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The Role of Policy in PV Industry Growth: Past, Present and Future

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2.1 INTRODUCTION

Recently, the photovoltaic (PV) industry has experienced phenomenal growth, with market demand expanding at an annual rate in excess of 40% [1, 2]. Technological improvements, increased economies of scale and manufacturing experience have allowed PV manufacturers to lower costs of production and, thereby, stimulate the market. But policy has been an equally important factor, and in some instances the most important driver of an industry boom (e.g. rapid growth in German and Spanish markets) that could rival global experience in computation and communications. Key policy instruments spurring PV's expansion include market and tax incentives (e.g. Feed-in tariffs, rebates and tax credits), regulations (e.g. renewable portfolio standards, new building codes requiring zero-energy capable operation, and solar energy mandates) and public research and development (R&D).

This chapter first provides a comprehensive review of policy strategies in key countries and markets and then offers a model to analyze and compare policy mechanisms to promote still wider and more rapid adoption of PV. With rising costs of conventional fuels and growing concern about carbon emissions from the energy sector, an even more rapid pace of PV's diffusion is likely to be needed if we are to address the challenge of sustainability [3–5].

2.1.1 Changing Climate in the Energy Industry

Over the course of the twentieth century, the energy sector became heavily dependent on fossil fuels and, recently, uranium for nuclear reactors. Although the share of fossil fuels (oil, natural gas and coal) in global energy supply has slightly decreased from 1980 levels (when they comprised 91% of worldwide commercial energy supply) by end of 2008 fossil fuels still supplied 87% of primary global energy (Figure 2.1). When nuclear energy is included, the conventional energy supply system is the source of 93% of current energy use. Due to high supply risks, volatile fuel

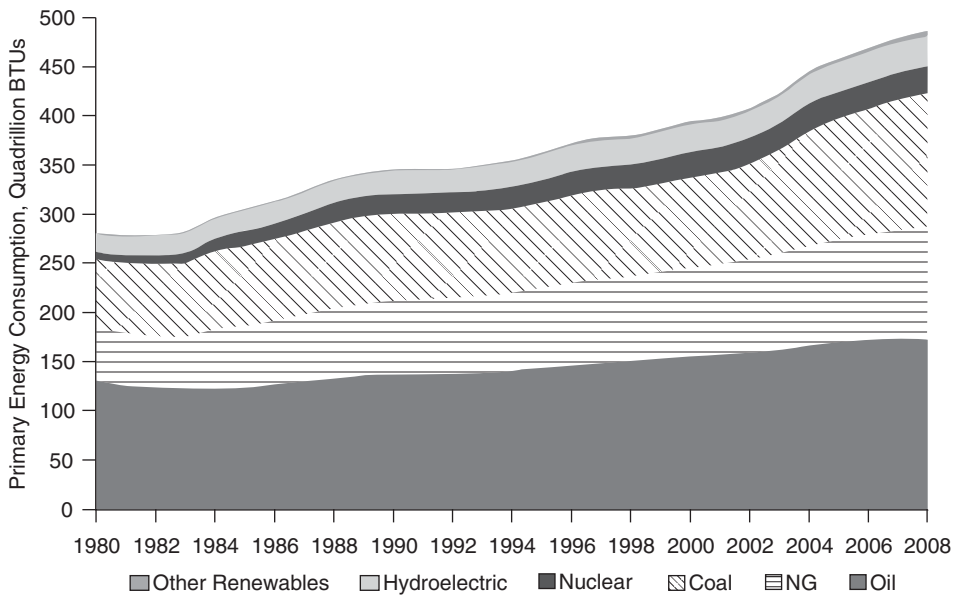


Figure 2.1 Global primary energy consumption. Data source [7]

prices and long-term environmental implications of fossil energy use, the existing energy supply structure is regarded by many as no longer viable [3, 5, 6].

For the last decade, energy prices for conventional power generation have significantly increased (Figure 2.2). Based on data from the US Energy Information Administration for 2000–2008, wholesale prices of residual fuel oil (No. 5 and 6 distillates) have increased by over 219% (\$0.61/gallon to \$1.94/gallon); the cost of natural gas used for electricity generation has increased by 113% (from \$4.38/MCF to \$9.35/MCF); the weighted average cost of uranium

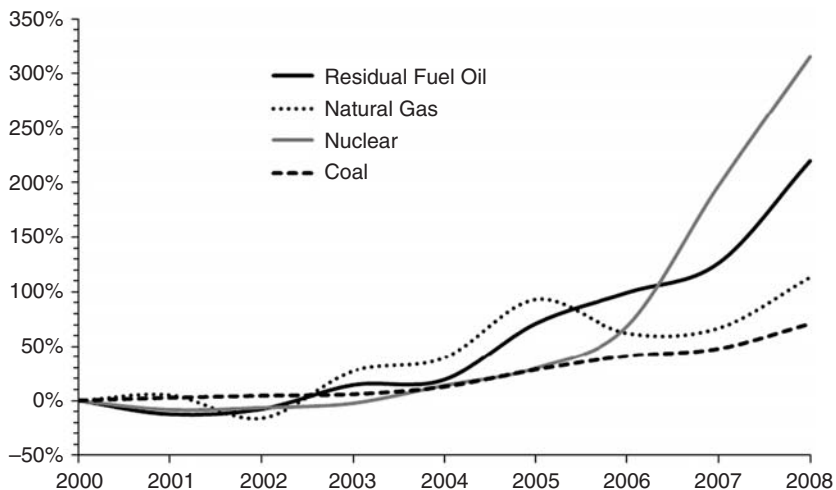


Figure 2.2 Energy price fluctuations for power generation in the US 2000–2008. Data source [9]

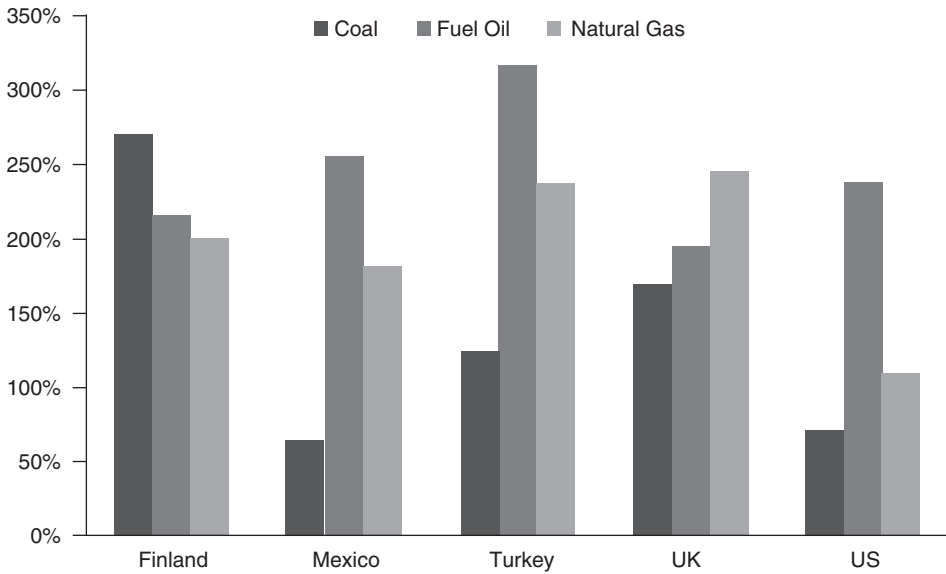


Figure 2.3 Percentage increase in energy price for power generation in selected countries, 2008 compared with 2000. Data source [10]

oxide (U_3O_8) used in nuclear power plants has increased by 316% (\$11.04 to \$45.88 per million pounds); and coal prices, despite being the least volatile, have also witnessed an increase of 72% (\$27.5 to \$47.4 per metric ton). Similar trends were also observed in other countries (Figure 2.3). In 2009, on the heels of the worst economic crisis since the 1920s, world oil prices fell, but only by about one-third of their peak 2008 value. Conventional fuel prices and downward pressure on material prices such as steel and copper resulting from the current economic crisis could reduce energy costs to end users in the short term, but the long-term trend is clear – conventional energy will cost more and, soon, much more [7, 8]. Higher conventional energy prices and the likelihood of significant fluctuations in the foreseeable future have made, and will continue to make, energy from PV power increasingly attractive.

Mounting concerns over global climate change and other environmental problems associated with conventional energy use are adding to the momentum to rethink the architecture of the energy sector. According to the IPCC [11], energy efficiency, changes in land use practices and wider adoption of renewable energy technologies are likely to be the principal tools to decarbonize the world economy (Figure 2.4). The baseline scenario in its 2007 assessment of mitigation options contains an IPCC forecast of 340 TWh of 2030 electricity generation, resulting in a decrease of 0.25 gigatons (GT) in CO_2e emissions. IEA's *World Energy Outlook* forecasts PV to provide 525 TWh or 2% of electricity demand under the 450 Scenario [7]. As discussed later in the chapter, these baseline scenarios can reasonably be surpassed, with as much as 25% of electricity needs supplied by PV, if the proper policy menu is embraced.

2.1.2 PV Markets

Over the last decade, the global PV industry has grown rapidly, faster than any renewable or non-renewable energy option. World PV annual cell production grew from 277 MW_p in 2000 to 6850 MW_p in 2008 (an annual average growth of more than 40%), reaching a cumulative worldwide

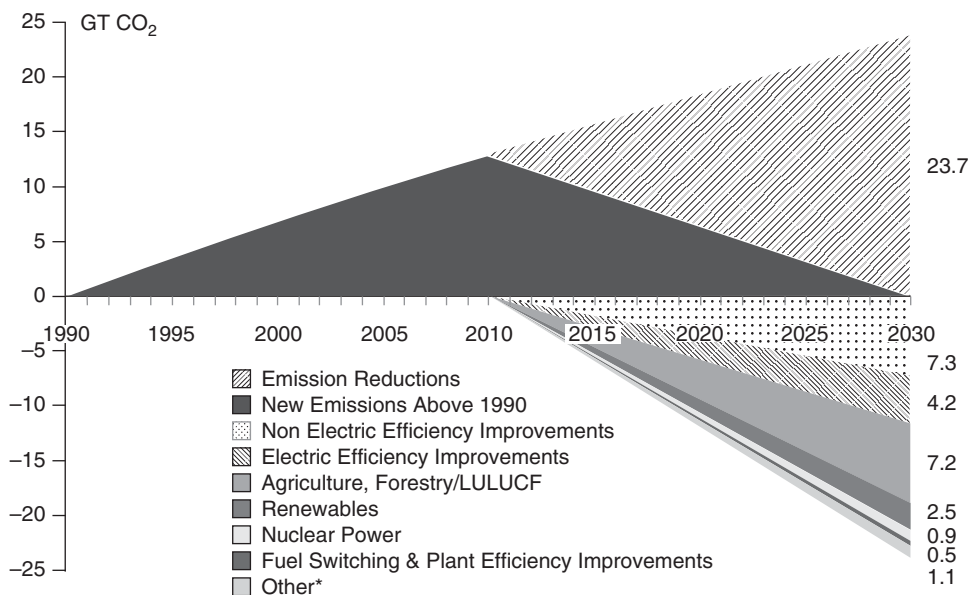


Figure 2.4 Potential GHG emissions avoided by 2030. * “Other” includes CO₂ capture and storage (0.4 GT) and improved waste management (0.7 GT). Data source: [11] (calculated by this chapter’s authors based on information in the Fourth Assessment of WGIII)

PV cell shipment of over 19 GW_p at the end of 2008 (Figure 2.5). Japan, Germany and the US are traditional leaders in PV cell manufacturing. However, in recent years new players have emerged, especially China, which manufactured 2150 MW_p of PV in 2008 and became the largest PV producer in the world (followed by Germany (1510 MW_p) and Japan (1230 MW_p)).¹ The US has lost its standing as a manufacturer, producing only 430 MW_p in 2008, less than one-half of the output of Taiwan (865 MW_p). While Spain supplied less than 200 MW_p in 2008, its industry growth is expected to lead it past the US in the next few years [12, 13].

In 2008, annual new PV installations reached a record high of 5950 MW_p [17]. The major PV markets that have fueled PV demand and growth are Spain, Germany, the US, South Korea, Italy and Japan, which at the end of 2008 accounted for 41%, 31%, 6%, 5%, 4% and 4% of demand, respectively, while the “rest of the world” and the “rest of Europe” accounted for 5% and 4% respectively [17]. Although Germany is a leader in cumulative solar PV installations (5.3 GW_p), its annual installations of 1.86 GW_p is now second to Spain, with the latter installing an impressive 2.5 GW_p (up from 0.64 GW_p in 2007). Use of the technology in the US is much slower, reaching 0.4 GW_p (an increase from 0.2 GW_p in 2007) [12, 17]. At the end of 2008 it was estimated that cumulative global PV installations for power production reached 16.4 GW_p [2], with most of the installations occurring in industrialized countries (Figure 2.6).² While the cumulative installed capacity of PV reached a significant milestone in 2008, it is only a small fraction (0.4%) of the total global installed electric power generation capacity of about 4000 GW_p [18].

¹ Nearly all of the PV cells manufactured in China are exported to other markets.

² Discrepancies between cumulative PV cell shipments and installations can be attributed to delays in installation after shipment. This can be significant under a fast growing PV market. According to industry analysts, on average there is a delay of two quarters between a module being shipped and its connection to the grid [132]. At the beginning of 2009, the industry had started with over 2 GW_p of inventory [21].

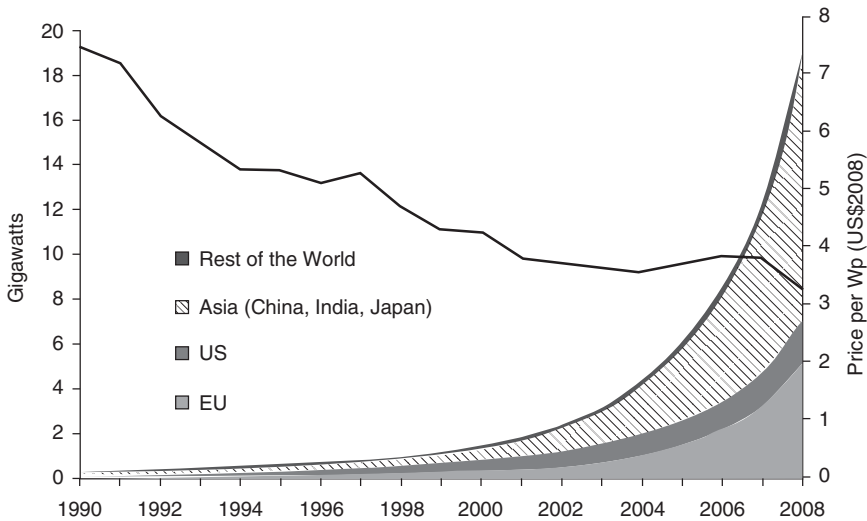


Figure 2.5 World cumulative photovoltaic shipments and retail prices (W_p) 1990–2008 (solid line = price per W_p). Data sources: [12, 14–16]

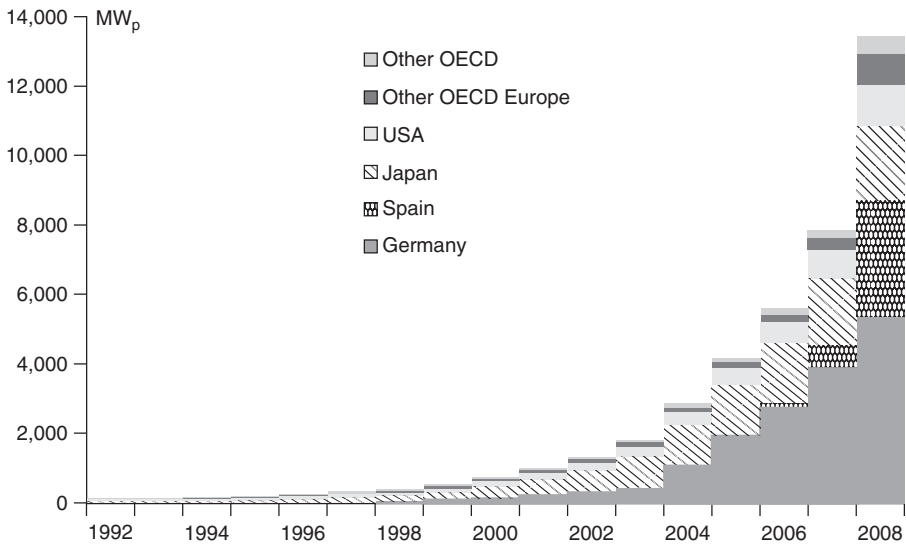


Figure 2.6 Cumulative photovoltaic installations in OECD countries 1992–2008. Data source: [12]

Until recently, upstream manufacturing improvements combined with downstream system integration experience served to drive down PV prices. However, since 2005 high demand for the technology led to a departure from this decade-long trend (Figure 2.5). A major contributor to the price increase was a shortage of polysilicon supply [19, 20]. Polysilicon historically sold at about \$35/kg, but since 2004, the spike in demand caused by PV market growth led to spot market prices above \$400/kg in 2008 [19, 21]. In response, a number of new polysilicon production lines were added around the world (particularly in China). As more suppliers enter the market, analysts

expect polysilicon contract prices to settle at around \$70–80/kg [19]. Accordingly, module prices are expected to return to their historical downward trend by 2010.

2.2 POLICY REVIEW OF SELECTED COUNTRIES

Although significant cost reductions have been achieved, currently electricity produced from PV is not cost-competitive with conventional sources of generation.³ National and local governments have supported PV deployment through a broad range of incentive, tax, regulatory and R&D instruments that include tax credits and exemptions, preferential interest rates and loan programs, direct incentives (e.g. performance-based incentives, capital subsidies), building code mandates, feed-in tariffs, renewable portfolio standards, voluntary green power programs, net metering, interconnection standards and “demonstration” or pilot projects [12, 22]. Policy leaders for PV deployment are Germany, Spain, Japan, South Korea and the U.S. Each country’s national and, in some cases, local policies are reviewed below.⁴

2.2.1 Review of US Policies

In recent years, federal and state policies have facilitated strong demand for PV systems in the US. In 1998, the US had only 100 MW_p of installed PV capacity; ten years later, cumulative PV installations have reached 1.2 GW_p, of which 68% are grid-connected [12]. On the national level, the solar Investment tax credit (ITC) and modified accelerated cost recovery system (MACRS), a tax depreciation rule for PV and other capital equipment, have played key roles in reducing PV developer costs.

The ITC was first established in 1978 under the Energy Tax Act, which provided a tax credit of 15% of installed cost for solar energy installations. The Tax Reform Act of 1986 gradually reduced the ITC to 10%, and it remained at this level until 2005 [23]. The Tax Reform Act also introduced MACRS depreciation rules for commercial entities, allowing PV installations for the business sector to qualify for rapid 5-year tax depreciation. The Energy Policy Act of 2005 (EPAAct 2005) increased the ITC to 30%. The Energy Improvement and Extension Act (EIEA) of 2008 removed the previous cap for residential installations (US \$2000) and extended the 30% ITC through 2016 [24]. In 2009, the American Recovery and Reinvestment Act (ARRA) allowed commercial entities to receive cash grants from the US Treasury for PV installations occurring in 2009 and 2010. Cash grants provide incentives for those businesses which do not have high tax obligations to fully utilize benefits of the 30% federal tax credit. ARRA also provided a bonus depreciation benefit of 50% for projects implemented in 2009 [25]. For business applications, the ITC and MACRS can reduce initial PV project development costs by more than 50% [26].

In addition to federal policies supporting PV deployment in the US, an increasing number of states have used two instruments to improve PV marketability. One is a policy called a renewable portfolio standard (RPS), in which load-serving entities (LSEs) in the electricity sector must provide a fraction of their electricity supply from PV or distributed renewable energy technologies (which also includes PV). By the end of 2009, 29 states and the District of Columbia had broad RPS mandates. Importantly, 14 states and the District of Columbia (Washington,

³ It should be noted that this comparison does not consider the relative subsidies for PV and its retail market competitors. When these are factored in, some analysts conclude that PV is very near to a market parity [19, 131]. If pollution and other external costs are included in the cost of conventional fuels, it is likely that PV is less expensive, at least over the long run [133].

⁴ While China is the world’s largest solar manufacturer, it mostly sells its production to overseas markets. This section focuses on policies to stimulate domestic use of PV and, for this reason, does not include China. Future editions of the *Handbook* will almost certainly need to profile China’s domestic market which recently began to expand.

DC) had specific solar or distributed generation requirements for LSEs under their RPS laws. In addition, California, Oregon and Texas have created specific targets for distributed generation or PV unrelated to their RPS laws [25]. The second favored policy instrument among US states is net metering. Currently, 43 states and Washington, DC support net metering of PV electricity. Net metering allows customer-sited PV generators to offset electricity provided by the LSE with kWh supplied by their PV system [27, 25]. With net metering, electricity generated by PV is valued at the retail electricity price, providing additional incentive for PV deployment.

Historically, states and electric utilities have also supported PV deployment through rebate programs. In recent years however, support has begun to shift towards production or performance-based incentives. By early 2010, 29 states had production-based incentives embodied in utility obligations to purchase Renewable Energy Certificates (RECs). Sixteen of these states had solar electric sales mandates, which included either production-based incentives (viz. solar REC purchase obligations for utilities) or credits (applied to meet RPS mandates) [25]. Nevertheless two states, California and New Jersey, represented 67 and 9%, respectively, of the total US grid connected systems, and were the policy leaders in the country. Their approaches to market development have been successful, causing, for example, an increase in grid-connected PV installations between 2005 and 2008 of 208% (California) and 622% (New Jersey) [28–30]. The PV policies of these key states are reviewed below.

2.2.1.1 California

California has a long history of solar market development. In 1984, the Sacramento Municipal Utility District (SMUD) installed a 1 MW_p PV plant (PV1) – one of the first large-scale PV power plants in the world [31]. Over the past two decades, PV1 showed steady performance and it was gradually expanded, reaching 3.2 MW_p by 2004 [32]. In 1993, Pacific Gas and Electric Company (PG&E) installed a grid-connected 500 kW_p PV system (in Kerman) to serve peak power demand. Performance of the PV system demonstrated that PV output could reduce coincident utility load peaks [31–33]. More significantly, it demonstrated the value of PV to the utility in avoided costs that were comparable to the value of electrical energy itself [34].

In 1998 as part of California's electricity sector deregulation, financial incentives were created for renewable energy technologies under the California Energy Commission's Renewable Energy Program [35]. The initiative contained a special provision for "emerging renewables" which referred specifically to on-site generation technologies – primarily PV and small wind. From 1998 to 2004, the California Energy Commission's Emerging Renewables Program (CEC-ERP) offered rebates, which on average amounted to 40% of the installed price, to reduce (buy-down) the initial cost of the system. Beginning in 2005, the CEC-ERP offered participants the following options: (1) they could receive rebates amounting to 40% of installed costs; or (2) they could receive incentive payments based on actual system performance in the amount of 50 cents per kW h for three years [36, 37]. The CEC-ERP supported PV installations by customers of the three major investor-owned utilities (IOUs) serving the state PG&E, Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E).⁵ Under the program (which ended in 2006), PV system size was limited to 30 kW_p. By the end of the program, 120 MW_p of grid-connected residential PV had been installed (this includes projects started under the program and completed in 2007 and 2008) [38].

⁵ As with many jurisdictions in the US, IOUs are only one source of electricity supply. Customers may also receive power from so-called municipal or publicly owned utilities (utilities owned and operated by a governmental jurisdiction such as a city or incorporated region), electric cooperatives (suppliers owned by their customers which often are not subject to conventional utility regulation), and special federal authorities such as the Tennessee Valley Authority and the Bonneville Power Administration. IOUs serve approximately 97 million customers, while municipal utilities, cooperatives, special federal and state authorities together serve 40 million customers. Retail power marketers serve the remaining 6 million customers of the US [123].

In 2001 the California Public Utilities Commission created its Self-Generation Incentive Program (CPUC-SGIP). It was intended to complement the California Energy Commission's program⁶ and provided incentives for PV installations exceeding 30 kW_p. By end of 2008, 135 MW_p of grid-connected PV systems were installed under this program [38].

These two policy initiatives were instrumental in promoting PV markets for IOU service areas. At the same time, a number of publicly owned utilities (POU) began developing policies to support PV installations within their service territories. Sacramento Municipal Utility District (SMUD) and Los Angeles Department of Water and Power (LADWP) were two major POU's pioneering PV use. As previously motioned, SMUD was one of the first public utilities in the world with a large-scale PV installation. Between 1998 and 2007, 11 MW_p of on-site PV was installed, utilizing a then-unique policy tool in which a SMUD citizen or business could elect to pay a higher electricity price and the utility would install, operate and maintain the system. This policy tool gave rise to a stream of new policies culminating in the property-assessed clean energy (or PACE) program in which electricity users voluntarily pledge an increase in their property tax assessments in order to retire the capital debt incurred by the installation of the PV system. This model is now being imitated across the US, and is the subject of national legislation [39, 40].

On August 20, 2004, California's governor announced the Million Homes Solar Plan which laid the groundwork for the 2009 Go Solar California campaign. Go Solar California aims to install an additional 3.0 GW_p of PV in the state within 10 years and is funded by ratepayers in the amount of \$3.3 billion [41]. Go Solar California was launched in 2007 and includes two new solar incentive programs – the California Solar Initiative (CSI) and the New Solar Homes Partnership Program (NSHP). Residences that are served by publicly owned utilities (e.g. local municipal utilities) are not eligible for the CSI and NSHP programs. However, California now requires publicly owned utilities to offer an equivalent incentive program for their customers [42].

The CSI began in 2007 and led to the rapid installation of more than 130 MW_p in PV installations in one year (Figure 2.7). For 2007–2016, the CSI Program has a budget of \$2.2 billion and a target of 1.75 GW_p of installations from the mainstream incentive program and an additional 190 MW_p from its low-income program (CPUC, 2008). Initially rebates stood at \$2.50/W_p for residential and commercial systems and \$3.25/W_p for government entities and the nonprofit sector. The incentive levels are scheduled to decline as the aggregate capacity of PV installations increases [25]. Installed and in-pipeline projects have already met 20% of the CSI target [38, 41].

The New Solar Homes Partnership Program provides funding for builders and developers who install PV systems on new, energy-efficient residential buildings that are served by investor owned utilities. NSHP is administered by the California Energy Commission. The program has a budget of \$400 million and a goal of installing 400 MW_p of PV on new homes by 2016. This includes a 36 MW_p target for new low-income housing (California Energy Commission, [44]). Initially rebates range from \$2.50/W_p to \$3.50/W_p (for low income housing) and gradually decrease as PV installations increase [25].

The CSI and NSHP incentives are designed to stimulate rapid market demand while reducing incentive levels as the market for PV becomes viable. Depending on system size and customer choice, incentives are paid on a dollar-per-watt or cents-per-kilowatt-hour basis. The former is referred to as an expected performance-based buy-down (EPBB) incentive and the latter is called a performance-based incentive (PBI). EPBB is intended for residential and small commercial customers with systems less than 50 kW_p capacity. The incentive is in the form of a lump-sum, up-front payment. PBI is intended for large commercial, government and nonprofit customers. It is mandatory

⁶ The CPUC has regulatory authority over the IOUs serving the state, while the California Energy Commission has responsibility for long-term energy policy and planning with special responsibilities for the promotion of energy efficiency, conservation and renewable energy (see www.energy.ca.gov/commission/index.html).

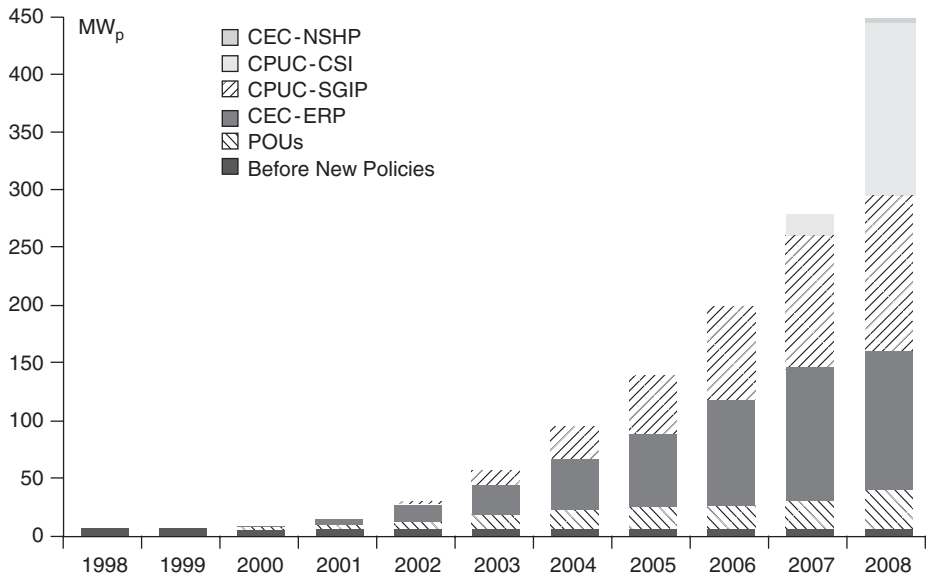


Figure 2.7 Cumulative grid-connected photovoltaic installations in California by policy, 1998–2008. Data source: [38]

for all systems greater than 50 kW_p capacity (systems less than 50 kW_p in size can opt in to PBI). The PBI program provides payments to PV users of 40–50 cents per kWh for five years. The incentive levels are scheduled to decline as the aggregate capacity of PV installations increases. Both incentives are performance based. In the case of EPBB, lump sum payments are predicated on a system's *expected* performance (factors include system AC rating, location, orientation and shading). This requires accurate and transparent predictive models. In the case of PBI, incentives are based on *actual* energy production and monthly payments are made during a 60-month period [42–44].

Energy policy innovation has been a hallmark of California for decades, and the promotion of PV use is no exception. The state hosts the largest PV capacity and greatest number of installations per capita of any US jurisdiction. Its policy tools have been widely adopted both in and beyond the country.

2.2.1.2 New Jersey

New Jersey has grown to be the second largest PV market in the US (by the end of June 2009, the state had 90 MW of installed PV systems). It was one of the first states to set specific targets for renewable energy sources in state electricity supply. In 1999 under the Electric Discount and Energy Competition Act (EDECA), a statewide renewable portfolio standard (RPS) was adopted and went into effect in 2001. A specific carve-out for PV was included which requires load-serving entities to procure 2.12% of electricity from PV by 2020. EDECA and the RPS laid the foundation for New Jersey's Clean Energy Program administered by the New Jersey Board of Public Utilities (BPU) [45].

From its launch in 2001, the Clean Energy Program (CEP) has directed significant funds for renewable energy development. Under CEP there were two initiatives supporting renewables: the Customer On-site Renewable Energy (CORE) strategy and the Renewable Energy Project Grants and Financing (REPGF) opportunity. CORE provided rebates for on-site renewable generation projects with less than 1 MW_p capacity. REPGF was to support development of so called Class 1 renewable

energy resources (which includes PV, solar thermal electric, wind, geothermal, fuel cells, landfill gas recovery and sustainable biomass) larger than 1 MW_p capacity for power generation [45].⁷

CORE has proved to be instrumental for PV market development in the state. Initially it provided rebates from \$3.75/W_p (for 100–500 kW_p systems) to \$5.50/W_p (for systems less than 10 kW_p). Later rebates were gradually reduced as installations increased and prices fell [46]. Under the program, 70 MW_p of PV have been installed [47] and an additional 50 MW_p of PV systems have been approved for rebates. In 2009, the Clean Energy Program redesigned its incentive program based on the success of CORE. A Renewable Energy Incentive Program (REIP) was created with lower rebates, but aggressive pricing for “solar renewable energy credits” (see below). Under REIP, a residential customer can receive a rebate of \$1.75/W_p for up to 10 kW_p of installed on-site PV if the customer agrees to receive a free energy audit (the rebate falls to \$1.55/W_p without an audit). Nonresidential customers can receive \$1.00/W_p rebates for up to 50 kW_p of installed PV [48].

The backbone of New Jersey’s solar policy is now its Solar Renewable Energy Credits (SREC) initiative. In a significant departure from its previous incentives, up-front capital incentives are being phased out, replaced by an emphasis on performance-based production incentives. In fact, the state intends to terminate all rebates by 2012 [49]. SRECs are tradable certificates that represent the clean energy benefits of electricity generated from a solar electric system. Each time a PV system generates 1 MWh of electricity, an SREC is issued that can then be sold or traded separately from the power. New PV projects and projects already in the CORE program queue are eligible to participate in the SREC program. However, starting in 2009 customers were required to forgo rebates to participate in the SREC program.

New Jersey has also adopted an 8-year Solar Alternative Compliance Payment (SACP) schedule intended to enable project financing for large PV systems without up-front rebates. Utilities are required to pay an SACP of \$711 per MWh if they do not meet the state’s Solar RPS through the purchase of SRECs. The SACP schedule gradually declines, reaching \$594 per MWh in 2016 [25–49]. The high SACP rate (the highest in the US) has led to high market prices for SRECs. In May 2009, for example, the weighted average price for SRECs was \$500/MWh, much higher than in previous years when prices hovered around \$240/MWh [50]. Only SRECs from PV installed within the state can be used by utilities to comply with New Jersey RPS [51].⁸

As a result, the SREC initiative has spurred rapid growth in the state’s PV installation rate, outpacing the experience of the state’s earlier and quite successful CORE program (Figure 2.8). When given the choice between up-front capital incentives (REIP) and production incentives (SRECs), customers have shown an overwhelming preference for the latter.⁹ This policy innovation is now being actively considered in many jurisdictions throughout the country.

2.2.1.3 Other states

While California and New Jersey are acknowledged leaders of US solar policy innovation, several other states also qualify as pioneers in this area. Table 2.1 identifies ten American states with the highest per capita PV installation rates by the end of 2008. Importantly this group includes not only “sunny” locations or large markets, but also smaller states (e.g. Delaware with a population

⁷ New Jersey has yet to build a PV project under the REPGF program.

⁸ Across the US, policies regarding out-of-state SREC registration varies. At the beginning of 2010, New Jersey, and Maryland did not allow an out-of-state SREC registration, while Delaware, Ohio, Pennsylvania and the District of Columbia have accepted out-of-state SREC registrations [51].

⁹ Customer support for the SREC approach may reflect the preference of solar project developers who reduce prices when SRECs are assigned to them. Because an SREC assignment for 8 years represents a predictable revenue stream, developers can sometimes find it easier to borrow needed capital from lending institutions.

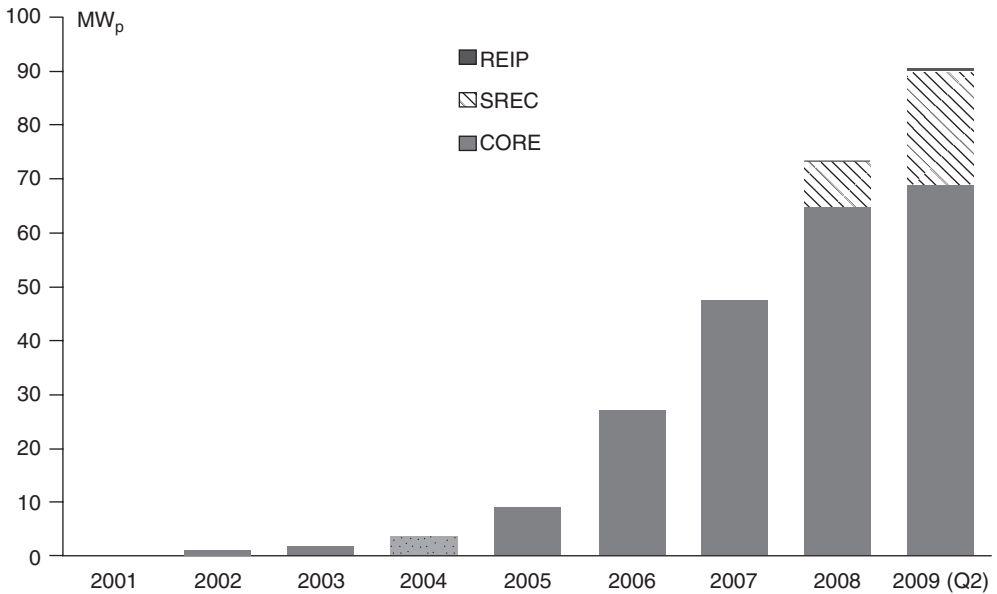


Figure 2.8 Cumulative grid-connected photovoltaic installations in New Jersey 2001–2009 (Q2). 2009 includes cumulative installations through second quarter (Q2) of 2009. Data sources: [52, 53]

Table 2.1 Top ten states by per capita capacity

	Per capita installed power in 2007 (W_p /person)	Per capita installed power 2008 (W_p /person)
California	9.1	14.6
Nevada	7.8	14.2
Hawaii	3.0	10.6
New Jersey	5.0	8.1
Colorado	3.1	7.7
Arizona	3.1	4.3
Connecticut	0.8	2.5
Delaware	1.4	2.2
Oregon	0.8	2.1
Vermont	1.2	1.8
National average	1.6	2.7

Data sources: [28, 29]

of approximately 900 000 residents) and those with above-average colder and cloudy days (Connecticut and Oregon). As the diversity of state leaders indicates, solar development is not necessarily driven by geographic, weather or insolation characteristics. Policy – both governmental and business – shapes how and how much PV is used. Four of states can be used to illustrate this point.

Nevada deploys PV on a per capita basis at the second highest rate in the country. The drivers for its performance are intersecting government and utility policy initiatives. The state was one of the earliest to create a carve-out provision in its RPS, requiring 1.5% of electric sales to come from PV by 2025. Having established an aggressive schedule for utility involvement in solar

energy development, the state organized a Task Force on Energy Conservation and Renewable Energy [25] to design utility programs to spur the market. A rebate program was launched in 2004 providing \$2.30/W_p of PV installed on residences and small businesses, and \$5.00/W_p for public buildings [54]. In addition, the state's largest utility agreed to buy SRECs for 20 years from the 14 MW_p PV plant at Nellis Air Force Base, making the project profitable. The state also took the initiative of supporting a 12.6 MW_p thin film solar farm in 2008 and its private backers – Sempra and First Solar – were able to obtain a long-term power purchasing agreement with the California utility Pacific Gas and Electric. The project showcases the benefits of a public–private partnership, with installed cost at \$3.20/W_p which some analysts have suggested is comparable to grid power [55].

Colorado also illustrates the importance of public–private partnerships. With only a moderate carve-out target of 0.8% of solar from PV by 2020, the state nonetheless hosts the third highest installation volume among the American states [28]. Its market has grown because utility programming has attracted investors. The state's largest utility, Xcel Energy, initiated a Solar Rewards Program that includes a rebate of \$2.00/W_p coupled with an SREC purchase agreement for 20 years at \$55 per MWh. Other utilities have followed suit, pushing Colorado's installed capacity above 38 MW_p by the end of 2009 [25, 56].

While Nevada and Colorado can count on large markets and good to excellent insolation, a state like Delaware has neither. Yet, its progress in promoting solar development is impressive. In 2005, the state adopted one of the most aggressive carve-out targets in the country, by which 2% of sales must come from PV by 2019, and created incentives which cover approximately one-third of installed costs [25]. By the end of 2009, installations already surpassed the RPS target for 2011 [57, 58]. But a major driver in Delaware has been its creation of the country's first Sustainable Energy Utility (SEU). With capital from proceeds of the state's participation in quarterly carbon allowance auctions under the Regional Greenhouse Gas Initiative [59], the SEU has become the largest SREC off-taker in the initial production years of the 10 MW_p SUN Park in the state's capital, Dover. The SUN Park will be completed in 2011 and will be one of the largest solar plants built on the American east coast. The SEU's participation is a key reason for the SUN Park's favorable economics. The SEU's program for SREC pricing has stimulated additional projects in Delaware, including a 2 MW_p rooftop application as part of a two-phase 6 MW_p PV installation at the state's largest university [60, 61] and another 2 MW_p distributed application on four campuses of the state's community college. Completion of these projects will catapult Delaware to a leader on a per capita basis from its present ranking as eighth (Table 2.1). The rapid growth in Delaware's sustainable energy market received national attention, with a recent story in the *New York Times* complimenting the SEU for its innovative policies [62].

Another small state – Vermont – is advancing an innovative strategy for PV market development. In 2005, its legislature created the Clean Energy Development Fund (CEDF) with authority to invest in PV and other clean energy options. The CEDF offers a wide range of financing from grants to loans, equity investments and direct incentives [63]. So far, the Fund has underwritten approximately 1 MW_p of PV installations [63]. Additionally, 1.7 MW_p was installed under Vermont's Small Scale Renewable Energy Incentive Program [64]. Vermont has also created its own tax credit for businesses investing in solar systems which covers 30% of initial capital outlays. Together with US tax credit of 30%, the state has dramatically lowered the up-front cost hurdle for investors [25].

Each state has crafted policies and programs that seek to take best advantage of the particular market and social assets of their jurisdictions in order to stimulate rapid growth in the utilization of PV. While some may worry that such policy diversity may create market confusion, state initiatives in the US have proven to date to be the incubators of policy innovation creating the country's fast expanding demand for solar energy. Indeed, researchers have shown that state policy innovation has nurtured a powerful civil society commitment to sustainable energy which is effectively challenging the country's traditional energy policies [65].

2.2.2 Europe

2.2.2.1 Germany

Germany has more than a 25-year policy history of promoting PV use. In 1983, with government support, the first 4 kW_p grid-connected PV system in Europe was installed on the roof of an occupied residence in Munich [66]. Yet, the German PV market was still in its infancy, accounting for only 1 MW_p in cumulative installations in 1989. The German 1000 Roofs Measurement and Analysis Program, introduced in 1990 as a pilot, spurred interest in the technology and led to more than 2000 roof-mounted systems with a capacity of 5.3 MW_p in just 5 years [67]. Performance of these systems was extensively monitored by government and university researchers, which led to significant technical and regulatory improvements. Several federal- and state-funded programs followed, which furnished capital subsidies per kW_p of installed PV ranging from 25 to 50% of initial investment costs [66]. These programs provided the initial government stimulus for funding PV systems.

At the end of 1990, Germany adopted the world's first feed-in tariff (FiT). Under the law, electric utilities were required to purchase electricity from PV systems at a price equal to at least 90% of retail electricity rates [68]. The first feed-in rate was not sufficient to spark significant development of PV. In contrast, wind, which initially shared the same tariff as PV, increased its penetration in electricity supply from 0% in 1990 to 1% in 1998 [18]. Nevertheless, the feed-in law, in combination with the country's 1000 Roofs Program and local grant initiatives, created a PV market of 54 MW_p of installed capacity by 1998 – a tenfold increase in just 5 years [69]. This experience would set in motion a policy regime that has arguably proved to be the most successful in the world.

In 1999, the national government initiated the 100 000 Roof Solar Energy Program, providing 10-year, zero-interest loans with the final installment (10% of the principal) being waived. By end of 1999, nearly 4000 systems with a total capacity of 10 MW_p were installed under the program [66]. In 2000, the government adopted the Renewable Energy Source Act (RESA), which increased the feed-in tariff for PV sixfold (from US\$ 0.08 to US\$ 0.50) and required utilities to sign minimum contracts of 20 years for a system's output [70, 71]. The high feed-in tariff, long contract length, and favorable financing through zero-interest loans created a rush to install PV projects throughout the country. During the first 4 months, more than 70 MW_p of PV projects sought government and utility support [66]. This was more than the existing 69 MW_p of installed capacity accumulated since 1983 [69]; in other words, in four months the new policy had created demand for PV that had taken 17 years to realize under the old approach. The capacity was much higher than anticipated (the original plan was to install 27 MW_p by 2000) and the government put a temporary moratorium on applications, dropped the waiver provision for the final installment of the loan, and increased the loan interest rate to 2%. It also increased the target for new PV system installations in the first year of the program from 27 to 50 MW_p, and shifted by one year the program's final target of 300 MW_p from 2004 to 2003.

The 100 000 Roofs Program met its goal by the end of 2003. To maintain growth in the PV market, the government then created the Solar Power Generation Program, administered by the KfW Promotional Bank [72], to continue its low-interest financing incentive. In 2004, the Renewable Energy Source Act was again amended, setting the feed-in tariff still higher, to between €0.54 per kWh (for systems larger than 100 kW_p) and €0.57 per kWh (for systems smaller than 30 kW_p) for building-based applications; and for ground-mounted systems, the feed-in rate was set initially at €0.46 per kWh [73].¹⁰ The law required a decline in the tariff paid to PV system owners of 5% per year for building-based systems and 6.5% per year for ground-mounted systems. This

¹⁰ These rates in 2004 US dollars are equivalent to \$0.66–\$0.70 per kWh for building-based PV systems and \$0.57 for ground-mounted PV systems (see <http://www.bankofcanada.ca/en/rates/exchform.html>).

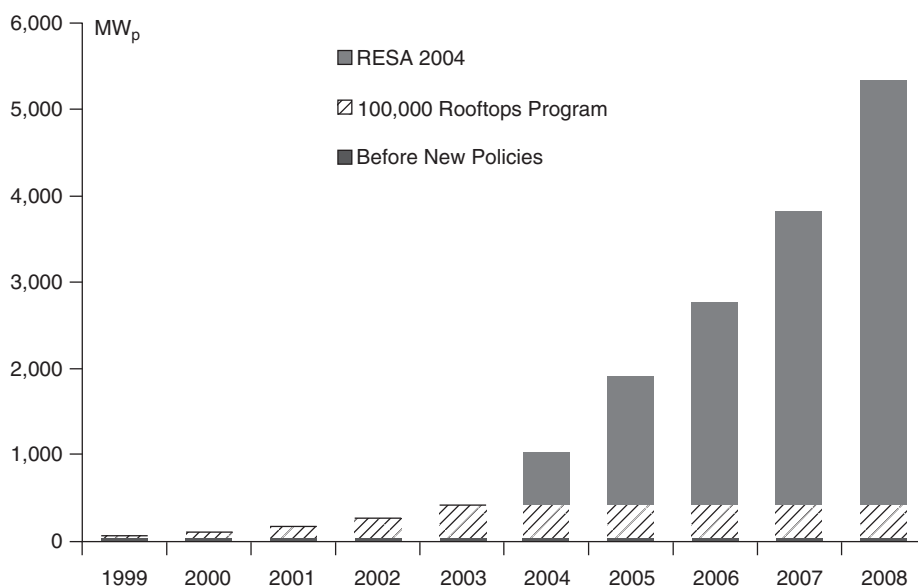


Figure 2.9 Cumulative grid-connected photovoltaic installations in Germany by policy, 1999–2008. Data sources: [12, 66]

reduction schedule applied through the end of 2008 (e.g. the 2008 feed-in rate paid to PV building system owners for applications smaller than 30 kW_p was €0.47.¹¹ The revised feed-in law created strong, sustained demand for PV in Germany and by the end of 2008 cumulative installed power reached 5.3 GW_p (Figure 2.9).

In 2009, the annual FiT schedule was again adjusted, with PV tariffs declining by 8% per year in place of the earlier 5% rate and the new rate applies to all systems less than 100 kW_p in size. For all ground-mounted applications and building-based systems greater than 100 kW_p, the tariff declines 10% per year. Beginning in 2011, the FiT is set to fall 9% per year for all systems. Additional adjustments may occur if actual annual PV installation rates grow faster than projections (Table 2.2). If the upper target is achieved early in a given year, the decrease in price will increase by 1%. Likewise, realization of the lower target will slow the FiT reduction rate by 1% [12, 74].

Table 2.2 German feed-in tariff reduction schedule: 2009–2011

	2009	2010	From 2011
Tariff reduction rate for small systems (<100 kW)	7% (<1000 MW)	7% (<1100 MW)	8% (<1200 MW)
	8% (1000–1500 MW)	8% (1100–1700 MW)	9% (1200–1900 MW)
	9% (>1500 MW)	9% (>1700 MW)	10% (>1900 MW)
Tariff reduction rate for large and ground systems (>100 kW)	9% (<1000 MW)	9% (<1100 MW)	8% (<1200 MW)
	10% (1000–1500 MW)	10% (1100–1700 MW)	9% (1200–1900 MW)
	11% (>1500 MW)	11% (>1700 MW)	10% (>1900 MW)

Data source: [12, 74].

¹¹ Due to the decline in the value of the US dollar, this rate was *higher*, nearly \$0.74 per kWh, when valued in American currency.

Through a combination of low-interest financing and multi-year FiT pricing, Germany grew its market faster than any country had previously achieved and catapulted it to the top of the world's nations in installed PV capacity. This stunning achievement demonstrates the central role of policy in PV market development.¹²

2.2.2.2 Spain

Until 2004 Spain did not have a sizable PV market (2003 installed PV capacity stood at 12 MW_p [12]). In 2004, the country's law governing renewables [75] was amended establishing a new legal and financial framework for renewable energy applications. For PV systems with a capacity of less than 100 kW_p, a feed-in rate of 575% of the reference tariff for 25 years was created; any output after 25 years of operation would receive 460% of the reference tariff. The reference tariff was based on the national average electricity generation price.¹³ For large systems (i.e. above 100 kW_p) the Spanish feed-in rate was set at 300%. The high FiT and the requirement that electric utilities purchase power from PV systems for a minimum of 25 years led to a rapid rise in PV installations.

By the end of 2004, PV installed capacity almost doubled, reaching 23 MW_p. In 2005 the Spanish government approved a new Renewable Energy Plan which established a national target of 400 MW_p PV installed by 2010 [76]. The announcement of the new Plan spurred even faster growth and by 2006 installed PV capacity had tripled from 48 MW_p in 2005 to 145 MW_p. Indeed, expansion of the Spanish market was so quick that the Plan target of 400 MW_p by 2010 was reached by the fall of 2007. The government promptly increased its target to 1200 MW_p [77]. In 2007 by

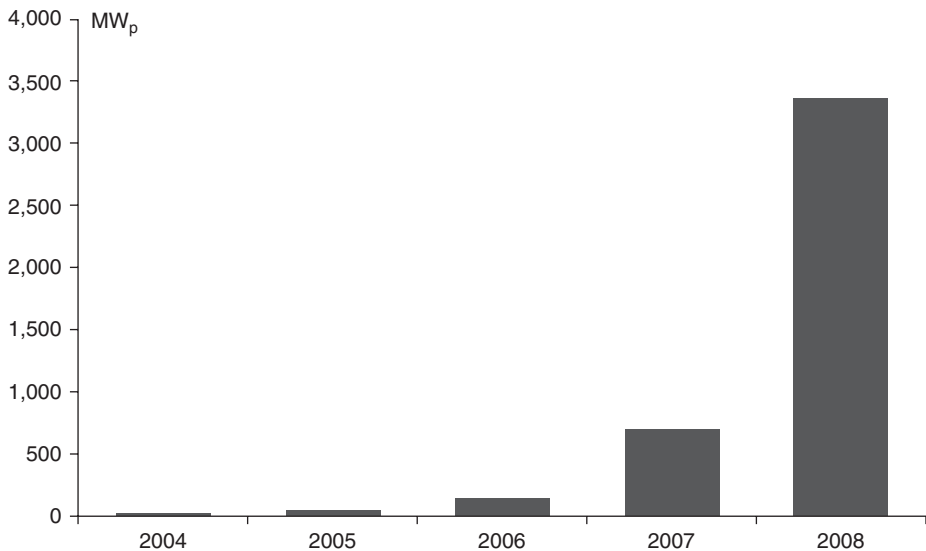


Figure 2.10 Cumulative grid-connected photovoltaic installations in Spain 2004–2008. Data source: [12]

¹² The importance of policy applies more generally to renewable energy as the German case confirms. The country has employed its FiT and financing approaches to wind, solar hot water and biomass markets with similarly impressive results, making Germany the leader in newly installed capacity in all of these markets [71].

¹³ In 2004, the average price in Spain was 7.24 Euro cents per kW h or 9.0 US cents, making the PV FiT equal to nearly 52 US cents for 25 years.

Royal Decree 661, the government modified the FiT structure for PV systems: small systems (less than 100 kW_p) receive €0.44 per kWh; a new category of system size with a range of 0.1–10 MW_p, receives €0.42 per kWh; and large systems (10–50 MW_p) receive €0.23 per kWh. All contracts are for a minimum of 25 years [78].¹⁴

In 2008, Spain's PV market experienced even higher growth, increasing installed capacity fivefold, to 3.4 GW_p of installed capacity, second only to Germany [12]. The extremely rapid rate of installation within one year created significant financial pressure on ratepayers [77] and distorted world PV module pricing. In September 2008, Royal Decree 1578 set new feed-in tariffs for PV systems installed after September 29th of 2008. Under the new tariff structure, roof-mounted systems smaller than 20 kW receive €0.34 per kWh for 25 years. Roof-mounted systems larger than 20 kW_p and ground-mounted systems receive €0.32 per kWh.¹⁵ The decree also capped the size of systems receiving FiT support at 2 MW_p for roof-mounted and 10 MW_p for ground-mounted systems. Total new installations receiving FiT support are limited to 500 MW_p in 2009, 502 MW_p in 2010 and 488 MW_p in 2011 [79] (Figure 2.10).

2.2.3 Asia

2.2.3.1 Japan

Japan has a long track record of supporting PV system deployment. In 1992, the government started the PV Field Test for Public and Other Facilities Program, which led to the installation of 4.9 MW_p of PV on public buildings such as schools, hospitals, clinics and government offices by 1997 when the program was ended. In 1997, the Japanese government through its Ministry of Economy, Trade and Industry (METI) initiated the Residential PV System Dissemination Program, managed by a government-created New Energy Foundation (NEF).¹⁶ The program was instrumental in promoting rooftop PV technology in Japan. Initially, subsidies covering 50% of installed costs were provided to residential customers, with the subsidy rate declining as system costs fell [80]. The program was closed in 2005 after resulting in 932 MW_p of installed PV capacity. This was nearly two-thirds of the total installed capacity of Japan [81, 82]. The government concluded that the program was no longer needed because market mechanisms were sufficient to drive growth [81].

In 1998, Japan initiated a Field Test Project on Photovoltaic Power Generation Systems for Industrial and Other Applications, which led to a total of 18.1 MW_p of PV installations by the time it ended in 2002. A successor program titled the Field Test Project on New Photovoltaic Power Generation Technology has led to 62 MW_p of industry-scale installed PV [83]. The purpose of the latest field testing program is to promote medium- and large-scale PV systems, with 50% of the system cost subsidized by the government.

The government has now folded its PV promotion efforts into a broad action plan to create a low-carbon society. Under the plan, 70% of new buildings are to have PV systems on their rooftops [84]. The plan sets aggressive goals for PV installation of 14 GW_p by 2020 and 53 GW_p by 2030 [12]. In addition to the national programs, up to 300 local governments have announced programs to support of PV installations. One of the largest programs was announced by the Tokyo Metropolitan Government, which is supporting the installation of about 1 GW_p of PV systems on homes and apartment buildings by 2010 [12, 84]. In addition, electric utilities have announced plans to build 30 centralized PV power plants with a total capacity of 140 MW_p by 2020 [12] (Figure 2.11).

¹⁴ In 2007 US dollars, these FiT rates are \$0.60, \$0.57 and \$0.31 per kWh.

¹⁵ In 2008 US dollars, these FiT rates are \$0.63 and \$0.50 per kWh, respectively.

¹⁶ The program began as the Residential PV System Monitor Program in 1994 [81].

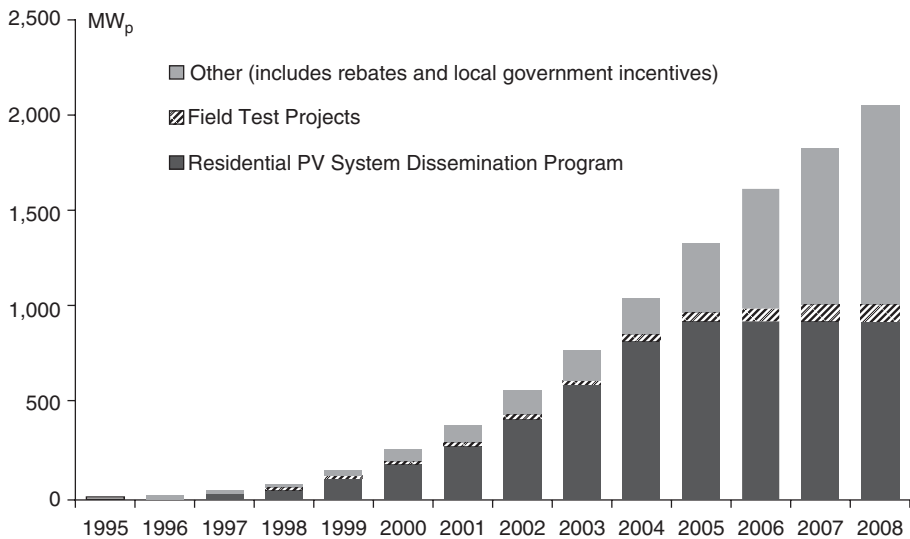


Figure 2.11 Cumulative grid-connected photovoltaic installations in Japan by policy, 1995–2008. Data sources: [12, 81, 83, 85–87]

2.2.3.2 South Korea

Since 1993, South Korea's Ministry of Commerce, Industry and Energy (MOCIE)¹⁷ has been responsible for implementing PV demonstration and field test projects. However, results were meager – by 2004 less than 10 MW_p of PV systems were installed, half of which were off-grid applications (12). In December 2003, the Korean government announced a goal of meeting 5% of total energy consumption from renewable sources by 2011. For PV, a goal of 1.3 GW_p in cumulative installed capacity was set for 2012 and 4 GW_p by 2020 [88]. Following this announcement, growth in the PV market was significantly accelerated.

Successful programs include a rooftops initiative in which the government initially supported 50% of the installed cost of 1–3 kW_p PV installations in the residential sector, hoping to reach its target of 100 000 rooftops by 2012 [89]. In 2008, the government adopted a national plan to construct one million green homes and 200 green villages by 2020. For this task the government provides 60% of the initial PV system cost for single-family and private multi-family residences, and covers all initial costs for public multi-family rental buildings [12].

The government further supports PV development in the public sector through its General Deployment Program and Public Building Obligation Program. The Program serves schools, public facilities, and universities. Under this program PV systems from 5 to 200 kW_p are installed with government funds covering up to 60% of the installation cost. Under the program, new public buildings larger than 3000 m² must spend 5% of their total construction budget on renewable energy system installations [89, 89].

These programs targeting public buildings and residential sector have played important role, but the major driver for the recent significant expansion of PV installations in Korea is a newly adopted feed-in tariff policy. Feed-in tariffs are paid for 15–20 years at 700 Korean Won per kW h.¹⁸ By the

¹⁷ The name of the ministry was recently changed to the Ministry of the Knowledge Economy (MKE).

¹⁸ In 2008 US dollars, this FiT rate is equivalent to \$0.68 per kW h.

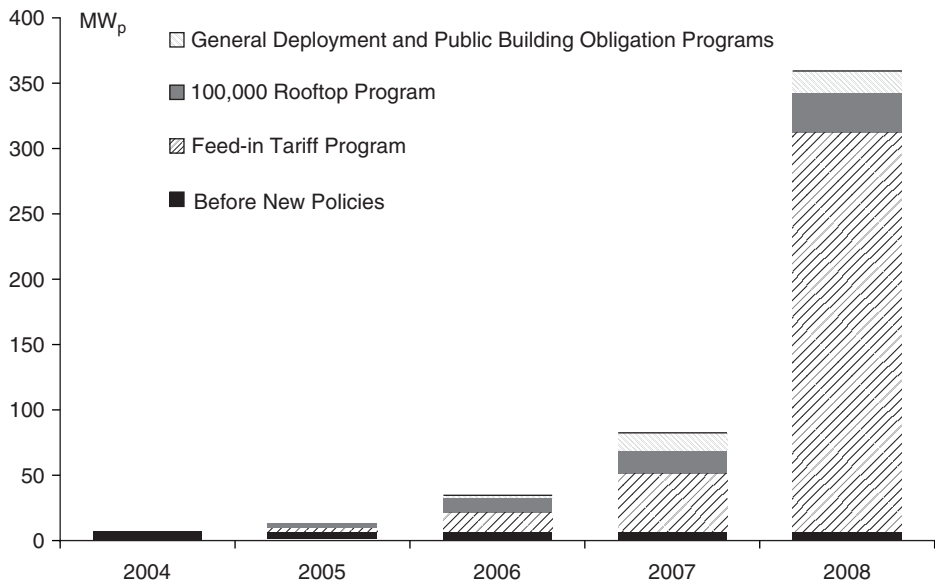


Figure 2.12 Cumulative grid-connected photovoltaic installations in Korea by policy, 2004–2008. Data sources: [12, 88–91]

end of 2008, approximately 300 MW_p of systems were installed under this scheme, 90% of which are larger than 100 kW_p in capacity, reflecting the very high percentage of residential, public and commercial buildings that are more than ten stories [12]. Beginning in 2012, the government intends to replace its feed-in tariff system with renewable portfolio standard scheme [90] (Figure 2.12).

2.3 POLICY IMPACT ON PV MARKET DEVELOPMENT

The US, Germany, Spain, Japan, and South Korea are the leading markets for grid-connected PV. By the end of 2008, the combined PV installations in these five countries stood at 12.4 GW_p, representing more than 90% of cumulative PV installations in the OECD bloc [12]. Review of PV deployment experience in these countries underscores the significance of policy in market development, market growth, and technology diffusion. It also enables us to identify policy effectiveness by the types of tools employed by this group.

Initial drivers of PV deployment in the US, Germany, Japan and South Korea were programs targeting small-scale installations in the residential sector. Germany and South Korea supported PV through their solar rooftop programs and Japan used its Residential PV System Dissemination Program to promote this sector's use of the technology. Likewise, California implemented its Emerging Renewables (CEC-ER) program, which supported PV installations in the residential sector. In order to achieve modest market start-up, these programs found that subsidies of 50% or higher of initial system costs were needed. Despite major differences in housing stock, these programs were able to launch small PV markets in the residential sector.

After initial success of PV deployment programs targeting small-scale residential applications, Japan, South Korea and the US supported programs with similar designs for their commercial

Table 2.3 Cumulative R&D spending in selected countries (in millions of US\$ 2008)

	1975	1980	1985	1990	1995	2000	2005	2008
Japan	12	49	403	726	1029	1459	2095	2268
Germany	42	278	633	1006	1405	1680	1909	2073
US	8	812	1568	1872	2332	2739	3160	3469

Data sources: US data for 1991–2008 was provided by Robert Margolis from NREL. Data for Japan and Germany, for 1975–2008 and US for 1975–1990 was obtained from the IEA Database [92].

and public buildings sectors. Here again, market development was modest, but steady. An important contribution of these programs was the confidence they built in the technology.

The policy history of these countries shows a marked shift in the last 10 years away from investment incentives and toward production-based approaches. Feed-in rates and tradable solar renewable energy certificate (SREC) schemes are the preferred policy tools in this period. Germany, Spain and South Korea have implemented feed-in laws, which have triggered significant market growth. Amendments to national FiT schemes have ensured a wide array of market applications (commercial, industrial, and public as well as residential uses) and technology configurations (e.g. thin film as well as silicon; ground-mounted as well as roof-mounted). In the US, New Jersey has shown an ability to replicate the fast growth of FiT strategies with its vibrant SREC market approach, and California has used production-based Incentives to quickly grow its Go Solar Initiative. It can be expected that production based incentives will gain more prominence through SREC trading in the US and other countries (e.g. South Korea is planning to implement an RPS scheme in 2012), and through the use of solar carve-outs in national target-setting for renewable energy use.

Financial assistance of PV deployment projects is crucial for wider adoption of this technology. However, it is also important to have strong government support for research and development (R&D). Indeed, the governments of Germany, Japan and the US have provided significant R&D funding over the last 25 years (Table 2.3).

R&D expenditures have enabled countries to spur improvements in technology performance and, thereby, reduce user costs. As we will show in the following section, this factor is very important for the goal of building a policy strategy for a *long-term* sustainable PV market.

Direct government incentives, whether capital or performance based, combined with R&D funding have played a major role in PV cost reduction. An important analytical question is to what extent direct government incentives, combined with R&D funding or other policy tools, such as carbon taxes, can impact future adoption of PV. In the following section, we describe the methodology for conducting such an analysis, and then we show concretely how different policy tools affect PV diffusion paths over the short and long term.

2.4 FUTURE PV MARKET GROWTH SCENARIOS

2.4.1 Diffusion Curves

The evolution of technology has been the focus of research for a long time. A prominent view holds that technology evolves in three phases: invention, innovation and diffusion [93]. Invention refers to the initial development of a scientifically or technologically innovative process or product while innovation refers to the point when the new product or process reaches the market. Diffusion

is the final stage in this evolution, and is the focus of this section. It refers to the process of dissemination through which successful innovations come to be widely available through the adoption by individuals and/or firms (Schumpeter, 1942, quoted in [93]). While the three stages of invention, innovation and diffusion are described sequentially, in actual practice there is a cyclical relationship between them. In this regard the role of feedback arising from diffusion, including second- or third-generation invention and innovation is important [93].

An interesting aspect of diffusion of innovation is the fact that not all potential buyers make the decision to invest in a product or process at the same time. Adopters can be categorized into five types based on personality and behavior, values and attitudes [94–96]. They include “innovators” who constitute about 2.5% of adopters; “early adopters” who constitute about 12.5–13.5% of adopters; “early majority” who constitute about 34–35% of adopters; “later majority” who constitute 34–35%; followed finally by the “laggards” who make up the remaining 15–16% of adopters [94–96].

Rogers [94] also proposes general characteristics for each adopter category, based on socioeconomic, personality and communications behavior. For instance, the “innovators” and “early adopters” tend to display characteristics such as more years of education and greater knowledge of the technology. This view has been modified by the argument that adopters who are “innovators” for one product, could be “laggards” for another product. This point underscores the importance of compatibility of a product, for instance photovoltaics, with the lifestyles, attitudes and values of potential adopters.

A useful addition to the diffusion of innovations theory is the idea of a “chasm” between the “early adopters” and the “early majority”. The entry of the early majority in the market is critical to the commercial viability of a product or service. Unlike the “innovators” and “early adopters” this “early majority” is unlikely to take the long-term view and put up with inconveniences and product complexity. The incorporation of innovations, product enhancements and other “attractive” features, often based on feedback from early adopters is required to win this segment over [97].

Nature, markets and technologies experience growth patterns which are usually confined by some limits. These limits could be the size of the potential market, as in the case of technological innovations, or an ecosystem’s carrying capacity, as in the case of animal and plant populations. The graphical representation of this type of growth resembles an S-shaped curve [98]. The diffusion of innovations, i.e. growth in the market for innovations, such as photovoltaics, computers or cellular phones, has also been found to follow an S-shaped or logistic growth curve [99, 100].

Logistic growth models have proven to be accurate tools for forecasting a wide range of phenomena, from human population growth (used by the Belgian mathematician Pierre Verhulst in 1838) to oil development [101, 102]. Often, technologies (e.g. computers or cell phones) grow exponentially during an initial phase. However, as a device eventually reaches saturation in the potential market, the rate of growth is seen to slow down and finally taper off. This methodology is commonly used to anticipate the entry of new technology [98, 103, 104], including new energy technologies [105, 106] (Figure 2.13).

A logistic growth curve, according to Laherrère [102] and Meyer *et al.* [98], can be represented by the following equation:

$$Q_t = \frac{U}{1 + e^{-b*(t-t_m)}} \quad (2.1)$$

where Q_t is the forecast variable (e.g., percentage of electricity supply by PV in a given year), U is the saturation (maximum) level for Q_t (e.g. maximum percentage of electricity supply assumed to feasibly come from PV), b is the slope term, reflecting an initial growth rate, t is a time variable (in years), and t_m represents the midpoint of the logistic curve.

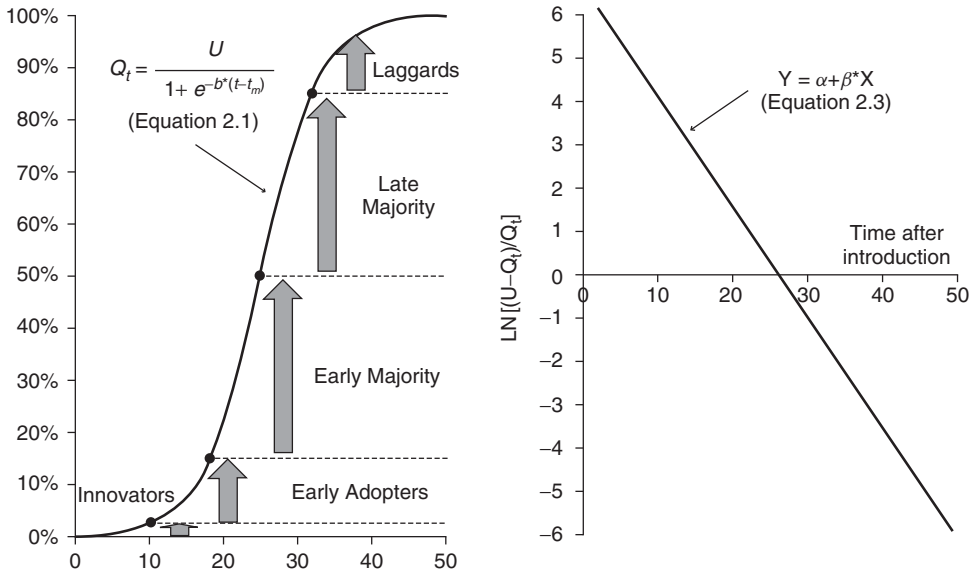


Figure 2.13 Representation of technology diffusion by an S-shaped curve and its linear form

Rearranging terms in Equation (2.1) and taking the logarithm of both sides gives:

$$\ln\left(\frac{U - Q_t}{Q_t}\right) = -b * t + b * t_m \quad (2.2)$$

Grouping variables, we then obtain:

$$Y = \ln\left(\frac{U - Q_t}{Q_t}\right)$$

This yields the familiar linear equation:

$$Y = \alpha + \beta * X \quad (2.3)$$

where $X = t$, parameter $\alpha = b * t_m$ and parameter $\beta = -b$.

Applying statistical regression methods to Equation (2.3), the parameters α and β can be robustly estimated.

Noting that $t_m = -\alpha/\beta$ and $b = -\beta$, Equation (2.1) can be presented as:

$$Q_t = \frac{U}{1 + e^{\beta\left(t + \frac{\alpha}{\beta}\right)}} \quad (2.4)$$

Equation (2.4) and the linear regression method used to estimate parameters in Equation (2.3) are consistent with the classic Fisher–Pry form of a logistic growth curve widely used to model technology diffusion [103]. In this way, a forecasting model can be built on available empirical experience to date for the technology of interest (PV, in this case). A key factor in the diffusion of new technology is cost-competitiveness with its alternatives. At the initial phase, technology diffusion can be supported through government programs and incentives. However, for wide-scale adoption the technology should have an advantage over other alternatives and at least be cost-competitive.

The link between technology diffusion and technology cost trends can be characterized through experience curves described in the next section.

2.4.2 Experience Curves

Experience curves, also referred to as learning curves, describe the link between long-term cost trends and adoption rates for new technologies. In 1936, Wright [107] was the first to provide a mathematical representation of the experience curve [108, 109]. Since then experience curves have become a helpful tool for analysts to assess trends in the cost-competitiveness of different technologies [110–115].

Experience curves are typically used for long-term strategic rather than short-term tactical analysis. But in the formulation of competitive strategies, experience curves can be powerful instruments to model market development of innovations [114]. According to Neij [110], experience curves offer a means of projecting future cost trends based on past cost developments.

Figure 2.14 provides a schematic representation of an experience or a learning curve for PV on double-logarithmic scales. On the horizontal axis is the cumulative installation of PV systems; on the vertical axis is system price per W_p .¹⁹ As cumulative installations of PV systems grow, so do the producers' and installers' experiences, leading to reductions in manufacturing and deployment costs. Mathematical representation of this relationship can be expressed as [112]:

$$C_t = C_o * \left(\frac{n_t}{n_o} \right)^\beta \quad (2.5)$$

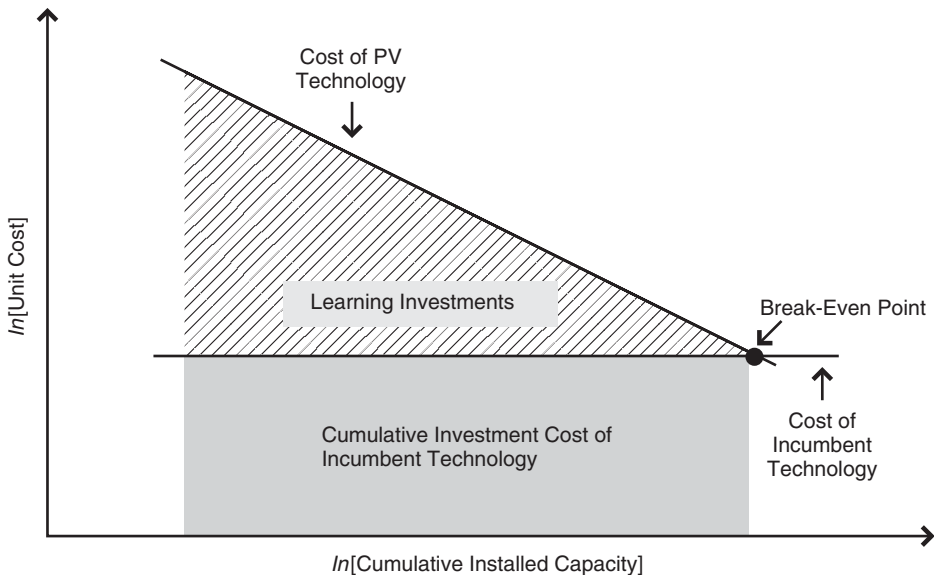


Figure 2.14 Schematic representation of learning curves and learning investments. Adapted from [116]

¹⁹ System price is the installed cost of a system including the PV device, balance of system (e.g. inverters, wiring, and panel array structure) and labor and other installation costs, as well as rates of return to the manufacturers and installers.

where C_t represents the expected cost at an n_t cumulative production level at some time in the future. C_o is the known cost of the product or installation at the initial phase of product deployment. Typically, C_o is calculated when cumulative production $n_o = 1$ (e.g. 1 MW_p or 1 GW_p). The exponent β is very important in characterizing the rate of price decrease as discussed below. In logarithmic form, Equation (2.5) can be written as:

$$\ln(C_t) = \ln(C_o) + \beta * \ln(n_t) \tag{2.6}$$

This yields the familiar linear equation:

$$Y = \alpha + \beta * X \tag{2.7}$$

where $X = \ln(n_t)$ and parameter $\alpha = \ln(C_o)$.

If data points for the experience curve are known, the parameters for the underling Equation (2.7) can be obtained through linear regression analysis. Equation (2.6) shows that, in logarithmic form, the change in the cost per unit is directly proportional to change in cumulative output.

There are two important metrics devised to parameterize the information contained in an experience curve and to apply it for analysis: the progress ratio (PR) and the learning rate (LR).

Comparison of different experience curves can be made by determining the change in price, when cumulative production volume doubles. The corresponding change in price gives the progress ratio. Thus, if the cost per unit reduces to 0.80 of the original price by doubling the cumulative output, then the progress ratio of such a technology is 80%. The learning rate for a particular technology is derived from the progress ratio by subtracting it from 100%. Thus, if the progress ratio is 80%, the corresponding learning rate for the technology is 20%. Progress ratios and learning rates can be obtained through the following equations:

$$PR = 2^\beta \tag{2.8}$$

$$LR = 1 - PR \tag{2.9}$$

where β is the slope parameter that can be obtained through the regression (Equations 2.6 and 2.7).

It is important to provide policy support until a technology becomes cost-competitive with alternative sources. The point at which technology becomes cost-competitive is referred to as the break-even point (Figure 2.14). Experience curve analysis can show the level of investments required to make a technology market competitive. However, experience curves do not forecast when, in time, this break-even point would be reached. Even so, experience curves can be an effective tool for energy policy makers to set targets and implement measures to enable new technologies to become economically viable.

The level of required investments needed to reach a break-even price can be calculated by integration under the learning curve (Figure 2.14). Learning investments (LI) can be calculated as follows (adapted from Zwaan and Rabl [112]):

$$LI = \int_{n_c}^{n_b} (C_c - C_b) * dn = \frac{C_c}{\beta + 1} * \frac{n_b^{\beta+1} - n_c^{\beta+1}}{n_c^\beta} - (n_b - n_c) * C_b \tag{2.10}$$

where β is a slope parameter derived from equation (2.7), C_c is the technology's current cost, C_b is its cost at a break-even point, n_c is the current cumulative production level, and n_b is the cumulative production at a break-even point, which can be derived from the following equation:

$$n_b = n_c * \left(\frac{C_b}{C_c}\right)^{1/\beta} \tag{2.11}$$

Recently, several researchers have proposed to extend the simple formulation of learning curves (described above), also referred to as a single-factor learning curve, to two-factor learning curves (2FLC) [117–120]. The 2FLC model provides the added ability to measure the impact of research and development (R&D) activities on technology cost reduction. The two-factor learning curve can be expressed as:

$$\ln(C_t) = \ln(C_o) + \beta * \ln(n_t) + \gamma * \ln(K_t) \quad (2.12)$$

where K_t represents the stock of knowledge in time period t acquired due to past investments. The knowledge stock is defined as a function of past R&D investments that includes depreciation and time lag factors. The knowledge stock can be expressed as [118, 119]:

$$K_t = K_{t-1} * (1 - \rho) + ARD_{t-l} \quad (2.13)$$

where ρ is the annual knowledge stock depreciation rate, ARD is the annual expenditure in R&D, and l is the time lag between R&D investment and its effect. For PV technology, a typical value used for the annual knowledge stock depreciation rate ρ is 3%, and for the R&D time lag l , researchers use two to three years [118, 121, 122].

The 2FLC results in two learning rates. The first is the learning-by-doing rate (LDR), representing experience gained through increasing scale of production and deployment and its impact on cost (analogous to an LR for single-factor learning curves). The second is the learning-by-searching rate (LSR), representing the impact of increased knowledge, obtained through R&D, on system cost. LDR and LSR can be represented as follows:

$$LDR = 1 - 2^\beta \quad (2.14)$$

$$LSR = 1 - 2^\gamma \quad (2.15)$$

where β is the learning-by-doing index and γ and is the learning-by-searching index.

The major problem with the 2FLC model is that its independent variables are highly correlated (i.e. high multicollinearity between cumulative installations and R&D knowledge stock). A common solution is to use a predefined value for the knowledge stock index (i.e. γ) and estimate the learning-by-doing index (i.e. β) by regression analysis. In our modeling, a value of $\gamma = 0.154$ is assumed (based on [118, 120]). Our findings using a 2FLC model are reported below.

2.4.3 PV Diffusion in the US under Different Policy Scenarios

As discussed earlier, the US PV Market in recent years has experienced very rapid growth. PV cumulative installations have increased from 43.5 MW_p in 1992 to 1168 MW_p by the end of 2008. However, even with such rapid growth, PV's share in the US electricity supply in 2008 was only 0.04% [12, 123]. Nevertheless, if the current trend continues, the share of PV will likewise increase. Below, we model this process and estimate the rising share of US electricity supply from solar electric power under three policy scenarios: (1) a national carbon tax cap-and-trade policy; (2) a national renewable portfolio standard; and (3) an expanded national commitment to R&D to promote higher-efficiency, lower-cost PV modules.

2.4.3.1 Building a business-as-usual benchmark for US PV market development

For our diffusion analysis, under different policy scenarios, we have assumed 25% as a reasonable target for the maximum share of grid electricity supply provided by PV in the next few decades

(see, e.g. [124]). A standard diffusion model based on values obtained from Equation (2.2) above (i.e. values of

$$\left[\ln \left(\frac{U - Q_t}{Q_t} \right) \right]$$

plotted against a time variable) is used, which adopts empirical estimates from regression analysis of diffusion rates for the period 1990–2008 (Figure 2.15). From the figure, it is evident that the regression trend line has changed with PV diffusion accelerating after 2000. The β value (i.e. diffusion rate) for the initial period of 1992–2000 is -0.1172 , but it more than doubles (-0.2543) for the later period of 2001–2008.

Between 2000 and 2008, PV’s share of US electricity supply increased by approximately 30% per year. Based on this historical trend, we built a diffusion model to estimate future PV supply, when saturation is assumed to occur at 25% of total electricity generation.²⁰ Additionally, it was assumed that electricity generation in the US will increase by 1% per year. This assumption mirrors that of the US EIA for the period between 2010 and 2030 [8], and our analysis extended this assumption after 2030 until 25% saturation is reached under each policy scenario, when necessary.

Utilizing EIA projected total electricity supply for 2010–2030 and assuming a 1% growth rate thereafter, estimates of total and PV-sourced electricity generation were obtained (Figure 2.16 and Table 2.4). The projected path of PV supply in Figure 2.16 is treated as the business-as-usual scenario (BAU). The BAU projects PV capacity to increase from 1.8 GW_p in 2010 to 1076 GW_p in 2055; correspondingly PV’s share of US electricity supply grows from 0.07% to 25% during the same period.

The BAU projections derived from our analysis are well within reach, particularly when we compare them with targets established by current state level RPS policies for PV and customer-sited

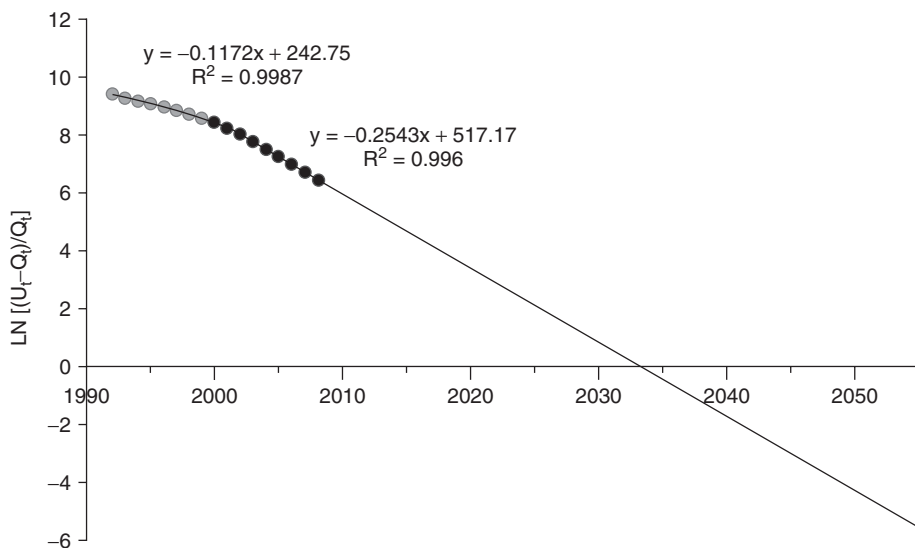


Figure 2.15 Regression analysis using a logistic growth model for US PV installation. Data sources: [12, 123]

²⁰ This saturation rate is based on research suggesting that the integration of intermittent resource into grid supply has a technical limit roughly at this rate (e.g. [124])

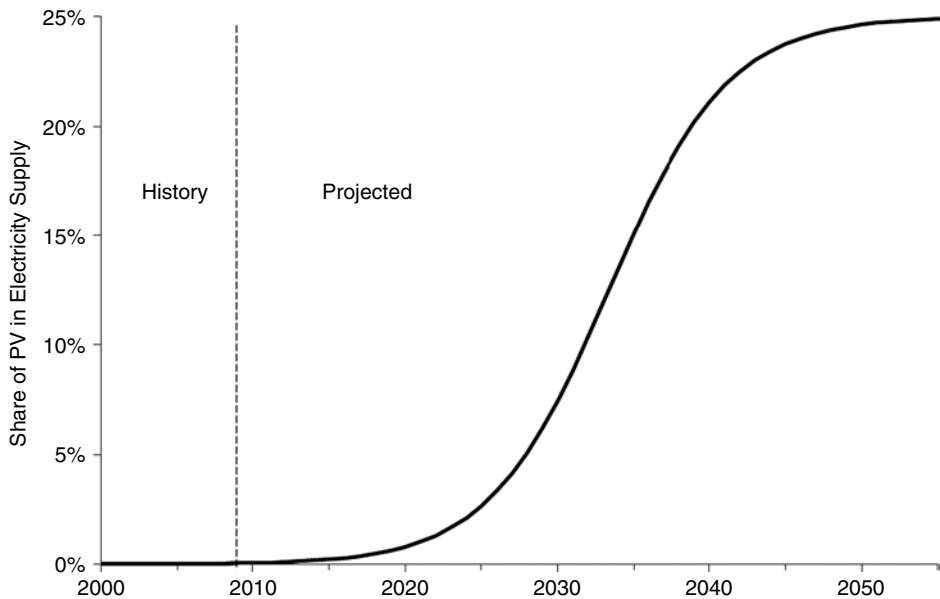


Figure 2.16 PV diffusion in the US under a business-as-usual scenario. This projection is based on the regression analysis shown in Figure 2.15, which assumes $U = 25\%$, and gives regression parameters of $\beta = -0.2543$, and $t_m = 2034$

Table 2.4 BAU projected PV generation and installed capacity

	US electricity generation* (billion kWh)	PV's share of US electricity supply (%)	PV generation (billion kWh)	PV capacity GW_p^{**}
2010	4162	0.07	2.72	1.8
2015	4339	0.23	10.07	6.7
2020	4573	0.81	37.02	24.7
2025	4840	2.67	129.16	86.1
2030	5055	7.48	377.90	251.9
2035	5312	15.09	801.79	534.5
2040	5583	21.12	1179.09	786.1
2045	5868	23.78	1395.21	930.1
2050	6166	24.64	1519.96	1 013.3
2055	6482	24.90	1614.01	1 076.0

*2010–2030 numbers are from [8]; for 2030–2055, 1% of annual growth is assumed.

**Assumes annual energy production of 1500 kWh per kW_p for PV.

distributed energy sources. As noted earlier, 14 states and the District of Columbia (Washington, DC) have specific solar or distributed generation carve-outs in their RPS requirements. California, Oregon and Texas have specific targets for distributed generation or PV [25]. Applying current PV/DG RPS requirements to these states' electricity consumption (based on 1% annual increases in electricity demand), and using state-specific solar radiation, we determined the PV installation capacity needed to meet the RPS carve-outs (Table 2.5). Results show that states with PV/DG RPS will, in total, require 3.5 GW_p in 2015 and 11.8 GW_p in 2020 to meet their legislated targets. These

Table 2.5 State PV and distributed generation carve-out

	Solar carve-out				Projected installations (MW)			
	2010	2015	2020	2025	2010	2015	2020	2025**
AZ*	0.50%	1.50%	3.00%	4.50%	143	452	951	1499
CA							3500	3500
CO	0.20%	0.60%	0.80%	0.80%	70	219	308	323
DC	0.00%	0.20%	0.40%	0.40%	3	16	40	42
DE	0.00%	0.60%	2.00%	2.00%	2	54	204	214
IL	0.00%	0.60%	1.10%	1.50%	0	716	1317	1978
MD	0.00%	0.30%	1.50%	2.00%	11	115	724	1014
MO	0.00%	0.10%	0.20%	0.30%	0	66	138	218
NC	0.00%	0.10%	0.20%	0.20%	23	168	254	265
NH	0.00%	0.30%	0.30%	0.30%	4	30	32	34
NJ ⁺	0.22%	965 GW h	2164 GW h	4610 GW h	137	742	1664	3545
NM	0.20%	0.60%	4.00%	4.00%	27	87	607	638
NV	0.60%	1.20%	1.30%	1.50%	131	276	319	381
NY*	0.10%	0.10%	0.10%	0.10%	108	176	185	195
OH	0.00%	0.20%	0.30%	0.50%	12	187	445	688
OR							20	20
PA	0.00%	0.10%	0.40%	0.50%	15	188	610	723
TX*							500	500
Total					686	3492	11 818	15 777

*Distributed generation (DG).

**Most of the RPS carve-outs have targets which must be reached by 2020.

⁺In January 2010, New Jersey changed its percentage-based solar target to a GW h target.

Data sources: [8, 25].

The analysis, based on EIA's most recent electricity forecast (8), assumes electricity consumption will grow 1% annually. The PV capacity required to meet solar or DG carve-outs is calculated using average daily solar radiation data from NREL [125], and a PV system performance ratio of 75%.

are nearly half (48–52%) of what is projected under our BAU scenario (i.e. 6.7 GW_p in 2015 and 24.7 GW_p in 2020). The selected 17 states (Table 2.5) and Washington DC represent one-half of US electricity demand (49%). Thus, if the remaining states follow similar policy initiatives and/or if the pioneering 18 US jurisdictions upgrade their targets while the bulk of the states without RPS rules adopt a policy strategy that approximates the goals of the early adopters, the BAU targets in Table 2.4 will be readily achievable. Moreover, in the BAU scenario, the projected PV share is 0.8% of total US electricity supply by 2020, which is not overly aggressive if we consider the current installed capacity of PV in other OECD countries.²¹ Germany and Spain, for example, already reached this level of PV adoption in 2008 [12].

A key factor in the rate of PV deployment is the cost of PV electricity relative to other generating fuels and technologies. Historically, the levelized cost of electricity (LCOE) of conventional electricity supply sources has been significantly lower than PV, even after accounting for transmission and distribution costs.²² For substantial penetration of grid-connected PV, the LCOE

²¹ The BAU scenario presented here, assumes maximum level of PV share electricity supply at 25%. This level is projected to be reached in 2055.

²² LCOE provides the means for economic evaluation and comparison of different electricity generation technologies. LCOE accounts for all costs over a technology's lifetime, including initial investment, operations and maintenance, cost of fuel, and cost of capital.

for PV production needs to decrease and/or non-PV LCOEs must increase. LCOE can be calculated as follows [112, 126, 127]:

$$LCOE = IC * \left(r_{O\&M} + \frac{r_{int}}{1 - (1 + r_{int})^{-n}} \right) \quad (2.16)$$

In this equation IC is initial capital cost including installation, $r_{O\&M}$ is the annual operation and maintenance cost (O&M) as a percentage of IC , r_{int} is the real interest rate, and n is the economic system lifetime in years. In this formulation, fuel costs appear in $r_{O\&M}$.

In 2009, the capacity-weighted average installed system cost of a PV system was \$6.80 per W_p [30]. According to a Deutsche Bank report, in the US, the financing rate associated with project development ranged between 6 and 8% [19]. For the annual inflation rate for 2010–2030, we utilized the EIA reference case [8], which assumes 2% per year for this timeframe, resulting in a real interest rate for PV of 5%.²³ Using a typical PV generation of 1500 kWh per kW_p for the US, with a project lifetime of 25 years, an installed cost of \$6.80 per W_p , annual O&M costs at 1% of initial installed cost, and a 30% federal tax credit, we estimated the LCOE for PV at 25.7 cents per kWh.²⁴ At the same time, the recent average weighted retail electricity price for commercial and residential customers in the US is 10.6 cents per kWh [123]. EIA projects no significant real price (adjusted for inflation) increases in their projections of US electricity retail prices [8]. Using this very conservative assumption, a \$2 per W_p PV system cost is required to be competitive with conventional grid-supplied electricity in the residential and commercial sectors. This \$2 per W_p system cost represents the PV break-even price.

The experience curve, as discussed above, offers a useful method for assessing cost-cutting knowledge gained through increasing scale of PV production and deployment. The cost reductions associated with this experience is expressed by a learning rate. Based on data obtained from NREL on the annual average installed system cost for 1998–2005 and cumulative installed capacity [30], an experience curve for the US PV system cost is derived. In the analysis, recent years affected by polysilicon shortages are excluded.²⁵ The resulting curve presented in double-logarithmic form is shown in Figure 2.17.

The slope parameter (β in Equations 2.5–2.8) for the experience curve displayed in Figure 2.17 has the value -0.214 . Using Equations (2.8) and (2.9), the US PV system cost trend exhibits an 86.2% progress ratio and a 13.8% learning rate. Based on this learning rate, a break-even price of \$2 per W_p system cost will be reached when cumulative installations equal 280 GW_p . Under the BAU scenario, this level of PV installation in the US would be met by 2031.²⁶ As shown in Figure 2.17, before PV installations reach a break-even level, the cost differential between system cost and break-even price needs to be subsidized. The total subsidy required to reach the break-even point is illustrated as the shaded area, labeled learning investments.²⁷ Government

²³ 5% was obtained using 7% as a midpoint of Deutsche Bank's financing values, adjusted for 2% inflation (i.e. $[1.07/1.02 - 1] \approx 0.05$).

²⁴ This rate does not include other federal (e.g. MACRS) and local incentives. If MACRS depreciation rules are included, PV's LCOE in the BAU case falls to 14.5 cents per kWh. Inclusion of tax benefits is justified on the ground that all power plants and non-renewable fuels in the US have been subsidized by tax and other policy treatments. It should be noted that, typically, LCOEs for fossil fuel power plant include the MACRS tax benefit.

²⁵ During 2006–2008, silicon PV module prices actually increased the first time in 30 years. Then in 2009, they fell rapidly as new production capacity made it to market. For a discussion of this situation see Chapter 1, Section 1.2.3 in this *Handbook*.

²⁶ As Figure 2.16 reports, once a break-even price is reached in 2031, PV market share will grow and realize the target of 25% of total US electricity assumption in just 24 years (i.e. the rapid-growth interval of 2031–2055 in Figure 2.16).

²⁷ These investments are of the learning-by-doing variety.

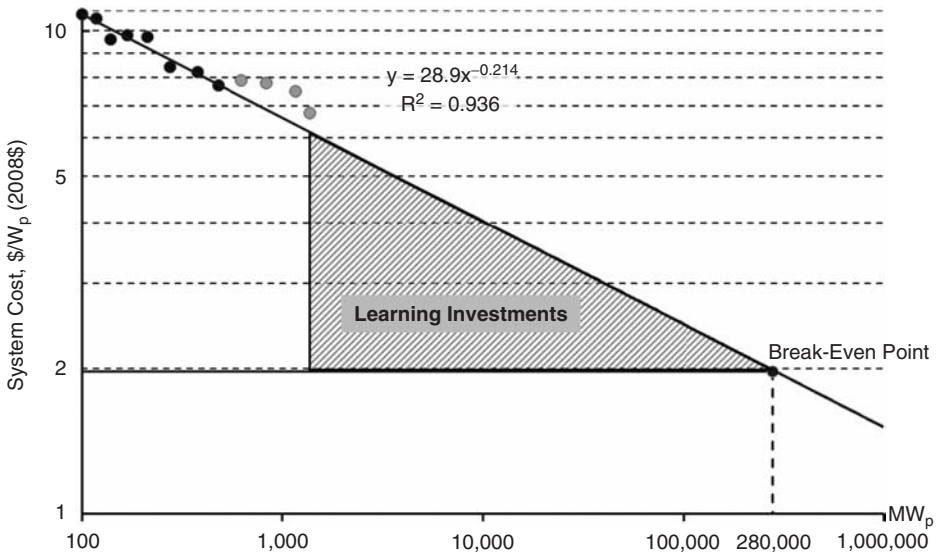


Figure 2.17 US PV system cost experience curve. Data sources: [30, 12]. The curve was derived based on system cost data for 1998–2005 and cumulative installations in the US Data from recent years affected by polysilicon shortages were excluded

programs and incentives can increase the rate of PV production and deployment, driving PV system costs down the experience curve. The level of subsidy required each year to meet targets outlined under the BAU diffusion path in Figure 2.16 are calculated based on Equation (2.10).

The results of this calculation are displayed in Figure 2.18, and show that the level of subsidies to meet BAU annual installation targets need to increase between 2010 and 2025,

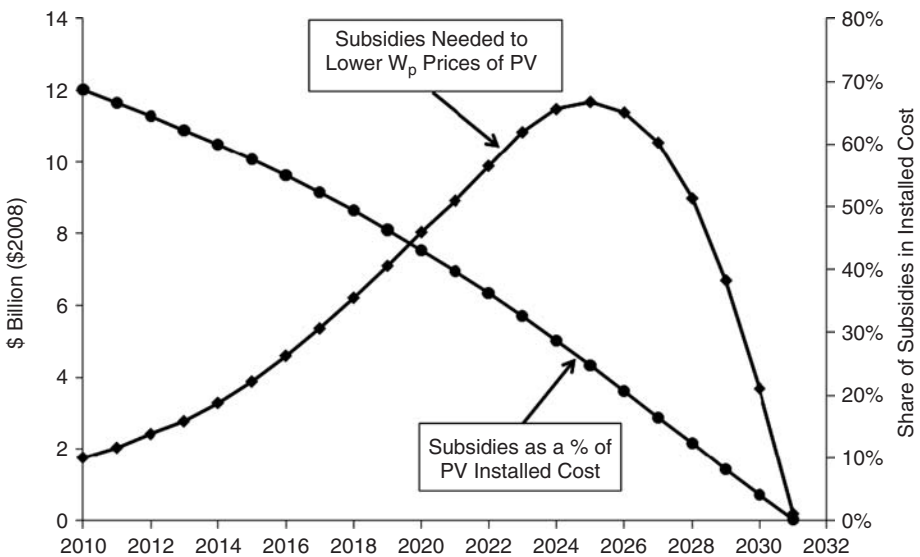


Figure 2.18 PV system cost subsidies required to follow BAU diffusion scenario

Table 2.6 Learning parameter estimates

	Index	Progress ratio (%)	Learning rate (%)
Learning-by-doing, estimated	-0.2028	86.9	13.1
Learning-by-searching, fixed	-0.1520	90.0	10.0

Annual R&D expenditure data for 1991–2009, used for these estimates was provided by Robert Margolis (NREL). Additional data for 1975–1990 was obtained from IEA Database [92]. The fixed learning-by-searching rate is taken from research Miketa and Schratzenholzer [118] and Kouvaritakis *et al.* [120].

with a subsequent decline thereafter. The share of subsidy in total PV investments gradually decreases from approximately 70% of total installed cost in 2010, until it reaches zero by 2031. This translates into a total learning investment of \$142 billion (in 2008 dollars). However, this number does not account for cost reductions associated with research and development (R&D) expenditures. This is discussed below.

To estimate the impact of R&D, a two-factor learning curve (2FLC) is developed. Following the methodology described in the previous section (see Equations 2.12–2.15), parameters for the 2FLC model were obtained. The results are presented in Table 2.6. The estimated “learning-by-doing” parameters reflect cost reductions due to manufacturing and other experience gained through PV system deployment. “Learning-by-searching” indicators represent cost reductions associated with R&D expenditures. After factoring in the impact of R&D, the learning rate attributed to experience gained through PV system deployment and associated cost reductions is reduced from 13.8 to 13.1%.

In order to assess the level of annual R&D investments required to continue the same trend of cost reduction in Figure 2.17, the single-factor and two-factor learning curves must be harmonized so that system costs in Equations (2.6) and (2.12) are equal for the same cumulative installation level n_t . Our method to achieve this is now presented. Equations (2.17) and (2.18) modify the original forms in order to reflect different intercept and slope parameters for learning-by-doing and learning-by-searching.

$$\ln(C_t) = \ln(C_{o1}) + \beta_1 * \ln(n_t) \quad (2.17)$$

$$\ln(C_t) = \ln(C_{o2}) + \beta_2 * \ln(n_t) + \gamma * \ln(K_t) \quad (2.18)$$

After combining these equations and rearranging terms, the stock of knowledge variable K_t introduced in Equation (2.12) can be derived as:

$$K_t = n_t^{(\beta_1 - \beta_2)/\gamma} * \exp\left(\frac{\ln(C_{o1}) - \ln(C_{o2})}{\gamma}\right) \quad (2.19)$$

After combining Equations (2.13) and (2.19), required annual R&D expenditures can be determined. An average of \$122 million per year in R&D is needed to meet targets outlined under the BAU diffusion path. Thus, between 2010 and 2031, in addition to \$142 billion required as learning investments, an estimated \$2.7 billion in R&D is projected to be needed to reach the break-even point.

2.4.3.2 US PV policy scenarios

In addition to tax subsidies and R&D programs that have traditionally supported PV deployment, a new array of policy mechanisms in support of a US transition to a “green energy” economy are

being discussed. This section evaluates three policy tools to ascertain their likely impact on the diffusion of PV into the national electricity market.

2.4.3.2.1 Pricing carbon

The first policy tool we examine is a carbon tax or carbon cap-and-trade strategy.²⁸ Due to the dominance of fossil fuels in electricity generation, the introduction of a carbon pricing scheme will increase the cost of grid supplied electricity. This in itself will raise the necessary break-even price for PV, at which the technology is cost-competitive with grid-supplied electricity. An effective carbon tax at \$25 per ton of CO₂ will increase the break-even system cost by \$0.32/W_p and a carbon tax at \$50 per ton of CO₂ will increase the break-even system cost by \$0.64/W_p (see Figure 2.19).²⁹

A carbon price of \$25 per ton is at the high end of the trading value in the EU [128]. The US is struggling to pass cap-and-trade legislature that would likely result in carbon prices less than \$25 per ton [129]. An additional scenario using a high price of \$50 per ton is included to capture what currently appears to be the outer reach of political possibility with regard to this tool.

Increasing the break-even cost will reduce the amount of cumulative PV system installations required to reach the break-even point. For the case of a \$25 per ton cost of CO₂ emissions, a break-even point will be reached at 139 GW_p, and for a \$50 per ton cost of CO₂ emissions a break-even point at 76 GW_p is needed (Figure 2.19).

The amount of required learning investments will be reduced from \$142.2 billion to \$47.0 billion under a \$50 per ton of CO₂ cost scenario and to \$79.5 billion under a \$25 per ton of CO₂

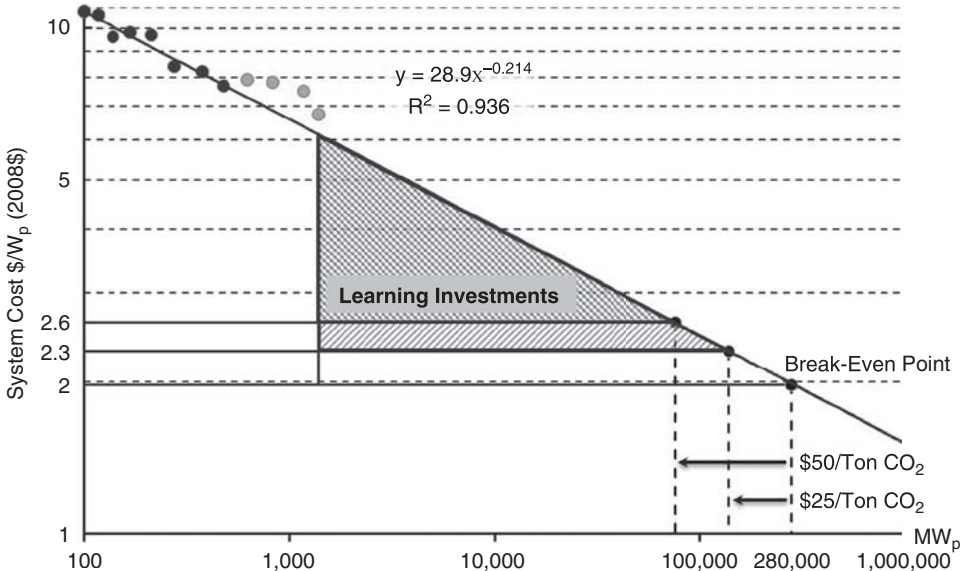


Figure 2.19 Impact of a carbon pricing policy on the break-even point for PV

²⁸ Although important differences exist between a carbon tax and a cap-and-trade strategy in terms of implementation, we focus here only on the effect on retail electricity prices. For this reason, we do not distinguish between the two in our analysis.

²⁹ For Figure 2.19, we assumed 0.6 tons of CO₂ is emitted per MW h of electricity generation, PV generation at 1,500 kW h per installed kW_p, and 25 year product life. A real 5% discount rate was assumed.

cost scenario. In this respect, if carbon taxes or cap-and-trade allowances collected from fossil fuel generators are directed to provide additional support for non-fossil fuel generation technologies, then PV deployment projects will not only gain from a higher break-even price, but would also benefit from increased public investment. For example, if PV generators, before reaching the break-even point, are paid \$50 or \$25 per ton for avoided CO₂ emissions, then additional monetary benefits to PV project development can be quantified at \$48 billion or \$44 billion, respectively.³⁰

We can now estimate the impact of the two carbon pricing scenarios on PV diffusion. For a carbon price of \$25/ton, and including the price effect on conventional grid power and the effect of using the proceeds of carbon pricing to incentivize PV use, we project grid parity to occur in 2024 and 25% saturation to be reached in 2050. For \$50/ton, we project PV to reach grid parity in 2020 and to realize 25% saturation in 2045.

2.4.3.2.2 *The impact of PV R&D*

We now turn our attention to the impact of R&D policy on PV diffusion. What would be the likely impact of increasing public investment in R&D? To answer this question we analyzed the R&D scenario under which R&D investments are committed at the same level as learning-by-doing investments (i.e., rebates, tax credits and other project level incentives), shown in Figure 2.18. Increased investment in R&D facilitates faster decline of PV system costs. We modeled the following scenario: conventional policy incentives for PV development were decreased by approximately \$25 billion over 8-year period; instead \$25 billion was dedicated to public R&D; this increased R&D during 8-year period by roughly factor of ten – that is from \$2.7 billion to \$27.9 billion. As is demonstrated in Figure 2.20, increase of R&D spending tenfold raises the slope on the US

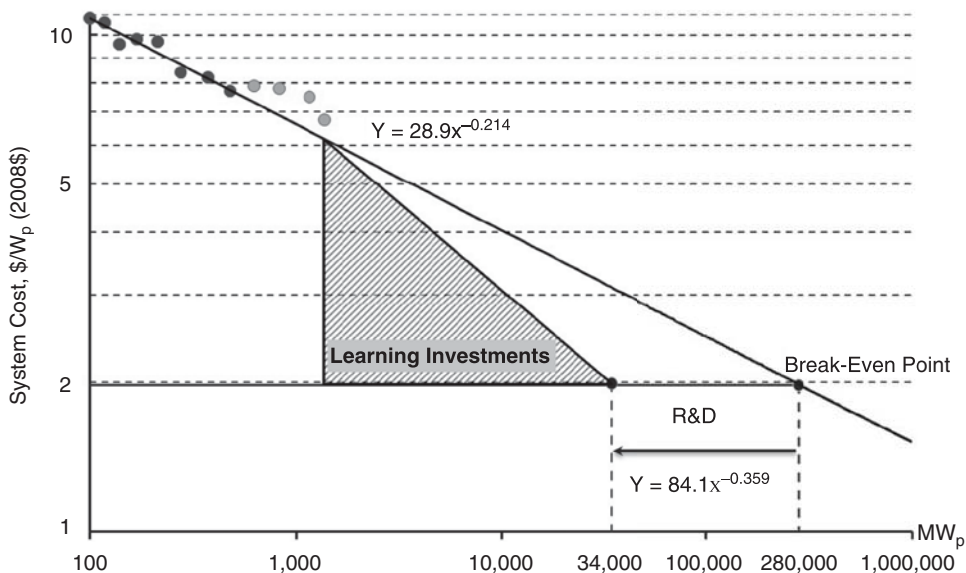


Figure 2.20 Impact of increased R&D expenditures on the break-even point for PV

³⁰ These numbers are based on the assumptions in footnote 29, and using the products of previously obtained numbers for carbon tax impact on break-even price and amount of additional cumulative PV installations required to reach a break-even point (i.e., $\$0.64/W_p * [76 - 1.3]$, and $\$0.32/W_p * [139 - 1.3]$).

Table 2.7 Effect of R&D on total investments for reaching a PV break-even point, \$2 per W_p

	BAU scenario	Increased R&D scenario
R&D Investments (billion \$)	2.7	27.3
Learning-by-doing Investments (billion \$)*	142.2	27.3
Combined Investments (billion \$)	144.9	54.6

*Learning-by-doing investments equal the total policy incentives (rebates, tax credits, etc. see Figure 2.18)

experience curve from -0.214 to -0.359 , thus, increasing the learning rate from 14 to 22% (see Equations 2.8 and 2.9).

Based on the results obtained, which are shown in Figure 20 and Table 2.7, it can be seen that Increases in R&D expenditures can significantly reduce the amount of combined (learning and R&D) investments needed to reach a break-even point.

Using these learning rates, we calculated that tenfold increase of US public R&D for PV would accelerate the year when grid parity would be reached to 2018 (from the BAU of 2031). It would also shorten the time to 25% saturation from a BAU of year 2055 to 2040.

2.4.3.2.3 Effect of a solar carve-out policy

Another policy option for rapid deployment of PV is the promotion of a solar carve-out under a national RPS, similar to those implemented in a number of US states (see Table 2.5). Under a Solar RPS requirement, energy suppliers need to create SRECs through their own power generation, or purchase them from third-party solar power providers. A well-structured RPS with sufficiently high noncompliance fees and a legal requirement for utilities to purchase SRECs through multi-year contract can result in rapid PV deployment similar to the German experience with feed-in tariffs. An RPS with a solar carve-out could create significant demand for Solar Renewable Energy Certificates (SRECs). By 2010, in states with established SREC markets, SRECs ranged from \$200 to \$700 per MW h [51]. For a national solar market, more conservative prices for SRECs were considered: SRECs are initially traded at \$200 per MW h (20 cents/kWh) in 2010 and gradually decrease to \$100 per MWh (10 cents/kWh) by 2020.

This scenario relies on an SREC pricing schedule that is below those in play in 14 pioneer states. Indeed, recent policy reforms in Delaware, Pennsylvania, Massachusetts, New Jersey and other states have led to SREC trading above \$200 per MW h [51]. In this sense, the carve-out scenario analyzed in Figure 2.21 is quite conservative. Under this scenario, the break-even point will be achieved at 66 GW_p of cumulative installations, and additional learning investments required to reach grid parity is \$30.5 billion (Figure 2.21).³¹

Under this conservative SREC pricing scenario, we project PV to reach grid parity by 2018 and to achieve a 25% market saturation by the year 2035.

2.4.3.3 Comparing policy impacts

Table 2.8 summarizes results of the policy scenarios discussed in this section. Under the BAU scenario, grid parity is reached in 2031 and it would require up to \$145 billion in cumulative combined learning investments (i.e. R&D and learning-by-doing). Of this amount, \$142.2 billion

³¹ As with the carbon pricing and R&D scenarios, required learning investments needed to reach grid parity are assumed to be financed by rebates, incentives and other public and utility policy tools.

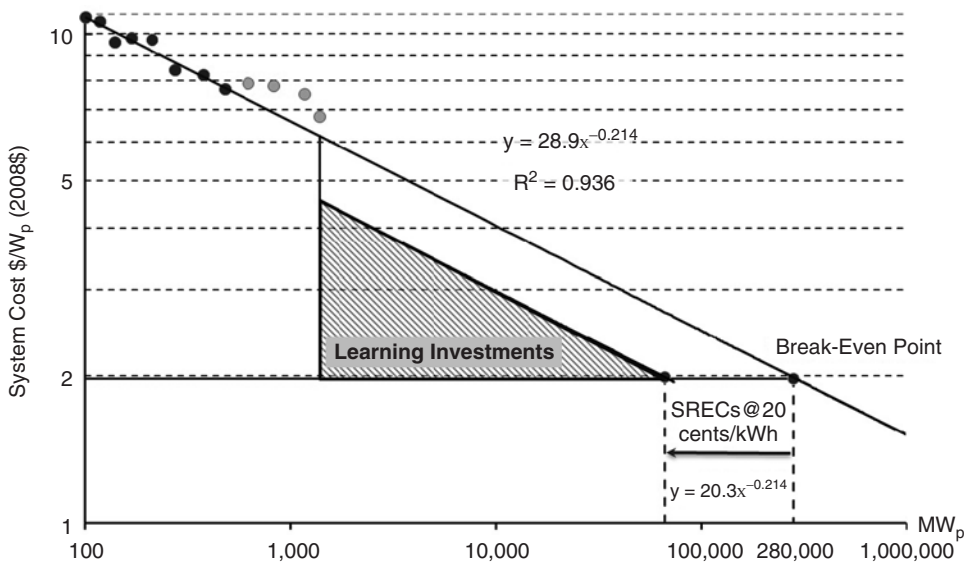


Figure 2.21 Impact of a national SREC requirement on the break-even point for PV

Table 2.8 Total investments required for reaching a PV break-even point, \$2 per W_p under different policy scenarios

	BAU scenario	CO ₂ Price of \$25 per ton scenario	CO ₂ Price of \$50 per ton scenario	Increased R&D scenario	SRECs at 20 cents/kW h scenario
R&D Investments (billion \$)	2.7	2.7	2.7	27.3	2.7
Learning-by-doing Investments (billion \$)	142.2	79.5	47.0	27.3	30.5
Combined Investments (billion \$)	144.9	81.2	49.7	54.6	33.2
Time to grid parity	2031	2024	2020	2018	2018

All scenarios assume learning-by-doing investments will be maintained at the schedule outlined in Figure 2.18 until break-even point is reached.

is policy incentives would be needed to reach grid parity in 2031. The introduction of carbon pricing (either through taxation or a cap-and-trade carbon market) would help non-carbon-based technologies, such as PV to compete with conventional fossil-based power generation technologies (natural gas turbines, coal plants, etc.) and would reduce the required learning-by-doing investments needed to reach grid parity. At a higher price per ton of CO₂ released, the cumulative volume of learning-by-doing investments needed to reach the break-even point on the learning curve would be lower (see Figure 2.19). Learning investments are reduced from \$142.2 billion to \$47.0 billion under a \$50 per ton of CO₂ emissions scenario and to \$79.5 billion under a \$25 per ton of CO₂ emissions scenario. Tenfold increase of public R&D would reduce the amount of learning-by-doing investments required to reach grid parity by \$115 billion to \$27.3 billion (the scenario assumes that same amount of cumulative investments are made in R&D). This dramatic reduction is mostly due to

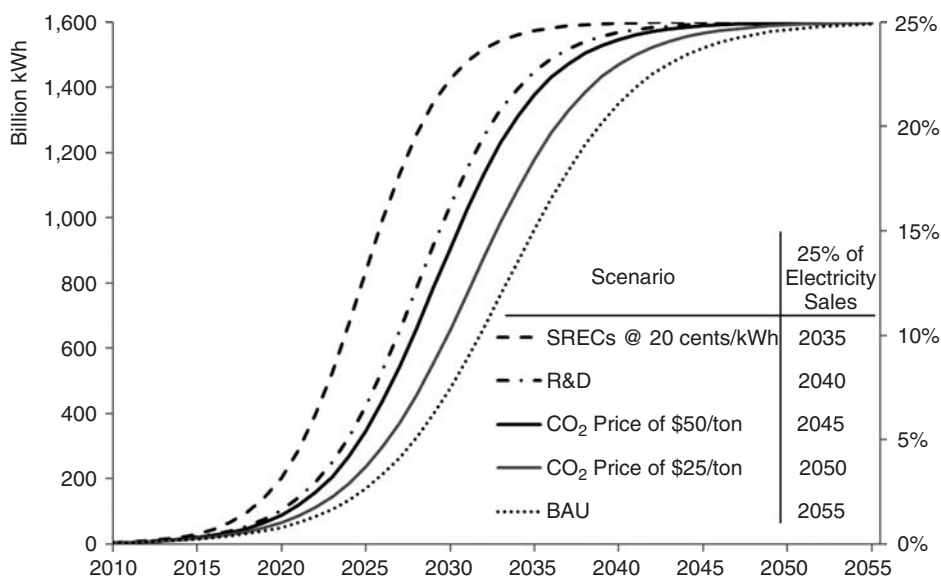


Figure 2.22 PV diffusion under different policy options in the US

the much earlier realization of grid parity, namely, 2018 for the R&D strategy compared with 2031 for the BAU strategy. Finally, the introduction of a national SREC market can reduce cumulative learning-by-doing investments to \$30.5 billion and shorten the time to grid parity by 13 years (i.e. the BAU case of 2031 to the SREC case of 2018). Again, the savings from this scenario are very large – nearly \$110 billion – and are attributable to the faster realization of the grid parity.

Diffusion curves under each of the policy scenarios investigated in this chapter were also constructed. The diffusion scenarios are benchmarked against the BAU scenario (see Figure 2.16). Based on this assumption, corresponding diffusion curves are constructed for each policy scenario. The results are presented in Figure 2.22, and show that a national RPS facilitates the fastest deployment of PV. A solar carve-out with SREC prices initially at 20 cents per kWh will shave nearly 20 years off the BAU time horizon of PV reaching 25% of the US electricity market share. That is, our BAU projection finds that 25% saturation will not occur until the year 2055, but a national SREC policy would hasten the achievement of that goal to 2035.

Increasing R&D funding for PV will also expedite the diffusion process. An expanded R&D policy can reduce the time needed to reach the 25% goal by almost 15 years. It may also rightly claim the benefit of strengthening the knowledge infrastructure to promote a green energy economy and, more broadly, a low-carbon future for the planet.

Finally, carbon taxes or cap-and-trade allowances have a noticeable impact, on PV diffusion, lessening the time for PV to reach the 25% goal by 5–10 years (compared with the BAU case). With regard to the effects of carbon pricing, three observations are in order. First, by comparison, the price of carbon modeled here is less than the SREC price options on a per kWh basis.³² Thus, it is understandable why its impact is weaker. Of course, it is also important to observe that US jurisdictions have been able to enact laws leading to substantially higher SREC prices than the scenarios we have modeled. By contrast, no country or region has been able to sustain carbon

³² A \$25 per ton price of carbon emissions would increase the average retail electricity price in the US by about 1.5 cents per kWh, while a \$50 per ton price would raise electricity prices by 3.0 cents per kWh.

pricing at or above \$25 per ton. This leads to the third observation. Carbon pricing is perhaps the most complex and difficult policy approach to legislate because its effects are wide-ranging and will adversely affect the economics of some of the most powerful industries and companies in the world. Evaluated in this light, PV R&D and SREC have a contained policy reach and do not directly require raising the costs of fossil fuel competitors. Equally true, these tools only modestly affect the cost–benefit matrix that underlies the US and world economies. In this sense, their impacts can be strategically large, but cannot substitute for the systematic effect of a carbon pricing policy, even when its effective pricing of the pollutant is modest.

2.5 TOWARD A SUSTAINABLE FUTURE

In one of the boldest maps in print for our future, Herman Scheer's *The Solar Economy* [4] plots a worldwide shift from a non-renewable and unsustainable energy system to a renewable and, hopefully, sustainable future. Some may agree and others will disagree with assumptions behind the map or calculations he presents in support of its path. But one aspect of the map is indisputable: achieving a sustainable future requires solar energy to be at the center of the new economy.

Realizing this fact will not be easy, and almost certainly the world will disappoint Scheer with the slow pace and lack of vigor in its pursuit of a solar economy. Just because there is no other safe harbor for our future does not mean that humanity will avoid getting lost in its journey. That said, there are reasons and evidence for hope. In the last 15 years, policies have sprouted across the planet that have led to truly remarkable progress. Compared with where we were, a steady stream of policy incentives put into action – feed-in tariffs, solar carve-outs, renewable portfolio standards, community solar financing, and sustainable energy utilities – demonstrate a capacity for change that few would have predicted. In this regard, Scheer is more accurate about our ability to realize a different future than policy skeptics, or even policy moderates. The policy review in this chapter provides a detailed portrait of real change that has been gained, and underscores the potential for vastly larger improvement by using already invented tools which have been tested in very different national contexts, but with common results – a measurable advance in realizing a solar economy.

The policy analysis occupying the last half of the chapter offers a concrete projection of large-scale change built upon the use of already invented policies. Surely a global solar economy requires significant US participation, and the analysis plots a course of action for that country which would result in 25% of its electricity supply from solar generation in as little as 20 years. Achieving the goal will require public investment in PV R&D to sustain progress in the technology's performance and economic value while incentives are utilized to organize at-scale investment in solar energy. The experience of Germany, Spain and South Korea, among others, with the feed-in tariff tool (invented by Scheer)³³ indicates that policy can work to mobilize capital and can evolve markets that sustain significant PV penetration rates. Because national politics and economies differ, tools that aspire to the same outcome are also needed. The imitation of a feed-in tariff with a properly designed RPS, carve-out and SREC policy suite can promise the needed result and this chapter's analysis of the option shows that a transformed US electricity supply path is feasible.

It is also clear that systematic policy regime for realizing a solar economy will require comprehensive pricing of carbon uses and emissions. In the case of this tool, designs that initiate the process, even when carbon pricing is modest, have a demonstrable impact. In the longer run, this tool will guarantee that *all* energy decisions and investments reflect this factor. At the same time, a systematic policy regime *must have* specific initiatives such as FiT or SRECs to ensure rapid, concrete change. It would be a tragic error in policy design to fail to adopt the PV-focused policies modeled above.

³³ The 2009 Karl Boër Solar Medal was awarded to Hermann Scheer for his invention of the FiT [134].

The challenge of sustaining a future in the greenhouse remains large, daunting, and even unnerving [130]. The policy record is mixed and advances are slow. Still the interface of policy, technology and society is hopeful. Large change has happened before and the improvements of the last 15 years are promising.

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