Jenny Chase

Solar Power Finance Without the Jargon

Second Edition

World Scientific

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BloombergNEF, Switzerland

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About the Author

Jenny Chase is part of the Solar Analysis team at BloombergNEF. She founded this team in 2006 at a startup called New Energy Finance, which was acquired by Bloomberg in December 2009. Now a division of Bloomberg, the firm provides market and investment research about clean energy for a primarily financial and corporate audience. Jenny is part of an international team based in Hong Kong, Shanghai, New York, San Francisco, London, and Milan to produce market research on solar power demand, supply, prices, companies, and technologies. She is the main author of the quarterly *BloombergNEF PV Market Outlook*, one of the most read publications on the financials of the global solar market. Jenny holds a BSc and an MSc in Natural Sciences from the University of Cambridge, UK. She now lives in the Swiss countryside with her husband, daughter, and a small flock of West of England geese.

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Contents

Chapter 1

Introduction

This book aims to provide a useful introduction to finance, via solar power, for people with an education in science, engineering, or humanities subjects and an interest in energy technologies. It assumes very little knowledge of finance, business, or economics, but fortunately none of those are difficult.

The first edition was written in 2018, as the book I should have read when I started working in the clean energy industry. By 2022, I had to write a second edition, because there are things I know now that I didn't know then. The Energy Transition (it seems we have jointly decided that revolution is too scary a word) has gone faster than I expected, and it feels like we're at the end of the beginning now. Batteries have turned out to be a much greater part of the solution than we thought in 2018; it's possible that managing daily fluctuations in power generation is not actually that complicated, we just need a load of batteries. The first edition also had a focus on the costs of subsidies that the energy crisis of 2022 made look quaint and myopic (though governments still should set subsidies sensibly!). There's a lot more in this second edition about hydrogen, and the energy crisis of 2022 changes perspectives radically and probably not temporarily. Somewhere along the way, heat pumps — which can pull more useful heat out of the air than they use in electricity, giving them efficiencies of several hundred percent — became just common sense for residential heating. This second edition has been extensively revised and updated to take into account these developments.

The rise and rise of solar power, and of batteries, is the main reason that I have hope for the future. Climate change is terrifying, and while governments are getting on board with the scale of action needed to transition to a net-zero greenhouse gas emissions world (countries representing 91% of emissions now have serious if not binding net-zero targets), I would have little faith in us managing it if the next few steps were not much easier than anyone would have guessed a decade ago.

The price of solar panels is just 6% of what it was in 2008, and that changes the situation significantly. Solar or wind is now the cheapest form of new bulk electricity generation in most countries, and it isn't even particularly close. Globally, solar and wind were only 13% of electricity generation in 2022, but this is up from almost nothing in 2000, and it is accelerating. For power generation, there is no longer a major compromise between cost and climate goals; in the energy crisis of 2022, Europe in particular was glad of every watt of renewable capacity it had. Poorer countries, from Pakistan to South Africa, look to solar and wind as the cheapest solution to their energy supply problems. Here in Switzerland and nearby in Germany, most south-facing apartment blocks now have solar panels hanging off balconies to shave a bit of power demand from the household's daytime use.

Is it going fast enough? Most models suggest, no, not fast enough to stop climate change from having terrible effects across the world in our lifetimes. But we (as individuals and as a species) can't exactly give up, and bemoaning the hopelessness of it all does nobody any good.

And it's not hopeless! When we stop burning coal, oil, and gas, we can dismantle the infrastructure to extract and transport those things, and though we will have to mine and manufacture the building blocks of the energy transition, on balance this is far less material being extracted and dragged around. This will make further decarbonisation a little bit easier. Just electrifying everything that can be easily electrified — transport with electric vehicles and heating with heat pumps — will cut our energy demand substantially.

Already, energy demand in many developed countries has flattened and started to drop even with rising population; Germany, for example, used just 546 TWh of electricity in 2022 (of which 47% was renewables), down from a peak of 615 TWh in 2007, according to utility industry association BDEW. It isn't impossible to turn around the story of fossil fuels. It's possible to give everyone a developed-world quality of life and still get to net-zero emissions.

It won't be easy, of course, nor is it certain. We will need to build thousands of kilometres of new power grids to connect solar and wind, and it is not clear who will pay for that. We will need to make large electricity loads — and probably even small ones — turn on when the sun is shining or the wind is blowing and turn off when power is scarce. We will need to make civilisation use power when the power is being generated so that we have some for later.

One powerful tool in this adaptation is markets, because moving around resources that are plentiful in one place or time and scarce in others is exactly what markets are good at. An economist's saying that gets used a lot at BloombergNEF is "the cure for high prices is high prices"; nothing stimulates innovation to supply something (or to reduce the use of it) like high prices for it. Likewise, low prices are remarkably good at stimulating innovation and behaviour change to find a use for something that is cheap. This applies to power at particular times, and also to various metals and minerals needed for the energy transition. Already, battery suppliers have changed the design of home batteries to use cobalt-free chemistries, and the next generation of large stationary batteries may well be sodium-ion, avoiding the use of lithium as well.

Even aside from changes in chemistry, similar improvements to those we have learned to make in manufacturing solar panels are also being made in batteries, and what drives those is deployment. One thing I want research-focused readers to understand from this book is that we are not waiting for these technologies. We are financing them and we are building them, and that is what is bringing down the cost.

It still isn't going to be easy. Electricity isn't the only thing we use fossil fuels for, and some sectors, like aviation, shipping, and industry, are much more difficult to decarbonise. There are weeks in many countries where the sun and the wind are so bad that even a vastly oversized power generation capacity may not meet demand. Batteries help over days, but not over weeks, and probably never will. Hydrogen will help in some parts of the economy but will probably involve many scandals, errors, and failures as well. The UK, Finland, China, and South Korea are probably wise to plan some nuclear as well as a huge renewables build which will happen anyway, to spread the risk.

Geopolitical tensions may complicate the transition. China leads the world in making solar modules that are not just cheap but also good. The US, India, and Europe have each decided to boost domestic solar manufacturing and have their reasons, but insisting on local content could stunt the growth of the solar industry.

Much of this book is history (though I've removed bits from the first edition that seem to have had few consequences), and much is discussion about what we used to think but were wrong about. The purpose of this is to show why things you have been taught and things you have read, by well-meaning intelligent people, may no longer be true. It isn't their fault; technology often makes fools of the best forecasters, and some things I have written in 2023 may be comically wrong by 2025. Skip the history chapters if you like, they are self-contained and wander all over the world, but sometimes it's useful to know how we got where we are.

This book is also intended to explain basic finance to people without business or economics training, who want to work in something that helps the climate. Many of you will work in industry and make decisions, so it's useful to understand that financial concepts aren't evil and are important for making decisions in an uncertain world. Because you cannot do nothing, and you cannot do everything, and while it's tempting to think we should all drop everything for full steam ahead on climate action, that's probably not sustainable. We must still do things we enjoy, raise our children, and care about how we treat one another while acting cleverly and effectively on climate. We do not have an exact roadmap on how to get to net-zero greenhouse gas emissions, but we have set off in the general correct direction, and over the next 10–20 years, people working on the energy transition will have to figure out the fine details of the journey ahead.

Chapter 2

Solar Technologies: The Basics

There are three major applications of solar power. They are passive solar heating, solar thermal electricity generation, and photovoltaics. The first two involve using the sun's heat to make a fluid — usually water — hot, and if you make it very hot, you can use the steam to run a turbine to generate electricity, exactly as in fossil fuel-fired power plants. They are included for completeness and because solar heat can, in the right place, significantly contribute to energy supply.

The third application, photovoltaics, is the main focus of this book, and the first major electricity-generating technology ever that doesn't involve making a turbine go round. It is a technology that has no moving parts and requires no material inputs once it is installed and generates electricity directly. It is also the one that has made great progress technically and economically in the last few decades and looks set to explode further.

2.1 A Note on Units

Anyone interested in energy markets should first have a good, intuitive grip on basic school physics regarding power and energy. This is too important, and too frequently poorly understood, to put in an appendix. Energy is the simpler of these concepts and refers to the potential to do work — to move a weight, or illuminate a light bulb for a period of time, or heat a volume of water. The scientific unit for energy is a joule (4.18 J make a calorie, but calories are not often used outside food science). A joule is a derived unit of more fundamental metrics, but basically 10 J is roughly enough to lift 1 kg a distance of 1 meter in Earth gravity.

When we discuss electrical energy and power, we usually use watts (W) and watt-hours (Wh). Power is the rate of delivery of energy and measured in W, where 1 W = 1 J/s. A lightbulb with a power rating of 28 W uses 28 J/s while it is switched on. To measure how much energy it uses over the day, we multiply the power by the time, i.e. watts × seconds. A 28 W lightbulb running for an hour uses 28 × 60 × 60 Ws or, as we would normally write it, 28 Wh. A cup of tea (say 250 mL) requires about 24 Wh to boil if it starts at 20°C and a kettle boils exactly the right amount (making anything hot is surprisingly energy-intensive). Wh convert directly into joules but are generally more intuitive units for electrical energy. In practice, we more often speak of energy delivered in kWh (kilo, k = a thousand), MWh (mega, M = a million), or even GWh (giga, G = a thousand million) or TWh (tera, T = a million million). When we speak of a power or capacity rating for a generating plant, it is usually rated in kW, MW, or even GW if it is large, which indicates the power it will generate under good conditions. A coal power plant is 1–4 GW. A power output of 1 GW would boil an Olympic-sized swimming pool starting at 20°C in about 14 minutes. A solar plant covering two hectares is roughly 1 MW, so a solar plant with peak power capacity of 1 GW would cover about 3,500 football pitches. The actual expected energy from these will be discussed later; obviously, the solar plant will generate only when the sun is shining, and then often not at full capacity, while the coal plant can to some extent be ramped up and down as needed.

When we discuss electricity prices, we usually talk about them by the kWh for households (the average annual electricity consumption of a European house is a few thousand kWh) and by the MWh for bulk electricity sales. A typical price for electricity sold to a European household is 20–40 euro cents/kWh as of 2023 (it was 15–30 euro cents before Russia's invasion of Ukraine in February 2022, and may fall again in future), in the UK 34 pence per kWh, and in the US prices range from about 11 cents (in Southern states) to 44 cents (in Hawaii) per kWh. I will generally use dollars throughout this text even for prices in non-US countries, as most of the world is aware of approximately what a dollar is worth, and it will save giving a long list of currency conversions which will inevitably miss out important ones.

When electricity is sold in bulk, a low price might be \$50/MWh, while \$300/MWh would be considered a high price and probably correspond to an unusual situation, such as an energy crisis, or power being generated by burning expensive diesel fuel.

All the electricity prices in this section have been revised significantly between the first edition of this book, in 2018, and the second edition in 2023. The drivers are discussed in Chapter 21 but involve the COVID-19 pandemic which began in early 2020 and disrupted supply chains for several years and then Russia's invasion of Ukraine in February 2022 which caused Europe to urgently reduce purchases of Russian gas.

Another unit worth being aware of is the tonne of oil equivalent (toe), a unit used when electricity, heat, and transport fuel are being compared together as 'gross (or primary) energy supply' by bodies such as the International Energy Agency (IEA) which historically focus on energy availability. A toe is 41.868 GJ (a standard measure, since different grades of oil have slightly different energy content) or, using the simple conversion that 1 W is 1 J/s, 11.6 MWh.

This, as used by the IEA, can be very misleading when applied to renewables. The methodology for calculating primary energy consumption counts input energy — for example, an oil-fired power plant literally burns tonnes of oil to produce electricity — rather than useful energy. Oil-fired power plants have conversion efficiencies of 30–45%, and the contribution of oil to the electricity supply looks larger when the power plant is less efficient. A direct electrical generation plant such as solar, wind, or hydro would be recorded at only its actual electrical contribution. This has the effect of making 100 MWh generated by an oil-fired power plant with an efficiency of 33% look three times as important to energy supply as 100 MWh generated by solar, which is nonsense. Similar calculations apply to coal and gas. An IEA report published in July 2008 pegged the global average efficiencies of electricity production at 34% for coal, 37% for oil, and 40% for natural gas.

This seems like a trivial definition point, and for the IEA, it probably is because the IEA understands it. Primary energy consumption/supply should be interpreted to compare how *dependent* a country (or other entities) is on different energy sources, not to measure their contribution. Oil company BP presents the data in a different way, assuming a thermal combustion efficiency (40.6% in 2021) to 'uprate' renewable energy to the fossil energy it displaces in its Statistical Review of Global Energy (which was more widely cited than the IEA statistics, probably because it was available for free, though in 2023 it was discontinued by BP and passed to the Energy Institute in London).

A typical example of primary energy consumption used to denigrate the contribution of renewables was a *Spectator* feature published on May 13, 2017, less-than-neutrally entitled *Wind turbines are neither clean nor green and they provide zero global energy*, which states that "to the nearest whole number, there is still no wind power on Earth. … From the International Energy Agency's 2016 Key Renewables Trends, we can see that wind provided 0.46% of global energy consumption in 2014."

The BP Statistical Review, which adjusts so as not to count wasted heat in power generation as useful energy, has wind energy at 1.2% of global primary energy consumption in 2014, which isn't a lot but completely negates the headline. (Wind rose to 3.4% of world primary energy in 2021. Solar, according to BP, was 0.35% of world energy consumption in 2014 and 1.9% in 2021.)

British Thermal Units are sometimes used instead of tonnes of oil equivalent as a measure of how much bulk energy goes into the system and have the same consequence of making less efficient fuel conversion methods look more significant.

2.2 Passive Solar Heating

Solar thermal technologies will not be the main topic of this book, as photovoltaics is now the dominant solar technology. For completeness, let's start with the oldest and simplest — using the sun to heat substances (usually water) to a temperature below boiling point.

Passive solar water heating can be incredibly useful in saving fossil fuel, but it's essentially just a set of black tubes that you place in the sun and pump water through. Some improvements are possible — vacuum tubes can be used to make the water heating more efficient, for example — and it has a place in heating water up to about 80°C for washing,

Figure 2.1 A simple thermosiphon home solar water heating system.
Source: Shutterstock.

swimming pools, and other everyday uses. Since it takes as much energy to heat water from 20°C to 30°C as it takes to heat water from 70°C to 80°C, it can make a major difference in the total cost/carbon emissions of having a hot shower even in relatively cool climates, but it is unlikely to completely change the world's energy mix. Basic, cheap solar water heating systems like those in Figure 2.1 are to be found on many roofs in China, Israel, and Greece. Although these simply use convection to circulate hot water into the tank and bring up cool water, more complex systems using pumps and thermostats are available and more likely to be used in cooler climates where some additional heating is often required.

Solar passive heating is also a term sometimes used for designing houses for warmth, for example, by putting large windows on the south side of houses in northern Europe to maximise the warming effect of winter sun, while keeping north-facing windows small to improve insulation.

Every now and again someone comes up with the brilliant idea of combining photovoltaics with solar thermal water heating, using the water to cool the photovoltaics and therefore make them more efficient. This sounds like a good idea if you really like trying to get a plumber and an electrician to come out to work on your house at the same time. I suspect that keeping water and electricity separate in household and small commercial installations will continue to be the norm.

2.3 Solar Thermal Electricity Generation

Solar thermal electricity generation (aka Concentrated Solar Power, CSP) is where vast fields of mirrors are used to concentrate solar heat on receiver tubes or boilers full of fluid to reach temperatures up to 600°C, producing steam to drive turbines to produce electricity. This once sounded promising but ultimately is probably too expensive to revolutionise the world's energy mix. The first solar thermal electricity plants were 350 MW built in the late 1980s in Kramer Junction, California. A crash in the price of gas drove the owner into bankruptcy, but the plants were bought at a discount, and as of 2023, some of the complex is still in operation.

Gigawatts of solar thermal capacity were deployed from 2007 to 2014, mainly in Spain and the US, and most of these plants are functioning well enough, but as of early 2023, the cheapest anyone has signed a power price agreement and actually built the project without substantial additional subsidy is $114/MWh (for Cerro Dominador in Chile, though it may be allowed to sell extra power at spot prices) versus well under $40/MWh for photovoltaics. Saudi developer ACWA reported a levelised cost of energy (LCOE) of $73/MWh for a complex comprising 600 MW of parabolic trough solar thermal, a 100 MW solar thermal tower, and 250 MW of photovoltaics in Dubai, but as Chapter 14 explains, never trust an LCOE unless you can see all the assumptions. Also, it was meant to be commissioned in 2021 and, as of early 2023, does not appear to be done. A project in Aurora, Australia, was offered a price of $61/MWh by the government but was cancelled in April 2019 after the developer failed to find any investors willing to take the risk.

Solar thermal electricity generation has a few advantages over photovoltaics. The power generation is much more stable, as the system has thermal inertia and the turbine will keep spinning for up to half an hour after the sun goes behind a cloud, and the heat can be stored in tanks of molten salt (which is then used to make the steam which pushes turbines round when the sun has gone down) or supplemented by burning gas, coal, or oil. Most solar thermal electricity plants burn at least a little gas to get the boiler up to temperature in the morning, and with a big enough mirror field and tank of hot salt, the plant can even run all night and provide baseload. Molten salt is not fun to work with; if it cools off in pipes to a chilly ~270°C, it will turn solid and become tremendously difficult to extract, and when molten, it has a habit of leaking out. Another reason why a truly baseload solar thermal plant is not usually economically effective is that power demand is low at night. Most North African and Middle Eastern economies have a power demand peak in the early evening, around 5–8 pm, when factories and air conditioning are still running but people also come home and start to cook dinner or watch television. This is well after the daily generation peak for photovoltaics, which is generally 10 am–4 pm; after this time, the sun is low in the sky and delivers little energy, for reasons which are apparent if you shine a spotlight torch onto a globe. When the light is coming in at an angle, the same light is spread over a much larger patch.

One effective configuration is to use enough salt and mirrors to store energy to run the plant for about 4 hours after sunset, covering the evening demand peak but not paying the extra to run overnight. In March 2014, the South African government agreed to pay solar thermal plants 270% of the base rate for power delivered for 5 hours in the late afternoon and evening — when it is in demand. The beauty of solar thermal is that plants can be individually tailored to deliver power when it is most optimal, but this is their flaw as well, for solar thermal plants cannot be standardised and mass-produced cheaply as photovoltaics can. Turbines and boilers are expensive, and engineering for each site and schedule is more so. At present, it seems likely that solar thermal electricity generation will at most be deployed in countries with weak grids and those with a strong evening peak and will ultimately lose to photovoltaics and batteries.

There are two major types of solar thermal electricity generation: parabolic trough (Figure 2.2) and tower and heliostat. These are discussed further in Chapter 18.

Figure 2.2 A parabolic trough solar thermal plant.
Source: Shutterstock.

2.4 Photovoltaics

The main, and by far the most exciting, type of solar is photovoltaics, a family of technologies which use light falling on certain materials ('semiconductors') to produce an electrical current. A photovoltaic module is a sandwich of glass, semiconductor, silver paste to act as an electrical contact, and materials to stop the water from getting in (water ruins semiconductors). Chapter 19 goes into more detail about the types of semiconductors which can be used and their advantages and disadvantages.

A solar module produces direct current (DC) — straightforwardly, electric current only flows one way out of it. Most modern devices and most grids, however, run on alternating current (AC) — an electric current that reverses direction many times per second. The reason we use AC in grids is that the alternation makes it possible to use very high voltages in long-distance transmission lines, which is more efficient than using low voltages, and 'step down' to lower voltages which can be used safely in homes. It is relatively difficult to change the voltage of DC power without first changing it to AC power and back, though high-voltage DC transmission lines are used in China and parts of Europe and are likely to be deployed elsewhere.

A solar module is electrically wired into an inverter, a device which transforms the DC produced by the solar module into the AC used by

Figure 2.3 Ordinary crystalline silicon modules installed on a roof.
Source: Shutterstock.

the grid. The AC capacity of a system is the capacity of its inverter; the DC capacity is that of its modules.

Photovoltaic modules like those shown in Figure 2.3 are essentially a commodity, which in economics means a marketable item that is not differentiated. When you buy a commodity, you specify a certain quality and then one tonne is much like another — like a particular grade of copper, steel, or wheat. Cars, computers, and clothes are not commodities; people tend to value some of these well above others, often for personal reasons. The reason for drawing this distinction between 'commodities' and 'not commodities' is that I am often asked which photovoltaic modules are 'best', and the truth is, as long as a module is not fundamentally badly manufactured, there are few reasons to have a strong preference.

The output of a module is measured in W, and modules are priced per W. This is the amount of power produced by the module under standard test conditions — a temperature of 25°C and incoming sunlight of 1,000 W/m2. This corresponds roughly to a sunny noon in Spain. In real-world conditions, PV panels produce their rated wattage only rarely in less sunny countries.

The actual energy produced by the module (in Wh or kWh) is a function of its rated wattage and how sunny a place it is installed and is usually expressed as a capacity factor percentage. This is the energy produced per year in Wh, divided by the W rating of the module, divided by the number of hours in a year. Imagine that the module produces either at peak power or not at all; the capacity factor is the percentage of the year it would be generating to produce the same amount of energy as it actually produces. Capacity factors for photovoltaics are not high; of course, they can never be over 50% because it's dark half the time. They are typically around 11–12% in Germany, rising to 23–25% in the Atacama Desert in Chile, or up to 35% if the panels are mounted on a tracking system to follow the sun.

All capacity factors here are expressed as a function of the DC rating of the modules. An alternative is to use the maximum output of the inverter, which gives a higher value in most configurations and is referred to as the AC capacity. If you see higher capacity factors for a photovoltaic plant, they are probably AC capacity factors, but DC is better. It tells you more about what the plant cost, how much energy it will generate, and how much space it takes up than AC does.

We have not mentioned efficiency, which is a red herring in popular understanding of photovoltaics — you may see the claim that photovoltaics 'need to get more efficient to be useful'. This is not true. Efficiency is a measure of the useful energy coming out of a generator, divided by the energy in. In photovoltaics, the energy in comes from the sun and does not cost anything, so although the efficiency of standard modules on the market is only around 22%, that merely means they are wasting sunlight. The main difference between high-efficiency and low-efficiency modules is the space they take up, and we are not running out of roof or desert any time soon. 'How much does it cost?' is a more important first question than 'how efficient is it?'

Of course, higher efficiency is desirable. The cost to install and wire up an olden-days-style (2018) 270 W module is about the same as for a modern 400 W module of the same physical size, and sometimes space is limited. Module manufacturers also try to tweak their 'recipe' for greater efficiency using the same materials, which increases their profit margin since modules are sold on a per-W basis. There are also occasional attempts to sell very low-efficiency photovoltaic modules (below 8%) as 'building-integrated' products installed instead of glass or a roofing material, but generally, this is an architectural gimmick, and since they are often installed without reference to where the sun will be, they are probably not worth the trouble of wiring up. They are also usually the modules that the manufacturer can't flog to a discerning buyer who is more concerned with how much they generate than how they look.

'Quality' in photovoltaic modules is something different to 'efficiency'. A photovoltaic module is under warranty for at least 25 years, after which it should still be producing at least 80% of its original output. However, the buyer does not want to have to claim the warranty, mainly because the manufacturer is likely to go bankrupt long before this (see Chapter 13). The buyer needs to know that the module has been manufactured properly, without cutting corners or using materials not tested for the whole lifetime.

There is another standard for modules, which is bankability. Banks are lazy, or, to be more specific, they cannot spend the time doing a lot of research for every loan they make (or they would make fewer loans and charge the borrowers higher fees). Banks therefore take information shortcuts. One of these is to consider technical due diligence reports on only a few of the solar module brands on the market, rather than read 500+ different pleas for consideration. This means that they are much more likely to finance a project using modules that they have looked at before. A module is 'bankable' if a bank can be expected to have heard of and looked at the brand.

(Bankability is a treasured quality. BloombergNEF publishes a quarterly 'tier 1' list of modules which have clearly gone through due diligence by banks because the banks provided non-recourse finance for multiple projects using the modules. I invented this tier 1 list and methodology around 2008 and do not want to talk about it with the 500-ish module makers, most of which are not tier 1. They get very intense about being on the list and have been known to show up unannounced at our offices or just keep calling our phones with threats and pleas. The team that calculates the tier 1 list at BloombergNEF is now strictly anonymous and does not accept calls.)

Bankability is pretty much independent of the semiconductor used, although as of 2023 about 97% of the modules on the market are crystalline silicon, with the remainder thin-film cadmium telluride.

There will still be attempts to develop a 'black swan' technology. A black swan is something that is significant but could not have been predicted. Originally, the term was a phrase used in Europe, possibly since very ancient times, to describe something impossible because the swan species in Europe are all white. Then, European explorers discovered a species of black swan in Australia, and the phrase acquired the meaning it has today. Obviously, I cannot rule out a black swan technology in photovoltaics, but neither can I predict it, by the very definition of a black swan.

Perovskites, a family of lead compound semiconductors, are currently the front runner for a black swan/rapid, market-changing breakthrough in photovoltaic module technology. Perovskites have improved efficiency very rapidly in the lab, above 20%, and may be suitable for applying as a second layer on top of conventional crystalline silicon wafers. However, current laboratory attempts to make a perovskite cell degrade significantly in a few years, which given ordinary modules are under warranty for 80% of their initial capacity for 25 years, are not going to work. Proponents suggest that a few years of power might be enough for some niche applications (indoor power, etc.). Generally, a solar module technology firm declaring it will focus on niche applications immediately precedes its failure.

Chapter 3

Startups

3.1 What Is a Startup?

A startup is a brand new company created by one or more founders who put money and time into the organisation. Usually, the term is used for companies that have ambition to become very large, rather than, for example, a new restaurant or small trading house which may target a small steady profit for the owners but is unlikely to grow rapidly. Although the stereotype of a startup is three recent graduates working in a garage, most successful startups are organised by experienced people who spot a gap in a market they know well. There are also 'serial entrepreneurs' who make a habit of spotting a market gap and spend a few years at a time creating companies to fill it. (Michael Liebreich, founder of New Energy Finance, is both an experienced person who spotted a gap in the market and a serial entrepreneur.) Although I cannot cite academic literature on this, it seems safe to say that startups founded by experienced people are more likely to succeed than those attempted by recent college graduates.

The founders of a startup own shares in the company jointly (a share is a small portion of a company, and these exist for private companies as well as those on public markets) and initially work on figuring out how their company could one day make money. If it is a simple concept and doesn't require much capital, they may have enough of their own money to get to profitability, but usually this is not possible. If they need more funds than they can have on hand, they may raise money from 'friends and family' or 'angels', i.e. rich people, or, if they need more, they seek a 'venture capital (VC) investor' and sell a stake in the company in exchange for cash that the company uses to develop the product and service. The founders may do this several times, and if the investor is satisfied that the value of the business is growing with the additional money put into it, they may increase their stake (sometimes at a higher valuation, i.e. paying more per share, if they think that the founders have in the meantime made the company more valuable, for instance by increasing revenues or attracting new users).

The ultimate aim of this is to achieve an 'investor exit', where all those who have put in money sell the shares that they have accumulated for more than they paid for them, and the founders sell at least some of their own shares and turn them into cash. Founders normally have a form of 'lock-in period' on most of their shares, to encourage them to stay around and work towards the ambitious growth plan they presented to whoever is buying the company. The lock-in period prohibits founders from selling (most of) their shares immediately, and there is usually an 'earn-out' period during which the acquired company is expected to meet certain performance metrics.

An investor exit might be an initial public offering (IPO), where a company lists its shares on the stock market and a different sort of investor, one that likes to own and trade publicly listed shares, can buy them. Or the startup might be bought by another firm for its technology, its people, or its business, in what is called a 'strategic exit'. Famous strategic exits include Yahoo's purchase of Tumblr for $1.1 billion in 2013 (Yahoo sold Tumblr in 2019 for $3 million with the buyer taking over its liabilities, so not all exits go well for the buyer) and Microsoft's acquisition of LinkedIn for $26 billion in 2016. A major solar exit was the IPO of German solar cell maker Q-Cells in 2005, which made some of its investors enormous returns — Apax, for example, reportedly received EUR 277 million ($334 million) from its investment of EUR 11.5 million just a year earlier. A much less famous example is the acquisition of my company, New Energy Finance, by Bloomberg in December 2009. This was considered successful by our angel and VC investors and by the staff who had received stock options.

The VC investor anticipates a high failure rate. Assessing the risk is the job of venture capitalists, and the failure rate is the reason they need to earn a massive profit from the few really big successes. VCs are often criticised for wanting a very high return on their investment, mainly by founders who can't raise money at the valuation they think their business deserves. Generally, if you can make your business a success without giving up a stake to VCs, it makes sense to do so. But many businesses really need the money in the early stages and could not reach profitability without it.

3.2 Startup Failure Rates

Failure is far more common in investment than I would have expected as a physics graduate. While it's difficult to put a precise figure on it due to questions about what counts as a 'startup' and what counts as a 'failure', it is generally estimated that 70–75% of startups fail. The Kauffman Institute, which studies US startup activity, found in 2016 that 48.7% of new businesses tracked reached their fifth year of operation.

Many that do not fail will barely scrape a profit, and the VC investor lives by the occasional big success. I estimate that about half of all the businesses I have written about in my 17-year career have gone bankrupt or ceased activities in solar power, even the big ones with hundreds of employees, and a much higher proportion of the startups.

Out of curiosity about whether this is the case in other sectors, I took the 2010 Global Top 100 Awards list of US VC publication Red Herring and tried to find out where they are as of 2023. Thanks to Google, this is not difficult to do approximately, although there will of course be subtleties. The first surprise about the Red Herring Global Top 100 Award Winners 2010 is that there are 102 of them.

Figure 3.1 shows the results. IPOs are easy to spot — a company once listed on the stock market becomes much more visible to a quick Google search — and probably represent the best outcome for investors, as a startup company must grow considerably to be eligible for a public offering. The six IPOs among the Red Herring 2010 winners included Israeli–US solar panel-level optimiser company maker SolarEdge, which was listed on the US Nasdaq in March 2015 and as of 2023 is highly successful, leading in the market for panel-level solar inverters. Two of these IPOs (live streaming platform Six Rooms Holdings/Huafang Group and US software firm Cardlytics) took place in late 2022 and 2023, showing that investor patience can eventually pay off.

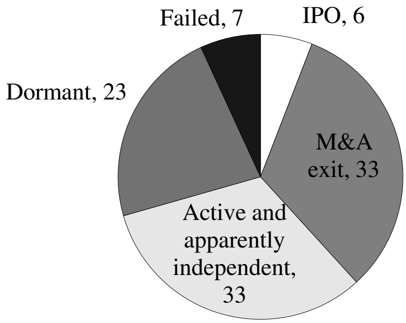

Figure 3.1 Status of Red Herring Global Top 100 Award Winners 2010, as of an Internet search by the author in May 2023.

Merger and acquisition (M&A) deals are probably the next best option for investors after IPOs. These are not much more difficult to find out about, although it's nearly impossible to identify which were highly profitable and which are simply investors cutting their losses. I did not count those where the coverage of their acquisition specified that the company had already failed and assets were being picked up by another firm, presumably for a negligible amount of money. With 33 of the 102 award winners acquired, this is clearly the most common sort of investor exit.

The next category is those still active (i.e. with a recently updated website, or recent press coverage) but which had not yet had an investor exit — perhaps the time is not right, but after 12 years, the investors may already feel that this has tied up their capital for too long. A further 23 companies were dormant, i.e. they had not updated their website for several years or no longer had a website, and seven, mainly US-based, had an actual paper trail of failure. It is likely that many of the dormant firms had failed, but understandably neither investors nor founders like to publicise this fact, and there is not always media interest in digging into the failure of a small and obscure private company.

Only 71% of the winners of a reasonably prestigious award were still around 12 years later. It is impossible to know in most cases if they have achieved profitability, and some may still be raising more rounds of VC on the strength of increasing client base or revenues.

Chapter 4

Startups: Case Study of a Startup (BloombergNEF)

After a more general chapter about startups, I'd like to share my experience of being part of a successful one, from very early on to its profitable acquisition and integration into a larger company. Most startups will not succeed, and I was very lucky to be part of one that did. Nonetheless, the experience of working there would have been worthwhile even if it had failed, for anyone with few responsibilities and a lot to learn.

This chapter is not pitched at people who have always wanted to join or found a startup and know all about small, fast-growing organisations. Skip this chapter if you are already planning your stock option negotiation opener.

4.1 The Early Days

In the summer of 2004, I was cleaning windows during the holidays from studying physics at Cambridge, where I'd learned that lots of people are smarter than me. I wanted to get a job in clean energy when I graduated, but my CV was somewhat sparse on relevant experience — I'd stacked wood, delivered papers, and washed dishes in a local pub. So when an internship came up in renewable energy data entry in London at 10 pounds a day, I applied and went off on the train to interview, wearing my mum's blazer.

The company was called New Energy Finance and the website looked professional to me. Apparently, a lot of the format code was lifted from a florist's website by a Polish programmer. My first interview, with editor Felicia Jackson, consisted of a lot of garbled enthusiasm on my part and my admission that I didn't have my own laptop computer to bring in and work on. My application was rejected, and I went back to cleaning windows (it was a pretty good gig at 6 pounds an hour for reasonably pleasant outdoors work with a nice boss).

A few weeks later, Felicia contacted me saying that someone else had dropped out of their internship program and a spare computer was available, if I still wanted to try for a few weeks. I did. I set off for London, moved in with an unsuitable boyfriend, and bought an Underground travel card.

The team consisted of founders Michael Liebreich and Bozkurt Aydinoglu, Felicia, and two or three interns, in the boardroom of a friend of Michael's. We had a water cooler and that was it for refreshments, just as well since there was a single toilet used by the entire building. What we were doing was removing superlatives from press releases to turn them into news articles (journalism!) and adding companies, renewable energy projects, and financial transactions to a database Michael and Boz had designed. They thought that there were maybe 800 companies in renewable energy worldwide. We quickly discovered a lot more than that. Last time I checked, we were tracking over 40,000.

Most of these companies are legitimate, but there was and is a shocking amount of suspicious behaviour that is borderline or properly fraudulent. The classic example is the 'pump and dump scam', now rare on the major stock markets of the world but still found on the minor 'over the counter' (OTC) stock markets. These OTC markets are lightly regulated and do not require companies to submit very thoroughly audited reports. They can be a route for young companies to raise money from a large pool of investors and to raise their profile, helping them commercialise their product or idea. Investors, meanwhile, can take a small gamble on an interesting firm. The companies are generally still majority-owned by their management and, unlike on the major stock markets, get away with a lot of poetic license in what they release (the positive way of putting it is 'the OTC markets are not shackled by excessive regulation'). It is normal for a very young company to have little or no revenue, and sometimes a grand plan to build a better mousetrap will actually pay off. There are legitimate companies on over-the-counter stock markets, genuinely trying to start a new and risky business with investor money.

There are also scams. One example I began, in 2005, by taking seriously was a company that had access to a large area of forest in Canada devastated by the mountain pine beetle. Since the trees were dead, the company planned to remove them and ship the wood to Europe, selling it as fuel for power plants, which would help European countries meet their renewable energy targets. The company regularly announced that it was on the brink of signing a contract worth hundreds of millions of dollars for this beetle-killed wood. The wording would suggest that the deal was practically done. This would increase the stock price, as naïve investors bought in. I assume that the management would then quietly sell some shares. Of course, nothing more would ever be said of the contract and it is probably safe to say that no dead trees were ever removed.

As an innocent journalist/researcher, I obviously wanted to cover the company properly and would frequently ring the number in the press release for an update on the contract. Finally, I was asked gruffly, 'What are you trying to do — catch me out?' I started to dimly realise that not all people with green plans are entirely honest. An experienced journalist would have realised immediately that the company was either uninteresting or fraudulent and ignored it. The company had yet to close a contract as of 2023 and the website domain is now available for sale.

Michael Liebreich's company New Energy Finance might easily have been one of those firms that were not quite on the level. Michael was a dot com entrepreneur who had ridden the boom all the way up and almost all the way back down; he had seen a vast paper fortune turn to almost nothing — though he was still richer than anyone else I knew — and was rolling the dice so he didn't have to go back to being a management consultant. He and his friend Bozkurt had decided in late 2003 to see if there was any substance behind the 'hydrogen economy' hype that was sweeping the business bookshelf at airports around the world; they had decided there probably wasn't. In the process, however, they had spotted two things others had missed: that renewable energy was on the move and that there was a dire lack of the sort of information that investors would need.

There were plenty of words written about renewable energy by credulous enthusiasts, academic papers on the workings of technology, and policy papers coming out of odd corners of governments but very little attempt to really size or define the market, analyse the economics, or think about where the money would come from. The narrative was that governments had to subsidise all renewable energy technologies, but there was little realistic projection of how long this would be necessary. The standard answer of the clean energy industry to ‘what do we want?’ was always ‘more subsidies!’ Back in 2004, there was little good information about how much these technologies cost or how they were being funded and by whom.

So the idea was to build a big database and sell subscriptions to investors, who would like to read about themselves and about opportunities to invest and be able to track down others with an interest in the sector. Michael’s cunning plan was to use starry-eyed interns earning 10 pounds a day to collect and enter these data, a model Michael had used at his first startup (a skiing website called Ifyouski.com; as of 2023, you can still visit it and book a holiday). Incidentally, Michael comes out quite badly from this brief description, but it will hopefully become obvious that he created considerable opportunities for those early interns. For many of us, it was the start of a career we love, and most of the others had a great time and learned a lot. As soon as it raised some money, New Energy Finance switched to reasonably-paid internships, accessible to people who can’t afford to live in major cities unpaid for months.

I was one of the earliest of these interns, and I must have done something right because Michael said I should come back and work for him when I graduated. He probably meant it as a joke. I started focusing on my studies for my final year and achieved the remarkably useless feat of improving my position from the worst 2.2 in the year to the best 2.2 in the year. Fortunately, it never crossed Michael’s mind that one of his hires could fail to get a top degree, as he had, and he never asked. (This caused some embarrassment years later when he introduced me to a crowd of potential clients as someone with a first class degree in theoretical physics from Cambridge. There are few good times to correct your boss on something like that, and that wasn’t one of them, so his illusion persisted for several more years.)

New Energy Finance survived, and 10 days after graduation in the summer of 2005, I went back to work for Michael and NEF for the grand sum of 17,000 pounds a year, which washes a lot of windows. I have no idea how that compares to market rates in London at the time, but the unsuitable boyfriend was earning 22,000 pounds as a programmer. My first paycheck was unbankable because Michael had forgotten to sign it (he did very promptly when this was pointed out), and I wasn't leaving the office before 9 pm, but I was learning — something I badly needed to do.

I spent my first six months at New Energy Finance covering general clean energy news and data entry, which I really recommend as a way to learn about a subject. Journalists aren't expected to know a lot, which is why they can go around asking questions which seem stupid to experts (good journalists don't remain ignorant for long, but they keep asking the questions).

We were, like nearly all startups, not profitable, and I knew that we relied monthly on our CEO Michael Liebreich paying us out of his savings and later on raising regular investment rounds. It was only afterwards that I found out how close to the brink we had been for the first couple of years. Michael now tells the story about how he closed the first round of external funding on January 17, 2006, with payroll due on January 26, no money in the bank, no savings, and no plan B in case the deal fell through. (As soon as he sold the company, the first thing he did was pay his debts to American Express and his brother-in-law.)

Fortunately, I had no financial responsibilities, and had we closed down, I would have given the required month's notice on my rent and moved back in with my parents in the countryside while applying for other jobs around the country and cleaning windows. I admire that Michael managed to impart continual confidence in the company's prospects, even when he must have been sweating about the imminent need to close the funding round, without ever making false promises or encouraging a false sense of security. An important property of a CEO is the ability to instil confidence in the company's future, while an important property of a startup employee is a plan to avoid homelessness in case the company folds and further salary is not forthcoming. This is tough on people without support networks or a financial safety net. I don't know what the solution is for everyone, but for me, it was reassuring to rent through London's extensive informal house-sharing economy, so as not to be locked into a long-term contract. Working for a startup is a difficult option for the settled.

Michael awarded 'stock options' to loyal staff quite early on, prompting me to do an Internet search to figure out what they are. Stock options are a right to purchase shares in the company at a fixed price, normally the price of shares in the latest venture round at the time the stock option is awarded. The options do not have to be exercised (i.e. the shares do not need to be bought and usually can't be) until an investor exit. They are therefore worthless at the time they are awarded and will be completely worthless unless the company succeeds. They are a way to reward employees without burning cash that would be better invested in the business. However, if an investor exit is achieved, it is likely that the per-share price will be much higher and therefore the employees will get a bonus, possibly quite a significant one. As an employee, it therefore makes sense to ask for as many stock options as possible if you believe the startup will be successful — and if you don't believe it will be successful, why are you there?

I was, obviously, surprised to get some stock options and would not have known to ask for them. Michael was scrupulously fair and generous on this point (perhaps I could have negotiated for more, but it probably would have been greedy).

Another thing that Michael always encourages founders to do is formalise the legal ownership of the company early, even if everyone involved is a friend or an intern. This might seem unnecessary before the company even has real existence, but venture capital investors need the ownership situation to be crystal clear before they even consider taking a stake, and arguments can get extremely acrimonious if the company is a success. You don't want a whole bunch of people surfacing at the last minute, claiming the founders offered them shares and threatening to sue.

I think my New Energy Finance experience was typical in that startups can be an interesting employment option for people at any stage in their career, and when they are straight out of university, they usually have the least to lose and few financial responsibilities and startups may offer interesting professional experiences. However, they are likely to offer low salaries and low job security, with stock options as a bonus. These stock options are worth having and worth asking for more of — but there is a very high probability that they will be worth nothing because the company will not be one of the success stories.

4.2 December 2009 — Acquisition by Bloomberg

In November 2009, I got a call from Michael Liebreich in a state of some excitement. He was in the process of selling the company and needed a few things from me, such as a more formal employment contract with a notice period and an agreement to realise the gains on the stock options he had given me. I agreed readily, even before he promised to make it a condition of the deal that I could work from the Zurich office full-time and try living with my boyfriend who lived in Basel. I was mainly flustered and flattered to hear that I was considered an asset that the company didn't want to lose.

In December, the deal went ahead, with Bloomberg buying New Energy Finance. I got more money than I had ever dreamed of having (I later spent it on a garden). We welcomed Bloomberg staff nervously into our scruffy offices in Holborn, a part of central London that has never been stylish, and quickly got the impression that our buyers were on a somewhat different level of polish than ourselves. (When Chris Greenwood, an experienced consultant, joined New Energy Finance without fanfare in 2007, I arrived at work one morning to find he had arrived and set himself to wash up the cups in the incredibly filthy communal sink. Chris turned out to be brilliant, unflappable even at 1 am with a presentation due at 8 am, and an excellent manager, but it was the washing up which first made a positive impression on me.)

From Michael's perspective, it was a good time to sell. Michael seemed to be enjoying being a CEO and running around being a well-regarded expert and giving great presentations, but he also needed some money that was not tied up in the company. Also, Michael was aware that while the company had established a strong lead in research on clean energy, that lead would come under increasing pressure from other energy information companies that were seeing the transformation in renewable energy affect the traditional heart of their sector. And the company would require further investment to maintain its rapid growth.

Previously, in 2007, NEF had acquired a two-man carbon price modelling team, Guy Turner and Milo Sjardin, and now it had ambitious plans to expand into power markets, natural gas, and water research.

Bloomberg had its own reasons for the acquisition — not only was NEF the leader in carbon and clean energy information but its clients were also willing to pay for its modelling, forecasting, and interpreting developments — something Bloomberg didn't at that time know much about. One thing that nearly derailed the deal was that the price of carbon on the European carbon markets crashed while the deal was being hammered out; the only thing that saved it was that our carbon team had consistently been predicting a crash, saying that they could not see a fundamental reason why the carbon price was as high as it had been in the first place.

So in the spring of 2010, we moved into the shining Bloomberg offices near Liverpool Street, London. We were at this point a horde of about 60 young people in London (150 around the world) quite accustomed to wearing jeans to work unless we had a client meeting, visitors being able to wander into the office off the street if they wanted to, and sleeping on friend's floors when we went to conferences. We'd cycle to work in the rain and drape our cycling clothes over the radiator. Right from the start, Michael had decided that NEF would be what he called an AFZ, an arsehole-free zone, which was and continues to be a major perk of working here.

We certainly had a fairly informal working culture by the standards of a large company. For example, our quarterly conservative and optimistic solar installation forecasts were known as the 'coffee' and the 'beer' scenarios. The idea was that the solar team of Francesco d'Avack, Martin Simonek, and I would first consider updated historical installation data, solar project pipeline, policy, investor appetite, and any other information and construct a forecast for each major solar-building country for the next 2 years. Then, as the evening drew long, we'd have a couple of beers in the office, maybe a pizza, Martin would get the slivovitz (Eastern European plum booze) out of his desk, and we'd do it again, with more optimistic results. Bloomberg does not condone drinking in the office, so the slivovitz tradition died. The forecasts did not get worse.

Bloomberg was different to being in a startup. The offices of Bloomberg around the world are uniformly gleaming, with a glass-and-lights aesthetic. They all have 'pantries', row upon row of gleaming coffee machines, and interesting and varied food — at minimum, crisps and sweets and fruit, sometimes entire fresh-cooked meals. We NEFers descended on the pantry like a swarm of locusts at first, living off lattes and apples and Marmite rice cakes for days. Eventually, the novelty palls a bit for all Bloomberg employees, and only the fresh-cooked food really evokes the locust reaction now. The Bloomberg employees are generally sharply dressed and very restrained, and we adapted by smartening up a bit but also getting used to all the proper Bloombergers assuming we were programmers. There is nothing wrong with being a programmer, but their dress sense is distinctive.

Integrating two companies after an acquisition is something you hear horror stories about — mass firings, formerly happy employees finding their roles changed and reduced, the acquired company being strip-mined for the most profitable bits, and bullying. This acquisition was nothing like that, although there were a few culture clashes. Bloomberg has fantastic offices, infrastructure, reputation, and most importantly data; there were genuine good reasons why working together made sense. And the people in charge of the acquisition from the Bloomberg side were highly competent and made us feel welcome and valued and listened to, which is a pretty important thing when your working life is being turned upside down.

The culture clashes were largely between a successful startup with minimal bureaucracy and a general trust in raw genius and quick fixes to produce good analysis, and an 8,000-person giant with defined processes in place to capture, maintain, and sell data and manage staff. We got used to everything taking longer and to needing to involve three people and explain to them why we wanted to change some data (which took longer than 'I'm the solar boss and this is solar data', which is what I was used to at NEF) before you could do it. There were other changes in the direction of more processes. One of the original NEF salespeople, someone who had been there even longer than me, quit immediately, took his stock payout, and went to live on a houseboat in north London rather than integrate. Travel became particularly tedious, although theoretically more comfortable, as we were issued AMEX cards that are only accepted at relatively expensive establishments. The process of booking travel became more complex than finding the cheapest flight and hotel and booking it. Understandably, Bloomberg wants to know where we plan to go and stay in advance, in case they need to find us or evacuate us in an emergency — a perk I hope I never have cause to be grateful for.

We got harassment training and legal compliance training and management training, which was useful. Harassment training in particular seemed like common sense that did not need to be stated at the time but in retrospect is obviously a very wise precaution to set explicit expectations of professional behaviour in company culture.

On the whole, having processes and HR and lawyers is something companies have to do when they grow up. Integrating with Bloomberg felt like a collision but was really just an accelerated version of the inevitable. And there are enormous upsides to working for a large and slightly bureaucratic company: job security, nice offices, a pension plan, and people not looking blank when you say who you work for at conferences.

Also, I got to work from the Zurich office from July 2010, and living with Björn is working out quite well so far, so I married him in 2012 and now we live together in the countryside halfway between Basel and Zurich and breed West of England geese. I also stepped down as the manager of the Solar team in late 2022 to do more writing about solar and let teammate Lara Hayim manage the team because it turns out you can just do that. It's great. Lots of people should do management for a while but 17 years was enough for me.

Chapter 5

Timeline of Relevant Milestones for Solar

This is a summary of photovoltaic progress so far. Many of the events after 2005 will be examined more closely in further chapters, but a preview may help put the story into context.

1839: Nineteen-year-old French scientist Edmond Becquerel demonstrates the photovoltaic effect in a liquid-based cell.

1876: London-based William Grylls Adams and Richard Evans Day make a solid-state PV cell from selenium.

1879: Patent for electric lightbulb filed by Thomas Edison.

1912: The UK completes the world's first large-scale electric grid.

1954: Daryl Chapin, Calvin Fuller, and Gerald Pearson develop the first silicon-based solar cell, at Bell Labs. Other photovoltaic materials had been discovered by this time, but this set a record at 4% efficiency and was later refined to 11%.

1958: First use of a solar cell on a satellite, an array less than 1 W in size, to power the radios on Vanguard I.

1963: Japanese firm Sharp starts 'mass' production of solar modules. The first 242 W array (half the size of a single typical module today) is installed on a Japanese lighthouse.

1964: NASA's Nimbus I spacecraft was launched, using solar panels to power scientific instruments. It was launched on August 28 and operated successfully until September 22, when the solar panels became locked in position and failed to generate enough power. Further, Nimbus satellites also used PV panels, which were substantially developed as a result of the Space Race between the US and the Soviet Union during the 1960s and 1970s.

1970s: The price of solar panels falls below $25/W in nominal dollars, or over $100/W adjusted for 2022 inflation, with work from Dr Elliot Berman at the Exxon Corporation (no longer a company particularly well known for its constructive interest in solar research). Solar panels for offgrid and emergency power become relatively commonplace. The Cherry Hill Conference, held in 1973 in New Jersey, set a US government-funded research target of 50 cents/W for solar module cost in 1985.

1982: First megawatt-scale photovoltaic system built in Hesperia, California by ARCO Solar (Figure 5.1). By 1984, this as expanded to about 6 MW, some of it using concentrated photovoltaics. During the 1990s, the plant was dismantled due to encapsulation issues with some of the panels and because the panels were then worth more on the market than the power sold by the plant was.

1985: First 13.8 MW Solar Electricity Generating Systems (SEGS) plant commissioned near Kramer Junction, California. This uses parabolic trough solar thermal, not photovoltaic, technology. The SEGS complex was built up to 354 MW by 1991, by Israeli tech pioneer Luz. Unfortunately, the price of power to these plants was set as a function of the avoided cost of generating power from natural gas in California. This fell, and Luz went bankrupt in 1991 after investing $1.25 billion in the plants. Parts of the SEGS complex are still operating in 2023 — under several rounds of new

Figure 5.1 The ARCO Solar project in Hesperia, California.
Source: Shutterstock.

ownership, and topping up solar with a significant amount of natural gas, but overall a technical success. Photovoltaic modules cost $6.50/W ($16.50 in 2022 dollars, i.e. adjusted for inflation), missing the Cherry Hill target in some way.

1994: Cumulative PV installation exceeds 200 MW.

1999: Cumulative PV installation exceeds 1 GW.

2004: After several smaller experiments, Germany agrees to pay a fixed 'feed-in tariff' of at least 457 euros/MWh for PV electricity, with no limits to how much can be built. German market accelerates, and firms like SolarWorld and Conergy start to develop projects and make modules in Germany.

Michael Liebreich and Bozkurt Aydinoglu found New Energy Finance, with the help of interns including this author and a Polish programmer called Jacek, whom Michael found on Rent-a-Coder (now Freelance.com).

2005: SolarWorld, SunPower, Energy Conversion Devices, Q-Cells, and Suntech all complete initial public offerings (IPOs) on stock markets, raising new money and becoming stock-market-listed companies. Their stock prices rise.

The author starts working for New Energy Finance full-time.

2006: Further solar IPOs including silicon makers REC and Wacker Chemie. Annual PV installation was about 1.5 GW, limited by the supply of silicon.

New Energy Finance raises first of several rounds of external funding. We move offices to a former chocolate factory near Westbourne Park tube station and get an office kettle; great is the rejoicing.

2007: Spain passes law RD 661/2007 to support solar power, which does not seem important at the time but sets a very generous feed-in tariff and brings investors to the market. Spanish PV hits 85% of its target PV capacity (371 MW) by September 2007, triggering a 'grace period' of 12 months where all new projects will also be paid the feed-in tariff. Various other companies IPO. Module price still around $4/W, but global new installation hits 2.8 GW in this year.

2008: The end of September is the deadline for Spanish projects under RD 661/2007. In the summer, modules are not available for love or money; there are reports of cardboard modules being installed in September to fool casual inspection until real ones can be obtained. In October, module prices start to crash. Spain had installed more than 3,400 MW of its 2010 target of 400 MW and was paying the feed-in tariffs for all of it.

2009: Module prices fall from $4/W to $2/W. The Czech Republic, which implemented a feed-in tariff in 2008, takes off as a solar market and hits 428 MW of new build PV in the year. Germany grows unexpectedly to 3.8 GW of new build. India sets target of 20 GW of cumulative solar by 2022.

New Energy Finance is acquired by Bloomberg in December, on day two of the Copenhagen Climate Summit, which spectacularly failed to deliver on all its hype.

2010: UK implements feed-in tariffs. Germany goes wild and installs 7 GW. World installs 18 GW. India holds world's first major solar auction, awarding bids at an average price of $230/MWh. Spanish government decides not to pay the amount previously agreed for RD 661/2007 projects (a 'retroactive cut').

New Energy Finance integrates with Bloomberg.

2011: Module prices approach $1/W. Italy takes a turn at unexpectedly high build, with annual build nearly 7.8 GW (Italy's National Renewable Energy Action Plan called for a cumulative 5.6 GW by 2015). China begins to worry about solar demand and implements its own incentives. New global PV builds 28.5 GW.

2012: World installs 29.4 GW of PV in this year. Q-Cells goes bankrupt (later bought out by Hanwha Corp), as does Energy Conversion Devices (not bought out by anyone).

2013: World installs 41.6 GW — of which 14.0 GW are in China. Suntech goes bankrupt (later bought by another Chinese firm, Shunfeng).

2014: New Indian Prime Minister Narendra Modi sets new 2022 solar target of 100 GW cumulative (up from 20 GW set in 2009; eventually missed, with just under 80 GW built by the end of 2022). World build 45 GW.

2015: World installs 56 GW of PV. Solar auction in Dubai is won at $58.4/MWh, a record-low price.

2016: World installs about 75 GW of PV. China becomes the world's first country to have a 30 GW+ year for solar build. Solar auctions in Mexico, Dubai, Abu Dhabi, and Chile won at prices below $35/MWh. Some countries delay renewable energy auctions because they do not need further power.

2017: World installs 98 GW of PV, of which 53 GW is in China. Module prices below $0.35/W are normal. Spain, Austria, and Germany have taxes on rooftop owners self-consuming their own power.

2018: In the spring, China pulls back on solar support, causing a short-term return to oversupply and a collapse in prices. In the first half of the year, five US states (Massachusetts, California, Nevada, Hawaii, and Vermont) get more than 10% of their in-state generation from solar [Hankey *et al.*, 2018]. In September, California — which would be the world's fifth largest economy by gross domestic product, if it was a country — passed a bill targeting 100% zero-carbon electricity by 2045.

In 1 year, the standard crystalline silicon module on the market switches from multicrystalline with the wafers cut with a slurry-based wire saw to monocrystalline ("mono") with wafers cut with the diamond wire saw.

BNEF projects that photovoltaics will supply about 23.6% of global electricity by 2050, from about 1.8% in 2017. Very few people laugh at this forecast.

2019: 118 GW installed. First edition of this book published. Vietnam sets feed-in tariff that targets 850 MW of solar by the end of 2020 and results in 18.2 GW by that date.

2020: COVID-19 pandemic fails to slow solar build, which hits 146 GW in the year, but prices drop to the lowest level ever, $6.3/kg for polysilicon and $0.19/W for monocrystalline silicon modules. China surprises the world by announcing a target of peak carbon emissions by 2030 and net-zero greenhouse gas emissions by 2060. Japan and Korea target net zero by 2050. Global new energy storage installations (excluding pumped hydro) hit record 5.6 GW or 11.3 GWh, led by the US, China, and South Korea and nearly all lithium-ion batteries.

2021: More than 50 countries make net zero pledges at COP26.

Strong demand and supply chain disruptions push prices back up for modules, freight, and metals. 182 GW of PV installed. Global new energy storage installations (excluding pumped hydro) hit record 9.5 GW or 21.6 GWh. Battery backup for solar and wind plants wins several auctions where fossil fuels were also allowed to compete, including in South Africa.

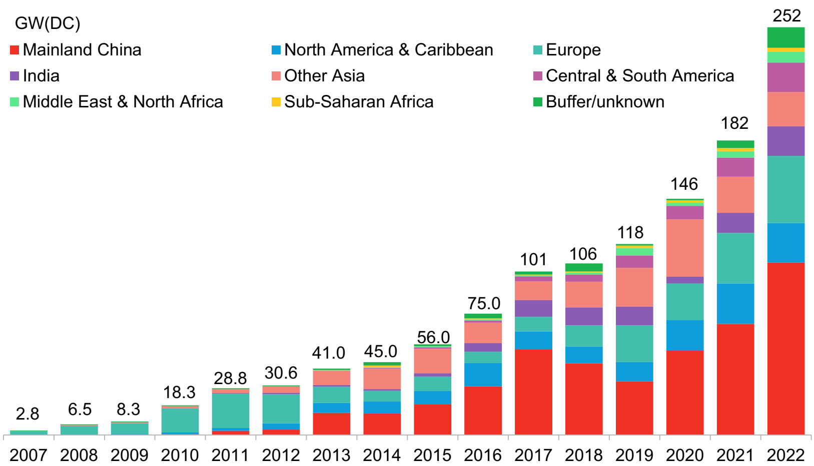

Figure 5.2 Annual PV build by year and region.

Source: BloombergNEF.

2022: Russia invades Ukraine in February, pushing spot power prices in Europe to new levels, often above 500 euros per MWh. This eventually gets passed on to consumers, triggering a boom in rooftop solar and new government plans even though the price of solar modules and batteries rises due to supply and logistics bottlenecks. Over 50% of new residential solar systems in Germany and Italy have batteries. US passes Inflation Reduction Act, which subsidises build of solar, wind, and batteries and also factories for all these, as well as clean hydrogen production. 252 GW of solar (Figure 5.2) and 16 GW/35 GWh of storage installed.

2023: Germany's surcharge on power bills, which funds its renewable energy feed-in tariffs, is reduced to zero because high gas prices mean that the renewables fleet is expected to save money this year. Cobalt, lithium, and polysilicon prices fall from their highs in 2021 and 2022. This book finished with global installation expected to exceed 390 GW of PV and strong storage growth.

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Chapter 6

2005–2008: The First Big Solar, Supply Constraints

I have chosen 2005 as the first year to write about mainly because it was the year I started working full-time in clean energy, but it is not unreasonable: new photovoltaic installations globally rose from 1,106 MW in 2004 to 1,488 MW in 2005, when the German 'feed-in tariff' introduced in 2004 started to kick in. This was a landmark piece of legislation that had both intended and unintended consequences and has been both emulated and cursed. It will be a brave government that passes an uncapped feed-in tariff for solar into law again, for reasons that will become clear. However, it was a major factor in driving the dramatic cost reductions in solar, and everyone now working in the solar industry owes the German electricity consumer a debt for paying those early high prices.

The phrase 'feed-in tariff' is a clumsy term, translated directly from the German word Einspeisevergütung (it doesn't sound better in German. Nothing does). It refers to a guaranteed payment for every kilowatt-hour of energy generated when it is 'fed in' to the grid for the first 20 (or sometimes 15 or 25) years of a plant's life. Germany's feed-in tariff was one of the first incentive schemes to reward actual generation, rather than making a single payment for setting up a solar installation. And, critically, there was no cap and very little paperwork; anyone building a solar plant would get the feed-in tariff, which was about three times the average power price to consumers at the time.

This feed-in tariff is paid to the project at the same rate for the next 20 years, regardless of what happens to the support level for future plants.

This is necessary because nearly all the investment in a solar plant is upfront, but it does commit the country to an ongoing liability. In Germany, this was funded through a surcharge on power bills, which reached a high of 6.76 euro cents per kWh in 2020, of the total of approximately 32 euro cents/kWh paid for electricity. The surcharge funded the difference between the market value of the electricity and the higher prices paid to plant owners. Whether you think this is a lot depends on your perspective — it certainly helped encourage energy efficiency in German households and was not notably widely unpopular with the German public.

German trade bodies advocated feed-in tariffs far and wide as the best solution to drive renewables deployment. They were widely criticized for this because not all economies are as able to absorb costs as well as Germany's is. However, for Germany itself, the feed-in tariff advocates had the last laugh. The energy crisis of 2022 increased power prices so much that, in October, the grid operator (Bundesnetzagentur) estimated that the value of the power sold by Germany's feed-in tariff power plants would total 13.1 billion euros in 2023 and payments to the plant operators 9.4 billion euros. In short, the renewables fleet saved the country money in the crisis. The surcharge was eliminated in January 2023, and any future costs (which could easily appear if power prices fall again) will be taken over by the government.

A fair criticism is that many feed-in tariffs were initially overgenerous. Setting the level of an incentive is never easy for governments. The traditional method is to go and talk to the local industry and ask them how much money they would need to do something. Astonishingly, the answer usually turns out to be 'a lot'. This is partly due to a genuine lack of understanding of how efficient they could be if the volumes they were building were 10, 20, and 100 times larger; I have sat in many meetings down the years with solar executives telling me that the costs achieved in Germany, Spain, and the UK are completely impossible in Italy, Australia, Japan, and the US. (Italy and Australia are now at similar cost levels to Germany.) However, part of the cost overestimate is obviously pure self-interest.

In solar, this tendency for local industry to exaggerate costs used to set tariffs is exacerbated by genuine sharp reductions in cost, driven by the falling prices of solar modules and the rapid cost reductions possible when a local installation industry doing 10–20 houses/year goes to 1,000. Germany's feed-in tariff, implemented in 2004, was a raging success in that the market climbed steeply.

This feed-in tariff, available to anyone with a plot of land or roof, stimulated an unprecedented response from the financial markets. There had been one or two solar companies listed on stock markets before, but now investors were hungry for opportunities, and the companies were hungry for money to invest in setting up new projects and factories. Venture capital investors which had patiently waited many years found themselves able to sell their companies at a profit. (Meanwhile, I was groping my way through the unfamiliar terminology, with Michael Liebreich bellowing at me to understand why initial public offerings (IPOs) were important. It was obvious to him that these deals showed that he had picked the right time to found a company providing financial information about clean energy because suddenly there was major interest from investors in paying to receive this information.)

For example, German solar company Conergy filed for IPO on the Frankfurt stock exchange in February 2005, selling 243 million euros worth of shares to investors eager to participate in or increase their stake in the boom. Conergy received 104 million euros of new capital after considering shares sold by venture capital investors, and reinvested this money in developing more land and more business. It generally did not own the projects itself, instead selling them to long-term investors eager to own assets with low risk (the sun is pretty reliable over a year) and reasonable reward. The investors in Conergy itself were taking a higher risk, putting their money into a company which would spend it on hiring and training staff, setting up offices, filing land use permits, and other activities which might or might not bring a profit. Conergy's investors expected higher returns in exchange for the risk than the investors in solar projects themselves. The company made many investments in small solar water heating installation and distribution companies, and energy efficiency firms, built a German factory in 2006, and eventually overreached itself and went bankrupt in July 2013. This happens to solar companies a lot.

The price of solar modules had fallen continuously since 1975 when the first modules became commercially available. At that time, they cost about \$107/W in 2022 dollars (i.e. adjusting for inflation — they actually cost \$25 in 1975, but a dollar bought a lot more back then). In 2004, the price of modules was about \$3.23/W and continued to fall — until Germany started buying. The price stabilised in 2004 and rose slightly to \$3.88 in 2008 (nominal or about \$5.90/W in 2022 dollars).

The reason for the increase in price was a huge change in supply and demand. Germany was sucking up the modules on the market with an almost insatiable appetite, and Spain introduced a similar incentive in 2007 (RD 661/2007). Companies like Suntech, SolarWorld, Trina, and Yingli responded by building new factories to make solar modules (and the cells and wafers that are part of the process). They quickly found themselves competing for the raw material, silicon (normally called polycrystalline silicon or polysilicon, which is just the purified silicon in chunks or rods ready to be melted and crystallised as required).

6.1 What Price Is Polysilicon?

In 2006, my colleague Lia Choi and I had a problem. Our clients were asking the price of the raw material polysilicon, and Michael said we had to give them an answer.

We didn't have a clue. We searched the Internet for 'price of polysilicon'. We called up the press departments of polysilicon manufacturers, who told us it was a commercial secret. We combed through the financial reports of silicon manufacturers. We were stuck. Michael was insistent. For every serious commodity, he said, someone gathered the data and you could just look up the price; silicon was going to be a serious commodity, and he wanted us to be the authority on its price. He wouldn't take no for an answer.

Silicon is the fourth most common element in the earth's crust, and silicon dioxide is simply sand. The polysilicon shortage had nothing to do with silicon itself being rare. The problem is that it is difficult to purify to the level required by solar and semiconductors.

The first step is relatively easy; you take a high-purity quartz sand and heat it up with a clean type of charcoal or coke. The carbon steals the oxygen from the silicon (i.e. reduces the silicon, in chemistry terminology) and the result is about 98% pure silicon, with impurities of carbon, boron, phosphorus, and other materials. Boron and phosphorus are particularly problematic as they are used later to 'dope' — change the electrical properties of — the wafer. This 98% pure silicon is known as 'metallurgical grade silicon'.

The next step is to heat the metallurgical grade silicon with acid and turn it into a gas called silane. (This is a simplification — there are several types of silane.) The gas is then put into a hot reactor vessel, with some cooler 'seeds' of silicon crystal, and condenses to form pure rods of silicon, which are broken into chunks for processing into wafers (Figure 6.1). The whole process is called the Siemens process and is still the main way to make silicon (another process called 'fluidised bed reactor', where the

Figure 6.1 Chunks of raw polysilicon and the finished solar cells.

Source: Shutterstock.

silicon seeds are dropped through the gas in the reactor vessel and extracted continually from the bottom, is otherwise very similar). It is inevitably energy-intensive as different parts of the reactor vessel are being heated and cooled at the same time.

This sounds much simpler than it is. In 2004, there were only six companies (Wacker, Hemlock, REC Silicon, MEMC Electronic Materials, Tokuyama, and Mitsubishi Materials) making significant volumes, and they all had teams of engineers who had been working on the problem for decades and knew how to sweet-talk a Siemens reactor into producing good quality silicon. However, a polysilicon factory is expensive to set up — around a billion dollars for a 10,000 tonne/year plant in those days, though it has come down to about \$120 million in China in 2023. The long-term average price of polysilicon up to 2004 was around \$25/kg, nowhere near enough to justify a large investment in a new factory. The semiconductor companies bought polysilicon under long-term contracts and had not asked for an increase in production, while the solar manufacturers took the scrap and offcuts and represented less than 10% of world demand for silicon. As solar demand soared, this waste material was no longer sufficient, and the price — in small, private negotiations — went wild.

So, back in 2006, nobody would tell us the price of polysilicon. Nobody wanted to get into trouble with their boss for either disclosing trade secrets or giving a number that might weaken the company's negotiating position with its clients or suppliers. The most talkative people were the small traders, who mostly don't have bosses, but they also had an incentive to lie because if we published a high number, the market might pay more for their inventory. A minor breakthrough was when the press officer at one of the big producers, Wacker Chemie, took pity on me and explained (I don't think it was a secret, but it was not an angle I had thought of) that the revenue they reported for a chemicals division was 'nearly all for polysilicon this year because it was a very warm winter and hardly any salt was used on the road'. Since Wacker Chemie had also disclosed a production figure for the chemicals division which only sold polysilicon and road salt, we had at last an approximate average price for one company (about \$80/kg) and a basis for some kind of comparison.

Encouraged, we went back to anyone who would talk to us with this number and asked them if it sounded about right to them. People are a lot more talkative if you have a starting point; it is human nature to correct bad information more readily than to provide new information. Lia also determinedly turned her considerable charm on Japanese, Korean, and German polysilicon people at numerous conferences, eventually convincing them we were serious (or at least persistent) and deserved answers. From this, we developed a system of asking buyers and sellers for the prices they were currently seeing on the spot market and anonymising the results into a very official-sounding Silicon Price Index. This was surprisingly helpful to the companies, particularly the buyers, as they at least had a starting point in their negotiations with sellers. Sometimes you can look really clever just by asking people the same question at regular intervals, writing down the answers, and averaging them. Michael was right.

From 2005, the solar manufacturers wanted more than the scrap silicon on the market — they needed real volumes, which meant new factories. Solar companies started asking about long-term contracts at lower prices. Polysilicon manufacturers are by nature cautious and risk-averse (desirable characteristics for handling toxic chemicals). They had lost a lot of money in the past building factories for expected demand that did not materialise, leaving expensive equipment sitting idle. They were therefore slow to respond to new demand from the slightly flaky-seeming solar sector and insisted on large down payments and 10-year contracts to buy the polysilicon at fixed prices from solar companies.

From 2005 to 2008, solar manufacturers went to the stock markets, seeking investment to make down payments (deposits) on long-term polysilicon contracts so that polysilicon manufacturers would build factories. Spain introduced solar subsidies too, and the solar modules were flying off the shelves as fast as they could be manufactured. These down payments could be around 30% of the entire lifetime value of the polysilicon contract — an enormous financial commitment, but if the companies making solar products did not sign up, they risked being unable to manufacture anything without raw material. The stock price of a polysilicon *buyer* rose when it signed a 10-year contract, terms shrouded in secrecy, on ‘take or pay’ terms, i.e. even if they did not need the polysilicon in future, they had to pay for it.

The spot price of polysilicon rose to over $400/kg in 2008. Understandably, dozens of companies which had never before made polysilicon decided that this was an exciting opportunity. Firms like GT Advanced Materials sold 'turnkey manufacturing plants' ('turnkey' means that in theory the buyer gets them ready to use, they just need to turn the key to get started. Spellcheck often helpfully changes this to 'turkey' which may cause confusion) to the wannabe polysilicon manufacturers. These included chemical producers and mining companies, logically enough, but also telecoms, textile, and animal food production companies.

It turned out to be much tougher than expected, and nearly all these new manufacturers missed their first expected production date and their second. Some of them poached polysilicon engineers from the Big Six, although polysilicon engineers are also cautious and tend not to jump from a well-built ship to one under construction, and certain US manufacturers reportedly threatened engineers with lawsuits should they depart to work for a rival. These firms also took down payments from customers to build their plants.

Between 2007 and 2010, we developed a 'Silicon Forward Price Index' to complement the Spot Price Index, for which we collected strictly confidential information on the pricing for future sales under the contracts. This was finally possible because we had gained a reputation for being respectable silicon price analysts, and companies wanted an idea of the average price including prices from their competitors as well. The contracts were being signed at prices of $60–90/kg, sometimes at this level for 10 years in the future (remember, the price of polysilicon before the solar boom was $25/kg). The polysilicon manufacturers had the solar wafer, cell, and module makers over a barrel, and investors were willing to make the massive down payments. Our Index may have stopped a few contracts from being signed at even higher prices as greedy polysilicon manufacturers claimed that the current $400/kg was the new normal.

Most of the companies attempting to get into polysilicon production were in China, but at least two — French SilPro and US-based Hoku Scientific — were high-profile Western companies which burned through hundreds of millions of dollars of investor money. Ultimately, the vast majority (including SilPro and Hoku) failed, shut down, and filed for bankruptcy without manufacturing any polysilicon. The down payments made by their customers were spent, and there was no way to recover the money. Making polysilicon may be quite easy in theory, but in practice, it requires several different types of chemical expertise. It has taken some years for new entrants (including Chinese companies GCL-Poly, DAQO, TBEA, and fish food maker Tongwei) to get good at it. By 2018, the polysilicon price squeeze was over and at least a dozen companies had become good at manufacturing the stuff to solar standards, though price still fluctuates with supply and demand. The lowest price ever was $6.3/kg in the summer of 2020, and a lesser polysilicon squeeze, with prices up to $38/kg on spot markets, ran from 2021 to 2022 as solar demand grew very rapidly again. We can probably expect polysilicon prices to stay in this range for the foreseeable future.

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Chapter 7

The Magic of the Experience Curve

One of the problems with economics and finance as sciences is that they tend to find a relationship in the past and assume it will continue into the future. This works well until it doesn't. Unlike with physics, there tend to be more variables than actual data, and experiments (for example, policy changes in the real world) generally change all the variables at once in a very unscientific way. It's very difficult to tell what will happen until it does, after which it is so obvious that any idiot should have predicted it.

One example of this is with the photovoltaic module experience curve. This is sometimes called the Swanson Effect after Dr Richard Swanson of SunPower. Although Dr Swanson has contributed greatly to the research driving the experience curve, he is the first to say that he did not invent it. If anything, it should be called the Maycock Effect after Paul Maycock, a market researcher who collected the most comprehensive set of solar module pricing data from 1975 to 2003, and whose data forms the basis of most attempts to construct this curve, including ours.

Experience curves are found in many industries and are an empirical relationship between the amount of experience the human species has at doing something and how cheaply we can do it. (An empirical relationship is one which appears to hold in practice but cannot be mathematically proven.) In the production of many commodities, the cost per unit decreases by a fixed amount (the 'learning rate') for every doubling of cumulative experience. This produces a curve declining exponentially to an asymptote, or a straight line in a log–log chart (see Figure 7.1).

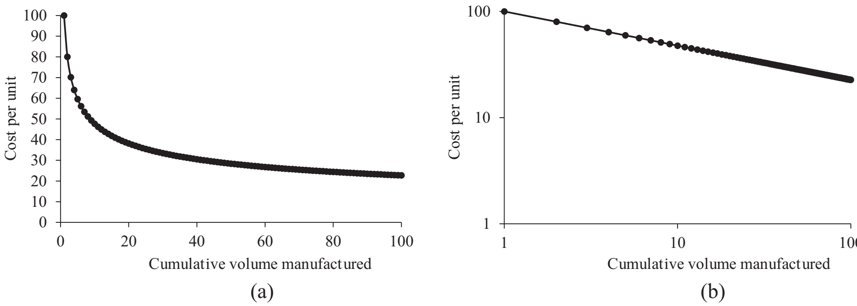

Figure 7.1 A generic experience curve. (a) Linear scale. (b) Logarithmic scale (base 10).

The shape makes intuitive sense — when something is very new, it is easy to find ways to make it better or more cheaply, while even a small improvement in a well-established manufacturing process is difficult to achieve because all the easy tweaks have been done already. It is interlinked with economies of scale and does not take into account raw material prices and other factors. For example, drilling oil wells in the sea probably follows an experience curve, but over time, the near-shore oilfields have been explored and exhausted, so future wells will need to be further offshore in deeper water and may therefore be more expensive. This is a factor in offshore wind farm costs for the same reason — some offshore wind farms are just onshore wind farms in a puddle and some are in the deep sea. It is easier to build them in a puddle.

The classic exponential curve shape usually means that cost reductions get slower over time, because it normally takes longer and longer to double cumulative manufactured capacity. It isn't a perfect relationship, but it's not a bad way of describing the behaviour of prices for manufactured commodities. Moore's law, which is a special case of this, describes the pricing per unit of computing power with underlying assumptions about deployment growth rates. Formulated in 1965, Moore's law states that the number of components (transistors) of an integrated circuit doubles about every 2 years. Part of the reason that this law held for a long time is that the computing industry uses it as a target, but it is also just a function of increasing scale with a high growth rate and the experience curve. As of 2022, chip densities are no longer doubling every 2 years, probably because the deployment growth rate has slowed down and the

2-year period was never the fundamental driver of the experience curve described as Moore's law.

Photovoltaic module manufacturing is a clear example of an experience curve, and since 1975, modules have become 24–29% (depending on exactly where you think the line of best fit falls — as of 2023, we incline towards 28.4%) cheaper on a per-W basis for every doubling of cumulative capacity.

This has not been a simple, linear progress when viewed from the inside. Professor Martin Green of the University of New South Wales, a founding director of the Australian Centre for Advanced Photovoltaics, remembers a famous 1973 working group in Cherry Hill, New Jersey, which established guidelines and targets for US government-funded solar research. "They were thinking of the mid-1980s as a target date for solar panels at 50 cents a Watt [about $1.25 per W in 2022 dollars]," he says.

This Cherry Hill target was wildly missed, as Figure 7.2 shows. The price of solar panels in 1985 was $6.50/W or about $16.50/W in 2022 dollars. However, Green says, the research resulting from the 1973

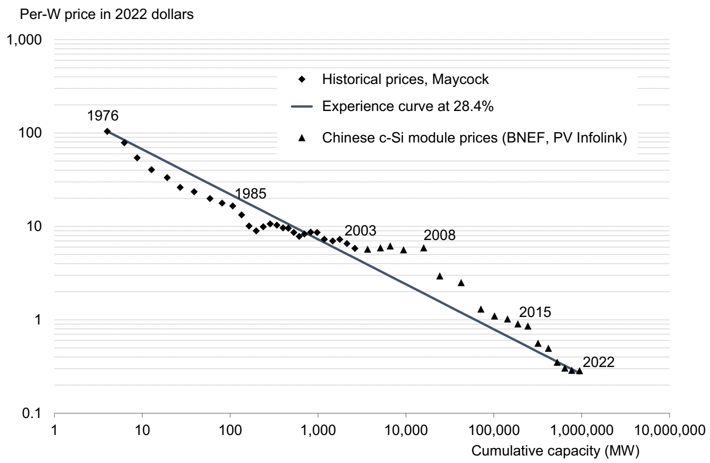

Figure 7.2 The BloombergNEF crystalline silicon photovoltaic module experience curve, early 2023.

Source: Maycock, PV Infolink, BloombergNEF.

working group established a lot of the fundamentals of solar technology today, such as screen printing of solar cells and lamination of solar cells under glass (silicone rubber was previously used as an encapsulant until the 1980s, but it was not fully hail-resistant and Australian parakeets liked to eat it). "The commercial industry was not vibrant during the 1980s," he points out. "A lot of the firms were oil companies doing greenwashing, and just trying not to lose too much money from solar. They weren't looking for new technology in the same way they are today. For example, we developed a buried-contact cell [which offered better efficiency] but one of the firms did not want to adopt it because they'd have to update all their data sheets [the official product description] if they increased their cell efficiency".

The experience curve is driven by improvements in efficiency, better conductive pastes, bigger individual cells, less silicon wastage in slicing, thinner silicon wafers, better structural design of cells, and optimisation of anti-reflective coatings and encapsulants. It continues the relentless grind to lower costs to this day (more details in Chapter 19).

There are a couple of common fallacies in the experience curve analysis. One is that the learning rate can change over time. If it does this, then it's not an experience curve (and most likely you are looking at temporary fluctuations in the demand or supply situation, or a move to a completely different technology). The other is to apply them to things that are not manufactured commodities. Experience curves generally work only for manufactured commodities, so it is difficult if not impossible to calculate them from local data, including non-manufacturing cost factors like installation. In practice, what level to disaggregate the experience curve to is a matter of considerable discussion; in solar modules, a tweak that increases cost at the wafer level may ultimately decrease cost at the module level, so trying to separate wafer and module experience curves would not be helpful. My feeling is that only the module experience curve and perhaps the inverter experience curve make sense as a calculation in solar. Batteries, however, have their own experience curves, as do wind turbines. The latter is complicated by the fact that wind turbines get bigger over time and produce more MWh per MW, because it's windier up high. So the wind turbine learning rate is better calculated on MWh, while with solar modules, it makes sense to calculate on MW. Solar modules are, to the first approximation, not generating more electricity per W over time because generation largely depends on how sunny it is where they are installed. The exception to this is bifacial technology, which means solar modules produce 6–9% more energy per W by capturing reflected light from the backside. This was essentially a one-off gain for new utility-scale solar plants from about 2020.

The ~20% learning rate for solar modules was well established in academic literature from 1975 to 2003 [De La Tour *et al.*, 2013], although academic literature went rather silent in 2004 as the price rose slightly and then stayed flat. A few commentators called it the death of the experience curve and suggested that the cost of solar panels had hit a fundamental lower limit.

Essentially, they were confusing the price and cost of solar panels. Prices had declined broadly in line with costs until 2004 when demand suddenly surged because of generous German feed-in tariffs. This demand overwhelmed the supply, which was limited by the amount of available polysilicon. Pricing stayed approximately flat from 2004 through to 2008, despite several doublings of cumulative global capacity.

In essence, the market was pricing solar panels at exactly the level required to absorb the feed-in tariff, rather than following costs down. (This is called value-based pricing and is a useful concept, especially if you want to sell something). Costs, meanwhile were not following the experience curve because — as we knew from our Silicon Price Index — the price of silicon had increased by a factor of 10. But there was no reason to think that it would stay that high once more silicon became available.

In May 2007, sitting in the back row of the Renewable Energy Finance Forum, the major conference for clean energy investors in New York at the time, Michael Liebreich sketched out what he thought was going to happen next. As soon as silicon supply could match demand, the price of solar cells and panels would collapse back to where the cost experience curve said it should be at that point. There would be a bloodbath among producers and a bonanza for installers. Later in the event, he presented this on stage based on illustrative figures he had made up and was greeted with a wall of scepticism. At the time, most investors and companies were making 10-year business plans around projected prices of $3–4/W, with prices gently sloping down from where they had been stuck between 2004 and 2008. Michael was convinced they were in for a shock.

As soon as he was off the stage, he emailed to tell me what he had done. We urgently needed our own experience curve to give Michael's illustrative numbers some credibility. My colleague Lia Choi and I ran the numbers and produced a short report predicting a 40% fall in module prices when polysilicon demand and supply came back into balance. As the author, I have to admit that it wasn't a very good report compared with our later efforts, using a poor proxy for module cost, too short a history, and a rather arbitrary means of predicting when the shortage of polysilicon would end (early 2009). Nevertheless, it was basically correct in stating that when undersupply ended, the price of solar modules would fall not 10% or 20% but a lot (it wasn't wrong about the timing, either).

In hindsight, it is amazing how many people missed the fact that the pricing was unsustainable — according to our Silicon Price Index, the spot price of polysilicon was over $400/kg, which meant that some Chinese and Taiwanese companies were paying that rate and still making a slim profit on modules selling around $4.20/W. But a solar module in 2007 required roughly 8 g of polysilicon per W, which costs about $3.20 at this price (as of 2023, average polysilicon use is down to about 2.7 g a W — the experience curve is a wonderful thing). The Chinese and Taiwanese firms were clearly able to do all the manufacturing from wafers to modules for less than $1/W. Meanwhile, more established companies in Europe and the US (Evergreen Solar, Q-Cells, and Schott) had locked in contracts around the $100/kg mark (about 80 US cents per W) and were still not making a great profit selling at $4.20/W. It should have been clear that if the Chinese and Taiwanese manufacturers got hold of cheaper polysilicon, they would be the winners of any pricing war, and the prices would be much lower than anyone else was predicting. This was also inevitable — even if more polysilicon did not become available on the spot market, giant Chinese firms like Suntech, Yingli Solar, and Trina Solar were playing the game of raising money on the public markets to lock in long-term contracts.

Solar companies had been planning for a future of limitless expansion and mild decreases in price, limited only by their technical ability to deliver. We knew they were in for a shock, and so it proved, for the experience curve had continued to work in the background even as the polysilicon shortage prevented prices from falling.

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Chapter 8

September 29, 2008: When the Solar Boom Went Bust

In 2007, the Spanish government made an amendment to a law, subsidising big solar projects in Spain for the first time. This was probably one of the most regretted pieces of legislation ever passed in solar. The Spanish government appears to have copied the German law and asked solar companies what level of incentive they would like. Spain is also significantly more sunny than Germany; a PV project built near Madrid would generate about 40% more electricity than an identical one built near Munich.

As in Germany, the government put no restrictions on how many plants could get the tariffs — except that once a certain level of installation was reached, there would be a 1-year 'grace period' during which projects could be finished and still receive the tariff. This was based on the assumption that solar projects would take 6–8 months to build, allowing a few months for projects which were already in the planning process when the grace period started. In photovoltaics, the level to trigger the grace period was 371 MW and was expected to be hit sometime in 2010.

Belén Gallego, an entrepreneur who was running solar technology and development conferences in Spain at the time, says "Everyone knew that it was not a wise decision by the government to not limit the amount of MW, we knew it was going to get very large very quickly. There was a gold rush mentality, but we did not know how bad it was going to get."

Another feature of the Spanish law was that it paid a much higher tariff to projects smaller than 100 kW than to projects over 100 kW — but did not specify how a project under 100 kW was defined. Spot the loophole?

Developers filed applications for tens or hundreds of 100 kW sites right next door to one another, meaning that they could get all the economies of scale of building a big project without losing the higher rate tariff. The tariff was therefore much more generous than originally anticipated and very popular. By September 2007, the capacity cap set in May 2007 for photovoltaics had been exceeded and the 1-year 'grace period' had begun.

It turns out that you don't need 6–8 months to build a 100 kW photovoltaic plant. Six to eight weeks is more accurate, if you have the paperwork in place. The main constraint on the Spanish solar market between September 2007 and September 2008 was the availability of solar modules, which was still limited by the shortage of polysilicon. It was not just a game for large companies, either, and in fact small family firms often proved more nimble at securing permits, negotiating engineering contracts and securing short-term finance to build.

The deadline for the end of the grace period was September 28, 2008, and as it approached, a frantic hurry swept the Spanish market. Modules were difficult to source at any price, and there are stories of project buyers putting up fake cardboard modules in order to pretend to casual observers that the deadline had been met, planning to replace them with real modules after the deadline. There was no way the government could manage a thorough inspection in a timely manner, and 350 projects lost their subsidies in 2010 when inspection finally caught up with them and established that they could not have had the generating equipment in place as claimed (there are unsubstantiated reports of diesel generators being used to power unfinished solar plants, with the owners seeing no reason to turn them off at night). "People were working weekends to get the plants built," says Belén Gallego. "But I think most of the rush was in the planning and negotiating stages in the few months before the deadline. I remember a lot of haste and nervousness, new companies formed every day offering solar services as it wasn't difficult for them to get work. One thing that wasn't obvious to people was that the regional governments and local politicians of Spain were competing to push technology in their regions, trying to attract business and jobs to their part of Spain. There was a lot of optimism from governments even though a lot of people knew it was unsustainable." The support of local governments helped developers and accelerated the growth of the market.

In total, about 3,400 MW of photovoltaic projects were built in Spain in 2007 and 2008 — compared with the 436 MW target by 2010. This sounds great if you are a solar advocate, but it left the bill with the Spanish electricity generation sector, which was already regulated into unprofitability and kept afloat by direct government handouts. This was a known problem, and the government was intending to reform the regulation as soon as they'd figured out how, but the solar boom made it much more acute.

The other effect was that as the sun rose on September 29, 2008, global demand for solar modules was significantly lower than it had been the previous week. Manufacturing industry leader Q-Cells issued a profit warning, "due to short notice unexpected developments … the uncertainty and the weakening market demand arising from the financial crisis have resulted in a number of Q-Cells' customers postponing agreed deliveries until next year. These volumes could not be placed elsewhere at short notice," which is a little surprising, since the end of the Spanish boom was hardly short notice. Q-Cells' Chinese competitors Suntech and JA Solar cut their guidance (the forecasts they had shared with the stock market) for sales in the fourth quarter. Prices immediately started to plummet from $4.20/W in Q3 2008 to the surprise of many analysts, who had expected that Germany would absorb the extra modules and that the fall of the Spanish market would cause only a 10% or so drop in module price. I'm proud to look back at a report we published at the end of 2008 [Bullard *et al.*, 2008] and see that we predicted $2.40/W ("perhaps lower") as a module price for 2009, based on an estimate of margins being made across the value chain. Actual module prices fell to $2/W in the year.

In one way, though, the other analysts had a point — Germany's solar market did have a bumper time in late 2008, installing 1.9 GW and cushioning the fall a little. German solar projects got a lot more profitable with the newly cheap modules. However, the situation was about to get a lot tougher for the manufacturers and for some of the investors.

To cut a long story short, the Spanish solar companies which had built projects in such a hurry did not get to keep all of their gains. On December 23, 2010, the Spanish government introduced a new decree which essentially said it would pay the agreed subsidies only for part of each solar plant's output. At a stroke, this decree cut revenues from the plants by between 7% and 30%, and further changes have been imposed over the years since. Some developers had done well out of the market by selling projects to other investors at a high price before this happened.

Spanish banks, especially small ones, were affected by the retroactive cuts because they had lent money to projects now unable to pay it back. Some owners defaulted on the payments, meaning that the bank now owns the projects — something the banks did not really want to do as they had no real interest in running portfolios of small projects. In some cases, they had even lost track of the projects. Belén Gallego says, "The small banks were bundled up in larger banks during the financial crisis. You cannot imagine the amount of stranded assets that resulted. When I was working as a technical advisor [in 2016–2017] we would get one of the big banks coming to us and saying 'we have located 50 more projects that we have in our assets, from 20 different local banks we acquired, and we don't know where they are.' Literally 8 years later this bank was trying to figure out what they have on their books. We found ourselves doing all the work to figure out who owned these plants, if they were abandoned, who was doing the maintenance."

Unfortunately, 'retroactive tariff changes' (cuts to incentives agreed for existing projects) became a trend across Europe from 2009 to 2014, with Bulgaria, the Czech Republic, and Romania backpedalling on their promised generosity. Although many investors lost money, this had surprisingly little medium-term effect on the solar industry as a whole outside Southern and Eastern Europe.

The moral of the whole sad story is that if something seems too good to be true, it probably is, especially when it is a badly designed solar subsidy. However, by 2018, Spain had reformed its electricity sector and started to reduce the deficit, and project developers started to trust the market again. As of 2023, the Spanish solar market is booming again, this time without significant subsidy.

Chapter 9

How Markets Set Power Prices

In the energy sector, even the most ardent proponents of the free market admit the need for some regulation. The decisions made — what sort of power plants to build, whether to add gas pipelines, and whether to invest in the power grid — will affect the country for the next 30–50 years, and conditions may change significantly. Building a fleet of gas plants at a time when gas is cheap leaves a country vulnerable to higher gas prices or disruption in supply in future. Building a coal plant today risks suffering from higher coal prices and carbon taxes in future. Solar and wind plants will not have higher input costs in future, but new plants will be cheaper than the old ones and may ‘eat their lunch’ (literally in the case of solar, which generates most at midday) without paying for dinner. This chapter aims to explain what that means.

Electricity provision is a natural monopoly, i.e. the bigger a firm is and the more power plants it operates, the cheaper it can sell power to consumers, so a large firm is likely to gain market share. In theory, a completely unregulated utility could drive all other utilities out of business and then charge as much as it likes for power, which would not be in the long-term interests of a population.

Consequently, most governments set up an energy regulator, a public body meant to stop utilities from behaving badly. Its job is to approve or reject utility plans to build new power plants, merge, change power prices, or make other significant business decisions. For example, a utility might ask to increase power prices to cover the cost of additional grid maintenance, or to build a new power plant, or just because it wasn't recovering its costs, and the regulator decides if this is reasonable. The UK regulator is Ofgem, but nearly all countries and most US grid regions have their own.

Generally, energy regulators encourage a diversified mixture of cheap power sources so that the country is not solely dependent on one source of energy. The regulator is quite conservative about new sources, as unlike companies they do not make any profit from being right to approve changes and will be blamed for anything that goes wrong. They are also responsible for making sure that utilities can cover their costs and make a reasonable profit from the revenue they get by selling power to consumers, that any subsidies get paid, and that the lights stay on. In Germany, the UK, and most other countries, renewable energy subsidies are paid initially by the utilities, which are allowed to collect the money back from power prices. Consumers might complain about the portion of renewable energy on the bill, but at least it was transparent and there is a system for paying.

Regulators are often involved in setting the level of subsidies, which depends on the cost of generating power from other sources and the cost of generating power from renewables.

In addition to the parts of the power system controlled directly by regulators, many countries have a 'spot power market' where companies buy and sell power in small amounts every hour, or even every 15 minutes in more sophisticated markets, 1 day or 1 hour before delivery. Although most power is sold under long-term contracts, the spot market helps match short-term supply and demand. The price is set by the 'short-run marginal cost of generation' (SRMC — also known as variable cost of production), an important concept which merits further explanation.

Let's start by looking at a system with no renewables. Figure 9.1 represents the power plants in operation in a rather simple 4.25 GW grid, ordered from the lowest SRMC to the highest. Nuclear is the lowest in SRMC because once you have built an expensive nuclear plant, the additional cost of generating a MWh from it in this period is very low — in fact, problems will arise for the operator if it needs to be abruptly switched off. For this reason, the nuclear plant operator bids the lowest price, enough to cover fuel and maintenance. (The debate on how much nuclear energy costs is considerably more complicated than this because the full

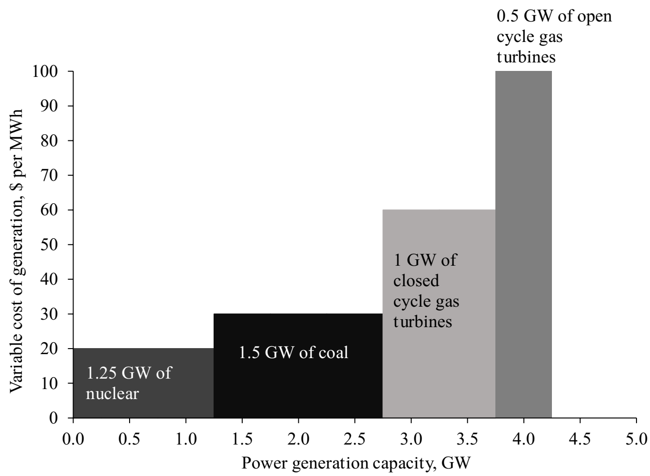

Figure 9.1 A hypothetical dispatch curve for one period on a power market. If demand is between 1.75 and 2.75 GW, the spot price of power is set by coal and so will be \$30/MWh. If demand rises to 2.75 GW but remains below 3.75 GW, the price will rise to \$60/MWh.

cost of nuclear includes the cost to build the power plant and a return for investors, which is the majority of the cost. This is returned to in Chapter 14). In this scenario, if demand for power is less than 1.25 GW, the price will be \$20/MWh — incredibly cheap. This is what happens in the middle of the night in France, which gets nearly 70% of its electricity from nuclear. French utilities pass on this cheap nighttime power to consumers, and many use electricity to heat their hot water tanks, effectively storing the energy for daytime use.

If the market in Figure 9.1 needs more than 1.25 GW of power, the nuclear plant is not sufficient and the buyers need to pay for coal. Coal plants are also cheap to run but do require fuel and maintenance. They are also quite hard to turn off and on again quickly, though easier than nuclear plants.

If the demand for power is more than 2.75 GW, the closed cycle gas turbines (CCGTs — the normal, high-efficiency type of gas plant) will need to be switched on, and the power price will rise sharply. Most of the time, in most developed countries, the power demand will sit in this region, making CCGTs the marginal source of power. They are also more flexible than either coal or nuclear, which means that they can be turned on or off again with relative ease (though are often kept moving as 'spinning reserve' through hours of disuse so they can be brought back online quickly). It's probable that our fictional grid usually has power demand between 2.75 and 3.75 GW, allowing it to use gas turbines to some extent but not all the time, and average power prices around $60/MWh.

If power demand exceeds 3.75 GW, the closed-cycle gas turbines will not be enough. This is when 'open cycle gas turbines' (OCGTs), which are inefficient power plants that are cheap to build and quick to shut on and off, switch on. These are for semi-emergency power and would not be expected to run many hours per year. A truly desperate grid, or one in an oil-rich country, might also use diesel generators as a last resort.

Hydroelectric power would fall somewhere in the middle of this; most hydro plants can be ramped up and down quickly, while some waste the power and some store it behind a dam when the plant is not required to be generating.

In theory, the prices on the spot market should be able to go from zero to very high indeed. If power demand is high enough, open-cycle gas turbines or even diesel generators become the most economic way to generate the last MW during a certain period, or the utility could simply allow some blackouts. Another option is for the utility or regulator to literally phone around industrial energy users and offer them money to turn off their factories during periods of power supply crunch, as was a regular occurrence in Texas even before that state's renewables boom. It can also be mandated; in the summer of 2022, the government of China's Sichuan province required local industry to shut down for several weeks during an acute heatwave in a time of low hydroelectric generation due to drought.

Sometimes power markets and infrastructure fail, and the lights go out, typically as semi-planned 'rolling blackouts' where parts of the country take turns to lose power. This is better than one part losing power for longer periods, but it is a crisis option. Most governments do not want utilities to decide that the lowest cost option is to cut customers off if it isn't economic to serve them. Governments also prefer that customers are not handed an unexpectedly huge bill because for 2 hours in December, power demand was so high that utilities had to fire up their most inefficient diesel generator and pay an aluminium factory millions

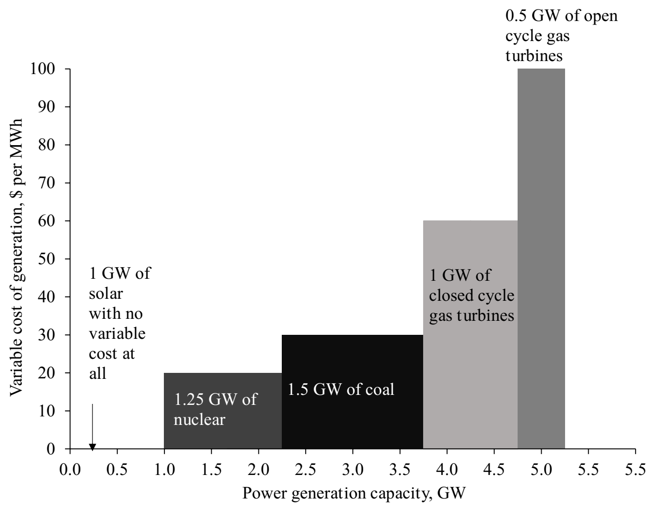

Figure 9.2 The same hypothetical power market as in Figure 9.1, with 1 GW of solar added and running.

of dollars to shut down. This is historically not a big problem in Western economies, which have enough gas plants to cover power demand.

A new situation occurs when you introduce a large amount of wind or solar power into the system. Wind and solar power have no marginal cost. Figure 9.2 shows what happens when 1 GW of solar is generated.

Solar plants are not going to shut down just because the price of power is low. Most can easily change their inverter settings to stop generating, but why would they do that while the price of power is positive? It doesn't cost them anything to operate.

This means that while the sun shines, unless power demand is over 3.75 GW, the gas plants are not going to be turned on. If it is very sunny when demand is low, the price of power can even drop to zero, or if the grid is legally required to take the power, negative. Negative market pricing of power has happened in Denmark, California, Spain, South Australia, Germany, and doubtless other markets, partly because some generators get paid anyway and partly because fossil generators often stay online to be ready for the evening. As soon as the sun drops, the gas plants need to be fired up. One extra driver of negative power pricing in California is that the gas plants have to keep running at low levels all day to be ready for the ramp-down in solar output. This is declining as California adds batteries to ease the daily transition from sun to night.

Intrinsically, not running fossil fuel plants (even for just a few hours) is the point of this whole 'building renewable energy' thing. The problem is a bit subtle; most gas plants are built with the expectation that they can operate for a certain number of hours per year and collect certain power prices for their output, every year for at least 25 years. When renewables are added to the mix through subsidies, these expectations are disappointing, and since gas plants incur startup and maintenance costs, the owner may want to shut them down and certainly not build new ones. This may cause problems for the few hours per year when wind and solar are not available.

The Texas way to handle this is to let power prices spike in those hours, to encourage generators to supply energy or major power users to cut demand. Power prices in the region of Ercot (the Electric Reliability Council of Texas, used as a word for the power grid interconnection region) sometimes rise to over $5,000 per MWh and are not capped.

Texas is a success story for renewables, with solar generating 6% and wind 25% of in-state power production in 2022, partly because it is relatively easy by US standards to get grid connection and land permits for solar and wind plants. Even in 2021, 9.6% of solar was curtailed (dumped) in Ercot, in spring, fall, and winter [Bolinger, 2022], presumably because the local grid was insufficient to move generation to where it is needed. However, so far, solar developers in Ercot have been undeterred because Texas power prices are usually highest in summer when air conditioning demand drives load. If you build a solar plant to sell on the spot market, it doesn't matter if you lose 10% of your generation when there's too much solar, if you get paid well enough for the rest of what you generate to make decent money overall. Curtailment of zero-marginal-cost power can be a feature, not a bug.

Texas is one of the regions with one of the purest commitments to running its power market without government intervention to cut high power prices. This was tested in February 2021 when a drastic cold snap (a polar vortex event) took out some of Ercot's nuclear, gas, and wind fleet at a time when electricity was badly needed for heating. Texas infrastructure was not designed for freezing weather, and power prices went over

$9,000/MWh and there were rolling blackouts. Plant operators have now 'winterised' what they can and are hopefully better prepared for next time.

The price spikes in Ercot do lead to a market response because the cure for high prices is high prices. Large electricity users including bitcoin miners are now paid to stop operating when the power price is high. There was about 1.8 GW of bitcoin mining baseload power demand in Ercot in 2022 and another 5–10 GW planned by 2024 [Limandibhratha, 2023], and this is probably one reason why solar project developers keep building in Texas despite the rising curtailment risk. Crypto mining continues to make economic sense even at quite high prices (up to about $180/MWh) for power, but it can be shut down if paid enough. Technically, this is exactly the sort of responsive demand that can assist in achieving a very high penetration of renewables into the electricity mix, and it is being achieved more or less through free market forces. However, nobody except the bitcoin miners feels great about bitcoin miners making large amounts of money for doing nothing.

The price of gas usually sets the marginal price of power on the spot power market, and therefore the price of power everyone selling the market gets. Usually, this doesn't bother anyone, but when the gas price goes really high, suddenly it does. In 2022, the price of gas in Europe caused a great deal of discussion about how it wasn't fair that solar, wind, and other fixed-price power plants selling to merchant power markets got the high power prices when their costs had not changed. (But then, life is not fair, and the plants were built with the expectation that sometimes power prices would be high and sometimes low. And at least the solar and wind plants were reducing the problem rather than contributing to it.) European countries put a cap on power prices received by zero-marginal-cost generators, mostly at 180 euros per MWh, which is still higher than most were built in expectation of but below spot market prices that could be around 500 euros. Honestly, developers of solar and wind plants in Europe appear phlegmatic about this windfall tax, and the main bottlenecks to building new plants in 2022 and 2023 are grid access and permitting. It's not really fair but it will probably work out.

Energy storage — batteries and pumped hydro — can use a market with large daily price swings to charge when power is cheap (or even negatively priced) and discharge when it is expensive. This has the useful effect for other generators of smoothing out the power prices, meaning that everyone else makes more money. However, if you have enough storage, theoretically, you would flatten out the power price completely and the energy storage owners would make no money. We are a long way from this!

Another option, other than relying on 'the cure for high prices is high prices', is to offer capacity payments to dispatchable energy sources to be available for emergencies. Regulators in the UK, the PJM transmission region of the US (which includes New Jersey, Pennsylvania, Maine, and Delaware), and several other areas offer the owners of gas and coal plants, and also increasingly batteries, payments for just being available. These can be very complex or they can be very simple. The effect they tend to have, however, is to reduce the prices of power on spot markets because they cover the fixed cost of capacity, and that capacity continues to exist even if it only sells at the variable cost of generation. For example, Russia's power grid is almost entirely supported by capacity payments, with the result that power prices on the Russian spot markets are very low (around $20/MWh). This results in little incentive to build any new capacity that doesn't receive capacity payments in Russia and little incentive to save energy.

Ultimately, power markets get a little philosophical and it is difficult to argue that the Texas market fundamentalist approach of uncapped prices and wild spikes is the only one. On the other hand, they are an efficient way to pass price signals between producers and consumers. China, long a planned economy, is also slowly liberalising its power markets to reduce inefficiencies in when fossil fuel power plants run.

Chapter 10

Forecasting Methods and Modelling Something That Has Never Happened Before

Physicist Niels Bohr is reported to have said "Prediction is difficult, especially about the future." While significant strides have been made in weather forecasting and predicting at least the frequency of earthquakes over the past 100 years, predictions relating to human behaviour and economics remain direly inaccurate. As statistician Nate Silver says in his excellent book *The Signal and the Noise* (2012), "we are unable to predict recessions more than a few months in advance, and not for want of trying." He observes that in December 2007, economists on *The Wall Street Journal* forecasting panel predicted only a 38% likelihood of recession in the next year, which was remarkable because the data would later show that the economy was already in recession at the time.

Energy experts and organisations have an equally poor record of forecasting oil price, electricity demand, power price, the uptake of solar panels, or pretty much anything. Experts miss black swans, under- or overestimate trends, ignore data that would challenge their preconceived notions, and make other errors or misjudgements. They have their own biases, either explicit (oil companies are unlikely to forecast very low oil prices when the rest of the market disagrees) or implicit. A true expert gathers a wealth of information and weighs it mentally and, often, uses a model to understand what it implies.

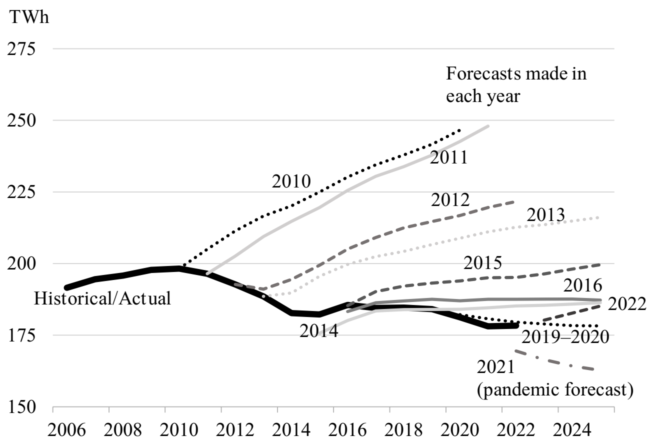

Figure 10.1 Australian electricity demand and forecasts by the Australian Energy Market Operator.

Source: Australia Energy Market Operator (AEMO), BloombergNEF.

Unfortunately, sometimes, the more information you have, the more interpretations it can support. Human forecasters tend to cherry-pick whatever data support the forecaster's preconceptions and sometimes to miss obvious conclusions in a wealth of irrelevant detail.

Even the closest companies to the data do not always get the results right and may have deeply ingrained biases. Figure 10.1 shows how the Australian Electricity Market Operator (AEMO), despite presumably having the best available data on Australian electricity demand, consistently forecasted that electricity demand will rise — while in fact, due to recession and energy efficiency improvements, it fell. The forecast does seem to be getting better from 2014, though, due to a combination of a slight uptick in electricity demand and also to AEMO adapting its methodology to more recent data. For example, AEMO began to account for the contribution of rooftop photovoltaics ('behind-the-meter' solar), which it perceives as a reduction of electricity demand to the grid.

BloombergNEF Australia analyst Leonard Quong explains that "AEMO got a lot better at power forecasting after 2015, in part because they were mocked so hard. They also have a wonderful tool now — http://forecasting.aemo.com.au/ — where you can easily pull all their old forecasts from and compare them. Things got a little spicy around 2020–2021, but all forecasts were awful during the early days of the pandemic. I will say AEMO's job is once again getting a lot harder, with uncertainties for electrification, electrolyzer demand, and behind-the-meter solar uptake (etc) once again causing some scenarios to hockey-stick like they did in the past — so I expect in a few years we'll be able to show the same divergence once again. But they are relying on scenarios to cover their bases nowadays."

You might legitimately ask what the point is of making forecasts at all. The main reason is that the alternative is worse; if you have not even tried to understand the future, how can you plan for it? Should you invest money and make public policy at random, or simply do nothing? Even a bad forecast is better than no forecast.

One rather cynical reason why there is a market for forecasts, even when forecasts do not perform well, is encapsulated in the saying that "nobody ever got fired for hiring McKinsey or buying IBM" — an appeal to authority can be a way to pass the buck.

A slightly less cynical rationale is that hiring an expert will give you not just the numbers but the means to help you convince potential investment partners that you know what you are talking about, much more quickly than if you had to research the topic yourself. You can ask them questions, get juicy details, and learn smart lines of arguments and ideas. The information conveyed may be parallel to the question of whether the investment should be made, but being able to talk smart is an important quality in getting that investment. Also, you can pick your experts depending on how much you are convinced by their rationales.

Right or wrong, it is unlikely that anyone will remember your forecasts years later when the excrement hits the ventilation. Nonetheless, at BloombergNEF, we do our best to get them right. We publish our forecasts to multiple parties, and we expect to be around next year with an updated but ideally not completely different forecast. Our old forecasts are still available to any client who wants to look, and we revisit our mistakes and try to learn from them. You can, if you wish, take a number of competitor forecasts and average them to see if you get a 'wisdom of crowds' effect (my team tries hard not to be deflected from our house view only by a different figure coming out of a competitor. If we did that, we'd end up all publishing the same numbers for no good reason. We do sometimes get asked why our competitors have different forecasts, though, and I don't know why they are wrong).

When data start getting complicated, when there are feedback loops and outside parameters that influence events in complex ways, it may make sense to build a model. Models are much misunderstood by laymen and even by people who should know better; as statistician George Box is reported to have said, "all models are wrong. Some are useful." They can certainly help us understand complex behaviour and which factors are important, and good modellers come back each year to test and improve their work on the basis of the newest data.

10.1 Short-Term Solar Build Estimates When the Market Is Small

One major weakness of models, however, is that they are only as good as the input data ('garbage in, garbage out'). The main metrics my team has been forecasting over the years — solar new installation in a year and price of solar components — are areas where there is not even a final answer in terms of what the data are. So we spend far more time looking for good data about the past than developing complex models for the future.

Installation in a year for an individual country may be known fairly well if the power grid operator tracks individual projects and publishes a total, as in Germany, Spain, and Italy (though grid operators even in these countries often come back and restate this figure a few years later). Other countries are not so organised, and we may have to rely on estimates from industry associations, trade bodies, incentive programme monitors, and local companies. We also collect total production estimates from the manufacturers, allowing us to triangulate on world new build in a year. Since 2015, we buy data from a Chinese customs data monitor on the value of photovoltaic goods going to individual countries and globally, which also helped us to identify countries which are major offgrid markets and refine our estimates. For example, Pakistan, Iran, and Yemen buy far more solar panels than any official data show them installing, probably because of poor grid access in these countries, though Pakistan may well be re-exporting to Afghanistan to power irrigation pumps for poppy crops for heroin production. We have often had to revise installation numbers several years old or make crude estimates when the official figures apply to timeframes that are not whole years. The Japanese reporting year runs from April to April, not January to January. India, Thailand, and the United States report AC capacity — the capacity of inverters connected — rather than the module capacity. (AC capacity is normally 10–50% less than DC capacity — further details in Chapter 19. I have used DC capacity throughout this book and believe that this should be the default worldwide for photovoltaics because it is the better metric for estimating investment, electricity output, and land use.)

In short, all historical solar new build estimates in MW have considerable uncertainty — plus or minus at least 5% — even years later. This is probably not unusual among economic metrics but may come as a shock to people with a physics or other hard science background. It also means that if your model relies on really exact numbers and you expect it to give really exact results, it's probably not going to work.

This being the case, why would we expect our forecasts to be either good or useful? Well, forecasts of new build are mainly used for figuring out where to put offices and staff, and whether to expand or scale back operations. The MW numbers are not, fortunately, required to be precise.

The 2-year forecast that we produce is therefore a short-term snapshot based on large projects we see, supportive policies in place, contracts signed, and a general sense of where things are going relative to the past. In 2018, we covered nearly 50 markets, with local analysts sitting down at least once a quarter to consider if revision is necessary based on new data or developments. As of 2023, we cover 146 markets and extend the forecast to 2030 based on targets, pipeline, and a lot of guesswork. Figure 10.2 shows the progress of our forecasts over time, with Q2 2023 being the most recent — and therefore hopefully the most accurate — the thick, highest line. (The International Energy Agency's forecasts are worse but it's rude to make fun of your competitors, and also I don't have them in Excel.)

We have almost always underestimated future growth, except briefly in 2018. This is despite using a high 'Rest of World' buffer in the forecast — basically, a sizeable chunk of forecast demand on top of the

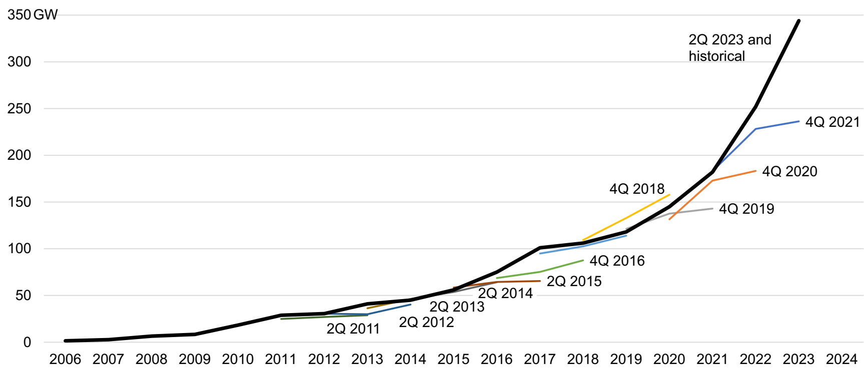

Figure 10.2 BloombergNEF mid-scenario forecasts of global new PV installation and development over time, to 2023.

Source: BloombergNEF.

known markets. This is necessary because first there are always new markets that you find out about later (one ends up saying things like, "Trade press PV Tech says Algeria installed 268 MW in 2015, and it seems to be confirmed by government data? We didn't even have Algeria in our forecasts") and second, my team members more often underestimate their own markets than they overestimate them.

Underestimation is a systematic bias in renewable energy forecasting, and it occurs partly because renewable energy analysts wish to seem objective rather than being cheerleaders for their sector. This also avoids arguments with clients (which include large oil, gas, and electricity companies, who are not necessarily anti-renewables but can be culturally resistant to forecasts of extreme change. Solar developers are often also resistant to high forecasts which may alert the government to an unsustainable subsidy, or attract competition). It's easier to defend a low forecast than a high one. Also, when you are an analyst or employee working in a country which installed 5 MW last year, it's hard to imagine a 5,000 MW market — even though solar incentives can quickly create exactly that.

Towards the end of 2010, we were perplexed by the fact that module prices were holding relatively firm even though our estimates of manufacturing output significantly exceeded known demand. Major markets were

Germany and Italy, both of which reported grid connection data monthly with a few months of lag time and did not explain what was going on. Uncertain, we assigned the missing modules to Germany, predicting a 10–11 GW/year. Even in January 2011, we continued to report that Germany must have installed 10 GW — even while Germany's October and November grid connection statistics came in suggesting it was much lower. In February 2011, we got the answer to the missing module problem: Italy (which we had pegged at about 1.2 GW) had installed the missing 3.4 GW but had not previously reported them because they were not yet grid connected. (They had a special legal exemption and became known as the 'Salva Alcoa' projects, which means 'saving aluminium'. I have never figured out why.)

Another error was our 2016 new build estimate for China, which was 26–27 GW at the beginning of 2017 (notice also how much the magnitude of the numbers has risen over time! It still amazes me sometimes. Also China installed 87.4 GW(AC) or about 107 GW(DC) in 2022). We were quite happy with this Chinese estimate because most of China's major support schemes for PV have a quota system — the federal government promises each province that it will fund a certain volume of projects at a pre-set price, and the provincial governments are supposed to allocate this quota to individual companies to build. The total quota available was limited to about 25 GW, and the programmes not subject to quota were small. So we were quite surprised when, in early January, China's National Energy Administration announced that 34.2 GW had been grid connected in 2016. It appears that some companies built solar projects early without guaranteed support, to get to the front of the queue when quota was allocated for 2017. Also, about 4 GW of projects were probably built in 2015 and grid-connected in 2016. In any case, it blew our buffer on the forecast for 2016. We saw a very similar story in 2017, although the Chinese government issues a further 86.5 GW of 'quota' in August 2017, encouraging developers to keep building.

Using the Rest of World forecast as a buffer to account for 'unknown unknown' demand is intensely criticised by clients — how can you say that a substantial chunk of the world's solar module production is just going to be sold without knowing where — but it has significantly improved our forecast accuracy. The same could be said for any way we made forecasts higher, though. The most accurate forecast of solar deployment made in 2010 for 2015 was Greenpeace's, which foresaw 98–108 GW of cumulative PV capacity by 2015. Actual cumulative PV capacity at the end of 2015 was 249 GW. Greenpeace appears to have made its forecasts simply by extrapolating current growth rates of over 40% on new build, but it was much closer than anyone else's because it was the highest. Simply extrapolating growth rates gave a better result than all my team's knowledge and work; however, it's clearly not something that can continue forever. This is a major problem with forecasting discontinuities (points at which the future does not simply look like the past extrapolated) — figuring out where they are going to stop. We probably should stop when every square centimetre of the world is plastered with solar panels, if not before.

Clients frequently want to build a 'proper' model for the solar sector (incorporating 'simple' factors like policy, power prices, consumer behaviour, amount of roof space, etc.) and usually send a bright intern to use data to crack the problem. The intern wrangles the data, fails to find consistent patterns (if you give people subsidy to install solar, they usually do, but you cannot predict how many people will or when the subsidies will be removed …), and leaves after 3 months, wiser and without revolutionising the world of solar power forecasting.

10.2 Proper Long-Term Energy System Modelling

The point of having a long-term energy system model is not so much to say what *will* happen but for policymakers and companies to understand what the implications are if certain things happen. For example, whether the power system will fall over if we go to 80% wind or solar in the electricity mix. Or whether the lights will go out across Europe in the winter if heat pumps and electric cooking replace all household gas use. Or what difference to carbon emissions is made if gas plants stay in service but are only used in periods of low solar and wind. Or to find a pathway to a system with no carbon emissions by 2050, keeping the total below a certain level. "Equilibrium models and simulations are the two ways to do this," says Auke Hoekstra, who is Program Director of the NEON research programme for the University of Eindhoven, and debunks nonsense about electric vehicles on Twitter. “Equilibrium models are a set of equations that solve towards a specific solution. They are mathematically complex and require many simplifications but are very explicit and quick to compute. Simulations divide the calculation into a series of time steps that are solved one by one, and are often used for complex systems (in which feedback loops play a role) that are impossible to solve mathematically. In the natural sciences this happens all the time. For example, a simulation for aerodynamics in which we calculate the interaction of a small part of a turbine blade with the other parts of the turbine blade and the surrounding air. Another example is dividing an energy system up in smaller part and calculating the behavior of each part for separate time steps.”

Hoekstra is dismissive of equilibrium models for complex sociotechnical systems and strongly favours simulations. He also points out that models are complex but can fall down on simple assumptions: “10 years ago, the people from Netherlands national forecasting body PBL told me my observation that people liked to drive EVs was wrong because they had just interviewed 2,000 people about it. However, it turned out less than 10 of those actually had experience with EVs and they liked it.”

David Osmond, an engineer at wind project developer Windlab in Canberra, Australia, has one of the most intuitive simulations. It addresses the following question: “What would have happened on the main Australian grid, the National Electricity Market (NEM), last week if we had a lot more wind and solar than we do today, plus about 24 GW/120 GWh of existing pumped hydro storage and new batteries?” He downloads the weekly electricity demand and generation data by source from OpenNEM, the near-real-time data portal for Australia’s main power grid, and calculates how the week would have played out if the electricity mix was scaled up.

Osmond’s model is highly simplified in many ways. For example, it does not assume any grid constraints and it assumes that operators have perfect foresight 24 hours into the future until the end of the week, after which they cannot see anything at all. This is important because the model forecasts ‘dispatch’, i.e. whether operators of storage (pumped hydro or batteries) would have charged or discharged at certain times,

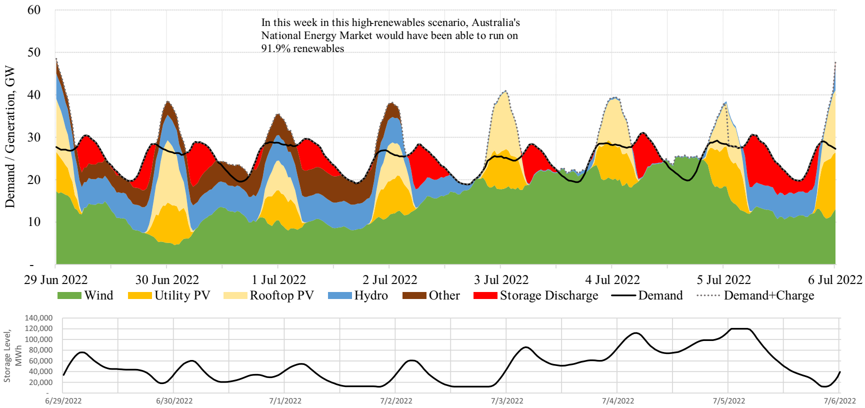

Figure 10.3 David Osmond's simulation of how Australia's National Energy Market would meet actual power demand in the lowest-renewables week between August 2021 and August 2022, in a high-renewables scenario with extra storage.

Source: David Osmond.

and doing this effectively requires good forecasts over the next 12–24 hours.

Osmond ran this simulation weekly from August 2021 and posts the results immediately on his Twitter account (@DavidOsmond8). This makes a compelling case that relying heavily on wind and solar would not be a disaster for Australia, particularly with a relatively high amount of wind. He gave the model enough wind to meet 60% of annual electricity demand, enough utility-scale solar to meet 20%, and enough rooftop solar to meet 25%. As he says, "Note that the sum of 60%, 25% and 20% is greater than 100%. This is important. Any optimised model of a highly renewable grid will have significant amounts of over-generation". A mix close to 50:50 wind and solar is likely to be optimal because they are negatively correlated with one another, with wind frequently stronger in the winter and over-night, while solar generates more in the summer and at midday.

From August 2021 to August 2022, Osmond's simulation ended up with 18% excess or curtailed generation and only requires 1.2% 'other' generation (which could be peaker plant gas, or hydrogen made from some of the excess/curtailed generation, or something else). In the worst week (Figure 10.3), Australia's main electricity grid in this scenario ran on 91.9% renewables, while over the entire year, it ran on 98.8%. Over the whole year, 82% of demand was directly powered by wind and solar, without even going through storage. This model, not published in academic journals, offers a vision of the future where the grid in Australia has been substantially scaled up to accommodate 41 GW of wind and 19 GW of utility-scale PV, plus 39 GW of rooftop PV. This is about five times as much wind, and four times as much utility-scale solar, as Australia has in early 2023, and it does not cover future increases in electricity demand for powering transport, heating, and electrified industry which currently run directly on gas or oil. But if you take one thing away from this book, please let it be that dramatic scale-up of renewable energy is entirely possible and often easier than you might have expected.

Models are also very bad at finding any solutions to real-world problems you have not told them about. "People assume demand response, sector coupling and power-to-X [turning power into a storable fuel like hydrogen or ammonia] can't exist, ergo you need ridiculous amounts of batteries for wind and solar, ergo they can never work," Hoekstra points out. All these are options which would make Osmond's model (or any given grid) able to drive out that small percentage of 'other' fuel in the power mix, with plenty of solar and wind generation.

Jesse Jenkins, Assistant Professor at Princeton University, works with the GenX electricity system optimisation model, a partial equilibrium model which he says "can explore the impact of long-term decisions to eg, build a nuclear power plant or a wind farm over the next 30 years. It can also consider technology investment decisions, where you're trying to develop the technology that will be competitive in 10–15 years rather than what's useful today." As you might expect, the variables it is most sensitive to are technology costs, electricity demand profiles, and policy drivers.

Jenkins observes that "GenX (like most models) tends to give bifurcated futures depending on what assumptions you use in the short term. For example, if you assume low gas prices, the model will tend to build a lot of gas power capacity instead of nuclear or hydro (or advanced geothermal if it's an option). Solar and wind compete directly with the fuel cost of gas, so often supply 70–90% of energy generation with the gas plants running at low capacity factors. If you make the model build nuclear, hydro or geothermal in the near term, it tends to end up at 40–50% energy generation from wind and solar because instead of displacing gas, they are displacing very low variable cost electricity sources."

Many models focus on the electricity sector, which is a reasonable starting point, but power is only around 30% of world carbon emissions and is the easiest sector to decarbonise. Adding electrified transport and heating increases the amount of electricity needed, and will also somewhat change when it is needed (heating, for example, is much more of a problem in the winter when solar generation is low). BloombergNEF's New Energy Outlook (NEO) model attempts to cover all greenhouse gas emitting sectors, many of which are much harder.

Since 2007, very early in the history of the company, Michael Liebreich has insisted that we have a central energy modelling team, bringing together the outputs from all the different teams into a single global forecast. This takes inputs on electricity demand by country, the planned building and scheduled decommissioning of coal and nuclear plants, cost of generation of various energy sources (most notably solar and wind, which are getting cheaper), and simulated hourly power demand and generation to 2050, including long periods of extreme conditions and changes to demand as other sectors start to use electricity, as well as modelling exogenous sectors. BNEF's New Energy Outlook model produces both an Economic Transition Scenario — where the model is allowed to build the cheapest sources of power to meet demand at appropriate times — and a Net Zero Scenario which forces the simulated world to build to a pathway to net zero emissions by 2050, while remaining within 1.77°C (because keeping it lower is too hard).

The BNEF exercise is very broadly similar to what the International Energy Agency (IEA) does in Paris — but less inclined to predict more of the same and more open to incorporating disruptive data and extrapolating observed cost trends. The IEA has been much criticised for forecasting low renewables uptake in its World Energy Outlook scenarios, although it is getting much better and, in 2022, declared that 'Solar is King' of the future electricity mix.

Like all good future power sector models, BNEF's NEO considers longer periods of extreme conditions, such as whole weeks of low solar and wind output and high electricity demand in a Northern European winter. This would drain the biggest battery in existence, and a bigger battery would not make economic sense because it would only be used a few times per year. The model responds with a legitimate solution when not ordered to reach net zero — it builds open-cycle gas turbines (low-efficiency but cheap gas power plants) to supply electricity during these periods. It doesn't really matter that these power plants are inefficient since they are cheap and only run in semi-emergencies.

The point of having this model is not to give a truly accurate output when the analysts put in their favoured inputs (events will almost certainly not come to pass as the model says); the main point is to ensure that the forecasts produced by each BloombergNEF sectoral team have to be internally consistent — you can't have the total of all the electricity production outstrip the global demand for electricity. You can also play with the inputs and look at what happens. Models are for avoiding blunders and understanding the world, not for predicting it.

What all these models have in common is that they do, generally, find a route to a much lower-carbon world even if they struggle to get the last bits of carbon out of the mix. BNEF's NEO Net Zero Scenario, for example, ends up relying heavily on carbon capture and storage (CCS) to clean up industry — CCS accounts for 11% of all emissions abated by 2050, which is a lot given the amount of carbon stored to date is approximately zero tonnes. BNEF's NEO also relies on a small amount of negative emissions technology — locking carbon in somewhere, for example, by burning biomass and pumping the carbon emissions underground. To me, this seems like a weird future and I hope we can find a better pathway than that. But the more of the real world a model includes, the more difficult it finds it to get to absolute net-zero greenhouse gas emissions without some form of negative emissions technology.

Jenkins, whose model only covers power, is more optimistic about his model offering a practical solution. "One finding from most model runs is that reaching net zero isn't World War 2 mobilization in America. Ten years ago, the model would have said that it was prohibitively expensive, but the cost of wind, solar and batteries have made a huge difference to that. Our scenarios for Net Zero America say that it would involve spending 4–6% of US GDP on energy services by 2050, compared with historical levels of 6–9%, and in crisis years like 2005, 10–14%. Although it's not expensive, it will be hugely transformative to reform the entire electricity mix in 30 years."

Getting to net zero should be possible, though it will be easier in power and transport than everywhere else. Models can help us understand how it might work if we can give them the right inputs, even if they do not cover everything. After all, points out Hoekstra, they often rely on "the assumption that people do everything for money and that you can predict their behavior with a money-optimizing utility curve. In reality people also decide based on group pressure, ingroup preference, marketing, lack of information, efficiency of decision making, care for others. Even empathy and love play a role sometimes, as improbable as economic models make that seem."

I'd rather not rely on empathy and love to keep the world from burning, but given we only really started looking at hydrogen and heat pumps around 2016 and now models have them as a major component of the solution, I am hopeful that if we set off in the right direction, we can use models to navigate the next steps.

Chapter 11

Networking and Other Stuff Not Taught at State Schools

One of the things I find hardest about the world of work — and, specifically, business rather than academia — is knowing how to behave in certain situations. Some people find this easy, some feel really awkward at the intersection of professional and social behaviour, and there's probably a class element as well. Maybe this is not a problem for you, in which case, lucky you, skip this chapter.

11.1 Networking Basics

Networking is an odd institution where you act as if you are meeting socially but it is actually about work. You exchange business cards, find out what other people do, show polite interest, use their names, and send a follow-up email. The email is not considered weird or binding, a simple 'nice to meet you' with some indication you remember what was discussed and would like to remain in touch. You don't have to go with a list of key aims and make a beeline for the right people — you might be better off simply having a mental list of questions and a curious mind. At its best, you get to have conversations about energy, and if you are reading this book, you hopefully find that sort of thing interesting.

Usually, a networking event is sponsored by a company which provides alcoholic beverages and, if you are lucky, canapes. It is considered bad form to scoff all the canapes and mainline the beverages.

Wear a jacket or dress with two pockets, or have a handbag with two sections. This is for business cards. One pocket is for your cards, the other for those of other people. Exchanging business cards in the West is awkward enough already since there is no protocol and sometimes you find yourself clutching your card nervously while the other person shows no sign of wanting it or going for theirs (or that may just be me). In most of Asia, there is protocol — you hold your business card carefully in both hands and extend it to them, and then take theirs and study it for a few moments, ideally saying something about it, like repeating their title in a thoughtful voice. This is a really easy habit to get into, so you can basically use it anywhere, and if you do this in the West, people will say "oh, you must have spent time in Asia," and you can smile and look cosmopolitan even if you haven't. In Japan, it is quite hard not to mirror the small head-dip bow people do (we are a species with a strong drive to imitate one another's behaviour), but I am told by my Japanese colleagues that bowing looks stupid on Westerners, or specifically on me, and is not expected.

There are three difficult parts of networking. The first is remembering people's names and faces, which I am terrible at (and it is really obvious if you only use their name after reading their badge). The second is making a good conversation, which we discuss more later. The third is escaping a conversation which has run its course with grace and elegance, ideally without then wandering the room looking desperately for someone else to talk to (this is a good time to visit the bathroom so it doesn't look like you were desperate to ditch them with no replacement conversationalist lined up. Unfortunately, there are only so many times you can reasonably visit the bathroom in a given timeframe).

Sometimes you do end up talking with someone you have nothing in common with, and awkwardly discussing the weather/cities/favourite restaurants/things to do locally. This can be OK too, it is a normal part of networking (my husband reads about football and cricket partly to have something to say). My colleague and super-networker Benjamin Kafri reads *The Economist* partly to have a short list of relevant topics to touch on, where he is not completely ignorant but would not claim native knowledge, although his true skill is remembering everything about everyone he meets. He can ask a person how the restaurant he recommended to them a year ago at a similar event was. He remembers if they like skiing or snowboarding. (A lot of people like one or the other. It is the sort of thing people in finance do. I just point out that in my opinion it is an expensive way to break one's legs and therefore better avoided, thus inviting the group to exchange their extensive repertoire of snowsport injury stories and think me a fantastic conversationalist for nodding along.)

Ideally though, you talk work because that is what you are both there for. It's always safe to ask people what they do at their company, and if you don't know the company, ask about what the company does. Often this is boring, long, and hard to follow. I find it helps, particularly with people keen to tell you about their business model at length, to adopt an innocent expression and ask 'so how does that make money?' This often gets to the heart of what they do. 'So who pays you for that?' is another good one in the same vein. If you don't ask these questions, you can spend half an hour listening to someone talk proudly about their business and not have the foggiest idea of who their customers are and what they sell. People are generally happy to answer questions that are a genuine attempt to reduce ignorance.

Also, high heels. Don't wear them unless you can stand around in them for hours because sitting down is not an option unless you find someone absolutely fascinating. And if you're going to a trade show or exhibition rather than a conference, you can wear trainers, the veterans do because you can end up walking many kilometres in a day of trade-show-floor meetings.

11.2 Being Female — Pros and Cons

As far as I can tell, as a cis woman professional, I am supposed to act like a role model for more junior women. I find this obligation awkward and uncomfortable, mainly because I have never experienced direct or definite negative discrimination for not having a Y-chromosome and have benefitted from positive discrimination when conference organisers are putting together a programme of speakers.

I recognise that this is a litany of privilege, but my point is that if you are a young woman starting out, it's not necessarily going to be awful for you — and good people exist. Both Michael Liebreich and Bloomberg the company make considerable efforts to ensure that women in their businesses succeed on their merits. Whatever the toxic culture of parts of the world, parts of business are well ahead and it's now embarrassing in the West to have a boardroom, office, or panel debate composed entirely of men.

Nonetheless, it's noticeable that the higher you look in most organisations, the fewer women there are. When one tries to put together a panel discussion and get some kind of gender mix, it is normally necessary to invite many more women than men to get the same number of acceptances (and senior women are rarer, hence harder to find to invite). My colleague William Young says that when inviting speakers to a major conference, about two out of three male speakers accept the invitation, compared with one in two invited women. My theory is that women are more likely than men to consider the merits of giving a conference presentation versus a day in the office getting some work done, and deciding in favour of the work.

The reasons why an individual woman doesn't end up in a senior role are different but often very rational. Anecdotally, it seems as if women are more likely to move country and take a career hit when following a male partner's job. It also appears to me that female professionals respond to feeling underpaid, underappreciated, or not making progress in their current job by seeking a new job — while their male counterparts more often express their dissatisfaction to their manager first, which makes the manager more alert for opportunities to move or promote them. Complaining doesn't always get what you want and can be overused, but it's more likely to change things positively than saying nothing until the day you announce your resignation and move to another company, where you'll need to prove yourself over again. Maybe I've just had great managers, but I would recommend people of all genders be honest with their manager if they're not happy with something at work.

There is always the odd awkward moment — a man twice my age hitting on me when I thought I was interviewing him — and I admit that aged 24 I cut my hair very short in the hopes of being taken more seriously, and am generally quite dowdy. It may have helped (but other people should wear whatever they feel comfortable with and cut their hair however they like). I have only three pieces of sartorial advice. First, if you wear dresses, there are some very nice ones available that are machine washable, and those will save you a small fortune in dry cleaning bills and are also better for the environment. Second, buy suit jackets with two pockets, one for your business cards and one for other people's because it is embarrassing to fumble around through a stack to give someone your card. Third, new suit jackets always have the pockets sewn up and you are meant to unpick them after purchase; apparently, this is one of those things that people go to private school to learn.

I think I get asked to chair or to moderate panel discussions much more often than an equivalently talented man would, because I am a woman. This is probably due to the laudable desire of conference organisers to avoid all-male lineups. Unfortunately, while moderating panels is a good gig for an analyst — we get to ask the smart questions — chairing an event is deadly dull; one has to try to memorise the biographies of a bunch of mostly-male speakers, explain where the toilets are, and stand there looking attentive a lot. This is a lot of work and fails to demonstrate to the audience that one has anything to say, so these days I politely decline such invitations. It's not much of a step forward for the representation of women in business if we are standing there introducing white male content speakers, and also, I am really bad at it.

I don't have a solution to the visible gender gap at the higher levels of organisations. Women should look out for one another but not to the extent of taking on an extra burden in comparison to men. Men and non-birthing parents should do childcare. But we have at least come a long way. Read Sheryl Sandberg's *Lean In* for better advice — or at least follow her suggestions that you should choose a partner (if you want a partner) who will support your career as much as they expect you to support theirs, that you shouldn't dial back on your professional ambitions now because in the next 5 years, you may have a baby ('don't leave before you leave'), and be part of an important meeting, conference, or conversation whenever you have a chance while ducking out of unimportant ones — it's OK to have better things to do.

11.3 Job Interviews

There are much better sources than this book for general tips on how to get a job. Get someone to proofread your CV before you send it, wear clean clothes, be on time, and don't start your cover letter to, say, Bloomberg with reasons why you want to work for McKinsey (this happens). We know you're not writing your best enthusiastic prose solely for our benefit, but a lack of attention to detail is not a good sign.

The people screening CVs and conducting interviews are human too. In general, one cannot interview all applicants — that would be a waste of everyone's time — and one wants to interview a diverse sample of the best. So one sighs with relief when an otherwise quite decent CV has a typo, or the cover letter starts Dear Sirs — it means one fewer thing to read carefully before making the difficult decision about whether it is worth one's own and the candidate's time to conduct an interview. There are perfectly good non-gendered forms of address — 'To whom it may concern', 'Dear hiring team', 'Dear analyst', or 'Dear [full name]' if you know the name but are not sure of their pronoun. Pronouns in bios are becoming more common, so pay attention to those, it's very rude to get it wrong.

Once in interview, good candidates make several bad and completely avoidable mistakes.

The first mistake is thinking that interviewers care about the answer to the warm-up question — a starting question about something the candidate really should know about, like why they are applying for the job or why they studied a particular course. This question is supposed to put the candidate at their ease. The answer should be appropriate but brief. The candidate will get no marks by talking about their passion for environmental sciences for 15 minutes and leaving no time for difficult questions. Candidates basically start with zero marks and score for insightful answers, so blathering about your passion just wastes your time to impress. We have dozens of passionate and pleasant applicants and we couldn't hire them all if we wanted to, so we really do need to get to the point — which is whether an applicant would be good at the job.

Another common mistake is panicking when applicants do not know the answer to a numerical or analytical question immediately. Generally speaking, the interviewer does not expect anyone to. The idea is to see that the candidate does not panic and is able to think and approach the question logically, asking for clarification. This makes sense — in the workplace, you generally will not know how to do everything, it is far more important that you stay calm and apply good reasoning skills to a problem when it arises.

Listen to the questions, and do not be afraid to pause for breath. The interviewer will probably have a list of questions for all candidates, to compare answers as fairly as possible. If the interviewer is trying to interrupt with questions, they are probably trying to steer the candidate back towards something that would actually credit them. It is wise to ask an interviewer ‘is this what you are looking for?’ or ‘should I go on?’ rather than making them cut you off; nobody wants to work with someone who doesn’t listen.

Things that are worth doing if applying for a job are as follows: have a two-line version of any relevant thesis or publication mentally prepared and any surprising findings. Know what the company you are applying for does and have a quick Google of the interviewers, if you know their names. Get any interview practice you can, to be focused but relaxed on the day. Send one or two emails asking what has happened to your application if you do not hear back for months but do not cold email an entire company.

Good luck. From an interviewer’s standpoint, the decision is always very difficult and we often want to hire everyone we meet, while also needing to interview everyone we have chosen to interview before making an offer. This is often why communication takes time. Sorry.

11.4 Advice from Other People to Those Wanting a Job in Clean Energy

I asked the various clean energy professionals that I spoke to for this book, in both 2018 and 2023, what advice they would give anyone looking to work in the sector. Their advice was extremely varied and probably covers most courses of action.

Charles Yonts, an equity analyst (someone who tracks the rise and fall of stock market-quoted companies and issues buy and sell recommendations), said, “Remember that solar panels are a commodity, so equities will trade and valuations fluctuate with demand and supply, moving in cycles just like they do in cement, steel and property. What is astounding is that even quite experienced investors fall into the trap of thinking that given the phenomenal secular growth in solar, it will somehow be immune from these cyclical patterns, and then they get destroyed. The flip side of this is that when we enter the down phase of the cycle, there is an up on the other side.”

Belén Gallego, an entrepreneur and co-founder and CEO of consulting firm ATA Insights, said, “We [the clean energy industry] need all the help we can get! There is not always much money in renewables, but you can still forge your own path.”

Dr Zhengrong Shi, who built a company from nothing and was at one point one of the richest people in China (more details on Suntech in Chapter 13), says that early-stage companies should not try to do everything and should be happy to take on small chunks of business. “I see startups that I work with get overexcited about 1–2 million dollar contracts,” he says. “But it’s good to get small orders that are not so high risk. Also, don’t try to sell a product before it is good”.

Jenny Nelson, Professor of Physics at Imperial College London and the author of *The Physics of Solar Cells*, has these words for those who wish to remain in science: “If you do graduate study in the area of solar cells, you might never invent a new type of solar cell, but you will gain knowledge of how it all works and ability to think around the problems.”

Research is not necessarily wasted even if it fails to deliver the immediate desired results, she points out. “Perovskite research has already benefitted from work done on organic and dye-sensitised PV in solving the problem of how to achieve current and voltage generation in something where you can’t use doping to make a p–n junction.”

Jesse Jenkins, Assistant Professor at Princeton University, suggested to US graduates in 2023, “consider government service in the US. We’re at an inflection point right now and the Department of Energy is hiring

1,000 people. We need smart people to drive and plan the transformation. And you can really have an impact — when I started out in 2006, I worked on requesting and reading utility dockets in Oregon, as part of a group which killed plans for 7 new coal plants and brought in a Renewable Portfolio Standard over the next two years."

Morgan Bazilian, Director of the Payne Institute and Professor of Public Policy at the Colorado School of Mines and previously Lead Energy Specialist at the World Bank, suggests that you should "have a specific skill set to contribute. It's attractive to think you can stay generic in your education, but study finance, or engineering, or social sciences."

Hannah Ritchie is Deputy Editor and Lead Researcher at Our World in Data, an excellent website which assembles and updates authoritative scientific consensus data on a wide range of important topics. She says, "When I did my environmental sciences degree, I found myself too focused on specific things that are going wrong in the world". "It's helpful to step back, look at problems at a higher level and use data to understand success stories. What did this country do to improve outcomes, and can we learn lessons to replicate elsewhere? With individual carbon footprints, it's easy to stress over every decision, when in reality there are 4–5 big drivers that you control." For example, OurWorldinData's work presenting the carbon footprint of different foodstuffs shows that, generally, the emissions of transporting food are much less than those of producing it, so eating local is less important than what you eat. "A lot of global problems come down to a few key levers you can pull," Ritchie says.

She adds, on the general topic of the challenges we face as a species, "Biodiversity loss is probably the hardest environmental problem to solve right now. There isn't a clear human lens for people to understand how it will affect them. But at least solving other problems should have positive effects there."

Being the most authoritative source for data is a responsibility. "We spend a lot of time digging into data sources, reaching out to scientists, and sometimes show multiple sources from different papers. We spend a long time doing simple stuff like deciding how to title a chart to make sure it accurately reflects the contents. And it's always best not to really care what the answer is, only that you have it right."

Attention to detail and commitment to truth are probably the most important workplace values. Practically, though, two ways to look organised and considerate are to always send people files with filenames that will be useful to them rather than you (e.g. not "solarnumbersforJenny", I have a lot of those) and by suggesting call slots in their time zone rather than yours.

Chapter 12

Solar After the 2008 Crash: Finding a New Normal

When the Spanish solar market hit its deadline in 2008, a global financial crisis was in full swing. The US subprime mortgage market collapsed in 2007, and the investment bank Lehman Brothers filed for bankruptcy on September 15, 2008. The financial crisis was widely blamed for the crash in solar module prices but, as far as I can tell, had little to do with it — the prices of physical modules (as opposed to the stock prices of companies) fell simply because supply grew faster than demand, as new factories came online. Annual new build volumes continued to hit a new record every year, and annual investment figures hardly saw a dent; the problem was a fundamental oversupply of every part of the solar value chain. The financial crisis almost certainly had a role in the fall in solar stock prices which made it more difficult for solar manufacturing companies to sell more shares and raise more money, but that was a secondary effect as most were not in an expansion phase anyway.

12.1 Manufacturers

After 2008, solar manufacturers went through a 5-year period of losing money, and a great many went bankrupt. New polysilicon factories came online, and the price of polysilicon dropped steadily, from over $400/kg in 2008 to under $20/kg in 2013 — barely the marginal cost of making polysilicon at the time, never mind paying polysilicon companies back for the capital they invested in factories (the price fell to an all-time low of $6.3/kg in summer 2020). The price under long-term contracts was still around $60/kg, and so the lawyers for the companies buying polysilicon scanned the contracts desperately looking for loopholes. In some cases, they found them; in many, the buyers got out of the long-term contracts by the time-honoured method of going bankrupt; in some cases, the two companies negotiated a deal where the seller accepted lower prices than originally agreed, in exchange for the customer continuing to exist.

Firms competed with each other fiercely to sell solar modules. Manufacturers which had made improvements in technology and cost-reduced prices and stayed afloat, while those which had coasted on long-term polysilicon contracts and high module prices went bust. "When the tide goes out, you see who is swimming naked," as investor Warren Buffett described this situation in general.

One example was BP Solar. Several oil companies have attempted solar manufacturing in the past and given up after a few years, for example, Shell sold its solar division to German solar manufacturer SolarWorld in 2006. Oil companies come in for a lot of criticism from activist shareholders and environmental lobbyists for quitting solar manufacturing. In my view, this is not wholly rational, as there are no synergies between the two businesses.

Since synergies is an overrated word, it may be worth using an analogy: take a busy blacksmith in a medieval village where the children go without shoes. Should she go into the shoemaking business? It depends. If shoemaking requires much the same tools and skills as blacksmithing, there are synergies and perhaps she should take an apprentice and expand her forge. On the other hand, if it would require her to retrain and crowd her forge with new equipment, she might find that her new business venture left the village's tools unmade, horses unshod, and her purse empty. In this case, perhaps someone else in the village should go and apprentice with a shoemaker elsewhere and come back to set up a shop. If there are no synergies, the blacksmith and shoemaker will most likely serve the village better and at a lower cost if they stay independent. (They can always borrow or rent equipment they only occasionally use from the other.)

Oil companies are good at finding oil, negotiating agreements with governments to get it out of the ground, and then getting it out and transporting it around. Solar manufacturers need to be good at continuously improving production processes, managing supply chains and inventory, and marketing. There are no major synergies, which is why no oil company has become a leading solar manufacturer since the industry reached a significant scale. (Outside manufacturing, oil companies do have some advantages. Some have major investments in solar and wind projects, and many have biofuel interests for obvious reasons. There are some synergies in relationships with governments in emerging markets, helping first-of-their-kind projects secure a promise to pay for the power. Oil companies also have relevant expertise in building and maintaining offshore infrastructure, like oil rigs and offshore wind projects.)

There is occasionally an attempt to make oil companies invest in renewables as a moral imperative. However, when we buy oil, we are treating it as a necessary evil; we shouldn't expect oil companies to operate in a business they are bad at as well, using oil wealth to compete with companies which are actually good at solar. The problem for solar manufacturers is that there are always new entrants trying to be the next big player, causing near-continuous oversupply and vicious competition. Pumping oil is much easier than staying a fraction ahead on manufacturing costs, but it doesn't really make much sense to cross-subsidise one activity with the other — and in one logical extreme would result in an oil company's solar division which literally could not fail, pushing out more innovative pure solar companies.

One casualty after 2008 was Massachusetts-based Evergreen Solar, which had a 'string ribbon' solar wafer-making technology that in theory could cut costs, by drawing wafers directly from molten silicon rather than slicing. Unfortunately, it had long-term contracts to buy silicon at prices that had looked good in 2007–2008 but were ruinously expensive in 2010. Evergreen Solar went bankrupt in 2011.

A lot of the blame for the module price crash was directed at the Chinese companies, which had built the largest factories in the world, often buying European or US-designed manufacturing equipment. Firms like Suntech, Yingli Solar, Trina Solar, JA Solar, Jinko, China Sunergy, LDK, Renesola, and GCL were some of the largest manufacturers and were able to offer some of the lowest prices on the market (although higher than the prices some of their less well-known competitors offered out of desperation). Initially, their European and US competitors tried claiming that Chinese modules were all poor quality, but this was not supported by laboratory or field tests. It is true that the pricing pressure led to some firms cutting corners — using substandard encapsulant and backsheet materials, for example, which degrade more quickly than the rest of the module and ruin either the transparent front or the waterproof back. There were almost too many small Chinese module manufacturers to name — at the annual Shanghai New Energy Conference in 2008, there were hundreds of stands representing companies with names like Zhejiang Sunlight Systems or Jiangsu Apollo. Of 568 exhibitors (according to the online catalogue), most were small module makers. Of course, not all of them were meeting the highest standards of material sourcing and fabrication — they were teetering on the edge of bankruptcy too. How was a module buyer to know which products were well made?

It's difficult to argue the value of advertising from a perspective of social good, but there is one way in which it can be done. Generally, if a company spends significant amounts of money promoting a branded product, it's likely to pay at least some attention to the consistency of the product — probably more than a firm which has no reputation to protect. If you bought a bad can of Coca-Cola, you'd be far more disappointed and remember the experience better than if you bought an unbranded cola-flavoured drink that turned out to be bad. For this reason, it can be logical to buy from a company which spends money promoting its products, even if smaller companies offer what appears to be the same quality product at a lower price. This can be done by having an eye-catching booth at a trade show, by sponsoring conferences and buying advertisements in trade magazines, and even by advertising in mainstream media or sports. For example, Trina Solar sponsored the Renault car team for the Formula One racing event in 2010, while Yingli sponsored the football World Cup in 2010, spending an estimated $30–40 million. It is not clear if any customer specifically requested Trina or Yingli modules as a result of this promotion; one suspects that this sort of advertising is good for the ego of the upper management, independent of its effect on the bottom line.

The first major consolidation phase of solar module manufacturing ran from 2008 to about 2012, and bankruptcy claimed large companies as well as many with names that are variants on Solar Power Systems (originality in naming has not been a notable feature of the solar industry to date). This is visible in the number of top-10 firms from 2008 and 2010 which went bankrupt (Table 12.1). Some, such as Suntech, were bought out and are back in business. Q-Cells and Solarfun were bought by Korean conglomerate Hanwha and aggregated into Hanwha Solar or Hanwha Q-Cells (the name has varied over the years). Others, such as Solon and Solarworld, have sunk without a trace. Japanese giants Sharp and Kyocera exited the solar market as the competition got fierce. US-based SunPower spun off its manufacturing to Maxeon in 2022. The largest solar module maker as of 2023, Chinese LONGi Green Energy Technology, was not even in a top-10 list until 2016.

12.2 Developers — Making Hay While the Sun Shone

The module price crash created huge opportunity for the companies which financed, developed, and built solar power plants. If they were lucky with the timing, they signed power price contracts or got feed-in tariffs locked in before the module price crash, and got to keep the price difference as profit margin. In places where solar power plants were built under negotiated contract with power users, like the US, developers could start to offer much lower power prices which appealed to more customers and begin to scale up their ambitions from a relatively small base. This was a payoff for years of work for some firms, like Jigar Shah's SunEdison. This company pioneered a business model of offering 25-year power purchase agreements to owners of large roofs, at prices which made immediate financial sense, with the payments going to external investors who had paid for the project.

Jigar Shah, the founder of SunEdison, remembers, "In 2003, our model was an immediate hit with customers, and we signed up [high-end US supermarket chain] Whole Foods, [office supplies chain] Staples and [furniture store] IKEA within six months. The customers said, the cost of one of these solar projects is the same as a brand new store. We're building two

Table 12.1 Top-10 solar module makers in past years, ranked by production in that year.

2008	2010	2012	2014	2016	2018	2020	2022
First Solar	Suntech	Yingli	Trina Solar	Jinko Solar	Jinko Solar	LONGi Green	LONGi Green
Suntech	First Solar	First Solar	Yingli	Trina Solar	LONGi Green	Jinko Solar	Trina Solar
Sharp	Yingli	Suntech Power	Canadian Solar	Canadian Solar	JA Solar	Trina Solar	Jinko Solar
Yingli	Trina Solar	Trina Solar	Jinko Solar	JA Solar	Hanwha Q CELLS	JA Solar	JA Solar
Solarworld	Sharp	Canadian Solar	JA Solar	Hanwha Q CELLS	Trina Solar	Canadian Solar	Canadian Solar
Trina Solar	Canadian Solar	Jinko Solar	Renesola	GCL System	Canadian Solar	Hanwha Q CELLS	Risen Energy
Sunpower	Hanwha SolarOne	Hareon Solar	First Solar	First Solar	Risen Energy	Risen Energy	Astronergy/Chint
Sanyo	Solarworld	SunPower	Sharp	LONGi Green	GCL System	First Solar	DAS Solar
Solon	Kyocera	JA Solar	Hanwha Solar	Yingli	Suntech	Astronergy/ Chint	Suntech
Jiangsu Linyang Solarfun	SunPower	Hanwha SolarOne	SunPower	Zhongli Talesun	Astronergy/ Chint	Suntech	First Solar

Source: BloombergNEF.

stores every month right now, why would I divert this money to solar systems instead? And they signed power purchase agreements."

The challenge was initially finding investors willing to take the bet on solar tech working, and some of SunEdison's first customers had to wait 2 years after signing up until the company found investors. Jigar Shah funded the first project on his credit card, and other early projects used capital from wealthy individuals.

Investors naturally had many questions about this new asset class, and not all of them could be answered based on past experience. Shah remembers, "Goldman Sachs asked, 'what is the residual value of these panels? What can you resell them for after the 25 years?' And I scoured the internet and found only about 12 transactions."

In June 2005, Goldman Sachs agreed to fund the first solar project with SunEdison. "People were more interested when Goldman came in, but we still needed to pay 'trust brokers' — individuals who vouched for us and had a knack for exclusive transactions. We paid syndication fees to one particular broker, who specialised in rolling stock — trucks, trains, etc. — for municipal and state governments, and had a record of bringing banks transactions that they liked. He helped us get one deal done with a low-level agent for Wells Fargo out of Minneapolis, who ran the division leasing diesel generators and other equipment. This avoided the top guy at Wells Fargo, who believed solar was too risky for leasing finance (and did not know they had done a solar transaction until 8 months later). Wells Fargo's holding company was making 11–12% return from solar and wind investments, but we got financing at 4.6% interest from the same company's leasing division. We never disappointed them though. We made all the payments on time."

By 2008, SunEdison was one of the largest solar companies in the US and had bought six smaller engineering contractors, and banks were becoming comfortable with lending to projects using experienced contractors (like SunEdison). It was able to scale up rapidly in 2009, moving into markets like Italy and Canada. It claimed a then-ambitious pipeline of 1.5 GW of projects in plan, when in November 2009 it was bought by polysilicon maker MEMC for $200 million. MEMC made SunEdison the main growth driver of the company, even changing its name to SunEdison (more about further developments, including bankruptcy, in the following chapter).

Jigar Shah, the founder, left to pursue other opportunities, ran an investment firm called Generate Capital from 2014 to 2021, and now is the Director of the US Department of Energy Loan Programs Office. In 2017, he coined the Jigar Shah Rule, "Countries should not have stupid policy." In October 2022, after the US passed the Inflation Reduction Act and increased his office's authority to arrange loans to $400 billion, Bloomberg News described him as "one of the most important players in the energy transition."

Chapter 13

Solar Failures 2009–2013: Case Studies

It's always easy to point at mistakes made by executives and companies with the benefit of hindsight, but the people managing solar manufacturers after the 2008 crash in global prices were in a very difficult situation. The selling price of modules was often below the cost of production, and the main way to improve the cost of production is by expanding production volume and setting up new, technologically advanced factories. The economically logical alternative, simply to shut down until the module price went up, would probably be the end of the company as competitors would continue to expand and bring their costs down. Large firms which had invested in their brand were unwilling to do this. The only good way forward for manufacturers was to start developing and building their own solar power plants, to capture some of the margin they were losing to competition on module sales.

It is a dangerous fallacy that simply expanding into a new part of the value chain will always add value to a company. A company's value is based on its return on capital employed, as well as its growth, and going into a new sector only makes sense if the return on capital employed in the new sector is at least as high as the return on its existing businesses. A company's return on capital employed depends on the profit, divided by the amount of money it has invested in its operations. When your existing business of solar module making is generating horribly negative returns, it can't really hurt to go into a part of the value chain where returns are positive — unless you do it very badly.

13.1 Suntech

Suntech Power Holdings was the first Chinese solar company to file for a US Initial Public Offering, on the New York stock exchange, in 2005. It grew to become the world's largest solar module manufacturer in 2010 and 2011 and was one of the best-known and respected Chinese brands. Its charismatic and affable founder and CEO, Dr Zhengrong Shi (Shi is his family name, and under Chinese convention would appear first), studied at the University of New South Wales, Australia, under Professor Martin Green, still a world-leading academic researcher on solar technology. In 2001, Dr Shi returned to China to found Suntech and, by 2005, was one of China's richest men, with glowing newspaper articles about the 'Sun King'.

To many at the time, Suntech symbolised the best of Western technology in partnership with Chinese industrial efficiency. Professor Green, speaking in July 2018, credits the firm with bringing real expertise in cell technology (not just module assembly) to China for the first time and accelerating cost reductions for the whole industry.

Like most solar manufacturers, Suntech made losses between 2008 and 2012 due to the oversupply of modules. Dr Shi himself went on a roadshow for investors and banks, explaining the technical edge Suntech had with the aim of differentiating Suntech's product and asking for a higher price. (I attended one of these roadshows and learned a lot about solar manufacturing technology — Dr Shi was generous with his time on follow-up questions, quite beyond a sales pitch. It was obvious even then that he was more interested in the technology than in the money.) Suntech had raised a $541 million convertible bond (i.e. it borrowed money which could be repaid in cash or converted into stock) in 2007, due on March 15, 2013.

Suntech was ahead of many of its competitors in realising that the market for modules would crash and that it should diversify. In June 2008, it took control of Global Solar Fund (GSF), which invested in PV projects in Spain and Italy. In May 2010, Suntech guaranteed a financing arrangement of 554 million euros by China Commercial Bank to GSF and related companies, using 560 million euros of German government bonds held by GSF Capital as collateral.

As the market got worse in early 2012, Suntech tried to sell GSF to raise cash but 'uncovered irregularities' during its internal due diligence.

On July 30, 2012, Suntech admitted that it had investigated and found out that the German bonds used as collateral did not exist. This was embarrassing, and Suntech's stock price fell 41%. Dr Shi was removed as CEO in August 2012, although he remained in the non-executive role of Chairman, and was still a majority owner of the company. The bizarre case of the non-existent bonds was settled in March 2013 without GSF directors admitting liability. Dr Shi was still listed on the entrepreneur magazine Hurun Report's China Rich List for 2013, with wealth of $300 million — albeit mostly tied up in Suntech stock.

Later in March 2013, Suntech's convertible loan came due, and the company did not have the cash to pay it. Although it attempted to negotiate a delayed settlement, it was forced to file for bankruptcy on March 20, 2013.

In September and October 2013, Italian courts ordered the seizure of 47 solar plants, totalling 37.8 MW, owned by GSF (i.e. Suntech), due to what it described as potentially fraudulent permitting and planning. This did not increase the chances of Suntech finding a way to negotiate bankruptcy as an independent company.

In November 2013, the local government in Suntech's home province of Wuxi found an acceptable way to keep the factories running and not lose the local jobs: Hong Kong-listed manufacturer Shunfeng Photovoltaic — formerly a very minor player compared with Suntech — took it over. Most of Suntech's many creditors were forced to accept just under a third of the money they were owed since no better options were available.

Suntech's fall shows that diversifying downstream in the value chain is not always a safe bet, especially when a firm with manufacturing expertise plays in the tricky world of Italian paperwork. Dr Shi, speaking with hindsight in July 2018, says of the company's fall that "We were cheated by a bad person [at GSF]. We knew this guy for 3 years, but sometimes people can change. However, there should have been no risk to the financing — for all the assets guaranteed, we had the project itself as collateral, there were three layers of security." The German bonds were never called upon. "Once we discovered that we were cheated, we willingly disclosed this to Wall Street. That triggered panic selling and the stock price fell, and the Board of Directors said someone had to be sacrificed for the board to save face." That someone was Dr Shi.

"This move to save face was counterproductive", he says. To build the company, Dr Shi had forged strong ties of trust with Chinese banks and local governments, and the Board — including David King, former Chief Finance Officer, who became CEO — had not. "Once I was removed, they hired a basic team to run the firm," he says. "David King had never lived in China, did not speak Mandarin, did not understand the way of doing things in China. The only thing the board could do was threaten and blackmail the government and banks that if they did not do such-and-such the company would go bankrupt." The Chinese authorities did not act to rescue the company under its American-style new management, and instead, it was sold at a knockdown price to new management under Shunfeng.

After Suntech went bankrupt, Dr Shi was free, though times were tough as the media reported that he was under investigation by the Chinese financial service authorities. He was still the largest shareholder, and in China, it is often assumed that the largest shareholder has operational responsibility — but he had no authority over the company's decisions after being removed as Chairman in April 2013. "I would have been put in jail many times if I had done all the things that media said I did! But I had just trusted the wrong people," he says.

He was cleared of deliberate wrongdoing and was free to move to Sydney. After 10 years of living the CEO lifestyle of constant travel, chauffeuring, and everything being arranged for him, he spent 4 months learning to drive, to shop, and to cook. "I could have eaten out every evening with friends, but I cooked alone, and after a few weeks I was so happy and confident. I lost 10 kg and finally had my body back!"

Dr Shi is now an adjunct professor at the University of New South Wales and has a number of investments in solar companies. He is particularly involved on the technical side of a new company, SunMan, making semi-flexible crystalline silicon PV panels under the brand name eArc.

Suntech is back in operation as part of Shunfeng. It no longer has an outstanding reputation for technological leadership among solar cell makers but is still a major cell and module manufacturer with a brand respected for quality.

13.2 Solyndra

Solyndra was a Silicon Valley-based company making solar panels comprised of racks of tubes with copper indium gallium selenide thin-film photovoltaic coating. The idea was that they were lightweight and had low wind resistance relative to normal solid modules and so could be installed on commercial roofs too weak for conventional solar. Best of all, they didn't use silicon, which, at the time the company was seeking to scale up, was spiking in price to over $400/kg. In 2009, Solyndra reported a module selling price of $3.29/W, about 80 cents/W more expensive than crystalline silicon but potentially easier to install — not too unsound an economic proposition. Several German firms were major customers, as the German feed-in tariffs were good and some German roofs are not suitable for normal modules. The argument Solyndra made was that these roofs would never be suitable for normal modules and therefore there would always be a market for an alternative product (this argument is still made today by makers of niche products. It hasn't worked yet).

In March 2009, Solyndra was awarded a $535 million loan guarantee from the US Department of Energy, as part of the '1705' economic stimulus programme intended to restart growth after the 2008 financial crash. The Federal Financing Bank provided the money, to be used to construct a second factory making 250 MW of modules per year. In addition, Solyndra raised nearly $1.2 billion from venture capital investors including Argonaut Private Equity, Rockport Capital, Redpoint Ventures, and Abu Dhabi state venture Masdar.

In August 2011, Solyndra ceased operations and shortly afterwards filed for bankruptcy. Many of its manufacturing assets were sold at auction, but little of the investors or government money was recovered. The firm had simply been unable to sell as the crystalline silicon module price dropped; in 2009, it had been competing with crystalline silicon modules at around $2.00/W, but by late 2011, the crystalline silicon module price was around $1.40/W. German tariffs had been reduced in line with the reduction in photovoltaic costs, exposing the fallacy of the 'niche market' argument; it was not economically viable to install Solyndra modules under the new, lower tariffs and increasing the tariffs again would have over-rewarded normal solar, even if the government had wanted to do it. Solyndra had no workable pathway to bringing the cost down to a competitive level and swiftly ran out of cash.

The Solyndra debacle was the trigger for many recriminations, particularly towards the US Department of Energy for using federal money to back a loser. The process of awarding the loan guarantee was examined and concerns were expressed about transparency and corruption, but ultimately nothing too scandalous was uncovered. The US government had simply decided to take a risk it expected to have a strategic payout, and along with the private investors, lost. Across the whole loan guarantee program that Solyndra was part of, losses as of 2022 have only been about 3% of the money lent, a perfectly acceptable rate for a government measure to support innovation.

The firm was not the first or last expensive thin-film failure; for a while, Silicon Valley venture capital investors seemed to feel that they all needed a thin-film company in their portfolio in case thin film was The Next Big Thing. This kind of groupthink is not unusual among humans.

Some companies were worse than legitimate businesses which made bad decisions.

13.3 Hanergy

Hanergy is a case study of a solar company playing in the murkier areas of stock market fundraising and local development finance. Whenever there is enormous enthusiasm for a particular product or technology, there can be firms taking advantage to raise money beyond their ability to deliver on promises.

To begin near the end of the story, the market capitalisation of Hanergy Thin Film Power Group (ticker: 566) started rising for no obvious reason from $4.4 billion in July 2014 and hit $34 billion on the Hong Kong stock exchange in March 2015 (see Figure 13.1).

The market capitalisation stayed around this level until May 20, 2015, when the company's valuation plunged $19 billion in 30 minutes and it

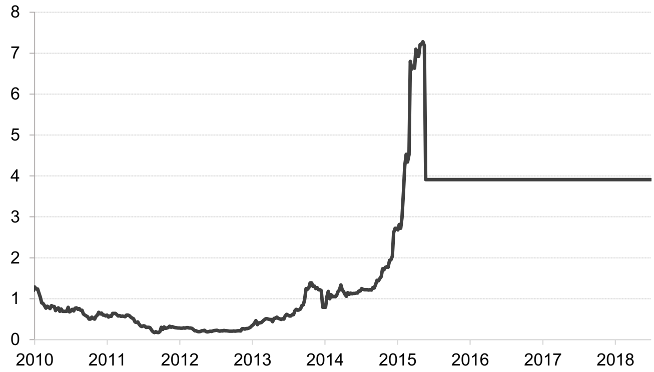

Figure 13.1 Stock price of Hanergy Thin Film, January 1, 2010, to June 29, 2018. Trading remained suspended until the company delisted in June 2019 and collapsed in December 2019.

Source: Bloomberg terminal.

requested that trading be suspended. The Hong Kong Securities and Futures Commission ruled that trading would remain suspended while it investigated the company. In December 2019, the company properly folded and laid off all staff around the world, many with no warning or benefits.

Hanergy Holdings was founded in 1994 and developed a number of hydroelectric dams in rural China, in partnership with local government. In July 2009, the company entered solar with a reportedly $4 billion research and development centre for thin-film silicon solar technology in Heyuan, Guangdong, China. The founder, Li Hejun, had a history of entering industries where government funding was available for local projects, of which the hydro projects were the only notable success. He had very ostentatious offices at a former nightclub on the Beijing Olympic Park, designed to impress government officials and other visitors and encourage them to commit capital to his ventures.

In May 2010, Hanergy Holdings went through a complex transaction by which it became both investor and customer to Hong Kong-listed thin film silicon solar tech company Apollo Solar. Apollo was renamed Hanergy Thin Film (HTF) because it really helps with clear reporting when both sides of a contract have the same name. Hanergy Holdings agreed to buy $2.6 billion of manufacturing equipment from HTF.

An article titled *Blinded by Hanergy's Light*, by media group Caixin in December 2012, detailed substantial local government loans and financing that Hanergy took, in exchange for promising investments in factories and projects that would create local jobs. These investments either did not materialize or were downsized, and since all factories were supposedly using HTF equipment, much of the investment was booked as revenue by HTF. There was also a 30 billion yuan ($4.5 billion) credit line extended by China Development Bank for projects, although this was probably not fully used (similar credit lines to other solar companies with the China Development Bank were quietly cut off when the market deteriorated).

Lucy Hornby of the *Financial Times* in Beijing points out that "this intersects on a much bigger issue outside solar power finance, the relationship between Chinese companies and their Hong Kong-listed subsidiaries. Sometimes mainland Chinese window-dress the results of the Hong Kong-listed subsidiary by stuffing any bad news into the unlisted operating companies." She explains that this boosts the Hong Kong company's stock price and may enable it to raise further financing more easily, by making the listed company appear more attractive than the corporation viewed as a whole. By any standards, however, HTF was unusually reliant on reporting revenue from Hanergy Holdings and appeared to have no sales to unrelated companies.

Hanergy Holdings then issued regular updates on the construction of factories in China's Haikou, Shuangli, Wujin, Changxing, Yucheng, and Heyuan districts or cities, using the equipment. These updates did not include claims of actual production. In November 2012, Hanergy Holdings said that it had 3 GW of annual thin-film silicon solar module manufacturing technology, which would have been very impressive if it really existed and functioned. There were few reports of Hanergy modules being seen in the field, although we saw a few samples at trade shows. Nowhere near 3 GW/year could have been produced because that volume would have shown up in the market somewhere. It is very common for manufacturing companies to report greater factory capacity than is actually in production at the time, but in Hanergy's case, the discrepancy was very large indeed.

In 2013, the firm went on a technology buying spree, acquiring thin-film companies in Europe and the US that had been developed using large amounts of venture capital (Miasole had raised $495 million). The entire portfolio — Solibro, Miasole, Global Solar Energy, and Alta Devices — cost about $200 million and definitely existed. Hanergy also bought UK solar installer Engensa, which definitely existed and sold products through the Swedish home shop IKEA. In 2013, I visited Hanergy Solar's stall in IKEA in Zurich and got a quote for getting my house fitted with solar (it seemed a little expensive and the subsidy regime at the time did not justify solar, but it was legitimate enough).

In 2014, Hanergy's stock price climbed steadily for no obvious reason. From July 2014 to March 2015, its market capitalisation rose from $4.4 billion to $34 billion. CEO Li Hejun was listed by *Forbes* in October 2014 as China's richest man, due to the value of HTF stock he held. The company's reported revenues and profits still seemed to be entirely due to HTF selling manufacturing equipment to Hanergy Holdings, however, and there was still no evidence that Hanergy Holdings was using the manufacturing equipment to make modules. A few journalists including Lucy Hornby at the *Financial Times* and a team at Caixin Global, me, and an equity analyst called Charles Yonts seemed to be the main people publishing output sceptical about the stock price rise.

Although few equity analysts covered the stock, it was included in several indices tracking the general clean energy market (including some selected by BloombergNEF. When you are constructing an index of quoted companies to track a sector, you are trying to choose a diverse and representative range of companies in the sector, not pick winners). It was very thinly traded on the Hong Kong exchange and so very hard to short sell (short selling is an investment strategy used when you believe a stock price will fall. You borrow the stock from someone who owns it, for a small fee, and sell it, planning to buy it back at a lower price to return to the owners. You make money if you buy the stock back for less than you sold it for, minus the borrowing fees).

Financial Times analysis in March 2015 showed that HTF share prices "consistently surged late in the day, about 10 minutes before the exchange's close, from the start of 2013 to February [2015]… This means that an investor who held HTF shares from the start of trading at 9 am to 3:30 pm would have lost money — despite the company's share price rising by 1,168 percent between January 2013 and February 9, 2015." This does not conclusively prove that the share price was manipulated but is unlikely to have occurred by chance.

In early 2015, I wrote a short note on the discrepancy between Hanergy's $34 billion valuation and that of its theoretical peers, First Solar at $6.1 billion or Trina Solar at $1.1 billion (both companies which were definitely making and selling large volumes of solar panels).

Charles Yonts, looking back in June 2018 on sentiment from Hong Kong stock market investors during the rise, said, "They were bemused. The reason that institutional fund managers were concerned was not that they wanted to hold the stock — anyone who looked at it even briefly felt assured that it wasn't something that they needed to own — but the problem was that Hanergy was in the indices which track the overall Hong Kong stock market [which rose due to Hanergy's presence]. How they are performing relative to the market is everything to a fund manager, and whatever they were doing, they were underperforming Hanergy, and getting questions from their bosses about that."

In May 2015, the HTF stock price crashed, and the Hong Kong stock exchange suspended trading while investigating the connected transactions between the legal entity Hanergy Holding and HTF. This was complicated because, according to the Hong Kong Securities and Futures Commission, Hanergy Holding refused to supply documents. In September 2017, Li Hejun was barred from "serving as a director on the board of any company in Hong Kong for 8 years, after a court ruled that he was involved in misconduct related to the running of the former solar giant" (*Bloomberg News*, September 4, 2017). IKEA quietly switched to a different technology supplier.

In May 2019, Hanergy attempted to resolve the situation by swapping the stock for a vehicle it said it would attempt to relist on an exchange. This evidently failed. According to an article from PV Magazine, all its 600-odd employees around the world were laid off without notice in

December 2019. There are still court cases dragging on, but the story is done. Li Hejun is still barred from serving as a director for any company in Hong Kong.

Charles Yonts concluded at the time that "Hanergy has been forgotten like a bad dream by Hong Kong investors." However, he added in 2022, "it pains me to credit the Hanergy debacle with anything useful, but it may have been the last straw which in 2019 forced the Hong Kong stock exchange to clean up its outrageous roster of companies which had been suspended for more than a year."

13.4 SunEdison

SunEdison had a confusing history as a polysilicon manufacturer called MEMC, which acquired a rooftop solar project developer called SunEdison from its investors and from founder Jigar Shah in 2009 and from 2013 onwards made solar project development the focus of its business. The firm, then with a market capitalisation of $1.9 billion, raised debt and equity to acquire or develop pipelines of solar and wind projects around the world. It was extraordinarily ambitious, sending teams into India, Latin America, and the Middle East to scout out project opportunities and buy options on land, as well as buying some successful wind project developers with pipelines. It even hired away one of BloombergNEF's researchers in Japan to find its solar projects to build there.

A recurring danger of project development is that costs occur well before revenue, and project developers tend not to have a large pile of cash to fall back on. The idea of being a project developer is that a firm will sell projects once they have been built to long-term investors, realising cash to reinvest in further projects — but if something goes wrong with this process, the developer can find itself owning a large number of half-finished projects but unable to pay its bills. Consequently, the timing of project sales is very important to developers.

In May 2014, SunEdison launched a 'yieldco' called TerraForm Power. Yieldcos are worth further explanation.

There are various risks in investing in a renewable energy project. Most of them are risks about whether you will get your money or not — performance risk, payment risk, and curtailment risk (this last is when the grid does not have enough capacity to take the energy your project is generating, so you lose it). If the project pays in a currency other than your own, there is currency risk — the project may pay a constant and reliable stream of rupees, for example, but they may be worth less of the dollars or euros that you needed to buy the equipment in the first place and that you need to pay your staff or pay dividends to your investors.

Another form of risk is liquidity risk: you may need to get your investment out in a hurry, for example, if you are an insurance firm that needs to make a big payout. This is a big problem if you have invested your money in buying a solar or wind project because to get a good price when you sell it will take time — a buyer will want to do due diligence on all aspects of the project. Hence, many funds have a restriction on how much of their money they can invest in such 'illiquid assets' which cannot quickly be sold for a fair price.

Yieldcos are, fundamentally, a way of reducing liquidity risk to attract a larger pool of investors with a low cost of capital. The idea is that a yieldco owns a portfolio of simple cash-generating assets — solar projects or wind farms, for example, or electricity transmission lines. The yieldco is then listed on a stock exchange, and the shares traded. It releases regular, transparent results about how its portfolio is performing and about projects it plans to buy. Investors hold stock in the yieldco, they expect dividends, and they can sell stock on the stock market if they need the cash in a hurry.

This is the classic model, used by European solar yieldcos, such as Foresight, Bluefield, and NextEnergy: launching traded funds which hold a fixed portfolio of solar projects and gave regular dividends. Sometimes, they raise more money from new investors, buying further projects and increasing the revenues to remunerate the new investors. Occasionally, they might get ambitious, for example, by renegotiating an operation and maintenance agreement downwards to increase return for shareholders slightly, or securing a loan at a lower rate of interest. But they were not intended to be high-return or exciting investments. As of late 2022, the 'boring ones' — the traded solar funds of Foresight, Bluefield, and NextEnergy — continue to be listed on the London stock exchange and doing basically what they promised. So the idea isn't fundamentally a bad one.

One problem with American yieldcos around 2014 and 2015 was that they were being marketed as stocks with a high growth potential. Jigar Shah, who sold SunEdison in 2009, explains that "at the time, comparable companies like Canadian income trusts told their investors that they would grow at 3–5%/year, while the US solar yieldcos offered, at the low end, 8%/year and SunEdison — the most egregious offender — offered 20% growth per year." One reason for this was that US renewable energy yieldcos could enjoy tax advantages if they kept adding more projects to their portfolios. However, outside the tax structure, it should have been clear to investors that growing a project portfolio without either further investment or taking risk was not possible. In any case, the promise of growth was alluring to investors but created a constant need within the yieldcos for more projects.

SunEdison's new yieldco, TerraForm Power, also started out on the hunt for projects but had an additional problem. Six out of twelve of TerraForm's advisory board members were also on SunEdison's board, and the projects bought by TerraForm were being sold by SunEdison. The setup was not unusual at the time. Spanish construction and infrastructure firm Abengoa had a similar arrangement with its own yieldco, Abengoa Yield and US manufacturer-developers SunPower and First Solar worked together with a vehicle called 8point3energy (light takes 8.3 minutes to travel from the Sun to the Earth, by the way). A few investors pointed out the possible risks of a company transferring assets from itself, to a vehicle controlled by itself but owned by external investors. The obvious risk is that the price paid by the yieldco (and therefore ultimately by investors) might be more than the project is really worth.

For the first 2 years, there was little evidence of any problems with developers using the yieldcos they controlled. In July 2015, SunEdison launched a second yieldco, TerraForm Global; while TerraForm Power was only investing in North American projects, TerraForm Global had a wider remit to buy SunEdison projects in the developing world.

In 2015, however, SunEdison was under some financial pressure. It had a lot of projects under construction, with suppliers and contractors demanding to be paid. Activist shareholders alleged that it was taking early payments from TerraForms to meet its urgent requirements and perhaps being optimistic about the assumptions used for valuing the projects being transferred to TerraForms.

Stock prices may also have played a role in the company's poor decision-making. Soaring stock prices depress the 'yield' of the yieldco (the yield is the annual dividend per share — a regular payout from cashflow — divided by the stock price). Jigar Shah says that "the yieldco was paying a dividend from its operating solar projects, but the yieldco's stock price went up so the yield went down. SunEdison made the mistake of thinking that people loved solar so much that they were willing to own the stock at a price which only paid a 3% dividend yield. So they said, our cost of capital has suddenly gone from about 7% to about 4%. To get our growth done, we can buy all of these assets at 4% return — including TerraForm Power paying two billion dollars in 2015 for a portfolio of wind projects from developer Invenergy. So SunEdison had lost discipline and was overpaying for assets because it thought investors were fine with paying for growth at any cost. This was not true, and as soon as the investors figured it out, they sold stock."

"The assets were good, but the company had paid too much for them [see Chapter 14 for how to calculate the value of cash generating assets]. The firm raised more debt, which was easy to do using the high stock price and consequent valuation of 30 billion dollars." SunEdison's stock price fell 93% from July 2015 to March 2016, not because of any obvious market developments but simply because investors had lost trust in its model. This made banks which had lent SunEdison money nervous about its ability to repay. Already, its interest payments were substantial — in the third quarter of 2015, SunEdison paid interest of $214 million and selling, general, and admin expenses of $296 million on revenue of $476 million.

SunEdison came up with a hare-brained scheme to buy US rooftop firm Vivint Solar for $2.2 billion, which caused further unhappiness among activist shareholders (notably billionaire David Tepper, who filed an action to block the sale in February 2016). Vivint pulled out of the deal in March 2016 and SunEdison filed for bankruptcy in April 2016. Over the next 2 years, all of SunEdison's assets were sold off piecemeal to other developers. The TerraForm yieldcos were bought in late 2017 by Canadian private equity fund Brookfield.

As of 2023, even the scandal-free US yieldcos like 8point3energy have been acquired by private firms which do not have those irritating public reporting requirements. However, the European ones which did not overpromise or claim to be exciting continue to trade as planned. The yieldco model (or something with a different name but working the same way) will probably come back at some point.

13.5 Conclusions on Solar Bankruptcies

The module oversupply of 2010–2013 left even some of the survivors, such as Yingli, with depleted balance sheets and high levels of debt. The grim truth is that making solar modules is never likely to be a very profitable business, and building bigger and bigger factories to drive down costs is a technique that works but keeps margins tight. In this respect, it is similar to semiconductor manufacturing, where customers rather than most of the companies capture most of the value generated [Heck *et al*., 2011].

Developing solar projects can be a profitable business, but missteps and miscalculations here can be just as dangerous as in any other segment.

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Chapter 14

Project Finance and Calculating the Cost of Energy

Solar panels are sold in Watts, while energy is sold in kWh or MWh. This chapter aims to lay the foundations of how to translate from one to the other and explains levelised cost of energy (LCOE), which is a way to compare different sets of future cashflows.

14.1 The Cost of Capacity and the Cost of Generation (Buying a Car Versus Total Cost of Driving)

So far, we have mostly discussed the cost of solar photovoltaics in terms of dollars per W. This is because the per-W cost is the main feature of solar that is dependent on technology and can be quoted without a long discussion of the assumptions made. A Watt is just the capacity to produce electricity under standard (nearly optimal) conditions; real solar projects will only produce this much for a few hours per day (at most). The capacity in watts tells you how large the solar plant is.

Electricity is bought and sold in Wh (or, usually, kWh or MWh). So a relevant question is as follows: How much does electricity from a solar plant cost per MWh? Unfortunately, this is not a simple question. (It is also not the only relevant question, but that complication will have to wait.)

An analogy is that the cost per W is like the price of a car, while the cost per MWh (LCOE) is the cost of driving a car per km — including the cost of buying the car, interest on the car, loan, fuel cost, insurance, and maintenance. In the car analogy, you may want to calculate this to decide whether you should buy a car or take the train to work, since you probably know the price of a train ticket.

We will return to the car analogy when we get to the maths. The best practical definition of LCOE is as follows: 'What would you have to pay someone per MWh to build the power plant and sell electricity to you?' In fact, if you are a government or electricity market planner, the easiest way to find out is to hold an auction — declare that you plan to buy, say, 5,000 GWh at the lowest price bid. Then, let the companies which specialise in developing solar projects figure out what they want to offer; there is now enough competition that you will get multiple bids and there will be pressure on bidders to submit their lowest price.

If you want to duplicate a bidder's process with your own model, there are three major variables (and one minor one, which is the operation and maintenance cost — see Chapter 20). The first is the 'capital expenditure' (capex) of the solar project, the cost per W, which we have already discussed. The second is how sunny it is at the location (i.e. the insolation, but there is really no advantage to using a technical term here. And many spellcheckers 'correct' it to insulation). Sunniness can be measured, but not controlled, and determines the 'capacity factor', which is how much energy is generated per year, usually expressed as a percentage equivalent to the hours running at full capacity. A solar project generates more energy in a sunny place than in a less sunny place. The capacity factor of a rooftop photovoltaic system in Germany is likely to be 10–12% and in southern California 16–21%.

The third, and conceptually most difficult for those of us with a non-finance background, is the cost of capital and time value of money. This will require a short diversion through the history and ethics of lending at interest. It also applies to the car analogy, where you may have to borrow money at interest to buy a car or at least will need to tie up your savings in the car; see Table 14.1.

Would you rather have $100 today, or $100 in a year's time? Probably, the answer is easy; even if there is nothing you want to buy, you could put

Table 14.1 Analogy: Levelised cost of energy of a power plant versus cost of running a car per mile.

Component of LCOE	**Equivalent component of cost per kilometre**	**Notes**
Capital expenditure (capex) to setup project	Cost of buying car	For a renewable energy project, this is most of the total cost.
Capacity factor	Kilometres driven per year	For a renewable energy project, this depends on the resource. For a gas-fired power plant it depends on how much the plant is needed.
Fixed costs/operation and maintenance cost	Cost of insurance and service	This is less important the more energy generated or distance driven. It is also historically very low for solar projects, but see Chapter 20.
Variable costs, e.g. fuel	Fuel cost	Zero for a solar or wind plant. Considerable for a fossil fuel plant. Can be negative for a plant burning rubbish which needs to be disposed of.
Cost of capital	Interest on auto loan for purchase (or opportunity cost of spending your savings on a car)	This is more important for renewable energy plants than for fossil fuel plants because more of the cost is upfront. It is generally proportional to risk; the higher the risk, the higher. the cost of capital.

the money in a bank account today and earn at least a pittance — let's say 1%/year when interest rates are low — of interest so that you would have $101 in a year's time. For such a small return, you might simply decide to spend it on beer or put it towards a really good-quality item of clothing which you'd enjoy wearing all year. This is how low-interest rates stimulate consumer spending.

Would you rather have $102 in a year's time or $100 now? What about $110 in a year? These answers really depend on you, both your rational and your irrational decision-making. If you have credit card debt on which you pay interest of 20%/year, rationally you should pick the $100 now unless offered more than $120 next year. But you might be offered $120 in a year and yet really really want that $100 now as you are about to go on holiday and want spending money. Whatever you feel, the money has a time value to you, and you have an implied personal 'hurdle rate' determined by the opportunity cost of other investments; 1% if you cannot think of anything better to do than put it in the bank, 20% if you could use it to pay some of the credit card debt, and perhaps more if having that $100 to spend on holiday means a lot to you.

The other thing that affects your decision is the risk. In the example above, we have assumed that you trust the person offering you money now or more money in a year. What if you don't? If you think the person is flaky, you'll take $100 now instead of any amount of money in a year. If you expect that they'll pay up but have some doubts, you might increase your hurdle rate/cost of equity (these two terms mean essentially the same thing).

Businesses and financiers are generally more rational in their financial decision-making than individuals, and so their hurdle rates are usually determined by other uses of cash available to them ('opportunity cost'), with consideration for the risk of investments. Taking higher risk should always require a higher return, as a basic principle of finance. This is one reason why banks set credit card interest rates higher than mortgage interest rates; if the mortgage owner cannot pay the interest, the bank gets the house and can sell it, while if a credit card owner does not pay, the bank may never get any of the money back (car loans are somewhere in the middle, as a car can be resold but for much less than its original price, and car loans may also be cross-subsidised by car manufacturers to increase sales).

Anarchist historian David Graeber points out in his entertaining book *Debt: The First 5,000 Years* (2014) that "looking over world literature, it is impossible to find a single sympathetic representative of a moneylender, or anyway a professional moneylender, which means by definition one who charges interest." He has a point there, but there's an argument that debt is not a bad thing.

Imagine a world with no debt. It's not that difficult — for much of European history, the practice of usury has been outlawed or severely controlled by the state. Jewish people, who were often banned from other businesses, were the main providers of consumer debt and were periodically persecuted for it even by the people who used their services. In much of the developing world, banks offering debt to individuals still don't exist as of 2023. On the plus side, this means no predatory advertisements of payday loans for beer and holidays at exorbitant rates of interest (which can be cynically targeted to exploit the financially illiterate). On the minus side, it means poor people have no access to capital when they could use it profitably. A small-time vegetable grower cannot borrow money to buy a handcart which would quadruple the amount she can sell every time she walks to the market, and pay off its initial investment in months. A farmer can't buy an irrigation pump that would triple the production of his fields and save him hours of backbreaking labour every day. Almost nobody can get together the money to build a huge but socially beneficial project like a railway or a power grid.

Sometime in the 20th century, Western banks realised that their previous policy of lending money only to states or to rich gentry with land assets was causing them to miss out on profits from lending to higher-risk people at higher rates of interest. "If you never miss a plane, you spend too much time in airports" pointed out 1982 Nobel Prize-winning economist George Stigler — in other words, if you lend money to many people and never have one not pay you, you are being unduly cautious. There are probably many slightly more risky prospective borrowers, who could reasonably pay a higher rate of interest, more than enough to justify the occasional failure to pay back.

An extreme example of this is microfinance, which is regarded as a powerful tool for reducing poverty in developing countries, even though interest rates can be over 25%. They are not the answer to everything. A study on microloans [Banerjee *et al.*, 2015] noted 'a consistent pattern of modestly positive, but not transformative, effects'. Another by the US Government Accountability Office found "that microenterprise assistance helped recipients in the short-term, but found little evidence of lasting effects. Academic reviews also show few long-term effects on women and the very poor" [Gootnick, 2021]. High-interest microfinance lending programmes in India and Cambodia have led to land seizures and suicides; debt must always come with the prospect of debt forgiveness if it cannot be paid. However, microfinance may be more appropriate for renewable energy than for other types of loans. This is discussed further in Chapter 23.

The cost of capital is much more important when determining the cost of renewable energy than for gas, coal, or diesel because nearly all the renewable energy cost is upfront, and interest payments (or dividends to equity holders) are a major part of the plant's lifetime expenses. The higher the cost of capital, the higher the levelised cost of energy generation. In general, the cost of capital is split into two parts: debt and equity. The equity holder is the legal owner of the project, just like a homeowner, while the debt provider has lent them the money to buy the project, like a mortgage provider on a house.

The interest rate on the debt is likely to be lower than the cost of equity because the debt holder carries less risk: if the project produces less revenue than expected, the debt investor gets paid their interest anyway, while the equity holder suffers. Only once the project is performing so badly that the equity owner is getting nothing does the debt holder suffer — and since the project will usually be funded with about 10–30% equity, that is some serious underperformance. For solar and wind projects, debt is usually 'non-recourse', i.e. the debt investor/bank cannot ask the owner to reach into their other assets and compensate them if the project goes horribly wrong and does not produce enough cash to pay the interest on the debt. The equity owner expects a higher rate of return from their money than the interest rate, because they take more risk, but will also get any 'upside' if the project performs better than expected. Borrowing debt increases the return on equity investment by 'leveraging' it and in fact affects the weighted average cost of capital by more than that, because interest payments are tax-deductible expenses. All-equity large solar projects are very unusual, although all-equity funding is common in household solar systems in Europe, where individual people (i.e. not corporations) often have limited options for investing their money.

The LCOE is a function of all those things — capex, resource, and cost of capital (and operating costs, like maintenance). It's really something you backcalculate from modelling the returns on a system where a power price (or annual revenue or savings, power price times generation) is an input.

Let's create a very simple discounted cashflow model, where a household solar system costing $5,000 saves the owner $300/year and the owner is satisfied with a return of 5% (her bank is offering her 2%/year interest, and although she considers the bank safer, she also likes the idea of being green and independent from her utility). For simplicity, let's assume she installs it at the very beginning of year 1 and that maintenance consists of a routine system check-up and cleaning every 2 years, costing $100 (see Table 14.2).

The discounted cashflow is a way to make sense of the line 'total cashflow in year' taking into account the time value of money. By dividing the cashflow in a given year by the discount factor in the fourth line — with 5% the discount rate — you equate the value of a series of cashflows in the future with a lump sum in the present. So $285.7 today would be worth $300 next year to you if your cost of capital is 5%. You can sum these, and if the sum of the discounted cashflows is positive and you trust all your inputs, you should make the investment.

We can easily figure out that the initial investment pays back in 20 years, but our plant owner is savvy and wants a return of 5%, so is this solar system a good deal for her over 25 years? This is much easier to do in Microsoft Excel or similar software, and I recommend that you do this if you are seriously interested in the topic. I calculate that this is a very bad investment, with a 'net present value' of minus $1,234. If she drops her return requirement to 2%, however (maybe she gets extremely annoyed with her utility), this is achievable.

LCOE is simply the power price the owner gets (or saves) for each MWh, to make the project worth doing (a net present value of zero or higher). This is usually stated assuming that the power price paid, and the maintenance cost, rises with inflation. (This means that inflation forecasts can become one of the most important factors in your LCOE results, which is very annoying. However, it is technically a true result that the relationship between a project's fixed cost of debt and equity, and inflation, is very important to whether a project is really a good investment over its lifetime.)

Table 14.2 Cashflows for the first 8 years of a residential PV system.

	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**
Initial cost	–\$5,000							
Maintenance cost			–\$100		–\$100		–\$100	
Annual savings (power price $*$ generation)	\$300	\$300	\$300	\$300	\$300	\$300	\$300	\$300
Total cashflow in year	–\$4,700	\$300	\$200	\$300	\$200	\$300	\$200	\$300
Discount factor	0	$1/(1+5\%)$	$1/(1+5\%)^2$	$1/(1+5\%)^3$	$1/(1+5\%)^4$	$1/(1+5\%)^5$	$1/(1+5\%)^6$	$1/(1+5\%)^7$
Discounted cashflow at 5% (i.e. cashflow times discount factor)	–\$4,700	\$286	\$181	\$259	\$165	\$235	\$149	\$213

Of course, a real project finance model is massively more complex than this — it will include cashflows to equity, cashflows to debt (which can be set up in different ways), tax, may handle cashflows seasonally or monthly rather than just annually, and may have changing revenues (the power price may rise over time, or of course it may fall). Engineering a project for the maximum financial value is an art and a science. But the basic principle is sound and may be helpful in everyday life if you are trying to decide on a present investment with future payoff (as in the car vs train ticket analogy. You can include all kinds of extra cashflows such as the ability to make non-commute trips with a car).

To summarise, LCOE is a function of the initial capital expenditure to build the project, the cost of capital, the resource, and the maintenance cost. And it's all just a way to calculate what you'd have to pay someone per MWh to build the project. If someone tells you an LCOE for a renewable energy project without including at least these three variables, they probably don't properly understand the underlying calculation and may have used very incorrect assumptions. The most common among academics is to assume that money is free, which will be a shock when they apply for a mortgage. The most common among people selling solar systems is to assume electricity prices will rise strongly and continuously over the entire 25 years, which cuts the level they need to start at and boosts the internal rate of return of the project substantially. The problem with assuming this is that it may not actually happen; electricity prices can fall as well as rise, particularly over 25-year periods.

14.2 Cost of Capital and the Role of Development Banks

Governments and multinational organisations often seek to reduce the cost or LCOE of renewables. They cannot influence the capacity factor or, in the short term, the capex.

The main lever that governments can pull to support renewable energy is to reduce the cost of capital, either by reducing the risk of a project or by setting up as an investor themselves. Providing a guaranteed power price for all production, through a feed-in tariff or an individually negotiated power price, is a way to reduce 'offtake risk', the risk that the project will be unable to sell its power at a required price.

Other governments support renewables through a development bank, a way to support infrastructure investment they consider desirable. Many development banks were founded after a specific period of disruption, to help rebuild and promote peace and prosperity. They have been extremely important to renewable energy deployment; in 2021, climate finance by multilateral development banks totalled at least $65 billion globally according to the 2021 Joint Report on Multilateral Development Banks' Climate Finance, compared with BNEF's estimate of $366 billion invested in renewable energy in that year [Cheung, 2022] (the two figures cannot be compared directly as they cover different sectors). While $65 billion was the direct investment, most development banks aim to bring in much more capital from private sector investors by acting as the first taker of risk ('leveraging') or by providing guidance and information. For example, the International Finance Corporation (the part of the World Bank Group most involved in bringing in private investment) calculates that "since 1956, IFC has leveraged $2.6 billion in capital to deliver more than $265 billion in financing for businesses in developing countries" [IFC website, July 2018].

The German Kreditbank für Wiederaufbau (KfW), the Credit Bank for Reconstruction, was founded in 1948 to repair houses damaged in the Second World War and to rebuild the country's energy system, and now supports student loans, individual investments, municipalities and small businesses in Germany as well as environmental infrastructure and exports by German companies abroad. KfW assisted the German solar boom by providing loans to local German banks, which then provided low-interest loans to small firms and individuals for rooftop solar.

Another post-Second World War creation, the World Bank Group, was founded as the International Bank for Reconstruction and Development in 1944. It is now a group of five institutions with 189 member countries and a remit to end poverty and promote prosperity in developing countries.

The European Bank for Reconstruction and Development (EBRD) was set up 'in haste' (according to its website) in 1991, to respond to the collapse of communism in former Soviet Bloc countries. It now also invests in Mongolia, Turkey, Greece, and northern African countries and, unusually, requires that member countries be democratic.

Other development banks have more specific national priorities. Brazil founded its own development bank, BNDES, in 1952 to invest in industry and infrastructure in the country. The China Development Bank was founded in 1994, with a remit to “serve China’s major long-term economic and social development strategies,” and claimed plausibly in 2018 to be the world’s largest development bank. The African Development Bank Group was founded in 1964 by 23 African countries to promote sustainable economic growth and reduce poverty on their continent and later grew to include all African countries and 26 non-African member countries.

Morgan Bazilian, former Lead Energy Specialist at the World Bank, now Research Professor of Public Policy at the Colorado School of Mines, notes that “Renewable energy is dramatically increasing as a percentage of development portfolios [of development banks] both because of cost declines and because of demand from client countries.”

One principle of development banks is that they should not replace (‘crowd out’) private sector investment. If government and development funding is too easily and widely available, it can reduce the opportunities for private investors to make good deals and prevent the emergence of a healthy local financial ecosystem. Consequently, most development banks are trying to fund or support only projects that would not happen without their help.

According to Morgan Bazilian, this balance is becoming increasingly complex. “Development banks have to be careful about not crowding out private sector investment, and when you have a commercially viable sector like solar is today, that makes finding the options which do not compete with private banks more limited.”

He also notes that development banks really need large deals. “Microfinance opportunities are often too small for development banks, which are motivated to make large loans and minimize transactions — that’s just how they are set up.”

“One thing the World Bank can continue to do is to provide risk instruments — of various kinds in various markets — and ‘regulatory wraps'. These latter can be powerful and include technical assistance, such as funding for studies that can inform power system design, establish a market architecture and associated regulation, and develop robust mechanisms for dealing with new or different revenue streams and management."

The countries that most need help with finance are not those with the structures in place to make it easy to invest. "In markets like Mozambique or Guyana, the institutions are too fragile to simply copy how places like Norway or Alaska have handled their extractive resource revenues," Bazilian observes. "In least developed economies, solutions need to be tailored to be short-term, practical and incremental, to show real progress that can be built upon. Afghanistan and South Sudan don't need 500-page reports on long-term scenarios for addressing climate solutions right now."

In January 2015, the World Bank's International Finance Corporation launched a programme called Scaling Solar, which provides a package of services to help countries (especially developing ones) get privately funded solar projects within 2 years. Scaling Solar includes a standardised tendering/auction process with competitive financing, guarantees, and insurance available to all bidders, templates for project documents, and advice on project siting and grid integration. This last point is important, as there is no point in building a solar project if you cannot get the energy onto the grid. An early 8.5 MW project built in Rwanda, by Norwegian firm Scatec Solar, was initially hit by rolling blackouts which took the grid down for 25% of the time and made the project unable to export its generation during these hours.

Scaling Solar aimed to break the deadlock that many developing countries found themselves in after 2010. Several countries, including Jordan, Kenya, Nigeria, and Egypt, had discussed power contracts for solar projects and even agreed on prices, but the whole process took so long that before the projects were built, the prices looked extremely over-generous and the governments balked and found reasons to back out and renegotiate.

Zambia was the first country to sign a mandate with the Scaling Solar programme, in July 2015, followed by Senegal, Madagascar, and Ethiopia. The programme has not entirely succeeded in its aim of deploying solar in 2 years; the first projects in Zambia went into operation in early 2019, over 3 years after the country signed up, though this is still incredible speed for infrastructure in Africa. Ethiopia dropped out of the programme due to complications and disagreements. Scaling Solar has also been criticised for a cookie-cutter approach which fails to involve local conditions and for a blind focus on costs (to be fair, these are part of the point of the programme).

It has certainly achieved the aim of low costs; the projects in Zambia are paid \$60.2/MWh and \$78.4/MWh, fixed in US dollars (i.e. investors are protected from a weakening in the Zambian currency, the kwacha) for 25 years. This is partly possible because of the guaranteed financing. BNEF estimated in June 2016 that the cost of debt to Zambia's Scaling Solar projects was about 6%, compared with 10–12% for other Zambia bonds paid in US dollars without development bank involvement. The second Scaling Solar projects to go to auction, in Senegal, were won with even lower bids of 38–40 euros (\$44–47)/MWh in April 2018 and brought online in May 2021. This is, by any reasonable standard, cheap energy for countries which need it.

As of 2023, the Scaling Solar programme was making progress on projects in Togo, Niger, Cote d'Ivoire and Uzbekistan. But it is difficult to call it a real success at, well, scaling solar.

Chapter 15

2014 and 2015: Solar Auctions, Auto-Consumption, and Sun Taxes

The solar market started to look brighter for some firms in 2014. Prices stabilised across the value chain, long-term polysilicon contracts expired and the best module manufacturers started to make positive profit margins. The European feed-in tariff policies had generally been removed or brought under control, and the solar markets of Western Europe flattened out or contracted. Some new ideas for paying for solar were invented in this period.

15.1 Big Solar

Meanwhile, the governments of China and Japan became serious about solar, in very different ways. The Chinese government had tried to support its solar manufacturers in the previous 5 years through cheap land and cheap debt but really threw its weight behind incentives for actually building solar projects in 2014. It allocated a feed-in tariff and then quotas of projects by province, and most of these projects were built on schedule.

However, the sunny, sparsely populated Chinese provinces, such as Gansu and Qinghai in the northwest, had little local power demand and limited grid to transport electricity to where it was needed. China's National Energy Administration estimated that 31% of solar and 39% of wind electricity generated in Gansu had to be curtailed (thrown away) in 2015. This was partly due to insufficient transmission and partly due to the way the Chinese power sector was planned, with fixed prices by technology rather than a power market. This meant that sometimes utilities would curtail a renewable energy project and run a nearby coal plant instead — which clearly makes no sense.

Since 2015, the country built new transmission lines from the northwestern provinces to the eastern cities. The government also encouraged developers to build solar plants in the east of China, which is less sunny than the northwest but has many more cities that need the power. Many provinces have also been experimenting with power markets to set the priority of which power plants to run. The national solar curtailment rate in China fell to 5.8% in 2017, from 10.1% in 2016, with solar and wind together generating 6.72% of the country's electricity (PV contributing 1.75%), according to China's National Energy Administration. In 2022, wind generated 8.9% of China's electricity and solar 4.9%, with solar curtailment just 1.7%. The measures worked!

Japan introduced a European-style feed-in tariff in 2012, and repeated the mistake of setting the level of tariff at about the level that the domestic solar industry asked for. The Japanese government also made the tariff applicable to projects when they applied for the tariff, not when they got built — so you could apply, and then wait several years for equipment costs to drop before spending the money on building. In addition, the application for the tariff was initially such an easy process that many companies submitted applications to the Japanese Ministry of Energy, Trade and Investment (METI) before they had even established rights to the land, never mind planning permission. The result was an expensive, slow boom, modulated constantly by METI tweaking the rules. The boom ran out of steam around 2018 because the regulator allowed utilities to limit how much can be installed in their service area, but in 2014 and 2015 Japan was the world's second largest PV market after China.

In Europe, most countries were on track to build or had already built as much as they had put into their National Renewable Energy Action Plans. Since the Germans started uncapped feed-in tariffs in 2004, successive governments implemented them and caused a boom and bust in large-scale ground-mounted projects; the last one was the UK, where the government had never really meant to encourage large solar at all.

Roof-mounted PV is generally viewed favourably by politicians as it means votes, but it is very difficult to set prices to encourage only rooftop solar. By the end of 2015, Germany had entirely eliminated feed-in tariffs for projects over 500 kW, and tariffs for smaller systems were lower than the power prices paid by businesses and households. We once considered this 'grid parity', when the price paid per kWh for solar electricity exports could be lower than the retail price of electricity, and some observers expected some kind of tipping point in mass deployment. This now seems somewhat naïve.

A new idea started to take hold; instead of trying to calculate the prices you had to pay companies to build solar, why not turn it around and ask for the lowest price companies would build solar for? From a government's perspective, this is very attractive. A competitive auction should get the best price for power without the government having to calculate it themselves and inevitably get it wrong, plus the government can control exactly how much gets built. Latin American countries, South Africa, the United Arab Emirates, and India were some of the first and most enthusiastic countries to adopt tenders, but France and Germany followed suit. For the French, the criteria are complex and opaque, and this may be intended to benefit French companies at the expense of foreign ones without explicitly contravening European free trade laws. Apparently out of curiosity, the German government held several competitive tenders for very large solar and received prices around 82–85 euros/MWh in 2015 — setting a new benchmark low for the country (in 2018, these fell below 50 euros/MWh and bumped along at 50–60 euros per MWh for a few years, rising in 2023 into the 70–80 euros per MWh range).

The auctions generally worked well, with new record lows for the price of solar power being set every few months from 2015 to 2017. The first Dubai tender was won at below $60/MWh in late 2014 due to a combination of competitive capex, great sun, and relatively low-cost debt from Saudi banks. In 2015, the UK held its first solar auction. It is called Contract for Difference because governments love coming up with new names for things made out of words for other things. (See Key Terminology for a more serious definition, but it's essentially another price paid for power.) Major developer Lightsource bid at 79.23 UK pounds/MWh, escalated annually with inflation. This compares with 92 pounds/MWh, also rising with inflation, for nuclear plant Hinkley Point agreed at roughly the same time. It started to seem unreasonable to say that solar was simply too expensive.

Auctions bring their own problems. One of these is that if the barrier to bidding in the auction is low — which governments want, to ensure that the auction is a competition between many players — it can attract rather speculative bids from companies hoping to win a contract at any price. These companies' plan is to hope for a stroke of good luck, like a collapse in technology price or cost of debt, which allows them to build the project at a profit. Some simply seem to have misunderstood the auction rules. For example, in the UK's Contract for Difference auction, you get the price of power that you bid, not the highest winning price (as in many auctions and in power markets). One inexperienced developer bid 50 pounds/MWh, a price that was clearly impossible, apparently expecting to be paid the highest winning price; they promptly admitted on LinkedIn that this was not feasible and withdrew from the auction. Some early Indian solar thermal projects have not been built, presumably because the prices were not rational. The problem escalated in 2021 and 2022 when solar equipment prices rose instead of falling due to strong demand and inflation, and many developers found the prices for which they had promised to build solar plants to be unfeasibly low.

Strictly speaking, it is not a big problem for a government if companies win an auction and then can't deliver. It wastes the time of everyone involved, but PV is quick to build, after all, they can always run another auction and hope the bidders take it more seriously this time. This can be partially enforced by requiring bidders to 'post a bid bond' (pay money into a government account, which they will get back if they deliver their project but lose if they screw up) to get a power contract, or by requiring bidders to have a minimum of previous experience. Unfortunately, some governments, particularly in Latin America, the Middle East, and Africa, have felt embarrassed by having selected a bidder who cannot deliver, and go to irrational lengths to avoid this (such as finding another company to buy the winning bidder, and build the project, in exchange for a later more favourable contract). In general, embarrassment is a poor reason for abandoning the principles of capitalism in the middle of a fundamentally capitalist process.

15.2 Small Solar

In the first quarter of 2012, the German feed-in tariff for solar plants below 10 kW dropped below the average power price paid by households, as part of the scheduled reductions in the feed-in tariff. For the first time, German households began to care when they generated solar electricity and when they used it, because they saved more money by using it directly than they would get from the grid.

The results were not dramatic, as batteries are still much too expensive to build for such a small gain (though a battery subsidy starting in 2013 drove several thousand systems), but there were small shifts. For example, installers began to put up systems facing slightly west, so that they lost power in the morning but generated more in the evening when the homeowner was home to use it.

In late 2014, Germany passed a law to raise more funding for its EEG subsidy fund, this time from solar projects. The owners of new PV projects over 10 kW (i.e. not household systems) paid a surcharge for solar power they used instead of buying from the grid. This was only 2–3 euro cents/kWh (it increased slightly in 2016 and 2017) and could be argued to cover some of the costs of the distribution grid. The projects also get a feed-in tariff for exported energy, which while not as high as the avoided cost of buying power, is better than nothing.

For a few years, the boom was over in Germany and the German feed-in (or export) tariff was linked to build volumes, with annual new build over 2.5 GW under the feed-in tariff resulting in a decline of the tariff, and undershooting this level resulting in the tariff not being cut. In 2018, volumes edged over the 2.5 GW limit and the feed-in tariff fell slightly. Since new solar projects get paid much less, the cost of wholesale power has risen, and thanks to the self-consumption tax, the surcharge on power bills in Germany to pay for renewables fell a little in 2018 and 2019 (Figure 15.1). This surcharge is calculated as the sum of (feed-in tariff minus average wholesale electricity price over a certain period) for all MWh generated, and the funds collected are distributed to the utilities which pay the solar owners the feed-in tariff. The careful calculations of surcharge (Figure 15.1) continued until the energy crisis in 2022, when the rising price of gas started to make the old feed-in tariffs look cheap.

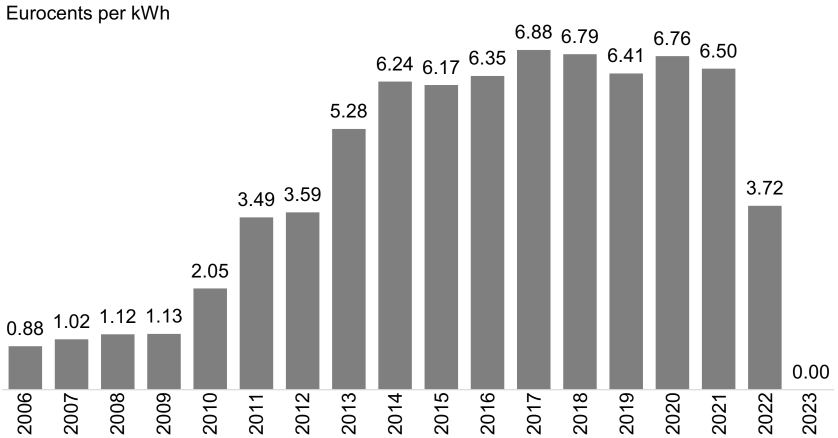

Figure 15.1 German surcharge on residential power bills to fund the extra cost of the EEG renewable energy subsidy programme on top of the wholesale power price.

Source: German Bundesnetzagentur (federal regulator of energy, telecommunications, and post).

The surcharge was abolished for 2023 because renewable energy across the country saved more energy than the feed-in tariffs cost, by an expected 3.6 billion euros in 2023. The German government will in future take over these costs, which are expected to be much lower than in the past. The Bundesnetzagentur statement explained "The main reason for the sharp fall in the EEG surcharge is the strong rise in electricity prices on the power exchange. The resulting higher revenues for renewable electricity considerably reduce the need for financial support. New installations coming under the EEG therefore require only a negligible amount of additional support. As in the previous year, the surcharge will also be kept lower due to federal government assistance, which will be funded from carbon pricing revenue."

We have got ahead of history again. In sunny Spain in December 2014, the government realised that homeowners could save money by putting up a solar rooftop, without any subsidy at all or even net metering (where solar generation runs the meter backwards). This represented a potential threat to Spain's existing power generators and to the entire power sector if a lot of consumers stopped buying in the daytime. The government brought in a 'sun tax' of about 5 euro cents/kWh self-consumed, with no export payment for selling to the grid. There was more public outrage about this than the German sun tax, probably because it directly affects homeowners rather than corporations. The 'sun tax' in Spain was scrapped in 2018, and the market recovered; in 2022, an estimated 2.5 GW(AC) (about 3 GW(DC)) of solar exclusively for self-consumption, with no export tariff or subsidy, was built on Spanish rooftops, parking lots, and patches of land adjacent to buildings directly using the power, according to industry association UNEF.

Italy also has solar cheaper than the grid. In 2014, the country brought in a new version of net metering, where exports to the grid are paid at the wholesale rate for power (about 50–70 euros/MWh in 2014–2020, versus 250–300 euros/MWh paid by households for electricity, plus projects are exempt from grid fees amounting to about another 50–70 euros/MWh).

Many US states had net metering for years, but it mostly didn't matter because solar was too expensive. There were caps to net metering, but they were far from being reached. In 2014 and 2015, US utilities started lobbying more forcefully to cut net metering laws, increased fixed charges to solar owners for being connected to the grid, and change net metering to a lower export tariff (as in effect has happened in Italy and Germany).

A number of US firms founded to build and arrange financing for solar on rooftops continued to grow strongly in 2014 and 2015. SolarCity, SunRun, and Vivint Solar became industry names, aiming to become household names with public marketing campaigns and large sales forces.

The age of rooftop solar competition with the grid had begun.

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Chapter 16

2016–2021: The Early Days of Cheap Photovoltaics

After 2015, it became increasingly undeniable that large-scale photovoltaics is the cheapest way of generating electricity in some countries. This shifted the focus of solar policy away from bulk subsidies for generation towards more tailored incentives attempting to get the best prices and to match electricity generation to demand. Nonetheless, some governments still made the same mistakes and drove booms and busts, with Vietnam a particularly spectacular example.

16.1 More Low Solar Bids in Auctions

Dubai's second photovoltaic tender awarded 800 MW at a price of $29.9/MWh in June 2016, a new record. In August 2016, Chile beat this, with $29.1/MWh. In December 2017, an auction in Mexico had an average solar price bid of $20.8/MWh (all these projects were meant to be, and were, built several years after they were bid). As you might expect from the levelised cost of energy calculation, sunny countries with relatively good political stability tend to attract lower bids; the cost of financing is low and the output high. Below $30/MWh is definitely in a range competitive with natural gas.

The auctions became more complex as the numbers dropped. Abu Dhabi's first solar tender, in September 2016, asked developers to bid to cover a particular patch of land with solar panels while paying 1.6 times as much for power in the months from June to September as in the rest of the year. The idea of this was to match output to power demand, which in Abu Dhabi peaks in the hottest months due to air conditioning use. The winning bid was to supply power at a price averaging around $29.4/MWh. These prices were seldom transparent about their inflation assumptions, which makes a big difference to the headline figure; a price of $29 rising at 3%/year is almost certainly better than $30 fixed.

In Chile, the government took another approach and ran a technology-agnostic auction, where developers bid to supply electricity within particular periods of the day, regardless of what type of generation. Since parts of Chile are extremely sunny, PV projects won the daytime blocks, at a lower price ($29.1/MWh) than the gas which won the baseload contracts.

India has run a long series of successful auctions, awarding capacity at prices fixed in rupees and not adjusted for inflation. The prices are low and the players big, and the system worked, driving 58.3 GW of capacity between 2014 and 2021, most of which has been built [Gadre, 2023].

Solar auctions did get a bit ridiculous during this period. One tension in auctions is that project development firms and the people working in them need to win capacity to continue to have a job. It's hard to justify your employment if your job is to keep bidding for projects but you never win. Losing may actually be in the bidding company's interest if the winning price is too low for the project to be built at a profit, but it's still hard to argue that preparing the paperwork, lining up the partners, and bidding in order to *lose* represents an achievement. So the incentive is to push the assumptions really hard to get a low price. You might also luck out with tech costs dropping or local currency getting stronger, and look like a genius. Also, on a personal level, if you win an auction at an unachievable price, you can probably change jobs before anyone finds out you made dubious assumptions.

This tension — developers needing to win capacity at all costs — led to a lot of hype in auction prices, and a few people (including Michael Liebreich on Twitter in late 2018) saying the cost of solar would soon be under one US cent per kWh. In addition, Saudi Arabia, Dubai, and Abu

Dhabi decided inexplicably that there was some kind of prestige to having the cheapest solar. Mostly, this gave them an incentive for the government to internalise various costs (with grid, land, and sometimes even labour paid for by the government) and report a price that is a synthetic calculation rather than the price you could actually get someone to build you a power plant for. This peaked in an announcement in April 2021 that seven solar projects totalling 3.6 GW in Saudi Arabia would sell power for 'a world record low price' of $10.4/MWh. I have no idea how they got to that number, but as of early 2023, none have been built yet and the Saudi government is quietly switching to just asking state developer ACWA Power to build a bunch of solar plants without fanfare.

The future of solar auctions is one of complexity, and buying power to specifications. Israel ran auctions for solar with 4 hours of storage in 2020, awarding 777 MW of PV and 3.0 GWh of batteries at a price of $56–64/MWh — not bad for plants which can, to a limited extent, dispatch power to the grid when it is most needed.

16.2 Solar as a Solution in South Africa?

South Africa ran a fascinating Emergency Auction in late 2020 to deal with a terrible and ongoing power crisis. Although the country's first few solar auctions in 2014 and 2015 were successful, they were limited, and by 2020 the country had frequent rotating blackouts caused by an ageing coal fleet needing maintenance, along with transmission bottlenecks and slow action by state-owned power company Eskom to buy new capacity of any type.

Before the 2020 Emergency Auction was held, BNEF expected the winners to be fossil fuel capacity. Our first headline was "South Africa's Emergency Power Auction Won't Help Clean Energy" [Champion, 2020], and concluded that "while aiming to deliver cheap power quickly, the request for proposals includes steep reliability requirements. These make it very challenging — if not impossible — for renewables and storage to qualify, despite their low cost. To qualify, solar-plus-storage projects would need to be several times oversized and be paired with batteries, while wind-plus-storage may struggle to qualify altogether." We expected the main winners to be ‘power ships’, gas-fired floating power plants often used in emergency situations.

However, our headline on the results of the auction in June 2021 was “South Africa Emergency Auction Will Help Clean Power” [Champion, 2021], a serious indicator of how batteries beat our expectations over this period. The auction was won by plans to build 1,687 MW of solar with 160 MW of wind, backed up with 640 MW of batteries and a smidge of diesel, plus 1,616 MW of gas (including some power ships). The winning prices were 1,462 to 1,885 South African rand (then $109–140) per MWh, with the power ships bidding in the middle of the range.

Unfortunately in 2022 most of these projects were severely delayed by rising costs for solar, wind, and finance, and we do not know when they will be built. Even the gas-fired power ships are stuck on the planning board, partly due to environmental permitting delays and partly because South Africa’s economy is in crisis because there is not enough power. Unfortunately, this hurts attempts to finance power plants of any sort in the country.

Some progress is being made on other solar projects in South Africa, as of early 2023. The country’s homes and businesses still experience regular blackouts, often losing power for many hours at a time, and the situation appears to be getting worse. The Emergency Auction plans for renewables included a small amount of diesel to meet the reliability requirements and would presumably have sought to burn as little expensive diesel as possible, but in the current situation, even intermittent power would be an improvement. Anecdotally, many businesses and individuals in South Africa are buying solar to be less dependent on the grid, although it is difficult to get good data on this because they don’t report to the grid. China customs data, however, shows that South Africa imported $261 million of solar cells and modules in 2021 and $349 million in 2022, about 2.3 GW in total. In August 2021, the South African government made it legal for solar projects up to 100 MW to be built without a generation license, and we expect many mines and businesses to be taking advantage of this.

In early 2023, the South African government introduced a very generous tax incentive for businesses (for two years, they can subtract 125% of capex spent on solar projects from their taxable income). In the first 7 months of 2023, $773 million worth of solar cells and modules were exported from China to South Africa — at least 3.5 GW of panels — up from $349 million in the whole of 2022. This strongly suggests a boom is happening. Eskom also released an estimate of rooftop solar capacity in July 2023, based on avoided blackouts, that suggested over 1.8 GW of rooftop solar was added in the first half of 2023. Perhaps South Africa will be the first country to use solar to solve a serious power crisis and leapfrog straight from ageing coal plants to clean power.

16.3 The Battle for US Rooftops

The US is an exceptional country for a lot of reasons. It orders its dates wrong, for one thing, and uses weird measures of weight and distance for another. But it is also the only country that has a significant long-term residential solar financing industry which has created public companies dedicated to installing and financing home solar, including two new listings on stock markets in 2022.

In the US, the main federal support for solar is an Investment Tax Credit (ITC), which allows solar investors to claim back 30% of their investment against the taxes payable over the next 5 years (or in the first year if they can). This is quite generous, but the catch is that you need to be paying enough tax to fully benefit from this tax credit. For a normal household, this may not be the case or it may take over 5 years to pay back the subsidy; therefore a substantial industry grew up offering 'third-party solar financing' where a company like SolarCity (now a division of Tesla), Vivint or SunRun would arrange for an investor to own solar systems on residential roofs. The residents of the house sign a 20 or 25-year agreement to buy the power at a favourable price compared with grid electricity. This was assisted by a second subsidy in many states, 'net metering', which essentially ran a consumer's meter backwards any time their solar system was producing more than the house was consuming. SolarCity/SunRun/Vivint would collect investment from firms which pay a lot of tax — investment banks like Morgan Stanley or JPMorgan, for example — and manage a large number of residential rooftops and their power payments. The power can be bought either under a power purchase agreement (PPA), which pays per-kWh, or a monthly fee called a lease for use of the power from the system. Leasing is, as far as I can tell, mainly to get around legal restrictions in most countries on who is allowed to sell power and call themselves a utility.

The Investment Tax Credit is not necessarily efficient from a subsidy-minimising perspective, because companies tend to report the cost of the system as rather more than it needed to be, in order to claim higher tax credit and pay for expensive sales and financing services. However, everyone involved in the deal can get what they want.

SolarCity and SunRun were hot venture capital investments which achieved profitable exits by listing on US stock markets in 2015, raising money and their profile. US companies are seldom content to stay small, and venture-funded companies need to be ambitious to please their investors. The long-term results have been mixed. The stock prices of Vivint, SunRun, and SolarCity fell substantially in 2016 as the similar SunEdison went bankrupt and these firms continued to make losses. SunRun's stock price fell 55% over the year, Vivint Solar's 10%. SolarCity's stock price fell 59% from the start of 2016 until it was bought out in November by Tesla, the electric vehicle company. SolarCity has largely disappeared into Tesla, and Vivint was acquired by SunRun in October 2020. SunRun survives and continues to grow revenue, its portfolio, and its operating losses. According to BloombergNEF solar analyst Pol Lezcano, "despite being public for a few years now, the business model of third-party residential firms remains questionable. Companies claim that long-term incomes from leases and power purchase agreements will exceed how much it costs them to acquire a new customer. But the validity of these claims depend on questionable cost of capital assumptions and unclear revenue predictions about upselling opportunities."

Customers also have the option of borrowing money as a loan to buy solar, and as of 2022, "about 60% of solar systems installed in the US annually use loan financing, and 20–25% use a lease or power purchase agreement structure. Households pay cash for the remaining 15–20%" [Lezcano, 2023]. Paying cash or a loan just means you own the system, and it's simpler. New firms such as Sunnova and Sunlight Financial also make loans to customers for them to buy their own solar, collecting high fees in exchange.

US solar customers mostly get what they signed up for. However, as a result of the structure of the Investment Tax Credit and the trade wars described in Chapter 22, the average selling price per W of home solar in the US (from online marketplace Energysage) was almost double that in

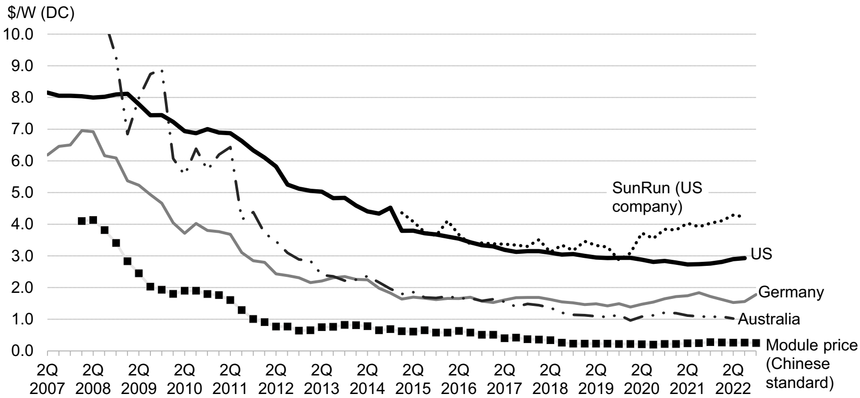

Figure 16.1 Capex of residential solar systems in different countries, over time. Before 2015, California is used as a proxy for the US.

Source: BSW-Solar, Solarchoice.au, Energysage, company filings, BloombergNEF.

Germany or Australia (Figure 16.1), without accounting for financing fees. The average cost of the single remaining quoted company that releases price data, SunRun, is higher still, though this may be related to more of these systems having batteries than the average. SunRun spends at least 30% of its revenue on sales and marketing to build portfolios of cash-generating assets, while installers in Germany and Australia generally get their sales leads from people calling the number on their van or from quote-aggregation websites.

A challenge that the US industry must adjust to, as solar generation rises, is that state utilities, regulators, and energy retailers will change power tariffs to make power cheaper at midday than in the evening when the sun is low. This is a reasonable change, intended to encourage homeowners to site their PV facing west to better cook their dinner, or to use their batteries to charge when solar power is plentiful on the grid and discharge when it is needed. The first major programme to adopt this was California's Net Metering 2.0 in 2017, which changed the tariff structure to time-based and paved the way for further changes to electricity price structures. There was some industry outcry about California's 'Net Metering 3.0' regulation in 2022, which dramatically cut rooftop solar export payments but will probably do little to slow down deployment as the economics are only slightly worse after the change, and favour storage.

The US rooftop solar industry continues to grow and hire a lot of people, creating a real shortage of qualified workers and pushing up wages. In 2022, rising power prices offset slightly higher capex and financing cost to set a new build record. With the Inflation Reduction Act offering a 30% Investment Tax Credit until 2032, US rooftop solar will keep growing strongly and probably continue to be really expensive by global standards.

16.4 China Becomes the World's Largest Solar Market

China's PV companies installed a record 53 GW in the country in 2017, nearly half the world build. This was obviously unsustainable, as the country pays subsidies out of a surcharge on power prices which feeds the Renewable Energy Fund. By 2018, this fund was collecting about 84 billion yuan and supposed to pay out 212 billion yuan per year (an annual deficit of about $19 billion) and the Ministry of Finance was unwilling to increase the surcharge on power bills.

In theory, China's new PV build was controlled by a system of quotas for receiving the subsidy (mostly feed-in tariffs) handed out by the federal government to provinces. The problem was that developers often built projects before they had been allocated subsidy, on the assumption that they would be first in line for next year's. The deficit got bigger and bigger.

On June 1, 2018, China's finance ministry slammed on the brakes, freezing the issue of new quota to subsidise photovoltaics and reforming how projects were supported. For solar, a subsidy budget was set centrally before being allocated using national auctions in 2019 and 2020. Projects competed on their per-kWh subsidy demand (the lower, the more likely to get what they bid for) across provinces. The subsidy awarded is paid as a supplement to the provincial price paid for coal-fired power, which is fixed by the local government and was guaranteed for the solar or wind project's life. It is also only paid when the fund finds money for it, in a 'byzantine' [Luan, 2020] allocation process — meaning many projects wait 2–3 years and are still waiting, although in the meantime they get the coal-fired power price part of the payment at least.

Solar build in China dropped from 53 GW in 2017 to 44.5 GW in 2018 and 33.4 GW in 2019. However, in May 2019, the first batch of 14.8 GW of solar (and 4.5 GW of wind) projects was announced as being 'zero-subsidy', i.e. only being paid the coal-fired power price (but fixed and guaranteed for 20 years, making it a sort of feed-in tariff). These were projects in prime resource locations where the coal-fired price was high, but slowly the zero-subsidy volumes got bigger. In August 2020, China's National Development and Reform Commission and the National Energy Administration announced 33.1 GW of 'subsidy-free' solar projects (and 11.4 GW of subsidy-free wind) across the country.

China's solar build recovered to 52.2 GW in 2020, 68.6 GW in 2021, and about 107 GW(DC) in 2022.

16.5 Boom in Vietnam

Vietnam had negligible solar in April 2017, when the government set a feed-in tariff of $93.5/MWh (paid in local currency, the Vietnamese dong, but indexed to the dollar). Very little happened until the feed-in tariff was about to expire in June 2019. In our February 2019 PV Market Outlook, BloombergNEF listed all the challenges to building solar in Vietnam: "the feed-in tariff agreement permits the national power company, Vietnam Electricity, to curtail output for technical reasons, without compensation. Legal disputes must also be handled by arbitration courts in Vietnam, which is considered risky by international investors … land ownership is also difficult to establish. We expect 1.7–1.8 GW of new build in 2019." This would have already beaten Vietnam's target of 850 MW of installed solar by 2020.

It cannot have been that difficult to build solar projects in Vietnam, because 5.4 GW were built in 2019, mostly in the first half of the year before the June deadline. Then the tariff was extended at a lower rate (our 2020 forecast in April 2020 was a "smaller activity rush" of 1.3 to 1.6 GW), and 12.7 GW were built in 2020, taking total capacity to 18.2 GW. Six gigawatts of this were built in the deadline month, December 2020.

One reason we underestimated Vietnam's solar market by a factor of nearly 10 in the year it was actually happening is that subsidy deadline rushes are very unpredictable. But another reason we were so consistently wrong is that we were mostly listening to international developers and banks talking about how difficult it was to finance projects. Nobody had told that to the Vietnamese developers. The Vietnamese banks were under instruction from the government to lend money to renewable energy projects, so they did.

The Vietnamese government does not appear to have intended such an extreme build, which has caused some problems. Output from some solar farms has had to be curtailed without compensation. It is likely that the Vietnamese banks will be lenient on debt collection, even without government pressure, because banks generally do not want to have to manage a bunch of solar farms. However, the boom is likely to depress solar build in the country until the curtailment issues have been ironed out; Vietnam's 2030 Power Plan currently calls for just 2.4 GW of additional large solar.

16.6 Batteries Become a Thing

Another major advance between 2016 and 2021 was that utility-scale batteries began to be deployed at scale, for the first time for bulk energy shifting (storing power when it's plentiful for when it is needed later, as from day to night). This is particularly driven by the US market, where the Investment Tax Credit favours batteries, and by China where several provinces mandate that large solar and wind can only be connected to the grid when batteries are added. The BNEF Energy Storage team was only founded in 2017, which seems remarkably late (though batteries were covered by an Energy Smart Technologies team as one of several technologies).

Actual amounts of batteries deployed are still small in most countries, but not all — as of early 2023 California can cover 7% of its peak power consumption with batteries, though not for long. This is already helping California deal with the 'duck curve', as Figure 16.2 shows. Batteries are charging — representing demand on the grid — when the sun is high and discharging in the evening.

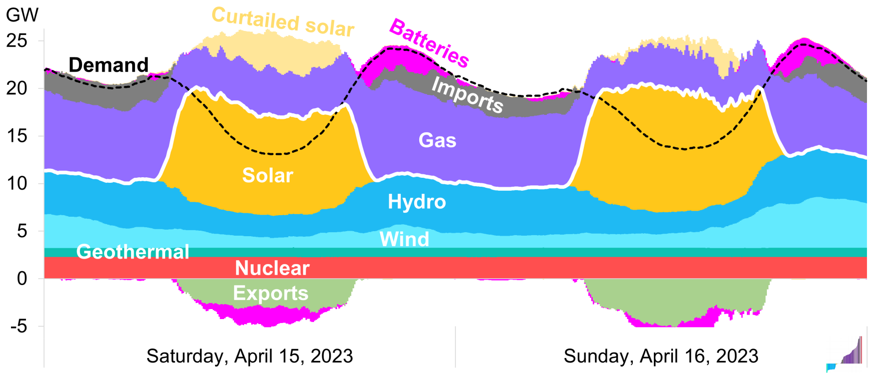

Figure 16.2 Power supply and demand in the California Independent System Operator (CAISO) region, 2 days in April 2023.

Source: Brian Bartholomew, CAISO.

Brian Bartholomew, energy storage analyst at developer company REV Renewables, explains that in California "Now, on the most extreme days, it's more about how far the rest of the system can flex to digest an abundance of solar energy — via gas plants dropping output or shutting down, exports spinning out to neighboring grids, batteries charging for the evening, or low hydro generation or nuclear outages 'making room' for more solar generation in their stead. As we implement solutions on the utility-scale side, it will continue to be important to align retail demand and incentives on the other side of the meter to promote consuming energy when it is least expensive and least carbon-intensive and conserving when it's scarce."

Figure 16.2 also shows significant curtailment of solar in daytime hours. Bartholomew explains, "When we hit limits on how far the gas and hydro fleet can flex down, how much energy batteries can charge, and how much surplus supply can be spun out to neighboring grids, California solar gets 'curtailed' instead of being sent to the grid. As avenues for flexibility expand, less solar should be curtailed, more costs can be lowered, and more emissions abated."

Batteries help, though, Bartholomew concludes. "During the September 2022 heat wave and near-blackouts, we saw around 3 GW of batteries (vs. net load peaks around 46 GW) provide a mix of energy and ancillary services to help keep the lights on as electricity became scarce. Through this spring, batteries have supplied similar amounts of energy and ancillary services to displace the dirtiest and most expensive gas plants and support California's evening load. Batteries remain small movers of megawatt-hours but critically important and growing dispatchable providers of power in the state's reliability decarbonization goals."

Batteries will be discussed in more depth in the following chapter.

16.7 Clean Energy Targets and the Energy Transition Goes Mainstream

Falling costs of renewable energy, and perhaps also the increasingly visible impacts of climate change, drove a noticeable change in global political attitude towards renewables in 2020 and 2021. Some feared that the COVID-19 pandemic, which began in early 2020 and continued to significantly affect the global economy at least until China gave up trying to contain the virus in late 2022, would hurt climate action. Perhaps it helped that carbon dioxide emissions dropped in 2020 for the first time in decades due to pandemic lockdowns, by about 6%, though unfortunately they rose again in 2021 and 2022.

However, 2020 and 2021 were great years for going beyond painfully technical degree-based negotiations, and straight to bold targets to reach net zero emissions. China aims for peak carbon dioxide emissions by 2030 and net zero by 2060, while South Korea, the US, the UK, the European Union, and Japan aim for net zero by 2050. India is a little slower, announcing only in 2022 that it aims for net zero by 2070.

Simply having targets is no guarantee that they will be met. But governments of reputable nations stating these targets firmly give some indication that there will be further support for clean energy. And, for the first time, serious people who are not already climate activists were talking about the Energy Transition as an inevitability, not a hope. ('Transition' is the term settled on, better than 'revolution' as it carries fewer connotations of chaos and disruption.) If nothing else, net-zero targets give corporations and financial firms some indication of the direction of travel, so they can prepare and invest and start to fear owning stranded assets. You're less likely to build a gas or coal plant if you expect no support and probable penalties from the government in the future, even if none exist at present. Most developed nations have stopped building new coal plants, even if phasing out the existing ones is taking longer than one would like. We are, at last, planning for a future with zero annual carbon emissions, even if we can argue endlessly about how to get there.

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Chapter 17

Intermittency, Batteries and Hydrogen

In late February 2018, the UK was in the grip of an extreme weather system called the 'Beast from the East'. This was a period of intense cold and snow across the country, which is usually protected by the warmth of the Gulf Stream ocean current, and has an infrastructure designed for a generally clement climate.

I was by chance in the UK at the time and had breakfast near the office with some colleagues, chatting and pointing out the new electric London buses passing on the road. Gas analyst John Twomey arrived late and in a manic mood; the UK National Grid had issued warnings about a shortfall in the gas supply. This was particularly low because the Rough storage facility, a depleted gas field off the coast of Yorkshire used to store about nine days' worth of UK gas supply, had been retired the summer before. There were also technical problems on a gas interconnector with the Netherlands. The UK relies on gas for a significant amount of its heating and electricity, and the cold weather meant that heating demand was very high. "It's so exciting!" said Twomey, with the delight of an expert about to learn something new. "We're about to see what happens to the UK power grid in a crisis!" And he ran off to help the power team write something up for our clients about it [Annex *et al*., 2018].

Fortunately, the Beast from the East did not bring the UK power system crashing down. Prices for gas shot up fivefold in a week, and since power is the most flexible source of demand for gas, generation from combined cycle gas turbines fell 30% week-on-week.

The shortfall was made up by wind and coal. One unusual thing about the Beast from the East compared with most UK cold weather systems was that it was very windy, enabling the UK's wind farms to produce about 25% of the country's power throughout. However, coal power output also increased by 79% in the week. Solar was almost no help as it was winter, and with a whole week of extreme conditions to deal with, any battery capacity would have quickly been emptied. To put it bluntly, if the coal had not been supported by government capacity payments so it stayed available, the country might have had to choose between light and heat. Coal was only 5.1% of the UK's electricity generation mix in 2018 and has kept falling to 1.5% in 2022, but it was important in that crisis.

The other point to note is that it is not only renewables which threaten the grid. Texas had widespread blackouts in February 2021 due to a polar vortex moving south, resulting in a chilly period including the coldest week in 21 years. Although Texas has a lot of wind and solar — 28% of its generation in 2021 and 31% in 2022 — it runs mainly on gas, and a lot of the gas infrastructure was unable to work in freezing conditions. One of the nuclear plants that generate about 10% of Texas power, STP Unit 1, also went offline due to a cold-related sensor problem. Many of the wind turbines also stopped, because Texas wind turbines are not designed to handle ice either, but low generation from wind was closer to scenarios considered by the Electric Reliability Council of Texas (Ercot). Photovoltaics, which run better when it's cold as long as there is sun, were a respectable contributor to daytime power supply throughout. Demand for residential power and heat was also exceptionally high for obvious reasons. By the end of 2022, Ercot had taken measures to 'winterise' key infrastructure to avoid a repeat.

Any discussion of making solar and wind a major part of our energy supply generally deals with how we handle intermittency, i.e. what we do when the sun goes down and the wind does not blow. Unfortunately, I don't have the final answer to this, but it's worth noting that sceptics have always said that the grid would go down at much lower reliance on wind and solar than we currently have. Human ingenuity put a man on the moon, brought electricity to nearly every house in the West, and put a remote communication device in nearly every human hand. I cannot believe our species needs to keep burning fossil fuels until we roast ourselves, simply because of a timing issue.

The problems of intermittency are different on different timescales (see Table 17.1).

Table 17.1 Summary of intermittency or high-renewable problems and potential solutions.

Challenge of very high renewable penetration	**Solutions**	**Level of fundamental technical challenge at today's technology level**
Distribution grid unable to handle reverse flows of power from houses to the grid.	Build stronger distribution grid as Germany has done. Add distributed batteries.	Low — happening.
Minute-to-minute fluctuations in renewable generation causing grid frequency problems.	Batteries providing ancillary services like frequency regulation. Demand response (i.e. turning off loads like freezers and aircon for minutes).	Low — requires some investment.
Day-to-night fluctuations, the 'duck curve'.	Mixture of solar, wind, and other clean power resources on the grid. Batteries. Time of day power pricing to encourage power users to change their use patterns. Long-range transmission infrastructure, especially east to west for solar to span timezones.	Moderate — requires investment.
Seasonal variation in solar or wind generation.	Mixture of renewables in the grid (wind and hydro generate more in the winter, solar in spring and summer). Long-range transmission infrastructure.	High — transmission lines are politically fraught, new wind and hydro plants can take years to get planning permission, and emergency power plants would still use fuel. Hydrogen

(*Continued*)

Table 17.1 (*Continued*)

Challenge of very high renewable penetration	**Solutions**	**Level of fundamental technical challenge at today's technology level**
	Chemical storage of energy (e.g. making hydrogen in summer for winter use). Emergency power plants, for example, diesel generators or open cycle gas turbines. Could run on biofuel or on hydrogen.	is inefficient and complicated, though may be the most widely applied solution. There is a very limited supply of truly sustainable biofuel.
Transmission grid unable to transfer energy from renewable energy plants to load centres.	Build more transmission grid. Accept curtailment of renewable generation when it is locally oversupplied. Batteries to store curtailment until output drops.	Moderate — transmission is hard to build. Batteries cost money and in this configuration do not reduce local grid investment. Curtailment is acceptable, especially at low levels, but is bad for renewable power plant economics and is unpredictable, making wind and solar risky investments.
Cannibalisation, i.e. low or negative power prices when solar and wind supplies are high and power demand is not high, discouraging further investment in any kind of power capacity (including dispatchable, which could cause the lights to go out).	Batteries, pumped hydro, or other storage to charge at times of low power prices and discharge at others. Capacity payments for dispatchable capacity (controversial as these are often subsidies to fossil fuels and reduce the power prices received by clean non-dispatchable capacity). Addition of new power consumers, ideally ones which can turn off in periods of high power demand. These could be flexibly charging electric vehicles, electrolysers producing hydrogen, or less usefully, cryptocurrency miners.	Very high — will be a major cause of delayed investments in wind and solar, for rational reasons. Some solutions are likely to be politically unpopular (e.g. paying cryptocurrency miners to switch off at times of grid stress). Flexible use of electricity is common sense and should be deployed wherever possible.

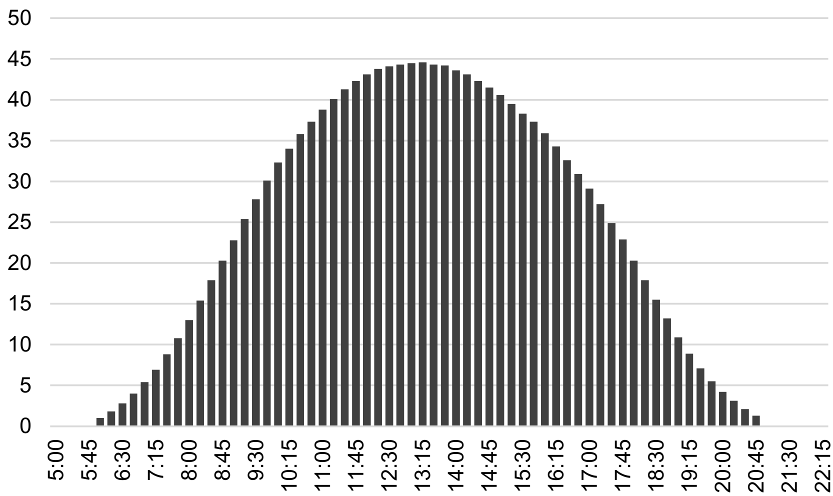

Figure 17.1 Generation of PV in the whole of Germany at 15-min intervals on May 29, 2023.

Source: SMA Solar Technology's website monitoring tool.

17.1 Minutes and Hours

Solar generation ramps sharply and falls quickly over a period of hours even on a uniformly sunny day (Figure 17.1), which immediately presents problems because most gas and coal plants are not designed to ramp up and down so quickly. Between 8:15 and 9:15 on the morning of the May day in Figure 17.1, the PV output in Germany rose by 10 GW or roughly 15% of Germany's entire average power consumption. This is the equivalent of three or four gas plants being shut off in that hour, or more likely the entire fleet of gas plants turned down a little. This is fine while you still have a fleet of gas plants to turn down, as Germany still does (about 32 GW at the end of 2022, plus 38 GW of coal).

This is predictable and does save fuel being burned during the day, but it relies on the gas plants being there and ready. The operators of the fossil power plants lose revenue ('solar eats their lunch') and may shut down if they stop making enough money to cover the upkeep cost of the plant. For power prices, a 'duck curve' develops with low or negative prices in the middle of the day (the belly of the duck) and high prices in the evening (the head of the duck) when the sun goes down.

In a perfectly free market, some of the gas plants would shut down permanently, and the spot market prices after dark would go sky-high, compensating gas generators which had kept their plants available to bring online for the lost profit. If electricity prices in some hours rise to thousands of dollars per MWh, it is also worth users exploring other options, such as 'demand response' (turning off power-consuming devices such as industrial freezers or office heating for minutes or hours until the power prices fall again) or batteries to store electricity. The cure for high prices is high prices.

Perhaps unfortunately, most regulators dislike power prices in the thousands of dollars per MWh and try other solutions such as offering the gas plants 'capacity payments' to stay open. This means that they are paid to be available even if they are not needed. Capacity payments cost money and may also discourage adoption of demand response and batteries by reducing the incentive to do so. Michael Liebreich argued in January 2017 that "simply layering on a capacity market is the wrong response: creating guaranteed demand for obsolete technologies has never ended well", and the argument for free power markets seems compelling. BNEF's power analysts, however, are not all on board with this market fundamentalist approach, mainly because power generation is a natural monopoly and therefore needs to be carefully regulated to function as a market at all. Slightly ironically, power markets need to be heavily regulated to enable free trade.

The problem with solar is often even worse on the minute-by-minute level for individual systems, where weather systems can cause output to swing up and down on timeframes which are more difficult to predict (Figure 17.2). The output on a cloudy day is likely to be predictable across a whole country, but local fluctuations can be considerable.

If the sun goes behind a cloud, the output from solar panels on the grid drops instantly, which causes the grid voltage to drop. The grid responds by dropping the frequency of the alternating current slightly, which can destroy sensitive devices, interrupt critical processes, and even cause other solar inverters — which work at grid frequency — to cut out, which takes more solar off. This can be a vicious circle ending with a blackout. It has been pretty much fixed in Germany and other developed markets by requiring inverters to have 'ride-through' capabilities, i.e. not go offline just because the grid frequency fluctuated briefly, so such a fluctuation does not crash the entire grid.

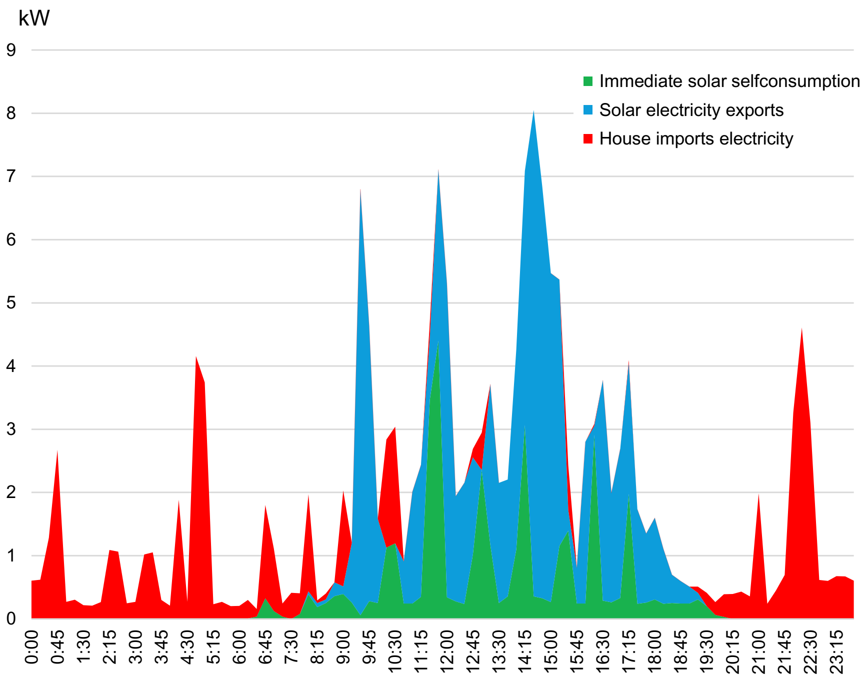

Figure 17.2 Output of the author's 13.2kW east-west mounted rooftop PV system at 15-min intervals on a day with fragmented cloud cover, plotted with household electricity consumption. The major electricity consumption spikes are from heat pump operation.

Source: SolarEdge monitoring software, the author's home solar system.

One of the main ways that early grid-scale batteries get paid in the UK, Australia, and the US is for 'ancillary services', i.e. to fix frequency fluctuations and other brief destabilisations from renewables and other sources. When there are very few batteries in the system, the price of ancillary services is high and is usually set by a short-term trading market. However, this market is 'shallow,' i.e. as soon as there are a lot of batteries all trying to sell short-term balancing services, the grid works fine but the price of the services falls and the batteries do not get as much money from it. BloombergNEF estimates that in 2016, 35% of grid-scale batteries worldwide were built mainly to provide ancillary services, while by 2022 this has dropped to 14% (Figure 17.5), not because fewer grid-stabilising services are needed but because more batteries are just being built for bulk energy shifting (e.g. from day to night). With care, batteries can be used for both.

Demand response can also help match electricity demand to supply. In Texas, even before renewables started to gain traction there, grid operators occasionally literally phoned major factories and offered them money to shut down for periods when the wind output looked likely to be lower than was forecast a few days earlier. Grid regulator Ercot now sends texts requesting people and businesses to turn down their power demand at times when the grid really needs it (more usually in the summer, when air conditioning demand is high). In the UK, in the difficult winter of 2022, the National Grid and utility Octopus Energy ran 'savings sessions', offering households some money and good vibes to reduce consumption for an hour or two when otherwise the nation's few remaining coal plants would have had to run. (My parents went for a walk in the dark, but there is nothing in the rules saying you cannot go to the pub.) Probably people would get tired of doing this too often, but it should be easy enough to make power-using devices like heat pumps, refrigerators, water heaters, and car chargers stop non-emergency consumption for short periods automatically without anyone knowing or caring.

Incidentally, this is why the 'smart home' falls under the subject of clean energy. A smart home, where all devices are online and can be remotely controlled, could in theory support the power grid without causing the owner the slightest inconvenience. However, if smart homes do become ubiquitous, security will be a priority and bugs will need to be fixed, because nobody wants to have their heating hacked or to be unable to cook dinner because the Internet is down. At present, it is difficult to see smart homes offering owners value worth taking this risk for, but if solar is practically free in the daytime, this may change. Early adopters of smart homes are generally doing it for fun or security, or out of curiosity. (Apparently, you can make lights change colour at home when you're not there, and if you're not the sort of person that appeals to, you're just not an early adopter of smart homes.)

17.2 Batteries

The first and simplest suggestion on how to handle a high penetration of intermittent renewables is always 'batteries', and one major change between the 2019 edition of this book and the 2023 one is optimism around batteries. Batteries are so easy; just buy a stack of power cells with a simple control system and plug it in, and it will save money in the day-time for later! In 2018, I thought that was too easy, and that we couldn't *just* build our way out of intermittency. I thought that it would cost too much, or we wouldn't have enough raw materials, and so we had to do something much more complicated to use existing infrastructure more cleverly.

However, it is possible that, after all, the answer to daily intermittency is just batteries. BNEF estimates that the average price for lithium-ion battery packs in 2022 was \$151/kWh, down from \$732/kWh (in 2022 dollars, i.e. inflation-adjusted) in 2013 (Figure 17.3).

The annual deployment has risen from 76 MW in 2010 to 16,400 MW in 2022 (Figure 17.4). As BloombergNEF's Head of Energy Storage Yayoi Sekine observed, "it alarms me that we used to celebrate 500 MW being installed in a year. Tallying up projects used to be easy, but there's no way one person can now track all the activity that's going on in the market. I'm sure this was similar with solar."

Batteries are following an experience curve, just like solar, and with similar disruptions for raw materials supply. For example, in 2022, the

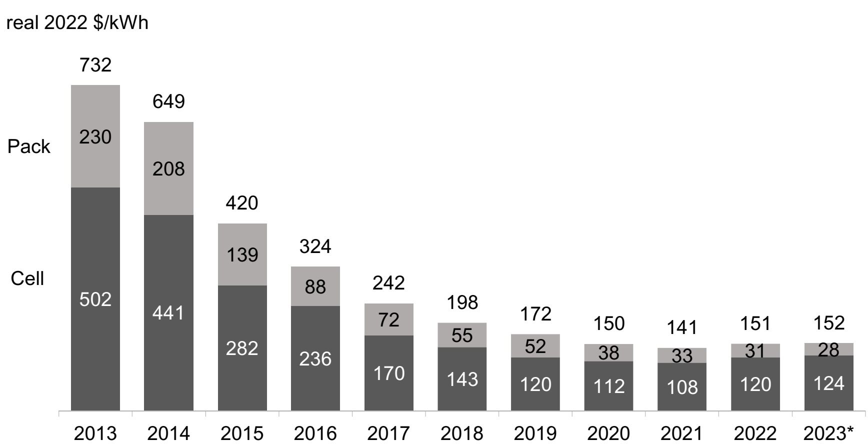

Figure 17.3 Lithium-ion battery cell and pack price, weighted average.

Note: *Estimate as of January 2023.

Source: BloombergNEF Top 10 Energy Storage Trends in 2023 [Sekine, 2023].

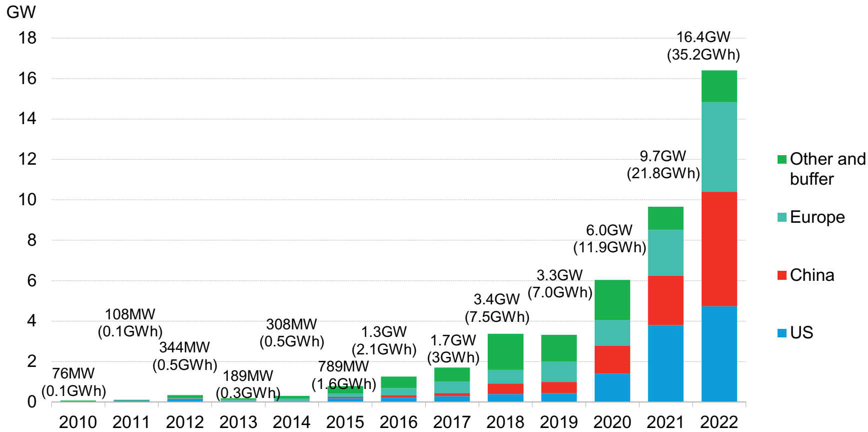

Figure 17.4 Global gross stationary energy storage capacity additions. The GWh label is provided for information and does not directly reflect any value charted, since the duration of batteries (number of hours they can charge or discharge at their rated capacity) varies between projects.

Source: BloombergNEF 1H 2023 Energy Storage Market Outlook [Kou, 2023].

price rose a little with the price of the raw materials lithium and nickel. The two main markets for batteries are currently the US, which encourages batteries through complicated but quite generous investment tax credits, and China which mandates that some large renewable energy plants have batteries alongside. (As of 2022, these Chinese batteries have very low utilisation rates, suggesting that it is easier to mandate their build than to effectively encourage their use.)

The capacity of batteries, and storage systems in general, is given in kW and kWh. The kW rating is the maximum power it can charge or discharge at, and the kWh rating is the amount of energy it can hold. If you think of a battery full of electricity as being like a tank full of water, the kW rating is the cross-sectional area of the hose that fills it or the pipe that empties it while the kWh rating is the size/capacity of the tank.

Batteries are nowhere near as standardised as solar modules. For starters, they can be optimised for power density or energy density. Most grid-scale batteries are very heavy for the amount of energy they contain since they are stationary. Car or laptop batteries, meanwhile, need to be fairly

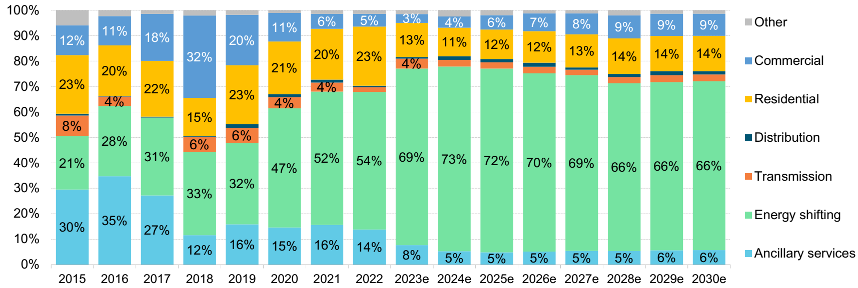

Figure 17.5 Application mix of energy storage projects deployed annually based on power output.

Source: BloombergNEF 1H 2023 Energy Storage Market Outlook [Kou, 2023].

lightweight. Some batteries may also need to discharge a lot of power in a short time (power density). Battery chemistry does not map exactly onto these categories, but generally, lithium nickel manganese cobalt oxide (NMC) batteries are the most energy-dense so are used in phones, laptops, and some cars. Lithium iron phosphate (LFP) batteries are fairly energy-dense, so the high-end ones can be used in cars and the low-end products in stationary storage. They do not contain cobalt. Chinese firms are working particularly hard to deploy sodium-ion batteries, first in stationary storage and perhaps even in cars.

In stationary storage alone, the main markets for batteries have historically been for supporting the grid in frequency and voltage ('ancillary services') and for homes and businesses to have backup power or support. These are generally power-optimised batteries that need to run for seconds and minutes. In future, we expect 'energy shifting', i.e. charging and discharging for whole hours to, for example, shift electricity demand from night to daytime so as to use solar power more effectively, to be the main application (Figure 17.5).

One of the big complaints about batteries is that they use minerals, particularly cobalt and lithium, which are in short supply and must be mined. For example, cobalt is used in NMC batteries, and over 70% of world cobalt production is in the Democratic Republic of the Congo [Ampofo *et al.*, 2022]. While the major mining firms in Congo do have regulations to keep workers safe, the cobalt price spiked in 2018 and 2022, which intensified the economic drivers for 'artisanal mining'. This means individuals, often children, search for cobalt in unregulated and often unsafe conditions. While in theory major companies buy only from regulated mining firms, it is difficult to be sure that artisanal production is not getting into the supply chain, when the price is right. On the other hand, reducing the price of cobalt does not directly help children forced by poverty to look for scraps of it. The best thing for them would be if a good portion of the wealth from cobalt extraction went to their parents and communities.

Lithium mining takes up large areas and drops the groundwater level in the salt deserts of Chile and China, resulting in droughts and hardship. Or it can be extracted from extensive ore mines in Australia and maybe in future in Europe. These are not great outcomes either.

As of 2023, demand for both cobalt and lithium has been lower than expected, while supply has risen with the opening of new mines. As a result, the price of both has fallen, with cobalt returning to only slightly above long-term levels and lithium still about four times higher. (The details on price often depend on which compound of cobalt and lithium is being used as a benchmark, since generally lithium is traded as lithium carbonate, lithium hydroxide, or spodumene, and cobalt as cobalt sulfate.) A major reason for the lower-than-expected demand is that battery chemistries have shifted from cobalt-containing NMC to LFP, which contains no cobalt, and shows signs of shifting to sodium-ion, which contains no cobalt or lithium. As far as I am aware, there are no key minerals in sodium-ion batteries that are likely to be in shortage, though the energy density of sodium ion is generally considered too low for anything but stationary storage (though there are now plans for sodium-ion battery cars). This may be another case of the cure for high prices being high prices and technological improvement solving a resource problem.

17.3 Seasons — Hydrogen?

The really tough problem for very high dependence on solar in countries that are not close to the equator is seasonal variation in output. My household solar in Switzerland produces 70 kWh on a sunny day in May and June, and 1.5 kWh on a normal grey day in January. Meanwhile, my house uses a heat pump instead of gas for heating, which is far more efficient, but also means it uses 40 kWh on a typical January day (60 kWh on a properly cold winter day) and 17 kWh on a typical summer day. Even if we had batteries that could store a night's worth of power, charging them from solar power in the summer to discharge in winter would be economically unreasonable — the batteries would cycle only once a year and thus would need to be ridiculously, absurdly enormous. (Not just economically ridiculous. Most batteries take a fair amount of energy to make but are good for at least 8,000 cycles, so the per-cycle initial energy expenditure is negligible compared with the clean energy they can integrate. If they only cycle once a year, though, the maths on energy payback looks different. The batteries may never store and dispatch as much energy as was used to manufacture them.)

Can we store summer solar power at all? Not easily. Possible solutions include warming large lakes of underground water or blocks of rock in summer, drawing the heat for use in winter. These are being tried, especially in Denmark for district heating, and may have a part to play but are currently considered niche. Again, the once-a-year cycle time makes the economics difficult, and it is particularly implausible to store heat at high enough temperatures to generate power. Compressed air storage is also an option, especially in places with natural airtight salt caverns which could be filled under pressure in the summer and then release air through a turbine in winter.

Alternatively, we could use summer electricity to make a chemical fuel such as hydrogen. This is a major difference between the 2019 edition of this book and the 2023 one; the first edition was slightly dismissive of hydrogen.

In 2023, I have to take hydrogen seriously as part of the structure of the long-term power mix. One reason for the change is that mathematical models for future energy systems were, for the first time, allowed to use hydrogen made using electrolysis and burned in power plants as a long-term energy storage option. The models like it. "Our 2016 paper on long-term storage only considered batteries and biofuels", said Jesse Jenkins, assistant professor at Princeton. "In 2020 we considered hydrogen as the main long-term storage medium in a California study."

Jenkins continues, "If you purely model hydrogen as chemical long-term storage with a poor roundtrip efficiency, even assuming cavern storage for hydrogen which is cheap, it is competitive if you have no other options. On the other hand if you have a hydrogen industry developing for industry and maybe transport, then pipelines and electrolysers are built for those applications and the power system can just buy energy from that."

Hydrogen is already used in oil refining, steel production, and production of ammonia to make fertilisers, as well as methanol as an industrial solvent. Because the hydrogen molecule is very small and difficult to store, it is usually made from natural gas in a process called steam methane reforming, close to where it is used. However, it can also be made by splitting water into hydrogen and oxygen using electricity, a process called electrolysis, and then collecting the lighter gas.

Electrolysis of water to make hydrogen is a standard school science demonstration (the resulting gas makes a squeaky pop when lit with a match). To make industrial volumes, you need huge amounts of electricity, and 'electrolysers' — the devices that make them — are expensive to build. The high capex of building an electrolyser means that you do not want it to run just 10% or 20% of the time, for example when renewable energy production is high. But you also don't want to run it when electricity is expensive, because while the efficiency of electrolysers has been increasing, it still takes 4.3–4.5 kWh to make a cubic meter of hydrogen under 'normal' conditions (0°C and 1 atmospheric pressure, so it weighs about 90 kg) [Wang, 2022]. The best compromise is probably to locate the electrolysers close to high-capacity-factor offshore wind or plants with both solar and onshore wind. These could be off the power grid, which would make sites with good wind and sun easier to find as they would not need to have a grid connection, and sending the hydrogen away by truck or pipeline is cheaper than building a long-distance electricity grid.

The cost of making hydrogen using renewable electricity varies widely depending on your assumptions, but BloombergNEF estimates it at $2–8/kg in 2022, still higher than that of steam methane reforming at $0.8–3.8/kg [Gao *et al*., 2022]. It is, however, coming down as electrolysers get cheaper and renewables get cheaper. An interesting figure for comparison with the $2–8/kg is that the US Inflation Reduction Act pays $3 production tax credit (i.e. government contribution on top of whatever price they can sell the hydrogen at) for each kilogram of hydrogen made using very low carbon sources. The rules for what constitutes a very low carbon source are not yet fully clear as of early 2023, but this could cause a very interesting situation in a few years if the cost falls below the subsidy for making it.

Once we have hydrogen, and assuming we can store it — in salt caverns, or tanks, or as ammonia — we can burn it in fuel cells or gas turbines for power when renewable generation is low, releasing only water vapour. That's how hydrogen works as storage. Fuel cells are more efficient but more expensive, and since this power supply is only likely to run for small fractions of the year, gas turbines are much more likely to be used to convert hydrogen back to electricity.

The gas turbines will have low utilisation because they are only used in near-emergencies, but the more expensive electrolysers can run for most of the year when renewable energy is available, filling the tanks. The cost per MWh would be high. BNEF once estimated the cost of seasonal electricity load shifting using hydrogen and fuel cells at 244 euros/MWh [Curry *et al.*, 2017], but I suspect the cost of using the now-more-likely gas turbines and a lower utilisation rate would give a higher per-MWh cost (but they would be needed for fewer MWh, so be a cheaper way to fill seasonal electricity supply gaps).

Energy storage is also not the only use of hydrogen if we can make it cleanly. Hydrogen is already a feedstock in many industrial processes, often via ammonia or methanol. Michael Liebreich has a very handy 'ladder' diagram for hydrogen applications (Figure 17.6), with long-term energy storage on the second rung from the top. We will almost certainly use clean hydrogen for oil refining processes like hydrocracking and desulphurisation, for making fertiliser, and for several other industrial processes because there is no very feasible alternative. On the other end of the scale, "you won't drive a hydrogen car and nor will your children" [Tengler, 2022] because batteries and electricity are a much better option for most forms of transport.

In the middle of the ladder, it is practical to make fossil-free steel or aluminium using hydrogen, and this will probably happen. Hydrogen can also be used to make ammonia or another synthetic fuel (e-fuel) for shipping, long-haul aviation, and a few other difficult-to-electrify applications.

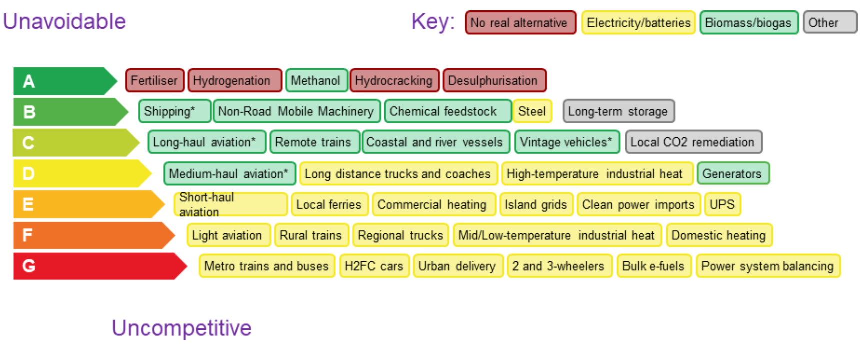

Figure 17.6 Clean hydrogen ladder of applications and competing technologies.

Note: *Most likely via ammonia or e-fuel rather than H_2 gas or liquid.

Source: Michael Liebreich/Liebreich Associates, Clean Hydrogen Ladder, Version 4.1, 2021. Concept credit: Adrian Hiel, Energy Cities. Slightly modified by Jenny Chase. CC-BY 3.0.

For long-term energy storage from season to season, though, hydrogen has few alternatives and is in principle scalable and suitable for mass deployment. This is why governments are making it a key part of their energy plans. As of 2023, the US, Europe, and China all plan a huge expansion of clean hydrogen production and use, though there is a bewildering range of hydrogen 'colours' representing different production methods. Green is renewable hydrogen made using electrolysis, grey is from natural gas, blue is from fossil gas with carbon capture and storage, and red/pink/purple is from nuclear made using electrolysis (Jigar Shah: "I feel like Crayola over here").

The European Union has targets for 42% of existing industrial hydrogen demand to be supplied by hydrogen made using renewables or nuclear by 2030 and 60% by 2035, which would require 28–72 GW of electrolyser capacity depending on utilisation rates [Bhashyam, 2023]. Germany has the world's largest funding target for hydrogen, planning to allocate 19.9 billion euros in 2023–2026 to hydrogen and industry decarbonisation. The US has the $3/kg tax credit under the Inflation Reduction Act, which may be so generous it is worth making hydrogen in the US and shipping it to Europe. China is leading on actual deployment, with 780 MW of electrolysers shipped in 2022 and a huge wave of factories set up to make electrolysers. We expect these electrolyser manufacturers, which include HydrogenPro, Cockerill Jingli, Peric, and solar manufacturers LONGi and Sungrow trying a new industry, to have the same problem as solar module makers: structural overcapacity, vicious competition, and many bankruptcies [Wang, 2023].

I asked several hydrogen analysts in early 2023 if hydrogen was a bubble right now and they all said "yes, obviously". However, solar has shown that bubbles can drive innovation, cost reduction, and efficiency improvement through deployment. It seems most likely that green hydrogen will be part of our energy future and help solve the problems of long-term storage, probably with some false starts and embarrassing failures.

17.4 Working Together

Beyond technological fixes like batteries and hydrogen, it helps to plan a grid well. An obvious choice is to have a mixture of solar, wind, and hydroelectric power in the grid since these electricity sources are anti-correlated. In countries close to the equator, solar power is particularly useful during droughts when hydro generation is low. Gigawatts of floating solar plants are being deployed across Asia on the hydro reservoirs themselves, because there is already space and a grid connection and those are the main things you need to build a solar plant nowadays. They also reduce evaporation and allow the reservoir to fill during hours of solar generation.

Wind is more valuable than solar in countries away from the equator. In Europe, the wind is usually strongest in the winter, when our power demand is highest (and will get higher as we electrify heat). Rational governments and regulators should move away from having completely tech-agnostic auctions where solar and wind compete, and allow wind to be the preferred technology where it can be built or supported.

Connecting a country's power grid with a neighbouring one, or improving connectivity within a country, is also a powerful tool for integrating renewables. The US power grid, for example, is divided into starkly separate regions with bad connectivity. Figure 17.7 shows what a difference this can make to pricing within regions at the same time. Clearly, if prices are negative in one region and over $350/MWh in a neighbouring one, this is bad for everyone.

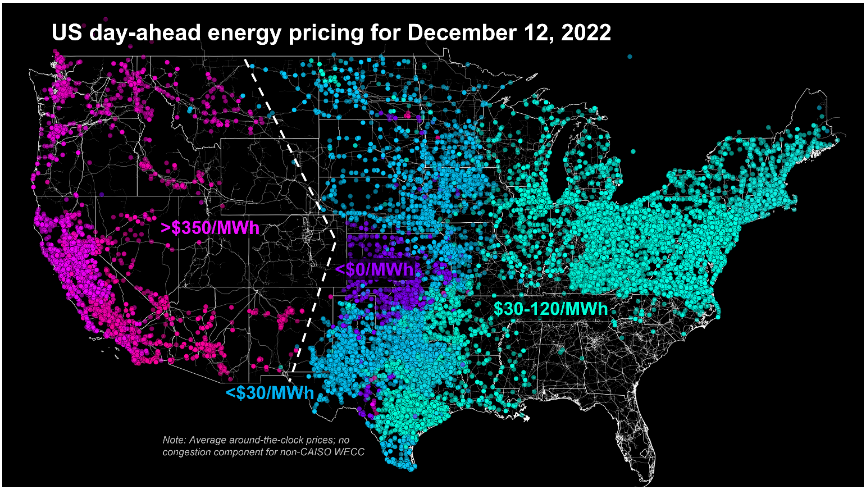

Figure 17.7 US day-ahead electricity pricing for December 12, 2022, showing how a lack of east–west transmission causes some US regions to pay high prices for power while others have low or even negative prices.

Source: Brian Bartholomew, US grid operators.

However, cables are expensive, politics is hard, and even within most countries it's not trivial to sort out the thousands of cases of land rights needed for a major transmission line. SunCable was a billionaire-backed plan to connect a vast solar array in Australia with Singapore via a 4,200 km, 4.3 GW powerline. It fell apart in early 2023 because apparently, after three years, those involved realised that that is a very long wire. However, there are advanced plans to make Europe more interconnected, with power lines planned across the North Sea and across Germany. The US Inflation Reduction Act of 2022 includes $39 billion of funding for grids to accommodate more renewables, along with more general grid funding. China has significant amounts of high-voltage grids and is building more.

Another option for Europe would be to run a power line towards the equator, to countries which are sunny even in winter (the Middle East actually has a low period in power consumption in winter, as the need for air conditioning is reduced, so it might happen to export solar power if it built enough to supply summer demand). This is technically practical but would leave Europe heavily reliant on the Middle East for energy again.

These solutions are not mutually exclusive, and all involve massive infrastructure rollouts. Some advocates are keen on the idea of individual households going off-grid, but we built the grid for a reason. It is much cheaper and more efficient to aggregate load, generation, and storage than it is to overbuild capacity for individual houses or indeed countries. Each country owning power capacity within its own borders for every eventuality is wildly inefficient infrastructure build, and attempts to assert rigid energy independence will almost certainly push back decarbonisation efforts.

It is reasonably clear how we can get to 80–90% of wind and solar in world electricity supply with batteries while electrifying heating and ground transport. Getting to 100% will not be easy and may require some expensive things like hydrogen for power, or some difficult-to-scale things like biomass and biofuel, or something not invented yet. Then we just have to decarbonise the other sectors — industrial heat, shipping, aviation, and agriculture — and phase out fossil fuels altogether.

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Chapter 18

Technology Focus: Solar Thermal Electricity Generation

Chapter 9 detailed how, in a normal power market, simultaneous power supply, demand, and the cost of generating a marginal MWh set the price of power. Generally, in hot countries, peak power demand is in the daytime for air conditioning but continues well into the late afternoon and into the evening when the outside temperature is still high and people come home to cook dinner. This load is not well served by photovoltaics, the output of which drops sharply in the late afternoon as the sun gets low.

One option for supplying the evening peak in electricity demand in a grid with plenty of photovoltaics is solar thermal electricity generation. This is also called concentrated solar power, CSP, though I dislike this term as there is also a concentrated form of PV. Concentrated PV doesn't work very well and has largely been abandoned as a commercial option, but it is definitely a technology.

Solar thermal electricity generation sounds good in principle. It uses a turbine, which can turn in time with the grid frequency and hence stabilise the grid. The heat can be stored during the daytime in tanks of molten salt or blocks of stone and used to run the plant after the sun goes down, potentially for the whole 24 hours, or just for the 4–6 hours required for people to run airconditioning, cook dinner, and watch TV after sundown. Natural gas can be used to boost the capacity utilisation of the turbine, which may offend purists, but is a whole lot better than just having a gas plant. Solar thermal was long a favourite new technology of the International Energy Agency in its forecasts, perhaps because it continues to look like a familiar fossil fuel plant in some technical respects.

The history of commercial solar thermal starts with the Luz or SEGS plants in California's Mojave desert, developed between 1985 and 1990 by Israeli firm Luz (which means 'light' in Hebrew — back then it was much more forgivable to have no imagination with solar company names). These were parabolic trough designs and generally worked to specifications. Unfortunately, Luz overstretched itself financially when a key tax credit was not renewed and went bankrupt in 1991 (noting, probably accurately, that at the time it produced 90% of the world's solar power). The 350 MW of SEGS parabolic trough solar thermal plants were sold for less than it cost to build them. Some were decommissioned in 2021, and some are still operating in 2023 after several changes of ownership.

The SEGS financial disaster in 1991, which does not appear to have been a technology problem, cooled enthusiasm for solar thermal for several decades until Spain experimented with a solar thermal subsidy in 2007. Over the next 5 years, Spanish companies built 2.3 GW of plants, nearly all parabolic troughs. The consensus began to build, however, that the only way to significantly reduce cost was to move to tower designs.

To engineers, solar thermal towers (Figure 18.1) are compelling. Parabolic troughs (pictured in Figure 2.2 back in Chapter 2) have literally kilometres of 'receiver tubes' carrying hot fluid, which need to be positioned above the mirrors and turn with the mirror to catch the sun. The temperature is limited to about 400°C in a trough plant, and it is relatively difficult to use a good heat transfer fluid like molten salt instead of steam.

Towers, by contrast, have a single focal point and thousands of mirrors ('heliostats') mounted on the ground, tilting to focus the sunlight on the elevated tower. This needs to be a work of perfect coordination, but the resulting hot fluid does not need to travel far to reach the turbine, and temperatures up to 580°C are possible. This is useful as the higher the temperature, the more efficiently a steam turbine can run and the more energy can be stored in a given volume of molten salt. Solar thermal engineers generally love towers as they are a very elegant solution compared with miles of tubing and can get to higher temperatures, achieving better efficiency. This is because the higher the temperature difference between

Figure 18.1 The Ivanpah tower and heliostat solar thermal project.
Source: Shutterstock.

two sources, the better the efficiency of an engine running on this difference. The maximum possible efficiency is called the Carnot efficiency.

There are several other designs of solar thermal plants, notably Fresnel concentrators and parabolic dish systems, but they appear to be dying out (see Figure 18.2). Most of the world's 7.0 GW of installed solar thermal capacity (as of 2022) is parabolic trough, with 1,291 MW of towers commissioned worldwide. There is, however, little in the planning pipeline and an auction held in Spain in 2022 set aside 220 MW of quota for solar thermal but received no bids under the maximum allowed price of 110 euros per MWh.

Solar thermal is one of the obvious solutions to the problem of evening peak demand in sunny countries, and like PV, costs have come down somewhat and the companies involved say it has much further to fall. However, in practice, it seems to combine many of the engineering challenges of running a fossil fuel or nuclear plant with those of collecting a distributed resource. There are pipes to explode, moving parts to wear, and in the case of plants with molten salt storage, the additional fun that molten salt freezes under about 240°C, so the pipes become full of

Figure 18.2 A Fresnel concentrator solar thermal design. The advantage of this type of solar thermal is that the mirrors are simple flat ones, and the receiver tubes are stationary (unlike with parabolic trough where the receiver tubes must tilt with the troughs, requiring complex joints). The disadvantage is that high temperatures are difficult to reach.

Source: Shutterstock.

solid salt. Molten salt sometimes leaks out. And you cannot control the input heat as you can in a fossil plant.

The solar thermal industry has more than its share of poor-performing plants, particularly towers, and very few it can cite as technical successes. Data released by the Spanish renewable energy regulator REE (website accessed May 2023) shows that the Spanish parabolic trough fleet ran at under 20% capacity factor in 2022. Most were originally expected to run above 30%, and it is not clear why they undergenerated in a year when power prices were very high and operators had every incentive to conduct rapid maintenance.

China has about 588 MW of mostly tower solar thermal plants built, according to the China Solar Thermal Alliance, and at least one tower plant — the 50 MW SUPCon Delingha plant in Qinghai, one of the sunniest parts of China — generated at its expected capacity factor of 33.4% in 2022. A further 500 MW at least of solar thermal is under construction in China, although this is dwarfed by the hundreds of gigawatts of PV planned.

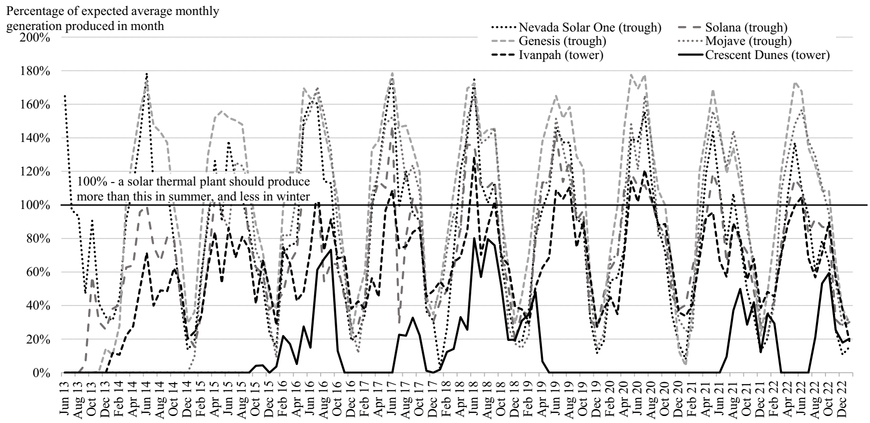

Figure 18.3 Annual generation of US solar thermal plants, as percentage of expected average monthly generation.

Source: US Energy Information Administration, company releases before commissioning collected by the author (for expected production).

Indian pioneer Godawari Power & Ispat Ltd, which has a 50 MW parabolic trough plant in Gujarat commissioned in 2013, complained in its 2016 annual report that the site does not have the Direct Normal Insolation (direct sunshine) that it expected and therefore the Indian Central Electricity Regulatory Commission should pay it more for the power; it is not clear whose fault it is that the site is less sunny than expected, but Godawari bid back in 2010, in an auction where the average price for solar thermal was 11,480 rupees ($197)/MWh. It did somewhat stabilise performance at the plant and achieved a 23.8% capacity factor in the fiscal year 2021, then quietly sold it to a trust.

Figure 18.3, based on data collected by the Energy Information Administration for solar thermal plants in the US, shows the monthly output of US solar thermal plants compared with their predicted average monthly output (usually publically announced or released at the planning stage). Obviously, these plants should be generating more than their predicted average monthly output in the summer and less in the winter.

While the parabolic trough plants are generally producing electricity as predicted or close to it, it is noticeable that the two tower plants, Ivanpah and Crescent Dunes, are not. Crescent Dunes in particular has never produced nearly as much as it was supposed to, not for a single month. Ivanpah has generally done better, but still below specs, and uses a little more gas than originally anticipated, to get it started in the morning.

Spanish entrepreneur Belén Gallego, who has been involved with the sector for over a decade, remained a fan of solar thermal in general as of 2018. “For sites with very clear skies and low seasonality [difference between winter and summer conditions], tower technologies are best, but conditions are make-or-break. You have to be looking at the specific site and the amount of aerosol in the air. And you need to focus mirrors from a kilometer away — if you are a hundredth of a degree off, you will miss the target. In the early days of the industry, this technology just didn’t exist. In parabolic troughs the concentration happens a lot closer to where the heat transfer fluid is, so the air composition is not so critical.”

No doubt the problems for solar thermal are solvable with enough investment. I am sure human ingenuity is capable of running a turbine on a distributed resource. But I would bet on a combination of PV and batteries, both of which work reliably, to deliver much the same thing at lower cost in most places.

There are a few non-electrical uses of heat collected using solar thermal projects. California-headquartered GlassPoint, for example, built a huge field of parabolic collectors enclosed in a protective greenhouse, intended to supply steam to an oilfield owned by Oman Petroleum and replace gas-heated steam used to extract more oil from difficult wells (‘enhanced oil recovery’). GlassPoint went bankrupt in 2020 and the fate of the project is unclear, though further developments are possible.

While I think it’s important to know about the history of failure of solar thermal electricity generation to have an appropriate degree of skepticism about new developments, it’s certainly possible that it will find applications or achieve a breakthrough. Richard Thonig, associate at the Research Institute for Sustainability in Potsdam, points out that “CSIRO, NREL, Sandia Labs and the Chinese government continue to support the technology. Solar thermal concentrators could be widely used in hybridisation with PV and thermal storage. I think they will also provide a significant amount of industrial process heat in breweries, factories and other applications."

Technology improvement continues here as well. Thonig observes that "ongoing R&D into third generation CSP [solar thermal electricity generation] plants hopes to improve the current second generation molten-salt central receiver towers. It targets the use of higher working temperatures between 700–1,000°C, novel heat transfer materials like solid ceramic particles, and the inclusion of a higher temperature supercritical CO_2 power cycle. Taken together these innovations allow to extend possible storage durations from diurnal into long-duration energy storage territory of days to weeks [which would be very useful, as observed in Chapter 17], which would further increase the value."

As Thonig says, "solar thermal for electricity generation isn't (necessarily) dead yet."

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Chapter 19

Technology Focus: Photovoltaics

As a solar analyst, I generally get away with treating solar modules as a standard product differentiated only by price. However, on longer timescales, solar panels continue to get more efficient and cheaper thanks to the efforts of thousands of people in labs and factories. This chapter does not go into enough detail to give due credit for their work, but it is an introduction.

Fundamentally, the limit to solar cell efficiency with up to three layers is probably about 56% under concentration [Henry, 1980]. More practically, according to Jenny Nelson, Professor of Physics at Imperial College London and author of the important textbook *The Physics of Solar Cells*, "the maximum possible efficiency of a single junction solar cell under one standard sun of incoming is about 33%. Adding a second junction [layer] can take that into the 40s." Today's commercial modules are around 22% efficient, which is adequate. Further tweaks to improve this without significantly increasing production costs benefit the companies involved but are unlikely to alter the trajectory of solar.

There are two main types of solar modules. Crystalline silicon is the workhorse of the photovoltaic power industry, making up about 97% of the modules sold in 2022. There is only one significant company making anything else: US-headquartered First Solar Inc, which makes cadmium telluride modules in the US, Malaysia, the Philippines, and possibly soon also in India.

Most alternatives to crystalline silicon are considered 'thin film' technologies, i.e. the process of making the modules involves depositing the semiconductor onto a glass as a vapour and letting it crystallise in place in a layer a few microns thick. This is in contrast to the standard crystalline silicon type, where the semiconductor (silicon) is first crystallised into a block (ingot) and then cut into slices at least 100 microns thick, a batch process with significant wastage (Table 19.1).

As of early 2023, most of the smart money is on crystalline silicon. Professor Nelson says that "If your goal [in lab research of semiconductors] is to beat silicon, give up."

Professor Martin Green of the University of New South Wales, Director of the Australian Centre for Advanced Photovoltaics and sometimes called the Father of Modern Photovoltaics, has conducted research on solar cell and module technologies since 1974. He agrees with Professor Nelson. "People don't realise how stable silicon is," he says. "Some manufacturers are offering 30-year warranties on silicon products, and we expect this to go out to 50 years in the fullness of time." His group continues to look for the right material to be used in a tandem junction cell with silicon, increasing the cell efficiency by capturing more wavelengths of light (about half the efficiency of the layer underneath, plus the efficiency of the upper layer).

"I've been surprised by how far the standard crystalline silicon solar cell can get us," added Professor Green in 2023. "At one point I thought it would never get below $1 per Watt, and we would have to look to a tandem junction with a second semiconductor for any improvements beyond that. There's been huge innovation in cell design and in wafer size."

Professor Nelson agrees. "If crystalline silicon was the only thing you could make, it wouldn't matter. But if anything was to displace crystalline silicon, I think it would be crystalline silicon with something on top of it. That second layer could be perovskites, organic PV, or kesterites [a family of inorganic compounds using relatively low-priced metals]."

Table 19.1 Types of solar module.

Semiconductor	Crystalline silicon (c-Si)	Cadmium telluride (CdTe) thin film	Copper indium gallium selenide (CIGS or CIS) thin film	Thin-film silicon	Organic, dye-sensitised, and perovskite thin films
Approximate market share 2022	97%	3%	0%	0%	0%
Companies (2023)	LONGi, Jinko, Trina, JA Solar, Canadian Solar, Hanwha Q Cells, Chint, Suntech, Maxeon, and over 500 others	First Solar	Solar Frontier, Hanergy (both former)	PowerFilm (small), otherwise used on as a heterojunction on silicon wafers by Meyer Burger, Enel 3Sun, Huasun and some other Chinese firms	Oxford PV, Saule Technologies, Evolar AB, Falab, and others
Status	Dominant	Competitive	Defunct	Niche	In the lab
Advantages	Mature and cheap. No intrinsic degradation mechanism. Silicon is plentiful and non-toxic.	Mature, bankable. Performs better (in kWh/kW/year terms) in low light and at high temperatures than	No intrinsic degradation mechanism. Solar Frontier products were mature.	Theoretically should be cheap. Good diffuse light performance. Excellent for calculator panels.	Theoretically cheap. Some could be made into tandem modules with c-Si, at high efficiencies.

(*Continued*)

Table 19.1 (*Continued*)

Semiconductor	**Crystalline silicon (c-Si)**	**Cadmium telluride (CdTe) thin film**	**Copper indium gallium selenide (CIGS or CIS) thin film**	**Thin-film silicon**	**Organic, dye-sensitised, and perovskite thin films**
	Fierce competition continues to optimise products.	c-Si, and has lower energy footprint. First Solar benefits greatly from US trade war with China.	Performs better (in kWh/kW/year terms) in low light than crystalline silicon. Flexible products have been made.	Can be used in a tandem junction with c-Si for high efficiency. Flexible products exist.	
Disadvantages	Batch manufacturing process with some ungainly stages, e.g. wafer slicing. Refining of polysilicon is energy-intensive. Heavy and can't be made totally flexible.	Only one company, so all cost reductions need to be done by that company. Double glass design is heavy and cannot easily be made bifacial.	Probably more expensive to manufacture than crystalline silicon. No commercial production.	Few companies left. Intrinsic degradation mechanism. Many modules installed have been replaced a few years later with c-Si. Unlikely to be cost competitive.	Manufacturing at commercial scale does not exist as of 2023. Most have intrinsic degradation mechanisms.

19.1 Crystalline Silicon (c-Si) Photovoltaics

c-Si photovoltaics is based on silicon wafers. After the polysilicon has been made by the processes described in Chapter 6, it arrives at a further factory as a sack of chunks. It is then shaped into monocrystalline ingots by melting it and allowing it to cool slowly.

To grow a monocrystalline ingot, the crystal needs to grow very slowly into a single perfect block. There is also the option of using a multicrystalline silicon ingot made much faster, by allowing interlocking crystals to form from multiple nodes. Monocrystalline silicon ('mono') makes a more efficient module and was an expensive minority product until the summer of 2018, when the Chinese wafer maker LONGi Green Energy Technology led the industry to switch en masse to diamond wire saws, making mono suddenly cheaper as well as more efficient. Multicrystalline (sometimes incorrectly called polycrystalline) silicon solar is no longer a standard product on the market.

The ingots are then sliced into wafers and 'doped' with phosphorus and boron, which change their electrical properties by making either free electrons or electron holes which respond when excited by light. The doped wafers are electrically connected and sealed into cells, then strung into modules. Crystalline silicon module manufacture is a batch process, i.e. one with many complex steps in different types of factories, and over the years critics have claimed that this will be its downfall. So far, they are wrong.

c-Si technology has been around since 1954, when the first silicon-based solar cell, by Bell Labs, had an efficiency of 4%. While the fundamental technology today is the same, many individual tweaks make up the experience curve described in Chapter 7. The first wafers, for example, were small silicon discs a few centimetres across, while today's typical wafer is 182 mm square. The silver paste used to make electrical connections has been improved and shaped more precisely so that the busbars take up less of the active area of the cell without reducing electrical conductivity.

From 2016 to 2018, the process of making monocrystalline silicon wafers has been disrupted by diamond wire saws, which replace old-fashioned (or 'traditional' as my Chinese colleagues refer to them, which conjures up a delightful but misleading image of a cottage industry) wire saws using abrasive slurry containing silicon carbide. One of the major disadvantages of wafer slicing with slurry is that roughly half the material is made into silicon sawdust ('kerf') and lost in the slurry, while the resulting wafers are thicker than they need to be to do their photoelectric job. Diamond wire saws are sharper, harder, and can slice thinner while losing less in silicon sawdust, compared with slurry-based wire saws. By December 2018, diamond wire saws had almost completely killed off slurry-based slicing, after coming to prominence just a few years earlier. (Phase change in technology can happen quickly. I took 4 months' leave to have a baby in May 2018 when multicrystalline silicon using slurry-based wire saws was the dominant solar tech, and when I came back in October, mono with diamond wire saws were the only thing anyone was using.)

Other crystalline silicon innovations include tweaks to cell architecture to reduce electron–hole recombination, reduce reflection, or improve conductivity of current away from the cell. Between 2018 and 2021, the Aluminium Back Surface Field (Al-BSF) solar cell at last gave way to a new design, Passivated Emitter Rear Contact (PERC). "In the early 1980s, we could see we would have to get rid of the Al-BSF, but we were still working on simple improvements like texturing to set our next world record," said Professor Green. "I wrote a paper in 1983 on cell voltage limits imposed by Auger recombination, where I predicted that the rear Al-doped layer would need to be replaced by either small-area or tunneling contracts for the cell to reach these limits. This led to my conception of PERC, that I first mentioned in a grant application, but PERC took several years to implement. The aluminium rear contact was very effective in removing impurities from the wafer, so switching away from it meant that [the industry] had to adopt much cleaner processing."

Between 2018 and 2022, the most common module type used for utility-scale power plants switched from monofacial (i.e. the side of the module facing the ground is an opaque backsheet) to bifacial (both sides of the module are made of glass, or one is made of a transparent plastic backsheet). Bifacial modules generate power from reflected light, as well as light which falls on the front side, which increases yield by 4–9%, though adding a few US cents per W to capex due to having more glass and mounting structures designed not to shade the back of the module. PERC cells are easier to make into bifacial solar panels than previous designs. As of 2023, PERC solar cell technology is giving way to tunnelling oxide passivated contact (TOPCon), which the China PV Industry Association (CPIA) estimates will be 18.1% of Chinese PV production in 2023, from 8.3% in 2022 (BNEF thinks it may be higher). "TOPCon offers higher efficiency and better voltage," said Professor Green. "And it's not too different from PERC so many of the same manufacturing lines can be used." TOPCon does use more silver, however, about 13 mg/W as of 2023, compared with 10 mg for PERC.

After TOPCon, the next generation might be silicon heterojunction (HJT) cells, a thin-film silicon layer on a base of crystalline silicon. The CPIA expects these to have a 3.0% market share in 2023, from 0.6% in 2022. Professor Green says, "Heterojunction cells aren't as rugged as PERC or TOPCon, so you likely need to use a special sealant on the edges of the module like First Solar does for its thin-film cells, and a better encapsulant. Heterojunction silicon cells also have a processing temperature limit of about 200 degrees Celsius, while the silver paste prefers much higher temperatures. So the final silver contacts are less conductive and more silver is needed [about 22 mg per W]. … But once the big manufacturers run out of efficiency improvements to make with TOPCon, heterojunctions may be the way forward, then cells with both contacts on the rear, like SunPower has been making for decades for niche markets. LONGi's just introduced a new mainstream module with both contacts on the rear, that might be a sign of things to come."

One area of innovation, or rather restandardisation, is moving to bigger wafers. The first ever solar wafers were tiny; for a long time, wafers with a side length of 156 mm were standard, then 166 mm, and as of 2023, the industry is torn between 182 and 210 mm. A few firms, notably LONGi, argue that 210 mm is simply too big and the sheer size of the resulting modules is a problem in the field and in the shipping container. "210 has got to be the winner!" says Green. "Though Trina [another Chinese manufacturer] is currently using rectangular cells, with a width of 182 mm and length of 210 mm, so that they can fit six cells — an even number — across a module that is 1.1 meters in width, allowing them to fit two boxes of these modules stacked on top of each other in a 2.4-meter-high shipping container." Apparently, an even number of cells across a module is easier to use in a module.

Green speculates on future wafer sizes. "The next ideal cell dimension would allow fitting 4 cells across a 1.1-meter-width module, so 250 mm wafers made of 350 mm-diameter ingots. Microelectronics [a company] was meant to go to 450 mm diameter wafers already, but some of the fine-linewidth processes become tricky over that area, so introduction has now been pushed back to 2029 at last count. One difficulty may be that the thin necks required at the start of ingot growth may not be strong enough to lift such a big ingot, so some additional clamping of the ingot during growth may be needed, but solar is probably going that way in the end." Manufacturing improvements can rely on very subtle physics, or they can be about ways to stop your chunk of crystallised silicon from breaking up before you can use it. Or about stuffing more solar modules into a standard shipping container.

19.2 First Solar and the Thin Film Investment Bubble

First Solar's share of about 3% of the global solar module market in 2022 represents almost all of the total success of a bubble in investor optimism for thin film technologies. Between 2006 and 2008, thin film solar companies raised over $2.5 billion in expansion capital, and for a while it seemed as if every Silicon Valley venture capitalist had to have one in their portfolio.

This enthusiasm for thin film was partly inspired by the success of First Solar itself at IPO in 2006, where the company raised $459 million after originally targeting $250 million and saw its stock price soar. First Solar, however, was founded in 1990 and benefitted from over a decade of patience from investors including the Walton family (the owners of Walmart). First Solar was ready to hit mass production of an incredible 21.4 MW in 2005 (2022: 9.1 GW) when the German boom started and the silicon shortage began to bite crystalline silicon module makers.

First Solar has also shown incredible ability to meet its milestones and targets over the last 20 years and has consistently communicated transparently and honestly. I'm almost sorry that in 2007, at an event held by trade promotion body Invest in Germany where the CEO of First Solar was speaking about the advantages of having a factory in Germany, I stood up and asked why their next planned factory was in Malaysia. The CEO, Michael J Ahearn, was nice about it, but I didn't get invited to the German embassy for drinks afterwards with the other participants.

As of early 2023, despite intense competition from crystalline silicon, First Solar has survived and is thriving, though largely to sell in the US where trade barriers make crystalline silicon modules much more expensive than in the rest of the world. While the module efficiency is around 19%, lower than the typical 22% for monocrystalline silicon, it is safe from potential US trade restrictions and so has an exceptionally strong pipeline of sales. The firm is expanding production in both the US and Southeast Asia.

For years, investment firms that had short seller positions on First Solar stock (and hence were hoping the stock price would plummet) published articles about the dangers of toxic cadmium and tellurium, imminent supply shortages, and other reasons to be fearful about the company. Very few of these stuck; there is no evidence that First Solar's modules are particularly likely to release toxic materials into the environment (cadmium telluride as a compound is in any case not as toxic as either of the elements which make it), the modules have consistently performed to specifications, and the company has effectively managed a module recycling programme, a large project development pipeline, and a smooth scale-up. It is unclear if cadmium telluride technology can continue to race crystalline silicon forever, but First Solar is making an excellent run of it.

It seemed perfectly logical in 2008 to back thin film technology, especially with First Solar making good profits and steadily increasing production. Silicon was expensive, and even if it became cheap, it did seem faintly ridiculous to continue with the crystalline silicon multi-step batch process involving sawing up blocks of semiconductors instead of laying it down directly. Most thin film technologies were less efficient than crystalline silicon, but as long as they promised lower costs per W, that didn't necessarily matter.

However, most of the other thin film companies were not, like First Solar, ready to begin mass production in 2005–2008. Astoundingly, it turned out to be more difficult than the founders promised, and investors hoped, to control complex and very sensitive manufacturing processes. United Solar Ovonics (Unisolar), Konarka, Abound Solar, Odersun, Flexcell, Solyndra, Tokyo Electron, and many others raised significant quantities of money for thin film between 2006 and 2013 but had exited the industry by 2014. Japanese copper indium gallium selenide manufacturer Solar Frontier hung on until late 2021 when it gracefully exited the business.

One problem with thin film is that it is vital to deposit the semiconductor in a uniform layer with consistent properties. If the active layer is patchy and uneven, the module will have the efficiency of the worst patch. Laying down semiconductor very evenly turns out to be quite difficult. Lab records for solar cells tend to be based on tiny scraps of active material, the best performing samples of a large bunch, and so a record set in the lab often does not translate to successful scale-up.

The other problem is almost unrelated to the choice of semiconductor, although those which require only low-temperature processes may be helpful. Many thin film companies have claimed that they will succeed by selling lightweight, flexible panels to niche applications, such as weak roofs. Flexible panels could be manufactured continuously ‘roll to roll’, in theory, bringing down the cost. However, there is a reason why ordinary solar modules use glass as their major structural and moisture-resistant material — glass is excellent for this purpose. It’s heavy, but it can last hundreds of years without losing its core properties of transparency and water resistance. Alternative encapsulants and front sheets are usually much worse at doing this, resulting in a product that degrades and underperforms — regardless of the semiconductor used. Since 70–80% of a solar panel’s weight is glass (more for ‘dual glass’ designs which sandwich the active layers between two sheets of glass rather than using an opaque plastic backsheet), the semiconductor used makes very little difference to the weight.

There is a recognisable phase in the lifetime of an exotic semiconductor solar company that is not doing well. This is the phase where they say “our product is expensive and unlikely to last 25 years, but it is lightweight and flexible and will find niche markets in solar backpacks and aesthetically pleasing buildings” (or words to that effect). So far, these markets have yet to materialise. Even offgrid markets, where you might think a flexible lightweight product would make sense, prefer to use small amounts of inflexible but cheap and long-lived crystalline silicon. The only firm to achieve longevity in this niche is Iowa-based Powerfilm, which makes small volumes of flexible thin film silicon modules under contract to the US military. Most companies developing organic and dye-sensitised solar modules have reached this stage, and it usually immediately precedes failure or stagnation.

Amorphous silicon also deserves a note of its own, although it is now seldom used for commercial modules. Amorphous silicon is made directly from silane gas, without going through the intermediate stage of polysilicon; it was hence unaffected by the shortage of purified polysilicon, as well as using a much thinner layer. It is the product used to power calculators since the 1970s, and is actually really good for this, as it performs well in low light conditions, such as indoors. Between 2006 and 2011, over 30 companies tried to make full-sized thin film silicon modules, 11 of them using manufacturing technology from Swiss material firm Oerlikon Solar and nine from US competitor Applied Materials [Chase, 2010]. Generally, these turnkey manufacturing plants were more difficult than anticipated to bring into production, particularly if they used microcrystalline silicon — a small step up from amorphous silicon but still a deposited layer rather than a sliced wafer. Where they did sell modules, we have sometimes found evidence later that these were replaced with crystalline silicon (for example, in Adani's 40 MW project in Kutch, India) — presumably due to significant performance problems. Applied Materials discontinued sales of its Sunfab solar factory in June 2010, and Oerlikon Solar was first sold to Japanese Tokyo Electric in 2012 and then discontinued in 2014. As of 2023, thin film silicon as a single junction has died out as a commercial product, though the technology survives in the hopes of heterojunction technology. European Meyer Burger and Enel 3Sun, and Chinese Anhui Huasun and many others, are increasing capacity for this technology rapidly.

19.3 The Possible Module Technologies of the Future

The most-hyped potential breakthrough technology of early 2023 is perovskites. These are semiconductors based on lead compounds. The reason researchers are excited is that, between 2011 and 2016, they went from being unknown to 22% efficient in the lab, an incredibly rapid progression of technical performance. They also have light absorption and manufacturing qualities that would make them a good fit for tandem junction with crystalline silicon.

However, perovskites still have short lifetimes and have not been manufactured in bulk. Professor Green was initially optimistic about them as the second layer in a tandem cell with crystalline silicon, pointing out that "perovskites are well suited to the manufacturing process for stacking onto heterojunction cells to make tandem cells, as they do not need high processing temperatures." However, he also said in early 2023 that while there's probably 10–20 thousand people working in perovskite research worldwide, he's "almost given up on it. Based on published work, if you stick an efficient perovskite module in the field for two months and it still works at better than 80% of initial performance afterwards, it would set a lifetime record for the technology. … there's not been the clear breakthrough in stability you would need to bring a product to market."

There are several firms, notably Oxford PV and Saule Technologies, who would probably argue with this assessment, but they have yet to introduce a commercial product and have been allegedly on the cusp of doing so for many years. I will get excited about perovskites when a major commercial module manufacturer publically makes a significant investment in perovskite production, and not before. (In May 2023, First Solar and Hanwha announced pilot investments. We will see how that goes.)

Organic and dye-sensitised PVs are other options, using semiconductors which are polymers or carbon-based compounds. They have been around for at least a decade in the lab, without making obvious progress towards commercialisation. Most at present have much too short a lifetime to use in a commercial product and are more at the lab test or even theoretical stage. Professor Nelson says with frustration that "it's very difficult to theoretically model the lifetime of anything new. You can't model it until you really understand it. With lifetime, the limiting factor is going to be the worst of a number of mechanisms — for example organic PV semiconductors can be metastable, but give them some heat and they can disintegrate."

It is possible that someone flicking through this book in 2030 will marvel at my failure to anticipate their perovskite or organic PV-powered world, but it's equally possible that the solar industry will achieve vast scale just with crystalline silicon. Also, as an analyst, you can achieve a remarkably high success rate with predictions just by being skeptical of the next big thing, especially when it looks a lot like things that have already failed. (This is also why analysts never become billionaires.)

Crystalline silicon is far from done reducing solar module costs. Perovskites, organic and dye-sensitised PVs, or another breakthrough technology *could* come and eat the lunch of crystalline silicon manufacturing companies. But the c-Si manufacturers are competing fiercely with one another to make better products for lower prices, and breakthrough technologies will have to beat their best efforts to be worth using.

19.4 Innovations in How the Modules Are Installed

There are several ways to optimise how photovoltaic systems are designed, whatever module you use.

The simplest is to change the ratio between the size of the inverter (the alternating current or AC rating of the system) and the size of the modules (the DC rating). This essentially caps the maximum power output from the modules. Figure 19.1 shows what this might do to the output of a photovoltaic system on a sunny day in Germany.

Why might one make a design decision that limits the maximum output of the system to below its actual output? Part of the reason is that you get slightly more output when the sun is not at its maximum (the 'shoulder periods') because inverters are more efficient close to their maximum capacity.

If the capacity of solar modules is fixed, a smaller inverter will activate (i.e. the system will start generating) slightly earlier in the morning as the sun rises than a larger inverter would and switch off slightly later at night. Also, there are not many really sunny days in Germany, so the power lost may not be worth paying extra for a larger inverter. As of late 2022, we estimate that an inverter costs about 4 US cents of the typical 72 cent cost per W (DC) of a utility-scale system with an inverter loading ratio/DC:AC ratio of 1.3.

Modules can also be installed on 'tracking systems', motorised mounting structures which follow the sun across the sky. While these can

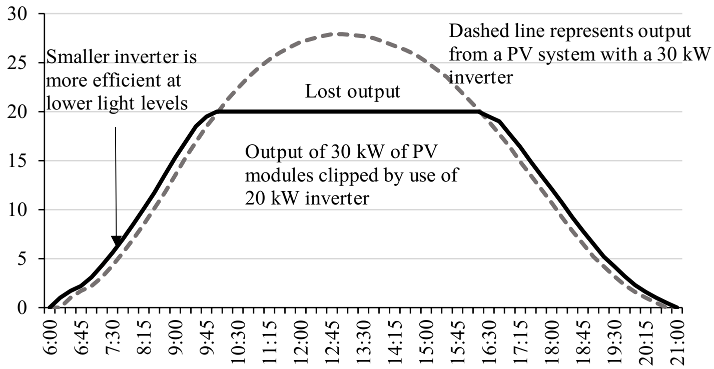

Figure 19.1 Illustrative power output, in kW, from 30 kW of modules on a sunny day. If the inverter is also 30 kW, there will be no clipping (but maximum power output probably never hits the full 30 kW). If the inverter is only 20 kW, there will be some loss of generated energy.

rotate on two axes to follow the sun both high and low, most trackers are single axis, i.e. they just turn from east to west facing every day. This increases the output from the modules by 20–30% compared to a stationary system. Adding a second axis for more delicate adjustments increases output slightly more but also adds the complication of a second set of motors, which doubles the chance of failure.

Tracking systems increase land use significantly, and operation and maintenance cost slightly because moving parts fail more easily than fixed ones, but the increase is worth it in sunny places where the 20–30% increase in generation is greatest. As a general rule, they add about 4 US cents per Watt to the system capex, although this varies with the steel price and other factors. Tracking systems have become the norm for utility-scale projects in most places more sunny than the middle of France.

Tracking systems increase generation in the morning and the evening, giving a wider shoulder to the generation shown in Figure 19.1. This can be particularly valuable in places where there is already a lot of fixed solar, and power at midday is no longer of peak value. Tracking extends the period of high generation later into the afternoon, meeting the demand for power for air conditioning for longer. Most ground-mounted PV systems being built in the US, Australia, South America, and southern Europe in 2022 use tracking, partly for this reason. By contrast, hardly any of the

PV systems in China use tracking, mainly because they are compensated at the same rate regardless of time of generation. Northern Europe is not sunny enough to warrant tracking systems.

East-west fixed PV systems are now a perfectly valid option on houses that already have east-facing and west-facing roofs (like mine) and are even sometimes used to pack solar modules densely in power plants. East-west alignment sacrifices around a percentage point of capacity factor (for example, my household east-west system gets only about 12% capacity factor, and a south-facing system would be around 13%), but it is not as complicated as tracking and gets many of the benefits. For example, I can do laundry with solar power as soon as the sun is up and be ready to hang it out to dry by the time the sun would even get fully onto south-facing panels.

Designing a PV system to increase airflow across the module can reduce the typical operating temperature of the module and increase output. This is because crystalline silicon solar modules lose between 0.2% and 0.6% of their efficiency for every degree Celsius above the 25°C standard operating temperature. High temperatures can also increase degradation.

19.5 Toxicity and Recycling

Solar and wind technologies are not completely free from environmental impacts. Wind farms do kill some birds, and magnets in the nacelle (hub bit in the middle of a wind turbine) use the rare material neodymium, mostly mined in China. Battery metals were discussed in Chapter 17.

Dustin Mulvaney, Professor at the Environmental Studies Department at San José State University, first became interested in the question of solar's environmental impacts during his postdoctoral training. "In Silicon Valley at the time, there were 12–15 thin-film manufacturers, mostly copper indium gallium selenide but some cadmium telluride. The semiconductor industry has left a pretty bad legacy of pollution in California, and my interest was in the consequences of this next generation of technology companies coming to the Valley." In collaboration with an Associated Press journalist in 2011, they obtained data from California regulators that showed wastewater contaminated with cadmium compounds was waste by solar companies that were not yet in commercial production. However, he says, "within a year, all those companies were gone" — in some cases due to market conditions and in others because of low manufacturing yields. Crystalline silicon solar panels do not contain cadmium at all, and CdTe leader First Solar has proper measures in place at its factories and provisions to recycle its panels at the end of their lives to minimise risks from using cadmium compounds.

Mulvaney continues to study environmental health and safety issues around the life cycle of clean energy technologies. "All the issues around toxic materials used in solar are completely manageable," he says.

There are two times in a solar panel's life where management of materials is critical: at the beginning and at the end. In the middle, solar panels sit in the sun being inert and encapsulated. This middle period should be at least 25 years according to panel warranty, but many solar firms now assume 30 or 35 years. One 10 kW installation near Lugano in Ticino, Switzerland, was put up in May 1982, and most of the cells still generate over 80% of its initial output 40 years later.

Crystalline silicon modules are not especially toxic; the vast bulk of them is glass, aluminium, plastic, and silicon wafer. The aluminium is in the frame and is easily removed and profitably recycled, and the rest is dirty glass. The most dangerous component is the lead in the solder used to make electrical connections in most modules, although SunPower has found a way to avoid using this, and the amounts are tiny compared with what is used in other industries. To put it into perspective, the Fraunhofer Institute estimates a 60-cell module that contains 12 g of lead [Wirth, 2021], which, assuming each module is about 315 W, would make lead use about 38 kg/MW or total 2021 use about 9,200 metric tonnes. The International Lead and Zinc Study Group estimates that 2021 global lead use was 12,326,000 tonnes, of which 80% was for lead-acid car batteries and 3% for ammunition. PV would be 0.07%. While lead in car batteries is very widely recycled, I cannot find statistics on recycling rates for lead used as shot and ammunition.

Solar panel recycling is in its infancy, but the main reason for this is that nearly all the solar panels ever installed are still in use. The volumes used are therefore quite small, and by far the cheapest way to get rid of broken or unwanted solar panels is to landfill them. Current recycling techniques allow the aluminium frames, glass, and even the silicon to be re-used, but unfortunately cannot extract the silver which is by far the most valuable material. Photovoltaics used about 11% of world silver supply (mined and recycled) in 2022, according to The Silver Institute, so long-term this is a real concern.

In Europe, producers are responsible for funding collection and recycling under amendments made to the Waste Electrical and Electronic Equipment Directive in 2012. European industry group PVCycle has recycled 62,300 tonnes of solar panels as of the end of 2021 and 17,100 tonnes in that year. By comparison, the European glass industry collected about 13.8 million tonnes of container glass for recycling in 2020, according to the European Container Glass Federation (FEVE), or about 79% of total use.

PVCycle CEO Jan Clynke explained to BloombergNEF in 2019 that "in the recycling sector, you need volumes to be economically efficient. You need at least 10,000 tonnes/year, ideally more like 50,000–100,000 tonnes/year. But because of the lifespan of solar panels, these volumes do not exist today. So glass recyclers who treat panels do not use dedicated, more refined PV recycling lines. They collect panels until they have a decent volume, and then use an existing recycling line for one or two days to process all the panels they collected. After, the line is used again to recycle other glass products."

Solar manufacturing involves more hazardous materials than are used in the field and can pose a risk to worker health and safety. There are two examples which usually form the basis of any news article desperately working a 'solar is actually bad' angle. One occurred in March 2008, when the polysilicon boom was at its height and spot prices were over $400/kg. A Washington Post article detailed how a Chinese company called Luoyang Zhonggui was dumping corrosive silicon tetrachloride on fields near local villages, causing respiratory problems to the inhabitants. The pollution was a result of the inexperienced company's poor implementation of closed-loop silicon tetrachloride recycling. Established silicon manufacturers process the silicon tetrachloride back into hydrochloric acid and silane feedstock, reducing the need to buy more of these expensive inputs. The Chinese government took measures in 2011 to close down companies without 98.5% silicon tetrachloride recycling. Even before that, the fall in the price of polysilicon after 2008 made manufacture without closed-loop recycling wildly uneconomic. They can't still be dumping silicon tetrachloride because it's valuable, and there has been no further news of that type of pollution incident after 2008.

The other example is the mess left by Abound Solar, a US manufacturer of CdTe modules which went bankrupt in July 2012. According to local newspaper *The Denver Post*, costs for cleaning up the cadmium-contaminated factory, encasing leftover cadmium materials in concrete and sending leftover panels to First Solar for recycling were estimated at between $2.2 and $3.7 million. Presumably, these were paid and the factory cleaned up, since it was bought by electric cooperative United Power in 2018.

Sometimes, the media gets extremely carried away with a particular 'dark side of solar' narrative. A typical example of the genre is an *LA Times* article in July 2022 titled "California went big on rooftop solar. Now that's a problem for landfills" which contained no evidence that large volumes of solar panels are ending up in landfills. The kernel of a story in the article is that in January 2021, California reclassified most end-of-life solar panels as 'universal waste' rather than 'hazardous waste', so regulations around handling and disposal are less stringent. This does mean that, yes, you can now send silicon-based solar panels to landfill in California because they're not toxic. But the article was full of underestimates of lifetime and exaggeration of how difficult it is to recycle at least the aluminium and glass in solar panels. Journalists can always get several supporting quotes from people at companies providing solar recycling services because these people generally think solar panel recycling is an important and under-invested field. It is important! But if a journalist got quotes from three different PV panel recycling companies, this isn't actually great evidence that nobody is ready to recycle PV panels. The problem for these companies is that current volumes of panels for recycling are small, and that is mainly because solar panels work for a very long time. They are being quoted because they want legislation to ensure all decommissioned solar panels come to them, and this is reasonable, but I am not sure even total end-of-life solar panel volumes in California would support three dedicated recycling companies at present. That particular article cited data showing that 335 panels were handled as universal waste in California in 2021. Not 335 tonnes, 335 panels. (I'm sure it was more than that, the data was only for certain handlers and sometimes solar installations are decommissioned early for various reasons. And volumes will rise. But 335 panels a year is a low base from which to start worrying. The article, mystifyingly, also claimed that future solar panels will have shorter lifetimes and I have no idea why this might be the case.)

Of course, the industry must act responsibly in producing and managing the materials needed to make solar panels and other components of clean energy. Best practice in manufacturing processes, worker safety, and recycling must continue to evolve with the industry. And legislation should be ready to enforce best practice in solar recycling. As a civilisation, we're going to have to move to a completely circular economy with full recycling of everything, ideally sooner rather than later. But solar should also not be put under more stringent obligations than much dirtier industries or standard consumer industries.

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Chapter 20

Operating Solar Plants

Chapter 9 on how markets set power prices assumed that the running cost of a PV plant is negligible, which is good enough for the first approximation. The beauty of PV is that it sits in the sun and generates energy with very little interference, and most plants (with the exception of those using tracking) have no moving parts to break.

For completeness, however, it is worth discussing operational costs. Of course, things can go wrong with a PV plant, and if you want it to continue generating electricity, these need to be fixed. Homeowners in particular often pay little attention to whether their solar panels are generating as promised once they are up, and this is a pity from an energy production perspective and for their finances. There are apps that do this, but only rather obsessive people check regularly (our installer sent us an email about our system underperforming after a few weeks when my husband accidentally disconnected it from the wi-fi, though).

Solar panels get dirty and in extreme cases can lose nearly all their output. My parents' home system in the damp UK accumulates a thick growth of algae, and a birch tree which has grown up since they installed it in 2010 is blocking their sunlight during the most productive hours. In Germany, many solar plants are not cleaned at all, instead relying on rainfall to wash off dust and dry weather to scorch off the algae. Ground-mounted solar plants in places where it rains need 'vegetation management', i.e. mowing the grass and cutting down the trees and bushes before they start to shade the panels. Usually, this is done with machinery, but sheep, goats, and geese can also do the job provided the plant has been designed so that they cannot access any cables. (Geese and goats will chew right through fairly heavy electrical cables just for fun.) In very arid climates, vegetation is less of a concern, but dust is more so; some US solar projects use special dust-settling sprays around their sites. In the Middle East, dust is a particular problem as very fine stuff blows in off the Sahara desert and is hard to remove, caking up when water is used.

This is another potential issue: solar plants do use water, though less than energy generation technologies which use heat to produce steam or for cooling. The International Energy Agency estimated in a 2012 report entitled *Water for Energy: Is energy becoming a thirstier resource?* that most gas, coal, and nuclear plants use about 1,000–10,000 L of water per MWh generated, compared with about 100 L/MWh for a photovoltaic plant. It's probably much less than that now for solar due to the rising efficiency of solar panels. All these figures can be reduced; gas plants can also be dry cooled (resulting in lower efficiency of converting fuel into electricity) to use around 10 L/MWh, and PV panels can also be dry cleaned with a brush, using no water. It's safe to say that washing PV uses an order of magnitude less water per MWh than most other generation technologies, although naturally solar plants in desert countries tend to be located in water-poor areas that are not valuable for agriculture.

Historically, solar plant operators have gone low-tech when it comes to cleaning. In the Middle East, the preferred technology is a bunch of people with brushes, going around at night scrubbing the panels. A few plants using tracking technology are designed so the panels align themselves correctly and then a truck drives up and down the rows rinsing and rubbing, like a carwash in reverse. In the future, panel-cleaning robots like those made by Israeli firm Ecoppia may do this labour-intensive, low-skilled, and not particularly satisfying work. Perhaps the union battles of 2030 will be between striking solar cleaners and robots.

The other major component of operation and maintenance of solar plants is fixing or replacing the electronics when they go wrong. The most common point of failure is the inverter, although cables, modules, and junction boxes can corrode. In the past, it was usual to replace the whole inverter, even for very large inverters which require a big truck to take them on and off the site, but now there are more likely to be exchangeable components which can be swapped out once a problem is diagnosed.

If a few modules fail, it is best to replace them as exactly as possible with the same. This gets more difficult as the power rating (efficiency) of new modules drifts up, and sometimes you may need to move all the good old modules onto the same string. The new warranty replacement modules then need to be installed on a different string. This is a lot of work, and it is really desirable that the modules not fail.

The effect of these costs on plant economics becomes increasingly obvious as solar power gets cheaper (i.e. the capex falls). A normal full-service operation and maintenance (O&M) contract between a solar plant owner and an O&M service company in Europe in 2022 costs about 14,500 euros (about $15,400)/MW/year, covering monitoring, cleaning, security, vegetation management, preventative maintenance, and replacement of broken parts [Hayim, 2022]. If the plant has a capacity factor of 20%, this is $9/MWh just in O&M, which seemed irrelevant when solar power costs hundreds of dollars per MWh but becomes critical when prices are below $50/MWh.

These operational costs are unlikely to see enormous improvements in the next 10 years. There are, however, ways in which technology can help a little. It is now quite common to identify the solar modules which have electrical manufacturing defects called ‘hotspots’ by flying a drone with an infrared camera over the field. Analyzing the images to spot modules with minor problems allows them to be replaced at the convenience of the contractor and the bill sent to the module manufacturer’s warranty department. The equipment to monitor the solar plants is also becoming increasingly sophisticated, collecting data at short intervals for every string of modules, which is fed back to a central processing hub. These data can be used to reduce unnecessary maintenance work, for example, by telling the contractor company exactly when cleaning the panels will be cost-effective to optimise generation or revenue for the cost, or indicating which components may be in pre-failure modes so spares can be ordered and repair staff can schedule site visits on a non-emergency basis.

The other major reason why O&M costs for solar plants have come down (and, anecdotally, the prices were higher than $50,000/MW/year in

2008, compared with under $20,000/MW/year a decade later) is that as the prices paid for solar power come down, it is not worth paying a huge premium to get a contractor who will instantly respond to problems. If 2% of your solar plant is out of operation because a chip fried in the inverter, it's unlikely to kill anyone (unlike in some other types of generation plants) and it will not black out half a city. This means there is no longer a strong incentive to keep duplicate components on site and engineering staff on call. If the problem can be fixed in a few days, that's probably good enough. In general, PV plants are not rocket science or nuclear engineering. They are meant to sit in the sun generating electricity without interference, and generally, well-designed plants do.

Other major running costs of a large solar plant include insurance — around 0.5% of capex per year — security against theft, and management fees. Security measures range from a large fence to a constant patrol of dogs, to prevent theft. Thieves used to take the modules for re-sale, but now modules are less valuable, they are more likely to go for the copper cables which have a much better value-to-weight ratio. Between 2013 and 2018, the choice of material for the bulk of PV plant cables switched from copper to aluminium, simply because copper prices rose on the world market and the wires became a target. Replacing stolen cables is both expensive and extremely tedious.

Management fees pay for services like billing the power buyer, making sure O&M contractors get paid, and renegotiating contracts. They probably have significant room to be brought down by software and by aggregating portfolios to have them run by one company. A PV management company might never actually visit the site but have effective ways to track performance and problems remotely.

Occasionally, something does go seriously wrong at a solar plant, for example, a tornado smashing through the site or failure of a large number of modules. The latter would usually be covered by accident insurance, though this is getting more expensive as climate change bites. Module failure should be covered by the supplier warranty, but often the supplier has gone out of business and the investor may lose money replacing them.

Solar plants can also be managed for more than the minimum amount of biodiversity. Since they are not substantially disturbed for over 25 years, they can be managed as a shaded wildflower meadow, occasionally grazed or mowed at appropriate times of the year, providing habitat and food for field birds and insects. Solar panels — especially bifacial one — can also be mounted vertically as fences and work well, though they will tend to be shaded by growing vegetation unless that is managed.

There is great excitement about 'agrivoltaics', combining solar farms with crop production. Historically, this has largely been a way for governments to subsidise bad farming and bad PV on the same land [Wang, 2020], but the production of some crops under some solar panels may make sense. Raspberries and strawberries, for example, are originally woodland plants which can do reasonably well in shade even in temperate climates and may benefit from shade in very hot ones. They are also usually harvested by hand, so mechanical access is less important as long as humans can reach the plants. Some studies have shown that in different climates you can grow broccoli and aloe successfully under solar panels. However, ultimately, it is difficult to farm crops at scale without ever using a tractor on the land to plough or to remove the previous crop. We will probably see a lot of attempts to do this over the next few decades, and the success will depend on local conditions and the crops chosen because farming food is a lot harder than farming solar.

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Chapter 21

2022: Energy Is Scarce Again

Europe was already a little short of natural gas in February 2022. We wrote in late January that "BloombergNEF currently forecasts end-of-winter storage inventories at 7.1 billion cubic meters (10.7% full) — a very low level with limited cushion should the weather turn colder than the seasonal average" [Ulrich, 2022]. In most years, Europe fills its gas storage reserves in summer from pipelines and shipped natural gas. In the winter of 2021–2022, Russia had cut gas flows due to low prices and as a negotiating tactic for long-term contracts and the construction of a Nordstream 2 gas pipeline. There were warning signs before Russia invaded Ukraine on February 24, but at the time it was just an increasingly tense geopolitical environment. (This is usually a euphemism for 'there might be a war'.)

After the invasion started, countries sought to stop bankrolling it, as they did by buying gas and oil from Russia. The European Union already had some sanctions in place against Russia but increased these quickly and by May had drawn up a plan, REPowerEU, to reduce dependence. This relied in the short term on severe energy efficiency measures, increased imports of liquefied natural gas (LNG), and a scramble to build more solar, wind, and heat pumps across Europe.

The immediate effect was to push up the price of LNG up to crisis levels. LNG is a weird commodity; it is natural gas cooled to about minus 162 degrees Celsius and loaded onto ships at special terminals which are expensive to build. The ships then can take it wherever in the world the price is best, and it then has to be regasified at further special facilities. It's more expensive than gas transported by pipeline and so tends to be the last resort of power producers, but this also means that it often sets the marginal price of power on spot prices (see Chapter 9).

The price of LNG more than doubled globally in early 2022. Prices of electricity in Europe, which are largely set by the marginal cost of gas generation, were often above 400 euros per MWh in 2022, from 30 to 60 euros per MWh in 2021. Across Europe, corporations and individuals which did not have long-term fixed-price contracts found themselves faced with sky-high power bills.

A long drought in China and Europe, which reduced hydropower production in autumn, and unscheduled nuclear outages in France over the summer of 2022 did not help the situation. The whole world, with the partial exception of the US which produces most of its own gas and has limited LNG export terminal capacity, felt the energy crisis.

There was also a huge individual response, from Preston to Prague, to inconvenience Russian president Vladimir Putin and save now-expensive energy by turning thermostats down, installing heat pumps, and building rooftop solar. According to the European Heat Pump Association, 3.0 million heat pumps were installed in 2022 in Europe, up from 2.1 million in 2021 and accelerating a very consistent rising trend of annual sales. Anecdotally, customers wanting to have a solar system installed were put on waiting lists of 8–12 months (and as of early 2023, this is still the case). 'Balcony solar' or 'plug-in solar,' consisting of just a few panels plugged into a standard household plug to cover instantaneous household power demand, can now be seen on houses and apartment blocks in Germany and Switzerland. We have very poor data on how much this actually adds up to, though it cannot be that much, with 1–3 solar panels per installation.

Europe (including non-EU Europe, but it's nearly all the European Union) installed about 42 GW of solar in 2022, up from 31 GW in 2021. The total would have been much more if the rooftop sector had had more staff available to put panels on roofs or if permits for using land or attaching projects to grid had been easier to get. Countries are taking their own measures to try to make it easier to build solar; France, for example, passed a mandate that all car parks for more than 80 cars must have solar canopies by 2028. Italy changed land use definitions for quarries, which were formerly classed as agricultural land and should now be easier to build solar on, and also eased permitting for PV combined with agriculture. Germany has specifically classified drained peat bogs as land suitable for solar panels, provided the solar plant re-wets the peat and preserves it under the panels, stopping it from releasing its stored carbon.

The US was having its own problems building solar in 2022, many of which were self-inflicted (see Chapter 22, Trade Wars). In August 2022, the US passed the Inflation Reduction Act (IRA), a landmark piece of the energy and climate transition which, in energy at least, seems likely to do almost anything but reduce inflation. The IRA supports a huge basket of technologies, both deployment and manufacturing, including solar and wind but also hydrogen, the grid, better buildings, lower-carbon farming, biomethane, and carbon capture and storage. The official cost estimate for the IRA's energy transition measures is $369 billion over 10 years, but a lot of the measures are uncapped, and Goldman Sachs estimated in March 2023 that the whole thing will cost over $1.2 trillion.

Governments exceeding budgets is often not a huge problem when trying to transition an entire society through an uncertain period. With such a large and generous suite of incentives as the US IRA, however, there are bound to be some of them that turn out perverse. For example, there is a credit for making hydrogen from biomethane, which is odd because biomethane is already very useful (possibly more so than hydrogen, because it's a bigger module that is easier to store and more dense in energy). The exact rules on what will get the IRA credits are yet to be determined as of mid-2023. But it provides a huge boost to the economics of solar and batteries in the US and to the deployment of capacity to enable integration of renewables into the grid.

In 2022, it became clear around the world that access to the grid is the real barrier to solar and wind build. Land permitting isn't easy, especially for wind because windy sites are rarer than sunny ones and wind turbines are usually subject to more complex rules on siting and more local opposition. You cannot hide wind turbines behind a hedge like you can solar panels. However, there is fundamentally a lot of suitable land. There is not a lot of suitable grid, and building new transmission is a huge undertaking. Even finding places where solar and wind projects could be connected to the existing grid is not easy, with many of the obvious sites now taken. When projects connect to a grid with a lot of nearby projects (a saturated grid), they may get their output frequently curtailed because there is neither the local demand nor the capacity to move the electricity away to where it is needed. South Australia, a small grid with limited connectivity to the rest of the country, regularly has long periods of 100% renewables but solar farms average over 10% of their output curtailed, with some significantly worse. Power prices in South Australia were negative for over 30% of hours in the fourth quarter of 2022, a significant problem for projects without contracts to sell power.

Many regions of the US, as well as Spain, Italy, France, the UK and other countries, have ‘queues’ of applications to build solar and wind projects, which now need to be accepted or turned down. There were over 2TW of solar, wind, and storage projects seeking to connect to the grid in the US at the end of 2022, according to Lawrence Berkeley National Laboratory. France, Spain, Italy, and the UK have 596 GW of solar and wind projects between them in similar queues [Hayim, 2023]. The public planning offices responsible for considering these applications and running studies to determine which should be given permission are usually underfunded and understaffed, and so projects which should be built are sitting in files for years alongside projects which probably should be rejected, and others which should be allowed but required to pay a share of the cost to upgrade the grid for them. The US Midcontinent Independent System Operator (MISO), which manages electricity flow across 15 states in the middle of the US and up to Manitoba in Canada, has one of the better approaches, performing ‘cluster studies’ on multiple projects in one small region, and communicating to the developers what it would cost to upgrade the grid to get them on it; as a result, typical waiting times in the MISO queue are a few years. Germany requires projects to have land permits before applying to the grid, which at least reduces speculative applications.

Both a reform of processes for grid access and a huge building process to add actual wires are needed in many countries to enable the energy transition.

Figure 21.1 shows the policy landscape as of early 2023 for solar. There is hardly a land mass in the world, except Antarctica, where solar

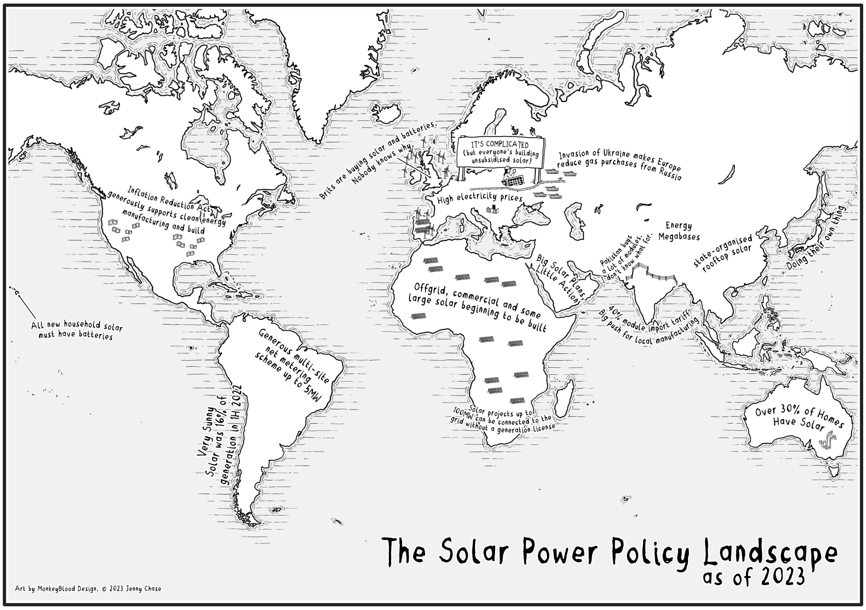

Figure 21.1 Selected solar policies, as of early 2023.

Source: Art by Glynn Seal of MonkeyBlood Design.

panels are not springing up like weeds after rain. Direct subsidy for solar projects is becoming rarer, but government policies are trying to enable solar by making grid access and planning permission on suitable sites easier, while also trying to bring manufacturing of solar and other clean energy equipment to their shores.

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Chapter 22

Trade Wars

Over the last 50 years, economies in general and Asian economies in particular have become better and better at producing all sorts of goods — plastic trinkets, shoes and clothes, semiconductor chips, and computer hardware — for a low cost. The exact dynamics change over time. I remember in the late 1980s, 'Made in Japan' was considered low quality at least in my corner of rural England, while it would now be a stamp of pride from a high-tech economy considered one of the most developed in the world. Perhaps by 2030, we will think the same of 'Made in Vietnam' or 'Made in Indonesia' as a similar statement of high quality.

In general, Europe and the US have enjoyed the rising availability of cheap semiconductor chips, computers, headphones, and other electronics made in Asian countries. Aside from occasional concern for the conditions of workers, there has been very little backlash. The story from the economist's perspective is that well-educated workers in the US and Europe will have to continue to innovate to stay ahead, using higher-productivity methods and equipment, while by the time the workers in Asia have caught up on skills, they will be asking for similar salaries and working conditions. Salaries certainly have risen in China, particularly in the province of Jiangsu where high-tech work is concentrated and factories are increasingly automated. According to the Jiangsu Provincial Bureau of Statistics, the average wage in Jiangsu rose 35% between 2017 and 2021, to $10,500/year. Productivity however rose 124%, according to China Photovoltaic Industry Association data showing that the average solar module worker in

China made 3.8 MW in 2021, up from 1.7 MW in 2017 [Tan *et al.*, 2022]. However, manufacturing in high-wage countries is more expensive and is frequently discontinued, leading to painful job losses.

There is legislation allowing industries to fight this. The argument is that if a nation secures a leading position in the manufacture of a good, then it can drive companies in other countries out of business, destroy industries in competing countries, and then once it no longer has competition, put its prices up.

The allegation behind a trade war is usually that a government has deliberately subsidised industries to offer prices that make no profit and are intended to drive foreign competition out of business and secure a monopoly position (presumably, to then raise prices again). This is called 'subsidisation' and leads to 'dumping', which is selling products at a loss or at a price lower than in their home market (both definitions of dumping are valid). Examples of goods on which the European Commission has opened investigations include 'certain concrete reinforcement bars and rods', 'Polyester yarn (high tenacity)', 'Hand pallet trucks', 'Footwear with uppers of leather (certain)' from Vietnam, and 'Ring binder mechanisms (certain)' from Thailand. There are lawyers in Brussels with large files about too-cheap ring binders.

In practice, it is seldom obvious which subsidies are unfair, and the cases keep many lawyers in good wine and expensive dinners. China's government has offered incentives to set up factories in industries the government considers strategic, for example, free land in a new industrial estate, tax breaks, cheap power from state-owned utilities, and lines of credit from state-owned banks. But so does the government in nearly every country. When an international company wishes to set up a factory — creating jobs — it can usually shop around for the best offer on where to put it, and country and local governments have people on payroll to conduct these negotiations on their behalf. The governments can then boast about the creation of 'green jobs'.

When it is an American offer, it is considered by Americans to be vital strategic support to accelerate development of the industry of the future and create jobs. When it is a Chinese offer, American politicians consider this to be illegal subsidisation with the aim of dumping products and destroying American jobs. The European Commission is historically somewhat more even-handed, although it also runs interminable investigations. The World Trade Organization (WTO) acts as a sort of international arbiter.

The redress within a country is managed by the Department of Commerce or equivalent and often takes the form of a tax ('anti-dumping' and 'anti-subsidy' tariffs) on imports from the country. Individual companies — for example, Chinese manufacturers of solar modules — are invited to submit information about the government subsidies they have received, from which individual anti-dumping and anti-subsidy rates are calculated by the company. Manufacturers which do not cooperate by submitting information usually get a single, much higher tariff rate. There is often negotiation, with the importing country using anti-dumping and anti-subsidy tariffs as a stick. For example, in Europe in 2013, Chinese solar manufacturers negotiated an 'Undertaking' with the European Commission, whereby they would sell solar modules only at or above a 'Minimum Import Price', and in exchange would not pay the import tariffs, set at least 37.2%. This Minimum Import Price was initially adjusted based on changes to BloombergNEF's Spot Price Index, rather to my trepidation as it created an incentive for companies to submit biased data to our price survey, which we had to take measures to counter. (Mostly, we requested to see recent contracts from companies applying to join the survey, and from companies submitting unusually high or low results. We also relied heavily on getting quotes from both buyers and sellers of components, so that hopefully subtle biases would cancel out, and wildly exceptional values identified and removed.)

The European Commission dropped its measures against Chinese modules in September 2018, and as of mid-2023, Europe is a free market for solar.

Sometimes negotiations fail and countries end up taking punitive measures. In 2011, the US set trade tariffs ('tariff' in this context means a fee as a proportion of price, also called duties payable) on imports of Chinese solar modules, kicking off the longest and most bitter of the solar trade wars so far. China responded by setting trade tariffs on US polysilicon imports, which was devastating to US manufacturers Hemlock

Semiconductor and REC Silicon. The whole affair was also inconvenient to Chinese buyers of US polysilicon and to US module buyers, all of which had to pay more.

One problem with using trade tariffs as a weapon is that there is usually a legal loophole, or a way companies can change their operations to avoid them. Is this unfair? If a government penalises one activity, like manufacturing solar panels in China, surely changing to a different not-penalised activity, like manufacturing solar panels in Vietnam, is what they want? Major Chinese solar companies have set up extensive factories to make first modules and then also solar cells in Malaysia, Vietnam, Indonesia, Thailand, Cambodia, and the Philippines. These factories are mainly for the US market; the import tariffs keep prices of modules in the US significantly higher than in the rest of the world (as of May 2023, about 36 US cents per Watt in the US compared with 21 cents per Watt in Europe, for the same brands). Manufacturing costs for solar modules in southeast Asia are slightly higher than in China (by 2 or 3 US cents per Watt) and often key materials like silver paste and encapsulant have to be brought in from the Chinese mainland. However, the factories in Southeast Asia are real ones using modern technology; allegations that they are just relabelling Chinese-made modules are false, even though most belong to the same Chinese companies. They also act as a hedge for the manufacturers against rising costs or supply disruptions in China.

It is worth noting that regarding entire countries as being in competition isn't the only way to look at the world. The solar manufacturers within China are competing with one another on cost, quality, and branding far more fiercely than the countries are. I do not think that the Chinese companies think about the US solar companies at all.

The exact terms of, and loopholes in, US solar trade measures on China since 2011 are a long and not particularly interesting story. In 2022, an industry body led by Auxin Solar (which claims to be a US module maker but is almost invisible in any context except leading this trade case) brought a case for further import tariffs on modules from southeast Asia, to protect or rather revive US manufacturing. This would have choked supply to the US market, as there are very few modules made outside either China or Southeast Asia. In June 2022, US President Biden passed a 2-year exemption from threatened tariffs, using emergency powers on the basis that the supply of solar modules is strategic due to the climate crisis.

Also in June 2022, the Uyghur Forced Labor Prevention Act (UFLPA) came into force in the US. This was in response to humanitarian concerns about the treatment of the Uyghur people, a mostly Muslim minority in the northwestern Chinese province of Xinjiang.

Xinjiang has rich coal reserves, and with support from the government and cheap coal power, has built a polysilicon production base which made 38% of the world's polysilicon in 2022. Polysilicon makers in the province, such as Xinte Energy and Daqo, have disclosed through filings that they have hired Uyghurs through state-sponsored labour transfer programmes. These programmes are common throughout China and involve moving people from rural areas with no work to places where there is work (for example, remote polysilicon plants). Chinese labour transfer programmes do not always constitute forced labour, but there is certainly a troubling lack of transparency, especially to concerned human rights organisations.

The Uyghur Forced Labor Prevention Act (UFLPA) blocked import of solar panels using any component made in Xinjiang to the US. A slight surprise in the final text was that this also covered metallurgical-grade silicon used to make the polysilicon, which would-be importers were not prepared for. However, there was plenty of polysilicon available from outside Xinjiang (the US was about 9% of the world solar market in 2022, and Xinjiang silicon was only about 38% of global production) but it took a few months in 2022 for firms to figure out what paperwork was needed to get modules through US Customs. The paperwork had to prove that the metallurgical grade silicon and polysilicon were produced somewhere other than Xinjiang, and the rest of the value chain was also outside the province (though Xinjiang has very little capacity for any other solar product). Mostly this meant that, for the US market, polysilicon made in the US, Germany, Malaysia, or other Chinese provinces like Inner Mongolia or Sichuan was crystallised into ingots and sliced into wafers somewhere in China, then shipped to southeast Asia to be made into cells and then into modules.

Then the US Inflation Reduction Act — possibly the single most generous piece of energy legislation ever passed in the US — was signed into law in August 2022. This pays out tax credits for every kilogram of polysilicon, for every wafer, and for every watt of cell and module made in the US, along with inverters and tracking systems and completely other products like hydrogen. A solar module for which polysilicon, wafers, cells, and modules were all made in the US would get about 16 cents per Watt of tax credits, at a time when the price of Chinese modules on the world market is about 20 cents. There is a surge of US factories for cells and modules planned, a few ingot and wafer plants, and a lot of factories by thin-film cadmium telluride firm First Solar. The trade war has been fantastic for First Solar.

The back-and-forth on possible US tariffs on southeast Asia, and the precise paperwork required to comply with the UFLPA, caused the US solar industry to miss build forecasts in 2022 as large solar projects were delayed. Prices are still very high in the US, and Indian suppliers like Waaree and Vikram are enjoying the new market for non-China module brands and even planning to set up their own factories in the US. It feels like a very dedicated effort by the US government to drive the market on one hand and block access to supply on the other, but maybe it will build a successful domestic manufacturing industry.

India tried to build a domestic solar manufacturing base first. Since 2013, India has had support for domestic module makers, including an Approved Module Manufacturers List (AMML) of 23 suppliers which are the only ones that can be used in certain government-assisted projects. In late 2021, the country stepped up its game and auctioned off production-linked incentives of its own to manufacturers building integrated factories. In April 2022, India blocked solar supply with a 40% tariff on imported modules and 25% on cells. This, along with inflation and the value of the rupee falling, caused the cost of building large PV in India to rise 50% in local currency terms from early 2021 to late 2022, a huge source of difficulty to project developers trying to get building.

India's sustained — though modest — support for its domestic manufacturers since 2013 did at least mean it has a handful of module makers ready to take advantage of the opportunity to sell to the US and also to expand to supply the domestic market. However, these are small and lack polysilicon and wafer expertise, and are generally not using the newest technology. As of mid-2023, India is the last market where price discovery firm PV Infolink still publishes a price for multicrystalline silicon modules, considered obsolete everywhere else.

Taiwan also has its own local content requirements, supporting solar projects in schools and community buildings if they use locally produced modules. Turkey and South Korea have import barriers protecting the domestic solar market as well, and these regions continue to be minor manufacturing hubs.

The European Commission appears disturbed by the US Inflation Reduction Act, which represents a major departure from principles of free trade and competition. There is some possibility that the US could end up dumping subsidised goods — for example, hydrogen which has received the $3/kg production tax credit — into Europe. In March 2023, a deal was struck which may allow critical battery minerals extracted or processes in Europe to be eligible for US tax credits, relieving US–Europe tensions a little.

Europe, however, also wants solar manufacturing back; in February 2023, European Commission President Ursula von der Leyen clarified a 'Green Deal Industrial Plan', a successor to REPower EU, a 2022 plan to replace Russian gas. Her statement somewhat optimistically declared that "we initially proposed [REPower EU] to get rid of the dependency on Russian fossil fuels. It went much faster than we expected ... So we have the possibility to redirect or reorient the additional funding of REPower EU — it is about 250 billion euros — to our net-zero industries … for example for tax breaks to the net-zero industry."

Many firms hope that this means European support for solar and other manufacturing on the same scale as the US Inflation Reduction Act. However, the European Commission has much less power to make central decisions than the US federal government. That 250 billion euros is not exactly sitting in a pot but rather loosely promised by European Union member countries. In March 2023, the European Commission passed the Net Zero Industry Act, which sets lofty ambitions without much detail on support measures. The most binding provision is that government-backed auctions of solar, wind, and battery capacity should offer a premium for bids using components made in countries which do not represent over

65% of the European Union's supply of that component. In short, are not made in China, though the phrasing carefully avoids singling out China and is instead all about the diversity of supply. This makes sense since Europe certainly does not choose Russian gas over Chinese solar panels.

What the Net Zero Industry Act notably doesn't do is support European manufacturing exactly, and the price premium for 'diverse supply' cannot be more than 10%. The Net Zero Industry Act also contains vague measures about helping to upskill workforces in key regions, which might be used to support solar. It also calls for removing barriers to siting industrial facilities, but these are more likely to help carbon capture and storage and heavy chemical plants than solar.

Nonetheless, the few remaining European firms — Wacker Chemie's polysilicon plant in Germany, which is badly hurt by high energy prices, and Meyer Burger, a former manufacturing equipment supplier that has pivoted to making high-efficiency heterojunction cells and modules in Germany — may benefit from more subtle support from the Net Zero Industry Act. At a minimum, it is unlikely the European Commission will forbid local subsidisation of clean energy manufacturing for free trade reasons. A number of solar firms are likely to get substantial grants to set up factories in Europe.

There's also a chance that Europe will apply a Carbon Border Adjustment — an import tariff calculated on the carbon footprint of manufacturing — to all products. I expect the calculation methodology of this to strongly favour European products, although it would be possible to argue that the best Chinese product might actually have a low carbon footprint too. GCL Technology, for example, claims that its fluidised bed reactor (FBR) polysilicon plant has a lower carbon footprint per Watt of wafer than a German Siemens process plant, and this is plausibly true. FBR generally uses less energy to make a kilogram of polysilicon than the Siemens process, though it is also more difficult to use FBR polysilicon to make top-quality monocrystalline silicon wafers. Also, some Chinese polysilicon plants run mostly on hydroelectric power cleaner than the average German power mix, though it could be argued that using this hydro to make polysilicon diverts it from other uses within China and hence burns more coal. Carbon footprint calculation is a scientific and sometimes philosophical pain, and it is likely any carbon border adjustment tariffs would choose a methodology to favour domestic firms.

Trade wars are complicated and this short history of solar import sticks and carrots is only a flavour of the enormous detail that tends to result. They create a lot of green jobs in legal work and generally, in my opinion, slow down the energy transition. However, it is understandable that countries are keen to establish more diverse supply chains, particularly after Russia's invasion of Ukraine in February 2022 which showed the dangers of relying heavily on a single country for energy (though buying gas to burn every day is different to buying a solar module which will be useful for at least 25 years).

China's zero-COVID policy from 2020 to 2022 also made it very difficult for anyone to leave or enter the country, or to hold conferences and events, and has probably increased distrust between the West and China. However, COVID had only transient effects on the manufacturing supply chain, and China kept most of its factories running smoothly throughout the pandemic, though shipping was severely disrupted. The price to ship a 40-foot container from Shanghai to Rotterdam rose at one point in 2021 to $14,800, above the long-term average of about $2,000 (in May 2023 it's back down to $1,645 if you need some stuff). But China still has the biggest, most integrated, most high-tech manufacturing bases, the lowest cost, and makes over 95% of the world's wafers and 89% of its polysilicon. Without China, solar would still be a cottage industry, and some of the plans of other countries to have their own factories look rather cute in comparison. But clearly, a new age of local factories is about to be attempted, and there are reasons to hope some are successful.

Chapter 23

Will Offgrid Solar Leapfrog in the Developing World?

The first and most intuitive market for solar panels is the world beyond the existing power grid, where solar competes with candles or kerosene for producing light, and with diesel generators for producing electricity. An additional major market for solar systems that can function off the grid is from people and businesses who do have a grid connection but for whom it is unreliable. This is a segment that, as of 2023, includes many in South Africa who are used to constant power supply and have fridges and computers and other significant electricity loads.

One of the earliest groups of buyers for unsubsidised solar was in Norway, where many families own a cabin (‘hytte’) up in the wilds where they holiday in the summer. These cabins are remote even for deliveries of diesel, and presumably the hum of a diesel generator spoils the tranquility. The electricity needs of the cabin are small, with just a few lights for the few dark hours of the Norwegian summer and maybe a small television, which can be handled with a modest solar panel and a battery. So, in the 1980s and 1990s, Norwegians bought some of the few MW of solar panels sold per year, and presumably still do, with the market limited only by the small number of cabins.

For many people, however, being off the electricity grid is not a charming back-to-nature leisure choice. As of 2019, 759 million people have no access to electricity; this was down from 1.2 billion in 2010 ("as electrification through decentralized renewable-based solutions in particular gained momentum" according to *Tracking SDG 7: The Energy Progress Report* from the World Bank and others) but there are indications it rose again during the pandemic.

If these people want light at night, their historical options are candles or kerosene lamps, which are expensive in the long run and also produce particulate matter and soot, which harms the human respiratory system. One option is to extend the power grid to every house, as has been done in most developed countries and, most recently, in India (where the electrification rate is 99% in 2021, according to the World Bank and Indian government definitions, but this grid electricity is often unreliable and limited for rural areas). Grid extension costs money, often a lot of money where people are widely dispersed, to serve people who currently have extremely low power usage. Often, people will walk kilometres several times a week to charge a phone at a privately owned diesel generator. A much cheaper way to get those people basic electricity supply — enough for light at night, mobile phone charging, even a small television or a fan for cooling to increase productivity — can be to use solar and batteries in some combination.

The very-small-solar space is a difficult market to get investors interested in, because honestly it is hard to make money selling tiny products to poor people. This chapter draws heavily from data on the work of the Global Offgrid Lighting Association (GOGLA), an association of major manufacturing and distribution companies in the field, which probably represents the upper end of price and quality products. GOGLA's 2022 Off-Grid Solar Market Trends Report estimates total turnover (revenue) for offgrid solar energy kits at about $2.1–2.2 billion in 2021, which makes it only about 1% of the world solar market even though it has been growing fast.

The most basic solar-powered lantern with phone charging costs around $5 as of 2022, although this probably isn't a very good one. According to GOGLA, a less basic solar lantern or one charging multiple lights has an average price of $27.

The problem is always paying for it. Many people find the money to buy 20 cents' worth of kerosene every week but might struggle to put together even $5 for a solar lantern, even if it would pay back within a year. It is very difficult to save money when there is no banking system.

British fantasy author Terry Pratchett described this problem as the 'Boots' theory of socio-economic injustice: a rich man might buy a pair of boots costing $50, which last him 10 years (this is not the time to quibble about the exact lifespan of boots. Maybe I'm buying insufficiently expensive boots). A poor man might have to buy a cheap pair of boots costing $10, which last 1 year. After 5 years, he has spent as much as the rich man, and he still sometimes has wet feet.

To develop Pratchett's idea: one solution is to give the poor man some good boots. Or you could give him $50, and he might buy good boots or something he felt he needed even more, like shoes for his children or mosquito nets. A further alternative, if you are not sufficiently philanthropic to hand over $50, or want to help more people with that $50, is to lend the man the money to buy good boots. At 10% interest rate, he still pays it off in 7 years with what he would have spent on bad boots and has 3 more years of dry feet, assuming nobody steals his boots. If someone nicks his boots, he'll have to buy more boots and may not want to pay back the $50, which is one reason you might want to charge a high-interest rate so the borrowers who do pay make up for the failure to pay off those who can't.

Microfinance is a keyword in circles focused on reducing poverty in developing countries. It means lending small amounts of money — enough for a handcart or an irrigation pump or a solar lantern — at interest rates which can be up to 25%. This often does not fully compensate the lender for the risk (in our boots analogy, the risk is that the boots are lost, stolen, or destroyed, or the borrower takes the boots and runs far away). This is particularly true in the early stages of setting up a microfinance scheme, when the cost to find the customer and set up the loan is very high. However, it can come down rapidly with scale. It may be difficult to find the first customer, explain the concept of a loan, do your best due diligence on them, and arrange a mechanism to collect payments, but once the idea spreads it will be easier to lend to the 100th person.

Mobile phones have spread rapidly across Africa and made life much more convenient for people with very little. A survey by the Pew Research Center in 2018 found that 70% of adults in Indonesia, 86% in Kenya, and

83% in Nigeria own a cellphone. These are used not just for chatting, but for small-scale commerce — to check the prices at the market before making the long trek to buy or sell, or to find out if a required item is available in a place without going there. And they are used for banking. Many countries in Africa have a network of kiosks, which will sell phone credit, and this can be used as a currency and transferred with a few clicks.

This enables more complex methods of financing solar lanterns and larger solar home systems. For example, you can sell a solar lantern on a payment plan, where the initial cost is low but an inbuilt chip makes the lantern ineffective if the user does not regularly transfer payments to the giver by mobile phone. This means that the user can make their usual kerosene payments (or often lower payments) to the solar lantern distributor instead, getting cleaner light, and after a year or two have paid off the solar lantern which is hopefully still good for further years of free light. It also means that if the lantern does get stolen, the borrower cannot be held liable for the debt (although there is usually a downpayment which they lose, and their embryonic credit rating will be affected). According to GOGLA, 38% of offgrid solar kit sales in developing markets were sold under pay-as-you-go schemes in the second half of 2022.

Microfinance isn't magic, although it does help many people make quality-of-life-improving investments they could not otherwise have made. GOGLA's 2022 report says that even before the pandemic, as many as 5% of people purchasing a solar home system and 9% of people purchasing a solar water pump through pay-as-you-go schemes had to regularly cut back on food consumption in order to afford payments. The solar products are designed to be cut off if payments are not made, because otherwise the loans are unlikely to be collected at all, the investors go bankrupt and the option stops being available. The solar pay-as-you-go loan providers reporting to GOGLA had a mean collection rate (the ratio of payments received to payments expected) of just 62% in 2021, from 66% in 2020 and 67% in 2019. While some firms were doing considerably better than this and even slow payers may eventually repay debt with interest, this suggests that some of both lenders and customers are in trouble. The COVID-19 pandemic hit African economies hard, and hopefully, as they recover, it will be easier for consumers to make payments and clear debts.

It's not just solar where microfinance can fail to help, or even exacerbate current problems. In Cambodia, microfinance has been used by development organisations to try to help farmers adapt to climate change. Between 2000 and 2020, the number of microfinance borrowers in Cambodia increased from 175,000 to 2.6 million people [Guermond *et al*., 2022], or about 15% of Cambodia's population. The average rural microfinance loan in Cambodia is about twice the average GDP per person, and many loans are being taken out to pay back other loans, with some households selling land to make repayments. This is a deepening crisis due to a number of factors, including failed or bad harvests despite increased use of machinery and fertilisers. One of the key things about debt is that sometimes it needs to be written off (the lender gives up on it) if the borrower simply cannot pay. It's quite common in the West too for banks and borrowers to renegotiate a debt when the borrower is in trouble, because often if the bank forces the lender into complete insolvency it will get even less of its money back.

Another option for poverty reduction using solar is a straight giveaway of solar lanterns. These are also controversial. Occasionally, organisations decide to do this, and in acute situations such as in refugee camps, it is the easiest option for very basic energy access (i.e. light and phone charging). However, where the problem of poor energy access is chronic rather than acute, giveaways can do harm as well as good. For example, the supply of a large volume of solar lanterns is usually tendered out to the lowest bidder, and since it is very difficult to control quality in bulk purchases, there is a risk that the products are bad, break down quickly, and give the users a poor impression of the technology's potential to help them. It also suppresses the development of local distribution networks selling solar lanterns for profit. Canada-headquartered solar project developer SkyPower announced in 2015 that it would give away 2 million solar lanterns in Kenya and 1.5 million in Bangladesh, and was criticised by GOGLA for this decision.

Solar lanterns are also extremely basic energy access; few of us would be satisfied with a trickle of light for the evenings and the ability to charge a non-smart phone. However, they are only the start. Already, slightly larger solar panel and battery systems are available off-the-shelf and can be linked together to provide more energy as a household's energy needs expand. A specialised market for reasonable-performance but low-energy-use TVs, fans, and other devices (usually running off direct current rather than alternating current, making them more efficient to serve with solar panels and batteries which both produce direct current) has developed to serve these households. The better the efficiency of a device, the smaller the solar and battery system need to be to power it.

Of course, the power demands of modern living don't stop at TVs, fans, and lights. Cooking using electricity takes roughly an order of magnitude more energy, and in rural areas, people continue to cook over open fires, which causes deforestation and hazardous indoor air pollution. Air conditioning is even more power-hungry. One option is for whole villages to be offered power for the first time using a combination of larger-scale renewables, batteries, and sometimes diesel, to form a microgrid. This usually requires an initial 'anchor customer', a business with revenue, to guarantee some sales. A risk to setting up a microgrid is that the government may at some point extend the grid to the village and remove demand, though this is probably less of a risk as the cost of solar and batteries falls and the microgrid should pay back faster.

I am very optimistic about the ability of solar and batteries to eventually provide a high level of energy service to people who currently lack it, leapfrogging or at least reducing the need for new grid and new power stations. However, development work is not easy, and even throwing money at the problem can have negative effects.

Chapter 24

Can Solar Save the World?

I'm going to assume that the reader already has serious concerns about climate change caused by humans burning fossil fuels. If not, it is unlikely that I can say much to convince you.

There is now general agreement that we need to kick the fossil fuel habit. From an energy transition perspective, you probably don't need to know the latest twist in international climate negotiations, and I'm glad people more patient than me are working on that. As of July 2022, countries responsible for 91% of global greenhouse-gas emissions have a net-zero target in force or under discussion [Rooze *et al*., 2022].

The question is how, not why or even when. This chapter focuses on whether solar can make a meaningful contribution to the world's energy supply so we can continue to use power, and have the standard of living we have come to expect in the West, and make sure everyone has that standard of living, without digging stuff up and burning it.

The conclusion of this chapter is that solar is unlikely to be able to eliminate carbon dioxide emissions by itself. However, it can help.

24.1 Individual Decisions

The challenge of decarbonising the world isn't about passing a personal purity test. We were born into a system that was fundamentally unsustainable, and our agency to change it or usefully opt out of it is limited. However, it's worth considering for understanding the scope of the problem and refuting some of the more obvious gotchas from fossil fuel advocates.

Some rough calculations for a solar system being added to our current electricity grid: an ordinary 4 kW household PV system in the UK produces around 3,854 kWh/year (an 11% capacity factor). A typical 2–3 person household in the UK in 2022 uses 2,900 kWh of electricity per year (plus the equivalent of 12,000 kWh of gas for cooking and heating), according to UK energy regulator Ofgem, so a PV system of this size would make the average household an electricity exporter over the year, but it would still be far off covering its entire energy needs given the gas consumption. A heat pump would replace much of the gas but add about 4,000 kWh/year of electricity consumption.

How much carbon dioxide equivalent would the PV system save? Well, the average carbon intensity of UK electricity generation was, according to the UK government's conversion factors for company reporting, 193 g/kWh in 2022 (down from 462 g/kWh in 2015, mainly due to gas and wind generation pushing out coal). So, if each kWh of PV is replacing the average kWh of electricity generation, this 4 kW system will save 0.74 tonnes of carbon emissions per year. The carbon cost of producing the modules is a complex calculation but is probably negligible; most academic estimates put the energy payback time of manufacturing a solar module at 1–3 years even if it is installed under less sunny conditions like the UK, and they are under warranty for 25 years and should last longer.

Is 0.74 tonnes of savings a lot? Well, at least according to carbonfootprint.com (an online carbon offset calculator — there are many, but they do give approximately the same results, although it depends enormously on assumptions made on factors beyond your control, such as how many seats on a flight are empty), it's roughly the same as a single flight in economy class from London to New York (Figure 24.1). In 2015, this would have at least covered the return flight, but the UK grid has got much cleaner due to the rise of wind and fall of coal that the effect is less. This is fundamentally a good thing! A similar 4 kW solar system in California would generate more energy — about 7,000 kWh/year — because it is sunnier. In 2021, the California grid was slightly dirtier than the UK's at 228 g/kWh (according to the US Energy Information Administration), so this would save about 1.6 tonnes by this extremely crude methodology. Californians also use more electricity, on average, than people in the UK.

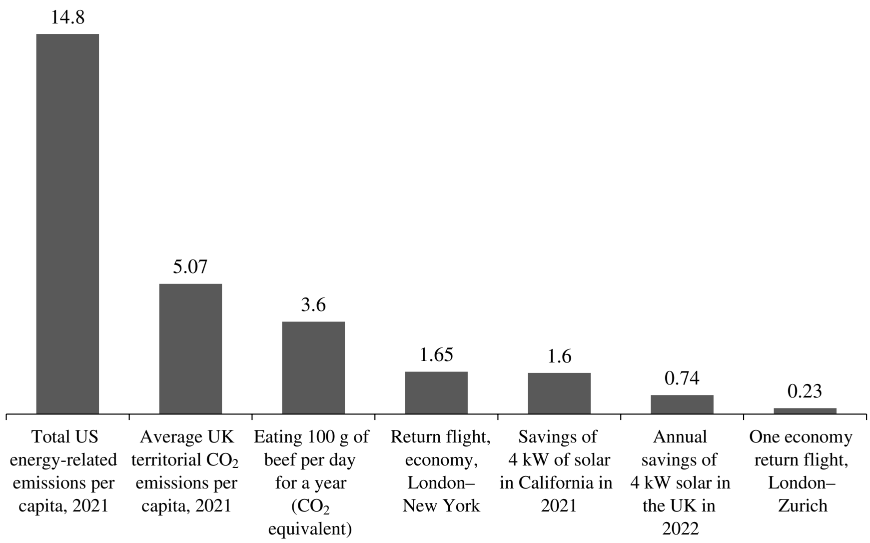

Figure 24.1 Carbon dioxide emission equivalent of various human activities (metric tonnes).

Sources: US Energy Information Agency, climatefootprint.com, Our World in Data based on Poore and Nemecek (2018), UK Department for Business, Energy and Industrial Strategy.

So, adding a few solar panels does actually address a good chunk of our personal direct household emissions. To brag, my 13.2 kW rooftop solar system here in Fulenbach, Switzerland, recorded a generation of 12.01 MWh in 2022 while the house consumed 9.8 MWh of electricity (and no gas), even ignoring the fact that my husband accidentally booted the monitoring system off the wifi for two weeks in August while trying to improve the speed of online video games. In these two weeks, solar production would definitely have exceeded consumption, but overall it was a warm autumn which cut the heat pump use. 2021 figures for my house were 11.89 MWh solar production for the year and 11.26 MWh consumption; 2020 was 12.73 MWh production and 9.61 MWh consumption. But when we get an electric vehicle, and assuming we drive it 16,000 km a year, that would use about 3.2 MWh, so we'll stop buying petrol but return to being net electricity consumers. Also, this direct calculation only works for people with big houses, which is a terribly resource-unfriendly way to live compared with people in apartments in cities (sorry).

There are a *lot* of complications. But the amount of energy used directly by a typical individual is at least in the same order of magnitude as the amount that could be generated from the roofspace available to them using solar panels, even in a cloudy climate like the UK's. It's not always available at the right time, but the numbers aren't intrinsically hopeless as some would have you believe.

24.2 Industrial, Commercial, and Non-electrical Emissions

Our direct individual emissions are only a small part of those of the civilisation it takes to supply us with what we use. Worldwide only about 48% of greenhouse gas emissions are associated with power and transport (Figure 24.2), and a good chunk of that is non-residential.

One example of someone concluding in good faith that solar is of little use when presented with the sheer magnitude of demand is

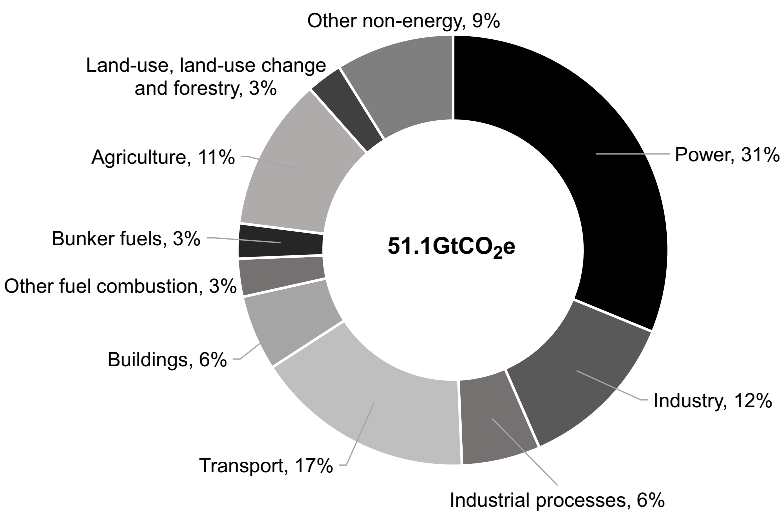

Figure 24.2 Estimated global greenhouse gas emissions in 2019.

Sources: World Resources Institute, BloombergNEF.

Note: Include all CO_2 and CO_2-equivalent emissions. BloombergNEF extrapolated the emissions between 1990 and 2018 to derive the 2019 emissions estimate for other fuel combustion, bunker fuels, energy industry, agriculture, land use, land-use change and forestry, industrial processes, and other non-energy related emissions.

David MacKay, in his influential 2008 book *Sustainable Energy — Without the Hot Air* (my copy is the 2016 revised edition). MacKay's book made a couple of valid points; we use a lot more energy (particularly when non-electrical consumption for heat and industry is included) than can trivially be supplied by UK rooftop PV and wind. Nuclear is an obvious way to supply a useful chunk of energy without emitting much carbon dioxide or relying on scarce resources. Overall, David MacKay's book argues against the idea that our civilisation can consume all the resources we like if we simply build a few wind turbines and solar panels, and this is still an accurate argument.

However, MacKay consistently mixes up primary energy with electricity, which doesn't make much sense; it effectively includes the efficiency losses in gas and coal power plants (50–70% of the input energy) as something renewables would have to replace. Also, developments since 2008 leave room for optimism. First, MacKay's assumptions on photovoltaics have turned out to be ludicrously pessimistic. In his calculations of land required, he assumed mass market modules were 10% efficient and expensive modules 20%; as of 2023, a typical crystalline silicon module is about 22% efficient (and even by the time of the 2016 edition of *Sustainable Energy — Without the Hot Air*, the typical silicon module was over 16% efficient). While economics was not MacKay's focus, he dismissed PV largely because other sources pegged the cost at around 571 pounds/MWh; the 2022 solar tender in the UK was won at 46 pounds/MWh. Wind turbines have made similar advances; a typical wind turbine built in the 1990s in Germany had a capacity of about 500 kW, while a new turbine in 2023 is likely to be at least 4 MW, and achieves a significantly higher capacity factor as well, through more reliable power electronics, better maintenance, and simply having the blades higher up where the wind is stronger. Wind has been a far greater part of the UK's power decarbonisation than solar, and supplied 26.8% of UK generation in 2022, according to the National Grid Electricity Operator, with solar adding 4.4%. The UK is not yet unreasonably forested with wind turbines, although it does need more grid capacity to bring wind power down from Scotland and from offshore plants.

Dr Ajay Gambhir, a Senior Research Fellow at the Imperial College London Grantham Institute for Climate Change and the Environment, suspects that land use will not be the limiting factor for solar. "From a physical perspective, photovoltaics is a much more efficient way of converting sunlight into power than is photosynthesis and harvesting of biomass," he points out. Research by NREL scientists concluded that there is potential on US rooftops alone for 731 GW of PV, or enough to produce about 25% of current US electricity sales while covering just 28% of small roofs [Elmore *et al.*, 2018]. Similar studies in the US and other regions suggest that, except in island cities like Singapore and Hong Kong, there is plenty of rooftops and land that is marginal for other uses to generate a large amount of the country's electricity demand. In some places, agriculture or wildlife habitat can be combined with solar panels, or solar can be used on lakes and reservoirs, which also reduces evapouration.

Another ground for reasonably hoping that MacKay was too pessimistic is that he may have underestimated the extent to which we can reduce our total energy use in transport, electricity, and gas.

24.3 Transport

The future of ground transport is electrification, and it is happening. About 10.4 million passenger electric vehicles were sold in 2022 and 13.9 million expected in 2023, up from 448,000 in 2015 [O'Donovan, 2023]. In the last quarter of 2022, just under 19% of cars sold globally were electric, with over 10% being battery electric (rather than plug-in hybrids which also have an internal combustion engine, an uneasy compromise since they still have to carry the heavy engine around). The rate of acceleration of electric vehicle uptake is encouraging and new models get steadily more attractive and affordable, with the batteries benefitting from the same experience curve-based improvement process as solar panels and semiconductor chips. Many markets now have official targets to phase out sales of internal combustion engine cars (ICEs) entirely, for example most of Europe intends to ban new ICEs between 2030 and 2040. Most observers think that these targets are not necessary, as nobody will want a new internal combustion engine in 2030 anyway.

Dr Ajay Gambhir says, “The low-hanging fruit now — and I wouldn’t have said this 10 years ago — is the electrification of light duty transport. There’s real momentum around reducing cost and increasing energy density [the weight of batteries needed to carry a certain amount of energy], range anxiety [the fear of being stranded between charging points, or of having to stop inconveniently often to recharge] is decreasing, and, to use a cliché, Tesla made electric cars cool. Countries are also competing to electrify transport and eradicate the internal combustion engine, and with it the diseases of local air pollution such as pulmonary disease.”

Do electric vehicles help reduce carbon dioxide emissions? Yes; it is significantly more efficient to generate electricity by burning fuel in a power plant than in an internal combustion engine, even if the power plant runs on fossil fuel. Plus most power grids get at least some of their electricity from low-carbon sources like hydroelectricity, nuclear, solar, and wind. This is partially offset by a car battery being more carbon-emission-intensive to make than an internal combustion engine but only partially.

For example, a 2018 Canadian study concluded that a typical electric vehicle (a Nissan Leaf) started to save carbon emissions after 30,000 km relative to a similar-sized gasoline vehicle if charged with clean electricity, and 60,000 km even if charged from the relatively dirty Alberta power grid [Argue *et al.*, 2018]. Most cars are driven for at least 150,000 km in their lifetime, and running electric cars emits less and less carbon dioxide as the power grid cleans up. Transport & Environment, a European group funded mainly by climate groups, has an interactive tool to estimate per-kilometre running carbon emissions and manufacturing emissions using updated data. This concludes that as of 2022, the worst-case European medium-sized electric car, using a battery made in China and driven in coal-fired Poland, has lower lifetime emissions after about 70,000 km (though this did assume the Polish electricity generation mix gets better) and has lifetime emissions after 225,000 km of 151 g/km, compared with 241 g/km for an equivalent petrol car. In the largely hydro-powered Swedish grid, the electric car would have lifetime emissions of 52 g/km. (Most studies conclude that hybrid vehicles, with both a battery and an internal combustion engine, just need to carry the weight of both around and so aren’t much good.)

The rise of electric vehicles should also give the future grid more flexibility. “The US will have about 2,000 GWh of car batteries on the road by 2030, compared with about 150 GWh of batteries in homes and embedded in the distribution grid,” says Jigar Shah. “Plugging in your car every day when it’s not in use, but having the operator allocate 4 hours when it may not charge if the grid needs the power, is a very efficient way to use that large capacity to approach the same dexterity of electricity load as we currently have in supply from gas plants.”

Einar Kilde Evensen, an expert on renewable energy at Norway’s largest bank DNB and more relevantly a Norwegian, says that this vision isn’t the far future, it’s just Norway. “In my country, we’ve had smart meters since 2019, and since then most consumers are paying the hourly floating spot power price, plus a grid fee,” he said in June 2023, waving an app showing the next 12–36 hours’ power price for his home, resulting from the national day-ahead auction market. “I set the app to automatically charge my Tesla in low pricing periods. This automated service gives me an estimated 9% lower electricity price for the car in 2022 versus average prices, and also helps balance the grid — which in Norway is already showing a duck curve in summer, at very low levels of solar penetration.” This is the future Jigar Shah wants. This would help balance a grid with a lot of variable renewables, as well as ensure that the cars are being driven almost entirely on clean energy.

Aviation is one of the most difficult-to-electrify sectors, even harder than shipping, because batteries are heavy. The energy density of batteries is lower than for fuel, and the batteries stay heavy even when drained, so having enough energy to even get the battery off the ground has historically been a challenge.

However, a Swiss solar-powered plane called SolarImpulse managed to carry a single human passenger in steps around the world in 2016, though it took 14 months. In September 2022, an all-electric plane called ‘Alice’ by the company Eviation took off and flew for 8 minutes, reaching an altitude of 1,066 m. As of November 2022, BloombergNEF had identified 59 companies working on electric airplane research and development [Kawahara, 2022]. These have purchase orders for over a thousand aircraft, including some with 30 seats. The challenge for these firms will be to deliver on the orders, but perhaps some electrification of short-haul flight is possible in the medium term.

Another possibility for aviation is liquid biofuels or synthetic fuels made out of hydrogen. Both are possible in theory, though biofuels for ground transport are mainly a way to keep subsidising farmers. Dan Lashof, a Director of the World Resources Institute, estimated on a Volts podcast in April 2023 that it takes about 300 times the land to run a petrol car on corn ethanol than to run a similar electric car on photovoltaics, and the photovoltaics doesn't have to be on decent farmland. Photosynthesis is only about 1% efficient at turning the sun's energy into biomass energy, though; electric planes would be much better if they could go the distance.

I'm dubious if we'll ever be able to fly as much as we like, sustainably, but technology could surprise me.

24.4 Efficiency and Electrification

There is considerable progress in making developed-world lifestyles more energy-efficient, most visibly in the residential sector but also in commercial and industrial use. UK regulator Ofgem's 2017 State of the Energy Market report pointed out that UK households reduced their average consumption of both electricity and gas by about 20% between 2006 and 2016, largely due to more energy-efficient electrical devices and upgrading of the building stock with cavity wall insulation and condensing boilers. Light-emitting diodes (LEDs) for interior lamps, for example, use less than a quarter of the energy of the incandescent bulbs that preceded them and last much longer while supplying the same amount of light.

There's an effect called the Jevons paradox, which states that over the long term efficiency actually drives more resource consumption because it increases the use of a resource (for example, more efficient coal-powered steam engines cause more industrial use of steam engines, therefore more use of coal). A UK study [Peñasco, 2023] found that energy savings from insulating houses disappear after 2–4 years, particularly rapidly in low-income households, but this is probably due to the buildings being under-heated to start with and then being kept more comfortable after insulation, a one-off effect. It is difficult to argue with the long-term aggregate trend of total residential energy consumption in the UK going down at least 15% between 2005 and 2022, slightly complicated by gas consumption being much lower in warmer years when less heating is needed. The overall decreasing trend in total household energy consumption in the country, despite rising population, is also observed in the US, Germany and other countries. There is further potential to reduce energy use through insulation.

Another game-changer is heat pumps, which are devices that use electricity to suck heat out of the cold outdoors and into homes. I think this is probably by magic, though there is a physics explanation. They can also in theory be run in reverse to make incredibly efficient cooling. Although burning gas to heat water to make steam to drive a turbine to make electricity to run a heat pump to make heat sounds incredibly inefficient, it somehow isn't. A decent air source heat pump can get 2–5 times as much heat energy out as is put in in the form of electricity.

Heat pumps are becoming a real thing; 3 million were sold in Europe in 2022, according to the European Heat Pump Association, up 38% from 2021 and clearly taking off since 2015. In the US, 4.3 million heat pumps were sold in 2022 according to industry association AHRI and up 10.7% in 2021. Each of these represents an improvement in efficiency, an increase in the potential for solar and wind to replace fossil fuels, and a house that could be disconnected from the gas grid, reducing methane leakage as well as the direct emissions of burning the stuff.

As we have discussed, the electricity doesn't necessarily need to come from fossil fuels at all, although it's difficult to get much of it from solar because heat demand is anti-correlated with sunshine. My house in Switzerland, with its 13.2 kW solar panels and heat pump, only generates about 10–15% as much electricity as it uses in December, the least sunny month, while in June, it generates easily three times as much as it uses. One challenge of electrifying Europe and other regions far from the equator is that peak demand for electricity is already during the coldest winter periods, and electrifying heat will make this peak higher. The US is generally south of Europe (a fact that is surprising to Europeans: New York is at roughly the same latitude as Madrid), so there's more useful sun in the winter, but the problem still applies. Europe needs something that runs in the winter as well, and wind is a good fit for generating some of this winter power.

The most plausible plan to put the human race on a trajectory to stabilising the greenhouse gas content of the atmosphere, while giving every human the standard of living we currently expect in the West, is to clean up the electricity mix, and at the same time electrify everything, while making electricity demand more time-flexible and making efficiency improvements everywhere that cannot be electrified.

24.5 The Nuclear Option

It's possible to argue that we do not have to reduce energy use at all, and we could simply electrify everything to cut carbon emissions, if we just expanded our use of nuclear power.

Historically the groups which have campaigned for renewables (Friends of the Earth, Greenpeace, the German green party) have also campaigned against nuclear. In addition, most owners of US nuclear power plants have historically also operated coal-fired plants and so have not committed to lobbying for nuclear on grounds of averting climate change, though more recently utilities have sought to close down their nuclear plants for economic reasons while government bodies seek to keep them open.

It remains difficult for many environmental groups to truly embrace nuclear power, even when it does not come bundled with coal. There is no doubt that high levels of radioactivity are dangerous and that nuclear waste needs careful handling. At least 58 people died as a direct result of the disaster in April 1986 at Chernobyl, Ukraine — and it could easily have been much worse. The accident was due to human error, and nuclear advocates point out that with today's much better safety procedures, it should never happen again. Nobody died as a direct result of radiation from the Fukushima accident in March 2011, although there are plausible reports that over 2,000 people died as a result of unnecessary evacuation. Nuclear critics point to human nature as Exhibit A for why accidents like Chernobyl, or worse, could easily happen again.

On the other hand, climate change would have progressed considerably further than it has today without nuclear, which emits practically no carbon dioxide (arguments about which non-fossil energy source has lower lifecycle emissions depend heavily on assumptions, and are pretty much irrelevant when the alternative is any sort of fossil fuel). In 1973 (the earliest date for which the IEA published data in its World Energy Statistics 2017), nuclear produced 203 TWh of electricity worldwide (3.3% of generation, versus 20.9% for hydro) and grew from there, peaking in 2006 at 2,779 TWh (15.8% of generation). Nuclear represented 10.3% of total global electricity production in 2021 while solar was only about 3.6%, according to BNEF data.

The effects of nuclear power on carbon dioxide emissions are very clear. France, which made a huge national strategic push for nuclear in the 1970s during an oil price shock (and founded the International Energy Agency at the same time), still generates about 70% of its electricity from nuclear and, in consequence, shines like a clean beacon on any emissions map of Europe. Ontario is similar, producing 54% of its 2022 electricity from nuclear, plus 26% from hydro, with no coal at all. Germany, which aimed to build renewables to replace nuclear rather than replacing coal, successfully reached about 47% renewables in its electricity mix in 2022, but still averaged about 380 g of carbon dioxide per kWh that year compared with France's 73 g/kWh and 25% renewables. (This data is from the website Nowtricity, which pulls data from European Network of Transmission System Operators for Electricity, ENTSO-E. Assumptions vary slightly between calculations from different sources.)

Nonetheless, nuclear is an industry in retreat in the West, though perhaps the energy crisis relating to Russia's invasion of Ukraine marks a turnaround. Germany closed the last of its nuclear reactors in April 2023. France plans to phase out nuclear in its generation fleet, although the timeline is unclear and keeps changing, and could even be reversed. The Olkiluoto 3 reactor in Finland finally began generating power in April 2023, 12 years behind schedule and three times over budget. A number of US plants were decommissioned ahead of schedule between 2010 and 2022. BNEF levelised cost of energy analysis pegs the cost of new nuclear at a minimum of \$61/MWh (for China), \$143/MWh (Finland, the lowest in Europe because the Olkiluoto plant has at least been built), or \$243/MWh in the US. This is not cheap power.

Although the Fukushima accident in 2011 was the trigger for a widespread move away from state support of nuclear, recent problems for nuclear have been mainly economic and technical. BloombergNEF estimates that over half of the 92 US nuclear plants could not cover basic operational costs in most years between 2010 and 2020 [Zhou, 2023], due to wholesale power prices of just $20–30/MWh. Power prices started to rise in 2021 and returned much of the US nuclear fleet to profitability, but the average age of the US nuclear fleet was 41 years in 2023. The US Inflation Reduction Act of 2022 supports nuclear with a $15 per MWh credit, but only if annual revenues (including other subsidies) are below $25/MWh generated or sold. The only new nuclear under construction in the US is Vogtle Units 3 and 4 in Georgia, which are years behind schedule and two times over budget, supported by government funding. In France, the great nuclear fleet had a badly timed set of extended outages over the summer of 2022, making it much less useful than it should have been during the energy crisis.

One feature of nuclear is that it has low operational cost, once spread over a large number of MWh (and nuclear plants have in the past typically run above 80% capacity factor, so 1 GW of nuclear power produces roughly as much energy as 4-6 GW of PV or 2 GW of onshore wind farms). The capex is extremely high, so if the nuclear plant does not achieve high load factors (for example, because the power is not needed), the economics are even worse than BNEF calculates. Nuclear plants do not save any fuel by not running for a few hours, like a fossil fuel plant would.

The process of shifting nuclear plant output up and down (‘ramping’) is quite complex compared with the ‘stop feeding it fuel’ approach for fossil generation, or the ‘use the inverter to move the system away from its optimal voltage-current configuration’ approach for solar. Reducing the output of a nuclear power plant is called ‘poisoning the reactor’ with elements which absorb neutrons and hence slow down the chain reaction, and it’s easier to ramp down one reactor a lot than all reactors a little. (I have been told that the term for changing the output of a nuclear fleet is ‘playing the piano’, with power plants as keys. If this isn’t true, it should be.) France uses some of its nighttime nuclear electricity generation to heat water for daytime use, rather than reducing output from its reactors (a technique that would also work to make use of short-term overproduction from renewable energy).

Because nuclear is best run as baseload, it has historically been considered fundamentally opposed to renewables, which are easiest to use in a high-gas grid which can ramp up and down quickly. I think this is an artefact of old-fashioned systems thinking from when batteries weren't a thing and renewable electricity was expensive. We probably don't want to plan on running our grids on 70% nuclear anymore, because it would cost a fortune and take at least 10 years, plus as the 2022 outages showed, nuclear isn't guaranteed reliability. Some European nuclear plants have also had to reduce power production in summer because the water level in rivers is too low for safe cooling, a problem only likely to get worse.

However, nuclear is very useful in those winter periods when the sun doesn't shine, and sometimes the wind does not blow for weeks, and the poor ramping economics of nuclear should matter less if we have a fleet of batteries to support renewables anyway. With renewables so cheap nowadays, it makes a lot more sense to pay the solar or the wind plants to shut down for a few hours when the batteries are full, rather than expecting the nuclear fleet to run flexibly. Having 10–30% nuclear in an electricity mix is likely to make energy supply more resilient, even if it isn't the answer for every country.

Therefore it is a good thing that the 2022 energy crisis is spurring renewed interest in nuclear, particularly in Asian countries which spent the year paying very high prices for liquefied natural gas. China has 18 reactors under construction, while India has eight. Japan, which still got 6.5% of its electricity from nuclear in 2021, plans to restart some reactors in 2023. South Korea, where 26.4% of electricity came from nuclear in 2021, scrapped a nuclear phaseout plan in 2022 and set a new target of nuclear contributing 32.4% of generation by 2030, cutting a previous target for renewables. Since the parts of South Korea that are not mountainous are densely populated, this may be a more practical way to reduce emissions than depending on a huge solar buildout (which may happen anyway). Turkey, Bangladesh, Saudi Arabia, Russia, Egypt, and Poland all plan new reactors.

There is also potential for new nuclear fission technologies to be smaller, safer, and cheaper. Small Modular Reactors, for example, are a scaled-down model under 300 MW similar to those used in nuclear submarines. China has built one, and the US and Canada could have first-of-their-kind small modular reactors by 2029.

Jigar Shah, previously encountered in this book as the founder of solar finance firm SunEdison and now Director of the US Loans Program Office, is keen to support next-generation nuclear investments, pointing specifically to the higher grid requirements of solar and wind. The Loans Program Office has supported the 2.2 GW Vogtle nuclear plants under construction in Georgia, US.

Shah says, "My intent in the past, with SunEdison, was to make solar acceptable to banks — and we have done that. In those days, we wished for solar to one day meet 75% of peak load. In my wildest dreams, I never thought we'd be discussing 80% of all electricity from solar and wind. But now we have a responsibility for making sure the power doesn't go off, and once you have that responsibility you see that solar and wind are not always the cheapest solution as everyone has decided they are. Solar and wind were cheap when there was slack capacity in the grid that they could use almost for free.

But today, to decarbonise the grid by connecting all that solar and wind, we need to increase current grid capacity by around three times. Clean firm power generation like nuclear wouldn't require that grid increase. If that's borne by solar and wind, the cost of electricity generation ends up around $100/MWh, pretty much where most clean firm generation like nuclear is. Everything ends up around $100/MWh! Solar and wind plus grid and batteries, or nuclear, or gas with carbon capture and storage, or geothermal ... all around $100/MWh! Hydrogen made with renewable electrolysis and burned in gas turbines ... higher than $100/MWh! So we shouldn't put all our eggs in one basket with climate solutions. Right now I feel like we have 15 technologies that need scaling up, and nuclear is the one falling behind, so I talk a lot about nuclear. Solar and wind don't need the help."

Whether or not the $100/MWh turns out to be approximately right (it may well do), this seems a reasonable sentiment. Jigar Shah's office has also supported several US battery metal processing and recycling schemes and guarantees loans to Sunnova's Project Hestia, which will lend money for 75,000–115,000 homeowners with low credit ratings to get home solar and actively participate in grid management as virtual power plants.

There's an unfortunate tendency for both nuclear and renewable energy advocates to suggest that their way is the only way to supply energy. But we need all the tools in the box to combat climate change, and certainly closing existing nuclear plants ahead of schedule is a bad idea. I would, given sovereignty over the world, build at least a few new nuclear plants in highly seasonal climates.

In definitions news, if a country sets a target for 'clean power,' this usually means renewables plus nuclear.

Chapter 25

What Next for Solar?

Every year, solar modules get a bit cheaper or performs a bit better. In 2018, the technology switch was from slurry-based wafer slicing to diamond wire saws and from opaque backsheets to dual-glass 'bifacial' modules which pick up 4–9% more energy from reflected light on the back. In 2022, standard solar wafer sizes increased from 166 mm side length to 182 mm or 210 mm side length, which makes modules bigger and very slightly more efficient. In 2023, we are observing the switch from PERC cells (made into modules 21–22% efficient) to TOPCon (making modules about 23% efficient).

Also, other sectors are making progress. The argument about 'do heat pumps work well in really cold weather' has been conclusively won by heat pumps in the last few years. In February 2023, the first electric car was launched using sodium-ion batteries instead of lithium-ion, the Sehol E10X in China. This may not be the start of anything, it's from a moderately obscure battery maker called Hina, but maybe it's the first step to substitute lithium for much more available sodium even in car batteries.

Human civilisation is still in the 'shallow decarbonisation' phase where solar and wind are nowhere near the fundamental limits of what they can supply, as most of the grid runs on fossil fuels, and we are still building solar and wind to connect to what Jigar Shah referred to as 'slack capacity' in the grid. However, most of the world now has political targets to achieve deep decarbonisation of even the hard-to-abate sectors. We're not going fast enough, but we are speeding up. If we don't manage to keep warming below 1.5°C (which frankly looks unlikely), we might still manage to stay below 2.

On solar specifically, it's now widely accepted that it is cheaper on a per-MWh basis in many sunny countries than natural gas. My current favourite example of this is from Pakistan's National Electric Power Regulatory Authority's 2022 State of the Industry report, "the existing average cost for supplying electricity to end-consumers is about 26 Pakistani rupees [about $0.12 at the time]/kWh. One way of reducing this high cost is to procure cheap electricity from indigenous resources like wind, solar…". Admittedly, it's not easy and the rest of the report takes broad swipes at Pakistan's distribution organisations, DISCOs, for slowing down the energy transition "for reasons best known to them" and "reasons not carrying merit". But, from Pakistan to Germany to South Africa, solar is now seen by official utility bodies as a solution to energy crises rather than an expensive luxury. It feels like a tipping point, especially in countries where access to energy will change lives.

Solar, in particular, is no longer being held back by brute economics, but it's not all smooth sailing from here. As of 2023, deployment of ground-mounted solar in Europe and the US is held back mainly by access to grid connections and processing of planning permissions. In Europe, rooftop solar build is being held back by a shortage of people trained and willing to climb roofs and put them up. In Africa, India, and parts of Latin America, the biggest problem is inflation and uncertainty in the financial system, which makes everything difficult to do even if in theory it should save money. When we have built a lot of solar, we will face the challenge of using clean power when it's abundant and storing it, saving it, or having an alternative when it isn't. And when we have decarbonised electricity supply, we just have to decarbonise everything else, make the world economy circular with perfect recycling, and set our species on track to complete sustainability.

These are huge challenges, but your ingenuity is equal to them. I hope this book has helped.

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Key Terminology

Anti-dumping and anti-subsidy tariffs: Payments, usually as a percentage of price, on goods imported to a country. Theoretically to compensate for underpricing behaviour in the country of origin (usually China) but really determined politically.

Bankruptcy: When a company or individual cannot meet their financial obligations and so loses all their assets (for example, factories or power plants) which are then owned by the entities they owe money to. The assets may be re-sold at a steep discount to their original value, but may continue to be operated or may be re-launched under new ownership with debts cleared at a discount.

Capacity: In the context of energy, this usually refers to the peak power generation of a power plant, in W (or kW, MW, etc.). In the case of solar modules, this is defined as their output under standard conditions, 25°C temperature and 1,000 W/m^2 of insolation. This insolation is roughly equivalent to noon on a sunny day in the south of Spain.

Capacity factor: How sunny it is. Usually defined as an equivalent percentage of the year the plant runs at full capacity, for example, a UK solar plant might produce for the equivalent of 964 hours/year, or 11% (964 divided by the number of hours in the year). It does not literally run at full capacity for 964 hours and zero for the rest, but more often as a proportion of full capacity.

Capex (capital expenditure): The initial cost to build or set up something.

Community solar: Solar getting one of a (usually American) set of subsidies for community solar. Ask what exactly this means in the case you're looking at, because it is not a stupid question and can just mean someone sung kumbaya when the plant was commissioned.

Contract for Difference (CfD): A slightly complicated way for a government to award a fixed price for power to a project. A reference or 'strike price' is set in negotiations or auctions, e.g. 52 euros/MWh. The project then sells power on the spot market, and if the spot market price in a period is lower than the reference price, the government pays a top-up so the project gets 52 euros/MWh. If the spot market price is higher, the project pays back to the government.

This is a classic two-way CfD; it is also possible for them to be one-way, ie the project keeps the gains and the strike price acts as a floor. Projects can also sometimes get more money than the strike price overall if they manage to trade power to get a higher average price than the mechanism by which the government calculates the spot power price (a feature, not a bug, since clever trading can support well-functioning power markets).

Cost of capital: How much of a return (interest rate for debt, profit for equity) investors require to invest in a project. Confusingly, 'capital cost' is another term for capex, not the cost of capital.

Cost of debt: Interest rate on money a bank would lend to a particular project.

Cost of equity: The return an investor would need to supply the equity to a project. Almost always higher than the cost of debt, because equity investments are riskier than debt because if something goes wrong the debt investors get paid first.

Discount rate, aka hurdle rate: The return an investor would require on a particular investment. For example, a German equity investor might require a 6% return on a German solar project receiving a fixed power price for 20 years, but 10% for a Spanish solar project with no power contract.

Duck curve: A pattern in power pricing resulting from a market having a lot of solar. Low or negative power prices (or net power demand) in the middle of the day when solar is generating, then a peak in price and demand in the evening, when air conditioning load is often highest, people are cooking, and the sun is going down while gas generators may still be ramping up. The shape of power prices and demand for non-solar power ends up looking like a duck, viewed with a little imagination. The high demand in the evening is the head of the duck, the midday low prices and demand are the belly of the duck.

Equity index: A portfolio of stocks selected to be representative of a market or sector (e.g. solar companies and companies listed on the Hong Kong stock exchange). The idea is that if investors want to put their money in this sector, they invest in an index rather than trying to pick companies that will be most successful.

Feed-in tariff: Often used to just mean 'price of power paid to a project'. Technically, when a government guarantees a fixed (or sometimes inflation-indexed) power price for a long period to all eligible projects, i.e. they do not have to compete in an auction or negotiate to get the price.

Initial public offering (IPO): When a company first sells shares on a stock market, becoming a listed company. Usually, this is good news for the early investors in the company, as they can get their cash out.

Insolation: Sunniness. Also called solar radiation or irradiation. See capacity factor.

Levelised cost of energy/electricity (LCOE): The price per MWh you have to pay an energy project developer to get them to build you a power plant. Usually quoted as an initial value in an inflation-adjusted contract for 20–25 years.

Net present value (NPV): The sum of future cashflows from an investment/ project, discounted at the appropriate discount rate. In theory, an investor should make the deal if the NPV is above zero and therefore the return will be above their discount/hurdle rate. If choosing between two projects, the investor should choose one with the higher NPV (not high IRR, since it is not easy to find projects that meet your hurdle rate, and some high IRR projects are very small and may be barely worth it).

Non-recourse finance (or non-recourse debt): Money lent specifically to a project, e.g. a solar project, not to the owner. If the solar project does not generate enough money to pay the interest, the bank can seize the project but not the other assets of the owner. Banks do not want to do that because it is a pain to own and manage small solar projects, especially underperforming ones, and so are likely to renegotiate to avoid having to seize the projects.

Opex (operational expenditure): The cost per day/month/year to keep something running. This could include fuel cost, maintenance cost, insurance, land rent payments, etc.

Return on capital employed (ROCE): Mathematically, net operating profit divided by the money (capital) a company has put into an operation. A measure of how profitably a company is investing. It is rational to require a higher ROCE for a risky investment.

Short selling: The sale of a stock that does not belong to you (usually borrowed for a small fee). A bet that the stock price will go down, so you can buy the stock back at a lower price to return it. Creates an incentive for some investors to identify companies that are overvalued by the stock markets, which is a useful function in the financial system.

Stranded asset: An investment, usually a physical facility, no longer worth much because the market has moved on. For example, a coal-fired power plant when carbon prices are high and cleaner energy plentiful, or a solar cell factory based on an obsolete technology. The aim of the energy transition is to make all fossil fuel infrastructure into stranded assets.

Tax equity: A US government support mechanism. Because the main US federal supports for renewables, the Investment Tax Credit and Production Tax Credit, are paid as a writeoff on taxes, a firm or individual needs to have 'tax appetite' (pay enough tax) to monetise them. Tax equity is investment made by a firm with the tax appetite to get the credits, and investment is typically structured to optimise this, with tax investors paid back and happily exiting the deal in a few years.

Value-based pricing: Setting the price of something at the value to the consumer, not the cost to produce. The norm in most businesses making non-commodity products or services, or where there is limited competition. For example, most installers of solar panels will try to price a system as close as possible to the maximum level where local power prices and incentives still make it attractive to the homeowner. As a seller, try to get value-based rather than cost-based pricing; as a buyer, get multiple quotes to determine the level of competition, and negotiate.

Weighted average cost of capital: The cost of equity × (proportion of equity) + (cost of debt)x(proportion of debt) × (1 – tax rate). Or the overall project hurdle rate. The (1 – tax rate) comes in because interest is usually tax deductible, so tax generally favours using more debt.

Yieldco: A way to remove liquidity risk from projects which are not easily bought and sold. The revenues from the projects are bundled together and listed on a stock exchange, so investors can buy and sell the dividends. This makes solar project investment more attractive to firms which cannot invest directly in panels and fields. There are also wind, gas, transmission, and other yieldcos. Suitable assets have predictable revenues and moderate returns.

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Index