit the deployment of some PV technologies as they reach beyond GW/year levels.

Also not considered is the full cost of capital (e.g. loans), or subsidies and other tax incentives. These aspects can also be included [13]. One important economic issue that is often neglected when formulating energy policy is subsidies that favor certain energy industries (e.g. those that are fossil fuel based) and distort costs.

CONCLUSIONS

A simplified economic analysis for the production of a PV module has been presented and integrated into a framework where the complete PV system can also be considered. This is useful for gaining insights as to whether a given material, piece of equipment or process can produce a cost-effective solar technology. The analysis presented in this text provides a framework by which decisions can be made and options can be compared. One conclusion is that the actual solar cell absorber materials can be a small fraction of the overall module and systems cost. Considering this, one might be able to find solutions in which the overall cost is minimized. In addition, one sees that even a solar cell that is free must have a minimum efficiency and lifetime for the cost of solar generated electricity to be competitive with conventional sources. The values used in this work for illustrative purposes are reasonable for current and near-term technologies. They illustrate that the cost of electricity generated from PV will soon reach parity with conventional sources. This will not take place unless the module costs are decreased along with the power conditioning and area-related Balance of Systems (BOS) costs.

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