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Achievements and Challenges of Solar Electricity from Photovoltaics

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1.1 THE BIG PICTURE

Congratulations! You are reading a book about a technology that has changed the way we think about energy. Photovoltaics (or PV) is an empowering technology that has shown that it can generate electricity for the human race for a wide range of applications, scales, climates, and geographic locations. Photovoltaics can bring electricity to a rural homemaker who lives 100 kilometers and 100 years away from the nearest electric grid connection in her country, thus allowing her family to have clean, electric lights instead of kerosene lamps, to listen to a radio, and to run a sewing machine for additional income. It can pump clean water from underground aquifers for drinking or watering crops or cattle. Or, photovoltaics can provide electricity to remote transmitter stations in the mountains, allowing better communication without building a road to deliver diesel fuel for its generator. It can allow a suburban or urban homeowner to produce some or all of their annual electricity, selling any excess solar electricity back into the grid. It can help a major electric utility in Los Angeles, Tokyo, or Madrid to meet its peak load on hot summer afternoons when air conditioners are working full time. Finally, photovoltaics has been powering satellites orbiting the Earth for 30 years or vehicles roving over the surface of Mars.

Every day the human race is more aware of the need for sustainable management of its Planet Earth. It upholds almost seven billion human beings of which one billion have adopted a

Handbook of Photovoltaic Science and Engineering, Second Edition
Edited by Antonio Luque and Steven Hegedus

high-consumption lifestyle which is not sustainable. “High consumption” used to refer materials that could become scarce, but it increasingly refers to energy. Here the term energy, refers to “useful energy” (or exergy), that once used is degraded, typically to waste heat, and will be no longer be useful.

Here we are concerned with electrical energy which is a secondary form of energy. Fossil fuel (coal, petroleum and natural gas) combustion and nuclear fission are the primary processes which create heat to turn water into steam which rotate giant turbines which generate electricity. When the C–H bonds in fossil fuels are burned in the presence of air for heat, they produce CO_2, and H_2O. The latter waste is not a problem because there is already so much water in the seas and in the atmosphere. But CO_2 is a different story. Analysis of the air bubbles embedded in Antarctic ice layers provides information on the CO_2 concentration of the atmosphere in the last 150 000 years. This content shows an unprecedented growth in the last 300 years, coinciding with the beginning of the industrialization. This fact is linked by most scientists to global climate change, including global warming, sea level rise, more violent storms, and changes in rainfall. This will disrupt agriculture, disease control, and other human activities. Thus, a substantial fraction of our energy must be generated without any C emissions within the next 10–20 years, or else the Earth will become a dangerous experiment. Besides, fossil fuels cannot last forever. Supplies of petroleum and natural gas will both peak and then decrease within decades if not years, and coal within few centuries. We must develop large-scale alternatives to burning fossil fuels very soon.

Another primary energy source for electrical generation is radioactivity in the form of uranium, which when conveniently transformed, fuels nuclear plants through nuclear fission. Concerning the uranium, most of it consists of the 238 isotope, which is not “fissile” (not a nuclear fuel) and only about 0.7% is the 235 isotope, which is fissile. With the present technology, nuclear fuel will peak within decades. However, uranium 238 can be converted to an artificial fissile fuel by proper bombardment with neutrons. With this technology, not fully commercial today, it would be possible to have nuclear power (with unproven cost effectiveness) maybe for a millennium. Nuclear fusion, which is a totally different nuclear technology, could be practically inexhaustible, but its practical feasibility is very far from being proven.

While nuclear plants emit no CO_2, they are still inherently dangerous. Nuclear engineers and regulators take many precautions to ensure safe operation, and (excepting very few cases) the power plants function without catastrophic problems. But the storage of highly radioactive wastes, which must remain controlled for centuries, remains an unsolved issue worldwide, along with the possibility of diversion of nuclear fuel to making a bomb.

So the situation at the beginning of the 21st century is that the previous century’s methods of generating our most useful form of energy, electricity, are recognized as unsustainable, due to either increasing CO_2 poisoning of the atmosphere or the increasing stockpile of radioactive waste with no safe storage. What about using existing energy more efficiently? This will be crucial for slowing and perhaps even reversing the increased CO_2 levels. Doing more with less energy or just doing less (considered unpopular with growth-oriented economic advocates) are certainly necessary to reduce our demand for energy. But a growing world population with a growing appetite for energy is difficult to reconcile with using less energy. Besides, there is a large group whose voices are often not heard in this discussion – namely, the one out of three human beings who lack any electricity at all.

In fact, access to and consumption of electricity is closely correlated with quality of life, up to a point. Figure 1.1 shows the human development Index (HDI) for over 60 countries, which includes over 90% of the Earth’s population, versus the annual per capita electricity use (adapted from [1]). The HDI is compiled by the UN and calculated on the basis of life expectancy, educational achievement, and per capita gross domestic product. To improve the quality of life in many countries, as measured by their HDI, will require increasing their electricity consumption by factors of 10 or more, from a few hundred to a few thousand kilowatt-hours (kW h) per year.

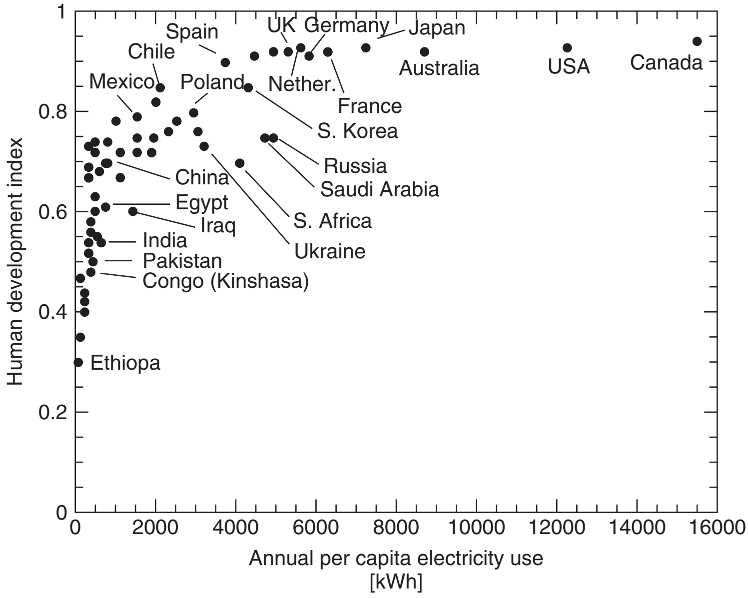

Figure 1.1 Human development index (HDI) versus per capita kW usage in year 2000 [1]

Adding two billion more inhabitants with increasing appetites for energy to the high-consumption pattern of today's one billion in the developed World, as would be expected from the development of China and India, would lead to unbearable stresses both in materials and energy. Barring their access (and that of others) to the wealth of the Western lifestyle is unfeasible, in addition to being unethical.

Renewable energies, and in particular solar energy, are the only clear solution to these issues. As matter of fact the amount of energy arriving on Earth from the Sun is gigantic: in the range of 10 000 times the current energy consumption of the human species. The ability of various forms of renewable energy to meet the "terawatt challenge" of providing world's present demand of 13 TW has been published [2]. We can also add geothermal energy (not renewable, properly speaking) and tidal energy, but they are insignificant in global terms, although locally, in some cases, their exploitation may be attractive.

Wind is generated by the solar energy (through the differential heating of the Earth in equatorial and polar regions). It has been calculated [3] that about 1% of the solar energy (10 times the global current consumption of energy) is converted into wind, but only a 4% of this is actually usable (but still 0.4 times the current consumption). It is estimated that with aggressive exploitation, land- and water-based wind generation is capable of providing about 10% of the world's expected energy demand [2]. Biomass converts solar energy in fuels but its efficiency is also very low, and its use for food has priority. Waves are caused by the wind and therefore a small fraction of the wind energy is passed to them. Sea currents, as winds also originate in the solar energy. The fraction passing to them is uncertain, but probably small. Finally, hydropower, produced by the transport of water from the sea to the land by means of solar energy, represents a tiny fraction of the total energy income, and the most promising sites are already in use. Summarizing, the direct exploitation of the solar energy is the real big energy resource [4].

Using photovoltaics with an efficiency of 10%, solar energy can be converted directly into enough electricity to provide 1000 times the current global consumption. Restricting solar collection to the earth's solid surface (one quarter of the total surface area), we still have a potential of 250 times the current consumption. This means that using 0.4% of the land area could produce all the energy (electricity plus heat plus transportation) currently demanded. This fraction of land is much smaller than the one we use for agriculture.

Achieving the required strong penetration of solar energy is not trivial. In the rest of this chapter we shall present a description of the status PV and broadly outline some of the challenges for it to become a TW scale energy source. But let us advance arguments that are seldom spoken: (a) PV is technologically more mature than advanced nuclear fission or nuclear fusion technology, the two non-renewable CO_2-free energies permitting substantial increments of the global energy production; (b) even well-developed wind energy cannot match the amount of energy directly available from the sun; (c) biomass energy can expect further scientific development, but will probably not reach efficiency levels that will make of it a global alternative to solve the issues presented; (d) concentrating solar thermal power (CSP) could produce electricity in concurrence with PV. We think that PV has a bigger innovation potential and has also modularity properties (it operates at small or large scale) and lacks the geographic limitations of CSP which makes it a clear winner in this competition.

1.2 WHAT IS PHOTOVOLTAICS?

PV is the technology that generates direct current (DC) electrical power measured in watts (W) or kilowatts (kW) from semiconductors when they are illuminated by photons. As long as light is shining on the solar cell (the name for the individual PV element), it generates electrical power. When the light stops, the electricity stops. Solar cells never need recharging like a battery. Some have been in continuous outdoor operation on Earth or in space for over 30 years.

Table 1.1 lists some of the advantages and disadvantages of PV. Note, that they include both technical and nontechnical issues

Table 1.1 Advantages and disadvantages of photovoltaics

Advantages of photovoltaics

- Fuel source is vast, widely accessible and essentially infinite
- No emissions, combustion or radioactive waste (does not contribute perceptibly to global climate change or air/water pollution)
- Low operating costs (no fuel)
- No moving parts (no wear); theoretically everlasting
- Ambient temperature operation (no high-temperature corrosion or safety issues)
- High reliability of solar modules (manufacturers' guarantees over 30 years)
- Rather predictable annual output
- Modular (small or large increments)
- Can be integrated into new or existing building structures
- Can be very rapidly installed at nearly any point-of-use

Disadvantages of photovoltaics

- Fuel source is diffuse (sunlight is a relatively low-density energy)
- High initial (installed) costs
- Unpredictable hourly or daily output
- Lack of economical efficient energy storage

What is the physical basis of PV operation? Solar cells are typically made of semiconductor materials, which have weakly bonded electrons occupying a band of energy called the valence band. When energy exceeding a certain threshold, called the bandgap energy, is applied to a valence electron, the bonds are broken and the electron is somewhat "free" to move around in a new energy band called the conduction band where it can "conduct" electricity through the material[1]. Thus, the free electrons in the conduction band are separated from the valence band by the bandgap (measured in units of electron volts or eV). This energy needed to free the electron can be supplied by photons, which are particles of light.

Figure 1.2 shows the idealized relation between energy (vertical axis) and the spatial boundaries (horizontal axis). When the solar cell is exposed to sunlight of sufficient energy, the incident solar photons are absorbed by the atoms, breaking the bonds of valence electrons and pumping them up to higher energy in the conduction band. There, a specially made selective contact collects conduction-band electrons and drives these freed electrons to the external circuit. The electrons lose their energy by doing work in the external circuit such as pumping water, spinning a fan, powering a sewing machine motor, a light bulb, or a computer. They are restored to the solar cell by the return loop of the circuit via a second selective contact, which returns them to the valence band with the same energy that they started with. The movement of these electrons in the external circuit and contacts is called the *electric current*. The potential at which the electrons are delivered to the external world is less than the threshold energy that excited the electrons; that is, the bandgap. It is independent of the energy of the photon that created it (provided its energy is above the threshold). Thus, in a material with a 1 eV bandgap, electrons excited by a 2 eV (red) photon or by a 3 eV (blue) photon will both still have a potential voltage of slightly less than 1 V (i.e. both of the

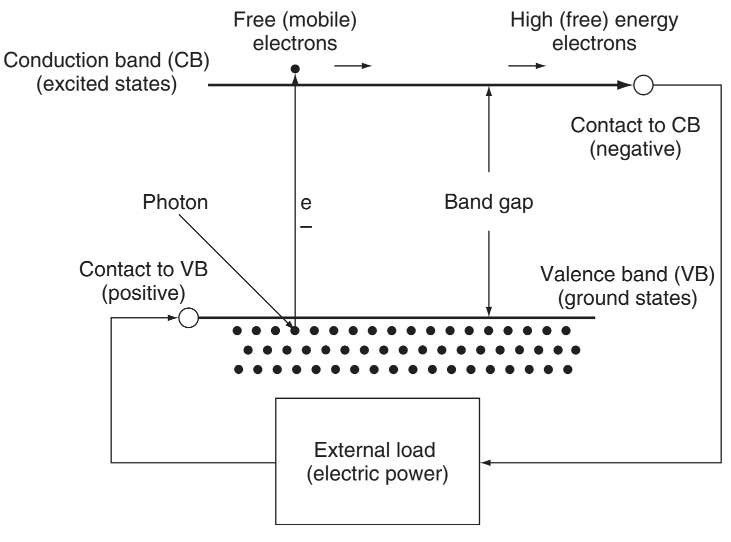

Figure 1.2 Schematic of a solar cell. Electrons are pumped by photons from the valence band to the conduction band. There they are extracted by a contact selective to the conduction band (an *n*-doped semiconductor) at a higher (free) energy and delivered to the outside world via wires, where they do some useful work, then are returned to the valence band at a lower (free) energy by a contact selective to the valence band (a *p*-type semiconductor)

[1] The bandgap energy or energy gap is a fundamental and unique parameter for each semiconductor material. To be a good absorber of solar energy on earth, a semiconductor should have a bandgap between about 1 and 2 eV. See figure 4.3.

electrons are delivered with an energy of about 1 eV). The electrical power produced is the product of the current times the voltage; that is, power is the number of free electrons times their electric charge times their voltage. Brighter sunlight causes more electrons to be freed resulting in more power generated.

Sunlight is a spectrum of photons distributed over a range of energy. Photons whose energy is greater than the bandgap energy (the threshold energy) can excite electrons from the valence to conduction band where they can exit the device and generate electrical power. Photons with energy less than the energy gap fail to excite free electrons. Instead, that energy travels through the solar cell and is absorbed at the rear as heat. Solar cells in direct sunlight can be somewhat warmer (20–30 °C) than the ambient air temperature. Thus, PV cells can produce electricity without operating at high temperature and without moving parts. These are the salient characteristics of PV that explain safe, simple and reliable operation.

At the heart of almost any solar cell is the *pn* junction. Modeling and understanding is very much simplified by using the *pn* junction concept. This *pn* junction results from the "doping" that produces conduction-band or valence-band selective contacts with one becoming the *n*-side (lots of negative charge), the other the *p*-side (lots of positive charge). The role of the *pn* junction and of the selective contacts will be explained in detail in Chapters 3 and 4. Here, *pn* junctions are mentioned because this term is often present when talking of solar cells, and is used occasionally in this chapter.

For practical applications, a certain number of solar cells are interconnected and encapsulated into units called PV modules, which is the product usually sold to the customer. They produce DC current that is typically transformed into the more useful AC current by an electronic device called *an inverter*. The inverter, the rechargeable batteries (when storage is needed), the mechanical structure to mount and aim the modules (when aiming is necessary or desired), and any other elements necessary to build a PV system are called the *balance of the system* (BOS). These BOS elements are presented in Chapters 19–21.

Most of the solar modules today in the market today are made of crystalline silicon (c-Si) solar cells (Chapters 5–7). About 10% are made of the so-called thin film solar cells (TFSC), comprising in reality a variety of technologies: amorphous silicon (a-Si, Chapter 12), copper indium gallium diselenide (CIGS, $Cu(InGa)S_2$, Chapter 13), cadmium telluride (CdTe, Chapter 14), and others (Chapter 11). Many think that thin film cells are more promising in reducing costs. There is also an incipient market of concentrator photovoltaics (CPV) where expensive and efficient multijunction (MJ) solar cells receive a high intensity of sunlight focused by concentrators made of lenses or mirrors (Chapters 8 and 10). The motivation of all these technologies is the same: to decrease the module costs compared with the dominant Si technology. Other options are under research and development, including organic solar cells (Chapters 15 and 16) and the new (or third) generation solar cells (Chapter 4).

1.2.1 Rating of PV Modules and Generators

A fuel-fired power generator is rated in watts (or kW or MW). This means that they are designed to operate producing this level of power continuously, as long as they have fuel, and will be able to dissipate the heat produced during its operation. If they are forced to operate at more than the rated power, they will use more fuel, suffer more wear and have a shorter lifetime. Some can be operated at lower power output, although with loss of efficiency, but many cannot be controlled at less-than-rated power.

PV modules, instead, are rated in watts of peak power (W_p). This is the power the module would deliver to a perfectly matched load when the module is illuminated with 1 kW/m^2 of insolation (incident solar radiation) power of a certain standard spectrum (corresponding to bright sunlight) while the cell temperature is fixed at 25 °C. An array of modules is rated by summing up the watts peak of all the modules.

These "standard test conditions" or STC are universally applied to rate peak power output of a solar cell in a laboratory or a module out in the field, but rarely occur in real outdoor applications (see Chapter 18 for a complete discussion of testing conditions and Chapter 22 for real outdoor conditions). Generally, the irradiance (insolation power) is smaller and the temperature higher. Both factors reduce the power that can be delivered by the module to the matched load. In some cases the load is not so well matched (or the modules among themselves) reducing further the power. Thus while the output power is well defined under these STC, output power under real conditions varies considerably. While a 10 kW diesel generator produces 10 kW so long as it has diesel fuel, a 10 kW PV array will produce from perhaps 0–11 kW, depending on sunlight and temperature.

To enable useful predictions, the energy (not power) in kW h produced by the solar radiation falling in a generator in one year (or one month or one average day) is obtained by multiplying the rated power in kW_p times the number of "effective hours" of irradiance falling on the generator in one year (one month, one average day) times the performance ratio (PR), which accounts for losses above mentioned in real operation plus those in the wiring, the inverter (whose efficiency may be 0.90–0.97), etc. Time for maintenance is also included here. The PR in well-designed installations varies from 0.7 to 0.8 as discussed in Chapter 19, but may be even lower in warmer climates because the efficiency of the cell is reduced with the temperature.

What are the "effective" sun hours? Since the rating irradiance is 1 kW/m^2, the number of "effective" hours at the rating power is the number of kWh/m^2 falling on a plane with the same orientation of the PV generator. Thus, a typical mid-latitude location might receive a daily average of 4 kWh/m^2 of sunlight integrated over a period of 24 hours (including night time) on a horizontal surface, due to an incident power that ranged from 0 to 1 kW/m^2. This is equivalent to a constant incident solar power of 1 sun = 1 kW/m^2 for a period of only 4 hours, hence 4 'effective sun hours'. Locations such as Phoenix (United States), Madrid (Spain), Seoul (South Korea) or Hamburg (Germany) have respectively, 2373, 1679, 1387 and 1059 kW h/m^2 per year (or equivalently the same number of effective hours) for optimally oriented surfaces (facing south and tilted about 10° below the latitude). In these locations a PV plant of 1000 kW optimally oriented, with PR = 0.75 will produce 1 779 375; 1 2259 250, 1 040 250 and 793 857 kW h in one year. Table 1.2 shows, for four widely varying cities, the average daily input in solar irradiance, equivalent hours of full sunlight (at 1 kW/m^2), and average annual yield in kW h from each kW of installed PV, assuming a system performance ratio PR = 1. Once multiplied by the actual PR, this average yield is independent of the efficiency or area of the modules, thus demonstrating the simplicity of this method. These represent close to the entire range of sunlight conditions found where most people live. A world map with the effective hours on horizontal surface (kW h/m^2·year) is presented in Figure 1.3.

Table 1.2 Daily irradiance (kW/m^2), equivalent daily "sun hours" of 1 sun = 1 kW/m^2, and annual energy production per kW of installed PV (assuming PR = 1), all for optimum latitude tilt

City	Phoenix	Madrid	Seoul	Hamburg
Daily kW h/m^2	6.5	4.6	3.8	2.9
Daily "sun hours"	6.5	4.6	3.8	2.9
Annual kW h/kW	2372	1679	1387	1058

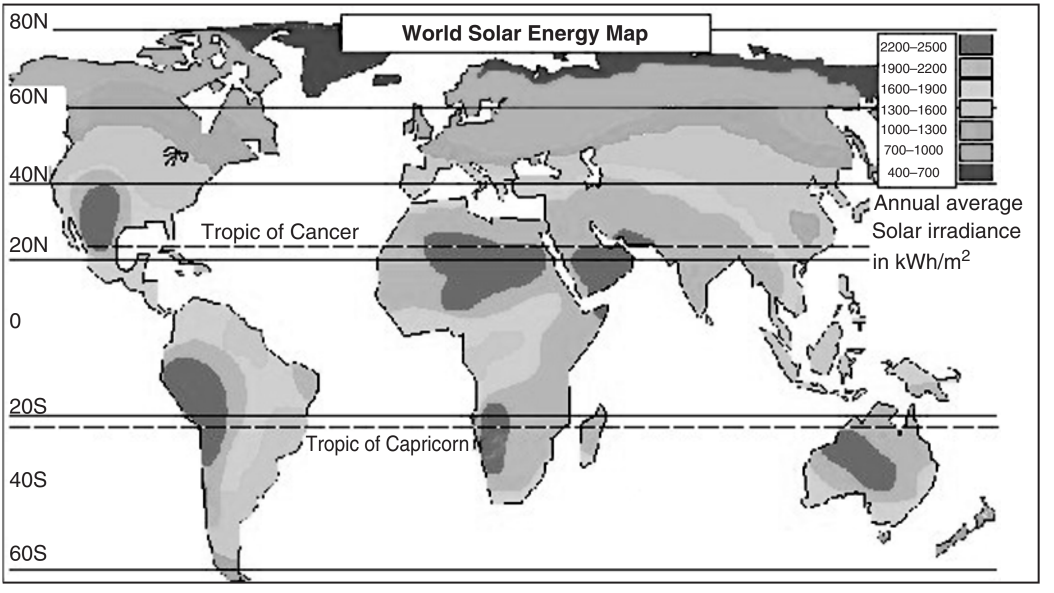

Figure 1.3 World distribution of the annual solar radiation (kW h/m^2) [obtained from www.rise.org .au/info/Applic/Array/image003.jpg] See Plate 1 for the colour figure

The rating of concentrator plants is still a subject of debate. Rating such a plant by summing the rating of the modules may be impossible as some concentrators do not have modules or they are too big for indoor measurements. However in other concentrators it might be applicable.

Chapter 22 contains much more detailed methods to calculate the incident sunlight and the PV module output as a function of location, time of day, month of year, etc. or various on-line calculators are available [5].

1.2.2 Collecting Sunlight: Tilt, Orientation, Tracking and Shading

Potential residential or commercial PV customers often worry "Does my roof have the right slope? Does my house have good solar exposure?" These are indeed important questions for fixed non-tracking arrays. Chapters 19 and 22 address these in more detail. The tilt angle to optimize yearly production for fixed non-tracking arrays is usually some few degrees below the local latitude (there is more insolation in summertime). However, many people are surprised to find that annual output is only weakly dependent on tilt, hence the slope of their roof. In fact, nearly any reasonable tilt is good, and even flat roofs are good for solar below 45° latitude. For example, at mid-latitudes, the difference in annual averaged effective hours varies by 10% as the tilt angle of the modules varies from horizontal (0°) to latitude tilt. Thus, for a home in Washington DC or Madrid or Seoul or Wellington, New Zealand, all at very roughly 40° latitude, the difference in annual effective hours between a horizontal flat roof (~4.4 effective hours per day) or a 40° tilted roof (~4.6 h/day) is 5%. The reason is that the sun's angle at that latitude varies from 27° to 72° between winter solstice to summer solstice at this latitude. In winter, a steeper roof will have more output than a shallow slope, and vice versa in summer, so the difference between flat and tilted averages out somewhat during the year.

What about orientation? For solar installations in the northern hemisphere, the optimum orientation for fixed non-tracking arrays is true south. But again, it is not very sensitive to minor deviations. An array oriented to the southeast will get more sunlight in the morning and less in the afternoon. Thus, for an array installed at 40 °N latitude with 40° tilt and oriented from 45° east or west of true south, the annual output will be only 6% less compared to the optimum true south orientation.

Or, you can install modules on movable supports that "track" the sun. They can track from E to W (oriented in long N–S linear arrays) called single-axis trackers. They can also be installed on special mounts that track the sun in both its daily E–W motion across the sky and its daily and seasonal variation in vertical height, called two-axis trackers. Single- and double-axis tracking generally increase the sunlight collected by 15–20% and 25–40%, respectively. They typically are only employed in large, utility-scale ground-mounted arrays. Of course, costs are higher than for fixed-mount arrays.

So, are there any limits to the location for the installation of an array such as on a roof or in a farmer's field? Yes! The array must not have much shadowing on it, at least not during the peak production hours from 9 am to 3 pm (solar time). The first obvious reason is that the shaded parts produce negligible energy because although PVs can operate with diffuse light, the amount of energy in this diffuse light is rather small. But there are other effects that are more insidious. Even a slight shadow, such as due to a thin pole or leafy tree, on a corner or edge of a module could dramatically reduce the output from the shadowed module and also from the entire array. This is because the modules are connected in series; restricting the flow of current in one cell will restrict the output of all other cells in that module and thus in all modules connected in it in series. But the use of bypass diodes in series strings reduces these losses to very acceptable values. This topic is further analyzed in Chapters 7 and 21. The shadow issue may present a significant limit in cities or towns with lots of trees or tall buildings. A proper preinstallation design will include a shading analysis. Some governments are considering "guaranteed solar access" laws to prevent a newly constructed building or neighbor's trees from shading another roof's array, but the legal problem is not trivial.

1.2.3 PV Module and System Costs and Forecasts

Although the important figure of merit for cost is \$/kW h, typically \$/W_P is used. Policy makers and consumers alike often ask "How much do PV modules cost?" Prices for the same module can differ from country to country. There are challenges of discussing a unique module price even within a single country such as Germany with a very mature and well-regulated PV market, educated consumers and high-volume installers. For example, using average module selling price data in Germany during 2009 [6], the factory gate price for c-Si modules was 2.34 €/W. Due to the excess inventory caused by the failure of the Spanish market in 2009 (a fact that will be explained later), the "market" price for c-Si modules was 16% lower. Market prices for less-efficient thin film a-Si and CdTe modules were about another 10% lower, approaching 1.50 €/W. Market prices for c-Si modules made in Asia were 19% below the average. This is consistent with a more detailed study showing 25% higher costs due to labor for a hypothetical 347 MW c-Si PV module factory in the US or Germany compared with China [7]. This range of module pricing in the most advanced PV market in the world indicates the difficulty of answering the question "how much does a module cost".

But what about the cost for complete systems? This is what really determines the price of solar electricity. We turn to a report analyzing installed costs of 52 000 PV systems (566 MW) installed in the US, mostly in California, from 1998 to 2008 [8]. The average price, before applying any incentives or state refunds, decreased from \$US 10.8/W to \$US 7.5/W, a 3.6% annual decrease.

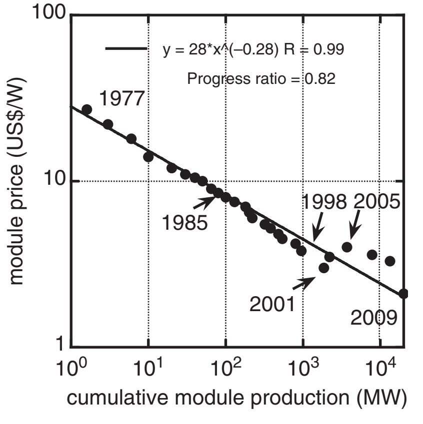

Figure 1.4 Experience curve for photovoltaics from 1976 until 2009. Straight line is fit indicating an experience factor of $1 - 2^{-0.28} = 0.18$ or equivalently a progress ratio $2^{-0.28} = 0.82$

As expected, prices decreased as the system size increased (2008 prices): \$US 9.2/W for small (2 kW) residential systems versus \$US 6.5/W for large (500–750 kW) commercial-scale system. Excluding any taxes, installed prices of residential systems in 2008 was \$US 6.1/W in Germany, \$US 6.9/W in Japan compared with \$US 7.9/W in the US. But prices decreased significantly in 2009 as this was being written.

Therefore, any discussion of module or system prices is complicated by numerous factors, including location, size of the system, discounts or incentives, and the PV technology. Furthermore, it is strongly time dependent. Nevertheless, analysts worldwide commonly assume some price in order to analyze trends and market influences, as in Chapter 2. A common method predict the cost evolution is the so-called learning curve that states the "price" (whatever definition of this is adopted) of the modules is reduced by a factor 2^n every time the cumulated production is doubled. Figure 1.4 shows a learning curve for PV modules based on their past prices. It suggests that to reach \$US 1/W at the present rate will require an order of magnitude increase in cumulative production.

1.3 PHOTOVOLTAICS TODAY

1.3.1 But First, Some PV History

The history of photovoltaics goes back to the nineteenth century. The first functional, intentionally made PV device was by Fritts [9] in 1883. He melted Se into a thin sheet on a metal substrate and pressed an Ag-leaf film as the top contact. It was nearly 30 cm^2 in area. He noted, "the current, if not wanted immediately, can be either stored where produced, in storage batteries, ... or transmitted a distance and there used." This man foresaw today's PV technology and applications over a hundred years ago. The modern era of photovoltaics started in 1954 when researchers at Bell Labs in the US accidentally discovered that *pn* junction diodes generated a voltage when the room lights were on. Within a year, they had produced a 6% efficient Si *pn* junction solar cell [10]. In the same year, the group at Wright Patterson Air Force Base in the US published results of a thin film heterojunction solar cell based on Cu_2S/CdS also having 6% efficiency [11]. A year later, a 6% GaAs *pn* junction solar cell was reported by RCA Lab in the US [12]. By 1960, several key papers by Prince [13], Loferski [14], Rappaport and Wysocki [15], Shockley (a

Nobel laureate) and Queisser [16], developed the fundamentals of *pn* junction solar cell operation, including the theoretical relation between bandgap, incident spectrum, temperature, thermodynamics, and efficiency. Thin films of CdTe were also producing cells with 6% efficiency [17]. By this time, the US space program was utilizing Si PV cells for powering satellites. Since space was still the primary application for photovoltaics, studies of radiation effects and more radiation-tolerant devices were made using Li-doped Si [18]. Similar achievements took place in the former USSR whose Sputnik II satellite in 1957, was already powered with silicon cells. In 1970, a group at the Ioffe Institute led by Alferov (a Nobel laureate), developed a heteroface GaAlAs/GaAs solar cell [19] which solved one of the main problems that affected GaAs devices and pointed the way to new device structures. GaAs cells were of interest due to their high efficiency and their resistance to the ionizing radiation in outer space. A significant improvement in performance occurring in 1973 was the "violet cell", having an improved short wavelength response leading to a 30% relative increase in efficiency over state-of-the-art Si cells [20]. GaAs heterostructure cells were also developed at IBM in the US having 13% efficiency [21]. Finally, in October 1973, the first world oil embargo was instituted by the Persian Gulf oil producers. This sent shock waves through the industrialized world. Several governments began programs to encourage solar energy, ushering in the modern age of photovoltaics and giving a new sense of urgency to research of photovoltaics for terrestrial applications.

An excellent history of the PV early times can be found in a book by John Perlin [22] or, more briefly, in Chapter 1 of the first edition of this book.

In the 1980s, the industry began to mature, as emphasis on manufacturing and costs grew. Manufacturing facilities for producing PV modules from Si wafer *pn* junction solar cells were built in the US, Japan, and Europe. New technologies began to move out of government, university and industrial laboratories, and into precommercialization or "pilot" line production. Companies attempting to scale up thin film PV technologies such as a-Si and $CuInSe_2$, which had achieved $>10\%$ efficiency for small area ($\sim 1\,cm^2$) devices made with carefully controlled laboratory-scale equipment, found that this was far more complicated than merely scaling the size of the equipment. Unfortunately, by the 1980s most large US semiconductor and oil companies gave up their R&D or pilot-scale efforts in the absence of large infusions of private or government support. One common result was the purchase of American companies and their technologies by foreign companies, displacing the center of the PV industrial activity from the US to Japan and Europe and later to China, currently the world's largest solar cell producer.

1.3.2 The PV Picture Today

In the last decade (1998–2008) the market of PV modules has multiplied by more than 20. The explosive growth transformed PV from a dream for environmentally conscious citizens to a reality that attracts investors eager to exploit this new Eldorado.

Who is making all the PV modules? Figure 1.5 shows where these modules have been produced. The US led the world in production during most of the 1990s (not shown) when Europe and Japan had relatively static manufacturing growth. Then in 1998, progressive and supportive government policies in Germany and in Japan resulted in substantial increases in their production. These policies were driven partly by a strong commitment to CO_2 reduction, as prescribed by the Kyoto Protocol, and partly to develop PV as an export.

But the big story in PV production since the first edition was published is the rapid rise of Chinese production since 2006. In 2003, none of the top ten manufacturers were from Asia. In 2008, three are from China and one from Taiwan. In 2009, China is expected to appear as the top manufacturing location.

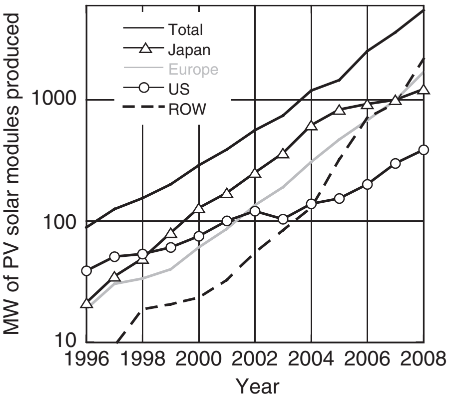

Figure 1.5 Production of PV modules by country or region (ROW = rest of world, mostly China and Taiwan, Europe is mainly Germany and Spain)

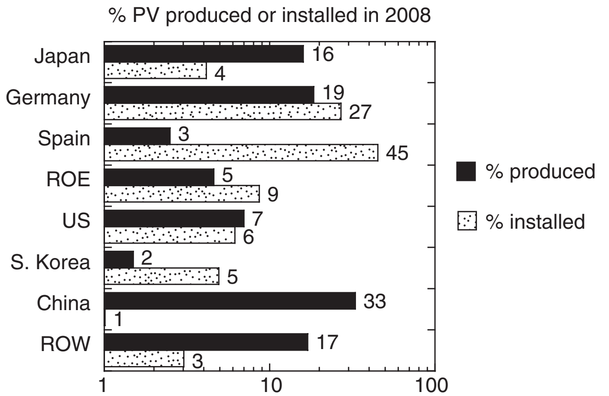

Figure 1.6 Percentage of PV cells/modules produced [23] and installed [24] in 2008 by country or region. Note the logarithmic scale. ROE = rest of Europe, ROW = rest of world (mostly Taiwan and India.). Total installed = 5500 MW; total produced = 7900

Where are the modules being installed? Figure 1.6 shows the geopolitical breakdown for 2008 including the top four producers – China, Germany, Japan, and the US – and the top four installers – Spain, Germany, US, and South Korea. Note that Spain installed 15 times more PV than they produced and China produced 30 times more than they installed. The US was nearly balanced in terms of imports and exports (6–7%). In 2008, Spain became the top destination for PV modules for the first time, overtaking Germany. Most of these modules were installed in large centralized plants >10 MW such as the one presented Figure 1.10. But the brief two years of Spanish leadership in PV installation, created by favorable feed-in tariff (FIT) legislation, ended in 2009 due to restrictive modifications of the law.

The difference between production and installation for 2008 has been variously quoted as 1500–2500 MW. This may represent a double counting of production caused by including both the cells produced in one factory and delivered to a second one for making into modules, and also counting the modules made in the second factory. Some believe that this discrepancy can be caused by a surplus in inventory of unsold modules, but this is doubtful because the module prices were high throughout 2008 and the market experienced a shortage. Prices only decreased significantly in 2009, when the Spanish markets collapsed.

1.3.3 The Crucial Role of National Policies

The real origins of today's surging PV growth started in the mid 1990s when residential scale grid-connected applications in Europe and Japan began to grow rapidly, primarily owing to strong government support. Until then, the primary destination for a PV module was in an off-grid application, whether a rural home in developing country, a water pump for cattle or people, a vacation cabin in the mountains, or a radio transmission antenna. The relative change in dominance of the three main PV applications – off-grid, grid-connected residential and commercial, and large utility scale – is shown in Table 1.3. There are two types of incentive programs responsible for the success of grid-connected residential or commercial applications. One approach, pioneered in Japan and later copied by many US states, provides home or business owners a rebate from the government or their electric utility agency for 10–50% of the PV system cost. Then, their electric bill is determined by the utility using "net metering" where the customer pays only the net difference between what they used and what they generated. Thus, they get a reduction in the initial price of the system, and their PV electricity is valued at the same rate as their utility electricity. This initiated the new market of grid-connected residential and commercial buildings, PV's first big burst in growth, beginning around 1995. Interestingly, government support of photovoltaics in Japan has been decreasing while the market for PV homes has continued to show a good growth rate. The second approach, pioneered by Germany, paid the home or business owners for the electricity they feed into the public electric grid at a rate that is several times greater than the rate that they buy electricity from the grid. Additionally, German banks provided generous loans for purchasing the installation. But there is no government rebate to reduce initial cost. This has resulted in solar arrays being installed on German houses, barns, commercial roofs, government buildings, schools, dairy farms, abandoned airports, and parking garages – in short, any place they can face the sun and still be connected to the grid. This concept, called either a feed-in tariff (FIT) or production tax credit (PTC), has been implemented in Spain, the Netherlands, South Korea, Canada, recently in Japan and soon will be in a few municipalities or states in the US. The German FIT initiated the second great wave in grid-connected PV growth in the mid 2000s. Chapter 2 discusses these and other funding policies to promote PV, including solar renewable energy certificates (SRECs) and mandated renewable energy portfolios (REPs). And the Spanish FIT resulted in the explosive growth of utility scale PV projects in 2007–2008. While many people, especially PV engineers and scientists, might think otherwise, the rapid growth of grid-connected PV, hence all PV, is due more to innovations in policy than to advances in technology.

Table 1.3 Approximate percentages (±20% relative) of different types of application installed

Year	Off-grid (%)	Grid-connected residential or commercial (%)	Grid-connected utility scale (%)	Total installed each year (MW)
1996	95	5	<1	89
2000	60	40	1	288
2004	30	68	2	955
2008	10	35	55	5600

Table 1.3 shows very approximate percentages (±20% relative) of each type of application installed in that year. Off-grid includes single module rural homes, cabins, water pumping, diesel hybrids, and remote communication transmitters. Grid-connected residential and commercial is typically roof-mounted arrays <200 KW in 1996 and 2000, but maybe <1000 kW in 2004 and 2008. Anything larger defined as utility scale. Data and definitions vary from a variety of sources [25].

The importance of the Spanish market in 2007–2008 (3.4 GW_p in total) and its sudden collapse deserves some reflection. The subject is very well explained in Chapter 2, but we want to add here some additional thoughts. The FIT, issued by a Royal Decree, guaranteed a generous price (of about 43–46 €cents/kW h in 2008) over 25 years for the electricity privately produced and sold to the grid by a PV installation, finished and registered in that year. Three Royal Decrees were necessary to permit the market to expand. The first Royal Decree limited FIT payments to generators of less than 5 kW. Some entrepreneurs circumvented this limitation by gathering many small investors and making bigger plants, called solar farms, where each investor owed 5 kW. A second Royal Decree in 2004 lifted the power limitation per owner to 100 kW. The reaction of entrepreneurs was to register dozens of 100 kW installations to effectively create MW plants. Clearly there was higher profitability in larger installations. Finally in 2008 any restriction on size was removed, triggering a frantic activity to build big plants in Spain, so that by the end of 2008 they had built 40 of the 50 biggest plants in the world [26], totaling 2.6 GW in only one year, including the world's biggest PV installation at Olmedilla de Alarcón of 60 MW. No other energy technology can expand so quickly. A 1 GW nuclear plant with about five times more capacity factor (equivalent to 5 GW PV plants) would require at least 10 years to be built, so utility scale PV can be built five times faster.

The trend to build big plants has continued and by early 2010 there were 15 plants with power above 25 MW: 8 in Spain, 5 in Germany, 1 in Portugal and 1 in the US [26]. There are 1000 plants in the world of 1.3 MW or bigger totaling a power of 4.5 GW out of the total 14.7 GW installed. Thus, the Spanish FIT was responsible for the third wave of steep growth, namely that of utility scale projects after 2006.

Unfortunately, the unexpected success of this program resulted in overwhelming the funds which had been allocated, requiring a significant reduction in scale. The collapse of this market in 2009 reportedly resulted in the firing of 25 000 of the 75 000 people working in PV in Spain. It was caused by the unexpectedly strong and fast growth of the market and downturn in the world economy, neither of which was foreseen by the Government. The present regulation plans for a market of only 500 MW in 2009, divided between installations smaller than 20 KW (26.7 MW) and larger than 20 kW (241.3 MW) and the rest in ground installations. The offer for ground installations has largely exhausted the quota by several times (the excess being on a waiting list) while the quota is still open for roof-mounted plants. To date, the FIT regulations have been the most successful policy to expand PV. They explain why Europe (where the climatic conditions are not the best) leads the world in PV installation, with over 70% of the world's total cumulative installed PV power. Some countries are reluctant to adopt a FIT program, sometimes because they consider it an unacceptable intrusion into the market laws. Yet the FIT allows the competition between various PV technologies (Si wafer, thin films, concentrators), installation strategies (roof-top, ground mount, BIPV) and companies. A well-designed FIT must decrease with time (the time when the installation is commissioned, not the time years later when the kW h are sold) in a predictable way to force the industry to reduce their costs and hence their selling price.

1.3.4 Grid Parity: The Ultimate Goal for PV

The ultimate goal for PV is to reach grid parity without subsidies. The relevant parameter to evaluate the long-term cost of any energy source cost is the levelized cost of energy (LCOE). Calculation of LCOE ($/kW h) for PV is complicated; it includes the output of the system over its lifetime (efficiency, solar irradiance and temperature at that location, tilt angle, system losses, annual degradation rate), cost to install and maintain the system (design, permits, BOS costs, site preparation, replacement cost of the inverter, batteries, repairs, profits), and cost of financing the system (discount rate, loans, inflation). Here, we present results from a model developed by NREL (US) called Solar Advisor Model (SAM) [27, 28]. A price in $/W is determined in six categories: module, inverter, BOS, installation, indirect (financing, design, permits, site preparation, and profits), and operation plus maintenance or O + M (replacing inverter, module cleaning, inspection) considering a given lifetime. The calculated value of LCOE can then be compared with the grid-supplied consumer or wholesale price to determine grid parity, cost–benefit for a given installation, etc. Table 1.4 shows the breakdown in costs and assumptions for four systems using SAM: 4.5 kW residential, 150 kW commercial, 12 MW single-axis tracking at tilt, and 12 MW two-axis tracking concentrator system. Parameters common to all are listed in the table. In the reference cited, each system is analyzed for 2005 (benchmark year using real data), and projected to 2011 and 2020 (using extrapolated data representing improved performance and costs). We list projected results for 2011. These results should not be taken as absolute values, but rather as relative comparisons.

According to this model, the residential system has the highest inverter, BOS, installation and LCOE costs. This derives from the higher design and fixed costs for the smaller systems, and less economy of scale. Note that the smaller inverters have lower lifetime, partly because they are supposed to lack professional inspection services. In reality, smaller systems like this would probably have higher module prices as well since volume purchases drive down costs. The 150 kW commercial system has the lowest LCOE costs, due mostly to the assumed lower installation costs. The two different 12 MW utility systems have very low inverter costs in common; most other parameters are quite different, yet they end with the same LCOE. They both have higher BOS costs, possibly due in part to having to purchase or rent land, unlike the other two rooftop applications. Module price is less than half of the total system price for the 4.5 kW residential, while it is more than half of the other types of systems. The LCOE ranges from $US 0.10 to 0.15/kW h, compared with the expected retail price for standard grid electricity of $US 0.07–0.12/kW h. An often neglected aspect of PV systems is the lifetime. Increasing the lifetime from 20 to 30 years decreases the LCOE by $US 0.023/kW h or 13%.

Table 1.4 LCOE analysis from NREL model SAM for four different systems, located in Phoenix (6.5 kW h/m^2·day) and projected for 2011. Common parameters: 96% inverter efficiency, 35 year lifetime, 1% degradation/year

Parameter (units)	Residential	Commercial	Utility 1-axis tracking	Utility concentrator
System rating	4.5 kW	150 kW	12 MW	12.5 MW
Module price ($/W)	2.20	2.20	2.20	3.00
Efficiency (%)	16	16	16	25
Inverter price ($/W)	0.69	0.51	0.35	0.35
Inverter life (yr)	10	15	15	15
BOS ($/W)	0.40	0.36	0.73	0.53
Installation ($/W)	0.57	0.17	0.16	0.33
Indirect ($/W)	1.14	0.76	0.46	0.09
O + M (% costs)	0.3	0.3	0.3	0.6
Installed price ($/W)	5.00	4.00	3.90	4.30
LCOE ($US/kW-hr)	0.15	0.10	0.12	0.12
Retail price of electricity ($US/kWh)	0.12 Residential	0.10 Commercial	0.07 Industrial	0.07 Industrial

Compared with the retail electric rates for the US shown at the bottom, the LCOE cost of a PV system in a very sunny location is very close to grid parity, in particular for the so-called commercial applications (roofs of factories or supermarkets). This is why in the US there is increasing interest in this type of system. Of course, such predictive calculations are only as valid as their assumptions, which do seem reasonable.

There is considerable uncertainty in future electric rates due to possible environmentally driven costs (carbon tax) and the need for substantial reinvestment in new transmission and grid control systems (which will probably be paid for by customers through higher rates). Thus, predicting the price of either PV or conventional electricity is problematic.

Figure 1.7 shows the dependence of the LCOE on available sunshine (irradiance in annual kW h/m^2) for module prices of $US 1 or 2/W. The system was assumed to be a 2.5 kW residential array with a 30 year mortgage at 6% and 30 year lifetime with 1% annual degradation. The other fixed costs were taken from Table 1.4, and amounted to $US 2.80/W. The module price of $US 2/W is close to today's selling price, and $US 1/W represents what many believe is achievable with reasonable advances in today's technologies in the near future. The symbols indicate the average residential electricity rate for various cities indexed by their annual irradiance. Already in 2009, PV electricity prices matched a few markets in the US and Europe that have relatively high-price electricity and/or high solar irradiation such as Italy, Hawaii, New York and California (San Diego, not shown), when determined as the LCOE. Similar analysis has been published using different assumptions (system cost of $EU 3/W) but showing similar trends and conclusions [7]. In reality, the cost of conventional electricity is presently less than the PV LCOE for most cities but the gap is narrowing. The LCOE cost would be less for a larger system as in Table 1.4 due to lower installation costs. This graph shows that grid parity is a complex relation between geographic location, price of electricity, and price of PV system (related to size of PV array). Note that increasing the incident sunlight, hence module output energy, by a factor of two reduces the LCOE by the exact same amount, thus having significantly greater impact than decreasing the price by a factor of 2.

In order to reduce the LCOE, it is acknowledged that efficiency must increase and cost must decrease. But what is their relative contribution? Where should we put our efforts? Figure 1.8(a) presents the dependence of LCOE on module efficiency for module costs of $US 1 and 2/W (again) for a 2.5 kW system in two US locations, sunny hot Phoenix or temperate coastal Philadelphia,

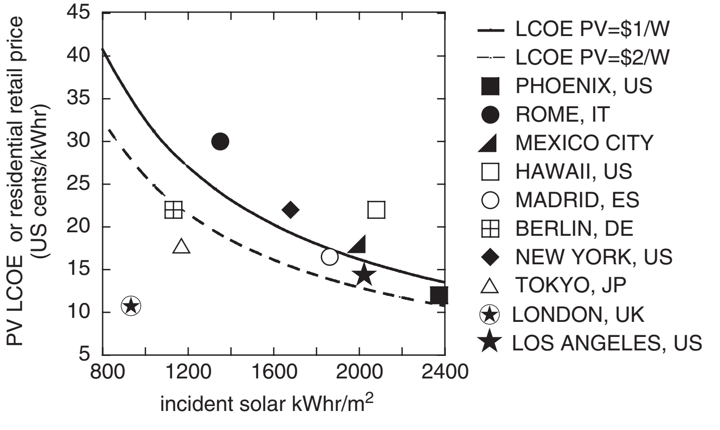

Figure 1.7 LCOE and cost of residential electricity versus average annual incident irradiance. LCOE calculated using SAM model parameters explained in the text assuming a 2.5 kW array with $US 1 or 2/W module cost

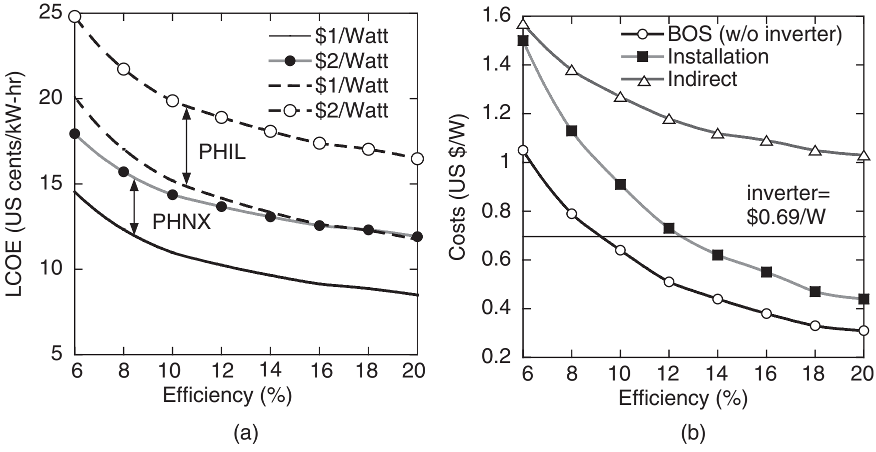

Figure 1.8 (a) Calculated impact of efficiency and module cost on LCOE for Phoenix (sunny, 2370 kW h/m^2/yr, solid lines) and Philadelphia (temperate, 1680 kW h/m^2/yr, dashed lines) for 2.5 kW systems at latitude tilt. (b) Fixed costs as function of efficiency. Indirect for $US 2/W module. A 30 year lifetime is assumed in all cases. Other assumptions are described in the text or caption for Figure 1.7

calculated using SAM with the same parameters as in Figure 1.7. (Philadelphia has comparable solar irradiance to Shanghai, Melbourne, New York or Madrid.)

As efficiency increases, the module area and hence area-related costs decrease. In this study, the number of 1 m^2 modules decreased from 41 to 12 as efficiency increased from 6 to 20%. The area-related costs were: BOS = \$64/m^2, installation \$91/m^2 and indirect \$180/m^2 as derived from Table 1.4 for the 2011 residential case. The 2.5 kW inverter cost \$1725 (\$0.69/W). For a factor of 2 decrease in module cost, the LCOE decreases by 12% (at 6% module efficiency) to 22% (at 20% module efficiency), independent of location. For a factor of 2 increase in efficiency (from 10 to 20%), the LCOE decreases by ∼20%, independent of location. For a factor of two decrease in module cost (at 16% efficiency), the LCOE decreases by ∼25%, independent of location. Thus both price and efficiency have comparable impact on LCOE. This weak correlation between either module cost and efficiency with LCOE might surprise some readers, but this just indicates the importance of area-related and fixed costs. The indirect costs are much greater than either the BOS or installation. This could be alleviated with lower interest rates for PV projects, and shorter mortgages. Figure 1.8(b) shows how the area related costs decrease with efficiency. Decreases in both LCOE and area related costs are steeper at low efficiency, becoming less sensitive at higher efficiency, suggesting the relatively greater impact of increasing the efficiency of low-efficiency thin film modules (rather than lowering their price) compared with high-efficiency Si modules. Together, these figures indicate the importance of efficiency and module cost as a driver to lower LCOE, but also the impact of reducing fixed or area-related costs as well, which are often neglected by research and development funding agencies. Finance charges must be minimized.

1.4 THE GREAT CHALLENGE

In this section, we discuss the requirements and limitations to very large-scale PV energy production in terms of the amount of land and raw materials needed, the environmental impact, the net energy balance, the reliability, and the readiness of manufacturing capacity.

First, what is size of the task? Estimating the world's demand for electricity in 2030 or 2050 is complicated by many assumptions. Will a larger fraction of our primary energy be shifted from chemical and thermal to electric (i.e. electric cars)? How large a role will efficiency and smart growth play in decreasing demand? How large a role will population and economic growth in developed versus developing countries play in increasing demand?

The 2007 Nobel Prize winning organization UN Intergovernmental Panel on Climate Change (UN-IPCC) [29] estimates the world will need the equivalent of 32 000 terawatt hours ($1\,\text{TW h} = 10^9\,\text{kW h} = 10^{12}\,\text{W h}$) of electrical energy by 2030, but efficiency improvements might reduce this to 22 000 TW h. Analysis by their Mitigation Working Group III on how this can be best accomplished to minimize the cost per ton of avoided CO_2 concludes that PV could only meet about ∼1–2% of this demand (∼150–300 TW h), limited largely by *cost* not technology or resource availability. This would be mostly to meet demand from rural electrification in developing countries. However, other bodies set higher targets for PV. The European Photovoltaic Industry Association (EPIA) predicts that PV could provide 12% of Europe's energy by 2020. The International Energy Agency anticipates the PV could provide over 11% of the world's electricity by 2050 [30]. California has a mandate to produce 33% of their electricity by renewable energy by 2020. Originally, PV was expected to contribute only about 10% relative (about 3.2% total) but due to recent PV price decreases,[2] the relative fraction of PV has been increased to 40% (about 15% total). Thus, Europe and California have similar expectations for PV, and are consistent with analysis of the ability of a well-regulated grid, without storage, to accept a variable energy source such as PV sets an upper limit of 10–20% by 2030 [31]. For instance, in Spain PV already provides about 2% of the annual demand, but if we add wind energy, the total intermittent energy is actually 14%.

How can we calculate how many GW (or more precisely GW_p) of installed PV would be required to produce a TW h of electricity?

In fuel power plants the concept of capacity factor (CF) is widely used. It is the ratio of the energy actually produced to the theoretical maximum energy that the plant could produce in one year (typically equal to the nameplate power rating times 8760 h). Thus, a 1 GW power plant operating at full capacity for half the year (or at half capacity for the entire year) has a $\text{CF} = 50\%$, and would produce $1\,\text{GW} \times 8760\,\text{h/yr} \times 0.50 = 4380\,\text{GW h/yr}$. The CF is usually below unity not only because the plants might need to stop for maintenance (the case of nuclear plants) but also because the management of the electric grid requires some plants to idle for certain periods.

In a PV plant CF is calculated as the effective sun hours (see Section 1.2.1) times performance ratio divided by the total number of hours in the year (even though the sun only shines 50% of the year on any location on earth). The CF for PV generators ranges from 0.08 (Hamburg, fixed panels) to 0.26 (Albuquerque, sun tracking[3]), so we will use 0.15 as an average. Thus, to provide 300 TW h in 2030, we would need 230 GW of installed PV capacity, or an installation rate of 11.6 GW per year for the next 20 years. In fact, the world produced about 7 GW in 2009, and

[2] In 2008, with installed system costs of \$US7/W or \$US0.30/kW h, it was expected most of California's 3.2% PV demand would be large, centralized power plants. By 2009, system costs fell to \$US3.70/W or \$US0.17/kW h due to availability of lower-cost thin film modules. Combined with land use permitting and transmission access difficulties for the large PV power plants, distributed small-scale PV looked more attractive to provide much of the 15% demand (from Garrett Hering in Photon International December 2009, 12–14.)

[3] Sun tracking increases the CF. The number of equivalent hours in a sun-facing plane (called a two-axis tracker) increases by about 40% with respect to the fixed optimally oriented module. This is discussed further in Chapters 19 and 22.

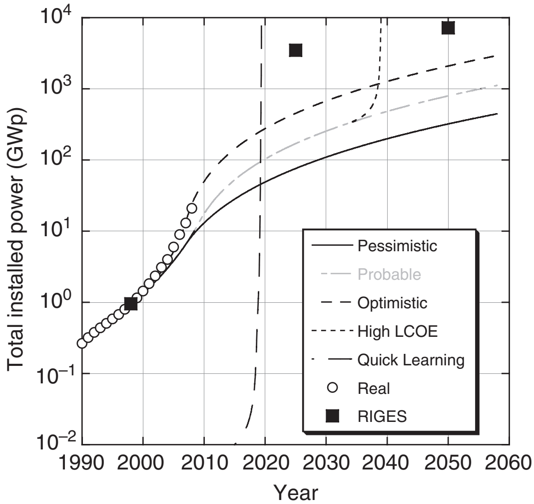

Figure 1.9 Forecast of the cumulative global PV installed power by year. (see [32] for details). "Real" represents the actual installed power (from P. Maycock, *Photovoltaic News*, 19(3) 1 (2000), more recent data from the *Photon International* yearly reports in the March issue). The dots labeled "RIGES" are the goals in Reference [33]

expects around 10–12 GW in 2010. So meeting the relatively low expectations of the UN-IPCC for PV will be easy, requiring no growth or scale-up at all.

In 2001 one of us published a paper [32] in which a differential equation for the evolution of the yearly market was formed by coupling the learning curve (Figure 1.4) and the demand elasticity (the relative reduction of price in a certain year divided by the relative increase of the yearly market). The price evolution was deduced as well as the cumulative sales for every year. For the initial forecasting period, the model parameters were extracted from past experience in yearly markets and prizes. The cumulative sales, approximately equating the total installed PV power, are represented in Figure 1.9 for several parameter choices.

The three curves: "optimistic" (developed countries are willing to spend 0.1% of their GDP on higher cost PV electricity), "probable" (spending 0.05%), and "pessimistic" (spending 0.025%) show a rapid increase followed by a slowing in growth as markets saturate compared with a given price of electricity. Note the striking coincidence between the actual PV installations up through 2008 (labeled "real" in the figure) and the "optimistic" forecast predicted in 2001. This coincidence gives credibility to the other implications predicted by this model. For 2030 this model predicted 1.6% of the total demand of 22 000 TW h forecasted by the IPCC under the hypothesis considered "probable" in 2001. This is not very different from the modest contribution of 1.4% assumed by the IPCC. But if we look at the real installations trend, which follows closely the "optimistic" forecast, the result is that by 2030 PV will be supplying the 4.4% of the demand. This is more than three times the prediction of the IPCC, but still modest.

So, let us assume that PV is to supply 12% (2,640 TW h) of the world's electricity by 2030, hence we would need to install on average 100 GW ($\cong$2640/(365 $\times$ 24 $\times$ 0.15 $\times$ 20)) per year (a nice round number) for the next 20 years. In fact a constant average annual production is completely unrealistic, but it serves to give the scale of the task. Some studies assume producing

20–30 GW/yr of PV until 2020 then ramping up an order of magnitude each decade until 2050 [34] while others see rapid initial growth followed by slowing as the installed capacity reaches its limit.

The paper which developed the model in Figure 1.9 stated in 2001:

First we predict several years of explosive market growth.... But this period cannot last too long. Not more than a decade. If it does, the capital involved will become excessive. Powerful voices will cease to consider PV as a curiosity and will question cost effectiveness. Other voices, not less powerful, will support PV. The equilibrium will determine subsequent growth. This equilibrium will induce a slower market growth, but at levels that are no longer negligible, at least in terms of business volume, but probably not enough for pollution abatement. Price decrease will continue, but slowly. For the next half-century they will be not competitive with common electricity unless some of the following facts happen.

(*a*) *Electricity prices rise.*
(*b*) *Commercial schemes substantially reduce commercialization, installation and financing costs.*
(*c*) *New inventions of lower initial costs or with more cost reducing potential appear.*

As the paper predicted, PV has become a substantial business (about €50 billion in 2008) but society has started to question its cost effectiveness, especially in view of the worldwide financial problems of 2009. For instance, there was the dramatic reduction of public support in Spain in 2009 discussed above, and less dramatic reduction in Germany in 2010, the world's two most active markets in 2008.

But let us examine now whether the conditions for competitiveness in the second part of the statement are being fulfilled or not. The model, intended to be simple, considers PV competing with only the wholesale price of the electricity, but if the retail price is taken into account instead, this would allow for a substantial growth within the first half of the century. The case is considered in the curve labeled "High LCOE". With this choice of parameters (consult the paper for details) a vertical asymptote appears around 2040 (assuming a module price of \$1.25/W_p). Since the actual trend is following the curve "optimistic", according to the model, the asymptote will appear before this date, maybe towards 2025. Thus, if a contract offered by the regional electric power provider is based on the retail price of electricity (essentially net metering), including the price paid to PV power plants, condition (a) would be automatically fulfilled.

The steep asymptotic increase in "High LCOE" is just an artifact of the model caused by the assumption that the electricity market is infinite. This is valid only if one knows when the LCOE "tipping point" is reached, not for studying the subsequent growth. In reality this asymptote will appear as a surge in the installations which will inevitably saturate and slow when sales to the new market sector are exhausted.

But, in addition, the model assumed that the cost of a PV installation was distributed in equal thirds, one for the module, one for the BOS and one for the commercialization, installation and financing. This is a reasonable assumption for distributed small home markets (prevalent when the model was developed) but the recent development of big power plants has drastically reduced the commercialization costs, leading to a situation where the plant cost is about twice (and not three times) the module's cost, according to the SAM model presented in Table 1.4. This fulfills condition (b) and brings the date of the surge in installations even closer.

Thus, what the model explains is what is already anticipated by many analysts, including the study presented in Figure 1.8 for a system price of \$US 2/W_p. This price is already being offered in Spain for big ground-mounted PV power plants, and we think that expected surge will take place within the next five years in several countries (or US States) where the combination of insolation and the electricity retail price are high enough to reach grid parity with the retail electricity price.

Note that the retail electricity price includes the cost of generation as well as transmission, distribution and commercialization; therefore, it is only fairly applicable to homes and commercial PV plants. Utility-scale PV power plants should compete with the much lower wholesale price of generation. The application of the retail price to big plants is dependent on political decisions that waive the cost of the distribution for the big PV producers. Yet the application of FIT incentive suggests that this policy can be adopted in many countries.

Thus we have justified why the goal of meeting 12% of the world's electric demand by 2020 or 2030 with PV is not just wishful thinking, at least from the point of view of reaching reasonable prices.

But this is not enough. At the end of this century, many analysts expect solar energy to provide a large part of the demand, i.e. about 60% of the energy demand (not only electricity) [34]. This requires fulfilling condition (c), a technological breakthrough with a faster learning curve (curve labeled "quick learning"). It might happen at any time (2015 is assumed in the figure). It is possible that it is already happening. Consider the recent success of First Solar, a thin film manufacturer, who became the biggest solar cell producer in the world in 2009. Maybe the breakthrough will appear in 5–10 years with the concentrator systems intended to exploit the ultra-high-efficiency (over 40%) MJ solar cells. Or maybe, at an even later moment, the exploitation of novel concepts for a higher efficiency will permit this faster learning curve and therefore dominate the wholesale production of electricity. Certainly the so-called third-generation concepts aim at this. This is why we said that PV has more technological options than concentrating solar thermal electricity and we qualified PV as a winning option.

But this high penetration (>20%) will only be possible if some cheap and efficient procedure for electricity storage is developed. Advanced PV and storage have to be among the leading tasks for all this century for scientists and technologists.

Let us concentrate now on other constraints and challenges associated with our immediate 12% goal implying the installation of 100 GW_p per year, on average, during the next 20 years.

1.4.1 How Much Land Is Needed?

Estimates of *household* electricity usage from various sources for the US, Japan and Europe indicate about 5 kW h/person/day, or 20 kW h/day per family of four. With a CF of 0.15 this demand can be satisfied with a PV installation $20/(24 \times 0.15) = 5.5\,kW_p$. For a rated module efficiency (at STC) of 15% (150 W_p/m^2) this requires an area of $5500/150 = 37\,m^2$ of modules. There are many properly oriented roofs (with a lot of flexibility in the tilt and orientation, but generally facing southwards if in the northern hemisphere) with 37 m^2 of well-oriented roof available (see Chapter 23 for architectural integration). In fact, many roofs are larger, and many homes have sunny areas of this size around them, so it is possible for a family of four, with all the conveniences of a typical modern home, to provide all their power averaged over a year from PV modules on their house or on racks on their yard.

Let us assume that of the 100 GW we must fabricate each year 25 GW_p are grid-connected homes of 5 kW_p. This will imply installing 5 million residential generators per year. This is certainly a challenge, but is not impossible if we consider that the car industry produces more than 60 million cars per year. Neither is the availability of capital a problem, if the business is profitable.

Perhaps it is illustrative to know that the 125 more densely populated towns in the world [35], (whose density of population ranks from 26 650 people/km^2 in Mumbai to 1550 in Denver) with a total of 619 million inhabitants occupy an area of 124 000 km^2. With the same daily electricity consumption of 5 kW h per person and the same capacity factor of 0.15, the area of 15% efficient modules required is 129 000 km^2, practically the same as the total town area. Obviously in Mumbai there will not be enough room for this, but in Denver it will be easy. There are many more towns less densely populated. We think this clarifies that space is not a limitation for generating a sizeable fraction of the electricity we use with PV, or for meeting our goal of 25 GW_p per year.

In the first edition we calculated how much land it would take to replace a 1000 MW coal or nuclear power plant. The answer was 60 km^2 (or 24 square miles). This is a square 8 km (or 5 miles) on a side. For the same electricity production, this is equivalent to the area for coal mining during a coal-powered plant's life cycle, if it is surface mining, or three times the area for a nuclear plant, counting the uranium mining area [36].

But building this size of PV plant is not a solution adopted by PV investors for the moment. Actually the 34 biggest plants built in the world comprise 1010 MW, occupying an area similar to the one calculated above. The size of these plants ranges between the 60 MW of the Olmedilla (Spain) plant to the 19.4 MW of the Helmeringen (Germany) plant. Figure 1.10 is a picture of the 10 MW plant at Jerez de los Caballeros (Spain) showing how PV is well integrated in the environment, permitting for instance, cattle raising. The PV "trees" are about the same size as the oak trees around, but collect solar energy about 100 times more effectively.

In any case we must not hide the fact that the annual electric energy (MW h) produced by the 1000 MW plant (or ensemble of plants) is less than the one powered by coal or nuclear energy because of the smaller capacity factor (0.15 in our example compared with at least 0.5 for the fuel plants).

Finally, how much land would be needed for PV to supply the 12% of worldwide demand (2 TW) we want for 2030. Others have analyzed very large-scale PV (VLS-PV) at seven extremely sunny, arid desert locations worldwide, roughly one per major geopolitical land area [37]. In those deserts, they would produce about 50% more energy per area than our typical, mid-latitude array analyzed above, so 100 MW requires approximately 1.7 km^2 of barren land. Scaling these areas from the VLS-PV study to our hypothetical 2 TW yields an area of 34 000 km^2, or about 5000 km^2 in each of the seven deserts. Certainly, an area of $70 \times 70\,km^2$ (43×43 miles) could be found in these deserts where the installation of PV arrays would be accommodated without significant disruption of the natural surroundings. (We point out again that PV does not require water for its operation.)

Figure 1.10 The Jerez de los Caballeros 10 MW PV plant. Reproduced by permission of Guascor Solar SAW

But following the actual trend, the construction of 1000 plants per year of average size of 75 MW will lead to the 75 GW that, added to the 25 GW in buildings, will complete our goal of 100 GW per year. This will be a challenge, but not impossible if the business is profitable. Remember that in the last 2–3 years 1000 plants of average size 4.5 MW have been built (totaling 4.5 GW) and the biggest are approaching the 75 MW size.

1.4.2 Raw Materials Availability

Are there sufficient raw materials on Earth to make enough PV modules to provide a significant fraction of our energy in the future? This is an important question, because if the answer is "no", then PV will be ultimately relegated to a minor role.

The main material used today to make solar cells is silicon. Being the second most abundant material in the Earth's crust (after the oxygen), there is not a foreseeable shortage. High-purity quartzite (SiO_2) ore is used to produce Si today. The present production of Si is about 50 times more than needed for PV use and can be easily increased, so that producing 12% of the electricity with PV, which implies an increase of the cell production by at most, 15 times, can be easily supplied.

But for non-Si based cells, this is a very complex question, requiring decisions about how much of a given element is economically recoverable and at what rate (ton/yr or equivalently converted to GW/yr of PV). Several studies [38–40] are in general agreement that the potentially limiting materials for PV are Ag for contacts to Si cells (but Ag is not essential), In for $Cu(InGa)Se_2$, Te for CdTe, and Ge for Ge substrates commonly used for III–V concentrators cells or a-SiGe cells. In and Te metals are not actually mined, but are dilute by-products of other metal refining; i.e. Te from Cu ore; In and Ge from Zn ore and also from ashes in the combustion of coal. Conclusions differ significantly as do the assumptions, but generally these studies find that solar cells based on In or Te could provide a few percent of the world's future electricity without significant reductions in utilization (i.e. thickness), thus potentially meeting the entire, although trivial, requirement for PV assigned by the IPCC. Another view suggests that historical production rates of In and Te could easily provide 20 GW/yr [39], thus meeting about 20% of our hypothetical PV requirement of 100 GW/yr with CdTe and $Cu(InGa)Se_2$. This does not mean they should not be considered, since it is unlikely a single PV technology will dominate. Supplies of In and Te can enable multi-billion dollar annual PV industries[4]. Reducing the cell thickness, recycling of waste and expired modules, and increasing efficiency in manufacturing will reduce the total demand for a given raw material and extend its ability to meet these targets. These are all promising and active areas of research.

As for III–V/Ge concentrator devices, operating at 500–1000×, there are not major problems in producing 100 GW/year [41]. The main limitation comes from the Ge, and from plastic for lenses. The use of hybrid glass–silicone lenses, beginning to be common today, would remove the limitation on plastics (because they use a very thin layer of silicone). As for the Ge, it is probable that enough can be found in other sources, but it could be recycled or substituted by Si.

1.4.3 Is Photovoltaics a Clean Green Technology?

Would large-scale PV manufacturing and deployment degrade the environment, although in a different way from conventional energy production?

[4] There are also competing technological uses to consider. For example, Indium usage has increased substantially in recent years due to the need for transparent conductive indium tin oxide (ITO) layers in flat panel displays.

One of the most valuable characteristics of photovoltaics is its well-deserved image as an environmentally clean and “green” technology, resulting from the cleaner operation of a PV electricity generator compared with a fossil-fuel or nuclear-fired generator. But this must also extend to the manufacturing process itself as well as the recycling of discarded modules. Let it be stated at the beginning that the present Si-based PV technology which dominates the market has few environmental concerns and is considered totally safe to the public.

Hazards can be classified by whether they affect workers at a PV manufacturing plant, customers with photovoltaics on or near their homes, or members of the public who consume air and water near the PV plant. Very little risk is associated with the public or the PV owner or installer; the main risk being that of electric shock already existing with conventional electricity, but more severe because large areas can be electrically live. Adequate grounding is strongly recommended.

Safe handling procedures for some of the materials and processes are already well established from the integrated circuit or glass coating industries. But in the case of some unique materials and processes, safety procedures had to be developed by the PV industry. The PV Environmental Health Safety Assistance Center at Brookhaven National Laboratory in New York, USA provides worldwide leadership in risk analysis and safety recommendations for the PV industry [42]. An industry-focused PV Safety Working Group has been established in Europe [43].

Si modules, currently the most widely used, are totally free from the suspicion of releasing dangerous materials. Si module manufacturers have long used Pb-based solder to interconnect the wafers, as did the electronic chip manufacturers. This represents a minor risk that nevertheless is being further reduced through the use of Pb-free solders.

There has been considerable research into occupational and accidental exposure and risk analysis of one PV material in particular – thin films of CdTe – since Cd is a known carcinogen. The general conclusion is that CdTe thin film modules do not pose a risk to the public [44]. Much of the concern is misguided for two reasons: there are significant toxicological differences between elemental Cd (toxic) and compound CdTe (much less so), and because the CdTe is hermetically sealed between two sheets of glass. Those concerned about Cd sealed in CdTe modules should consider that most Cd in our environment is released directly into the atmosphere by combustion of coal and oil. Chapter 14 has more about Cd environmental issues. Even in the event of a house fire, studies have shown that roof-mounted PV modules do not release any potentially hazardous materials [45], and this is also true for those containing cadmium.

A related issue is what to do with PV modules at the end of their projected 25- to 30-year life. An excellent strategy is to recycle the modules. This solves two problems at once, namely, keeping potentially hazardous materials out of the environment and reducing the need for additional mining and/or refining of new materials. Semiconductor vendors have indicated a willingness to accept used modules, and to extract and purify the CdTe, CdS, or $Cu(InGa)Se_2$ for resale and reuse. As for the recycled Si, it is inherently purer than the Si used today as raw material.

Thus, we can say with confidence that PV is the cleanest and safest technology with which to generate electricity even at the GW production scale.

1.4.4 Energy Payback

Can PV modules produce much more energy over their lifetime than it took to make them; i.e. are they net energy producers? This oft-expressed concern is baseless. This concept is quantified by the “energy payback time ” or EPT, which is how many years the PV system must operate to produce the energy required for its manufacture. After the payback time, all of the energy produced is truly new energy.

Many studies have concluded that EPT's have steadily decreased over the past decades, now estimated at 1.5 to 2.5 years for crystalline Si and 1 to 1.5 years for thin films [45, 46]. Thus, all the energy needed to produce our fictional 100 GW every year will be paid back to the grid within the next two years.

For crystalline Si, melting and forming the crystalline wafers is the major energy requirement. For thin films, where the semiconductor layers are 100 times thinner, and deposited at much lower temperature, their energy requirement is negligible. Instead, it is the energy embodied in the glass or stainless steel substrate, which is the major energy sink. The cosmetic Al frame around the module is responsible for a surprisingly large fraction of energy, and is being phased out. Although thin film modules have a shorter energy payback, they also have lower efficiency, which means a larger BOS is needed to support the larger number of modules. Thus, a larger amount of energy is embodied in the BOS for thin film photovoltaics compared to crystalline Si photovoltaics.

The case of concentrators is less studied, but again the use of semiconductor is reduced and the BOS becomes more important than even for the thin films because the concentrating structures are more massive. However, their efficiency is much higher. In summary, we can guess that their EPT will be similar to the case of thin films.

Recently, PV has been examined in terms of its potential for Carbon reduction [46–48]. The amount of CO_2 released during manufacture of PV systems is much less than the CO_2 avoided by the power it produces during its lifetime. PV technologies are responsible for about 30–50 g CO_2 emission per kW h produced over their life-cycle (all due to fossil fuel energy consumed during manufacturing) while coal-powered generating plants release about 20–30 times more. As the CO_2 load from our energy sources decreases, the amount of CO_2 per kW h of PV will decrease as well. Thus, PV is an excellent strategy to mitigate global climate change.

1.4.5 Reliability

Most modules seem to lose about 0.5–1% of their relative output annually for a variety of reasons. For the past few years, most modules have been sold with guarantees to maintain at least 90% of their rated output after 10 years and at least 80% after 20 or 25 years. They must pass rigorous reliability testing using accelerated extreme weather conditions. A recent study of >200 modules [49] produced in the early 1980s, before many of today's more rigorous standards and improved encapsulation methods and materials were available, found that after >20 years continuous operation outdoors, only 18% of them had lost more than 20% of their rated power (and they were only warranted for 10 years back then!). And remember, even if they lose 20% of their output after 20 years, they are still providing free electricity! Also, solar modules have been operating in space, a very harsh environment, for decades.

1.4.6 Dispatchability: Providing Energy on Demand

Could PV meet all of the world's needs today if we would just pass laws requiring photovoltaics and halting all fossil and nuclear plants?

The first technical problem faced would be the intermittent nature of the solar radiation, available only during the day and strongly reduced in overcast skies. Energy storage would solve this problem, but no cheap storage method appears on the horizon, although pumped hydro storage [50] is already used and compressed air [51], grid-tied electric vehicle batteries (when parked and plugged in) called V2G [52], and new battery technology (Chapter 20) are being actively explored.

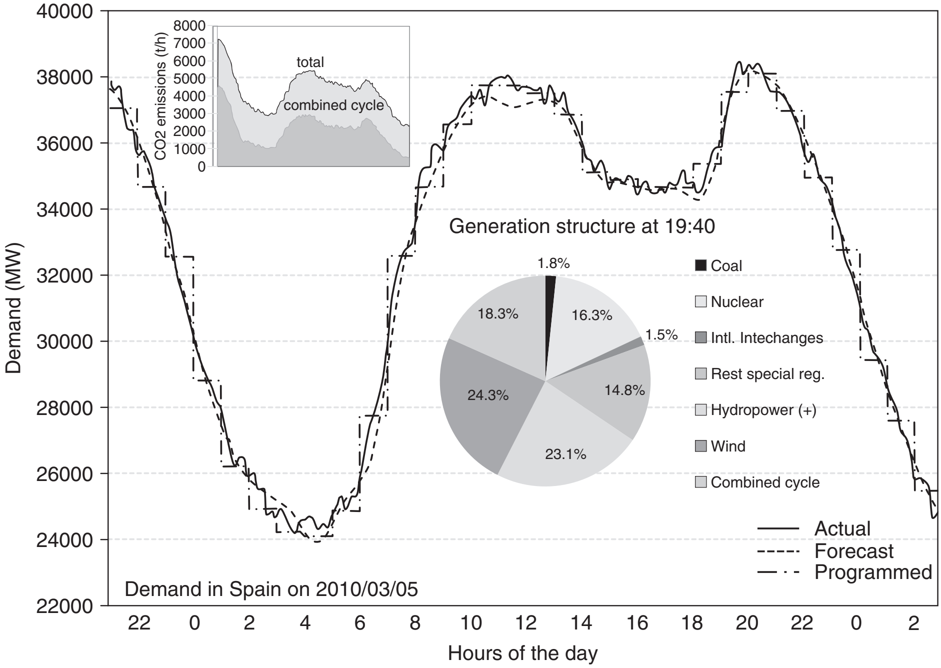

Figure 1.11 Dispatching of electricity in Spain over 24 hours on 2010-03-05; actual, forecast and programmed (dispatching plan). The wind energy resulted in 24.3% at the peak consumption time. PV is not independently registered. It is included in "Rest special regime" of 14.8% (the estimate for PV is about 2%). The high penetration of renewable is permitted by the high proportion of hydro/gas (combined cycle) plants which are easily dispatchable. Coal generation, very important in the past, has almost disappeared to allow for renewable introduction. Coal is the most CO_2-intensive source. Adapted with permission of Red Eléctrica de España

The problem of electricity storage is not specific to the intermittent production of electricity. It is a general need of the grid management. Actually, electricity demand is quite variable with the hour of the day and even seasonally, where differences of 40% are possible daily between its peak (maximum) load and its base (minimum) load. Thus, the electricity operators, who have a statistical knowledge of the demand behavior, plan the connection or disconnection of power plants to produce enough energy that approximately matches the demand as shown in Figure 1.11. The output of power plants is adjustable within certain limits. This process is called dispatching.

The production of intermittent electricity is also predicted statistically and the output needed from fuel-based power plants can be planned accordingly. In Spain, about 14% of the yearly demand is intermittent or variable and this fraction may be much higher in specific windy or sunny moments. Baseload coal or nuclear power generators must be permanently connected and generally run at full power. As the wind/solar fraction grows (assuming no storage), on windy/sunny days when the intermittent generation alone can meet the demand, some of the wind/solar generation will have to be shut down, because conventional baseload plants cannot be disconnected or decreased quickly. A cheap storage, such as pumped hydro plants, would permit more penetration of intermittent renewable electricity. Either way, in any grid (even without intermittent renewable energy) there is always some idle generation capacity and the associated financial losses, but this can be increased by excessive intermittent generation. Adequate grid management would allow up to 35% of the electric production to be intermittent [33], even without sensible storage.

1.5 TRENDS IN TECHNOLOGY

Most of this book's chapters deal with technology. This section will give a broader perspective that the specific chapter authors cannot provide.

In 2008 almost 8 GW_p of modules were manufactured. The breakdown among the different technologies appears in Table 1.5 for 2003 and 2008. The crystalline Si (c-Si) modules dominated the market (87% in 2008) and are divided into multicrystalline (multi-Si), single- or monocrystalline (mono-Si), or ribbon silicon, depending on the type of Si wafer used. The thin film modules, a minority, but whose market share is expanding, are divided into a-Si, CdTe and CIS modules. The rest of the technological options are yet too immature to appear in the market breakdown.

As shown in Figure 1.8a, efficiencies are one of the most critical factors to reduce cost of electricity generated. "Champion" cell efficiencies are presented in Figure 1.12 for several technologies. Two technologies not yet commercially significantly appear in this figure (ironically having the highest and lowest efficiencies). Improvements in champion cell efficiency have slowed in the last decade, except for the III–V based multijunctions and CIGS. The efficiency of champion cells is typically 25–50% higher than the efficiency of the commercial products because the techniques used for making the highest efficiencies are seldom acceptable for cost effective manufacturing. This seems to be in contradiction with the statement that efficiency is the main driver of cost reduction, so we will qualify it as follows: the industry goal is to obtain the highest module efficiency compatible with a reasonably cheap, high-throughput, high-yield and reproducible process. Figure 6.18 in Chapter 6 shows a historic view of the evolution of the breakdown among technologies.

1.5.1 Crystalline Silicon Progress and Challenges

Table 1.5 show that c-Si, as either single or multicrystalline wafers or ribbons, was responsible for almost 90% of worldwide PV production. How did its dominance occur? First, Si cell technology has benefitted from the tremendous development of microelectronics that is also based on the same Si. While thin film cell researchers had to develop their own manufacturing equipment, Si

Table 1.5 Total MW of production and percentage of the three Si wafer and three thin film technologies in 2003 (when the first edition was published) and 2008

Technology	2003		2008	
	MW	%	MW	%
Multi-Si	429	57	3773	48
Mono-Si	242	32	3024	38
Ribbon-Si	33	4	118	1
a-Si	*34*	*4.5*	*403*	*5*
CdTe	*8*	*1*	*506*	*7*
Cu(InGa)Se_2	*4*	*0.5*	*79*	*1*
Total Crystalline Si	704	93	6915	87
Total Thin Films	*46*	*7*	*988*	*13*
total	750	100	7910	100

Data from *Photon International*, March 2009, p. 190

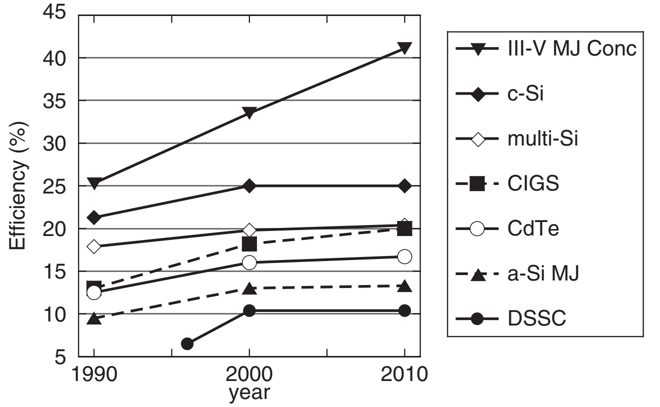

Figure 1.12 Best small-area (0.5–5 cm^2) efficiency for various cell technologies measured under standard laboratory test conditions as of 1990, 2000, 2010. MJ concentrators are double junctions before 1995, and triple junctions after. MJ a-Si represents stabilized efficiency after extended light soaking (see Chapter 12). Data for 2000 and 2010 from independently verified Solar Cell Efficiency Tables (*Progress in Photovoltaics*, John Wiley & Sons, Ltd, UK)

cell researchers could use that already developed for microelectronics, sometimes off-the-shelf and sometimes with some minor modifications. Second, the silicon bandgap, of 1.1 eV, is almost optimal to make a good solar converter (see Figure 4.3 in Chapter 4). Furthermore it is very abundant, clean and nontoxic. Finally, Si solar cells are very stable, even without encapsulation.

However, Si has mechanical limitations (it is brittle) and optical limitations (it absorbs sunlight weakly), requiring relatively thick cells. Therefore, some of the electrons pumped by the photons to the conduction band have to travel distances of the order of the thickness, to be extracted by the front face through the selective contact (the one-way valve of Figure 1.2 representing the *pn* junction). Consequently, a good material with high chemical purity and structural perfection is required to fight the natural tendency of the conduction-band electrons to return to the valence band. To avoid this loss process, called *recombination*, the electrons must be highly mobile, as they are in perfect silicon. Impurities and imperfections must be avoided as they can absorb the extra energy of the conduction-band electrons, thus eliminating the free electron.

Metallurgical grade (MG) Silicon is obtained by reduction of quarzite (SiO_2) with charcoal in an arc furnace. PV only uses about 2% of the world production of MG-Si. Then it is highly purified, commonly by a method developed by and named after the Siemens Company, consisting of the fractional distillation of chlorosilanes, which are obtained from the reaction of a chlorinated source with Si. Finally, chlorosilanes are reduced with hydrogen at high temperatures to produce hyperpure silicon, usually called s*emiconductor grade* (SG) s*ilicon* or just *polysilicon* which has many random grains of crystalline Si, typically of about 1 mm. Methods to produce polysilicon or a lower-cost form called solar grade Si are described in Chapters 5 and 6.

In the past, the polysilicon was produced by about half a dozen factories for the microelectronic manufacturers. Today PV is the biggest user of this polysilicon and more new factories are appearing now specializing in solar grade polysilicon. The definition of this grade is the subject of controversy as some manufacturers obtain it as enhanced MG-Si with reduced impurities, leading to a cheaper material, but unable to make high-efficiency cells; others want to keep the high purity, even with higher cost, necessary for the higher efficiency. More about this debate can be found in Chapters 5 and 7.

By melting and recrystallizing polysilicon, the wafer producers grow either single mono-Si crystal ingots by the Czochralski (Cz) technique or cast multi-Si blocks (grain size about 1 cm). Both methods yield large solid blocks which must be sliced into wafers (150–250 μm thick). Conventional Si cells are made by diffusing the junction and screen printing the contacts. Mono-Si wafers produce cell efficiencies of about 16–17% while the multi-Si wafers produce cells of about 13–15%. Mono-Si wafers are necessary to implement the unconventional and higher-efficiency structures such as the HIT and IBC cells, both with champion cell efficiencies of over 20% (see Chapter 7 for details).

Wafering the silicon blocks implies kerf losses and a sizeable proportion (40%) of the expensive polysilicon is lost in “sawdust”. To avoid this, sheets of silicon can be grown as “ribbons”. However the cell efficiency is not quite as high as multi-Si. The same few factories making Si ribbon also integrate it into cells.

Most crystalline solar cells are fabricated from wafers by the screen printing technology that is described in Chapter 7. There are some exceptions, such as the IBC and HIT cells also explained in that chapter. The bigger cell factories integrate the crystal growth and wafering processes.

The mono-Si technology comes directly from the microelectronics industry and was the first to be used for solar cells. The multi-Si technology was developed specifically for PV to avoid the high costs of the Cz growth process. But it has not been able to clearly dominate the market because of the slightly lower efficiency. There is considerable research to develop processing steps to reduce the efficiency gap between mono-Si and multi-Si. Concerning ribbon, besides the low efficiency, the growth per cm^2 is slower than for wafers, leading to higher capital costs. The production of fast ribbon growth without losing efficiency is the desired goal, but it is difficult, in part because the ingot formation is also a purifying step that is incompatible, for physical reasons, with fast ribbon growth (Chapter 6).

Once the cells are manufactured they are assembled into encapsulated modules, as described in Chapter 7. This is done, either in the cell factories or in module assembly factories that purchase cells from a variety cell factories. Thus nearly identical Si cells can be bought from a variety of suppliers and integrated into modules. This is an important origin for double counting the module production in market studies (because the cell manufacturers may count all their cells as MW_p produced and then the module manufacturer counts them again). This may cause discrepancies in the reports on manufacturing as well as in the breakdown between technologies (that are not very substantial).

A consortium of European Si PV companies and research groups (CrystalClear) has been collaborating on reducing the cost per watt of various Si PV cell technologies [53]. They established the cost structure for the current baseline standard multicrystalline Si module, called Basepower, averaging 2.1 €/W (2005 reference technology). Figure 1.13a presents the costs in terms of process step and Figure 1.13b is the cost in terms of manufacturing cost category.

The fraction of polysilicon cost (i.e. feedstock) is only ∼14%, but during 2008 (in the explosion of the Spanish market) a shortage of polysilicon caused its price to rise occasionally in the spot market to about 10 times its normal price (of about US$50/kg). The combined shortages and high prices of Si modules gave an opportunity to less-mature technologies, such as TFSC and CPV to find a place in the market. Not everyone was prepared to profit from this, but we think that the extraordinary success of First Solar (the world’s biggest company in 2009) with its thin film CdTe modules is partially due to this unique opportunity.

Increasing efficiency, followed at a distance by reducing the polysilicon cost, are the main single drivers of cost reduction in Si technology. In this respect the appearance of such technologies as the IBC of SunPower and HIT of Sanyo, both able to produce wafer-sized cells of more than 20%, are very promising. It is not really known if they are more cost effective than conventional screen printed cell technology (still largely dominating). But in 2008 they became the ninth and

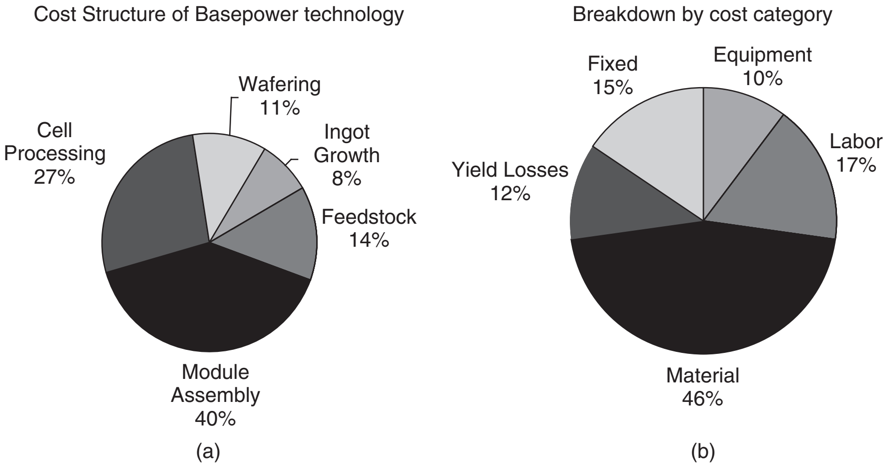

Figure 1.13 Breakdown of costs in the fabrication of a Si-wafer-based PV module. (a) The left-hand side is the percentage in terms of technical process steps; (b) the right-hand side is the percentage in terms of financial activities (adapted from del Cañizo *et al. Progress in Photovoltaics* 17, 199–209 (2009)). About half of the module assembly costs are materials

tenth largest solar cell manufacturing companies in the world, SunPower with 3% of world market and Sanyo with the 2.7%.

1.5.2 Thin Film Progress and Challenges

Why develop a totally different semiconductor technology for photovoltaics when Si is so well established? The simplest answer is in order to achieve lower cost and improved manufacturability at larger scales than could be envisioned for Si wafer-based modules.

The TFSC are based on materials that strongly absorb sunlight so that the cells can be very thin (1–3 micrometers). The electrons freed by the photons need to travel only this short distance inside the cell to the cell contacts (and from there to the external circuit to produce power). This reduces the demand for high purification and crystallinity of the material, one of the causes of the high cost of the Si cells. However, where the thin films have a real business advantage is that they are made directly into modules and not in cells. In other words, while Si cells are manufactured from wafers, then processed and assembled to form a module, in TFSC technology many cells are made and simultaneously formed as a module.

But there are disadvantages and in fact they have not yet dominated the market. We must understand why.

It was recognized almost as early as c-Si PV cells were developed in the 1950s that thin film semiconductors could make good solar cells. When fabricated into useful devices, they are so thin that they must be deposited on a foreign material, called a substrate, for mechanical support. This can be a glass and metal or a sheet of plastic, all of them of low cost (at least as compared with the self-supporting Si wafer). A framework for analyzing the material properties, device structures, device physics, and manufacturing issues unique to TFSC had to be developed since they differed considerably from Si wafers [54, 55]. Between 1981 and 82, four thin film technologies demonstrated the ability to cross the magical 10% efficiency barrier, thus becoming candidates for serious consideration: Cu_2S/CdS [56], a-Si [57], $CuInSe_2/CdS$ [58], and CdTe/CdS [59]. Of these four TFSC technologies, Cu_2S/CdS would soon be rejected for commercialization due to fundamental and fatal stability problems related to electrochemical decomposition [60]. In contrast, a-Si has a minor stability problem that, once stabilized, is predictable, reversible and seasonal, as discussed in Chapter 12. No fundamental stability problem has been found with $Cu(InGa)Se_2$ and CdTe modules, although they can develop unique degradation modes if not properly encapsulated. Consequently, significant industrial and government-sponsored research and resources have been directed worldwide at TFSC technology. This led to steady progress in champion cell efficiencies through the 1990s, as seen in Figure 1.12.

But the efficiency of TF modules is 25–50% lower than for Si modules which makes it difficult to translate the low cost per m^2 of TFSC modules to cost per W_p. This lower efficiency causes a higher area-related BOS cost when a TF array is installed, partially negating the natural cost advantage of TFSC, as discussed in connection with Figure 1.8b.

To obtain low manufacturing costs, TFSC plants must be operated at high volume throughput to offset the initial capital investment[5]. A detailed study of thin film module manufacturing options concluded that costs of current technologies would decrease 30–50% as the production facility increased from 25 to 200 MW per year [61].

The TFSC manufacturing process is designed such that they are deposited sequentially on moving substrates as in a continuous 'in-line' process or on many substrates at a time in a stationary batch process. This minimizes handling and facilitates automation, including laser scribing, to isolate and interconnect individual cells on the module, called monolithic integration. They are deposited at relatively low temperature (200–500 °C compared with ~800–1450 °C for the different main processes of c-Si). TFSC are either polycrystalline with small ~1 μm sized grains such as $Cu(InGa)Se_2$ or CdTe, amorphous like a-Si, or mixed amorphous/crystalline Si phases called nanocrystalline Si. The noncrystalline structure is a consequence of being deposited at temperatures too low and at rates too fast to allow perfect crystalline bond formation. TFSC typically consist of 5–10 different layers whose functions include reducing resistance, forming the *pn* junction, reducing reflection losses, and providing a robust layer for contacting and interconnection between cells. Some of the layers are only ~20 atoms thick (10 nm), yet they may be a meter wide! This requires excellent process control.

Besides the lower efficiencies (so far), TFSC have a much less-developed knowledge and technology base compared with c-Si, and their properties are more difficult to control. Consequently, under-capitalized companies have had to struggle to develop not only an understanding of the materials and devices, but also the equipment and processing to manufacture them. The thin film PV industry has had to develop the technologies all by itself with considerably less financial resources than the Si PV industry had. They were not able to adopt a mature technology from the Si electronics industry. These factors can lead a purchaser to hesitate to buy a product that is less mature, and not so cheap (because of the small manufacturing volume), and thus to prefer the standard Si wafer-based product.

What are the strengths and remaining challenges for the TFSC industry? We will review the salient characteristics of the three leaders: a-Si, $Cu(InGa)Se_2/CdS$, and CdTe/CdS.

Amorphous Si (Chapter 12) is deposited from hydride gases such as SiH_4 using plasma to decompose the gas. This is called *plasma-enhanced CVD* (PECVD) and allows for large areas to be coated rather uniformly and with excellent control, using the same technology as large-area flat panel displays. The a-Si film has 1–10% hydrogen bonded to the Si, and is often designated

[5] This is being proven by First Solar which has been manufacturing CdTe thin film modules for 10 years, achieving the lowest manufactured price per watt since 2008 (<1.00 $US/W), becoming the world leader in PV module production in 2009.

as *a-Si:H*. The H atoms passivate a large number of the defects resulting from the incomplete bonding of the Si atoms. The atomic structure lacks the long-range order of other crystalline or polycrystalline materials. This can be an advantage because the light absorption is increased with respect to c-Si. Films are typically deposited between 150 and 250 °C, the lowest temperature of any of the TFSC materials, allowing the use of lower-cost, low-temperature substrates. a-Si solar cells are deposited on glass, stainless steel foil, or plastic. The last two substrates are flexible allowing for "roll-to-roll" manufacturing where all the layers are deposited as the roll moves through their process zone. Nearly all a-Si modules contain multiple junction devices where two or three junctions are grown on top of each other. This allows for more efficient utilization of the sunlight. Increasingly, a nanocrystalline form of thin Si is being used as the low bandgap partner in making "micromorph" a-Si/nc-Si multijunction cells (Chapter 12, Section 12.5). The highest reported cell efficiency was 15% for a triple junction, which degraded to about 13% before stabilizing [62]. Micromorph modules 1.4 m^2 or larger are being reported with 8–10% stabilized efficiency, as discussed in Section 12.6, but standard products (not micromorph) are in the 5–7% range. The three major challenges for a-Si technology are: (1) to improve the standard module efficiency to 10–12%; (2) to minimize or eliminate the self-limited degradation which reduces efficiency by 2–3% (absolute); and (3) to increase the deposition rate of the layers and utilization of the gases, especially the nanocrystalline layer to allow faster, lower-cost manufacturing.

Polycrystalline layers of $Cu(InGa)Se_2$ (Chapter 13) alloys have produced the highest efficiency TFSC devices and modules. TFSCs based on $CuInSe_2$ (no Ga) achieved 12–15% efficiency, but were limited by the low bandgap. Alloying with Ga and/or S increases the bandgap and increases the efficiency of delivering the electrons to the circuit. While many deposition methods have been explored in the laboratory, there are two different processes under commercial development. Co-evaporation forms the alloy by simultaneous evaporation of the Cu, In, Ga, and Se from sources onto a heated substrate. The other process is called *selenization*, because layers of Cu, In, and Ga are deposited by a wide variety of methods onto a substrate, then heated in the presence of Se from a gas such as H_2Se or a Se vapor, thus contributing the fourth constituent of the alloy. A very active area of research is developing methods to incorporate these atoms and others into low-defect alloys to increase the bandgap even further.

Substrate temperatures typically reach 500–600 °C during some stage of the growth unless the substrate is a polymer, in which case 450 °C is the maximum. Substrates of Mo-coated glass are typically used although Mo-coated metal foils or plastic are in manufacturing. If sodium is not available from the substrate (diffusing from glass), it must be provided directly, either during or after deposition, to enhance electronic quality of the $Cu(InGa)Se_2$ and increase voltage. The $Cu(InGa)Se_2$ films are *p*-type, typically 1–3 μm thick and have crystallites or grains on the order of 1μm. The *pn* junction is formed by depositing an *n*-type layer of CdS, ZnO, or other new materials under development to replace the CdS (largely for "environmentally friendly" bragging rights). The highest reported cell efficiency is presently 20.0% [63] and several companies have limited manufacturing capacity (<20 MW) of modules with 10–13% efficiency. Transferring a high-efficiency small scale laboratory process on a stationary substrate to manufacturing on a large area moving substrate has proven more difficult for $Cu(InGa)Se_2$ than for a-Si or CdTe. The three major challenges for $Cu(InGa)Se_2$-related technology are: (1) to control the composition (Ga, S, Se, or Na) of the alloy through the film in a manufacturing environment on a moving substrate; (2) to find alternative junction partners to replace CdS; and (3) to find new alloys (with Ag, S, Te) or new deposition methods to give high-performance devices with higher-bandgap alloys.

Polycrystalline layers of CdTe (Chapter 14) have been investigated for photovoltaics since the 1970s. In contrast to limited process options for a-Si or $Cu(InGa)Se_2$, there are over 10 methods to deposit the CdTe films that have produced CdTe solar cells exceeding 10% efficiency. Four have reached precommercialization: spray pyrolysis (SP), electrodeposition (ED), vapor deposition (VD) and close-spaced sublimation (CSS). Some take place in liquid baths that are barely warm

$\sim$50 °C, with CdTe deposition rates of μm/h (ED) while others take place in vacuum systems at temperatures high enough to soften glass $\sim$600 °C, with CdTe deposition rates of μm/min (CSS). There seem to be three critical steps, however, that all efficient CdTe solar cells require. First, they need a post-deposition anneal in the presence of Cl and O_2 at around 400 °C. This chemical/thermal treatment enlarges the grains, passivates the grain boundaries, and improves the electronic quality of the CdTe. Second, all CdTe layers need a surface treatment before applying a contact. This treatment can be a wet or dry process and prepares the CdTe surface by etching away unwanted oxides and leaving a Te-rich layer needed to make a low-resistance contact. Third, nearly all high- efficiency devices have a Cu-containing material somewhere in their CdTe contact process but again, there are many ways this can be achieved. Details of these three process steps tend to be very proprietary. Whichever process is used to deposit the CdTe, it has been found that the entire device process is highly coupled since processing steps strongly influence previous layers. This is partially due to the CdTe grain boundaries which act like paths for interdiffusion.

The *pn* junction is formed by first depositing an *n*-type layer of CdS on a glass substrate with a transparent conductive oxide contact layer (typically SnO_2) followed by the 2- to 8-μm-thick CdTe layer and appropriate chemical annealing. Once the solar cell is made, the CdTe films are slightly *p*-type with crystallites or grains of the order of 1 μm. The highest reported efficiency for a CdTe/CdS device is presently 16.5% [64] and modules are around 10–11%. Some CdTe modules have been in outdoor field-testing for over 10 years with negligible degradation. Of the three leading TFSC technologies, CdTe has surged into first place in terms of manufacturing capacity and lowest cost on the strength of a single company. The three key challenges are: (1) to better understand the various post-deposition optimizing treatments so they can be simplified and transferred into production; (2) to increase the output voltage commensurate with its bandgap; and (3) to maintain and evolve the safe and cost-effective Cd usage in the workplace, followed by recycling at the end of the module's life.

Technically astute investors know that other factors can be more important than efficiency in selecting a technology for development. This point is made obvious by examining the relative performance of the three major TFSC technologies – Cu(InGa)Se_2, CdTe, and a-Si – in Figure 1.12. Note that a-Si has always had the lowest efficiency. Yet, of the three, it was a-Si that was commercialized much earlier and more widely. This is partly because there has only been one generic deposition technology – PECVD – while CdTe and Cu(InGa)Se2 have a wide range of technologies, meaning each company must develop the unique process technology and equipment themselves. a-Si also had a stronger scientific research base, partly due to the other applications such as flat panel displays, which ensured that the relation between deposition conditions and fundamental material and device properties were well characterized, which comforted investors. In contrast, CdTe and Cu(InGa)Se_2 are "orphans" because they have no real application outside of photovoltaics. In 2008, Table 1.5 shows that a-Si accounted for about 4%, CdTe for 7%, and Cu(InGa)Se_2 still about 1%. Yet Cu(InGa)Se_2 has had the highest laboratory efficiency for two decades (Figure 1.12). This shows that translating research-grade champion cell performance into production modules coming off the production line day after day is a very challenging task. The phenomenal growth of CdTe is due to one company, First Solar, whose modules are among the lowest priced on the market. But it took them over 15 years of research and development with significant public and private investment to get there.

Conjecturing that the ideal PV technology would have some of the merits of c-Si (abundance, nontoxicity, stability) but be deposited as a thin film a few micrometers thick, several groups have tried to achieve the "best of both worlds" by developing thin films of multi-Si deposited on an inexpensive non-Si substrate. This is the subject of Chapter 11. At present, the best thin film multi-Si modules have the same efficiency $\sim$10% as their CuInGaSe_2, CdTe, or a-Si based predecessors. This is partly because multi-Si thin-film photovoltaics also inherits some of the problems of both c-Si and thin films. In particular, passivation of grain boundaries and surfaces seems to be a major problem, yet many of the well-established passivation methods from c-Si are not applicable to multi-Si thin films due to temperature limitations (<600 °C).

There are new thin-film technologies such as the solid–liquid junction dye-sensitized (Chapter 15) and polymer-based organic (Chapter 16) solar cells that operate on very different principles than an all-solid-state solar cell. Their main attraction is the potential for very low cost. However, these fascinating new technologies present many new challenges, including strong sensitivity to air and water vapor, hence the need for excellent encapsulation. There are some private investment efforts to scale them to manufacturing.

1.5.3 Concentrator Photovoltaics Progress and Challenges

Concentrator Photovoltaic Technology or CPV is based on separating the area for collection of sunlight from its conversion. The collection area is an optical element, mirror or lens, which casts the light into a much smaller area of solar cells. This allows using high-efficiency but more expensive solar cells since the area of cells is >100 times smaller than the light collection area. The design and operation of CPV is described in Chapter 10.

PV technologists were aware of this possibility from the beginning of PV development. In general CPV needs sun-tracking systems that makes it unsuitable for small-scale applications of PV. There were attempts in the 1980s when Si solar cells were still too expensive and the markets were still too small.

The interest in CPV has spread in the last five years when MJ III–V-based solar cells, discussed in Chapter 8, developed for space applications, started to approach 40% efficiency, which they have already surpassed, as shown in Figure 1.12. CPV can take advantage of these ultra-high-efficiency cells, which are inherently very expensive, because the total cell area is reduced under high concentration, thus mitigating their high cost. Concentration levels of 500× (the cell is 500 times smaller than the optical aperture) are common with this technology and there is a trend to move towards the 1000× which presently operates at slightly less efficiency. Projected costs of such concentrator systems might be very small [65]. Concentration helps to increase the efficiency which theoretically increases as the logarithm of the intensity, until it reaches too high a value of current density, leading to ohmic losses that reduce the efficiency. Thus concentrator cells must be specially designed to have very low series resistance.

However, there are disadvantages. First, CPV does not utilize diffuse radiation, thus losing ability to convert at least 10% of the global radiation even in the best climates, and often much more. Second, at 500–1000×, CPV requires tracking the position of the sun very accurately every minute of the day which adds cost and complexity to the installation. Non-imaging optics is a new scientific tool that may soften this requirement. Third, the optical elements reduce the overall efficiency. Nevertheless module efficiencies of 30% have been presented at conferences and are about to appear commercially. Finally, CPV modules must be able to dissipate a significant amount of heat, leading to complex construction and reliability issues.

Another temporary issue is the rating. An array is usually formed by modules mounted on a tracking system, but only when mounted can the efficiency of the array be determined because the tracking itself affects the efficiency. Even in a good tracking system it varies in about 5% from second to second because of small misalignments, so that defining the kW rating of an array, and how to measure it, is not yet decided. Under these conditions the bankability of a concentrator system is still difficult to assess or guarantee. Nevertheless, under the silicon module shortage in 2008 the Spanish company Guascor Solar, with license of the American Amonix, installed over 9 MW of concentrators, being so far the first in installed CPV.

With the short learning curve in CPV, competing with the cheap Si modules from China, and to some extent with the cheap CdTe modules from First Solar, is very difficult. It will be necessary to demonstrate good credibility in performance at low installed prices to see this technology widely deployed. The recently created Institute of CPV systems in Spain (ISFOC), has subsidized the installation of 3 MW from seven companies (three from Spain, two from the USA, one from Germany and one from Taiwan) to provide accredited performance data to help gain this credibility and to establish the rules for measuring CPV performance.

Some think that they will be able to make a low-concentration system with Si cells that will beat in prices the complex high-CPV systems and the flat panel systems alike. As matter of fact the Guascor Photon sales have been obtained using highly efficient (~25%) IBC-silicon cells, although they are moving now to MJ III–V cells.

So the result is that many companies, start-ups and established, are today involved in developing CPV options in the high and low concentration ranges. The next years will tell us about the success of these efforts.

1.5.4 Third-Generation Concepts

In 1961 Shockley and Queisser (SQ) published a paper [66] setting the thermodynamic efficiency limit[6] of a single-junction solar cell of about 40% under certain hypotheses that were thought to be fundamental and absolute. Cells based on principles that violate some of these hypotheses are called third- [67] or next-generation [68] solar cells.

The most studied (called by some revolutionary) third-generation solar cells [69] are: the Intermediate band solar cell [70] which discards the SQ hypothesis that photons below the bandgap are not absorbed, the multi exciton generation solar cell [71], which discards the SQ hypothesis that a photon can only pump one electron; and the hot carrier solar cell [72] which discards the QS hypothesis that the electrons are at the lattice temperature.

Some progress has been made in all three concepts since the first edition of this book, but a high-efficiency cell has not been produced with any of them. The 1st and 2nd generation solar cells used today have required decades to yield reasonably high efficiencies and a reliable manufacturing process. It will be the same with these new concepts. They will probably not be available to meet the 2030 challenge. Third-generation concepts may enable TFSC to operate with efficiencies above 20% or may permit achieving efficiencies of 50% in CPV cells permitting modules of 40%. To accomplish this, we will need detailed knowledge of these new fundamental concepts and more importantly how to integrate them into a functional device.

1.6 CONCLUSIONS

The human race is increasingly aware of the need for sustainable development. Solar energy is almost the only, and certainly the most developed way of producing energy for this sustainable development. This will be possible mainly through PV.

PV constitutes a new form of producing electric energy that is environmentally clean and very modular. It is highly appreciated by the public. It is unique for many applications of high social value such as providing electricity to people who lack it in remote areas. In recent years PV has experienced an unprecedented burst of growth. Today PV is a big business of around $US 50 billion

[6] This limit applies to the individual cells in a MJ stack, but not to the stack as a whole.

worldwide and growing at ~50% annually. PV-powered homes, commercial buildings, and power plants have been built around the world. It has been recently shown (in Spain) that PV electricity can be installed five times faster than nuclear power plants and that a penetration of intermittent electricity of around 15% can be handled by the electric grids with positive environmental effects.

Common forecasts predict that PV electricity will contribute only a few percent by 2030. We have shown that there is easily enough land, raw materials, safety protocols, capital, technological knowledge and social support to allow PV to provide over 12% of our electrical needs by 2030. And we have to be much more ambitious for the future because PV has to become the biggest supplier of electricity by the end of the century. This will require finding new ways of energy storage.

The present PV development has been possible by the public support, driven by public opinion, which has led to governments spending substantial money to subsidize PV. However, this has not been a waste. It has been an investment. Today PV electricity is very close to grid parity. Thanks to this we predict that PV will continue to grow at a fast pace towards the 12% goal by 2030. Still strong political support will be necessary. And the promise of significant growth in employment – due to raw materials processing, module manufacturing, installation, and non-PV system components – is becoming a major driving force behind that political support.

PV possesses a panoply of novel technologies that ensure a continuous advance in the reduction of costs throughout the whole century. In this PV is unique compared with other energy technologies. Nations that want to lead this irrepressible movement will have to support it by investing in R&D, industry and markets.

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