Photovoltaic Systems, The Experience Curve, And Learning By Doing: Who Is Learning And What Are They Doing?

by

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Abstract:

The photovoltaics industry has been growing at extraordinary rates over the past ten years as a result of increased government support for the technology. Yet supporting the technology is expensive and there is uncertainty over the future rate of technological progress for photovoltaics. Experience curves have been an important part of the argument to justify continued government support of as well as private investment in solar technologies. In this thesis, I argue that a more sophisticated understanding of experience curves and their underlying mechanisms will be important if we are to preempt a renewable energy "bubble." I begin by providing a brief history of photovoltaic technology and policies that have supported end photovoltaic end markets. Next, I examine the use of experience curves for photovoltaic technology, finding numerous conceptual inconsistencies. Finally, based on an economic analysis of almost 55,000 photovoltaic systems in the United States, I attempt to disaggregate the dynamics of cost-reduction in photovoltaic systems, with a particular focus on the behavior of the systems integrators/installers. My analysis includes measures for experience, competition, and installer characteristics. This thesis contributes a better understanding of cost dynamics in photovoltaics and calls for a more sober and more sophisticated discussion about cost dynamics when considering renewable energy policy.

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Table of Contents

List of Figures

List of Tables

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All errors in this thesis remain my own.

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Section I - Introduction

Solar photovoltaics is in many ways an ideal energy source: it is abundant, it does not produce carbon dioxide, every nation has access to it and the fuel is free. It would seem to be a good candidate for solving the suite of energy challenges that are currently being faced: climate change, energy independence, and economic development. To meet the climate change challenge we will need to replace current carbon emitting generation with non-carbon emitting generation and do so at a rate fast enough to slow climate change. President Obama's goal for the United States is to reduce carbon emissions to 20% of 1990 levels by 2050. This is an immense task that means the decommissioning otherwise valuable generation assets and the deployment of more expensive renewable energy technologies. Adding to the difficulty of the task, energy demand is expected to increase in the future, doubling by 2050 and tripling by 2100 (Nocera and Lewis 2006). The energy independence challenge has been a concern since the Arab oil embargo in 1973 and has not yet been solved. Recent high oil prices and instability in Russian oil supplies have highlighted the continued relevance of this problem. In the long term, changes to the global economy in which developing nations like India and China are rapidly increasing their energy demand will likely lead to increased energy prices in the future unless more energy supply is added. The economic development challenge of developing globally competitive industries and providing jobs for citizens is a constant concern for all nations. As the need for a new energy infrastructure is becoming apparent, so is the economic opportunity in industries that can provide new energy technologies. Countries like Germany have supported renewable energy and energy efficiency as part of their industrial policies for more than 10 years. In the United States, where manufacturing continues to move off shore, renewable energy industries hold out the prospect of "green jobs" that could reinvigorate the country's manufacturing base, especially in the Midwest.

Despite the many attractive features of solar technology, deployment of the technology faces several challenges – not the least of which is the fact that it is simply too expensive. Although solar "fuel" (i.e. light from the sun) is free, the device required to convert light into electricity is not. Considering the cost of the device and amount of electricity generated over its expected lifetime, the cost of solar electricity is about five to ten times more expensive than electricity generated from non-renewable energy sources like coal and natural gas. Further complicating this problem is the fact that the cost must be paid up front. Once the system is purchased, it will produce valuable electricity for the next 20 to 30 years over the system's life. Thus, even if the value of the electricity outweighed the up-front cost of the system on a net present value basis, financing would still be required. The availability of capital to finance installations becomes another constraint to wide-scale deployment of solar.

Managing the intermittent power generated by solar is a second broad challenge. Because the amount of electricity generated depends on the amount of light striking the photovoltaic device, no solar energy is produced at night and the most is produced at around noon. Although the profile of generation approximates the profile of electricity demand throughout the day, solar power output would ideally be shifted about two hours. Solar energy is also not dispatchable, meaning that it complicates the management of the grid and coordination of other power generation. Denholm and Margolis (2007) estimate that solar power can only supply up to 15 to 20% of total generation because of this constraint[1]. This issue has so far not been critical because the deployment of solar is so small (0.0125% of electricity generated in 2007 according to the Energy Information Administration, 2008) but as more photovoltaic generating capacity is installed it will no longer be possible to ignore this cost. Although the simplest solution to the intermittency and non-dispatchability of solar generation is energy storage, energy storage technology is also currently too expensive.

Regardless of these challenges, the photovoltaic industry has been growing at extraordinary rates over the past 10 years. Since 2000, annual production has increased at a rate of 45% per year through 2008 (Maycock, Solarbuzz). Venture capital investment in energy now matches investment in biotechnology, and venture capitalists are creating practices around energy and sustainability-related technologies (Pernick and Wilder 2007). The number of manufacturer in commercial production active in the United States has doubled (Energy Information Administration 2009).

This extreme growth has led many countries and cities to question how they can become involved in some part of the industry – be it research and innovation, manufacturing, or deployment. Germany has so far been the most successful in creating a strong national photovoltaic industry. Abu Dhabi, in the United Arab Emirates, is attempting to create a research and production center in Masdar City. Ohio seeks to leverage its glass industry to tap into jobs being created by the photovoltaics industry.

However, caution is advised for policymakers considering joining the bandwagon because the industry growth has been generated artificially through government intervention. In 1994, Japan was the first country to have a national incentive program for the installation of photovoltaic systems. Germany followed shortly after, offering an incentive in 2000 that has become the primary model around which countries develop support programs. By introducing a "feed-in tariff" whereby a utility company was legally bound to buy electricity from photovoltaic systems at a fixed price over 20 years, two problems

[1] The fundamental limitation is that the amount of electricity generated must equal the amount of electricity consumed at all times. Because the power output of solar system cannot be known precisely beforehand, other generation must be turned off and on so that supply equals demand. These other forms of generation must either be sufficiently nimble or the energy must be stored.

were solved. First, the price received by the system owner was much higher than the price of conventionally-generated electricity; it was a categorically attractive financial investment. Second, by guaranteeing that the payment would last for 20 years, the uncertainty around the quantity and value of electricity produced was eliminated. Financing was much easier because the 20 year price guarantee eliminated a major source of risk. Today, many developed countries have some kind of incentive program to support solar, though they vary in design and in size[2]. It has been the growth of these incentive programs worldwide that has driven the growth of the photovoltaics industry.

Government incentive programs entail a significant commitment of resources. California has committed more than $3 billion to support the technology through its California Solar Initiative (California Public Utilities Commission 2009). Germany committed about €6 billion in ratepayer surcharges in 2008 through its feed in tariff[3]. One of the primary reasons governments are willing to support solar is the expectation that costs will decline in the future, which means that the government commitment in time and money will be limited. Government is not alone; universities and private industry are also committing resources to photovoltaics.

The concept of the experience curve has served as justification for this expectation (e.g. Algoso et al 2005, Ingersoll et al 1998). Massive production growth, the result of government support, is expected to create a virtuous cycle whereby increased production will drive down the cost of photovoltaics and in turn generate greater demand. If the historical trend of photovoltaics costs continues into the future, then every doubling of cumulative output will entail a 20% reduction in cost. Many are optimistic that the cost of photovolatics will continue to decline through a multitude of avenues for technology advancement (higher efficiency cells, new device design, new materials, new deposition techniques) and larger investments going into production capacity (Greenpeace 2004, European Commission 2005). The ultimate goal for photovoltaics cost is grid parity – the retail cost of electricity drawn from the grid. While the cost of traditionally generated electricity varies from state to state and country to country,

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[2] Why countries are adopting incentive programs for photovoltiacs now is not exactly clear. One reason might be the growing awareness of climate change and the need to reduce carbon emissions. Support for renewable energy technologies like solar are one way of moving towards existing commitments from Kyoto and anticipated future commitments from the Copenhagen Climate Summit. Other reasons may be the goal of energy independence and economic development. Motivations may be more complex. For some countries, a concern may be the prospect of falling behind other countries in terms of industry strength and technology deployment. Another possibility is that politicians start programs since renewables have appeal to voters. Depending on the mix of motives, we might expect different levels of perseverance when the solar industry faces challenges.

[3] In 2008, 1.5 gigawatts was installed in Germany. Given Germany's insolation, this capacity produces about 1.1 terawatt hours per year (using the rate of 730 kwh per kw of capacity in Jahn and Nasse (2004)). Assuming it is roof-mounted, the feed-in tariff is €0.465 per kilowatt hour or € 511 million for an entire year of generation. The feed-in tariff is good for 20 years and the net present value of 20 annual payments of €511 million (at a discount rate of 5%) is €6.38 billion.

reaching grid parity will require that the photovoltaics cost must come down by a factor of anywhere from two to five. The most optimistic estimates contend that grid parity will be attained by 2012 (BSW-Solar 2009).

The unknown question for industry is whether the technology can be developed to grid parity before government support runs out. The major risk for an industry built on government support is that support can be taken away as fast as it was given. The 45% annual production growth rate could grind to a halt if government support ends. If support does end, then we would repeat the problem of start-and-stop support for energy technologies (Margolis 2002). The many resources invested in solar – financial capital, labor, business investments, scientific attention – would have to be redeployed. Some may argue that anything that advances the technology is good (Friedman 2008). But that begs the question, at what cost? If the technology fails to live up to high expectations, it may lose the widespread support that has so far been vital in bolstering the industry.

Although it is likely that the cost of solar electricity will eventually reach grid parity, the key question is whether estimates for the length of time and level of cumulative output are at all accurate. The market for photovoltaic systems currently hinges on the level of government support. Large feed-in tariffs, up-front rebates, tax credits and other incentives are currently used to generate demand for the more expensive energy source. But these policies come with a cost and if the cumulative output to reach grid parity is high, then the government support required to bolster photovoltaics demand will also be high. For policy-makers interested in environmentally friendly energy sources, in energy independence, in strengthening the local economy, there are options other than photovoltaics (McKinsey 2009). Policy-makers must consider whether an investment in supporting photovoltaics is the most cost-effective relative to other approaches such as energy efficiency, wind, or nuclear.

Lost in the recent excitement over photovoltaic technology is the degree of uncertainty in predictions of future cost. Photovoltaics experience curves have been used to predict a cost reduction – a learning rate - of 20% for every doubling in cumulative production output (IEA 2000). Despite other estimates of 17% (Strategies Unlimited) and 26% (Maycock), no reliable measure of uncertainty has been provided. Such a measure is critically important since the cost of supporting photovoltaic technology is highly sensitive to the learning rate. Compared to a learning rate of 25%, a learning rate of 15% requires an order of magnitude higher cost to support PV technology to the point where it reaches grid parity (van der Zwaan and Rabl, 2003). Learning rate uncertainty also has implications for the total production volume and the total number of years required to reach grid parity.

Industry commentators and policy discussions have given much weight to advances in module prices and module technology. Yet although the module is the core component of the photovoltaic system and accounts for approximately half the system cost, it is also important to examine price dynamics at the system level. Ultimately, it is the system cost that determines the cost of electricity generated and we cannot assume that the price dynamics of photovoltaic modules also apply to non-module components. This thesis is intended to contribute to the policy debate by examining the dynamics of photovoltaic system costs.

The goal of this work is not to argue against optimistic predictions that solar electricity will not reach grid-parity in the next 5-10 years. Such prognostications are inherently difficult to make. Instead, the intent is to examine in detail that widely-held belief, and to stress the need for a better theoretical understanding of the photovoltaics experience curve. The current conventional wisdom suggests that the future cost of photovoltaics is predetermined, and that all that is necessary is to increase cumulative output in order to "ride" the experience curve downwards. In reality, the eventual cost of solar electricity is unknown as are the mechanisms that will decrease its cost in the future. Experience curves (in general and for photovoltaics specifically) do not address those mechanisms. They do not explain *how* the cost will actually decrease and instead take it as a matter of faith that the costs will decrease through one mechanism or another.

In this thesis, I explore the cost dynamics of installed photovoltaic system installations in California, Massachusetts and New Jersey. These dynamics are examples of mechanisms glossed over by the experience curve but that provide important insights into the industry and policy. I begin by introducing the photovoltaic technology and industry. Then I describe the government measures being used to encourage industry growth and technology deployment. Next, I critically review the rationale for continued investment in the technology which often hinges on the experience curve. I include a brief discussion of the potential avenues for cost-reduction in photovoltaic systems. Finally, I use the dataset of photovoltaic system installations to explore and conduct a regression analysis of the systems installation stage of the value chain. This provides a richer understanding of the systems installations business that can be used to design more precise policy interventions.

An Introduction to Photovoltaic Technology

What are photovoltaic systems?

Photovoltaic systems convert energy in the form of light into electricity and are comprised of several components. At the core of a photovoltaic system is a series of photovoltaic modules. Each module is approximately one square meter in area and contains a number (usually 36) of photovoltaic cells. When light strikes the photovoltaic cells, they generate electricity which is sent through and out the module. Modules are wired together in series and parallel and generate electrical current. The cells are made of semiconducting materials – typically silicon - which are ensconced in the module, typically sandwiched in between a layer of glass and a layer of plastic and framed in aluminum. Light striking the semiconducting materials energizes electrons which can be directed by an electrical field to generate current.

The second most important component of the photovoltaic system is the inverter. Because photovoltaic modules produce electricity in direct current, it is of little use for powering most electrical devices which operate on alternating current. The inverter converts the electricity in the form of direct current to electricity in the form of alternating current.

The third necessary component is mounting structure. Modules can be mounted on the roof of a building or on the ground. A mounting structure allows the modules to be tilted at the optimal angle to the sun (which varies depending on the latitude) and also allows for air circulation to cool the module (standard modules experience reduced output at higher temperatures). In addition to these three components, there are also miscellaneous components generic to electrical work, e.g., wires, disconnects, and junction boxes.

Two other components that are sometimes found on photovoltaic systems are batteries and a tracking system. Batteries are typically lead acid. While the vast majority of systems installed today are connected to the electrical grid and do not use batteries, some do and batteries are necessary if the photovoltaic system is not connected to the electrical grid. This would be the case for applications such as boats or buildings in remote locations. Because the photovoltaic system will generate electricity only when the sun is shining, batteries provide some buffer and allow electricity to be used even when the system is not generating electricity.

The other optional component is a tracking system. Tracking systems are typically used on larger installations where there are few space constraints. Ideally, light shines onto the photovoltaic modules at a normal 90 degree angle and for every square meter of area normal to the sun's rays, sunlight provides one kilowatt of energy. If the modules are not ideally angled, then the effective area of the module (relative to the direction of sunlight) is reduced and the photovoltaic system will produce less electricity. Tracking systems change the angle of the photovoltaic modules throughout the day to ensure that they are receiving the maximum amount of light possible. They are also typically found in areas with few space constraints because module arrays (several modules grouped together) on a tracking device must be spaced far apart enough so as to not shade other adjacent arrays.

Basic trends of the photovoltaic industry

The photovoltaic industry has been growing at a tremendous rate. Annual module production has been growing by 28.4% year on year from 1976 to 2008, and by 45.7% year on year between 1999 and 2008. Figure 1 shows the cumulative global production of photovoltaic modules since 1976.

In the US, cumulative photovoltaic installations exceeded 1 gigawatt in 2008 (see Figure 2). A significant minority is in off grid applications, which was the dominant type of application in the 1970s and 1980s. The U.S. currently has the world's fourth largest installed capacity base, but had the world's largest PV capacity through 1996. As shown in Figure 3, Japan overtook the US in 1997. As a result of its national incentive program for solar, Japan's annual installation rate began to exceed that in the US in 1994. Japan was later overtaken by Germany in 2004; the annual market for photovoltaics in Germany exceeded Japan's in 2004 and cumulative capacity in Germany exceeded Japan's the following year. Germany's rapid growth was the result of a new substantial incentive program put in place in 2000.

Spain has the second highest cumulative solar installations, a result of high levels of installation in 2008. Although Spain began supporting solar photovoltaics through a feed-in tariff starting in 1998, it was a revision in 2007 that made the Spain a very attractive location for new installations. High feed-in tariff rates combined with good solar insolation led Spain to a point where it would meet its 2010 capacity installation target of 400 megawatts prematurely (Barron 2007). While the government was considering a revision to the feed-in tariff to slow the rate of installations, it froze the existing feed-in tariff rates for systems installed by September 2008 leading to a rush of installations. Spain's new policy will cap installed capacity at 500 MW per year (Wang 2009).

Figure 1. Annual Production of Photovoltaic Modules, 1976-2008
(Source: Maycock, SolarBuzz)

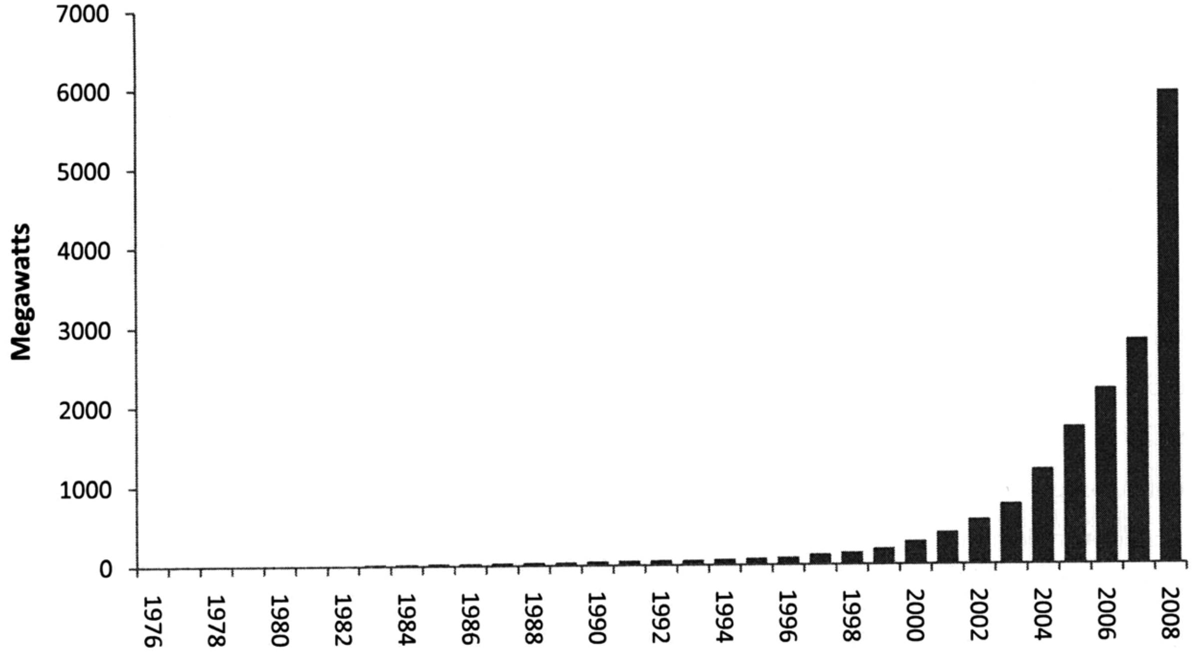
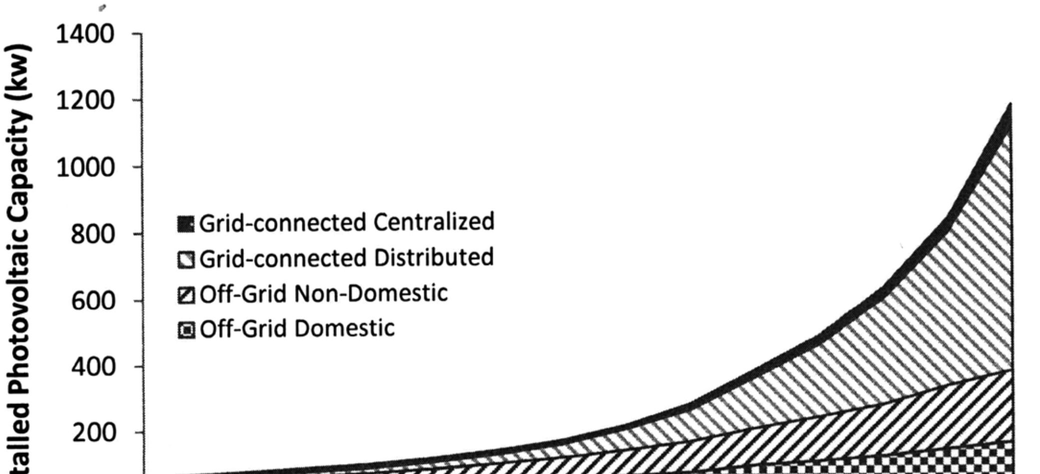
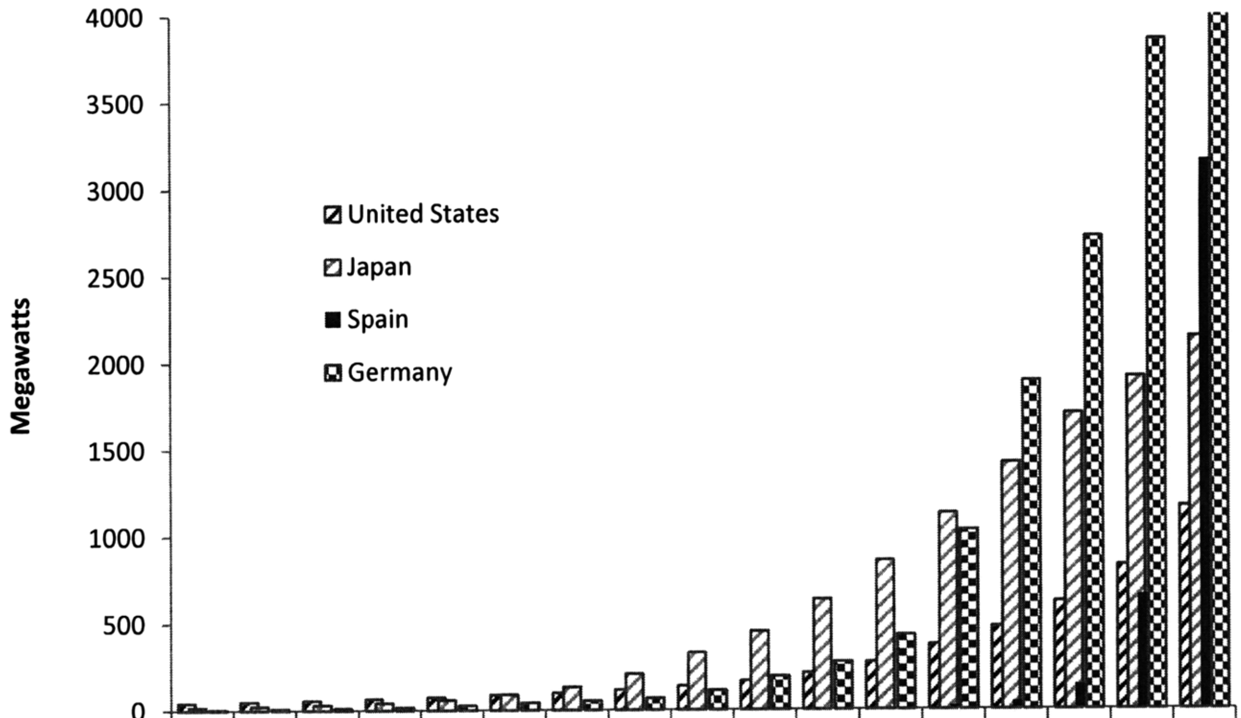


Figure 2. Cumulative Photovoltaic Installation in the US, 1995-2008
(Source: IEA-PVPS)



	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Grid-connected Centralized	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	18.0	22.0	27.0	32.0	40.5	63.5
Grid-connected Distributed	9.7	11.0	13.7	15.9	21.1	28.1	40.6	63.6	95.6	154.0	219.0	322.0	465.0	735.0
Off-Grid Non-Domestic	25.8	30.2	35.0	40.2	46.7	55.2	64.7	77.7	93.7	112.0	133.0	156.0	191.0	216.0
Off-Grid Domestic	19.3	23.3	27.5	32.0	37.5	43.5	50.5	58.9	67.9	88.0	100.0	114.0	134.0	154.0

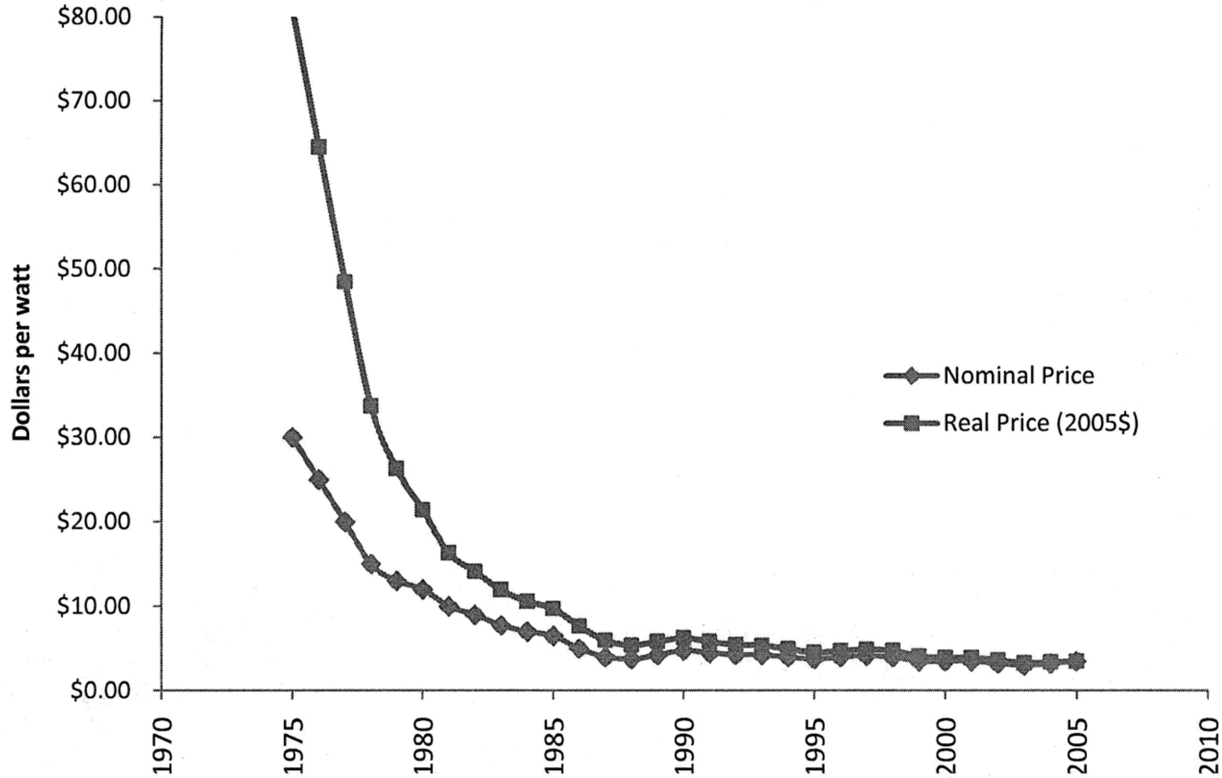
Figure 3. Cumulative Installed Photovoltaics in the Four Leading Countries, 1992-2008
(Source: IEA-PVPS, EPIA)



	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
United States	43.5	50.3	57.8	66.8	76.5	88.2	100.1	117.3	138.8	167.8	212.2	275.2	376	479	624	830.5	1169
Japan	19	24.3	31.2	43.4	59.6	91.3	133.4	208.6	330.2	452.8	636.8	859.6	1132	1422	1709	1919	2149
Spain	0	0	0	0	0	0	0	0	1	3	7	11	22	45	143	655	3166
Germany	5.6	8.9	12.4	17.7	27.8	41.8	53.8	69.4	113.7	194.6	278	431	1034	1897	2727	3862	5362

Declining module prices have been an important part of the history of photovoltaics ever since the first photovoltaic device was developed in 1954. The dramatic historical decline has encouraged hopes of lower solar energy costs in the future. Figure 4 shows data from Paul Maycock, one of the key sources for the historical module price data (data presented in Henderson et al 2007). The real module price is deflated using the producer price index for domestic manufacturing in the US. It shows that module prices have decreased substantially since 1975, and that the bulk of the cost decreases occurred between 1975 and 1990.

Figure 4. Average Photovoltaic Module Price, 1975-2005
(Source: Maycock)



The cost of solar energy

Solar energy is currently not competitive with traditional non-renewable energy sources. Only with government subsidies is investment in a photovoltaic system worthwhile. The size and form of the subsidies varies from country to country and, within the US, from state to state. Thus, the attractiveness of a solar investment varies by county and state. The cost of electricity can be calculated be determined by assessing the net present value of cash flows associated with buying a solar system. The primary cost is incurred up-front in the purchase of the system. The benefits are received over the lifetime of the system while it produces electricity, and through the receipt of subsidy payments from government.

Below I show the calculation for a prototypical four kilowatt photovoltaic system installed in Massachusetts for someone of average income and on an average home value:

Costs

The costs considered here are the cost to purchase and install the photovoltaic system, the cost to replace the inverter which has a lifetime of about 10 years, and miscellaneous operations and maintenance costs. The average installed system cost per watt in Massachusetts for 2008 is $8.84 per watt (Massachusetts

Technology Collaborative 2009). For a four kilowatt system, the installed cost is \$8.84 x 4000 watts = \$35360.

Although photovoltaic modules have an expected lifetime of 20 to 30 years, inverters have a shorter lifetime, typically 10 years. According to the Solarbuzz inverter price index (May 2009), the average inverter price is \$0.721 per watt. I will assume that any future inflation will be offset by technical improvements and will use \$0.721 per watt as the price for replacement inverters.

The final costs to consider are operation and maintenance costs. Low operating and maintenance costs are considered one of the attractive features of photovoltaics; without moving parts, there is simply less to maintain. Nonetheless, it would be unrealistic to assume there are no operation and maintenance. Thus, the analysis will make an allowance for miscellaneous operation and maintenance costs. For this cost, I will assume 0.5% each year with adjusted each year for inflation at a rate of 3%.

Benefits

The direct benefit of installed a photovoltaic system is the value of the electricity that it produces. To estimate this value, begin with the estimated annual electricity output which, according to the PVWatts program at the National Renewable Energy Lab[4] is 4975 kilowatt hours. This number incorporates various losses in system output and assumes that the system will produce only 77% of its nameplate capacity (NREL 2009). These losses include: inverter losses in converting AC to DC, operating at higher temperatures, voltage mismatch (i.e. modules wired in series operate at the voltage of the lowest voltage module), voltage losses across diodes and connections, wiring, soiling (i.e. accumulation of dirt), module output lower than nameplate output (from uncertainty in testing), and system downtime (e.g. when it is receiving maintenance). It also assumes that the panels are optimally oriented for a system without a tracking system (i.e. fixed-tilt) - southwards and oriented at an angle equal to the latitude of Boston, Massachusetts – 42 degrees. The higher power output is attained when the modules are oriented normal to the incident light. Thus, systems installed in the northern hemisphere should be oriented south and should be at an angle equal to latitude. Although the tilt of Earth's axis changes throughout the year (and thus the optimal angle changes throughout the year), tilting the panels at the number of degrees latitude provides the highest average over the entire year. For example, a system installed at the equator should be tilted at zero degrees - completely flat.

Massachusetts, like most states, offers 'net metering' which means that excess electricity generated at any point in time is supplied back to the grid and credited to the system owner, helping to defray costs

[4] http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/

incurred when electricity is being drawn from the utility. The system owner is charged for the "net" consumption. This means that the electricity generated can be valued at the retail price of electricity, which in 2008 averaged 17.5 cents per kilowatt-hour for residential customers in Massachusetts, i.e., 4975 x $0.175 = $870.625 per year. We also assume in this calculation that the electricity rate increases by 3% each year, and that the system output degrades over time at an annual rate of 1%.

The system owner receives several other cash streams from subsidy programs at the state and federal levels. The most salient is the state rebate. While rebate levels and requirements vary from state to state, Massachusetts offers a base rate of $1 per watt (Massachusetts Technology Collaborative 2009). If the income of system owner is of "moderate income" (i.e. less than 120% of the median state income), the rebate increases by $1.25 per watt. If the home on which the photovotaics system will be installed is of "moderate home value," the rebate increases by $2 per watt. Thus, the total rebate is $4.25 per watt for a system owner of "moderate income" and with "moderate home value." However, because the rebate is considered taxable, the after-tax rebate would be a bit less[5]. A system owner of average income would fall into the 25% marginal federal income tax bracket (IRS 2008). Thus, the after-tax rebate value is $4.25 per watt x (1-0.25) x 4000 watts = $12750.

The next most important incentive is the federal investment tax credit that was established as part of the Energy Policy Act of 2005. Because the Massachusetts rebate is considered taxable income, then the full value of the system cost counts towards the 30% federal tax credit. The value of the investment tax credit is 30% x $35360 = $10608

Other incentives for the installation of solar systems in Massachusetts are the state tax credit, property tax waiver, and sale of renewable energy certificates (DSIRE 2009). Although the policy on state tax credits varies from state to state, Massachusetts offers a tax credit of 15% with a cap of $1000. This credit is claimed after paying federal income tax, so the state tax credit is effectively taxed by the federal government. Thus, its value is $1000 x (1-25%) = $750. Also in Massachusetts, although the photovoltaic system increases the value of the property, and the increase in property value is not assessed for the purpose of property taxes.

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[5] There is still no consensus on whether the state rebate is considered taxable. At first glance, this would seem to be an important consideration affecting the size of the incentive. And while it does make a difference, it is smaller than one would expect. The difference comes down to the owner's marginal income tax rate.

If the state rebate is considered taxable, then the owner can consider the full value of the system as the basis on which the 30% federal tax credit applies. If the state rebate is not considered taxable, then the owner must deduct the value of the state rebate when calculating the tax basis on which the 30% federal tax credit applies. Thus, if the system owner's marginal tax rate is greater than 30%, then she is better off if the state rebate is not considered taxable income. If the system owner's marginal tax rate is less than 30%, then she is better off if the state rebate is considered taxable income.

Renewable energy certificates provide another source of value for solar electricity. A renewable energy certificate is essentially the credit for generating carbon-free electricity. It is a credit that some are willing to pay for and its actual value is determined on the market for buying and selling certificates. The market for renewable energy certificates varies from state to state. In a voluntary market, renewable energy certificates are sold to entities as a pseudo donation to renewable energy. This price in voluntary markets is small but non-trivial: ~ $0.02 per kilowatt hour in (Wiser et al 2009: 23). At the opposite end of the spectrum are states where utilities are mandated by the government to acquire a certain percentage of their generation from solar (e.g. New Jersey and other states that have Renewable Portfolio Standards with solar "carve-outs"). In New Jersey, the average renewable energy certificate in May 2009 was sold for $0.50 per kilowatt hour (New Jersey Clean Energy Program 2009). In Massachusetts, a system owner would have the option of selling on the voluntary market or selling through a program called ECANE (Energy Consumer Alliance of New England) at a rate of $0.03 per kilowatt hour. The contract is for three years and renewable. This analysis will assume it is renewed for the life of the system.

Table 1 summarizes the costs and benefits of installing a photovoltaic system. Using a discount rate of 5%, the rate of return on a photovoltaic system is a modest 3.79%. This value already incorporates a 3% inflation rate in maintenance and electricity costs. This also assumes that the project is financed with 100% equity[6].

[6] If the system owner could receive a loan for less than the rate of return for the photovoltaic project, he could realize a higher project rate of return by taking a loan and using the positive future cash flows to pay off the debt (Deutch and Lester 2004)
In addition, the rate of return could be affected by any tax advantages of debt. Interest payments on debt may be tax deductible (e.g. for a residential customer, in the case of a home equity loan; for a commercial customer, it would be considered a business expense). I do not consider the impact of financing on the rate of return because my primary interest is in assessing the value of the photovoltaic project.

Table 1. Cash Flows for the Purchase of Photovoltaic System

Year	Costs			Benefits					Total Cashflow
	System Cost	Maintenance	Inverter Replacement	State Rebate	Federal Tax Credit	State Tax Credit	Electricity Value	Renewable Energy Certificates	
0	-$35,360.00								-$35,360.00
1		-$176.80		$12,750.00	$10,608.00	$750.00	$870.62	$149.25	$24,951.07
2		-$182.10					$887.78	$147.76	$853.43
3		-$187.57					$905.27	$146.28	$863.98
4		-$193.19					$923.10	$144.82	$874.72
5		-$198.99					$941.28	$143.37	$885.66
6		-$204.96					$959.83	$141.94	$896.80
7		-$211.11					$978.74	$140.52	$908.14
8		-$217.44					$998.02	$139.11	$919.69
9		-$223.96					$1,017.68	$137.72	$931.43
10		-$230.68	-$2,884.00				$1,037.73	$136.34	-$1,940.61
11		-$237.60					$1,058.17	$134.98	$955.54
12		-$244.73					$1,079.02	$133.63	$967.91
13		-$252.07					$1,100.27	$132.29	$980.49
14		-$259.64					$1,121.95	$130.97	$993.28
15		-$267.43					$1,144.05	$129.66	$1,006.28
16		-$275.45					$1,166.59	$128.36	$1,019.50
17		-$283.71					$1,189.57	$127.08	$1,032.94
18		-$292.22					$1,213.00	$125.81	$1,046.59
19		-$300.99					$1,236.90	$124.55	$1,060.46
20		-$310.02	-$2,884.00				$1,261.27	$123.31	-$1,809.45
21		-$319.32					$1,286.11	$122.07	$1,088.87
22		-$328.90					$1,311.45	$120.85	$1,103.40
23		-$338.77					$1,337.29	$119.64	$1,118.16
24		-$348.93					$1,363.63	$118.45	$1,133.15
25		-$359.40					$1,390.49	$117.26	$1,148.36

Rate of Return
3.71%

For a policy-maker, a useful way to quantify the value of solar energy is the cost per kilowatt hour, excluding the subsidies offered by government. This provides a convenient benchmark that can easily be compared to the current price of electricity (in Massachusetts, $0.175 per kilowatt hour for residential customers).

Table 2 illustrates the calculation for cost per kilowatt hour, considering the same costs as the previous calculation and excluding all benefits with the exception of the value of electricity. The value of the electricity is equal to the annual system output multiplied by the value per kilowatt hour. The value per kilowatt hour is considered an unknown in the analysis and is solved for by equating the net present value of system costs and the net present value of electricity generated. For the analysis, I assume that electricity prices increase at a rate of 3% each year and a discount rate of 5%. Thus, the electricity value in year n is given by: annual electricity production x electricity value x (1+3%)^n.

The cost of solar energy is calculated at $0.474 per kilowatt hour. This number changes depending on the assumptions made. If operations and maintenance and inverter replacement costs were not considered, the cost of solar energy would be less, $0.403. If a 30 year lifetime was considered, the cost of solar energy would be $0.421. Considering both a 30 year lifetime and no inverter replacement or operations and maintenance costs, solar electricity would cost $0.358[7]. The cost of solar energy is also sensitive to the discount rate used. Using a discount rate of 8% in the base case scenario, the cost of solar energy increases from $0.474 to $0.614 per kilowatt hour.

The cost of solar energy is expensive even compared to the price of residential electricity in Massachusetts. In 2008, the average retail price for electricity in Massachusetts was $0.175 per kilowatt hour while the national average was $0.113 (See Figure 5).

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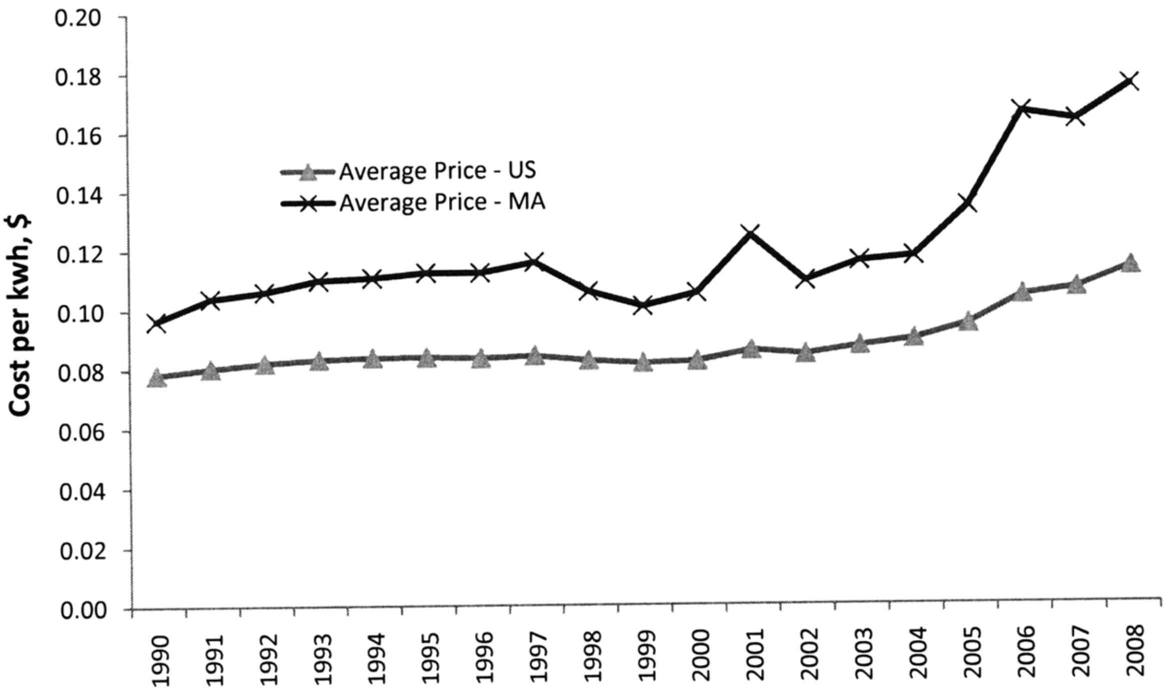
[7] By comparison, in California (San Francisco), assuming inverter replacement, operations and maintenance, and a 25 year life, the cost would be $0.408 per kilowatt hour. Considering both a 30 year lifetime and no inverter replacement or operations and maintenance costs, solar electricity would cost $0.308. per kilowatt hour.

Table 2. Cash Flows and Cost of Solar Electricity

	Costs					Electricity		
Year	System Cost	Maintenance	Inverter Replacement	Total Costs	Net Present Value of Costs (5%)	Electricity Production	Electricity value @ $0.474 / kwh	Net Present Value of Electricity (5%)
0	-$35,360.00			-$35,360.00	-$41,591.72			$41,591.72
1		-$176.80		-$176.80		4975	$2,427.84	
2		-$182.10		-$182.10		4925	$2,475.67	
3		-$187.57		-$187.57		4876	$2,524.44	
4		-$193.19		-$193.19		4827	$2,574.17	
5		-$198.99		-$198.99		4779	$2,624.88	
6		-$204.96		-$204.96		4731	$2,676.59	
7		-$211.11		-$211.11		4684	$2,729.32	
8		-$217.44		-$217.44		4637	$2,783.09	
9		-$223.96		-$223.96		4591	$2,837.91	
10		-$230.68	-$2,884.00	-$3,114.68		4545	$2,893.82	
11		-$237.60		-$237.60		4499	$2,950.83	
12		-$244.73		-$244.73		4454	$3,008.96	
13		-$252.07		-$252.07		4410	$3,068.24	
14		-$259.64		-$259.64		4366	$3,128.68	
15		-$267.43		-$267.43		4322	$3,190.32	
16		-$275.45		-$275.45		4279	$3,253.17	
17		-$283.71		-$283.71		4236	$3,317.25	
18		-$292.22		-$292.22		4194	$3,382.60	
19		-$300.99		-$300.99		4152	$3,449.24	
20		-$310.02	-$2,884.00	-$3,194.02		4110	$3,517.19	
21		-$319.32		-$319.32		4069	$3,586.48	
22		-$328.90		-$328.90		4028	$3,657.13	
23		-$338.77		-$338.77		3988	$3,729.18	
24		-$348.93		-$348.93		3948	$3,802.64	
25		-$359.40		-$359.40		3909	$3,877.56	

Cost of electricity per kwh
$0.474

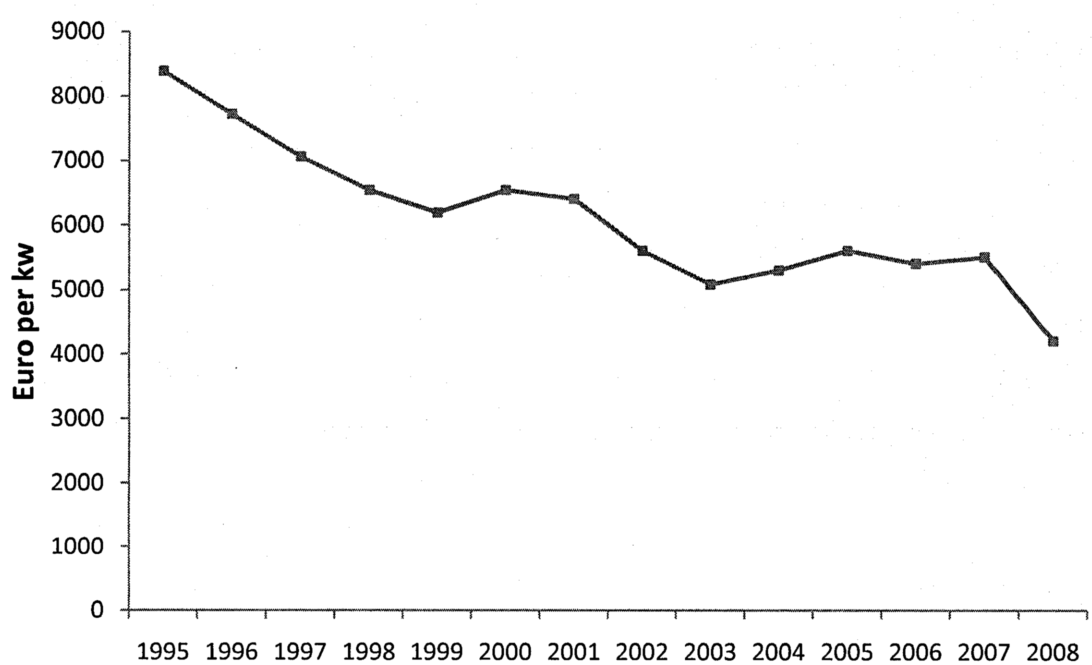
Figure 5. Price of Retail Residential Electricity in MA and US, 1990-2008
(Source: Energy Information Administration EIA-826)



The Case for Investment in Solar: A History of Falling Prices

The high cost of generating solar electricity calls into question the high levels government support and private investment going into solar photovoltaics. A key part of the argument for government support is the downward trend of system prices observed in other counties. In Germany, nominal system prices (without incentives) have declined from 8.39 euro per watt to 4.2 euro per kilowatt – almost a 50% decrease between 1995 to 2008 (see Figure 6). Adjusting these numbers for inflation using the producer price index for domestic manufacturing, system prices have decreased by 57%.

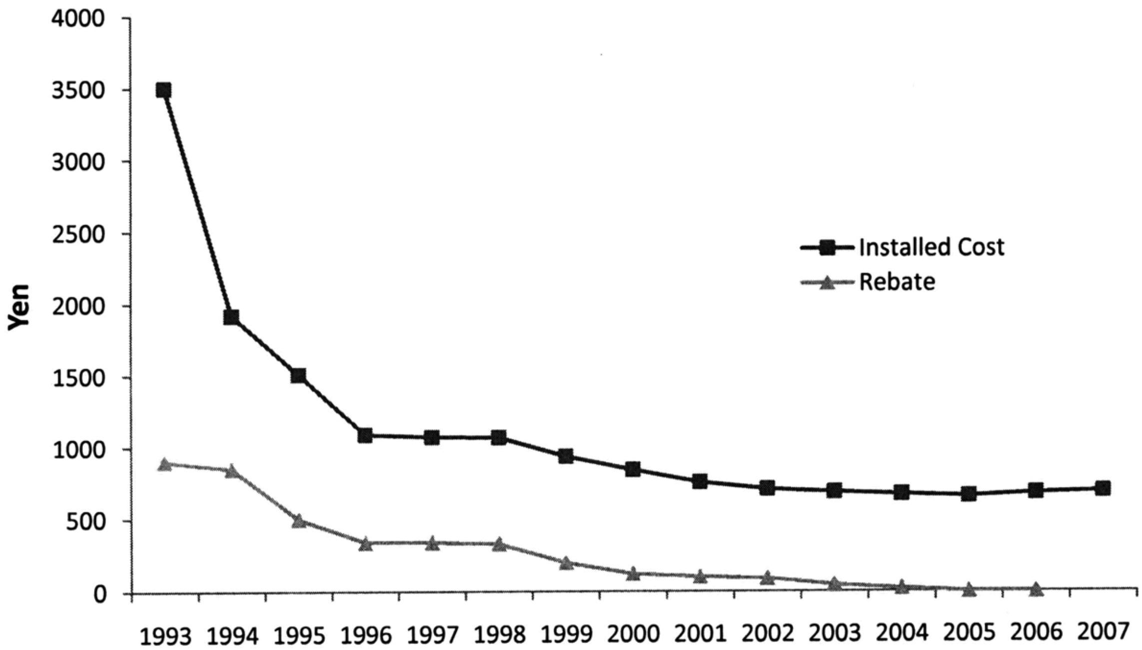
Figure 6. Installed Photovoltaic Systems Price in Germany, 1995-2008
(Source: IEA-PVPS)



Japan has also experienced similar price decreases. The average price (before any incentives) has declined from 3500 Yen in 1993 to 696 Yen in 2007 – a decrease of more than 80%. Adjusting these number for inflation, the decrease in system price is slightly larger, 81% (recall Japan's economic conditions at the time led to an equal amount of deflation as inflation).

A particularly powerful part of the narrative for government support is based on the observation that system prices have declined in parallel with government incentive levels. Japan was the first country to subsidize solar through a rebate program at the national level starting in 1994. As reflected in a series of revisions to the incentive program, the government pursued a policy of decreasing the size of the incentives. This was intended to encourage cost improvements and price reductions while maintaining a steady rate of installation growth. As shown Figure 7, it seemed successful and the Japanese model was seen as one to be emulated.

Figure 7. Installed Costs and Subsidy Levels in Japan, Residential Systems, 1993-2007
(Source: IEA-PVPS)



The reasoning that developed was that the technology held promise and the problem was the lack of sufficient incentive for firms to further develop the technology and make investments in advanced manufacturing facilities. If the government could subsidize a portion of the overall system cost, it would create a market large enough to encourage market entry and investment by private firms. Prices would decline.

Another piece of evidence that seemed to support this view was the photovoltaic module experience curve. The experience curve is a generalization of the learning curve and both essentially posit that experience (measured in cumulative units produced) leads to decreases in cost. With experience, producers become more efficient in their operations, further develop the technology, and sell their goods at a lower price.

A more thorough and critical review of the learning curve will be given later, but this section will provide an introduction to the learning curve. Constructing a learning curve is straightforward; cumulative experience is plotted along the x-axis using a logarithmic scale and the good's cost is plotted along the y-axis, also using a logarithmic scale. Data points including the cost and cumulative experience at various points in time are plotted in the log-log space, and a best-fit line is drawn. The slope of the line is the key parameter, since it defines the progress ratio and learning ratio of the technology. The progress ratio and learning ratio are derived from the line's slope and have a simple interpretation. The progress ratio is equal to $2^{(\text{line slope})}$. Conceptually, with every doubling of experience, the good's cost will decrease by a factor equal to the progress ratio. Thus, for a technology with a cost of \$10 and progress ratio of 0.9, the cost after doubling cumulative experience will be \$10 x 0.9 = \$9. The learning rate offers an alternative measure of the rate of cost reduction and is equal to 1 – (progress ratio). Thus a technology with a progress ratio of 0.9 can also be said to have a learning rate of 0.1.

Historical price and production data for photovoltaic modules show an impressive progress ratio. Figure 8 shows the price and cumulative production data as well as a best-fit line. The prices are adjusted for inflation using the producer price index for domestic manufacturing in the United States (OECD). While not all production took place in the United States, the US producer price index closely follows the producer price index for G7 countries available from the OECD only after 1982. This provides greater confidence in using the US producer price index[8].

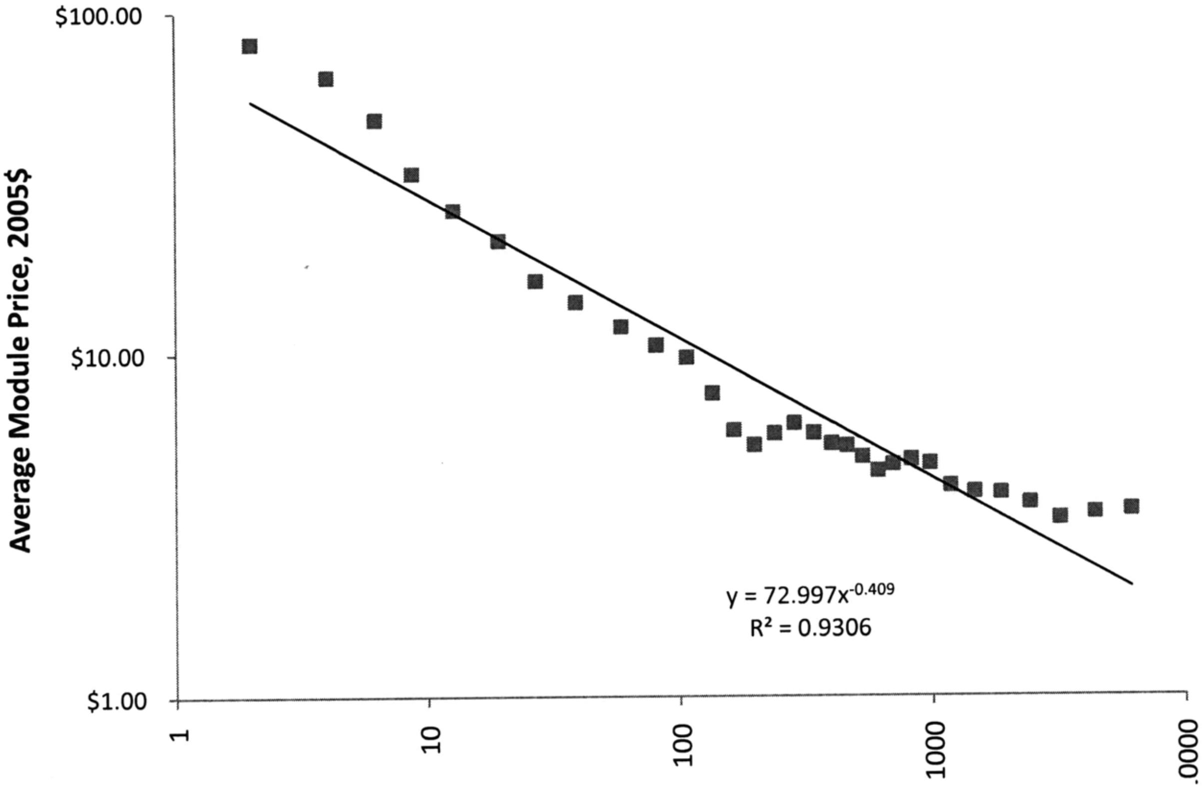
Prices have declined substantially since 1975 from a price of almost \$100 to a price of less than \$10. The learning curve suggests it is possible to "buy down" the cost of the technology, committing to purchases while it is in its early and expensive form so that it can be purchased later at a lower cost (i.e. "riding" the learning curve). The slope of the best-fit line corresponds to a progress ratio of 0.75. To put this in perspective, progress ratios between 0.80 and 0.85 are considered typical, progress ratios greater than 0.90 are poor, and progress ratios below 0.80 are good (see McDonald and Schrattenholzer 2001). With the photovoltaic module production is increasing at a rate of 40% year over year, the industry is accelerating down the learning curve[9].

---

[8] Comparing the US and G7 producer price indices, it does appear that inflation was probably higher in the US than in the G7 throughout this time period. Thus, the use of the US producer price index may overestimate the real prices in earlier years, leading to an estimate of a lower (better) progress ratio.

[9] It is more technically correct to say that the industry the production growth is helping to mitigate the "slow down" from moving in log-transformed space.

Figure 8. Experience Curve for Modules, 1975-2005
(Source: Maycock)



The size of the "buy down" cost depends on the progress ratio of the technology. In fact, the buy down cost is highly sensitive to small changes in the progress ratio. The difference is illustrated in

Table 3, which estimates the size of the buy down cost based on different progress ratios. The three progress ratios are drawn from prior experience curve calculations. The first, by the International Energy Agency (2000), presents an often-cited progress ratio for photovoltaic modules. The second estimate is based on the Maycock data is cited in Nemet (2006). Although Nemet (2006) also uses data from Maycock, the progress ratio differs slightly from the progress ratio calculated in Figure 8 because Figure 8 includes several more years of data. However, for the purposes of illustration, I will use the Maycock progress ratio cited in Nemet (2006). The third progress ratio is also calculated by Nemet (2006) but is based on a dataset from Strategies Unlimited.

Table 3. Cost and Experience to Reach Grid Parity Using Learning Curve

	International Energy Agency (2000)	**Maycock (Nemet 2006)**	**Strategies Unlimited (Nemet 2006)**
Progress Ratio	0.80	0.74	0.83
Required Cumulative Capacity to Reach Grid Parity ($1/Wp modules)	299 GW	109 GW	645 GW
Module Cost to Reach Breakeven	$409 billion	$155 billion	$852 billion
System Cost to Reach Breakeven (System cost is about 2x module cost)	$818 billion	$310 billion	$1704 billion
Total Government Buydown Cost	$220 billion	$92 billion	$415 billion

$$c_t = c_0 \left(\frac{n_t}{n_0}\right)^{\propto}$$

$\propto$ *is the slope of experience curve*

$progress\ ratio = 2^{\propto}$

c_t *is the cost at time* t; use value equivalent to grid parity = $1 per watt

c_0 *is the cost at time* 0; use Maycock's value for 2005 = $3.5 per watt

n_0 *is the cumulative production at time* 0; use Maycock's value for 2005 = 6.1 gigawatts

n_t *is the cumulative production at time* t; unknown

The total cost required is calculated by taking the integral of the experience curve from time 0 to the time when grid parity is attained. As shown in Van der Zwaan and Rabl (2004):

$$Total\ cost = \int_{n_0}^{n_t} c_n dn = \frac{c_0}{\propto +1} \frac{n_t^{\propto+1} - n_0^{\propto+1}}{n_0^{\propto}}$$

The total buydown cost for photovoltaics can be considered the cost required to "ride the learning curve" until photovoltaics can produce electricity equal to the cost of electricity generated by the utility using non-renewable energy sources. The installed cost equivalent to grid parity will depend on the level of insolation and the price of electricity available from the grid but for this calculation, we will assume that to reach grid parity, the installed system cost must be $2 per watt and cost of the modules must be $1 of the $2 total[10]. In calculating the total government buydown cost, assume that people will buy a photovoltaic system if the installed price is $2 per watt, the cost which is assumed equivalent to grid parity.

As shown in Table 3, the government buydown cost using the International Energy Agency progress ratio is $220 billion, more than two times greater than the buydown cost based on the Maycock progress ratio and one half the buydown cost based on the Strategies Unlimited progress ratio. The difference in the buydown costs based on the Strategies Unlimited data and based on the Maycock data is $323 billion, a factor of four.

The progress ratio can also be used to estimate the year in which grid parity will occur, assuming a rate of production. The European Photovoltaic Industry Association (EPIA 2008) estimates cumulative production capacity for 2008 of 13 gigawatts. Assuming full utilization of capacity but no new capacity added, it would take a little over eight years to reach grid parity in the Maycock scenario, 23 years to reach grid parity in the IEA scenario, and almost 50 years in the Strategies Unlimited scenario.

This simplified analysis is meant to highlight the sensitivity of the buydown cost to differences in progress ratios. It is not meant to determine the true cost of reaching grid-parity with solar photovoltaics. Such an analysis might include the variation in electricity cost by state and customer type and the cost of grid upgrades and energy storage required to manage the intermittent solar generation. This is beyond the scope of this paper.

Because the total buydown cost is sensitive to differences in progress ratios, any uncertainty in progress ratios will magnify the uncertainty in the total buydown cost. It turns out that any estimate of the progress ratio has at least two sources of uncertainty. First, there is unexplained variance when the best-fit line does not align perfectly with the data points. Some measure of this error is quantified in the standard error of the slope. Second, there are measurement errors in the data points themselves, errors along the y-axis (i.e. price) and errors along the x-axis (i.e. cumulative capacity). This second source is much more difficult to quantify. Since there have been so few data points collected (30 – one per year for

[10] These figures are reasonable and need not be exceedingly precise since the purpose of this calculation is to show how sensitive the total buydown cost is to the estimated progress ratio.

30 years), we cannot estimate the uncertainty of those data points. However, the level of uncertainty is suggested by the very existence of three progress ratios – from the IEA, Maycock and Strategies Unlimited. The difference in progress ratios can be attributed to different underlying estimates of module price and cumulative production at several points in time. These errors matter for government policymakers and private investors. A world with a low progress ratio may be one where the buydown cost is politically feasible and the return on investment attractive, while a world with a high progress ratio may be just the opposite.

This thesis will point out a number of empirical inconsistencies with the experience curve – a generalization of the learning curve - and offer a critical review of its theoretical premises of. Although it is tempting to place faith in the experience curve, its theoretical underpinnings do not warrant that faith. While the learning curve may suffice for "back of the envelope" calculations, for the purposes of drafting serious policy that will come at significant cost to taxpayers or ratepayers, a more thorough rationale should be pursued. Policymakers can only use the tools provided by research and this thesis provides a richer understanding of the learning curve in general and of the dynamics of the photovoltaic industry in particular.

Section II - The Evolution of the Solar Industry

An understanding of both past and present policies is critical for designing future policy. This section will provide an overview of the solar photovoltaics industry and the market policies that have supported it.

The organization of the solar industry

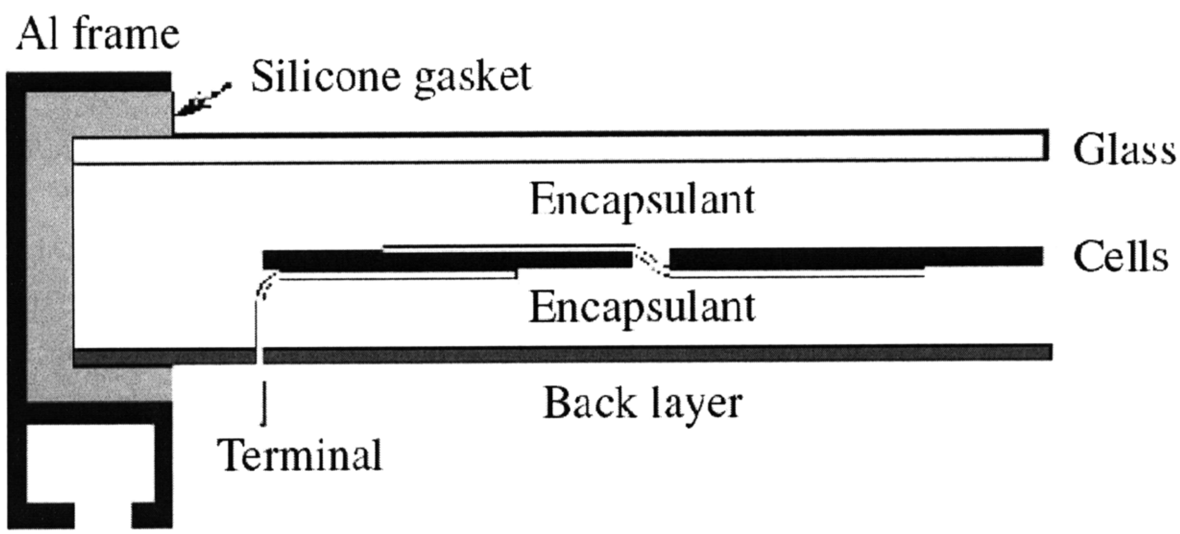
The photovoltaics value chain consists of multiple stages and several separate "branches." Along the main branch are silicon producers, cell manufacturers, module manufacturers, wholesalers and distributors, systems integrators and installers. The other branches of the value chain include inverter manufacturers, the manufacturers of mounting hardware and tracking systems, and financiers that help to coordinate the sales of large systems.

Describing the main part of the solar value chain, the process begins with the production of high-purity silicon. Although silicon is the second most abundant element on the Earth's crust, it must be of high purity to be used in a solar cell. As a raw material, silicon is used in numerous applications, the most salient being semiconductors. Silicon has typically been sold at two different levels of purity: metallurgical grade and semiconductor grade. Semiconductor grade silicon, the higher of the two purity levels, is required for solar cells. Recently, some silicon producers have begun selling "solar grade" silicon, which has a purity level just below that of semiconductor grade.

Cell manufacturers begin with high-purity silicon already doped with boron and produce solar cells. The silicon is shaped into an ingot and then sliced into thin square wafers of silicon, typically 125 millimeters across and 200 microns thick. The wafer is then processed to remove damage from the slicing process, texturized to better trap light, and doped with phosphorous. An anti-reflective coating is applied, and metal contacts are printed on the cell by first depositing a paste containing silver powder and then heating the cell to transform the paste into a solid semiconductor. The metal contacts will collect and channel electrons excited by the photoelectric effect.

As a general rule, cell manufacturers also package the cells in modules. In the manufacture of the solar module, solar cells are wired together in series - usually 36 in a single module. The cells are sandwiched two layers of encapsulant (usually ethylene-vinyl-acetate) and then sandwiched between a layer of glass and plastic. Then, the module is heated under vacuum so that the encapsulant melts and cures, thus embedding the solar cells in the module. The edges of the module are sealed with silicone and then the module is framed in aluminum. A junction box is added to each module so that multiple modules can be wired together. Figure 9, taken from Tobias et al (2003), shows the components of a typical photovoltaic module.

Figure 9. Layers of a crystalline photovoltaic module



In selling the product, module manufacturers deal directly with wholesalers and large system integrators. Wholesalers manage the transportation and distribution of the solar modules and are the main point of contact for many smaller system integrators. Systems integrators in turn deal directly with the person or organization that will use the photovoltaic system. Systems integrators acquire all the necessary system components, handle administrative tasks such as interconnection with the electrical grid, and manage the installation process. Sometimes the installation labor is sub-contracted out to an electrician or general contractor and sometimes it is done in-house by the system integrator.

Historical Development of the Industry

The history of the industry will focus the cell and module manufacturers. The reason for this is that it is the most distinctive step in the solar value chain. Many of the other stages exist in one form or another but serve other industries. For instance, silicon producers existed well before solar developed as a major industry, supplying the large semiconductor industry. While I focus on the cell and module manufacturers, the other related industries that have a part in the overall solar value chain have also developed throughout this timeframe.

The development of the solar industry can best be understood by considering the primary applications and the primary motivations for pursuing those applications. The solar industry began in the US in the mid 1950s when solar cells were used as a power source for space satellites. In the 1970s the primary application shifted to producing bulk terrestrial power, the motivation for which was the Arab oil embargo. When the concern over energy independence faded in the 1980s, the interest in the industry declined. Around 2000, growing concern over environmental issues led to government support of photovoltaic end-markets and in turn has resulted in the emergence of a global industry.

The First Generation of Photovoltaic Firms

The first modern photovoltaic device was developed in 1954 at Bell Laboratories in New Jersey. Made from silicon, the solar cells had an efficiency of 6% while the solar module had an efficiency of 2% (Chapin, Fuller and Pearson 1954, Green 2005) The technology was licensed to National Fabricated Products and the first intended application was terrestrial, but the cost was too high (Perlin 1999). The cost at that time was $286 per watt, which in 1954 dollars was extraordinarily expensive. At the time, the only applications in which photovoltaics made any sense were in novelty devices like toys.

The first significant application was in providing power for space satellites. In 1955, President Dwight Eisenhower announced plans for the US to launch a satellite in celebration of the international geophysical year. Each branch of the United States military - the Army, Navy and Air Force - began formulating design proposals for the launch rocket and satellite. Engineers found themselves confronted with the challenge of finding a reliable power source, ideally one with a high power-to-weight ratio. It was estimated that the cost to launch an additional pound of mass into space was $4000 and, against this metric, even photovoltaic electricity was worth the high price when compared to the cost of using chemical batteries (National Research Council 1972). Although the very first satellites were powered by batteries, photovoltaic technology quickly established itself as the standard technology for powering satellites and remains so today.

How solar photovoltaic technology found its way from Bell Labs and into the US space program begins with two men associated with the US Army Signal Corps (Perlin 1999). General James O'Connell had heard of the invention of the first silicon solar cell at Bell Labs in 1954 and sent Hans Ziegler, a scientist in charge of power devices, to visit. Ziegler was enamored by the technology and set out to find as many useful Army applications as possible. However, given the cost, the only feasible application was the US space satellite proposal that was currently in the works.

Unfortunately for Ziegler, the Navy proposal ended up winning the competition over the Army. Ziegler, committed to see photovoltaics used in space, sought to convince the Navy to replace its proposed power source, chemical batteries, with photovoltaics. With persistence, Ziegler won. He had made an appeal to the civilian panel overseeing the program, the Technical Panel on the Earth Satellite Program. The panel, convinced that photovoltaics was the superior choice, pressed the Navy into altering their design to use solar cells.

Interestingly, despite these efforts, the first three satellites were launched without photovoltaic cells. The first two were launched by the Soviet Union in 1957, Sputnik I and Sputnik II. The launching of the Sputnik satellites created a crisis of confidence for the United States and increased the urgency of a successful US space launch. The first planned launch took place in December 1957 using the Navy's Vanguard TV3 but it failed to launch. In a panic, the Army proposal which had been developed as a backup in October 1957 after Sputnik I was launched in October 1957, was to be launched as soon as possible. The Explorer I was launched successfully in January 1958.

The Explorer I, however, was not powered with photovoltaics. It was the Navy's second attempt, the Vanguard I, launched in March 1958 that definitively demonstrated the utility of solar cells on space satellites. Small photovoltaic cells powered one of its two radio transmitters, and continued to transmit data for eight years. In contrast, the first Sputnik was powered by silver-zinc batteries that weighed 51 kilograms, out of a total satellite weight of 83.6 kilograms. After three weeks, the satellite stopped transmitting data. The second Sputnik, launched in November 1957 with a small dog on board, required even more power and its chemical batteries only lasted only six days. The Explorer I was powered by nickel cadmium batteries, accounting for 40% of the 30.66 pound total weight. One of its transmitters lasted 31 days and the other lasted 105 days. (NASA 2009).

By the mid 1960s, photovoltaics had taken over as the power source of choice for space satellites, though after a short delay. The delay was partially attributable to the predominant view at the time of nuclear power as the ideal power source. To some, solar was seen as a stopgap while "nuclear batteries" were being developed. When atomic energy did not develop at the pace and with the capabilities that many people had expected, photovoltaics assumed the dominant spot.

The solar industry at the time consisted of only a handful of firms and demand was driven entirely by the needs of the US government. The main reason the industry was so small at the time was that the small and unpredictable market generally did not warrant investment by startups or established firms. Between 1958 and 1969, the US government purchased about 10 million[11] small solar cells which powered 600

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[11] Although this seems like a large number, two other pieces of information should be considered. First, this is the number of solar *cells*, not solar *modules*. Multiple cells are wired together in a single module. Second, these cells were very small. According to the National Research Council (1972) each had a capacity of approximately 0.05 watts and,at 10% efficiency, had an area of only 3.5 square centimeters! By comparison, solar cells manufactured today have an area of 225 square centimeters (15 centimeters square) and a capacity rating of four watts.

satellites and other spacecraft (National Research Council 1972). The annual market for solar cells was worth about $5 million, $15 million if the costs of producing a module and installation are included. Hoffman Electronics, located in the Los Angeles area, was the firm that produced the solar cells for the Vanguard I. In 1956, Hoffman Electronics[12] had acquired National Fabricated Products along with the patent license to the original photovoltaic technology invented at Bell Labs. Originally, the company had planned to produce solar cells for off-grid terrestrial applications but found customers unwilling to pay the high price.

One of the earliest competitors to Hoffman Electronics was a company named Heliotek. Heliotek was founded by Alfred Mann, a spinoff from an earlier company founded by Mann, Spectrolab[13]. Mann served in World War II as a bomber navigator and later studied at UCLA where he obtained Bachelors and Masters degrees in physics. He had an interest in studying light and his first job upon graduating was for Technicolor, a Los Angeles firm whose color film processes had been dominant in the motion picture industry since 1922. The Army approached Technicolor for help in light filtering for a missile guidance system but, when Technicolor did not pursue the work, Mann left to found Spectrolab in 1956 with an Army contract in-hand worth $11,200. Also located in Los Angeles, Heliotek applied Spectrolab's light filtering expertise for use in solar cells. Its solar cells were used in the Pioneer 1, which was launched in October 1958.

Other than Hoffman Electronics and Heliotek, only three firms entered the market for solar cells at the time - RCA, International Rectifier, Texas Instruments- and all three had left the market by the end of the 1960s (Wolf 1972). For these companies, unlike Hoffman Electronics and Heliotek, solar cells were only a small part of their overall business. RCA was a major radio company while International Rectifier and Texas Instruments were semiconductor companies.

The Second Generation of Photovoltaic Firms

After 1970, a second generation of solar photovoltaic firms began to emerge. Unlike the first generation, which was focused on space applications, the second focused on terrestrial applications supplying bulk electricity. Interest in space exploration had begun to decline after Apollo 11 landed on the Moon. Yet several firms believed that the advanced technologies that had been developed in the space race could

[12] Hoffman Electronics later became Centralab and even later Optical Coatings Laboratory Inc.

[13] The two companies were united in 1960 when both were acquired by Textron. Spectrolab still exists today and is the leader is super high efficiency solar cells.

have economically attractive applications elsewhere. Two firms began developing the technology for terrestrial applications by 1972.

The two firms that had entered the solar business before the oil embargo were the Solar Power Corporation and Solarex. Solar Power Corporation was a subsidiary of Exxon. Exxon's view was that energy prices would only increase over time, and they were interested in a technology that would keep them atop the energy business when the demand for oil declined. Solarex was a new company formed by Joseph Lindmayer, a scientist who had worked for COMSAT in Washington, DC. COMSAT was an organization tasked by the Communications Satellite Act of 1962 to manage the placement of communications satellites into space. Solarex pioneered the use of multicrystalline silicon.

The work of the Solar Power Corporation was instrumental in opening up the terrestrial market (Perlin 1999). In the early 1970s, the cost of a solar module was about $100 per watt. Over the previous ten years, there had not been much change in this cost because the small and uncertain market made it difficult for firms even to stay in business let alone invest in technical improvements. Solar Power Corporation's market research had indicated that to find a terrestrial market, the cost would have to decrease from $100 to $20 per watt. Although the eventual goal was to supply solar electricity for bulk use, the first markets the company targeted were off-grid terrestrial markets – in particular navigational aids managed by the Coast Guard which were powered by batteries.

The founders of Solarex came from COMSAT, an organization in Washington DC tasked by Congress to form a commercial satellite communication system. Powering these satellites were solar cells; given the intended long life of the satellites, chemical batteries would not suffice. Through his experience with solar cells Joseph Lindmayer, the founder of Solarex, came to believe they had promising terrestrial applications.

Much of the early efforts of Solar Power Corporation and Solarex came to be overshadowed by the single most influential event in the history of the solar energy industry, the Arab Oil Embargo. With the embargo came higher energy prices and recognition of the risks of relying on foreign energy sources. Solar energy was perhaps the ultimate panacea for the latter concern, since sunlight is available to all nations.

To many firms, solar technology's experience in the space program suggested that it was not only an advanced technology feasible in the lab and the most exotic of applications, but might be ready for commercial production after only a few additional years of development. New companies entered the market for solar cells and large established firms also began lines of business in solar photovoltaics. Oil companies were probably the highest profile of these new entrants with all major oil companies getting involved to some degree. They were receiving bad press for high oil prices, had a lot of cash, and had a lot to lose should oil be replaced with another energy source.

The beachhead of terrestrial markets was off-grid applications where competing energy sources were already expensive. Oil platforms abandoned the use of batteries as the standard power source for oil platforms by the end of the 1970s. Oil and gas companies used photovoltaics to provide cathodic protection for their remote wells; a small current running through the metal well would provide resistance to corrosion. The US Coast Guard also began to use solar cells to power lighthouses and buoys. Off-grid photovoltaic systems were installed in developing countries where the cost a photovoltaic system would be less than the cost of building transmission and distribution infrastructure.

A Serious Government-Sponsored Research Program Emerges

Pushing towards the ultimate market of bulk electricity to supply the power grid, the young industry received substantial support from the US government. As the industry grew between 1954 and 1980, silicon-based photovoltaic technology was well past the development stage. In the 1960s, more than $50 million had been spent on research and development for space solar cells. For many of the firms founded in the 1970s, the main challenges were twofold: (1) "downgrading" the cell design of space cells with the goal of making terrestrial cells much less expensive while sacrificing only a little cell efficiency, and (2) setting up cost-effective commercial scale production.

From the government perspective, the primary challenge was seen as encouraging industry to make adequate investments in the technology (DOE 1982, Margolis 2002). The perceived solution to this problem was government purchases that would ensure adequate demand until commercial markets developed – first in remote applications and later in grid-connected applications (Hart 1983). This approach had apparently worked for the semiconductor industry that got its start in the 1950s and 1960s with Department of Defense purchases (Saxenian 1994). In addition, a focused research and development program would help to improve the technology. It was believed that it would "cost $500 million to achieve its goals of a $500-per-kilowatt manufacturing price by 1986[14]" (Herman et al 1977: 87).

[14] For reference, the Department of Energy (and its predecessor the Energy Research and Development Administration) had spent this much on research by 1981. According to Paul Maycock, the average module price was $30 / Watt, or $30,000 per kw in 1975. And in 1986, the average module price was $5 / Watt or $5,000 per kw.

Even before the Arab Oil Embargo, the National Science Foundation has been looking for ways to leverage scientific knowledge to further national interests and solar energy was one area where there seemed to be potential. The program the NSF was running at the time was called Research Applied to National Needs (RANN) and had been organized to help develop applied research and transfer basic research out of research institutions and into industry. As part of the effort, the NSF organized a series of workshops in 1972 and 1973, one of which was the well-known Cherry Hill conference in October 1973. The Cherry Hill conference is notable for bringing together representatives from industry, academia and government who had an interest in advancing the technology. Those attending the conference outlined a 10-year research plan that was later included in President Ford's (originally President Nixon's) Project Independence Blueprint (US Solar Energy Task Force 1974) and shaped the national research program for the next ten years.

Based on recommendations from the Cherry Hill Conference, the Jet Propulsion Laboratory proposed and received funding for the first major effort coordinated by the US government – the Flat Plate Solar Array Project (also known as the Low Cost Solar Array Project and the Low Cost Silicon Solar Array Project). Its goal was to coordinate with industry to reduce the cost of modules, increase cell efficiency, and increase module lifetime. By the end the research project, the technology would be handed over to industry where it was believed the technology would be commercially viable. For solar cells, this meant achieving a conversion efficiency of 10%, 20 year module lifetimes, and a manufacturing cost of $0.50 per watt. If the technology could be developed to this level, it was believed that industry could profitably manufacture solar cells.

The Flat Plate Solar Array Project involved many other research organizations such as MIT's Lincoln Lab, the MIT Energy Lab, Brookhaven National Lab, the NASA Lewis-Research Center, the Army's MERADCOM, and the newly formed Solar Energy Research Institute (which would evolve into the National Renewable Energy Lab). Administering the Flat Plate Solar Array Project was the Energy Research and Development Association (ERDA) which had taken over as the lead government agency for photovoltaics research after it was formed in 1974. The ERDA evolved into the modern US Department of Energy in 1977.

The research plan outlined at the Cherry Hill conference laid out a ten year research program for photovoltaics. It called for $250 million to be spent to improve monocrystalline silicon technology, and $45 million to be spent on polycrystalline silicon. It was important to involve industry as much as possible so that what was learned from the project could be directly brought to commercial production.

There was a set of clear milestones which included not only efficiency and cost targets but also production targets.

The Flat Plate Solar Array Project was a qualified success and it notably helped to establish quality standards for the incipient industry (Jet Propulsion Laboratory 1986). The Jet Propulsion Laboratory conducted several rounds of solar cell purchases from US manufacturers. For manufacturers to qualify for the government purchase, they had to meet certain performance requirements dictated by the Jet Propulsion Laboratory. Five rounds of purchases over a six year period, each with a higher standard than the previous one, led to a uniform performance standard. In between purchases, the modules were extensively tested – outdoors, for humidity and temperature extremes. Twenty-six Project Integration Meetings drew together hundreds from industry, academia and government to discuss outstanding issues and ongoing research.

On the demand side, the federal government also established two purchase programs to support photovoltaic manufacturers in their early stages. The Federal Photovoltaics Utilization Program authorized $98 million to support installation of photovoltaics systems in remote off-grid applications. The Program Research and Development Announcement allowed firms to competitively bid to install medium to large PV systems as demonstration projects. By 1982, the former program funded the cumulative installation of 660 kilowatts of photovoltaics and the latter program supported 729 kilowatts (Margolis 2002).

The Photovoltaics Industry During and After the Energy Crisis

Two of the best known PV firms emerging shortly after the Arab Oil Embargo were founded in California by former employees of Spectrolab. Spectrolab had been founded by Alfred Mann shortly after he founded Heliotek, one of the original solar cell suppliers for the US space program. Eventually the companies were both sold to Textron and were merged and Heliotek's legacy in photovoltaics continued through Spectrolab. In 1975, Bill Yerkes, President and CEO of Spectrolab, left the company to found a new firm named Solar Technology International. Ishaq Shahryar, a scientist at Spectrolab, also left the company in 1976 to found a new firm named Solec International.

Solar Technology International would eventually come to have perhaps the most storied history of any solar photovoltaic company in the United States. It was acquired by the Atlantic Richfield Company (ARCO) in 1977. ARCO Solar became the dominant solar cell company in California and one of a few large solar companies across the United States. Going into commercial production in 1980, ARCO built the first production facility of greater than 1 MW (annual) capacity. ARCO was involved in several high profile photovoltaics projects including the first utility-scale plants, all in California: a 1MW plant in Hesperia serving the Southern California Edison utility, a 6 MW plant in Carrisa Plains serving the Pacific Gas and Electric utility , and two 1 MW plants in Rancho Seco serving the Sacramento Municipal Utility District. Internationally, ARCO developed partners and sold photovoltaics for off-grid applications in over 80 countries. By the time the company was sold to Siemens in 1990, ARCO Solar was the largest photovoltaics manufacturer in the world.

Outside of the California, one of the other major companies was Mobil Tyco, located in the Boston area. Tyco had been operating a research and development lab in Waltham, Massachusetts. In 1965, the lab developed a technology for forming aluminum oxide – also known as sapphire – through a process called Edge-defined Film-fed Growth or EFG. NASA supported EFG research in 1971 for the growth of silicon crystals for space satellites. When it became apparent that EFG silicon could not match the efficiencies of monocrystalline silicon, NASA lost interest. However, when interest in terrestrial solar applications grew after 1973, JPL quickly identified EFG as a lower cost alternative that did not have to meet the same performance standards as space solar photovoltaics.

The standard process for forming the silicon wafers of solar cells involves the casting of a large silicon crystal which is then sliced into wafers approximately 200 microns thick. Slicing such thin wafers generates a high percentage of waste – about 50% - increasing the cost of the silicon per wafer. Because EFG circumvents the slicing process, it offered the possibility of fabricating wafers in a less costly way. Tyco began fabricating silicon using EFG in 1974 and acquired Mobil as a partner. By 1976, Mobil-Tyco began formulating plans to manufacture and license the technology.

Despite the progress and optimism of the 1970s, the 1980s was not a good decade for solar photovoltaic technology and industry. With the election of Ronald Reagan in 1980, there was a philosophical shift over the role of government in industry. The new thinking was that government should stay out of industry and allow the free market to drive economic growth. Instead of seeking to handoff a commercially-viable technology to industry, federal research was to be oriented towards higher-risk research that industry was unlikely to pursue on its own. Demonstration and commercialization activities, which had been important parts of the national photovoltaics program under President Carter – were now considered as best done by private industry.

Government support came to follow a "collaborative paradigm" in which government serves to encourage and coordinate industry development (Bozeman 2000). Japanese industrial success in the 1980s seemed premised on the Japanese government's involvement in coordinating industry. To remain competitive against Japanese firms, the US government sought to work closer with industry, through cost-sharing partnerships. At the same time, firms were beginning to look to external parties to develop collaborative research relationships. With the decline of basic research conducted by industry, a greater share of basic research was being carried out by universities. Firms looking to tap into that research began collaborative relationships with research organizations. Mowery and Rosenberg (1993) summarizes this:

> *"Increasing pressure to reduce R&D costs, to monitor a wider range of merging areas of scientific research, and to speed the commercialization of scientific research has driven many firms to attempt to develop relationships with an array of external institutions...to complement and enhance the payoff from their in-house activities."* (Mowery and Rosenberg 1993 p 54)

Research and development in photovoltaics fit the collaborative pattern. The original national photovoltaics program – in which industry would be handed a commercially viable technology by research scientists and engineers - was dismantled over Reagan's first term. The photovoltaic research budget was cut from $151.6 million in 1981 to $74 million in 1982 to $50 million in 1984 (see Figure 10). The staff of the Solar Energy Research Institute was cut by over 50% from 1000 to 500 and the four regional solar energy centers (in Minneapolis, Boston, Atlanta and Portland) were eliminated. The Reagan administration also sought to eliminate completely the $3.025 billion budget of the Solar Energy and Energy Conservation Bank, an organization originally intended to provide financing to encourage commercialization of renewable technologies. It was only through Congress that it received $150 million. Reagan even proposed eliminating altogether the Department of Energy.

As with the solar research budget, market support declined significantly, through less precipitously, after Reagan took office. When the business and residential tax credits expired in 1985, the residential tax credit was not renewed and the business tax credit was renewed in a much weaker form. The tax credit for business was set at 15% in 1986, 12% in 1987 and 10% in 1988. After 1988, the business tax credit was extended one year at a time making medium to long term project planning all but impossible. It was only in 1992 when the Energy Policy Act established the 10% business tax credit indefinitely.

Any resistance to budget cuts was blunted by decreasing energy prices and slower-than-expected technical progress. The halt of energy price increases and later energy price declines undermined the interest of government as well as industry (see Figure 11, Figure 12, Figure 13). After oil demand fell in the early 1980s and Saudi Arabia broke OPEC's ranks by increasing oil production in 1985, the energy crisis seemed to be at an end. The belief in the 1970s that energy prices would only increase in the future had fed the burning desire to develop alternative energy sources like solar photovoltaics. It no longer seemed true. Decreasing costs in other fossil fuels also hurt the solar industry in a very concrete way. Under PURPA, producers of solar energy were able to sell their electricity to the utility at a rate tied to the cost of fossil fuels (i.e. the "avoided cost"). Lower oil, gas, and coal prices meant solar had to compete against lower priced competition. Finally, technical progress had proved slower than initially expected. One of the original goals set in 1975 for the Flat Plate Solar Array Project was to be able to manufacture solar cells at a cost of $0.50 per watt. In real terms, the solar industry has met this cost only now (in 2009), more than 30 years after the start of the national photovoltaics research program.

Figure 10. United States Federal Budget for Solar Research, 1972-2009

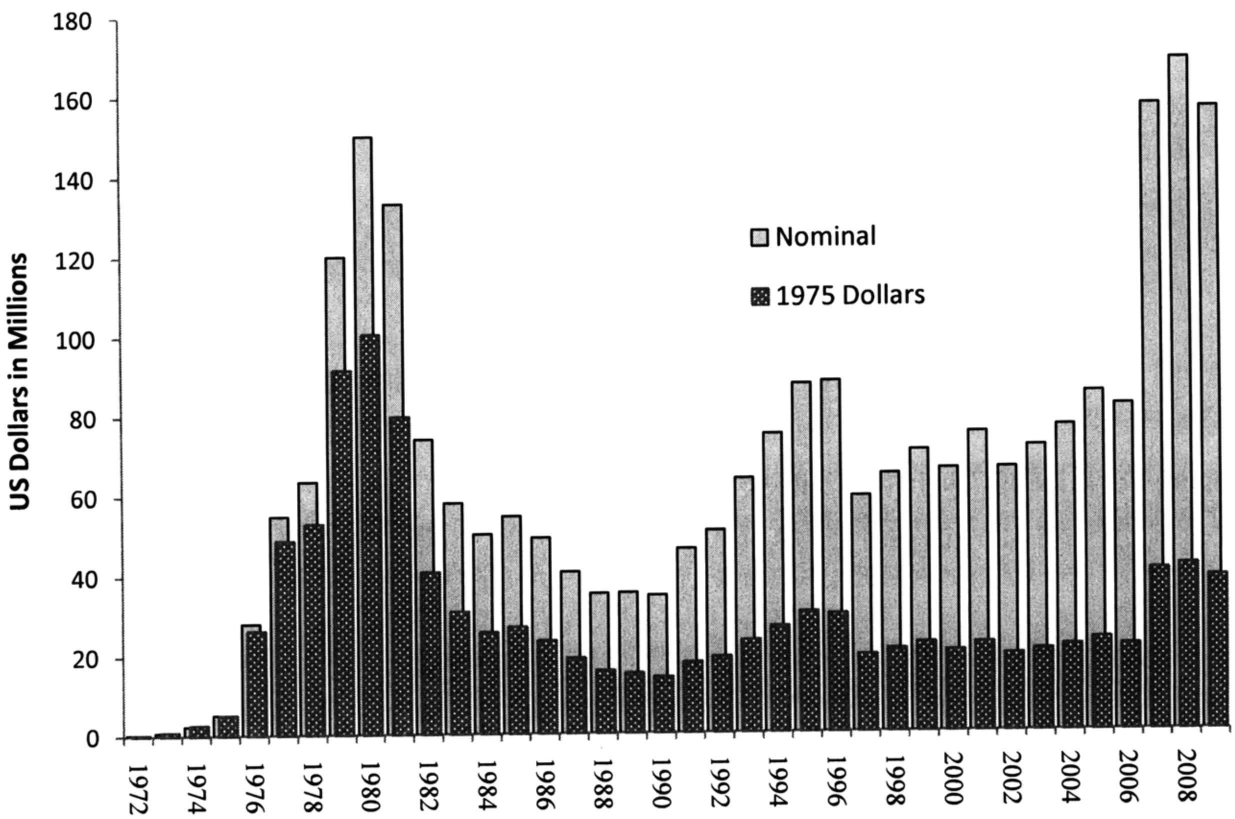


Figure 11. Real World Oil Prices, 1970-1990
(Source: EIA)

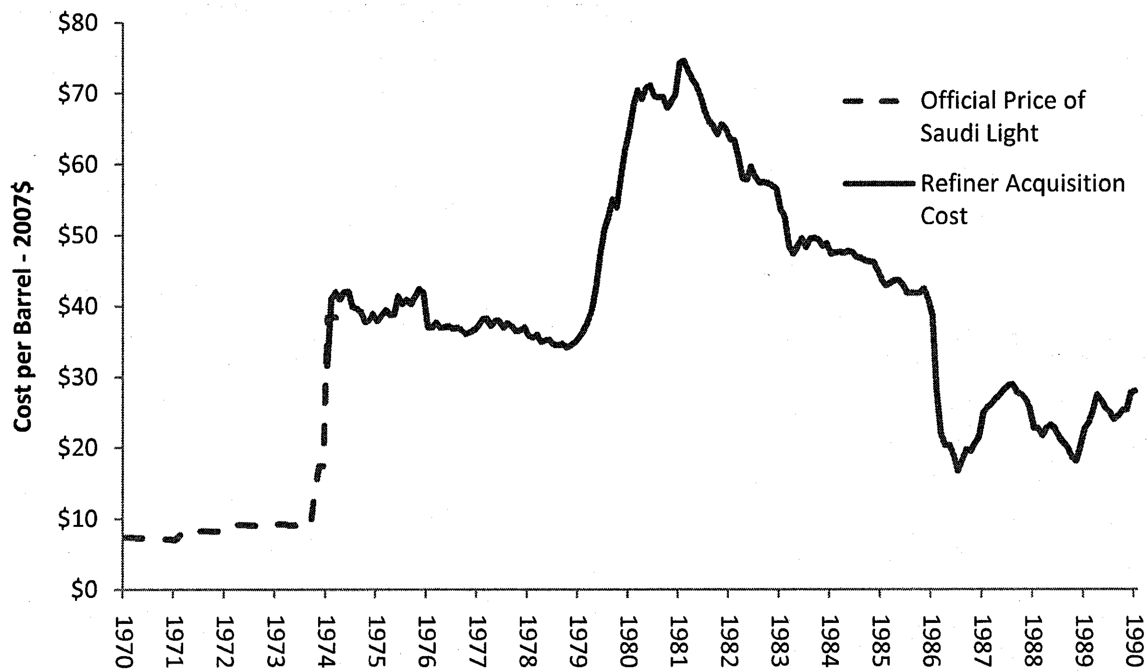


Figure 12. Price of Coal in the United States, 1970-1990
(Source: EIA)

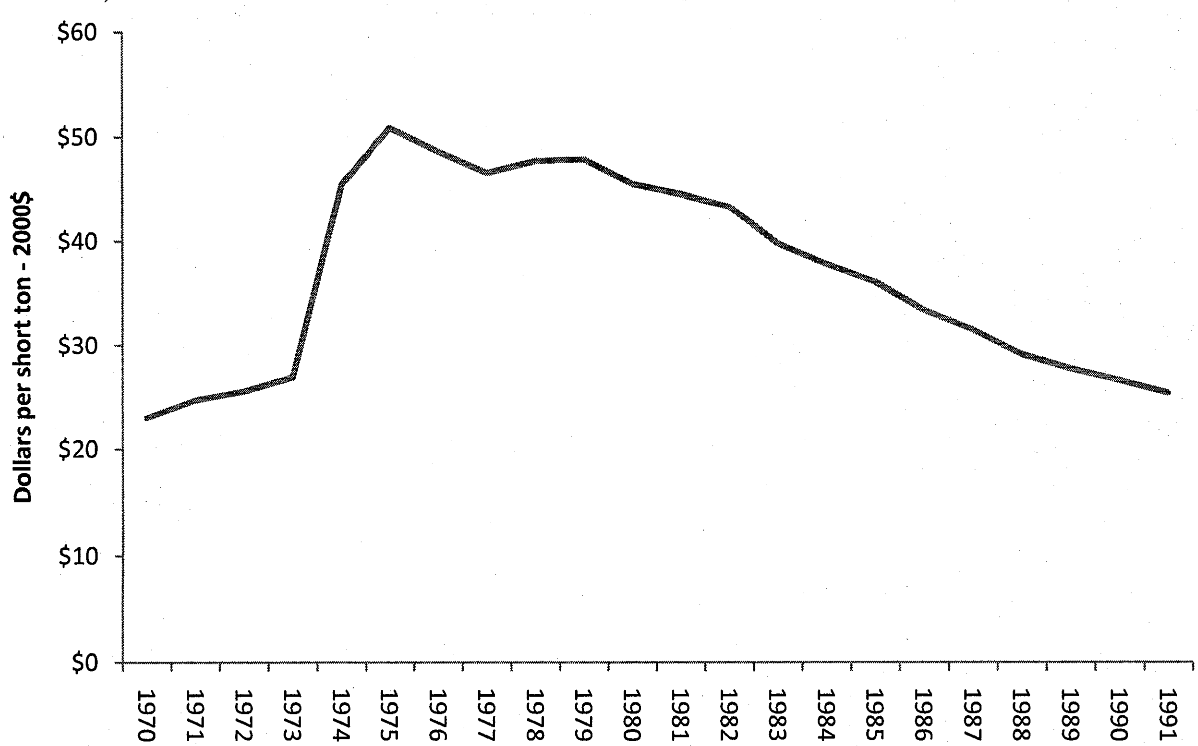
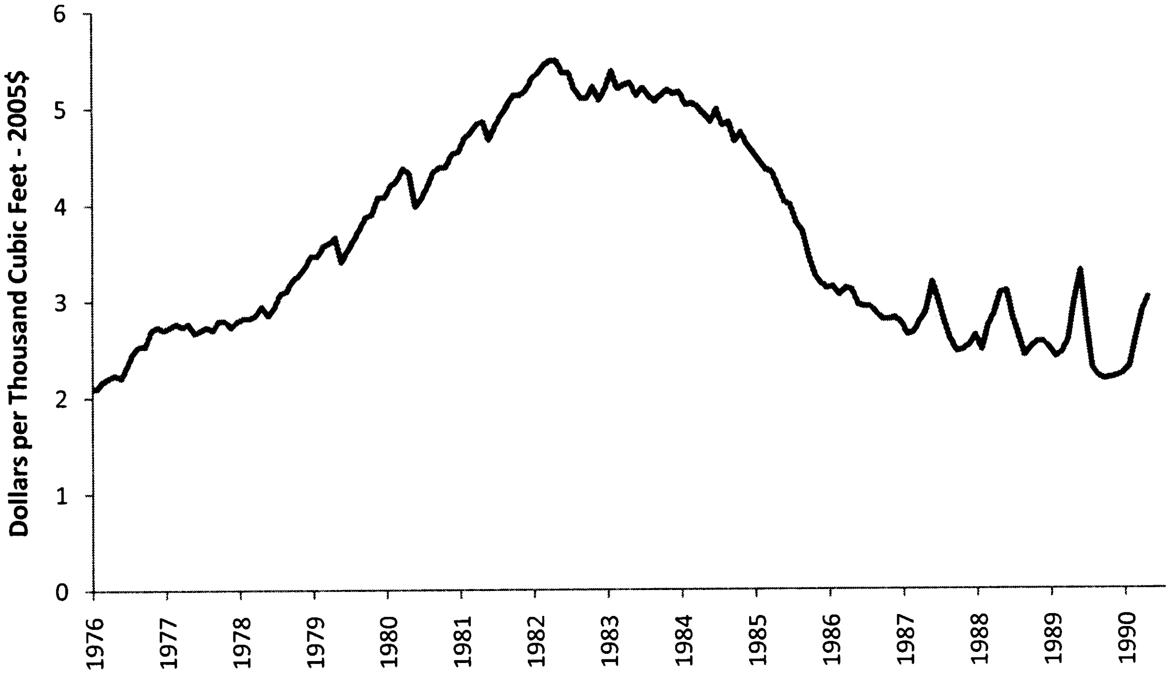


Figure 13. US Natural gas Wellhead Price, 1976-1990
(Source: EIA)



Modest Support and More Modest Growth through the 1990s

In the late 1980s and early 1990s renewable energy was sidelined as the primary focus of the policy agenda shifted to the restructuring of the utility industry. Previously, electric utilities had operated as regulated monopolies, but the goal of the new policy was to introduce competitive forces. Generation of electricity was to be separated from the transmission and distribution of electricity. With drastic changes expected in the near future, many firms and individuals were not prepared to invest until the new rules became clear. In 1992 the Energy Policy Act was passed. The legislation called for the deregulation of electric utilities but left the implementation of the policy up to the individual states. (As of May 2009, 14 states and the District of Columbia had restructured while nine states were in progress.)

During this time period, there were major changes to the organization of research and development and the way new firms were founded. Government helped to encourage industry research and development, often through collaborative arrangements. New firms were founded around more advanced technologies and, as a result, had closer ties to research organizations.

These changes were the result of a newer understanding of the innovation process. Before the 1980s, the view of technological innovation had been strongly influenced by the linear model of the process of technological development described by Vannevar Bush in *Science, The Endless Frontier*. In this view, basic research preceded applied research which in turn preceded development. Based on the success of university-based research in World War II, the belief was that an investment in basic research in universities would lead to technological advances downstream in industry. This was the predominant view of research in the aftermath of World War II. It was also the view implicit in President Nixon's Project Independence. In the same way that university research assisted the World War II effort, university research could be used to assist the US in attaining energy independence.

After 1980, the linear view of innovation held little sway. The experience of separating research from product development, as reflected in the role of central corporate R&D labs in the 1950s and 1960s, was no longer seen as sufficient. Industry stopped doing basic research, creating a division of research labor between universities and firms. Throughout the 1970s, industry was more willing to invest in R&D because they were better able to capture returns from research. But as other countries began to catch up with the US, foreign firms were able to benefit from the research of US firms. In addition increases in the real cost of capital and a slowdown in the growth rate led to a decline in the returns from R&D (Mowery and Rosenberg 1993). The belief that a firm could invest in basic research and eventually produce breakthrough commercial products no longer seemed credible (Hounshell 1996). Ongoing collaboration between universities and industry was seen as the key to technological innovation.

The passage of the Bayh-Dole Act in 1980, shortly followed by an increase in patent and licensing activity, drew attention to intellectual property as a key mechanism for technology transfer. In addition, the success of Silicon Valley and Route 128 led to an interest in studying how regions could develop into entrepreneurial centers. Universities were considered an important element because of the local character of knowledge spillovers and the geographically-constrained behavior of star scientists. Another important element was the emergence an organized institution for investing in innovation – venture capital – which had been developing throughout the 1970s and was validated with the IPO of Genentech in 1980.

Research programs coordinated by the Department of Energy have continued, though none were at the same scale as the Flat Plate Solar Array Project. Three of the best known programs coordinated by the DOE after 1986 are PVUSA, PVMaT, and the Thin Film Partnership and. These programs were funded through a cost-sharing arrangement between industry and the Department of Energy.

PVUSA (Photovoltaics for Utility Scale Applications) started in 1986 as a continuation of a grid-integration project funded during the Energy Crisis[15]. It was a demonstration program that allowed

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[15] The program was called the Solar Photovoltaics Residential Project and was run out of MIT's Lincoln Lab.

utilities to develop more experience with photovoltaic systems. Utilities could get hand-on experience with photovoltaic systems, manufacturers could test new products, and both could gain experience on how systems behaved and were maintained. Systems were installed starting in 1989 and the PVUSA continued through 1998.

The success of PVUSA led to the Renewable Energy and Energy Efficiency Technology Competitiveness Act in 1989 (Taylor et al 2007). It directed the DOE to solicit joint venture proposals as the primary vehicle for renewable energy research and development. PVMaT and the Thin Film Partnership were designed in this model. Beginning in 1992, PVMaT's goal was to reduce manufacturing costs. The program solicited research proposals from industry over five rounds in the areas of "problem identification," "process specific manufacturing" and "product-driven module, components and systems technology." Participating manufacturers achieved production cost decreases of 38%, and the program was considered a success.

The Thin Film Partnership began in 1992 and continues today. It built on this film research that had been going on at SERI throughout the 1980s. It was the first coordinated research effort that covered the primary three thin-film technologies – amorphous silicon, cadmium telluride, and copper indium diselenide. For each technology, teams were formed between industry, universities and the National Renewable Energy Lab. The general goal for each team was to develop the technology far enough so that industry could continue research and development, moving the technology form the pilot plant stage to commercial production.

Only a handful of firms were founded in this time period. The paucity of new firms reflected the stagnant market for photovoltaics. While the off-grid market continued to grow, it was a small market; the technology had not advanced to the point where it would be competitive with other technologies feeding into the utility grid. The new companies, as well as the existing solar firms, had to subsist on the off-grid market, on government research programs, and on niche applications.

Two of the highest profile companies founded in this time frame were UniSolar and Sunpower. UniSolar had benefitted quite directly from participation in the Thin Film Partnership. Founded in 1990 as a joint-venture between Energy Conversion Devices and Canon, it is the oldest company to produce and sell thin-film solar modules. Sunpower was initially founded around a concentrated solar photovoltaic technology but eventually came to focus on high-efficiency crystalline silicon. It is currently one of the industry's leading firms.

Sunpower was founded by a former Stanford professor, Richard Swanson, in 1985. In 1989, Swanson took a sabbatical to develop the company using Series A venture funding and, in 1991, left Stanford to pursue Sunpower full time. Throughout the 1990s, Sunpower sought out niche applications with customers requiring very high efficiency cells and willing to pay the high costs, notably, Honda and NASA. As a small startup subsisting on a small amount of funding from two venture capital firms in the Bay Area, Sunpower could not compete in the bulk terrestrial market against large firms such as Sharp, BP, Shell, Kyocera, Siemens that had diversified into the area and that could endure years of losses before finally turning a profit. Sunpower was a small, high tech firm that was strongly research oriented.

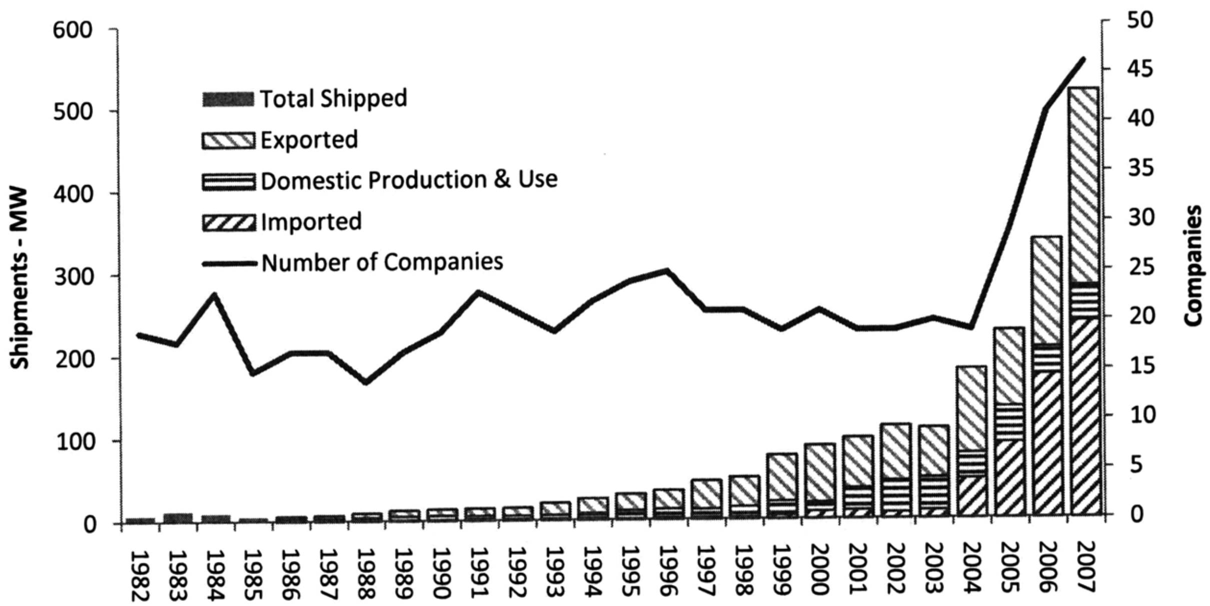
Without a clear, large end-market, Swanson had difficulty of obtaining the type of large investments required to ramp up production capacity, describing his efforts as talking to venture capitalists and banks "until he was blue in the face." In 2000, he found a strategic investor, Cypress Semiconductor, whose CEO, TJ Rodgers, felt comfortable enough with the basic technology to see the potential for growth. In 2001, Cypress Semiconductor invested $150 million in Sunpower and provided its expertise in semiconductor manufacturing. Sunpower began full commercial production in 2004 and went public in 2005[16].

The Current Industry Boom

Around the turn of the century, solar end-markets did begin to materialize and, along with this, more photovoltaic manufacturers (see Figure 14). While the technology was making steady advances, progress was still slow. Solar energy still could not compete directly against other forms of generation, but international government support began to change the economics of solar from the perspective of a potential buyer. Japan, Germany and to a lesser extent the United States had begun to create end markets for the technology by providing subsidies of various forms. This led to a rush of demand that existing and new firms sought to fill.

[16] The successful public offering of Sunpower demonstrated investor interest in photovoltaic technology. Shortly after, in 2006, another successful photovoltaics company - First Solar - went public. Venture capitalists have become more interested in photovoltaics, investing in high profile companies like Nanosolar and Miasole, along with over a hundred starts in the Bay Area.

Figure 14. Active Companies and Shipments in the US, 1986-2007
(Source: EIA, Taylor et al 2007)



*From 1982 to 1985, shipments were not identified as imports, exports or domestic. Thus the "total shipped" from 1982 to 1985 includes imports, exports and domestic. After 1985, the total quantity shipped is the sum of imports, exports and domestic.

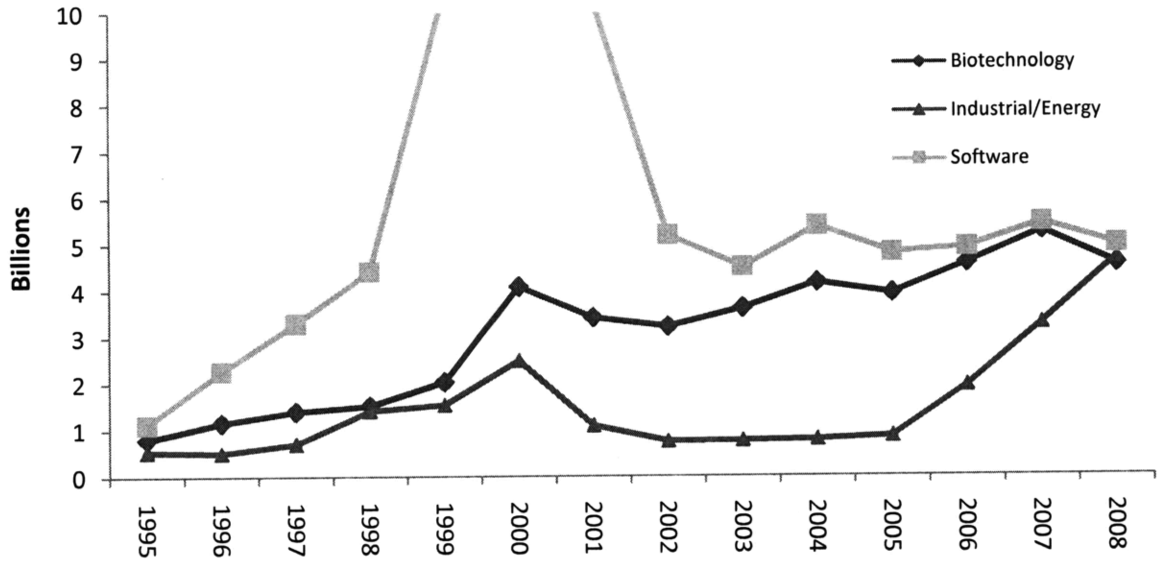
In general, the photovoltaics industry can be divided between firms backed by a large oil or electronics company and "pure play" firms that are pursuing only solar photovoltaics technology. Firms like BP Solar, Sharp and Sanyo belong to the former category while firms like Sunpower, Q-Cells and Nanosolar fit into the latter. Prior to the current industry boom that began at the turn of the century, there were only a handful of pure play solar firms. Without the support of a large backing company, the small firms had difficulty weathering the ups and downs of the market. With the rapid expansion of demand, more room opened up for new firms to be created and to expand. The first category of firms are companies that have significant financial and human capital developed from other lines of business and are diversifying into the solar market. They tend to focus on more established technologies that can be commercially produced with little development time, a strategy that cannot be imitated by many potential competitors.

New, pure play firms can be further divided into two general types. Some of the new firms focus on producing the standard photovoltaic technology that is essentially available "off the shelf." These firms are competitive because of lower manufacturing costs, often owed to temporary cost advantages of locating in eastern Germany shortly after German Reunification. Q-cells was one of several firms founded in Germany that produced photovoltaic cells and modules using standard crystalline technology. Their competitive advantage was in low manufacturing cost and easy access to the growing German end-market. Set up in a part of the country that had once been part of East Germany, the company had access to abundant skilled labor and large subsidies from the European Union and federal and state Germany governments. The same phenomenon of using "off the shelf" technologies while also being globally competitive can now be found in China, a place whose competitive advantage is low cost.

Other new pure play startup firms pursue competitive advantage through technology. They hope to develop a more advanced technology that, if produced commercially, has a chance of defeating the traditional technologies in the marketplace. These firms have been developed by entrepreneurs following the Silicon Valley model of innovation. Before 2001, the interest of the investment community in Silicon Valley was focused on the life sciences and information and computer technology, which had attracted significant capital and scientific and entrepreneurial talent to the region. After the Internet bubble burst in 2001, investors and entrepreneurs sought out new types of technology to invest in. "Clean technologies" have emerged as an important class of high technology investments alongside information technology and life sciences vying for the attention of entrepreneurs and venture capital. One example of this type of firm is Nanosolar, a company that plans to produce copper indium gallium diselenide (CIGS) photovoltaic cells in the form of a printable ink. Another is Nanogram, a firm using its proprietary deposition processes to produce cost-effective thin crystalline cells[17]. Figure 15 illustrates the growing investment in energy technologies.

[17] Thin crystalline silicon is a fairly recent approach to solar cells. It begins by depositing a thin layer of silicon on a substrate and then heating it until the silicon crystallizes. The appeal of thin crystalline silicon is to have the low materials cost of thin film technologies, while also having the high efficiency of crystalline silicon.

Figure 15. Venture Capital Investment in Energy, 1995-2008
(Source: PWC Money Tree)



The History of Incentive Programs and Policies Supporting Solar

Although the ultimate goal remains to reduce the cost of solar so that it can compete against and replace other forms of generation, several countries have considered solar such an attractive proposition that they sought to accelerate its development and deployment. It was the policies Germany and to a lesser extent Japan and the United States that set off the recent phase of rapid industry growth.

Germany

Although part of Germany's response to the energy crises of the 1970s was to begin solar research (which started in 1974), its overall strategy was to focus on coal and nuclear energy. Interest in photovoltaic technology did not take off until nuclear fell out of favor. Throughout the 1970s and early 1980s, there had always been strong but not overwhelming opposition to nuclear power. It was the Chernobyl accident, however, that took place nearby in the Soviet Union in 1986 that turned the tide strongly against nuclear energy. Fear of radioactive fallout led people to remain indoors as much as possible and even slaughter cattle thought to be exposed to radiation. Until 1985, public opinion was split over the nuclear energy question but after Chernobyl, public opposition to nuclear increased to 90% (Jahn 1992). Chernobyl also had an effect on the Germany research budget for solar energy. Solar research increased every year from 1974 until 1982 when it started to decline. It was because of Chernobyl that this downward trend reversed.

Amongst people and firms alike, there was a growing recognition that alternative energy sources would be necessary. Large German firms vested in nuclear technology, such as Siemens, began looking for alternative lines of business. Siemens was perhaps the first major German company to start a solar line of business. They were the primary participant in a research program funded almost entirely by the Germany government in the late 1980s. Siemens eventually bought ARCO Solar in 1990, the largest solar company at the time, and renamed it Siemens Solar.

While the United States is most notable in the history of photovoltaics for being the birthplace of the technology and its many variants, Germany is most notable for developing a large and stable end market. Incentives for renewable energy started at a national level in 1991 and were revised in 2000, 2004 and 2008.

In 1991, the German government established the first feed-in tariff through the Feed-In Law of 1990. It required utilities to buy electricity from third parties at 90% of the retail electricity rate. This meant that non-utility actors could build generation capacity and that renewables would not have to compete directly against traditional generation (rather, renewables would compete against traditional generation plus transmission plus distribution). Although the rate offered by the 1991 feed-in tariff was still too low to encourage the installation of photovoltaic systems, it did encourage significant wind installations and set the precedent for later feed-in laws.

Although the feed-in tariff was proposed as early as 1988, the first concrete step in supporting photovoltaics was a demonstration program called the 1000 Roofs Program[18]. Between 1990 and 1995, the 1000 Roofs Program had supported the installation of over 2000 photovoltaic systems with a total capacity of 5 megawatts. The incentive it offered was substantial – 70% of the total system cost. "New" states in the recently reunited Germany paid 10% of this while the federal government paid 60%. For states that were part of West Germany, the federal government paid 50% of the subsidy and the state government paid the remaining 20% (Margolis 2002, Lauber and Mez 2004). With the end of the 1000 Roofs Program, the Germany solar market maintained some stability through state and local incentive programs such as the enhanced feed-in tariff offered in Aachen.

[18] Incidentally, it was also the first salvo in an international competition of "Roofs Programs." Japan later organized what is called the 10,000 Roofs Program. Germany, not to be outdone, set up a 100,000 Roofs program a few years later. Though a late entrant in the competition, the United States boldly proposed a Million Solar Roofs Program.

However, the next major period of growth came with the rise of the Red-Green Coalition to national power in 1998. A key part of their platform was job creation and economic development through environmentally-friendly energy policy (Lauber and Mez 2004). Under the Red-Green coalition, construction of future nuclear plants was halted with the Nuclear Energy Phase-Out Act. The government embraced the Kyoto Protocol and reaffirmed carbon-dioxide reduction targets with the Climate Change Policy Action Program. The government also set a target for 12.5% of electricity supplies to come from renewables by 2010 and 50% by 2050[19].

Its first major action to support solar photovoltaics came in 1999 with the start of the 100,000 Roofs Program. Although the initial goal had been to revise the feed-in tariff set in 1991 to be more amenable to solar, there was concern that working out the details of the new feed-in tariff would slow down industry growth. The 100,000 Roofs Program was designed as a stop-gap measure. It was a subsidized, guaranteed loan program with 0% interest. The loan would be paid back annually over ten years with no payments required for the first two years. If the borrower successfully made the first seven payments, then the last payment would be waived. This amounted to a 35% subsidy (Stryi-Hipp 2004). The government budget for the program was €460 million and its goal was the installation of a cumulative 300 megawatts by 2004 when the program was scheduled to end. While the 100,000 Roofs Program did encourage the installation of photovoltaic systems, it was not initially as successful as hoped. The installation goal for 1999 was 18 megawatts, but only nine megawatts were installed that year.

In 2000, the Renewable Energy Sources Act was passed establishing a new feed-in tariff with a rate of 1 Deutsche Mark per kilowatt hour (about $0.50 per kilowatt hour). Unlike the 1991 feed-in tariff, the 2000 feed-in tariff was cost based, that is, the designers of the tariff calculated the cost to install a photovoltaic system with a modest return on investment and set the feed-in tariff rate to that level. To encourage cost reduction by industry, the level of the feed-in tariff was to decrease by 5% every year. Also, unlike the 1991 feed-in tariff, the rates were set for 20 years. Between the 100,000 Roofs Program and the new feed-in tariff, the government set an installation goal of 350 megawatts by 2003. As originally designed, the feed-in tariff was capped at 350 megawatts of capacity. With the addition of the new feed-in tariff, the terms of the 100,000 Roofs Program were adjusted downwards. The last payment was no longer waived and the interest rate was increased from 0% to 1.9%.

The combination of the feed-in tariff and subsidized loans created overwhelming demand for solar systems. In fact, it strained the annual budgets for the subsidized loan program. The feed-in tariff cap of 350 megawatts was raised to one gigawatt in 2002 and eliminated altogether in 2003. By the time the

[19] Germany has already met the first target. In 2007, 14.2% of electricity was provided by renewable energy sources (German Federal Ministry for Environment, March 2008).

100,000 Roofs Program ended in 2002, it had given out €1.72 billion in loans, almost four times the original budget. Germany had exceeded its 350 megawatt goal with 431 megawatts of solar installations.

The German experience over the past few years suggested that a subsidized loan program would only encumber growth. Planning the 100,000 Roofs Program required the government to set a budget and when that budget was exceeded, government action was required to increase the budget. The revision to the feed-in tariff made the rates slightly more attractive and differentiated between types of systems. Small rooftop systems would receive € 0.574 per kilowatt hour and ground-mounted systems would receive € 0.457 per kilowatt hour. These rates were designed to give investors a 6.5% return on their investment and, like the 2000 feed-in tariff, these rates would also be decreased each year – by 5% for roof-mounted systems and 6.5% for ground mounted systems.

Table 4. Past and Future German Feed-in Tariff Rates

	Year	Feed in tariff (for roof-mounted systems)	Baseline feed-in tariff reduction rate for following year (for roof-mounted systems)	Lower bound (MW)	Upper bound (MW)
Original Feed in tariff, 2000	2001	50.6	5%		
	2002	48.1	6%		
	2003	45.3	N/A (law revised)		
Revised Feed in tariff, 2004	2004	57.4	5%		
	2005	54.5	5%		
	2006	51.8	5%		
	2007	49.2	5%		
	2008	46.8	5%		
Revised Feed in tariff, 2009	2009	43.01	8%	1000	1500
	2010		8%	1100	1700
	2011		9%	1200	1900

The dramatic success of the feed-in tariff in encouraging installations from 2004 to 2008 prompted another revision in 2008. The main change was to accelerate the rate of decline in the feed-in tariff from 5% for roof-mounted systems to 8%. (The new rate for ground-mounted systems is 10%). A means to adjust the rate decrease was also put into place. If annual installation volume stays within a certain range, then the decline of the feed-in tariff will remain at 8%. If volume falls below the range, then the feed-in tariff will only decline by 7% and if the volume falls above the range, then the feed-in tariff will decline by 9%. Table 4 list the upper and lower bounds that would trigger an adjustment to the rate of decline. Note that cumulative installation in 2008 was 1500 megawatts. If system costs can keep up with the feed-in tariff rate decrease schedule and electricity prices continue to increase at 3% annually, the German government expects to reach grid parity between 2012 and 2015.

Japan

Although Germany's policies have been critical in spurring industry growth since 2000, Japan should be recognized for being the first country to subsidize the installation of photovoltaic systems at a national level. Like Germany, Japan first showed interest in solar energy after the Arab Oil Embargo. It began a broad research program – the Sunshine Project – in 1974 that set a research budget for solar energy along with funding for coal gasification, geothermal energy and hydrogen fuel cells. Japan's interest in solar stems from its lack of natural energy resources (e.g. oil) and resulting dependence on foreign imports. It was calculated that if solar systems were installed on 22% of single family homes and 50% of multifamily homes, that 5% of Japan's total electricity consumption could be supplied by photovoltaics.

Japan's support for the technology initially focused on materials research but by 1983, it shifted support to focus on deployment of the technology – developing photovoltaic systems and manufacturing techniques. It oriented research towards the mass production of small system. Given Japan's mountainous geography and high population density, flat land is scarce and expensive. Large, utility-scale solar plants were ruled out as a cost competitive option and economies were sought out through mass production instead.

In 1986, Japan field tested one of the earliest distributed generation systems on Rokko Island (Green 2000). Photovoltaic systems were installed on 180 "dummy" houses which ran many of the typical electronic appliances found in Japanese homes. The field test allowed scientists and engineers to study the technical issues associated with distributed generation in a systematic way under well-controlled conditions.

Starting in 1993, Japan's New Sunshine Program sought to pursue the commercialization and deployment of solar technology. The following year, its flagship incentive program, the Residential PV System Monitoring Program, was started. Initially the government paid two-thirds of the total system cost, but this was quickly scaled back to pay one-half of the total system cost. The government also issued the Basic Guideline for New Energy Introduction in 1994, calling for the installation of 400 megawatts of photovoltaic capacity by 2000 and 4.6 gigawatts by 2010[20,21]. This was believed to have sent a signal to industry that the government saw its support to solar energy as a long term commitment. Japan also ran several "Field Test" programs which also supported the installation of medium sized photovoltaic systems. However, these programs were relatively small in scale and intended more as a demonstration program for solar installations in new operating conditions.

Adding to the value of the photovoltaic systems, the utilities had agreed to buy back any excess power generated by the system owner at the full retail rate. No law was required and the utilities volunteered to do this as far back at 1992. Even excluding the Japanese subsidy program, the incentives for solar energy in Japan (electricity sold the retail rate) was greater than incentives in Germany (electricity sold at 90% retail rate).

The residential incentive program was revised in 1997 and renamed the Residential PV System Dissemination Program. The subsidy level was decreased from one-half to one-third and a schedule put in place for further reductions in the subsidy level. In 2000, the subsidy decreased to 24%; in 2001 it was 16%; in 2002, it was 14%; and 2003 it was 13%. The decreasing subsidy level was an innovation photovoltaic support and was later imitated by Germany and California.

In 2003, the program was revised again and set to be phased out completely after 2005. The same year, Japan announced a national renewable portfolio standard with solar expected to generate 1.35% of total electricity demand by 2010. One of the unexpected observations about system installations in Japan is that the market continued to expand even as subsidy levels decreased. Observers abroad in the United States and Germany hailed this as a great success to be followed, interpreting the decreased installation prices and market expansion as the result of industry learning.

Recent developments in Japan have cast some of these observations in a new light. After the incentive program was phased out in 2005, it was expected that local incentive programs would keep the photovoltaic markets growing. While installation levels did not drop off entirely afterwards, they did

[20] The 4.6 gigawatt target was adjusted upwards to 5 gigawatts in 1998 under the revised Long-term Energy Supply and Demand Outlook (Ikki 2003).

[21] Japan will probably fall short of this target. Through 2008, Japan had about 2.2 gigawatts of installed capacity and a steady annual installation rate of 200-300 megawatts since 2001 (see Figure 3).

level off. Some have argued that it was not the lack of incentives per se, but rather the perceived lack of public support coupled with a declining housing market, shortages in polysilicon supply and large photovoltaic demand in Europe (Jäger-Waldau 2009). Hoping to reverse this trend, the government has reinitiated the subsidy program in 2009. With a budget of 29 billion yen, it will offer an incentive level of 70 yen per watt.

One mystery that emerges from this is how the Japanese managed to continue installations at a modest rate without subsidies to bridge the cost – benefit gap. Wiser et al (2009) estimate the cost of photovoltaic systems in Japan at $5.9 per watt. Using that cost, along with the PVWatts insolation value for Matsumoto, Japan, the cost of solar energy is still $0.357 per kilowatt hour. In contrast, the average cost of residential electricity in Japan for 2006 was $0.178 per kilowatt hour (International Energy Agency 2008). This begs the question as to whether there are other incentives that are not understood (at least by international commentators) or whether system buyers do not make the same cost-benefit calculation as is made in the United States and Germany.

The United States

The history of market support for solar in the United States parallels its support for solar research: bold possibly brash early steps followed by steep cuts in support then followed by more sophisticated but modest support.

During the Energy Crisis, solar photovoltaics were supported in three ways by the government. The first was direct federal purchases of photovoltaics - enabled by the Department of Energy Act of 1977, the National Energy Conservation Act of 1978 and the Solar Photovoltaic Energy Research Development and Demonstration Act). The Federal Photovoltaics Utilization Program, established by the Energy Conservation Act, authorized $98 million to support installation of photovoltaics systems in remote off-gird applications. The Program Research and Development Announcement (PRDA) allowed firms to competitively bid to install medium to large PV systems as demonstration projects. By 1982, the FPUP funded the installation of 660 kilowatts of photovoltaics and the PDRA supported 729 kilowatts (Margolis 2002). Government purchases were also made for research purposes, as part of the Flat Plate Solar Array Project.

The second approach was to encourage purchases by private companies. The key mechanism was tax cuts. The Energy Tax Act of 1978 set a 10% tax credit for businesses installing photovoltaic systems. This was enhanced in 1980 by the Crude Oil Windfall Profit Tax Act of 1980 which increased the tax credit for business to 15% and introduced the first residential tax credit at a rate of 40% applicable for up to $10000 (essentially capped at $4000). In addition to the tax credits, the 1981 Economic Recovery Act established a five year tax depreciation schedule for photovoltaic systems instead of a 15-year schedule, increasing the net present value of tax benefits from the purchase. It also set up a 10% general equipment investment tax credit which could be combined with the 15% tax credit from the Crude Oil Windfall Profit Act; this amounted to a 25% tax credit.

The third was to create space in the electricity generation industry for producers of solar energy. Congress passed the Public Utilities Regulatory Policies Act (PURPA) in 1978 which opened the door for distributed generation. It was at first intended to encourage cogeneration – using the heat in generation for electricity generation as well as industrial processes (at a chemical plant for instance). It mandated that utilities purchase electricity from non-utility power producers at utilities' avoided cost; this established a clear economic value. Prior to PURPA, utilities had no obligation to buy electricity generated by third-party power producers. PURPA sowed the seeds for deregulation of the utility industry by recognizing the right of non-utilities to generate power and, when some non-utilities turned a profit, raising questions of whether the natural monopoly model of utilities was most efficient.

As with the solar research budget, market support declined significantly, through less precipitously, after Reagan took office. When the business and residential tax credits expired in 1985, the residential tax credit was not renewed and the business tax credit was renewed in a much weaker form. The tax credit for business was set at 15% in 1986, 12% in 1987 and 10% in 1988. After 1988, the business tax credit was extended one year at a time making medium to long term project planning all but impossible. It was only in 1992 when the Energy Policy Act established the 10% business tax credit indefinitely.

The restructuring of the utility industry, starting in the 1990s, helped create room for solar generation. The Energy Policy Act of 1992 established a class of power producers known as exempt wholesaler generators. Though exempt wholesalers were not assured a price for electricity generated as cogeneration facilities under PURPA, they were assured access to transmission infrastructure and were exempt from certain requirements for generation facilities under PURPA. This made it easier to directly compete for generation against utilities.

In the current system of photovoltaic market support, solar is supported by a combination of incentives at the federal and the state levels that encourage the purchases from private entities. The federal government offers tax credits for business and individuals. Tax credits for solar increased with the passing of the Energy Policy Act of 2005. It increased the business tax credit to 30% and reinstated the residential tax credit also at 30% but capped at a $2000 total. While generous, one drawback was that the tax credit had only been established for only two years, making long term project planning difficult. It was extended through the Tax Relief and Health Care Act of 2006 extended it for one more year (for 2008). This problem was solved in October 2008 when the Emergency Economic Stabilization Act was passed, extending the tax credit for an eight year period in October 2008, removing the $2000 cap for residential systems and allowing utilities to take the tax credit (they had been barred previously).

The tax credit was augmented in February 2009 as part of the American Recovery and Reinvestment Act. It addressed the problem of a weak market for tax equity – a requirement for monetizing the tax credit. For commercial photovoltaic systems, the act allowed owners to apply for grants equal to the amount of the investment tax credit as an alternative to the credit. While this will only last for 2 years and does not apply to residential systems, it is helpful in a low capital economic environment.

The depreciation benefit established in 1981 continues to the present and has been temporarily enhanced with the Economic Stimulus Act of 2008 and the Recovery and Reinvestment Act of 2009. This allowed for "bonus" depreciation for systems acquired and placed in service in 2008 or 2009. Half of the property value can be deducted the first year with the remaining 50% of the value is depreciated over the standard 5 year schedule.

State governments also encourage the solar energy markets by providing financial incentives and setting up market conditions that encourage solar generation. Many state governments offer direct rebates to businesses and individuals installing a photovoltaic system and some even offer state tax credits. The majority of states also allow net metering, which allows electricity consumers to sell their electricity back to the utility at retail rates and pay for only the net electricity consumption. Also, state public utility commissions can influence the rate structure for utility customers. Tiered electricity rates and time-of-use pricing can make solar generated electricity more valuable than under flat electricity rates. Finally, many states are implementing renewable portfolio standards which can help to establish a value of energy generated from renewable sources.

At the state level, 16 states had offered incentive programs for solar as of 2007 and California's has been the largest by far. Several features of the California electricity market make it an attractive market for photovoltaics. Most salient are the direct rebates that reduce the net cost of a PV system. The first statewide rebate program was the Emerging Renewables Program which started in 1998 as one component of the deregulation of the California energy market. In 2001, it was enhanced by the Self-Generation Incentive Program which was targeted towards large PV systems. Both these programs ended and were replaced by a larger incentive program as part of the California Solar Initiative (CSI) starting in 2007. The goal is to support the goal set out by the Million Roof Solar Initiative, which called for the installation of 3000 MW of solar capacity by 2017. Of the $3.3 billion total, $2.1 billion is administered by the Public Utility Commission to support incentive programs for the large investor owned utilities – Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric. About $800 million is set aside to support incentive programs for municipal utilities like the Los Angeles Department of Water and Power. In addition, $400 million is set aside to support the New Solar Homes Partnership which encourages photovoltaics and energy efficiency in new construction. Up to $50 million is set aside for research, development and demonstration. The program is funded by ratepayers.

The incentives provided by CSI in the area served by the three large investor owned utilities are guided by the principle that the level of incentive should decrease as more photovoltaic capacity is installed. For each territory, potential capacity is divided into a series of "steps." Each step is associated with a certain amount of PV capacity and a certain rebate rate. After the capacity of one step is accounted for, new system installers would move on to the next step, which has a smaller rebate level.

Step 1 was 50 MW in capacity and had a rebate level of $2.80 per watt. Step 2 had 70 MW in capacity and a rebate level of $2.50 per watt. Residential systems in the PGE area are currently (as of July 2009) on Step 5, which has 160 MW and a rebate level of $1.55. The numbers provided here are for residential system owners; for government or non-profit organizations, the rebate level is about 30% higher.

An important feature of the California incentive system is the way the system size is determined. Many other states measure size in terms of DC capacity, that is, they simply add up the ratings of solar modules (20 x 200 watt modules = 4000 watts). While system size is correlated to the amount of electricity generated, it is often not an accurate predictor of the electricity that will be generated. DC capacity does not consider environmental conditions (like temperature), angle of installation, inverter losses, shading, and so on. California uses a more sophisticated method for calculating effective system size, which is approximately 85% of the DC capacity. This difference in calculation is significant because the incentive amount applies to this smaller system size, leading to a smaller incentive than if it were calculated using DC capacity. California's term for the rebate reflects the adjustment based upon expected performance: the Expected Performance Based Buydown.

CSI also makes a distinction between small and large systems. Owners of systems larger than 50 kw cannot receive an up-front rebate and instead they receive 60 monthly payments based on the amount of electricity that is generated. The expectation is that, by rewarding electricity output, system owners will be encouraged to maximize output through design and maintenance decisions. Like the rebates, the size of the incentive decreases over a series of steps. Step 1 had 50 MW and offered an incentive of $0.43 per kwh. Step 2 had 70 MW with an incentive of $0.39 per kwh. The PGE area is currently in step 6, offering $0.15 per kwh. As with the rebate level, the incentive for government or non-profit organizations is about 30% higher. California calls this a Performance Based Incentive.

Another important feature of the California market is its electricity rate structure. The standard rate structure is has five price tiers and the more electricity that is consumed, the higher the tier (like the US federal income tax). After the California energy crisis in 2001, more revenue was required to repay the debts that had been incurred and the then-two-tier pricing structure was changed into a five tier structure. The difference between tiers is significant; Compared to a "baseline" level of use, marginal electricity in the fifth tier (for electricity consumed beyond 300% of the baseline quantity) is charged at approximately twice the baseline price. Depending on the energy use of a PV system-owner, solar electricity may only have to compete against the high marginal cost of utility-generated electricity. Another alternative for ratepayers is to select a time-of-use rate plan. Electricity rates differ for "peak" and "off-peak" consumption and by the season of the year (there is no real-time pricing). Since solar electricity production peaks at around midday, it only needs to compete against the "peak" rate rather than the average or "off peak" rate.

California's Renewable Portfolio Standard (RPS) mandates that 20% of all electricity generated must come from renewable sources by 2010. The RPS was originally established in 2002 and called for a 20% target by 2017. In 2006, however, a more aggressive goal was established: 20% by 2010. As of 2007, California's three large investor-owned utilities supplied 12.7% of their power from renewable sources. An unofficial goal of 33% has been set for 2020, and there is interest in passing legislation to bind the state to the new target. However, the RPS will only encourage some types of photovoltaic installations. Large photovoltaic plants – either owned by the utility or whose output is sold directly to utilities – counts towards the RPS target. However, distributed solar generation that is net metered cannot be used by a utility to fulfill its RPS requirement. Thus the RPS will not incentivize utilities to encourage their customers to install photovoltaic systems.

Other features that enhance the attractiveness of the California market for solar PV include the state income tax credit, the market-based feed-in tariff and the property tax exemption. California offered residential and commercial tax credits starting in 1976 at a rate of 10% capped at $1000. The tax credits were modified many times – 1977, 1978, 1979, 1980, 1983, and 1985 - before expiring in 1986. At one time, California's commercial tax credits were an extraordinary 50% (Margolis 2002). More recently, a state income tax credit of 15% was put in place in 2001, supplementing the federal tax credit which was only 10% at the time. It applied to the cost of the PV system net of other incentives at the federal, state or municipal level. In 2003 and 2004, the tax credit was reduced to 7.5% and by 2005 the credit was eliminated. Despite attempts to continue the tax credit, the 30% federal tax credit that was passed in 2005 rendered the state tax credit unnecessary. The feed-in tariff, known by the bill number in which it was passed (AB1969), allows solar power producers to sell their electricity to the utility in lieu of receiving a rebate from the state at a price based on the market price of comparable electricity. Since it is based on the market price (unlike the German feed-in tariff which is cost-based), it offers a much lower rate than feed-in tariffs in Europe and elsewhere and has failed to create a large stir in the California PV industry. The property tax exemption started in 1999 and was recently extended to 2016, making the additional property value from the solar system excludable for purposes of assessing property tax.

Interconnection and net metering allow system owners to connect their PV system to the grid. It obviates the need for a battery and charge controller which would increase the overall system cost. So long as solar energy makes up only a small proportion of the total energy on the grid, the feeding of electricity from decentralized intermittent sources will not be a problem. Net metering, along with simplified rules for grid connection, was allowed for systems in California up to 10kw starting in 1996. Starting in 2000, time of use net metering was allowed, meaning that system owners could sell their electricity at "peak" rates during the middle of the day. Today, systems of up to 1 MW in size can be net metered, though there is a cap on net metered electricity of 2.5% of the system's aggregate peak capacity (thus the utility does not have to deal with the intermittent nature of the energy source). California's own interconnection standard, Rule 21, was established in 2000 before the national technical standard, IEEE 1547[22]. It contains details for a broader set of issues than Rule 21, though the portions that overlapped were updated to be consistent with IEEE1547.

Closing Remarks on Incentive Programs

Incentives for solar energy have been important not only for deployment and reducing carbon emissions, but for the development of local industry. Having easy access to a reliable source of demand is an important factor for the development of a new regional cluster (Bresnahan, Gambardella and Saxenian 2001). Thus far, the presence of strong domestic demand has helped to develop local industry. For Germany, the feed-in tariff is part of an industrial policy. The policy considers photovoltaic solar energy as an inevitable part of future generation and when the technology progresses to the point where it is directly competitive with traditional forms of generation, then German firms with German workers will be at the forefront of industry.

[22] In 1998, standards for interconnection varied from utility to utility and the DOE began an effort to standardize interconnection nationally. The result was IEEE 1547 approved in 2003.

There are exciting prospects for the future of photovoltaic technology and industry. Yet as we saw in Table 1, buying down the cost of solar energy can be an expensive proposition. There is inherent uncertainty in terms of total cost and time required to reach grid parity. Considering the magnitude of the climate change problem, are resources best spent on photovoltaics? Another concern is the implicit assumption that reaching grid parity for photovoltaics is a resource-constrained problem. Regardless of the resources committed, how soon can grid parity be attained? And will this be soon enough to play a significant role in meeting carbon emission reduction goals for 2050? There may be a natural "elbow point" in the tradeoff between the level of resources committed and the value derived from investment in photovoltaics. Policymakers should think carefully before going beyond this point.

Section III - Why Will the Cost of Solar Decrease?

Many have made the argument for why the cost of solar energy will decline in the future. Some of these arguments are engineering-based, looking at specific technical changes to features of photovoltaic systems to estimate future costs. Other arguments are made on the basis of the experience curve. In this section, I will provide an overview of both types of arguments.

To understand the technical reasons why the cost of photovoltaic systems might decline, it is necessary to understand what exactly comprises the cost of these systems in the first place. Figure 16 shows the breakdown of system costs per watt according to Pacific Gas & Electric. Built into these figures are the direct costs as well as overhead and profit.

A system integrator will design the system, conduct administrative tasks, coordinate the system installation and purchase the system's physical components - the photovoltaic modules, inverter, and mounting hardware. The costs, overhead and profit of the system integrator fall into the two rightmost blocks of Figure 16, each block accounting for $1.35 of the total system cost Mounting hardware and miscellaneous electrical components like wire and junction boxes fall within the $0.45 "other components" block of costs. The inverter manufacturer's cost, overhead and profit is $0.45 per system. The remaining four components – totaling $4.30 show the breakdown of module manufacturing costs, which also include overhead and profit of the module manufacturer[23].

Table 5 shows a comparison of the Pacific Gas & Electric cost breakdown with other estimates. Where possible, the table splits out the direct cost of the component from overhead and profit. Although the exact numbers vary from estimate to estimate, there is some consistency of general trends. Module costs per watt range from $3.75 to $4.50, about 50% of total system costs. Installation costs range from $2.00 to $3.25 per watt, about 35% of total system costs. Costs for the inverter and other hardware range from $0.90 to $1.41 per watt, about 15% of total system costs. This suggests that to reduce system costs, the two general areas to target in module manufacturing and in system integration and installation.

[23] The distinction between "cost" and "profit" depends on whose point of view is taken. The direct costs of manufacturing the module (e.g. labor required to wire cells together) is pooled together with indirect costs (e.g. maintenance of machinery), overhead (e.g. renting the land for the plant), and profit into the price that the manufacturer charges the customer. From the perspective of the module manufacturer, the cost would only include the direct costs. From the perspective of the system integrator, the module cost includes all related costs as reflected in the manufacturers sales price.

Figure 16. Breakdown of Grid-Connected PV System Costs
(Source: Henderson et al 2007 citing PG&E)

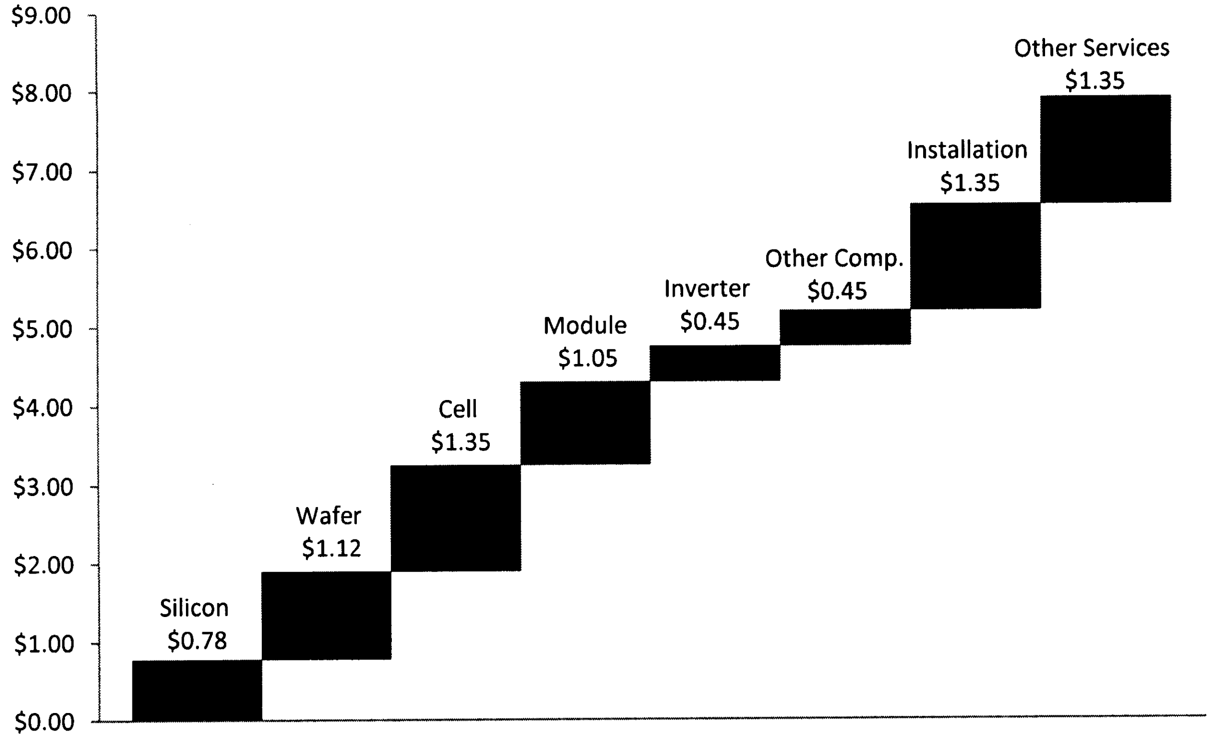


Table 5. Comparison of Several Estimates of PV Systems Costs
All values are price per watt (DC)

		Pacific Gas & Electric	Lawrence Berkeley National Lab (Wiser et al 2009)	Photon Consulting (2007)	Wall Street Journal/Thomas Wiesel partners (Osborne 2008)	IPC Interviews
Module*	Silicon	$0.78	$3.94	$0.78	$1.50	$4.50
	Wafer	$1.12		$1.12	$0.75	
	Cell	$1.35		$1.30	$0.75	
	Module	$1.05		$1.05	$0.75	
Inverter	Cost	$0.45	$0.57	$0.30	$0.50	$0.53
	Overhead & Profit			$0.15		$0.13
Other hardware		$0.45	$0.57	$3.05	$0.75	$0.75
Installation	Installation labor	$1.35	$0.74		$1.25	$0.50
	Overhead & Profit on installation labor		$2.38		$0.75	$0.50
	Design/sales/permitting cost	$1.35			$1.25	$0.50
	Design/sales/permitting profit					$0.50
TOTAL		**$7.90**	**$8.20**	**$7.75**	**$8.25**	**$7.90**

*Module production cost is estimated at about $2 per watt.

*These figures are expressed in terms of cost per DC watts. Estimates mentioned later in this document refer to cost per AC watt. Although the precise conversion rate from DC to AC depends on the equipment being used, a representative conversation would be to multiply by (1 / 0.85).

Learning Curve Based Arguments for Cost Reduction

The standard justification for investing in and supporting solar technology is based on the learning or experience curve[24] (Ingersoll et al 1998, IEA 2000, Algoso et al 2005, BSW-Solar 2009). The argument goes as follows:

> *Today, electricity generated using photovoltaics is too expensive. However, if we look over the 50 year history of the technology, we can see that cost has declined significantly. A measure of the rate of cost reduction can be given by the experience curve. The experience curve seems like a reasonable methodology because it was developed more than 70 years ago, has been used by high status firms like the Boston Consulting Group, and has been written about in the Harvard Business Review. All that is required to construct an experience curve is past record of cumulative production levels and the cost of modules.*
>
> *The role of the government is to provide incentives that will buy down the cost of photovoltaics. This will cost money, of course, but it will be worth it to "ride the learning curve." Once solar is economically competitive with traditional generation, photovoltaic installation will increase significantly, displacing carbon-dioxide emitting forms of generation.*
>
> *Calculating the total buy-down cost and time when grid parity will be achieved is fairly straightforward with the experience curve. Once you establish a target cost for solar energy – say grid parity – it is possible to predict the amount of experience necessary to go from today's cost to the cost target. Then, if you assume a certain rate at which experience is gained, you can predict the year of grid parity. Looking over the past ten years of the industry, production has been growing at a 45% rate year over year. If that rate of production growth continues, then the industry will reach grid parity in the next 10 years.*
>
> *Government can design an incentive program that offers decreasing subsidy levels over time. This will encourage industry to learn to decrease their cost of sales and pass on those savings to the photovoltaic system owners. Japan offers an important example of how this works. Incentive levels in Japan started high, 50%. But as they decreased, photovoltaic market did not dry up and instead the market continued to grow.*

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[24] It is sometimes useful to draw a distinction between the experience curve and the learning curve. I will use the terms interchangeably here.

A Review of the Experience Curve

Because the experience curve forms an important part of the argument to support solar, it is worthwhile to review the history of the experience curve and to develop a sober assessment of its application to photovoltaics.

The learning curve first appeared in a 1936 issue of the *Journal of Aeronautical Sciences*. The topic was "Factors Affecting the Cost of Airplanes" and among a number of other factors, it was noted that the quantity of planes produced affected the cost of the next plane. Greater production quantities helped to spread the costs of fixed assets such as production machinery but also created an "economy of labor" (Wright 1936: 124) in which labor cost decreased with production quantity. Wright plotted the relationship between labor cost and quantity and on log-log paper formed a straight line with a slope of 0.322. Translated into meaningful terms, this meant that with every doubling of production capacity, labor cost would decrease to eighty percent of its previous value. Support for the learning curve was found in other industries as well. Searle (1954) tracks the labor required in the wartime production of Liberty ships.

A 1954 article in the Harvard Business Review argued that the learning curve could be applied as a general "production tool." The 80% rate that Wright had identified seemed to hold in several other industries like railroad cars and gun barrels. Application of the learning curve could help in various business decisions – in long term planning, in make-or-buy decisions, in evaluating supplier contract proposals. It was suggested that there was a general theory underlying the learning curve. "A worker learns as he works and the more often he repeats the operation, the more efficient he becomes, with the result that the direct labor per input unit declines." (Andress 1954: 87).

An article published in the same journal ten years later (Hirschmann 1964) began to wrestle with the question: was the learning curve and the 80% rate of cost reduction a law of nature that could be discovered and used to make smarter business decisions, or was the learning curve an epiphenomenon of other actions inside the organization? If the latter possibility is true, then efforts at cost reduction should go beyond simply increasing cumulative experience and should instead focus on the actions of managers, engineers and labor. Hirschmann walks a fine line between these two possibilities. After observing the many apparent successes of the learning curve in predicting future costs, he considers factors that affect learning and concludes that it is the "inherent susceptibility of an operation to improvement" and "the degree to which that susceptibility is exploited." Inherent susceptibility depended on the labor content of the process. The degree to which susceptibility was exploited depended on factors such as "effect of faith" in the learning curve, "open-ended expectations" that future improvement was possible, diligent effort by managers and workers to learn and improve operations, and external pressure on the organization that pushed it to learn or go out of business. Despite these non-technical factors, the rate of learning ought to be regular enough to be predictable.

Hirschmann's article also reflects an evolution in thinking about the learning curve: it is not only the learning by direct laborers that drives the learning curve. Changes in the organization of operations and other indirect processes also have an impact on cost reduction independent of direct labor learning. Maintaining the learning curve depends on the actions of a wider set of players.

The third Harvard Business Review article (Abernathy and Wayne 1974) discussing the learning curve was much more critical. Its authors, Abernathy and Wayne, argued that there was a "dark side" to progressing down the learning curve. The company becomes more and more specialized, and loses its flexibility to react to changing market conditions and exogenous shocks. It then becomes more vulnerable to attack by other companies that either take advantage of the changing market or even change the nature of the market itself. The authors point out the experience of Ford when it relinquished its position as the top US auto manufacturer in the 1930s. Throughout the 1920s, the company had been extremely successful with its Model T and was the paragon of increasing the scale of operations to achieve lower unit costs. However, General Motors was able to alter the nature of the market so that consumers began to care not only about price but about design characteristics[25]. The famously homogenous Model T did not fare well in this new market and, while Ford eventually adapted, it was never able to reclaim its number one position.

A major change in the way the learning curve was used was brought about by the Boston Consulting Group (1968), the first to write about the experience curve, a bold generalization of the learning curve. While the learning curve applied only to human labor in production operations, the experience curve conceptualized of learning in a broad sense. Cost inputs that were susceptible to learning included "all costs of every kind required to deliver the product to the ultimate user." This included direct labor, research and development, sales and marketing, and other overhead.

The experience curve could be applied not only to cost data but to price data and not only to single firms but to entire industries. Abrupt shifts in the experience curve plotted with price data could be explained by changes to the industry structure. During periods of stable market structure, profit margins remain relatively constant and decreases in prices reflect commensurate decreases in costs. However, during periods of structural change in the industry (e.g. an industry shakeout), profit margins may increase or

[25] General Motors famously introduced the concept of annual model revisions.

decrease. Thus a careful application of the experience curve required the user to view the slope of the curve in light of industry dynamics. The authors also added that experience curves could capture changes to the nature of the technology. Drastic changes would result in an abrupt downward shift in the curve, after which a more moderate cost reduction rate would resume.

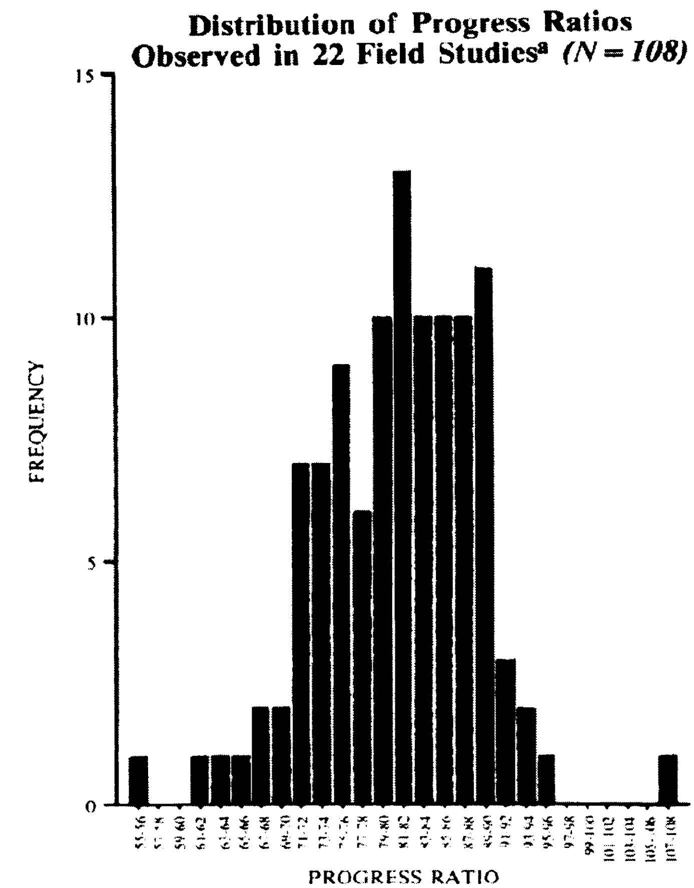
There were many other analysts, mostly academics, who were much more conservative about the applicability of the learning curve. Nadler and Smith (1961) found extensive variation in the progress ratios at the level of the individual production processes of several manufacturing plants. Alchian (1963) found that predictions made using learning curves were not very reliable and could be costly. Based on RAND manufacturing data of 22 aircraft models, he found an average margin of error of 20 to 25%. This was calculated by creating a learning curve based on the first 20% (approx) of total production for each model and then attempting to predict the labor required for the remaining 80%. The difference between the predicted and actual labor hours was as high as +116% (i.e. labor hours were overestimated) and as low as -31% (i.e. labor hours underestimated). With the average of 45 million labor hours per aircraft model, the 20 to 25% margin of error translates into millions of direct-labor hours.

The widespread acceptance of an "80%" experience curve may partly have been the result of the use of the experience curve as a control device, leading to a self-fulfilling prophecy. Conway and Schultz (1959) write about the learning curve in the Journal of Industrial Engineering (Conway and Schultz 1959: 41), "Industrial engineers have long known that once a control of quantitative objective is imposed upon an organization there are strong forces created to make the performance fit the objective." The US Department of Defense also began requiring that defense contractors incorporate learning curve price reductions in their proposals (Air Force 1970).

Overall, there was a divergence of learning curve studies into two paths (Dutton, Thomas and Butler 1984). One path was led by academics who sought to develop the theory of the learning curve and who applied it rigorously in empirical studies. Several economists took the general principle and incorporated it into economic theory (e.g. Arrow, Alchian, Hirshleifer). The other path was travelled by industrial engineers, marketing, and management consultants offering prescriptive advice. These writings tended not to cite many past learning curve articles and, when they did, they mainly cited other practitioner articles.

Interpretation of a later review of the experience curve illustrates this divergence. Dutton and Thomas (1984) compiled an authoritative sample of progress ratios based on a possibly comprehensive review of learning curve studies up to that point. They present a distribution of progress ratios, shown in Figure 17, to highlight the variation of rates that has been found across processes and even across time in the same plant. The authors write, "For policymakers these findings are highly suggestive, but they do not illuminate which factors in the underlying process are subject to control; nor do they show how the process can be influenced. Progress curves are aggregate empirical descriptions of a process and they mask its underlying dynamics" (Dutton and Thomas 1984: 237). Interestingly, this distribution has been interpreted as evidence supporting an "average progress ratio of 80%" (IEA 2000), discounting the problem of variation in progress ratios.

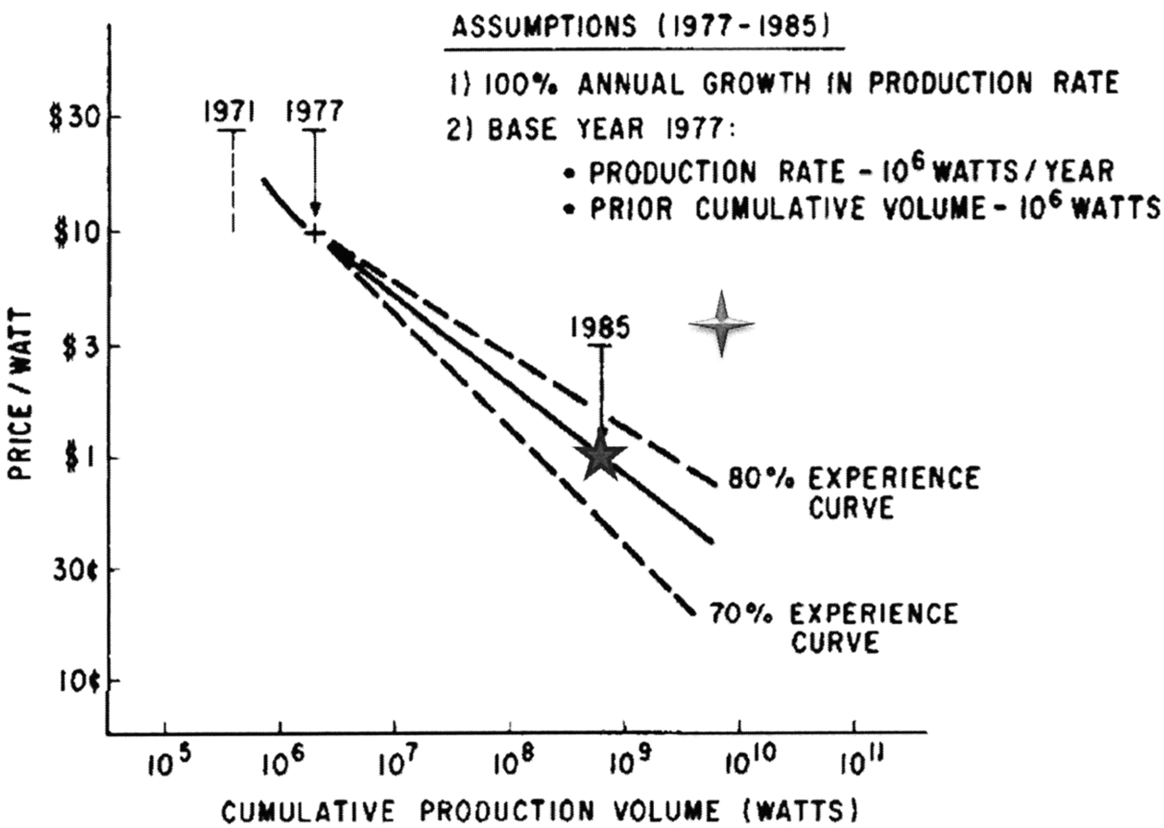
Figure 17. Distribution of Progress Ratios as shown in Dutton and Thomas (1984)



The experience curve was first applied to photovoltaics in 1976 by Robert Moore, a scientist at RCA Labs, in one of the early attempts to assess the future of the technology (Moore 1976). Using the experience curve, he estimated that a $1 per watt module price was possible by 1985 given a certain set of assumptions. These assumptions were largely consistent with the strong national push towards solar energy and vision of a transformed energy system - a 100% annual growth rate. This growth rate over a relatively short period of time (10 years) also reflects the belief that it would take only a little development work and a lot of production process scale-up and development to reach this cost goal.

Perhaps most importantly, the prediction is wrong. Figure 18 is taken from Moore (1976). Two stars have been added to highlight the error. The five-pointed star is Moore's prediction for 1985: a $1 price per watt after cumulative production of 10^9 watts. The four-pointed star is the actual value for 2009: a $3 to $4 price per watt after cumulative production of 10^{10} watts. This is indicative of the types of errors possible when using the experience curve. A price-reduction model based on the experience curve and several other assumptions can lead to predictions with superficial validity. However, in the hypothetical world of using simple mathematical models to make predictions in a social and technical system, it can be difficult to separate the good models from the bad. The poor assumptions of bad models are hidden by quantitative data, graphs and equations.

Figure 18. First Application of Experience Curve to Photovoltaics



The International Energy Agency published a report in 2000 describing the experience curve as a useful tool for making energy policy (IEA 2000). Experience curves could be used to quantify the size of the "learning investment" necessary to deploy technologies that reduce carbon emissions. The IEA uses 0.80 as the progress ratio for photovoltaics, after supplementing data from Williams and Terzian (1993) with their own data. The report also made a distinction in the level of analysis where the learning curve should apply. For global markets like photovoltaic modules, the appropriate way to measure cumulative production is to examine worldwide global production. However, for activities like systems installation where knowledge generated in distant markets may not be applied in the local market, cumulative experience should be measured using local production.

Issues with the Experience Curve

Despite the long history of the experience curve and its application to photovoltaics, there are a number of empirical and conceptual issues that have not been addressed head on. Examining these issues is important because the experience curve is being used to predict future cost decreases and is used as the basis for public policy. These issues introduce a degree of uncertainty to any prediction made with the experience curve approach and raise concerns over the robustness of policy decisions. Understanding what may be missing – the sources of this uncertainty – can be useful in assessing the robustness of policy decisions.

On the empirical front, the first problem is that the estimate of the progress ratio is not presented with any measure of uncertainty. For instance, are the three progress ratios presented earlier in section II (83%, 80%, 74%) consistent with one another? It is worrisome that three different progress ratios should have been estimated to describe what should be the same underlying phenomena. The discrepancy also suggests the presence of sources of uncertainty that are not reflected in any one dataset used to estimate the progress ratio. A commonly made argument is to cite the R-squared statistic to support the appropriateness of the experience curve. The problem with this is that the data used are yearly averages, and averaged for the entire industry. In compiling these averages, variation in costs across manufacturers, across factories, and across time is removed. For example, if the data were compiled monthly by firm, the data would exhibit much more variation and the fitted experience curve would have a lower r-squared. . Not only would this change the goodness-of-fit measure, but it would also help to provide an estimate of the standard error of the statistical parameter used to estimate the progress ratio. From the multiple measures of the progress ratio that have been used by various sources, it would appear that the standard error may be too large for comfort (i.e. a world with a 74% progress ratio is very different from a world with an 83% progress ratio.) Without a measure of uncertainty, it is difficult to tell whether policy decisions will be robust.

Another challenge in estimating that uncertainty is the nature of the experience as the key independent variable. The progress ratio is estimated by taking the log transformation of the unit cost and regressing it against the log transformation of cumulative experience. Ordinary least squares regression is used to estimate the regression coefficient, which graphically represents the slope of the line showing the relationship between the two variables. The slope is then converted into a progress ratio by exponentiating it with a base of 2.

The problem is that estimation by ordinary least squares regression assumes that the observations are completely independent. This allows the errors to also be considered independent and assumed to fit the normal distribution, allowing inferences of statistical significance to be drawn from the coefficient, the standard error and the z statistic. In the case of the experience curve, the data does not meet this assumption. The cumulative nature of experience means that the value of experience can only increase and the observations are thus not independent.

Third, experience curves are often plotted using price data instead of cost data, mainly because the latter are much more difficult to collect. The problem is that this increases the possibility of unobserved factors affecting the progress ratio. To make inferences on the cost dynamics of a technology using price data, one must make the assumption of a constant industry profit margin over time. This assumption can be problematic when data is collected over a long time period since it is likely that the structure and organization of the market will have changed over that time.

Fourth, experience curves have been used almost exclusively with photovoltaic modules, ignoring the dynamics of photovoltaic systems. This is unfortunate because it is the cost of the photovoltaic system that directly translates into the cost of electricity. Less data is available for non-module system costs since it was only in 1994 that photovoltaic systems began to be installed on a large scale. Nonetheless, non-module costs account for approximately 50% (35% for installation, 15% for inverter and other hardware) of total system costs and attempts should be made to understand progress in this area. Many of the mechanisms that drive cost reduction of modules are different for non-module costs. For example, reducing the thickness of a solar cell would reduce the quantity of silicon used and thus the module materials cost but would have no effect on non-module costs. While cost reduction for photovoltaic modules is likely to be dependent upon advances in manufacturing and product design, cost reduction for non-module costs is more likely to result from changes in financing and interconnection procedures, for example.

On the theoretical front, one of the biggest problems is that the mechanisms for cost reduction are not understood. It is an oft-cited adage that correlation does not equal causation. Extrapolation of a curve drawn from past data is an intrinsically tricky proposition. However, the argument is strengthened if, in addition to a statistical relationship, one can also invoke a theory of the processes at work. Concern over the lack of theory underlying the experience curve has long been a concern amongst academics (Baloff 1966).

Theory is precisely where the experience curve is at its weakest. It asserts that costs decrease as experience is gained. This is an intuitive argument that, upon first blush, seems difficult to argue with. But because it makes no claims about the processes driving cost reduction, it is hard to tell at what rate the costs will decrease. Abell and Hammond (1979) argue that a firm's progress ratio is a predetermined constant that can be achieved by exploiting and controlling various sources of progress.

At the industry level, many mechanisms may be at work simultaneously. Dutton and Thomas (1984) note that cost reduction may be the result of technological change, labor-learning effects, and scale effects in addition to miscellaneous local effects. By technological change, Dutton and Thomas refer to an increased investment in capital goods which changes the production environment and contributes to progress (Arrow 1962). The labor-learning effect refers to direct labor learning as well as tooling and process adaptations by staff and managers. Scale effects refer to improvements made when there is a higher expected production volume that allows fixed costs to be distributed over a greater number of units as well as the use of more advanced production techniques requiring greater fixed investment but delivering lower unit costs. Woerlen (2004) makes a distinction between economies of scale in production and economies of scale in input factors. An example of economies of scale in input factors may be a large module manufacturer paying less per unit of silicon if it commits to purchasing in large quantities.

Another possibility is "learning-by-research" in which technological progress stems from investments in research and development (Kouvaritakis et al. 2000). New photovoltaic technologies may increase the efficiency – in terms of percent of incident solar energy converted to electricity – of solar cells, thus reducing the cost per unit of electricity generated. Alternatively, research and development may permit the use of new, less-expensive materials, which will also reduce the unit cost of generated electricity ceteris paribus. Economies of scale may also play an important role in cost reduction. Increased end-use demand may make increased investment in production technology more feasible.

Second, experience curves conceptualize experience – operationalized as cumulative output – as the only predictor of unit cost. The experience curve does not consider (i.e. control for) other factors that might be relevant such as cumulative level of government R&D or total investment in capital. The learning curve was an analytical technique developed before the invention of computers and before the widespread use of statistical methods. While one of its benefits has been the relatively small amount of data required to construct it (Woerlen 2004), this also speaks to a limitation of the method. Because it uses small amounts of information, there are inherent limitations to the conclusions that can be drawn. Modern statistical methods tend to use much more data with the challenge being drawing the correct inferences from that data. Sophisticated statistical methods can help draw conclusions from larger, more complex data.

Third, the functional form of the experience curve is appealing, but potentially misleading. The log-log curve is imposed upon the data on the premise that the rate of learning is independent of the starting point and that there is always room for further cost reduction. This mathematical form suggests that the progress ratio should be constant over time. It fixes the ratio of improvement with every doubling of production, so allows greater absolute improvement early in a technology's history. However, because this mathematical form is imposed on the data, it is not surprising that extrapolations of the curve show a continuous decrease in cost long into the future. One risk of using the experience curve model is that while the model may be wrong, it still holds an air of authority. We must be careful to make sure that the very model we use to understand the data does not lead us to biased conclusions.

Issues with the Photovoltaics Experience Curve

There are several specific issues in using the experience curve to analyze cost reductions in photovoltaics. One inconsistency arises when examining the module prices from 1975 to 2005. Historically, the progress ratio for photovoltaic modules has been 0.73, but estimating a progress ratio for a more recent time period results in a very difference progress ratio of 0.88. Compare Figure 19 with Figure 20. Given the functional form of the experience curve, such deviations should not occur since the potential for greater cost reductions has already been accounted for. And while one might expect small variations based on noise in the data, the difference between 0.73 and 0.88 is highly significant and suggests two different processes of learning at work.

This difference can only start to be explained by exploring the factors that have contributed to the cost reductions. Nemet (2006) offers a nice analysis of the factors that have affected module costs between 1976 and 2001. He quantifies the portion of module cost reduction resulting from seven factors: increases in module efficiency, increases in plant size, decreases in silicon consumption, decreases in unit prices for silicon, increases in production yield, increases in silicon wafer size and increases in the proportion of multicrystalline silicon use. Of the seven, he finds that module efficiency accounted for the greatest proportion of reduced module cost, followed by plant size and silicon cost.

Nemet also notes additional factors contributing to cost reductions in the 1970s. The transition from an industry oriented towards space satellites to one oriented towards terrestrial applications led to three changes that may have accelerated cost reduction over and above the other seven factors he considers.

Figure 19. Experience Curve for Phototvoltaic Modules, 1975-2005
(Source: Maycock)

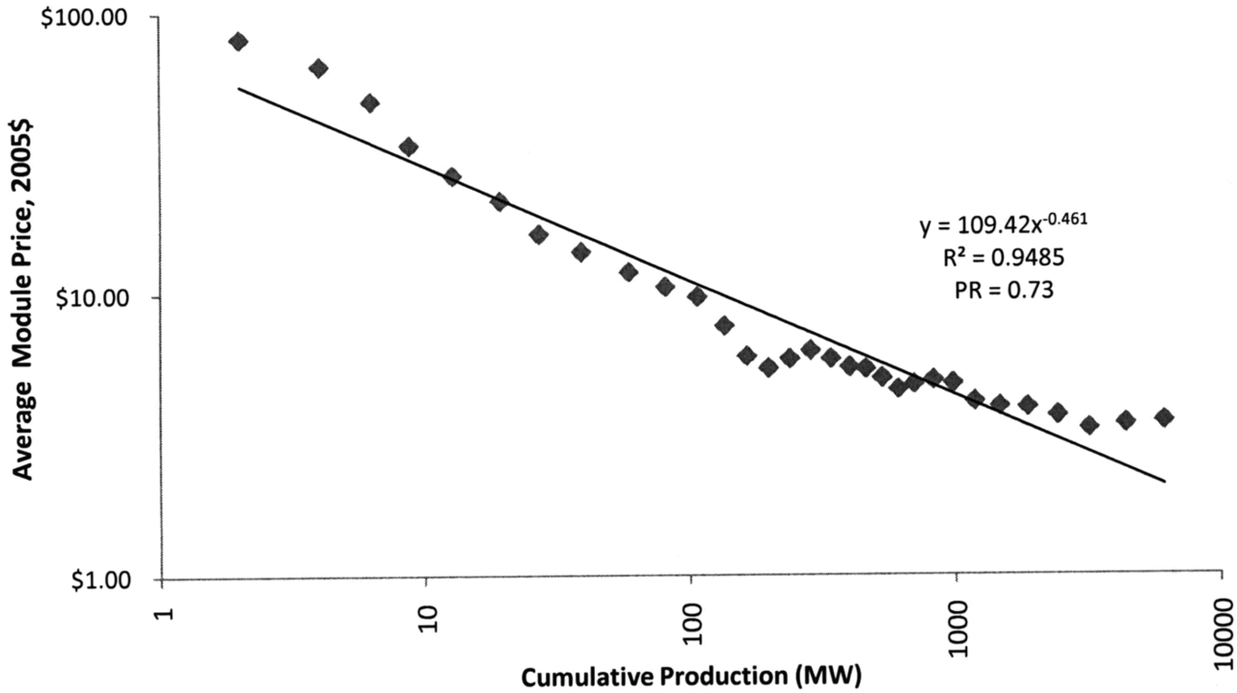
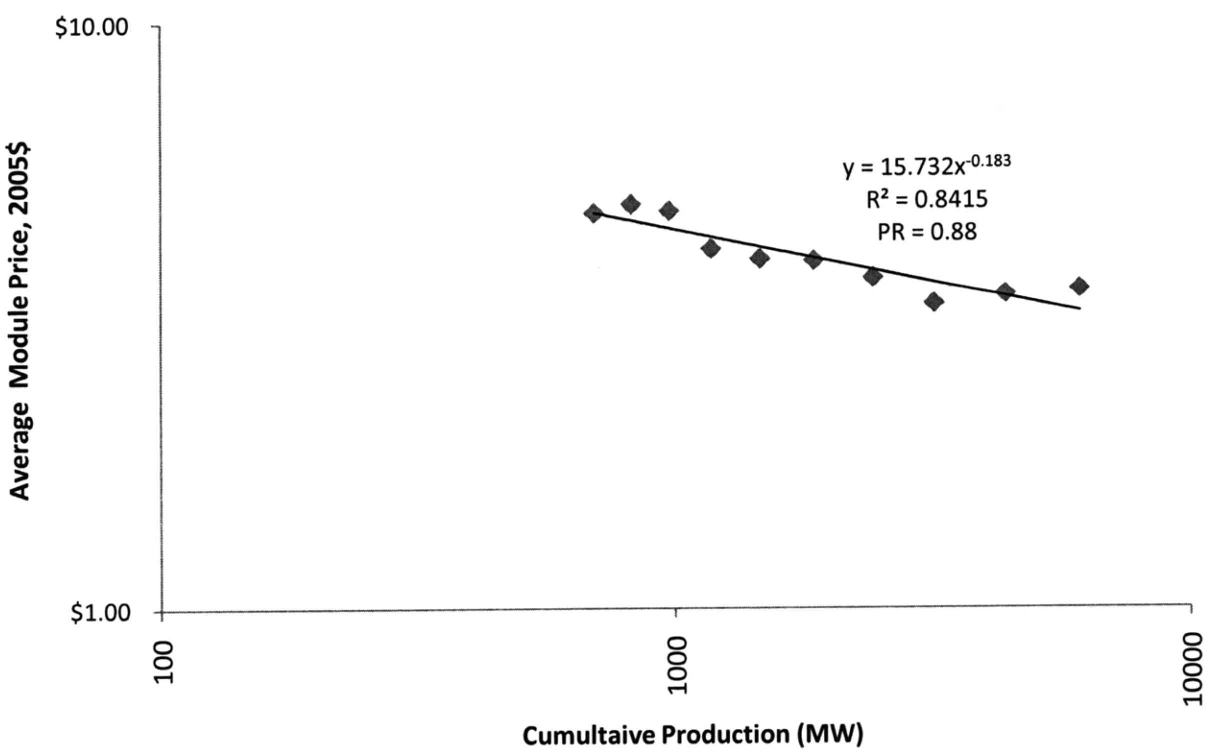


Figure 20. Experience Curve for Photovoltaics Modules, 1996-2005
(Source: Maycock)



First, the downgrading of solar cells designed for space – where high power output and low weight are at a premium – to solar cells for terrestrial applications allowed manufacturers to reduce cost per watt by eliminating design features that have a high marginal cost per watt. Second, as more companies were entering the market, greater competition reduced the profit margins module manufacturers could earn. Third, since the primary customer was no longer the government running space programs where the cost of photovoltaics was a tiny portion of the overall program budget, customers in the terrestrial market would likely have a lower willingness to pay. This also reduced the premium that module manufacturers could charge. To these factors, I add another. Improvements to module efficiency were enabled by the vast body of research and production experiences that the computer/semiconductor industry had accumulated for silicon.

Prospects for Cost Reduction in Photovoltaic Modules

Popular belief in the photovoltaic learning curve is likely the joint product of a simple and compelling mathematical relationship and the numerous ways that costs can decrease. There are two general arguments for continued cost reduction in photovoltaic modules. The first points to the many incremental changes possible to the product design and to production processes, and the second points to the many emerging technologies still in research and development.

In the first category are the factors identified by Nemet (2006). Increases to silicon module efficiency can decrease the cost per kilowatt hour generated. Although the laboratory efficiency of silicon has not increased since 1999 (Kazmerski 2005, Green et al 2009), the average module efficiency in industry has been continually increasing. It may be an open question how far module efficiency can decrease costs since there is a theoretical limit of about 29% (Swanson 2004), but average module efficiencies range from 12% to 18% and the top companies are producing cell efficiencies greater than 22% (Sunpower's Pegasus line is 22%, Sanyo's HIT is 23%). Increased plant size allows manufacturers to exploit economies of scale, investing in fixed costs to realize lower unit costs. Plants in 1976 had a capacity of about 76 kilowatts per year while plants in 2001 had a capacity of 14 megawatts per years and new plants in 2007 have capacities of over 100 megawatts (Nemet 2006, DOE 2008 Wafer Roadmap). Reduced silicon consumption and silicon cost also hold the promise of lower costs in the future. Lower silicon consumption has been achieved primarily by reducing kerf (i.e. "sawdust" made when slicing the ingot into wafers) losses and using thinner wafers. Increased use of string-ribbon technology can also reduce the silicon consumption. Lower silicon costs are the product of economies of scale by silicon producers who have increased capacity in response to the growth of the photovoltaic market.

Improved module lifetime can also change the cost of solar electricity. One of the goals of the Flat Plate Solar Array Project was a 20 year module lifetime. Today manufacturers typically offer 25 year warranties and 30 year lifetimes are the new goal (Hulstrom 2005). Progress on this front would change the cost of solar electricity by increasing the total generation of the system. Although the value of electricity generated in these additional five years is discounted more heavily by time value of money, an additional five years of generation would still reduce the cost of solar electricity from $0.474 per kilowatt hour to $0.421 per kilowatt hour (See discussion of Table 2 on page 15).

How far these mechanisms can reduce the cost of photovoltaics is unclear. There is clearly a limit to the efficiency of solar cells, and as solar cell efficiency reaches that limit, further improvements will likely be more difficult to make. Increases to plant size also likely have a limit before diseconomies of scale in managing a large and complex operation begin to set in. Wafer thickness can only be reduced to about 50 microns in order for the silicon to absorb as much of incident light as possible (Chopra et al 2004).

The second argument is that the cost of solar energy will decrease when a new photovoltaic technology replaces crystalline silicon modules, creating a discontinuity in the experience curve. Silicon modules have been in use ever since 1954, but there are several possible alternatives to silicon. In the 1980s, research into thin film technologies began and continued into the 1990s. While thin film technologies are less efficient than crystalline silicon, thin film technologies hold out the promise of lower material and manufacturing costs. Other technologies currently being researched by university scientists may end up in commercial production further into the future, perhaps 20 years or more. These can broadly be described as approaches exploiting localized electronic states and would include quantum dots, organic photovoltaics and nanostructured devices (Buonassisi, T. Class lecture, Fundamentals of Photovoltaics, Fall 2008). Furthermore, there are also a wide range of possible semiconductors that could be use to create a photovoltaic device and the ones tried so far have only scratched the surface of the possibilities (Wadia, Alivisatos and Kammen 2009).

Prospects for Cost Reduction in Non-Module System Costs

Most discussions of the lower future cost of solar electricity focus only on module costs. Much less is known about the cost dynamics of non-module costs. Although there seem to be many opportunities to improve the technologically complex design and production of photovoltaic modules, the opportunities for cost reduction for non module costs are less clear. Intuitively, the simpler the activity, the less room there will be for improvement over time, suggesting that the potential for learning will be much less. Van der Zwaan and Rabl (2003: 28) pose the rhetorical question, “Is there indeed still so much to learn in construction the balance-of-system?”

The one study that does examine non-module costs is the Photex Project (Schaeffer et al 2004). Collecting data on 3600 systems installed between 1983 and 2001 in several countries in Europe, the authors estimate a progress ratio of 0.78 for non-module costs of systems installed in Germany and a progress ratio of 0.81 for non-module costs of systems in the Netherlands.

Separating non-module costs into different components provides further illumination. The price of inverters has come down only marginally. Schaeffer et al (2004) estimate the progress ratio for inverters to range from 0.91 to 0.96. A Navigant Consulting report to the National Renewable Energy Lab is slightly more optimistic, estimating a progress ratio of 0.90 for inverters (Navigant Consulting 2006). It says that inverter costs have been reduced by about 5-10% a year since 1999. Although this is a modest gain, the report also argues that progress has been made in terms of reliability, size, weight, ease of installation, and ease of use.

For mounting hardware, it is difficult to imagine vast improvements in cost. Mounting hardware already accounts for a small portion of the system cost and it is already commoditized. Tracking systems add about 30% to the power output of a photovoltaic system (depending on latitude and season) but cost about $1 per watt. Currently, the additional power output gained when using a tracking system is generally offset by the increased up-front and maintenance costs (they also require more space), but the exact economics can vary by location. Since the technology in a tracking system is also fairly mature (sensors detect the location of the sun, motors reposition the modules), it is not clear how much technical potential lies in tracking systems, though certainly more than in fixed-tile mounting hardware.

The potential areas of improvement for installers and system integrators are in system design and project management. Shum and Wanatabe (2008) argue that cost reduction comes from economies of scope. While the components may be standardized, their combination must be customized for the individual customer. Photovoltaic systems are customized for the customer not only in terms of the system size and preferred manufacturers, but also in terms of orientation of the building, type of roofing materials, and potential sources of shading. When systems integrators develop broad experience in combining the modular system components, costs will decline. Nonetheless, these types of cost reduction opportunities do not seem especially promising. At least in the United States, systems are installed by general contractors and electricians. From their perspective, the installation of a photovoltaic system is not much different from that of any other construction project they might undertake. Based on their general experience, they are likely to automatically find ways of reducing time and cost.

Other factors that may matter in systems integration are the organization of the installation industry and the nature of the housing stock. In Japan, single-family homes tend to be modular, and are made by a handful of large construction companies. This would seem to make system installation easier . In Germany, installation is carried out in a franchise-type model where individual contractors partner with large installation companies and receive assistance in system design, in acquiring system components and in marketing.

In addition to the greater inherent difficulty of reducing non-module costs, less attention has been paid to understanding and reducing non-module costs. Other avenues for cost reduction in systems integration may lie in areas outside the direct control of system installers - uniform incentive application procedures across states and municipalities, uniform permitting across municipalities, and uniform interconnection procedures across utilities. Since these require the participation of many actors, the political challenge of inducing many to make relatively minor changes may be large. More likely, these standards will emerge in a bottom-up manner over time.

Summary of Cost Reduction Arguments

The basic shortcomings of the photovoltaics experience curve are that the data is uncertain, interpretations drawn from the data are fuzzy, and policy decisions are not robust to different progress ratio estimates. The experience curve has been an important part of the argument for increased investment by industry and government, but it has a weak theoretical basis and an uneven empirical track record. While plotting price against experience can be provide a useful measure of the price changes, one must be careful of the causal logic that may be implied, namely that increasing output leads to price reductions at a rate specific to the technology.

A closer examination of the mechanism that may bring about cost reduction in modules reveals a number of possibilities. Yet it is unclear whether incremental improvement will be enough to reduce the costs to grid parity. What encourages many observers to be optimistic are the numerous technological avenues that are being explored and that might be explored in the future. There is obviously no guarantee that further research will uncover a game-changing technology, but the potential remains.

Much less attention has been paid to non-module costs and the potential there is somewhat of a mystery. The arguments that have been made for continued reduction of non-module costs are ultimately unconvincing. Several other factors would seem to matter but have not been adequately addressed. More research is required in this area and a better understanding the dynamics of non-module system costs would provide great leverage in predicting system costs.

Section IV - The Photovoltaic Systems Dataset & Introduction to the Installation Industry

As shown in Figure 21, California has by far the greatest number of photovoltaic system installations of any state, with 69% of all photovoltaic capacity in the US installed there by the end of 2008 (IREC 2008). New Jersey runs a clear second with 9% of all PV capacity. While having significantly less, Massachusetts still rounds out the top 10 states with 1% of total installed capacity.

Data

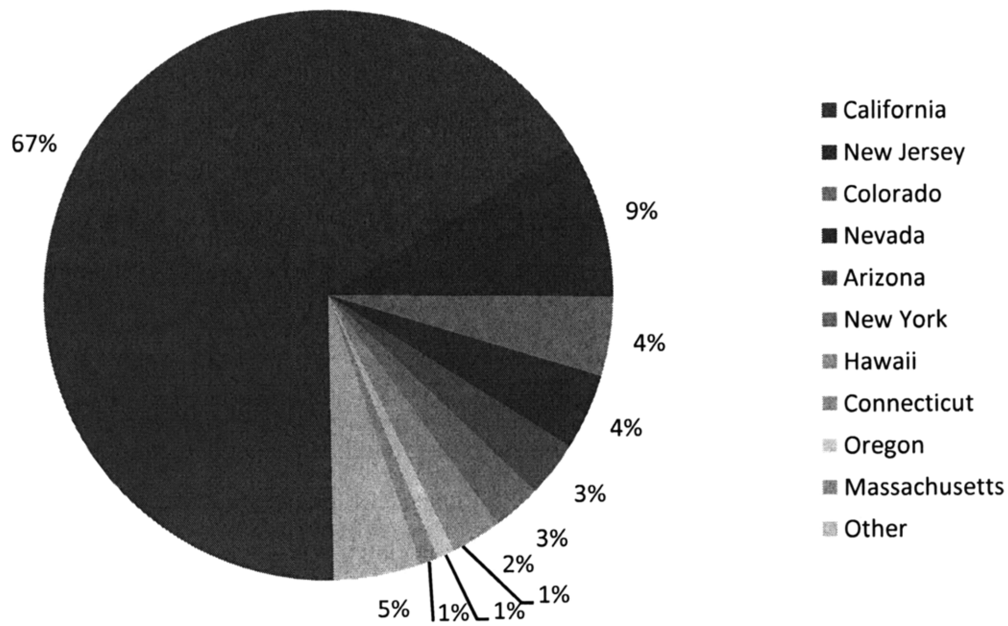
In collecting data, my intention was to develop a better understanding of the systems installation part of the value chain and the dynamics that might affect non-module system costs. I assembled a dataset of installed photovoltaic systems in the United States: from California, New Jersey and Massachusetts. Combined, the data set represents approximately 80% of total photovoltaic capacity installed in the United States. The other 20% includes the systems of several other states also with incentive programs for solar – Arizona, Connecticut, Illinois, Maryland, Minnesota, New York, Oregon, Pennsylvania, Wisconsin, Nevada, Colorado, Hawaii, and Texas.

The data are available from the organizations administering the state incentive programs. For California, this is the California Energy Commission and the California Public Utilities Commission. The New Jersey Clean Energy Program maintains the New Jersey dataset and the Massachusetts Technology Collaborative collects systems data for Massachusetts. These organizations collect and make public some data from the incentive applications filled out by the system owner.

To provide some background about the incentive application process, after a would-be system owner decides to purchase a photovoltaic system, she submits an application along with the system installer to the state. The application includes information about the system – cost, capacity, equipment models – in addition to basic information about the system owner and the system installer. The application is reviewed by the state organization administering the program. Once the application is approved and the system owner knows she will receive the incentive, construction begins. After construction is completed it is inspected by the town and connected to the electrical grid.

While details of the dataset vary from program to program, the data generally includes: the town and zip code of the installation, the size of the installation, the total cost, size of the incentive received, name of the system installer, brand of the photovoltaic modules, and brand of the inverter.

Figure 21. Cumulative Grid-Connected Capacity by States, 2008
(Source: IREC)



The data is drawn from several different programs from each of the three states. California, with the longest history of supporting solar energy, has run several incentive programs since 1998. The Emerging Renewables Program ran from 1998-2006 and the Self-Generation Incentive Program ran from 2001-2006. For solar photovoltaics, the California Solar Initiative replaced both programs in 2007 and is planned to run until 2016. Massachusetts has also had a few incentive programs, though over a shorter time period. The first program dedicated to solar photovoltaics was the Small Renewables Initiative, running from 2005-2007. Currently, Massachusetts's program to support photovoltaic installations is Commonwealth Solar. This began in 2008 and is intended to be a four year program. Prior to 2005, Massachusetts subsidized the purchase of a number of photovoltaic systems as part of a broader initiative to support affordable "green" housing. Data through 2008 are included in a dataset obtained directly from a contact at the Massachusetts Technology Collaborative. Although the Commonwealth Solar data for 2009 is publicly available for download at the Massachusetts Technology Collaborative website, it provides less information (i.e. data fields) than the dataset obtained from contacting the Massachusetts organizations directly. For that reason, the data does not include any Massachusetts systems for 2009. New Jersey's primary solar incentive program is known as CORE (Customer On-Site Renewable Energy) which ran from 2003 to 2008. As of 2008, it was replaced by an initiative to support solar installations using solar renewable energy certificates (SRECS). The data is drawn from a spreadsheet publicly available for download from the New Jersey Office of Clean Energy that was updated on February 9, 2009. Although this data was updated again in May 2009 and included about 200 systems that had not been completed by February 2009, these systems were not included in the final dataset used for this analysis. Table 6 lists the original data sources used to compile the dataset.

The total number of systems included in the overall dataset is 57,148, a larger number than any other solar dataset known to the author. Wiser et al's 2006 study, performed at Lawrence Berkeley National Lab, includes 18,942 systems. A later study, published by Wiser et al in 2009, covers the largest number of states of any analysis but includes only 36,992 systems. Wang's (2009) thesis conducted at the Massachusetts Institute of Technology's Industrial Performance Center covers 17,957 systems from the California Solar Initiative.

Of the 57148 total, some data points were removed because they were not considered to be part of the population of interest. 1909 systems were removed because they had been cancelled, were suspended or were facing some delays that made completion less likely. Because of the possibility that characteristics of proposed but uncompleted photovoltaic systems might be correlated with their delayed status, they were eliminated from the final dataset.

271 systems were dropped because their price per watt was over \$150. After running preliminary regression models, many of these systems appeared as influential outliers based on Cook's Distance. Cook's Distance (or Cook's D) is a measure of the outlying system's impact on the regression results. Data points with the highest Cook's D values were inspected to understand why they were outliers and whether they should be included in the analysis. Systems with a high Cook's D had extremely high cost per watt but were also small – less than 1 kilowatt. The conclusion drawn was that these systems were customized, high-performance systems possibly including a battery and/or a tracking system. Because the data provides no information about these system "extras," the analysis cannot control for them. While the vast majority of systems are believed not to include these features, these extras will introduce some noise into the dependent variable. Thus, if possible, these systems should be eliminated so that the analysis can focus on standard grid-connected fixed-tilt systems. The 271 small and expensive systems were inferred to be outside the norm and were removed from the dataset.

Twenty observations were deleted where the incentive per watt was prohibitively small – less than \$0.10 per watt. In most cases, the total incentive was exactly \$1. Since it is unlikely that the system installer, system owner, or the state would carry out the application rebate process to obtain a rebate of \$1 (the value of time required for the clerical work almost certainly exceeds \$1), this was considered to be a data entry error. After removing these data points, 54948 remained and were used for the final analysis.

Table 6. Source Data Used for Final Dataset

Source Dataset	Years Covered	Number of Systems
California Emerging Renewables Program	1998-2006	28813
California Self Generation Incentive Program	2001-2006	983
California Solar Initiative	2007-2009	20782
Massachusetts (Green Affordable Housing Program, Small Renewables Initiative, Commonwealth Solar)	2002-2008	1102
New Jersey CORE	2003-2008	3268
Total		54,948

Description of data

Table 7 shows the distribution of systems by state and lists the average price in each state. California has the largest number of systems in the data set and covers the longest time span. Massachusetts has the most expensive systems per watt, though it should be noted that this is with other cost factors uncontrolled. New Jersey falls in between California and Massachusetts in terms of number of systems and price per watt.

Table 7. Distribution of Systems by States

	Years Covered	Number of Systems	Average Price ($/AC watt, 2008$, excluding subsidies)
California	1998-2009	50578	$11.10
Massachusetts	2002-2008	1102	$12.09
New Jersey	2003-2008	3268	$11.57
TOTAL		57147	
AVERAGE			$11.15

Table 8 shows the distribution of systems and the average system size over time. The general trend is acceleration in the number of systems installed each year and an increasing average system size. Note that Massachusetts and New Jersey have continued to support the installation of photovoltaic systems, but data for 2009 was not included in the dataset. .

The trends in New Jersey are not straightforward to interpret because it is not clear if they are artifacts of the switch of incentive programs. According to the table, the number of installations has been decreasing as has the average system size. It is unclear whether the trend of decreased system size in New Jersey is the result of the migration to an SREC based incentive program. (Residential systems, which tend to be smaller, may have remained in queue for the CORE rebate while larger commercial systems were encouraged to pursue the SREC incentive).

Table 8. Average Size and Distribution of Systems by State, By year

	Number of Systems				Average Size (AC Watts)			
Year	CA	MA	NJ	Total	CA	MA	NJ	Yearly Average
1998	94			94	5588			5588
1999	193			193	3348			3348
2000	221			221	4540			4540
2001	2,111			2,111	5521			5521
2002	2,537	6		2,543	9218	4610		9207
2003	4,611	108	176	4,895	7860	3426	17784	8119
2004	4,881	108	386	5,375	12208	4750	14432	12218
2005	4,385	139	983	5,507	11981	5647	14897	12342
2006	7,225	255	680	8,160	12243	7626	22108	12921
2007	9,639	255	782	10,676	12449	4113	8781	11981
2008	11,128	231	261	11,620	12572	9713	7213	12395
2009	3,553			3,553	18149			18149
Total	50,578	1,102	3,268	54,948				
Average					11832	6291	14421	11875

Figure 22 shows the average system price per watt over time. The data is compiled quarterly and is adjusted for inflation using the Producer Price Index for Inputs to Construction Industries (available from the Bureau of Labor Statistics.)

Examining the price trend over time, we see that it decreased sharply in the first few years, but has leveled off after 2001 and has remained more or less constant at $10 per AC Watt in constant terms. It is not clear whether this amount of cost reduction has been significant. On the one hand, a reduction of a factor of approximately two (from a high of $23.9 in the second quarter of 1998 to $10.23 in the second quarter of 2009) sounds significant. However, a different picture emerges when the data is plotted in terms of an experience curve.

Figure 22. Average System Price per Watt (AC), excluding subsidies, 1998-2009

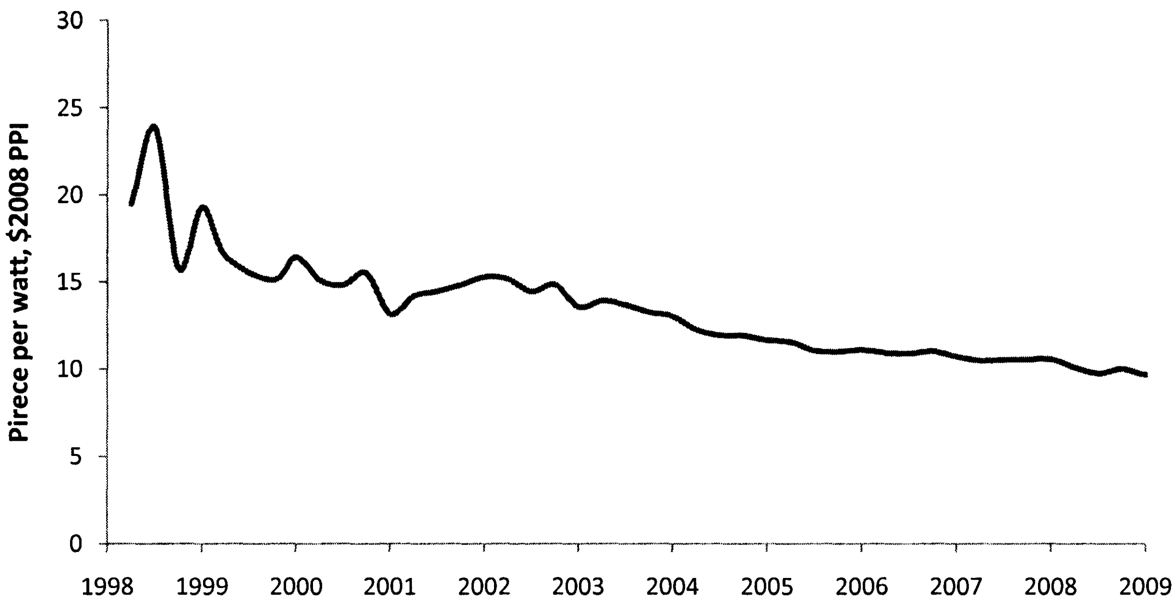
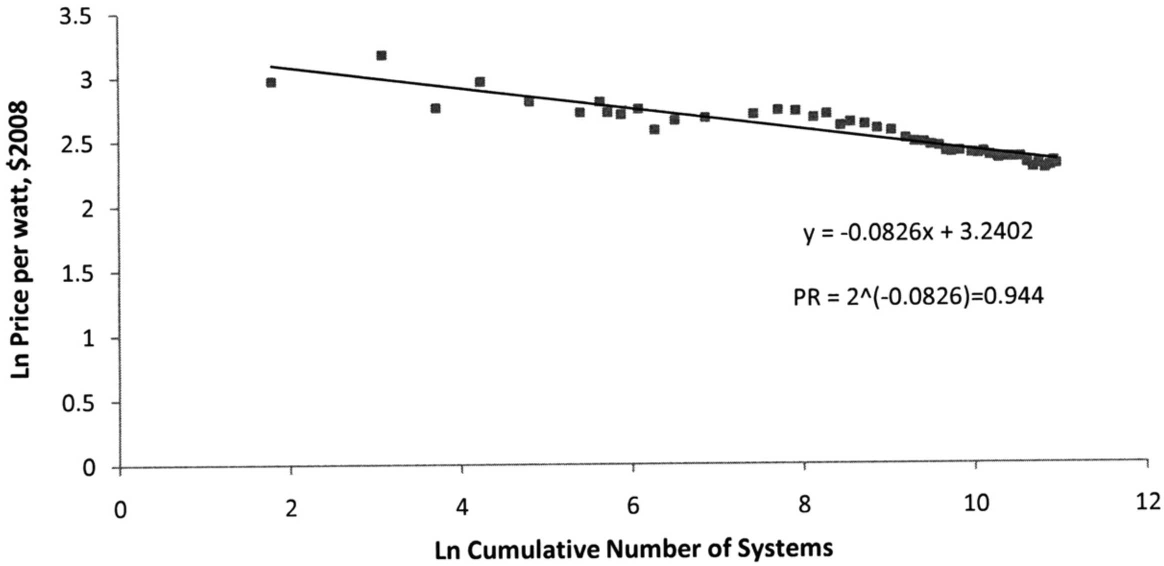


Figure 23 plots the same price data but uses the cumulative number of systems as a measure of experience. The progress ratio for installed photovoltaic systems is 0.944 (calculated as 2^-0.0826); this means that with every doubling of cumulative installations, the price declines by a factor 0.944. Compared to progress ratios in other industries, this is very low and, considering the historical progress ratio for modules of 0.73 (Figure 19), begs the question as to what is going on with systems installation in the United States. This poor progress ratio is robust to the specification of experience. An alternative measure of experience is the cumulative number of watts but it makes little difference in terms of the progress ratio. The progress ratio using number of watts is 0.952.

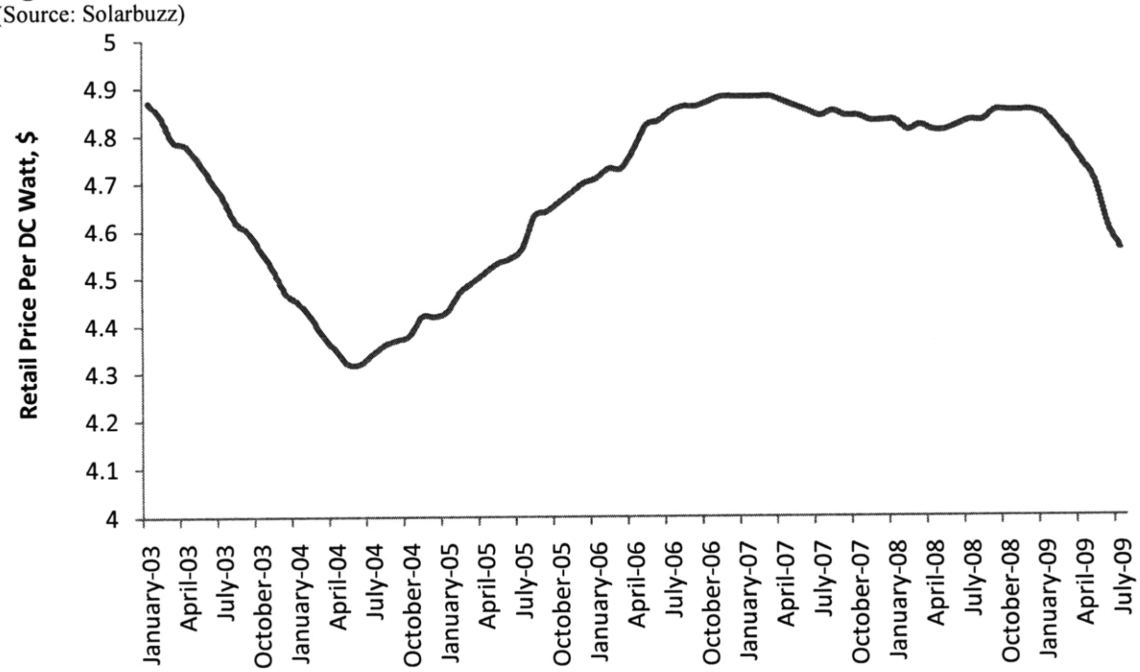
This poor progress ratio suggests some questionable implications. Using the cost and cumulative installation from the last quarter of 2009 ($10.01 per watt and 833 megawatts) and following the same learning curve methodology as in Section II, the capacity required to reach grid parity (approximated as $2 per watt peak or $2.35 per watt AC) is 30.9 petawatts. This far exceeds the total power demand of the entire world – 15.5 terawatts in 2005 (Energy Information Administration, 2008).

Figure 23. Experience Curve for Photovoltaics Installations



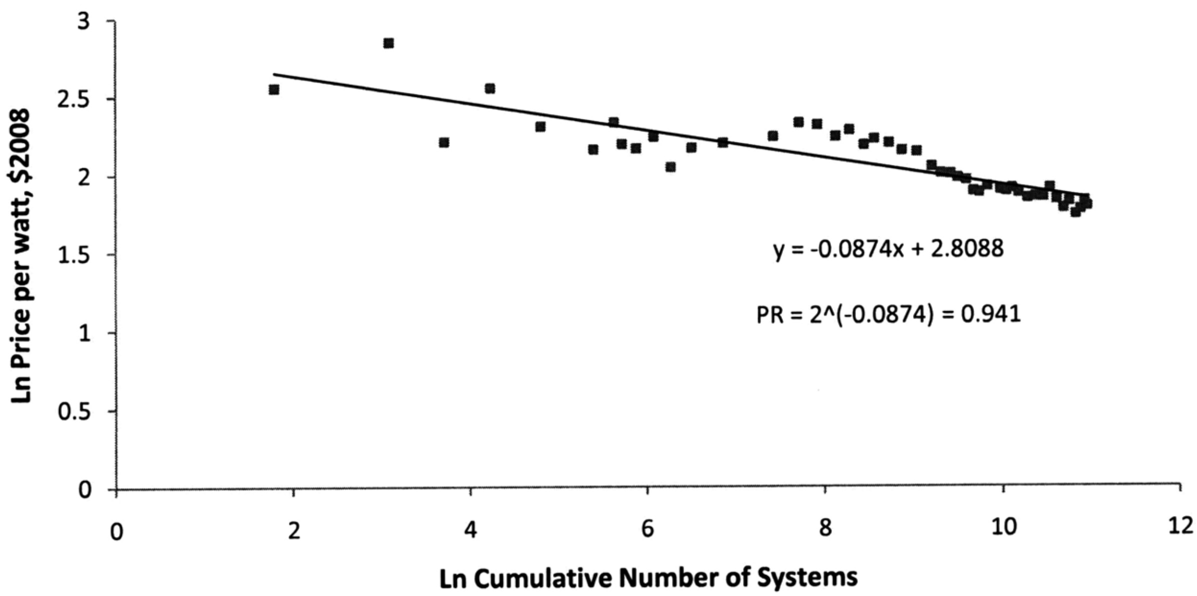
One explanation for the poor progress ratio might be the slow price declines in module prices. As shown in Figure 24 and earlier in Figure 20, the price of modules has remained roughly constant over the past few years. Industry commentators have explained this as the result of a shortage of silicon refining capacity which has lead to a price increase of the raw material.

Figure 24. Retail Module Price Index, January 2003-July 2009
(Source: Solarbuzz)



This possibility can be explored by backing out the module costs from the total system costs to obtain an estimate of non-module system costs by subtracting an average module price for each year. The methodology used to calculate the module prices estimate is described in the next section. In Figure 25, the natural log of the non-module costs are plotted against the natural log of cumulative installed systems. The progress ratio for non-module costs is only marginally better at 0.941.

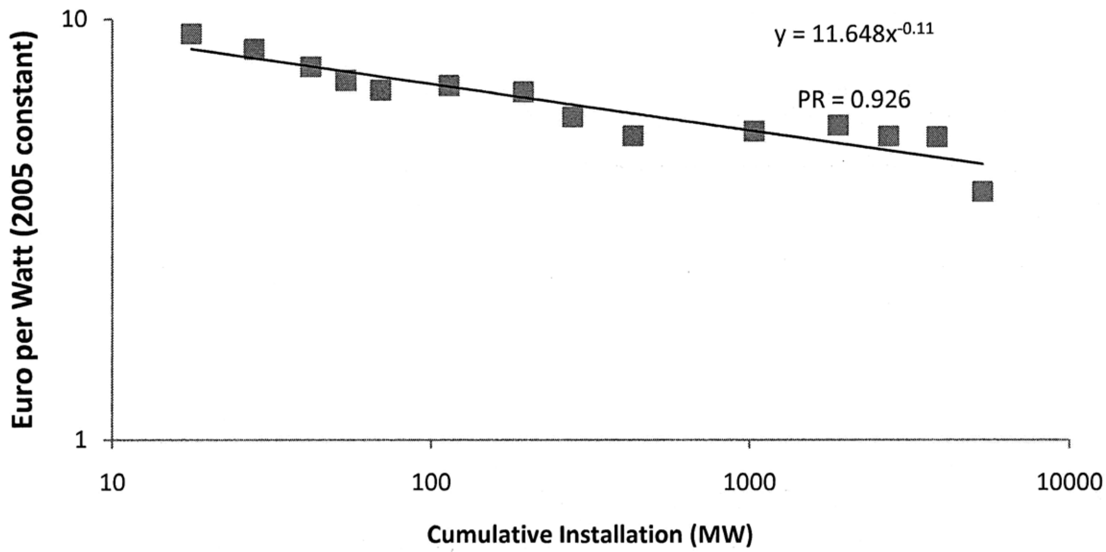
Figure 25. Experience Curve for Non-Module Costs



From these data, the conclusion is that costs are coming down but not at the rate suggested by the historical module price experience curve which is cited as having an average value of 0.80. By comparison, the progress ratio of 0.944 (total system cost) or 0.941 (non-module costs) is extremely poor. If photovoltaic systems are to progress at a rate of 0.80, then the learning rate for non-module costs must equal or even be below than 0.80.

Comparison of the US experience curves with those from Germany and Japan presents a more complicated picture and raises several hard questions. The prices are adjusted for inflation using the producer price index for domestic manufacturing available from the OECD. Figure 26 shows the experience curve for systems installed in Germany between 1995 and 2008. While the reduction in system costs has been hailed as a success, the progress ratio is a modest 0.926 (2^-0.11)

Figure 26. Experience Curve for Photovoltaic System Installations in Germany, 1995-2008
(Source: IEA-PVPS)



Scheaffer et al (2004), in a report of the Photex Project, argue that Germany's poor progress ratio results from the mixing of two learning systems – a global learning system for modules and a local learning system for systems integration. The authors suggest that the combination of low market growth outside of Germany, which would contribute to cost reductions in modules, and the high market growth inside Germany leads to "erroneous results." As written, this argument is difficult to understand since experience gained in other countries should provide "bonus" experience not considered within the national system. Ignoring experience gained outside of Germany should lead to an underestimate of cumulative experience and thus an overestimate of the rate of cost reduction. Instead, the problem is that cost reduction appears to be occurring too slowly (i.e. too high a progress ratio).

Perhaps what Scheaffer et al (2004) mean to say is that the lack of progress in module costs offsets the progress made in non-module costs over this time period. Anecdotal evidence does suggest that module costs have declined at a low rate (IEA Germany National Report 2007) meaning that most of the cost reduction at the system level can be attributed to improved costs in non-module costs. Unfortunately, this could not be confirmed since average module prices in Germany over this time period were not available and the non-module cost experience curve could not be constructed.

Better data is available for Japan. Figure 27 shows the experience curve for residential systems in Japan from 1994 to 2007. The prices are adjusted for inflation using the producer price index for domestic manufacturing available from the OECD. It shows a modest progress ratio of 0.831. Backing out the average module cost in Japan over this time period, it is possible to construct the learning curve for non-module costs, as shown in Figure 28. The progress ratio is a quite impressive 0.766.

Nonetheless, the robustness of these progress ratios is questionable. The first two years of data seem particularly high. The average system price in 1993 was 3500 yen per watt, or about $30 per watt (using a conversion of 107 yen per watt for 1993); the average system price in 1994 was 1920 yen per watt or about $19.6 per watt (using a conversion of 98 yen per watt for 1994). It is hard to imagine how the cost of installing the system could be so high since, other than the buying the system components, the task of installing the system is not much more sophisticated than standard electrical work. One possibility is a price premium for the additional risk and uncertainty of installing these early systems[26].

If we believe in the mathematical form of the experience curve, the omission of these two points should not affect the progress ratio drastically. Recall that the form of the curve already makes allowance for larger absolute cost decreases early in the life of a technology when costs are higher, because it is the improvement ratio that is fixed. Figure 29 shows the experience curve for residential systems between 1996 and 2007. The progress ratio is dramatically lower, 0.895. Figure 30 shows the experience curve for non-module costs between 1996 and 2007 and reveals a progress ratio of 0.845. Given such inconsistent progress ratios, it is unclear which (if any) best describe the current cost reduction dynamics of photovoltaic systems and non-module costs.

This inconsistency is a problem for protagonists of the experience curve. By committing to using the experience curve, one is implicitly saying that there is a multitude of factors that drive costs downwards, and it is their combined effects that are evident in the observed progress ratio. While some factors may drop off, they will be replaced by other factors. It is inconsistent to advocate the use of the experience curve on the one hand while on the other hand explaining away what are perceived as deviations from it.

For the remainder of this thesis, we take the view that the experience curve provides one way to describe the cost dynamics of a technology without affirming the role of specific causal mechanisms that are frequently inferred from the experience curve. Reliable explanations of observed cost reductions and predictions of future cost reductions require disentangling the individual causal factors and assessing the likelihood of their continued effect in the future.

In particular, understanding what drives the non-module cost progress ratio requires a closer examination of the actual process of designing and installing an photovoltaic system, the administrative process

[26] If this is true, then should reduction of the risk premium really count as "learning?"

associated with interconnection and incentive acquisition, and the competitive dynamics of the systems integrators who install photovoltaic systems.

Figure 27. Experience Curve For Residential Systems In Japan, 1994-2007
(Source: IEA-PVPS)

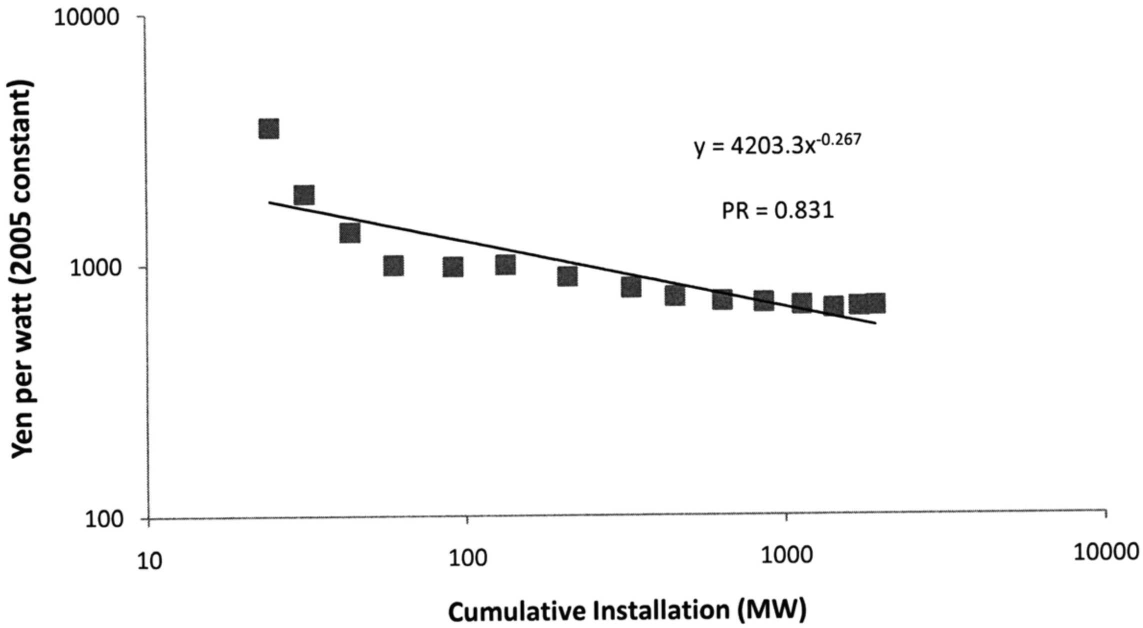


Figure 28. Experience Curve for Non-Module Costs in Japan, 1994-2007
(Source: IEA-PVPS)

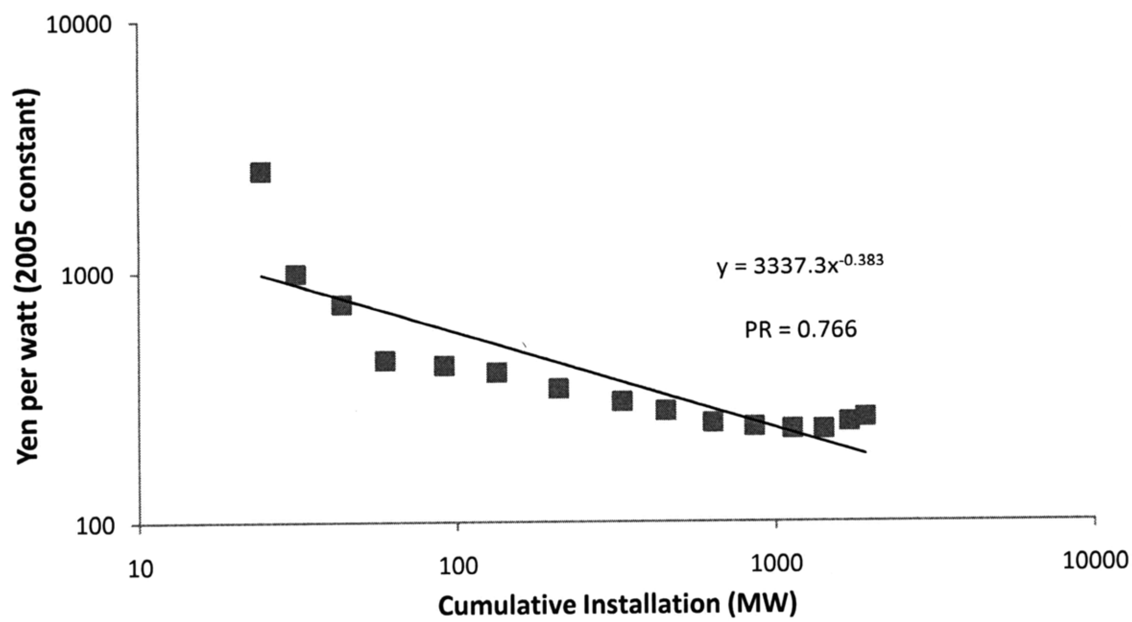


Figure 29. Experience Curve for Residential Systems in Japan, 1996-2007

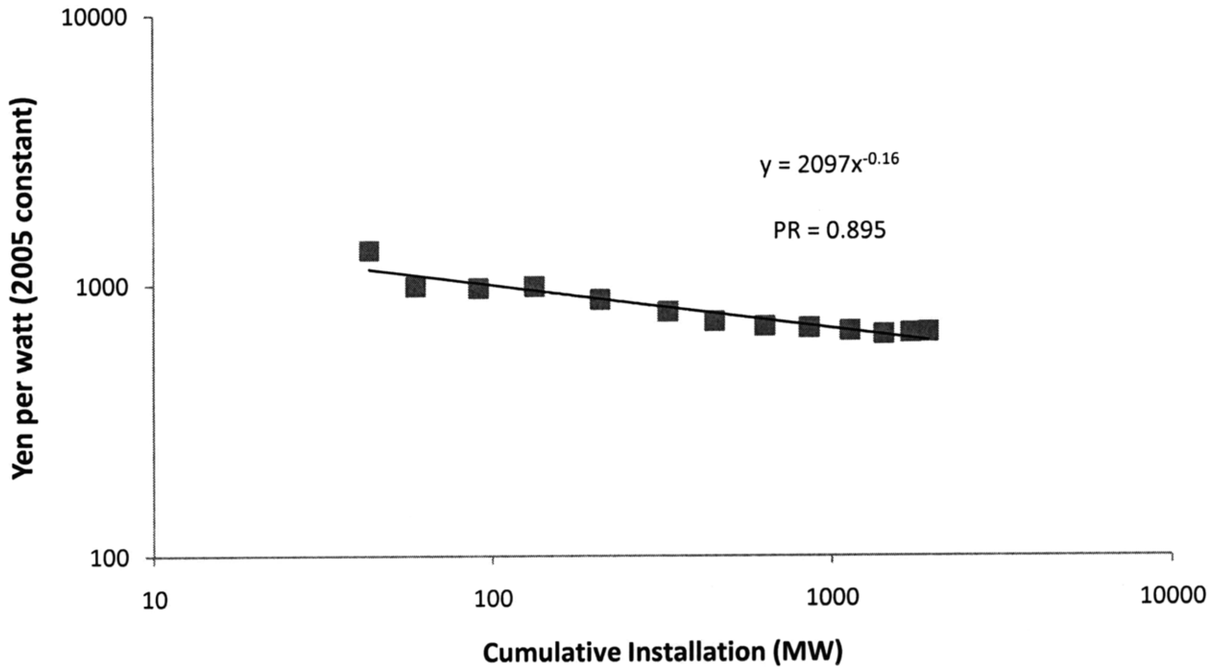
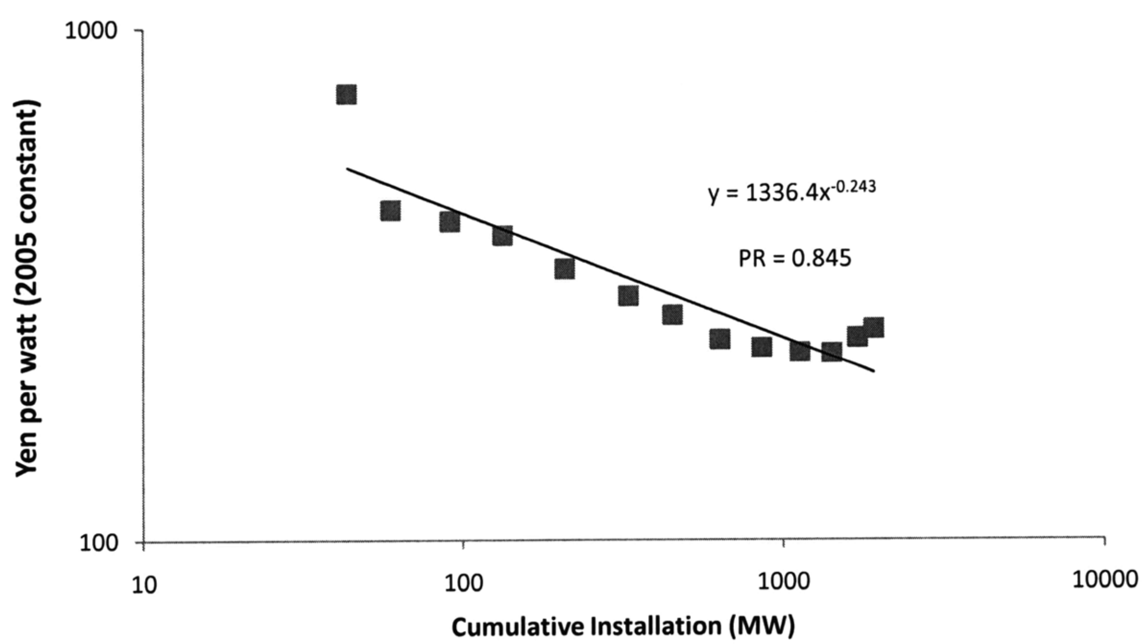


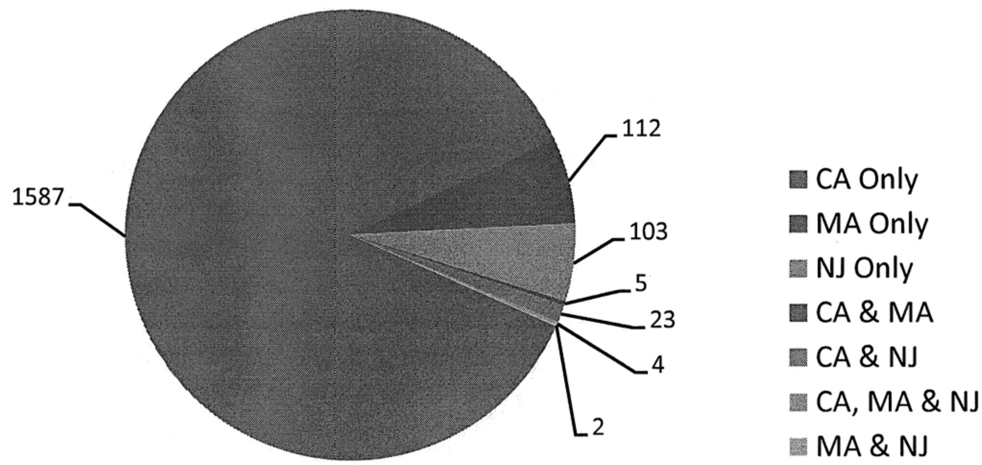
Figure 30. Experience Curve for Non-Module Costs in Japan, 1996-2007



Observations of System Installers

Little is known about the firms that install photovoltaic systems. This section will provide some descriptive data about installers that appear in the California-Massachusetts-New Jersey photovoltaic system dataset. It is intended to sharpen the questions we will ask of the more sophisticated regression analysis. Examining the installers listed in the dataset, there are 1836 installers that have installed at least one system in the dataset (Figure 31)[27]. Approximately 600 are still active in the final year of the dataset (2008 for New Jersey, 2008 for Massachusetts, 2008 and 2009 for California), meaning that about 1200 firms stopped installing systems at some point in the past.

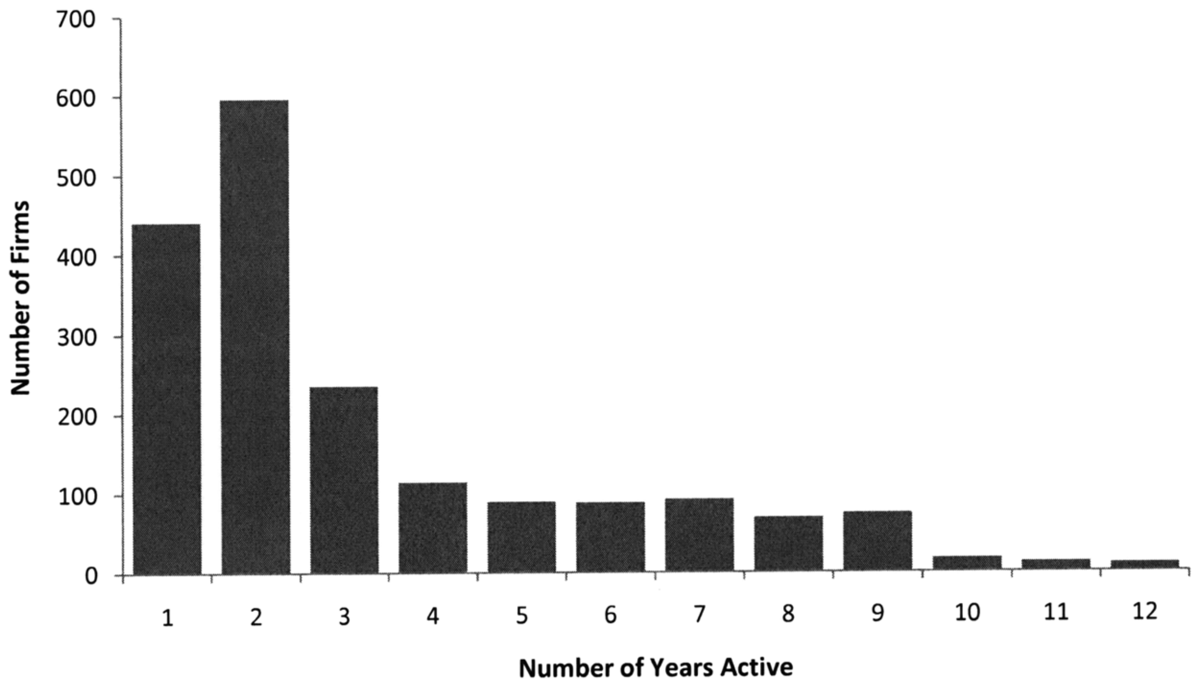
Figure 31. Number of Current and Past Firms by Operating Area, n = 1835



[27] The list of installers started with 2256 installers and with 2283 unique installer-state pairs (a few installers operate in more than one state). This list was reduced to 1836, with 1868 unique installer-state pairs, by merging installers with very similar names. In many cases, it was obvious that two firms names referred to a single firm. For instance, "ABC Inc" and "ABC, Inc." In some cases, similar firm names had alternate spellings. In these cases, names were data was merged if the firm name was unique (e.g. "Talbott Solar & Radiant Homes" and "Talbott Solar Homes" with "Talbott" not appearing in any other names), or an alternate spelling appeared a few times while the other appeared dozens (e.g. "Roger" installed 157 systems and "Roger The Little House" installed 7 systems), and the firms operated in the same geographical area. I refrained from merging if the names were a permutation of common terms (e.g. "Solar Power Inc" and "Solar Power Systems Inc.") or if they operated in distinct geographical areas. Some of the California data listed a seller as well as an installer. This likely means that the work was subcontracted out by the systems integrator to an electrician or general contractor. Conceptually, this distinction is not important because the system integrator and its contractors can be considered a single unit of analysis for the purposes of learning in industry. Thus, in cases where both a seller and an installer was listed, the firm in listed in the seller field was used.

Figure 32 shows the distribution of firms by the number of years they have been active in system installation. The majority of firms have only been active for 3 years or less. This dispels the image of an installer base with little turnover and that improves by gradually gaining experience. Instead, this view must be revised by considering the effects of firm entry into and exit from the system installation market. Installers, on average, have had only a short period of time to learn. Compared with early market entrants, later market entrants may come in with a better understanding of the industry.

Figure 32. Number of Firms by Firm Lifetime



This right-skewed distribution of firm "age" is driven by two processes. First, firms that have entered the industry in only the past few years and are still operating account for the many of the data points to the left of the distribution. Second, firms that entered the industry in the late 1990s and early 2000s stopped installing photovoltaic systems. Thus to be one of the few firms to be active for ten years or more (on the right side of the distribution), one must have entered the industry early and then remained in continuous operation since.

Figure 33 below shows the pattern of firm entries to and exits from the industry from 1998 to 2008[28]. It reveals that the installation industry remained small, at least in terms of number of active firms, until 2001 when the number of firm entries increased. This may be due to the introduction of time-of-use net metering in April 2001 and from California's introduction of a 15% state tax credit also in 2001.

The similarity of Figure 33 with Figure 34 reflects California's dominance of the market. From 2001 to 2006, the California industry grew at a steady rate. And in this timeframe, installers begin operations in Massachusetts and New Jersey shortly after the two states introduced their own incentive programs (see Figure 35 and Figure 36).

In 2006, the rate of entry in California and Massachusetts probably increased because of the introduction of the federal tax credit that increased its value for commercial system owners and introduced the first residential tax credit for the past 20 years.

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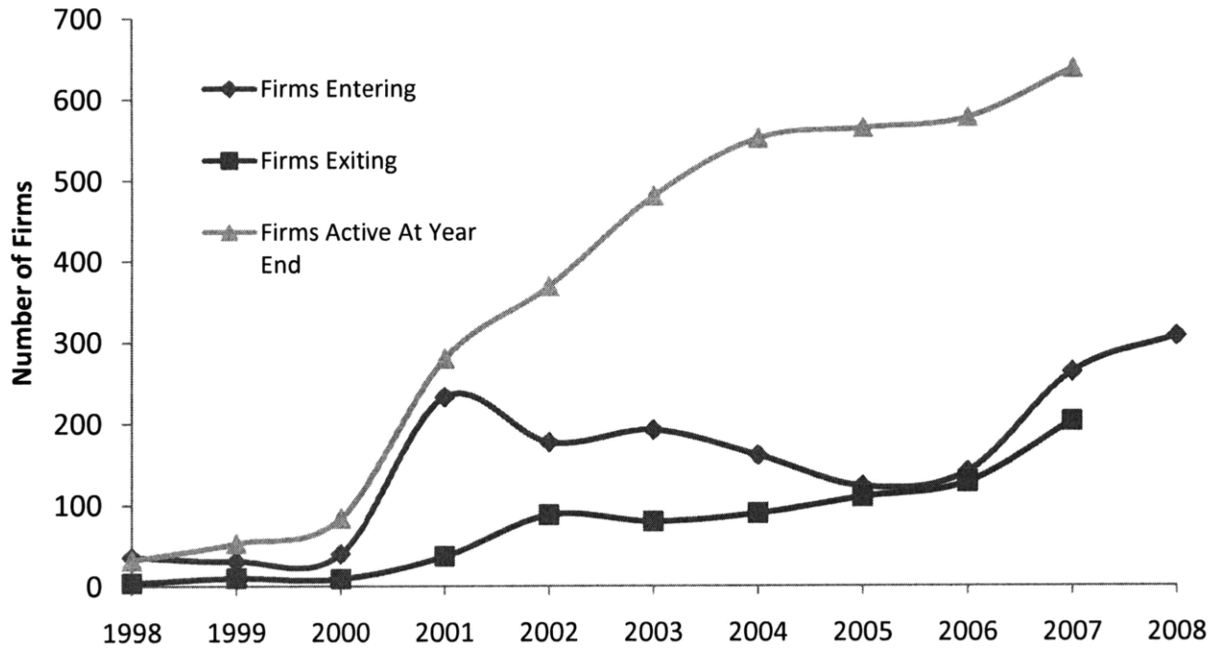
[28] Note on the methodology: A firm was considered to have entered the industry in the first year that it installed a system: more precisely, the first year when a rebate application was approved, which occurs before the physical installation of the system. A firm was considered to have exited the industry in the final year it completed the physical installation of a system. This, of course, does not count the final year of the dataset; firms that installed in the final year of the dataset (2008 and 2009 for California, 2008 for Massachusetts and 2008 for New Jersey) were considered to be still active. Because I only know if a firm has exited the industry if it goes an entire year without an installation, my knowledge of firm exits lags the dataset by one year. This is why most of the data series go only until 2007. The number of active firms was calculated for each year by subtracting the cumulative number of exits up to that year from the cumulative number of entries up to that year.

One concern for the estimated number of exits is that even with a one year lag is right censoring. It may be possible that a firm goes on a one year hiatus from installing photovoltaic systems and returns to the business the following year. To assess the magnitude of the potential bias, I examined all 1836 firms to see how many firms operated continuously before exiting or until the present time period and how often a firm went on a one year hiatus. Firms operated continuously 89.3% of the time. Firms took a one year hiatus 7.8% of the time and took a hiatus of more than a year 2.9% of the time. This means that I may overestimate firm exits in 2007 by about 10.7% and may overestimate firm exits in 2006 by about 2.9%.

Figure 33. Installer Firm Entries and Exits in Complete Dataset, 1998-2008



The patterns of exit and entry in Massachusetts reflect the timing of its incentive programs (See Figure 35). Massachusetts' first dedicated incentive program for solar began in 2005, explaining the small increase in entries in 2005. Yet it is interesting that there has not been a noticeable increase in 2008 with the start of the Commonwealth Solar program. Perhaps this will only be revealed once the 2009 data is examined.

New Jersey shows a very different pattern from California and Massachusetts (see Figure 36). There is a notable decline in the number of entries and a gradual increase in the number of exits over time. This may be explained by the history of the NJ CORE program. When it first started, the CORE program offered very large rebates which led to long queues and some concern over whether the money was being well-spent since it was paid for by the state budget (Hart 2009). New Jersey changed their incentive program from a rebate-based model to a SREC-based model, reportedly causing some consternation amongst installers. This may have reduced the interest in acquiring photovoltaic systems and/or meant that the data was not being collected in the CORE dataset used to construct the figure.

Figure 34. Installer Firm Entries and Exits in CA, 1998-2008

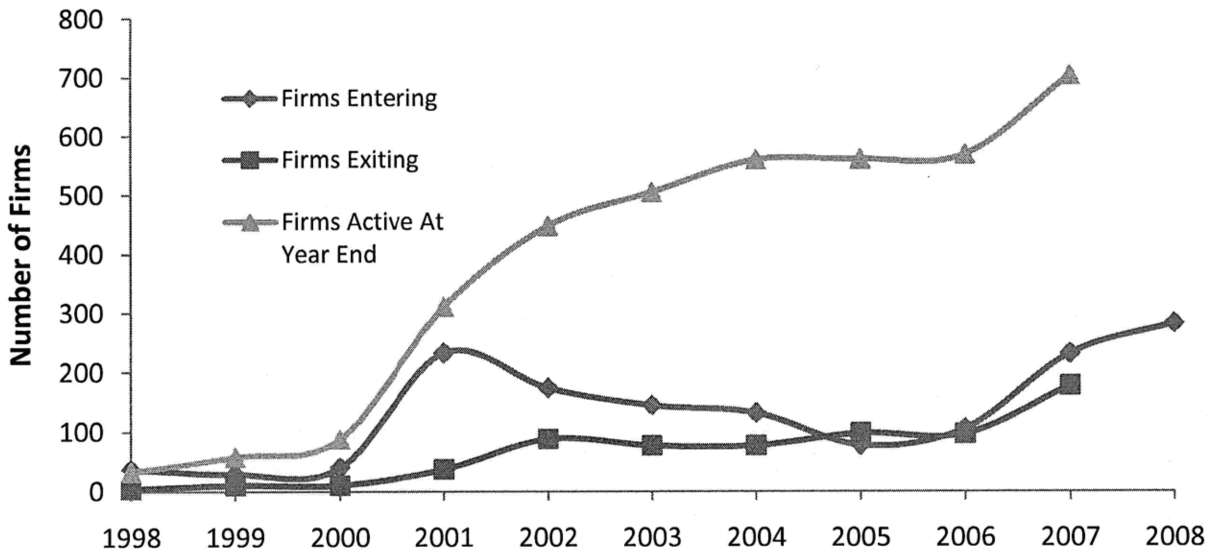


Figure 35. Installer Firm entries and Exits in MA, 1998-2008

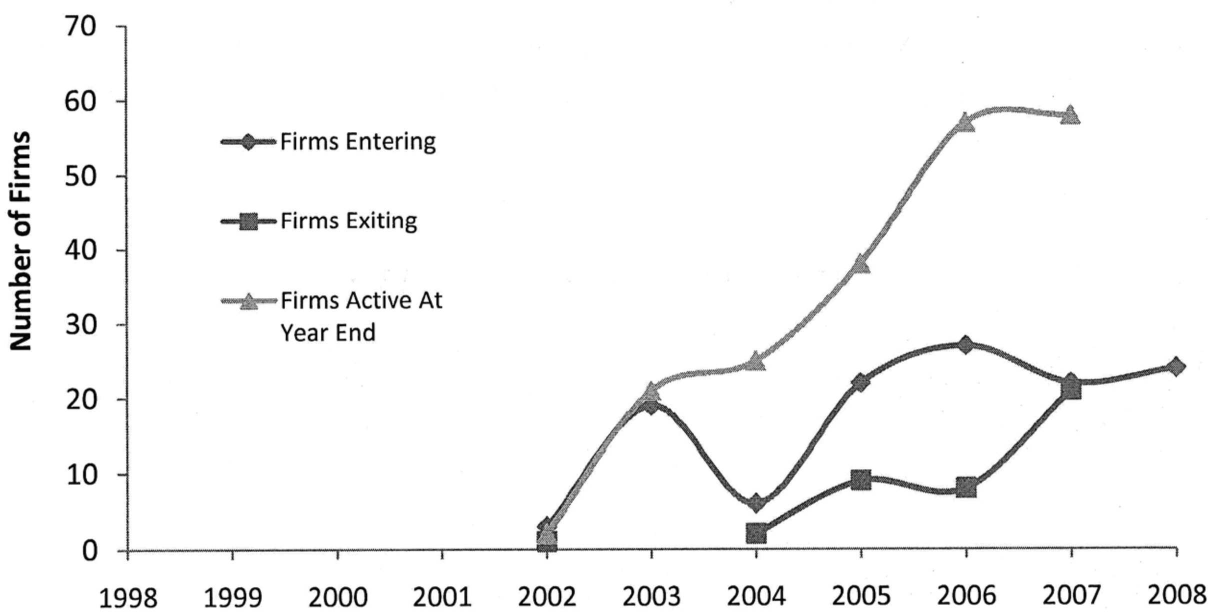
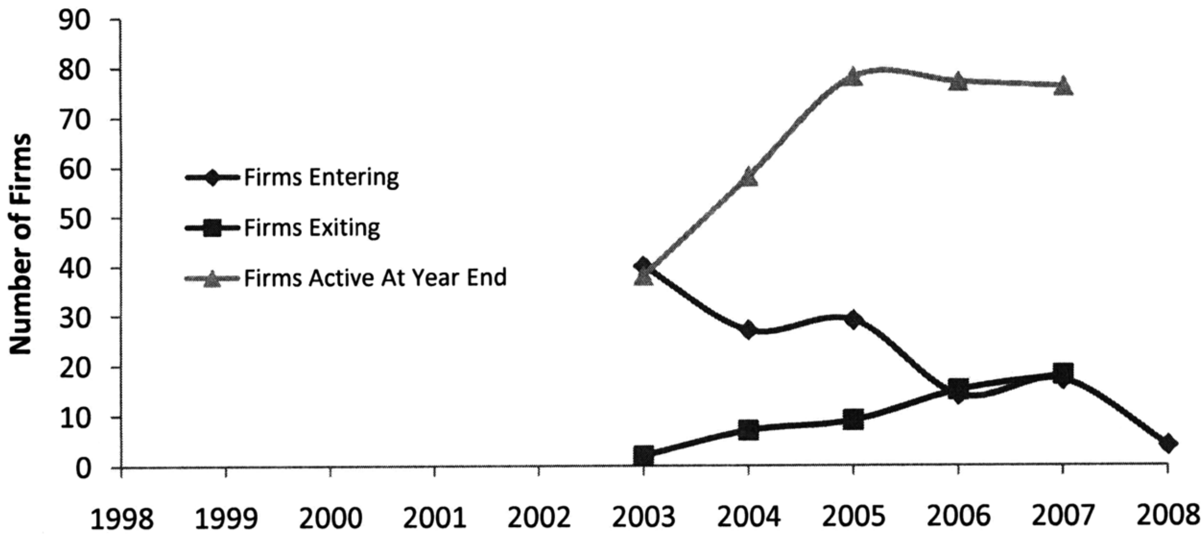


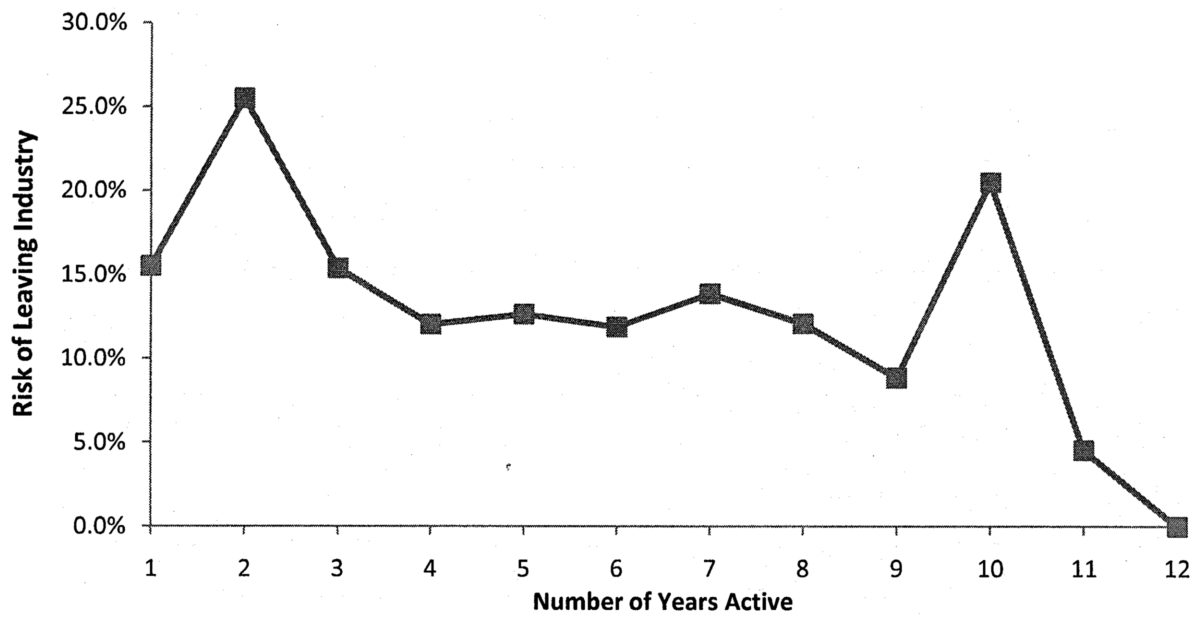
Figure 36. Installer Firm Entries and Exits in NJ, 1998-2008



Going beyond a direct description of the data and trying to understand the competitive dynamics of the industry, Figure 37 shows the hazard rate for installers exiting the industry. The hazard rate is the risk of a firm exiting the industry conditional upon the firm operating in the previous year. It is different from Figure 32 in that it considers the appropriate risk set. For instance, according to Figure 32, a firm active for 1 year may have entered the industry and exited after one year or may have only recently entered the industry and is still in operation. Figure 37 does not consider firms that are still active when calculating the appropriate risk set and the rate of exiting the industry. Thus, the hazard rate reflects the risk of a firm exiting the industry at any firm age.

The figure shows that firms have a slightly greater risk of exit in the first three years of operations, with a peak of 25.5% in year two. Beyond year seven, the risk of exiting declines slightly (despite the peak at year ten). The decreasing risk of exit likely reflects, at least in part, heterogeneity in firm capability and fitness; with each year that passes, less capable firms leave the industry and leave more capable firms in operation. The decline in the hazard rate in subsequent years reflects the greater capabilities of the remaining firms.

Figure 37. System Installer Hazard Rate



Examining the activities of firms, Figure 38 shows the distribution of firms by the number of systems installed. Following the X-axis from left to right, the figure shows that more than 1000 installers have installed at least one photovoltaic system, about 100 firms have installed 100 systems, and less than ten firms have installed more than 1000 systems. The figure shows that the vast majority of firms install only a few photovoltaic systems each while a small minority of firms install the majority of systems. The figure also shows what the curve would look like if each of the firms installed an equal number of systems (a little over 30 systems each). Deviation from the "square" curve reveals the extent of unevenness in the cumulative number of systems installed.

Figure 39 shows the number of systems installed by the top firms. Reading the x-axis from right to left, the figure shows that the top 1836 installers (i.e. all of them) have installed all 54,948 systems. The top 1801 installers have installed almost 54, 948 systems, the top 201 installers have installed about 45,000 systems (actual number is 46,980), and the top 101 installers have installed about 40,000 systems (actual number is 39, 479). The diagonal shows what the curve would look like if each firm installed an equal number of systems. Deviation from the "triangular" curve reveals the extent of unevenness in the cumulative number of systems installed.

This distribution also leads to further questions of how the experience curve is supposed to work. If the story is that as firms gain experience their cost of sales decrease, this should hold true for the top installers but not hold true for the other installers. Other installers presumably do not install enough systems to gain enough experience and reduce their cost of sales.

Figure 38. Distribution of Cumulative Installation Across Firms

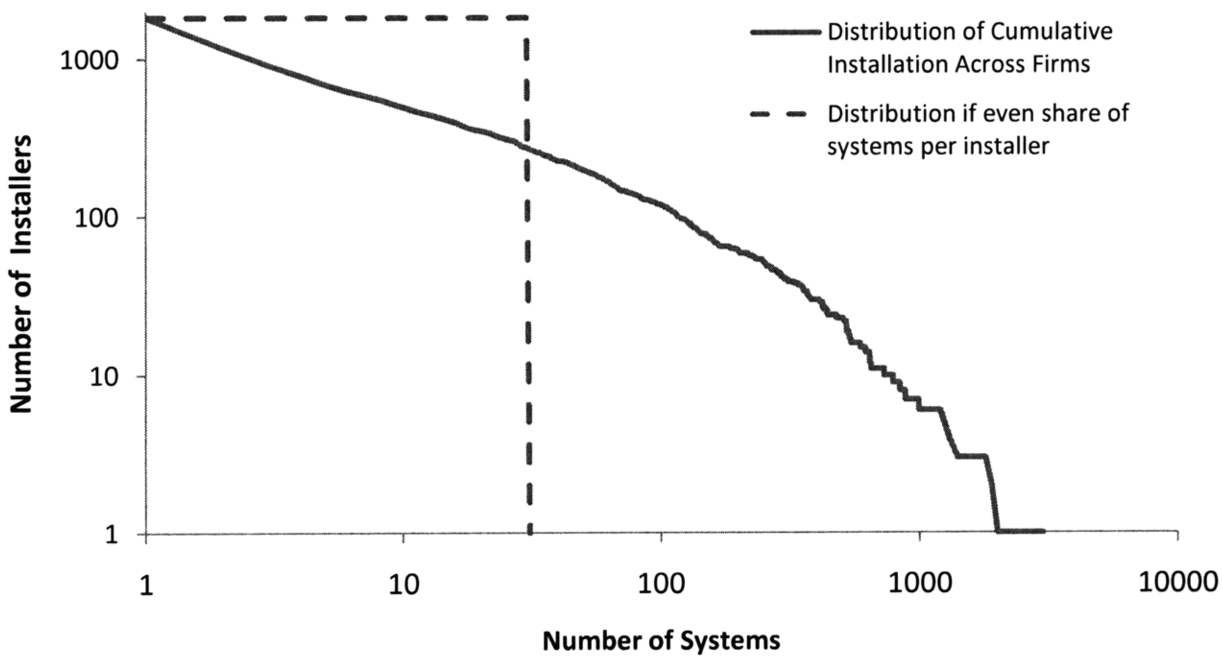
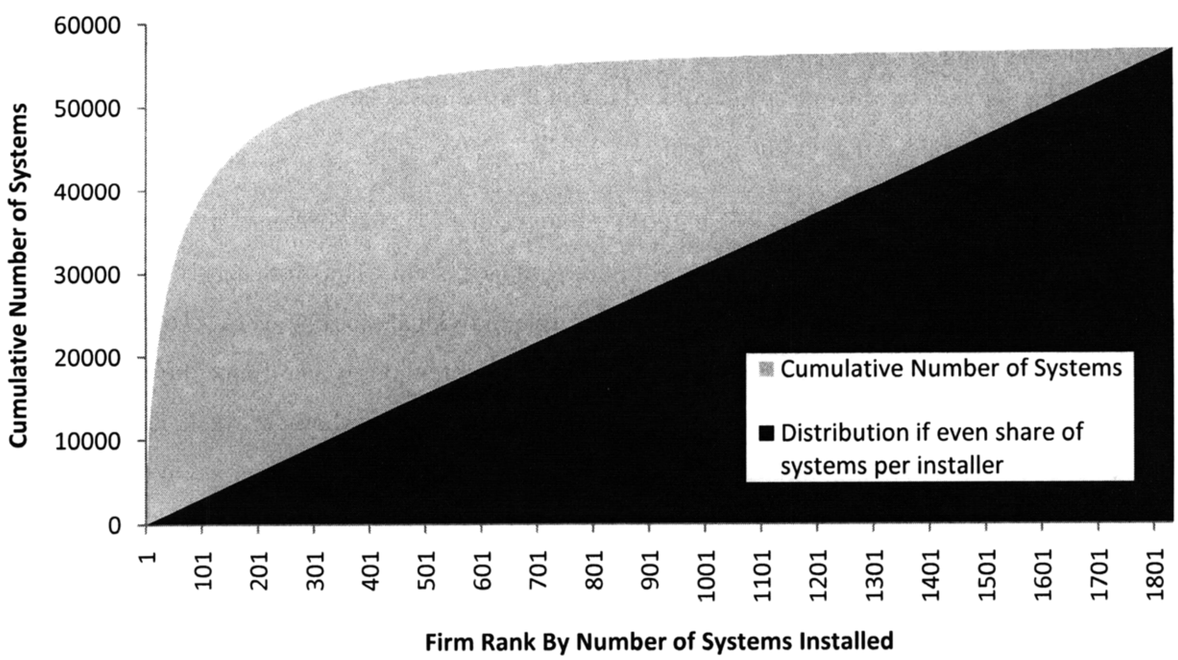


Figure 39. Cumulative Number of Systems Installed by Top Firms



Another question this distribution raises is: how many installers are pure play solar installers? That is, how many firms do nothing but install photovoltaic systems? We can imagine at least three categories of system installers. First are the pure play solar installers, which can perhaps be identified in the data if they have a solar-specific name (e.g. Borrego Solar or Akeena Solar) and install enough photovoltaic capacity to support a full-time staff. Second might be firms that pursue solar installations opportunistically. Although solar is not their main business, they will do it if they are approached by a customer. It may be possible to identify these firms by a non-solar-specific name (e.g. David ACE Hardware, Skelley Electric) and low levels of system installations. The third type falls somewhere in between the first two. For this third category of firm, solar is one of several formal lines of business. They may have solar-specific names but be part of a general contractor. Or they may offer a wider range of renewable energy technologies (e.g. small wind turbines), of which photovoltaics is just one. It may also be possible to switch from one category to another, for instance, by beginning to pursue solar installations opportunistically but, upon gaining some experience, decide to pursue solar as an official line of business.

While the exact number of pure play firms cannot be known without distributing a questionnaire, a basic analysis suggests that only a small percentage of firms install solar photovoltaic systems exclusively. Let us begin with some prototypical numbers. Let us imagine a firm that installs systems with an average size of 10 kilowatts, has been in operation for 3.3 years and employs five people. Ten kilowatts is slightly below the average of 11.875 kilowatts AC (or 14 kilowatts DC), but would be considered large for residential systems and small for commercial systems. 3.3 years is the average number of years a firm has been in operation, (shown graphically in Figure 32). Five people would be fairly small for a single firm, considering the variety of work tasks required to run the business – sales, system design, installation, accounting and general management.

The Renewable Energy Policy Project (REPP 2001) estimates that 22.25 labor hours are required for systems integration and installation per kilowatt of photovoltaic system. Thus for each 10 kilowatt system, 222.5 labor hours are required, enough work for five individuals for one week. To be fully employed, this firm of five people must install one 10 kilowatt system per week. Since the average firm has been in operation for 3.3 years, over this time period at a rate of one system per week, the firm would have installed 171.6 systems throughout its lifetime. Returning to the numbers observed in the dataset (Figure 38), only 65 firms have installed more than 171 systems. Thus, it is likely that the vast majority of firms are not pure play solar installers and carry out other lines of business.

Table 9. Labor Requirements Per Megawatt of Photovoltaics
(Source: REPP 2001)

Table 3. Labor Requirements Per Megawatt of Photovoltaics[a]
(in hours)

Project Activity	Occupational Category									TOTAL by Project Activity
	Prof. Tech & Manage (0/1)	Clerical & Sales (2)	Service (3)	Agri. Fishery, Forestry (4)	Processing (5)	Mach. Trades (6)	Bench-work (7)	Structural Work (8)	Misc. (9)	
Glass	50				50	50			50	200
Plastics	50					250				300
Silicon	1,550	200	200		3,300	200	200			5,650
Cell Manufacturer	800				1,600		600	50	150	3,200
Module Assembler	3,500				1,600		8,250	750	6,850	20,950
Wires	150					1,700				1,850
Inverters	750				1,000	1,000	1,000	1,000		4,750
Mounting Frame	500	500				150	100	150	100	1,500
Systems Integration	8,900	2,850								11,750
Distributor Contractor/	1,500	1,500							1,000	4,000
Installer	2,500							8,000		10,500
Servicing[b]	5,000									5,000
TOTAL by Occupation	25,250	5,050	200	0	7,550	3,350	10,150	9,950	8,150	69,650
TOTAL Person-Years	12.9	2.6	0.1	0	3.9	1.7	5.2	5.1	4.2	35.5[c]

a. Figures derived from a survey to determine labor requirements for a 2-kW residential PV installation.
b. Includes servicing for ten years of operation.
c. Totals for person-years do not add up due to rounding.

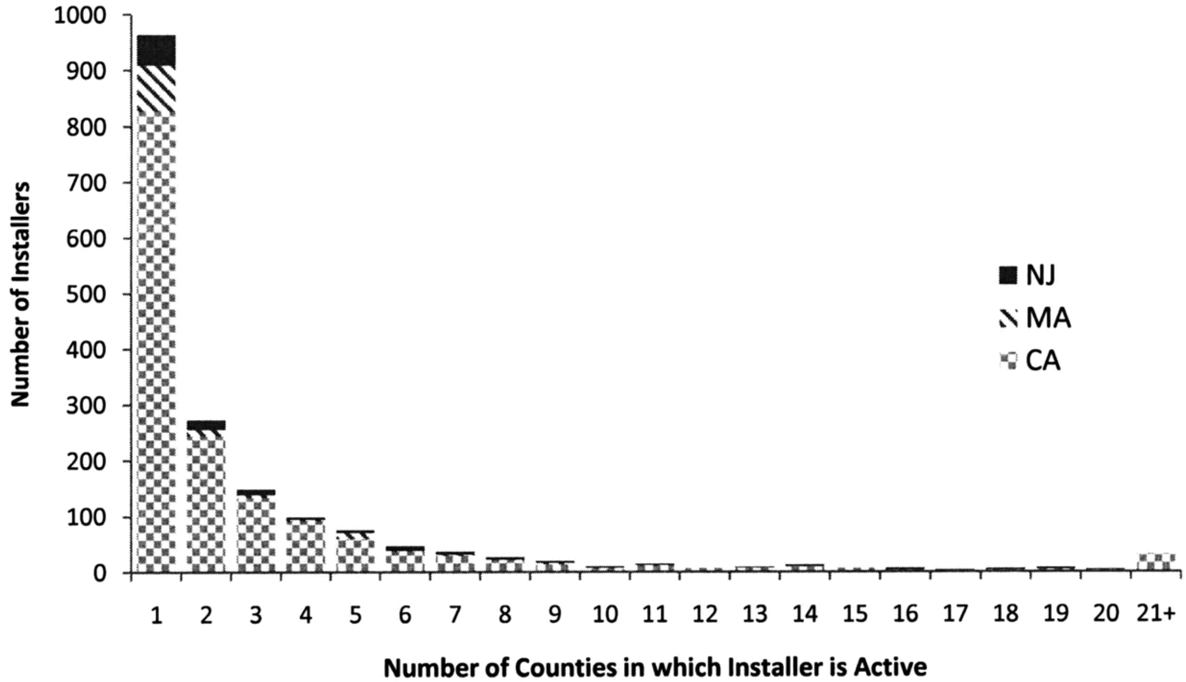
Turning to the geographic area in which installer operates, Figure 40 shows the distribution of number of counties in which firms operate. Nearly 1000 (the exact number is 964) have operated in only one county and the number of firms operating in more counties decreases. The average number of counties in which a firm has operated is 3.2 in California, 2.1 in Massachusetts, and 4.4 in New Jersey.

Few installers operate in large geographical areas, and even the largest installers are not represented in every county in the state. The firm that operated in the most counties in California operated in 41. To compare, California has 58 counties in total and 55 where at least one photovoltaics system was installed in the dataset. The firm that operated in the most counties in Massachusetts operated in 11. To compare, Massachusetts has 14 counties in total and at least one photovoltaic system was installed in all 14. The firm that operated in the most counties in New Jersey operated in 20. To compare, New Jersey has 21 counties in total and at least one photovoltaic system was installed in all 20. This suggests that system installation is a geographically constrained industry. New Jersey is the smallest state by land area and it has the highest average number of counties in a firm's operating area and the most geographically diverse installer operates in 20 of 21 total counties.

There are several reasons why this might be possible. Travel time should be a consideration. Driving to a customer site 30 miles away would added a half hour drive each way and one hour of work per person. Travel time may shift the economics such that an installer may be economically competitive only within constrained geographical boundaries.

Another possibility might be the way that interested individuals and businesses identify candidate system installers. While this requires further investigation, one may speculate that advertising may be done through word of mouth. Although firms may be listed in a directory that is distributed broadly, that information may only be enough to enter the customer's consideration set. It may not necessarily be enough for the customer to commit. For many people, the process of purchasing, owning and operating a photovoltaic system seems fairly opaque. An interested customer must educate themselves or be educated by someone in the industry. Thus connection through local social networks may matter in getting new business. In other words, a customer will probably be more likely to use a solar installer that has installed a system for someone the customer knows than an installer about which the customer has no other information. This dynamic gives local firms an advantage over distant firms because local firms are more likely to be connected into the local social and economic networks.

Figure 40. Operating Areas of Photovoltaic System Installers



One other feature of the dataset also seemed worth examination: the number of module manufacturers and inverter manufacturers used by each installer. The use of multiple brands might suggest some latitude by installers in choosing suppliers, which might be useful in diversifying supply chain risks and, if the installer is large enough, might provide some leverage in price negotiation. However, some firms may commit to using one or a few manufacturers in order to receive lower prices from the manufacturer or wholesaler.

The data reveal that most firms only used a small number of module manufacturers and inverter manufacturers, as shown in Figure 41 and Figure 42. Using only a few brands, of course, would not be surprising for firms that installed only a handful of systems. Looking at the top 25% of firms (in terms of total capacity installed), there is a fairly even distribution among number of manufacturers used. One might expect that firms that install many systems would have ample opportunity to use many equipment brands and might also encounter a broad range of end-customer preferences requiring the use of a diverse set of equipment. However, firms that were in the top 25 percentile and used only one or two brands likely did so as part of a supply arrangement, that provided some discount on the module and inverter prices in exchange for brand loyalty.

Figure 41. Number of Module Brands Used By Installers

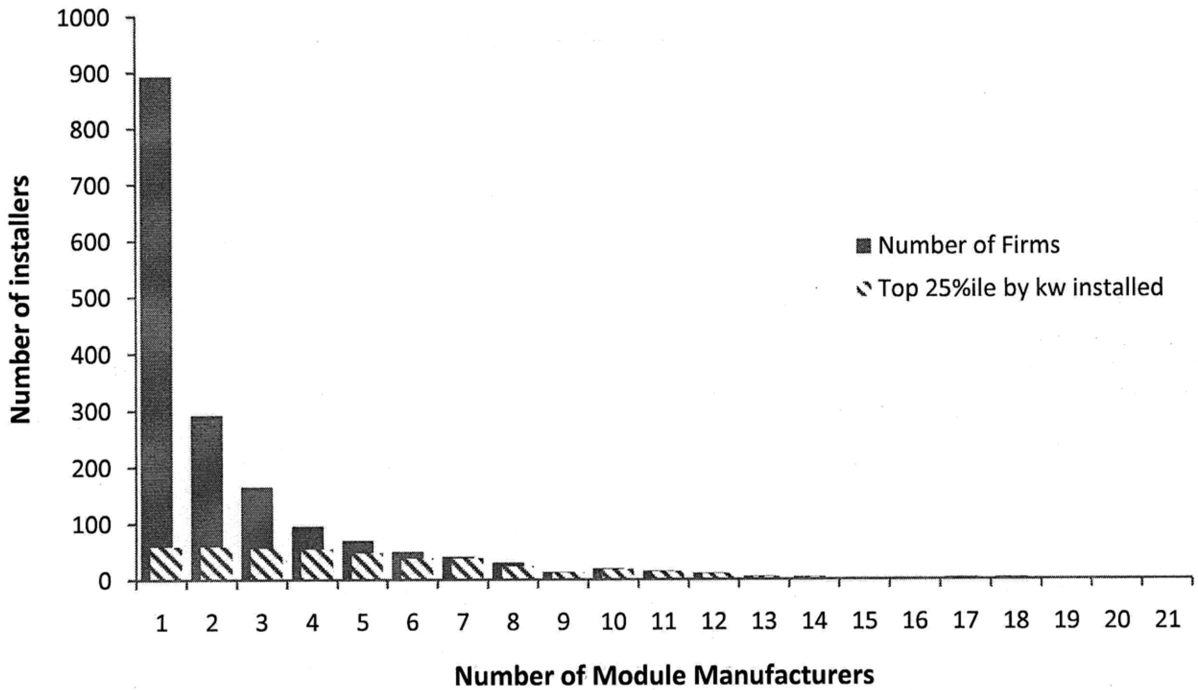
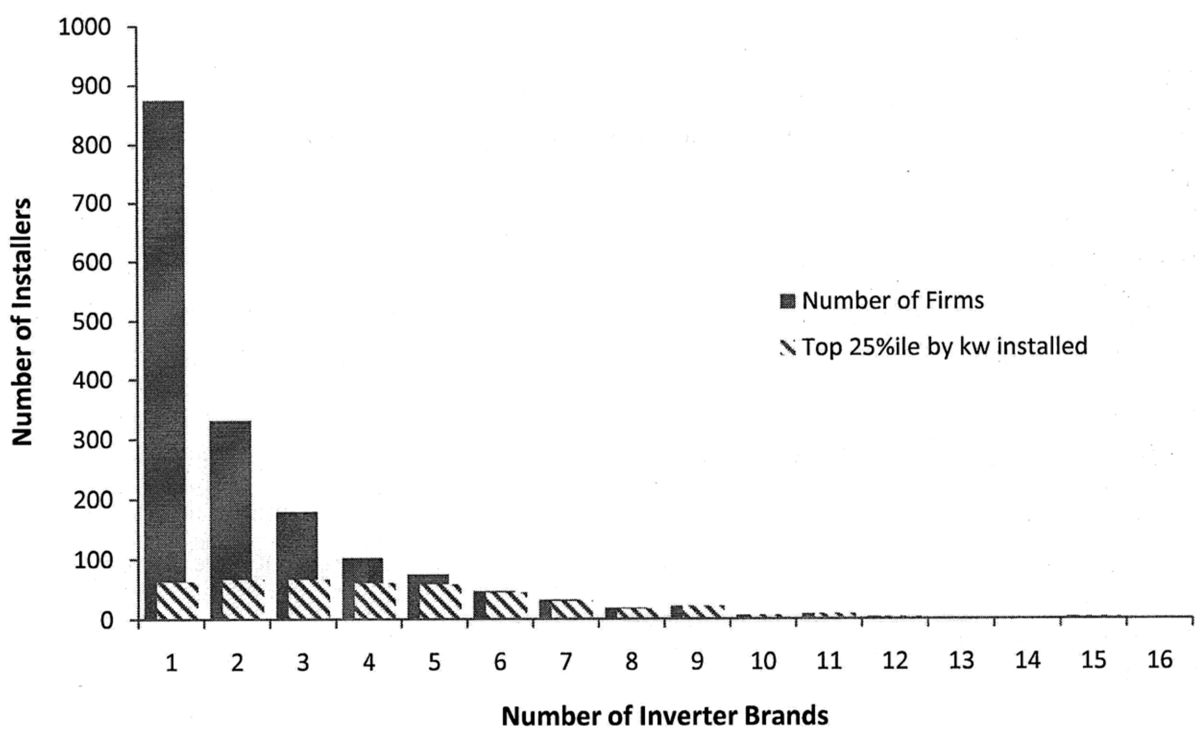


Figure 42. Number of Inverter Brands Used By Installers



Research Approach and Hypotheses

Based on the review of the photovoltaics industry, experience curves, alternate mechanisms of cost reduction, and descriptive measures of system installers, we can now lay out a set of predictions we would expect to see in the data.

The observed price of the photovoltaic system should depend on supply and demand characteristics. Based on standard models of consumer demand, we can expect consumers to maximize their utility.

Consumer's willingness to pay = f(consumer income, system price, financial value of system, utility from supporting renewable energy)

where, *Financial value of system =*
value of tax credits + value of state rebate + value from REC sales + quantity of electricity produced X retail electricity rate

We would expect demand to increase as system price decreases, as financial return from the system increases and as the utility of supporting renewable energy increases.

Based on standard models of production, we can expect producers to maximize profit.

Profit = f(cost of sales, system price)

Where, *cost of sales =*
cost of components + installation labor + design/interconnection/permit labor + indirect labor + overhead

We would expect supply to increase as system price increases and cost of sales decrease.

Basic Hypotheses

A basic set of hypotheses relates to factors that influence the installers' cost of sales and the systems' financial value to consumers.

To quantify cost of sales, measures were obtained for labor costs, cost of photovoltaic modules, system size, whether the system was installed as part of a multisystem project, whether the system used building-integrated photovoltaics, whether the system used thin film photovoltaics.

H1: Systems that are more costly to install will have higher prices.

To quantify financial value to the consumer, measures were obtained for the retail electricity rate, solar insolation (which affects the amount of electricity generated), the size of the rebate received by the state, and the type of federal tax credit received. Consumer income was quantified using median household value, and adjusted gross income.

H2: Systems that are of greater value to the system owner will have higher prices.

H3: Systems sold to consumers with greater income will have higher prices.

Hypotheses Relating to Experience

The primary mechanism hypothesized by the experience curve is that experience will provide a firm or industry the opportunity to learn and reduce their costs. Under stable market conditions, this will also translate into reduced market prices.

H4: Systems installed by firms with greater experience will have lower prices.

Hypotheses Relating to Competitiveness

While experience may help firms to reduce their own cost of sales, competitiveness may force firms to reduce their profit margins. In order to compete and acquire business, firms must be able to offer prices comparable to their peers. In markets where there are low levels of competition, firms may tacitly collude and receive larger profit margins than would be possible in areas with high levels of competition.

H5: Systems installed in areas with high levels of competition will have lower prices.

Nonetheless, over the long run, high levels of competitiveness may help to decrease cost of sales. In order to survive, firms will be forced to continually adapt in an effort to increase their profit margins while offering similar prices as competitors. As all firms in the population adapt, the industry as a whole improves.

H6: The price of systems installed in areas with high levels of competition will decrease over time.

Hypotheses Relating to Industry Turnover & Firm Heterogeneity

A look at the firms in the system installation industry uncovered greater detail about their patterns of behavior.

Of the 1836 system installers that appear in the dataset, a relative small number install a large proportion of total systems. One might expect these top installers to have lower system prices than other installers, since the ability to install at lower costs may allow a new entrant to stay in business and become a top installer.

H7: Systems installed by top installers will have lower prices.

Because the vast majority of firms have only installed a small number of systems, those firms may be less able to benefit from their experience than system installers who have installed many more systems.

H8: The effect of experience will be greater for systems installed by top installers.

Firms who have just entered the industry pose an interesting case. On one hand, it would be expected that since they have the least experience, they will have the higher cost of sales on average and must thus charge higher prices. Yet on the other hand, one might expect that because they are an unknown entity, they must charge lower prices in order to compete against better known firms. I suspect the latter will outweigh the former.

H9: Systems installed by new entrants to the industry will have lower prices.

Firms who have special committed relationships with suppliers may have lower components costs. Thus, these firms are likely to offer lower prices to potential customers.

H10: Systems installed by firms with committed relationship with suppliers will have lower prices.

Generating variables and cleaning the data

Table 10 lists the variables used in the final regression analysis.

<u>log of system price per watt</u> - dependent variable. The price per watt was calculated by taking the total system price and dividing by the size in AC watts. The number were then adjusted for inflation using the Producer Price Index for inputs to construction industries (Series Id: PCUBCON—BCON). A log transformation was useful for improving the distribution of the dependent variable. The untransformed variable was right skewed (i.e. several systems were extremely expensive on a per watt basis) and the transformation results in a distribution that better approximates the normal. This will change the interpretation of any regression coefficient such that a one unit increase in the independent variable will be associated with a *one percent* increase in the dependent variable.

<u>Electricity rate</u> – From the Energy Information Administration EIA-826 database which includes monthly sales information for all utilities in the United States. The figures used in the final dataset vary by utility and by year. Each major utility had its own rate while small utilities were assigned the average rate for all non-major utilities. Residential retail rates were used if the system was smaller than 10 kilowatts (AC). If the system was larger, then it is unlikely that it was installed by a private individual. Thus for systems

larger than 10 kilowatts (AC), commercial retail rates were used. The numbers are then adjusted for inflation using the Consumer Price Index from the Bureau of Labor Statistics.

Population density – Population density was calculated based on data from the 2000 US Census which provides data by zip code tabulation area (ZCTA). Zip code tabulation areas generally correlate to postal zip codes. When conducting the census, the US Census Bureau defines a geographical area by the predominant postal zip code in the area. However, in the ten years between any two censuses, postal codes may change according to the internal operations of the US Postal Service. For this reason, only the first three digits of the ZCTA were used because it produces a better match between data from the Census and zip code information of the photovoltaic system when compared to using all five digits. The population of each ZCTA was divided by the land area of the ZCTA.

Log of household value – Household value was also available from the US Census in the "Summary File 3 (SF 3) - Sample Data" which provides a range of housing statistics by ZCTA. This variable is the log of the median household value.

Construction Wage – Data on wages was taken from the Bureau of Labor Statistics' quarterly Census of Employment and Wages. The data is expressed in terms of annual income and was converted into an hourly wage by dividing by 2000. The average construction wage varies by county. However, data for only 2005 was used since it was complete for all counties in the three states (Other years had some missing data). This was considered reasonable since, a priori, most of the variation in wages would seem to be across geography rather than across time.

Insolation – The value for insolation is the average of amount of sunlight incident on horizontal ground, measured in kilowatt hours per square meter per day. The original data is maintained by NASA and includes the average insolation – based on observations from July 1983 to June 2005 – for each degree of latitude and longitude. The coordinates were matched up to the coordinates for each zip code tabulation area provided by the US Census Bureau.

Log of System size – System size is a basic field in the system data provided by each state. Size was measured in terms of AC watts because California's Emerging Renewables Program based its rebates based on size in AC terms. Other programs differ in the size used to calculate the incentive, but all measures can be converted into AC watts. The main alternative to AC watts is the nameplate rating which is used by Massachusetts and New Jersey. The nameplate rating is the same as "peak Watts" or "DC" system size which is calculated as the simple sum of the individual ratings of each module in the system. The difference between capacity measured in DC watts and capacity measured in AC watts is that AC watts considers electricity losses from the modules performing in PVUSA Test Conditions (PTC) instead of Standard Test Conditions (STC), and from efficiency losses in the inverter. In short, the difference between PTC and STC is that modules operate in a higher temperature in PTC[29] and crystalline silicon modules lose about 0.5% of efficiency per degree Celsius. Inverters, converting DC to AC, have an efficiency of 90-95%. To convert DC size to AC size, I multiplied by a factor 0.85 which was the average ratio of DC capacity to AC capacity in the California dataset (which includes nameplate capacity and AC capacity)[30]. Incentives from the California Solar Initiative are based on an effective system size, which apply a "design factor" to the AC system size. However, the data from CSI also includes the AC system size.

BIPV – BIPV is a dummy variable indicating that the system used building integrated photovoltaics. A system was classified as using BIPV by comparing the module type used in the system to a list of modules eligible for rebate for the California Solar Initiative which indicates BIPV models.

Thin Film – Thin film is a dummy variable indicating that the system used thin film modules. A system was classified as using thin film by comparing the module type used in the system to a list of modules eligible for rebate for the California Solar Initiative which indicates thin film models.

Self_install – Self-install is a dummy variable indicating that the system was installed by the system-owner. Although there was not an explicit field for this, any references in the data record to "owner" "self" "owner installed", or "self installed" led to the system as being coded as owner installed. While these data would not include off-grid systems that were built by highly self-reliant individuals because these people were unlikely to have applied for a rebate, it is more likely that the photovoltaic system equipment was sold by a company that typically installs the system but did not in certain circumstances.

Ind_Large_Project – Photovoltaic systems are sometimes installed in multisystem projects. The data does not indicate which systems were part of multisystem projects. However, it is possible to infer this from patterns in the data. Going through the data, I looked for projects installed in the same month, in the same town, of the same size by the same installer. Because it is hard to imagine many unrelated systems sharing these characteristics, if three or more did share these characteristics, then I concluded that they were part of a larger multisystem project.

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29 STC measures efficiency when the cell has a temperature of 25 degrees Celsius. PTC measures efficiency at ambient temperatures of 20 degrees Celsius, which leads to an actual operating cell temperature of about 50 degrees Celsius.

30 In estimating system output based on nameplate capacity, NREL's PVwatts uses a "derate" factor of 0.77. This takes into consideration more sources of efficiency loss than the AC watts measure used by California.

Table 10. Univariate Statistics of Variables Used In Final Analysis

Variable	Description	Mean	Min	Max	Std Dev	N, if dummy
log price per watt	AC, 2008$, adjusted by PPI for construction inputs, log	2.473	0.336	4.936	0.2097	
electrate_by_util	average utility rate by utility & customer type;adjusted by CPI; cents/kwh	15.105	9.79	18.159	1.1514	
popdensityby3digit	1000s per square mi (land area), by county according to 2000 Census	0.1801	.00118	15.629	3.136	
log_householdvalue	log of median household value by county according to 2000 Census	12.398	11.308	13.496	0.5224	
constructionwage2005	average hourly construction wage by county in 2005, $	23.123	13.505	37.083	3.544	
insolation3dig	insolation incident on horizontal surface, 22 yr avg, by 3 digit zip, kwh/m2/day	5.0485	3.596	5.398	0.396	
log_size	log of system size in AC watts	8.341	4.025	13.921	0.927	
bipv	1 if module is BIPV	0.0274	0	1		1503
thinfilm	1 if module is thin film	0.0156	0	1		875
self_install	1 if any mention of owner install	0.017	0	1		934
ind_large_project	1 if system was part of a multisystem project	0.0516	0	1		2834
Yr1998	1 if system was approved in 1998	0.0017	0	1		94
Yr1999	1 if system was approved in 1999	0.0035	0	1		193
Yr2000	1 if system was approved in 2000	0.004	0	1		221
Yr2001	1 if system was approved in 2001	0.0384	0	1		2111
Yr2002	1 if system was approved in 2002	0.0467	0	1		2543
Yr2003	1 if system was approved in 2003	0.0891	0	1		4895
Yr2004	1 if system was approved in 2004	0.0978	0	1		5375
Yr2005	1 if system was approved in 2005	0.1002	0	1		5507
Yr2006	1 if system was approved in 2006	0.1485	0	1		8160
Yr2007	1 if system was approved in 2007	0.1943	0	1		10676
Yr2008	1 if system was approved in 2008	0.2115	0	1		11620
Yr2009	1 if system was approved in 2009	0.0647	0	1		3553
state_ma	1 if system was installed in Massachusetts	0.0201	0	1		1102
state_nj	1 if system was installed in New Jersey	0.0595	0	1		3268
state_ca	1 if system was installed in California	0.9205	0	1		50578
module_cost_index	average module price each year, 2008$	3.483	2.884	3.927	0.318	
year_approved	number of years after 1997 when system was approved	8.808	1	12	2.237	

log_incentive	log of state rebate	1.095	-1.841	3.68	0.411	
fed_tax_cred	1 if eligible for federal tax credit	0.6919	0	1		38016
residential_ftc_cap	1 if federal tax credit capped at $2k	0.5217	0	1		28664
exp_county	Experience in 100s of systems, calculated each quarter, pooled at county level	11.137	0	54.59	11.288	
inst_years_active	years experience at time of system installation	4.819	1	12	2.472	
exp_installer	Experience in 100s of systems, calculated each quarter, for each installer	3.187	0.01	28.62	4.95	
Instlr_per_Hshld	Number of active installers divided by the number of households	1.788	0.0173	14.632	1.705	
InstlHsdXyear	Interaction between Instlr_per_Hshld and year_approved	16.52	0.0183	160.96	17.244	
herf_cty_year	Herfindahl index by county, by year	0.129	0.0388	1	0.0988	
herfXyear	Interaction between herfindahl index and year_approved	1.089	0.16	12	0.777	
top_100	1 if system installed by a top seller	0.6715	0	1		36798
installer_rookie	1 if the system was installed by an installer in their first year	0.0747	0	1		4107
survivor	1 if the system was installed by an installer over 3 years old	0.9505	0	1		52226
supply_arrangement	1 if the system was installed by a firm that has a preferred supplier arrangement	0.0522	0	1		2863
experienceXTop	interaction between exp_installer and top_100	3.093	0	28.62	5.012	
experienceXsurvivor	interaction between exp_installer and survivor	3.179	0	28.62	4.954	
survivorXrookie	interaction between survivor and installer_rookie	0.049	0	1	0.216	

Year approved, Yr1999-Yr2009 –The primary measure for when the system was installed is the year that the rebate application was approved. The typical process for receiving a rebate begins with the owner submitting an application after he has decided to purchase a system but before the system is physically installed. Only after the application is approved will construction commence. The time when the application was approved was chosen because it is the closest point in time available to the time when the decision was made to purchase a system. Factors that influence the final price of the system will have played themselves out while the prospective owner evaluates the system installer's offer, ultimately shaping the final details of the system.

State_ma – This is a dummy variable indicating that the system is located in Massachusetts.

State_nj – This is a dummy variable indicating that the system is located in New Jersey.

State_ca - This is a dummy variable indicating that the system is located in California. Although California serves as the reference state in the final analysis, the California dummy variable is included for completeness.

Module cost index – This variable provides an average value for photovoltaic modules for each calendar year and is meant to control for changes that affect worldwide module production, such as the silicon shortage that ended in 2008. It is calculated using a similar methodology as Wiser et al (2006). The baseline values are taken from Paul Maycock's average module price which runs until 2005. Values for 2006 through 2009 are estimated by extrapolating from Maycock's 2005 value but using the price trend from Solarbuzz's module cost index which was available for 2003 to 2009. The numbers are then adjusted for inflation using the Producer Price Index from the Bureau of Labor Statistics.

Log of incentive per watt – Incentive per watt was calculated by dividing the total size of the incentive and dividing it by the size in AC watts. Whereas previous studies calculated the incentive amount based on system characteristics (Wiser et al 2006) and the guidelines of the program, I use the actual incentive amount which was included in the dataset. This is a simpler approach because it obviates calculating the incentive based on the programs of three different states that are revised (in terms of rebate levels and requirements periodically.

Some systems installed under the California Solar Initiative received a "Performance Based Incentive" which is paid out over five years through 60 monthly payments. The value entered in the incentive field of the CSI data is the undiscounted sum of the payments based on the CSI design rating of the system. I adjust these numbers by taking the net present value of the payments, using a 5% discount rate. Effectively, this means reducing the size of the incentive for system receiving the PBI by a factor of

0.883. The numbers are then adjusted for inflation using the Producer Price Index from the Bureau of Labor Statistics.

Federal tax credit – This is a dummy variable indicating that the system was eligible to receive the federal tax credit. The federal tax credit was reestablished for residential system owners (and enhanced for commercial system owners) by the Energy Policy Act of 2005. Essentially, this means that the system was installed in 2006 or later. Year of completion, rather than year of approved application, was used to determine eligibility.

Note: I also created a dummy variable for a state tax credit but ultimately did not use it because of multicollinearity. Massachusetts has had a tax credit available since 1979. California had a 15% tax credit from 2001 to 2003 and a 7.5% tax credit in 2004 and 2005. Whatever effects these tax credits have had will show up in the analysis through the state dummy variables.

Residential FTC cap – This is a dummy variable indicating that the system received the capped federal tax credit. Year of completion and system size were used to determine eligibility. Only systems completed between 2006 and 2008 were considered since the 2008 Recovery and Reinvestment Act removed the $2000 cap for residential customers starting in 2009. Then within the subset of systems completed between 2006 and 2008, only systems smaller than 8.5 kilowatts AC (or 10 kilowatts DC) were considered since these were likely residential systems.

Experience_county – Experience is measured by the cumulative number of systems (in hundreds) installed in the same county as the system in question. It is calculated for each quarter and lagged by a quarter. It is lagged based on the assumption that a firm could not apply learning from one project to another project running concurrently. In this image of learning, the project must be completed and the project outcome known (e.g. went well or poorly) before it can be registered as "experience." Thus, for a system installed in Middlesex County, Massachusetts in May 2007, the value of this variable would be the cumulative number of systems installed in Middlesex County by the end of the first quarter of 2007.

Inst_years_active – This variable is an alternative way of measuring installer experience. While exp_installer (below) measures experience in terms of number of systems completed, this variable measures experience in terms of firm age. The value of this variable is the age in years of the installer at the time the system was installed.

Experience_installer – Experience is measured by the cumulative number of systems (in hundreds) installed by the same installer as the system in question. It is calculated for each quarter and lagged by a quarter. Thus, for a system installed by Borrego Solar in May 2007, this value of this variable would be the cumulative number of systems installed by Borrego Solar by the end of the first quarter of 2007. Measures of experience at the national level and at the state level were also attempted, but ultimately dismissed because of unacceptably high correlation with year approved.

Herf_cty_year – herfindahl index. This is the primary measure of competition. It is based on the number of systems installed each year in each county. The Herfindahl index is calculated first by calculating the market share held by each firm, expressed as a faction of the total market. The fraction represents each firm's market share. The market share for each firm is squared, and the squared fractions are added together. The sum is known as the herfindahl index.

The index measures the number of firms competitive in an area and the "evenness" of their market shares. Equally distributed market shares suggest high levels of competition where no one or two firms dominate the rest. To develop some intuition about the value of the Herfindahl index, a low number means that the market is competitive and a higher number means that the market approaches a monopoly. If there is only one firm that controls the entire market, then the Herfindahl index is equal to one. If there are an infinite number of firms, each with a tiny fraction of the overall market, then the Herfindahl index will approach zero. The Herfindahl index is used by the US Department of Justice to determine whether mergers are equitable to society. Herfindahl indices between 0.1000 and 0.1800 are considered to be *moderately concentrated* and indices above 0.1800 to be *concentrated.*

A key concern in calculating the Herfindahl index is how to define and bound a market. The data presented earlier on the operating areas of system installers (see Figure 40) suggests that there are geographic constraints on the activities of installers. Since no single installer operated throughout the entire state, the state is considered too large a unit for use in defining the boundaries of the market. Yet, since installers frequently operated in multiple counties, it would suggest that the county is too small a unit for use in defining market boundaries. Acknowledging that the ideal measure would be somewhere in between the level of a state and the level of a country, I use county since it provides a better sense of competition heterogeneity throughout the state.

Installers per 10000 housing units – This is an alternative measure of competition meant to adjust for the potential photovoltaic system market. While the Herfindahl index only considers the number of systems actually installed, the intensity of competition may also depend on the size of the potential market in the area. This measure is calculated by taking the number of installers active that year in each county and dividing it by the total number of housing units in the county. The total number of housing units is taken from the US Census. The number of housing units is meant as a proxy for the total number of systems that could be installed in the county[31]. The data is taken from the US Census Bureau.

Installers per household x year – This variable is an interaction term between installers per 10000 housing units and year_approved.

Top 100 – This is a dummy variable indicating that the system was installed by a top 100 installer. Each of the 1836 installers was ranked according to the number of systems installed per year that the installer was active. Thus, a firm that installed 20 systems per year for two years (40 systems total) would be ranked higher than a firm that installed five systems per year for 10 years (50 systems total). This provides a better measure of the firm's level of activity.

Rookie – This is a dummy variable indicating that the system was installed by a firm in its first year of operation. This distinction may be important because firms' pricing strategies and cost of sales may not have stabilized in their first year.

Survivor – This is a dummy variable indicating that the system was installed by a firm that survived in the industry for more than three years. Firms have a 46.7% chance of exiting within the first three years of operation and firms that survive the first three years are inferred to have superior operating capabilities[32].

Supply_Arrangement – This is a dummy variable indicating that the system was installed by an installer that likely had a preferred supplier arrangement. With a supplier arrangement, the installer commits to the almost exclusive use of certain equipment manufacturers and receives a discount in return. Although there was no field indicating that a system installer used supplier arrangements, it was inferred by the patterns of equipment use by each installer. Firms likely to have supplier arrangements were also likely install large amounts of system capacity. Thus, I limited the field to the top 25% percentile of firms in terms of cumulative capacity installed. From these top firms, I looked for firms that used only one or two different module manufacturers of the 75 module manufacturers that appear in the dataset.

Experience x top – This in an interaction variable between experience_individual and Top 100.

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[31] Though it is not exactly right because not all buildings where a system could be installed are housing units and the proportion of buildings that are housing units varies by county. Also, not all photovoltaic systems are mounted on a building.

[32] 46.7% is calculated by adding the probability of exiting in the first year, plus the hazard rate of exiting the second year times the probability of the firm not exiting the first year, plus the hazard rate of exiting the third year times the probability of the firm not exiting in the first two years. These values are 15.5% in the first year, 25.5% x (1-15.5%) in the second year, 15.4% x (1 – 15.5% - 25.5% + 15.5% x 25.5%) in the third year.

Experience x survivor – This is an interaction variable between experience_individual and Survivor.

Survivor x rookie - This is an interaction variable between survivor and rookie.

Results

To test the stated hypotheses, a series of regression models were applied to the data. Thirteen models are included in the final analysis and are shown in Table 11.

The analysis was conducted using ordinary least squares regression. Robust standard errors were used and errors were clustered at the installer level to minimize problems of heteroskedasticity. Ideally I would have used county and year fixed effects but because many of the measures of interest were calculated at a county level, their effects get aggregated into the county fixed effect. I begin using year fixed effects in model 1 but switch to a linear time trend for subsequent models.

Models 1, 2 and 3 include factors that increase the cost of sales of the system installer but also increase the value of the system to the consumer

Model 1 includes basic control variables and the dummy variables for each year. With a few exceptions, the control variables behave largely as expected. Systems whose owners paid higher electricity rates tended to pay less for a photovoltaic system[33]. Counties with higher population densities tended to pay higher prices for their systems. Household value, a measure of wealth, is positively related with price per watt; a one percent increase in household value corresponds to a 0.0163 percent increase in the price paid per watt. Construction wage has a positive, though non-statistically significant, effect on installed system prices. Solar insolation had a positive but non-statistically significant effect on system prices. System size is negatively related to price per watt, meaning that larger systems cost less on a per watt basis. The coefficient of -0.0525 means that a one percent increase in system size corresponds to a 0.0525 percent decrease in price. Thus compared to a system of 4 kilowatts AC, a system of 8 kilowatts AC costs the customer 0.0525% X 100% = 5.25% less per watt (or about $0.585 more per watt at the mean price).

[33] This result is counter intuitive. However, in all subsequent models in which there are more controls, this variable is not statistically significant.

Table 11. OLS Regression Results

	Dependent Variable: Log Of Price Per Watt											
	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M12
electrate_by_util	-0.0118	0.0031	0.0013	0.0023	0.0024	0.0025	0.0019	0.0024	0.0031	0.0036	0.0036	0.0036
	(0.0039)**	(0.0036)	(0.0029)	(0.0027)	(0.0027)	(0.0027)	(0.0026)	(0.0027)	(0.0028)	(0.0026)	(0.0026)	(0.0026)
popdensityby3digit	0.003	0.0032	0.0025	0.0023	0.0026	0.0026	0.0026	0.0025	0.0024	0.0022	0.0022	0.0021
	(0.0010)**	(0.0010)**	(0.0010)**	(0.0010)*	(0.0011)*	(0.0011)*	(0.0011)*	(0.0011)*	(0.0011)*	(0.0011)†	(0.0011) †	(0.0011) †
log_householdvalue	0.0163	0.0138	0.0125	0.0144	0.014	0.0139	0.015	0.0143	0.0157	0.0188	0.0187	0.019
	(0.0097)†	(0.0096)	(0.0096)	(0.0101)	(0.0102)	(0.0102)	(0.0102)	(0.0103)	(0.0102)	(0.0098) †	(0.0099) †	(0.0098) †
constructionwage2005	0.0018	0.002	0.0028	0.003	0.0025	0.0025	0.0021	0.0023	0.0024	0.0024	0.0024	0.0024
	(0.0013)	(0.0014)	(0.0014) †	(0.0014)*	(0.0014) †	(0.0016)	(0.0017)	(0.0013) †	(0.0013) †	(0.0013) †	(0.0013) †	(0.0013) †
insolation3dig	0.0326	0.0262	0.0007	0.0062	-0.0008	0.0005	-0.0082	-0.0017	0.0003	0.0086	0.0086	0.0082
	(0.0313)	(0.0331)	(0.0325)	(0.0334)	(0.0333)	(0.0415)	(0.0431)	(0.0323)	(0.0321)	(0.0319)	(0.0320)	(0.0319)
log_size	-0.0572	-0.0541	-0.0659	-0.0666	-0.0634	-0.0634	-0.0635	-0.0636	-0.0633	-0.0623	-0.0624	-0.0621
	(0.0036)**	(0.0038)**	(0.0049)**	(0.0050)**	(0.0043)**	(0.0043)**	(0.0043)**	(0.0043)**	(0.0043)**	(0.0043)**	(0.0042)**	(0.0043)**
bipv	0.0843	0.0618	0.0673	0.0683	0.0786	0.0785	0.0796	0.0781	0.0782	0.0795	0.0797	0.0798
	(0.0325)**	(0.0384) †	(0.0349) †	(0.0357) †	(0.0355)*	(0.0355)*	(0.0359)*	(0.0355)*	(0.0355)*	(0.0280)**	(0.0280)**	(0.0279)**
thinfilm	0.0639	0.1039	0.0933	0.0912	0.0326	0.0326	0.0327	0.0326	0.0319	0.0329	0.032	0.033
	(0.0618)	(0.0790)	(0.0705)	(0.0689)	(0.0405)	(0.0404)	(0.0406)	(0.0404)	(0.0400)	(0.0385)	(0.0386)	(0.0385)
self_install	-0.1778	-0.1557	-0.1614	-0.1603	-0.1472	-0.1473	-0.1479	-0.1473	-0.1474	-0.1495	-0.1517	-0.1493
	(0.0172)**	(0.0167)**	(0.0165)**	(0.0159)**	(0.0143)**	(0.0143)**	(0.0144)**	(0.0143)**	(0.0144)**	(0.0141)**	(0.0148)**	(0.0142)**
ind_large_project	-0.08	-0.0837	-0.1008	-0.0993	-0.105	-0.1051	-0.1075	-0.1041	-0.1036	-0.086	-0.0873	-0.0865
	(0.0293)**	(0.0313)**	(0.0310)**	(0.0321)**	(0.0313)**	(0.0312)**	(0.0310)**	(0.0311)**	(0.0310)**	(0.0259)**	(0.0262)**	(0.0259)**
Yr1998	0.4423											
	(0.0537)**											
Yr1999	0.421											
	(0.0379)**											
Yr2000	0.3521											
	(0.0415)**											
Yr2001	0.3608											
	(0.0312)**											
Yr2002	0.4171											
	(0.0267)**											
Yr2003	0.2915											
	(0.0249)**											
Yr2004	0.1695											
	(0.0232)**											
Yr2005	0.1148											
	(0.0221)**											
Yr2006	0.0941											
	(0.0233)**											
Yr2007	0.0754											
	(0.0275)**											
Yr2009	0.0551											
	(0.0087)**											
state_ma	0.1373	0.0998	-0.0336	-0.0335	-0.044	-0.0419	-0.0519	-0.0432	-0.0398	-0.0324	-0.0329	-0.0372
	(0.0483)**	(0.0491)*	(0.0530)	(0.0540)	(0.0546)	(0.0679)	(0.0698)	(0.0550)	(0.0547)	(0.0548)	(0.0549)	(0.0549)
state_nj	0.1044	0.0991	-0.0764	-0.0657	-0.0805	-0.0787	-0.093	-0.0794	-0.0756	-0.0635	-0.0637	-0.0639
	(0.0409)*	(0.0414)*	(0.0497)	(0.0506)	(0.0497) †	(0.0604)	(0.0629)	(0.0502)	(0.0499)	(0.0496)	(0.0498)	(0.0496)

module_cost_index		-0.0145	0.0495	0.0503	0.0452	0.0453	0.0348	0.0466	0.0376	0.0326	0.0335	0.0315
		(0.0162)	(0.0190)**	(0.0198)*	(0.0198)*	(0.0198)*	(0.0204) †	(0.0198)*	(0.0202) †	(0.0204)	(0.0205) †	(0.0205)
year_approved		-0.0486	-0.0323	-0.0313	-0.0317	-0.0317	-0.0333	-0.032	-0.0273	-0.0283	-0.0283	-0.0283
		(0.0038)**	(0.0035)**	(0.0039)**	(0.0038)**	(0.0039)**	(0.0040)**	(0.0039)**	(0.0047)**	(0.0046)**	(0.0046)**	(0.0046)**
log_incentive			0.1998	0.1942	0.2118	0.2121	0.2182	0.2111	0.212	0.2109	0.2109	0.2109
			(0.0213)**	(0.0212)**	(0.0188)**	(0.0188)**	(0.0194)**	(0.0190)**	(0.0191)**	(0.0191)**	(0.0192)**	(0.0191)**
fed_tax_cred			0.0626	0.0637	0.0537	0.0538	0.0541	0.0539	0.0543	0.0563	0.0554	0.0554
			(0.0154)**	(0.0152)**	(0.0122)**	(0.0122)**	(0.0120)**	(0.0121)**	(0.0122)**	(0.0115)**	(0.0116)**	(0.0115)**
residential_ftc_cap			-0.0769	-0.0773	-0.0637	-0.0638	-0.0629	-0.0639	-0.0633	-0.062	-0.0617	-0.0609
			(0.0196)**	(0.0178)**	(0.0094)**	(0.0094)**	(0.0093)**	(0.0094)**	(0.0094)**	(0.0092)**	(0.0092)**	(0.0091)**
exp_county				-0.0004	-0.0007	-0.0007	-0.0005	-0.0007	-0.001	-0.001	-0.0011	-0.001
				(0.0004)	(0.0004) †	(0.0004) †	(0.0004)	(0.0004) †	(0.0004)*	(0.0004)**	(0.0004)**	(0.0004)**
inst_years_active				-0.0019	-0.004	-0.004	-0.0038	-0.004	-0.004	-0.0041	-0.0048	-0.0038
				(0.0024)	(0.0024) †	(0.0024) †	(0.0024)	(0.0024) †	(0.0024) †	(0.0024) †	(0.0026) †	(0.0024)
exp_installer					0.0061	0.0061	0.0062	0.0061	0.0062	0.0065	0.0395	0.0066
					(0.0027)*	(0.0027)*	(0.0027)*	(0.0027)*	(0.0027)*	(0.0028)*	(0.0212) †	(0.0028)*
Instlr_per_Hshld						0.0003	-0.0216					
						(0.0030)	(0.0123) †					
InstlHsdXyear							0.0023					
							(0.0012) †					
herf_cty_year								-0.0232	0.1435	0.1557	0.1599	0.1509
								(0.0407)	(0.0885) †	(0.0879) †	(0.0883) †	(0.0886) †
herfXyear									-0.0225	-0.023	-0.0237	-0.0225
									(0.0102)*	(0.0102)*	(0.0102)*	(0.0103)*
supply_arrangement										-0.0511	-0.0514	-0.0519
										(0.0246)*	(0.0248)*	(0.0246)*
top_100										-0.006	0.0061	-0.0063
										(0.0119)	(0.0119)	(0.0119)
survivor										-0.035	-0.0395	-0.0608
										(0.0170)*	(0.0173)*	(0.0252)*
installer_rookie										-0.016	-0.0126	-0.0585
										(0.0126)	(0.0122)	(0.0262)*
experienceXTop											-0.0329	
											(0.0205) †	
survivorXrookie												0.0549
												(0.0287) †
Constant	2.4962	2.9053	2.5815	2.5231	2.5435	2.5364	2.6288	2.552	2.5027	2.4728	2.4698	2.4998
	(0.1994)**	(0.2134)**	(0.2231)**	(0.2493)**	(0.2533)**	(0.2852)**	(0.2985)**	(0.2462)**	(0.2449)**	(0.2361)**	(0.2377)**	(0.2375)**
Observations	47011	47011	47011	46320	46320	46309	46309	46309	46309	46309	46309	46309
R-squared	0.35	0.32	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36

Robust standard errors in parentheses

† Significant at 10% * significant at 5%; ** significant at 1%

Systems using building-integrated photovoltaics cost 0.0843*100% more per watt ($0.94 per watt at the mean price)[34]. Photovoltaic systems that were installed as part of a multi-system project cost 0.08*100% less per watt ($0.89 per watt at the mean price). An examination of the coefficients of the year dummies shows that systems installed earlier cost up to 0.44 percent more per watt (in 1998) but that the size of the coefficients decreases over time. The decrease is approximately linear, with some exceptions for 2002 and 2009. Thus in subsequent models, a linear time trend will be used. The dummy variables, state_nj and state_ma, are statistically significant, suggesting that systems installed in New Jersey and Massachusetts cost 10 percent and 13 percent more respectively.

Model 2 includes the linear time trend and the module cost index. Module cost index could not be run in Model 1 because of multicollinearity with the year dummies. This is the primary motivation for using the linear time trend: it allows module cost to be controlled for in subsequent regression models.

Model 3 adds variables for the incentives received by the consumer. The coefficient of log_incentive indicates that a one percent increase in the incentive corresponds to a 0.2 percent increase in the system price per watt. Thus, compared to an incentive of $3 per watt, a $4 per watt incentive corresponds to a 0.2 x 33% = 6.6% increase in price per watt. At the mean system price of $11.15, this is equivalent to $0.736 per watt.

The coefficient for the federal tax credit is 0.0626 indicating that in year when the tax credit was available, system prices were 0.0626*100% or, using the mean system price, $0.70 per watt higher. Putting this into perspective, commercial customers were able to receive the full value of the 30% tax credit. Considering the average system price was $11.15 per AC Watt, this translates into $3.35 per watt. Non-profits and government clearly cannot benefit from the tax credit since they do not pay taxes, so they receive $0.00 per watt. Residential customers were not permitted to take the full 30% and were capped at $2000. For a small residential system (1 kilowatt AC), this is about $2 per watt and for a large residential system (10 kilowatt AC), this is $0.20 per watt.

However, examining the coefficient of the federal tax credit along with the coefficient of the residential tax credit cap, a more nuanced story begins to emerge. The coefficient for the federal tax credit is 0.0626 and the coefficient for the residential federal tax credit cap is -0.0769. This means that for the years when there was a federal tax credit and a residential cap, the tax credit has essentially no net effect on system

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[34] Interpreting the coefficients when the dependent variable is log transformed alters the interpretation of the regression coefficients. If the independent variable is also log transformed, then the coefficient can be interpreted as a one percent increase in the independent variable will result in a β percent increase in the dependent variable. If the independent variable is not transformed, then the coefficient can be interpreted as a one unit increase in the independent variable will result in a β x 100% increase in the dependent variable.

prices (compare 0.0626 – 0.0769 = 0.0143 to the standard errors of the coefficients). However, in 2009, the residential cap on the federal tax credit was removed. The regression model then suggests the interpretation offered in the previous paragraph – that the presence of the federal tax credit has had a positive effect on system prices.

Models 4 and 5 introduce variables related to experience.

Model 4 introduces a term for experience measured at the county level. As expected, exp_county is negative and while it is not significant in model 4, it is significant at the 10% level in model 5. For every unit increase in exp_county, which is measured in hundreds of systems, system price decreases by 0.0007*100%, or $0.008 based on the mean system price per watt. Model 5 also includes one measure of installer experience – the age of the firm at the time the system was installed. Also as expected, the coefficient of inst_years_active is -0.004 in model 5, suggesting that for every additional year of experience, a firm will decrease its sales price by 0.004 *100%, or $0.045 per watt at the mean price.

Unexpectedly, the coefficient for exp_installer is positive and significant. The coefficient of 0.0061 indicates that for every increase in installer experience of 100 systems, the price of the system was 0.61 percent higher.

Model 6 through Model 9 include coefficients for competition.

Models 6 and 7 measure competition in terms of the ratio of active installers to the number of housing units. Although the main effect of Instlr_per_Hshld is not significant in model 6, when an interaction term is added in model 7, both the main and interaction effects become statistically significant at the 10% level. The main effect is negative as expected, meaning that when the ratio of installers to housing units is higher, the system price is lower. The direction of the interaction effect is unexpectedly positive and suggests that, as the industry has matured, the effect of competition on system prices has decreased.

A substantively similar interpretation is suggested by models 8 and 9 which include the Herfindahl index as a measure of competition. Again, the main effect of the competition measure – Herfindahl index – is not significant as seen in model 8. However, when the interaction effect is added in model 9, both the main and interaction effects become statistically significant. The main effect is positive with a coefficient of 0.1435. To understand this effect more intuitively, a market with 100 equally sized installers compared to a market with 2 equally sized installers will have a price that is [100*(1/100)^2-2*(1/2)^2] X 0.1435 = 0.07 *100% lower. Applying this number to the average system price means this is a $0.78 lower price for the market with 100 installers.

Similar to the interaction effect for the previous measure of competitiveness, the interaction effect of Herfindahl index and year_approved has the opposite sign as expected. This also suggests that the effect of competition driving down system prices is lessening with time.

Models 10 through 12 include coefficients that explore firm heterogeneity, entry and exit[35].

The coefficient of supplier arrangement is negative throughout models 10, 11 and 12; systems installed by firms with committed supply relationship charge about 0.05*100% less on average than firms without committed supply relationships.

The variable Top_100 is not statistically significant in any of the models suggesting that the firms who have installed the greatest number of systems do not have significantly higher or lower prices when controlling for other factors. When the interaction term between Top_100 and experience is added in Model 11, the interaction becomes marginally significant and the coefficient of exp_installer increases. This suggests that for firms who are not top installers, the effect of experience is 0.0395 – six times greater than the main effect of exp_installer in model 5 (0.0061). For firms that are top installers, the net effect of experience is 0.0395-0.0329 = 0.0066, which is likely not significant considering the standard errors of both terms (0.0212 for exp_installer and 0.0205 for the interaction effect). Thus the trend for price to increase with experience seems to exist only for firms not in the top 100.

The coefficient for survivor is -0.035 in model 10 meaning that systems installed by firms that survived the first three years in industry were 0.035 * 100% less expensive. It should be noted that this includes systems installed in the first three years of a surviving firm's lifetime, so represents an effect that varies by installer.

Installer_rookie is not statistically significant in models 10 and 11. However, when an interaction term is added between survivor and rookie in model 12, both the main effect and interaction term become significant. The combined effects of the survivor and rookie can be understood with the following table.

[35] NOTE: The stories I have used to interpret the coefficients have evoked the imagery of firms who are 100% in the business of installing, and when they exit, go out of business. Although this image is likely not true (earlier I argued that most of the system installers in the dataset were probably not pure play solar installers), it does not change the basic interpretation. When a pure play firm "exits" it means that it goes out of business. But when a non pure play installer "exits", then the firm chooses not to offer that line of business anymore,likely because the firm did not find the solar installation business attractive.

Table 12. Combined Effects of Survivor and Rookie

	Rookie year	Non rookie year	Δ rookie – non-rookie
Survivor Firm	-0.0608-0.0585+0.0549 = - 0.0646	-0.0608	-0.0038
Non Survivor Firm	-0.0585	0.00 (Base case)	-0.0585
Δ survivor – non-survivor	-0.0061	-0.0608	

Reading the middle cells in the table, a non-survivor firm in its rookie year of operation will charge 0.0585 * 100% less than a non-survivor firm not in its rookie year. A survivor firm in its non-rookie year of operation will charge 0.0608 * 100% less than a non-survivor firm in its non-rookie year. A survivor firm in its rookie year of operation will change 0.0646 * 100% less than a non-survivor firm in their non-rookie year.

Looking at the "Δ" column on the right, the differences suggest that the rookie effect holds primarily for non-survivor firms (the Δ for survivor firms is essentially zero). In other words, non survivors tend to charge lower prices and then raise their prices over time. Looking at the "Δ" row at the bottom, the difference suggests that the survivor effect holds primarily in a firm's non- rookie years (the Δ for rookie firms is essentially zero). In other words, survivors begin like any other firm but become relatively better over time. Considering the previous conclusion that the rookie effect holds primarily for non-survivor firms, we can further conclude that survivors begin like any other firm in charging low but do not increase their prices over time (as non-survivors do).

What do the regression results say about the hypotheses?

With the basic findings of the regression models now explained, I next relate them to the ten hypotheses laid out earlier in the section.

H1: Systems that are more costly to install will have higher prices.

Supported - System size was found to be negatively related to price. Larger systems which should have scale economies and thus cost less to install were also less expensive to the end-consumer. Systems with building integrated photovoltaics - which we expect to cost more on a per watt basis because extra manufacturers must deal with the added constraint of creating photovoltaic modules in the form of building materials – had higher prices than systems without BIPV. Self installed systems were less expensive than systems installed by firms, which makes sense because the firms' cost of sales are lower. Systems installed as part of multisystem developments are also expected to cost less because of scale economies and, indeed, had lower prices.

Less impressive results were found for construction wage, thin film, and module cost index. Coefficients for construction wage are significant at the 10% level in most of the models, including the later models where numerous other effects are controlled for. Module cost index was significant in some models but not all of them. No effect was found for thin film. This finding is not unreasonable; on one hand, thin film systems are expected to be less expensive since lower cost is the fundamental motivation for selling thin film, but on the other hand other studies have found that systems installed with thin film modules were more expensive (e.g. Wiser et al 2009, Wang 2009).

H2: Systems that are of greater value to the system owner will have higher prices.

Supported – While the support was mixed across the variables meant to measure value to system owner, the measures of the non-significant variables were not as good as the measures for the significant variables. Several of the measures did not work, but I am less confident about them.

The strongest results were for the incentives offered by the government: Log_incentive, federal tax credit and residential federal tax credit cap. They all behaved in the expected ways. Higher rebates and the federal tax credit were positively related with higher system prices, while the federal tax credit cap was negatively related.

The measures for which no statistical significance was found were: electricity rate and insolation. The effect of electricity rate may not have been captured properly because of the availability of time-of-use rates in California. The measure was constructed using average retail rates by utility area by year. If most system owners switch to time-of-use rates once they buy a photovoltaic system (which is likely to be true) then the average retail rates do not reflect the revenue opportunity for the system owner.

The effect of insolation may not have been significant because there was not enough variation in the data. The dataset includes systems from only three states and the variation between states is greater than the variation within states. State fixed effects were included in all regression models, meaning that the insolation term would only pick up variation within state while the state dummies would pick up the variation between states.

Ideally, this variable would be constructed using the insolation value assessed by the system installer and used in the sales proposal given to the system owner. That would be the number most relevant to the decision made by the customer to buy, and would almost certainly have more variation than the insolation dataset provided by NASA.

H3: Systems sold to consumers with greater income will have higher prices.

Limited support –Customer income is measured using the log of household value. It is marginally significant in only some of the models, though it was significant in the later models which controlled for more factors.

H4: Systems installed by firms with greater experience will have lower prices.

Supported – This hypotheses is supported based on the interpretations of exp_county, inst_years_active and exp_installer. The coefficient of exp_county indicates that counties with more installations had lower system prices. Installers with more years of experience at the time the system was installed tended to offer lower prices.

However, there was mixed evidence regarding exp_installer. The coefficient was generally positive, suggesting that firms that had installed more systems in the past sold systems at higher prices. Yet, this interpretation is altered after examining model 9 which adds an interaction between experience and top 100. Model 9 suggests that the positive effect of exp_installer holds only for firms not in the top 100.

H5: Systems installed in areas with high levels of competition will have lower prices.

Mixed support - In models with only the main effects of the competition measure (models 6 and 8), there was no statistically significant effect. However, once interactions with time were added, both the main and interaction effects did become significant. The main effects were in the expected direction, revealing that higher levels of competition at the county level drove prices down. Yet the interaction effects were in the opposite direction of the main effect, suggesting that the competition effect is diminishing. I speculate that this is because as the market has become more mature, competition is becoming less local and we should thus expect to see similar prices across counties despite the local, county-level measures of competition.

H6: The price of systems installed in areas with high levels of competition will decrease over time.

No support. - The interaction terms between the competition measures and time were in the wrong direction: positive for installers per housing unit and year, negative for Herfindahl index and year. Whatever the effect of competition, it is lessening with time, at least when competition is measured at a county-level.

H7: Systems installed by top installers will have lower prices.

No support - The prices of systems installed by top installers did not have significantly different prices from the systems installed by non-top installers. This means either: if top installers have lower cost of sales then they are earning a greater profit margin, or if top installers have the same cost of sales, then they are earning the same profit margins but are committed to the solar installation business for other reasons.

H8: The effect of experience will be greater for systems installed by top installers.

Supported but not in the way expected – The original expectation was that system prices would decrease with increasing installer experience, and that the rate of decrease would be greater for top installers.

What the regression analysis reveals was that the effect of experience is to increase system prices. However, the interaction term between experience and top 100 was of the same magnitude and the opposite direction as the main effect (see Model 9) which suggests that the effect of experience increasing prices does not exist for the top installers and exists only for non-top installers. Thus, consistent with the original expectation, the effect of experience on top installers is more negative than the effect of experience on non-top installers.

H9: Systems installed by new entrants to the industry will have lower prices.

Mixed support - The coefficient of rookie is not statistically significant until the interaction between rookie and survivor is added in Model 12. Examining the combined effects of rookie and survivor (see Table 12), this rookie effect is found to exist but only for non-survivor firms. Survivor firms did not experience the rookie effect.

H10: Systems installed by firms with committed relationship with suppliers will have lower prices.

Supported - The coefficient for supply_arrangement is negative and significant in all models in which it appears.

Section V - Discussion

The results from the regression analysis are thought-provoking. This has been the first time that the dynamics of experience, competition, and firm entry and exit have been systematically explored. Abstracting further from the regression coefficients and their close interpretation, these results raise a number of empirical mysteries which may be touching on important industry dynamics. This section will further explore these mysteries and their implications for policy.

But before addressing these questions, it is useful to discuss some themes underlying these questions up front. First is the added complexity in interpreting price data. The ideal dataset would include price as well as cost data because it would allow analysis to predict not only the system cost per watt but also the profit margin per watt. Mechanisms such as the experience effect should influence system cost, while mechanism such as competition should influence profit margins. Because we only have price data, we cannot separate the cost of sales to the system installer from the installer's profit margin. Thus if we attempt to draw conclusions from the data about either profit margin or cost of sales, we must make a logical argument to "control for" the other.

The second factor that complicates interpretation of the results is our ignorance of whether supply or demand conditions are driving system price. It is probably the most intuitive is to think of supply conditions affecting price: system installers incur certain costs when installing a system, they charge a markup for overhead and profit, but this markup cannot be too high otherwise they cannot compete with other installers.

However, dynamics on the demand side may also be affecting price. Deployment of solar has not been particularly widespread. Putting the 55,000 systems in the dataset into broader perspective, the US Census Bureau estimates there were 19.5 million housing units as of 2007 in California, Massachusetts and New Jersey. This means that 0.28% or about 1 of 350 housing units have a photovoltaic system, begging the question of whether this tiny fraction is different from the rest of the population. These "early adopters" may not be very price sensitive and may see some non-financial value in owning a photovoltaic system (e.g., they may be more environmentally aware). The data include little information about the characteristics of the buyer, so this cannot be controlled for in the analysis[36]. Thus the prices

[36] This second factor could perhaps have been mitigated if I had been able to use county fixed effects in the regression analysis. Again, this was not possible because I had to use town and zip code data to generate measures like insolation, household value, and competition. If these measures could be obtained in other ways, the use of county fixed effects would be possible.

observed in the dataset may reflect the ability of system installers to locate and market to this segment of people.

Questions Raised by Regression Analysis

Question 1: Why do survivor firms and non-survivor firms charge similar prices in their rookie year, but non-survivors charge more after their rookie year?

To be competitive with existing firms, both survivors and non-survivors likely have below average (unsustainable) profit margins in their rookie year when their operation costs are at their highest. Either survivors have lower cost of sales than non-survivors in their rookie year or they are better able to decrease their cost of sales after their rookie year. Although the prices the survivors charge do not change over time, their profit margins may increase to a sustainable level (if they are not already at that level) and they are able to stay in the solar installation business. Non-survivors may enter the industry with higher cost of sales and/or are less able to decrease their cost of sales over time. In an attempt to earn sustainable profit margins, they are forced to increase their prices after their rookie year. Since they are unable to obtain enough business at the prices they would have to charge to earn a reasonable profit, they exit the industry.

As far as policy considerations are concerned, the industry is clearly better off if it has more of the types of firms that survive. However, we do not know much about what makes a firm a survivor and do not know how to attract these types of firms to the industry. Subsequent analysis should understand what makes a firm a survivor. Perhaps it was previous experience in the energy industry or a highly experienced workforce?

One possibility that was investigated was whether rookies or survivors were affected differently by the presence of local competition. A separate analysis, not included shown in Table 11, tried interactions: herfindahl X rookie and herfindahl x survivor. Neither was statistically significant.

Question 2: Why does experience affect top firms differently from non-top firms?

Firms not in the top 100 were found to sell systems at higher prices as their experience increased, while experience did not have a positive effect for firms in the top 100. For Top 100 firms, this is not at all surprising. Although they are highly active in the solar installation business and had many opportunities to learn, they would not sell at a price lower then they have to. Presumably cost of sales stayed the same or decreased with experience (controlling for the cost of inputs to the system installer like modules or labor wages). However, just because the firm is can charge lower prices does not mean that it will.

Given some fixed demand that will be met by a number of system installers, an installer must only do better than the worst installer who get business. System installers that can consistently perform better than their peers can continue earn higher profit margins.

For firms not in the Top 100, it is hard to imagine why experience would be positively related with system price. It is probably reasonable to assume that their cost of sales do not increase, after controlling for the cost of the system components and the labor. One possibility is that the firm started off charging too little for the systems in the first place and, only after gaining some familiarity with the task of solar installation, did it develop a better estimate of true cost. Another possibility is that these firms pursue solar installations opportunistically, not as an important line of business. These firms can be more selective about the jobs they take and they end up choosing only projects where they can charge a high price per watt.

Question 3: Why is experience measured in years (inst_years_active) negatively related to system prices while experience measured in the number of systems (exp_installer) unrelated or positively related to system prices?

The effect of experience measured in years is actually in the expected direction but seems inconsistent with the effect of experience measured in number of systems. That prices decline with greater experience is not entirely surprising; a firm gets better at installing photovoltaic systems at lower costs and this is reflected in the price that is charged to the consumer. However, I had previously argued that the good system installers with below average cost of sales would not necessarily pass that onto customers in the form of lower prices. One way to resolve this apparent contradiction would be to focus on the price offered by the worst installer that gets installation business. This price drives the market price and is probably better related with time than with the number of systems installed by any particular supplier. Thus the negative effect of experience measured in years on system prices exists because although the system installer has gotten better, he will only pass on that value to the end consumer if he is forced to do so by competition and competition has gotten better over time.

Exp_county probably picks up part of both these dynamics. As the installers who operate in the area gain experience, their cost of sales decline. Yet because multiple installers are active in a county, they must pass on some of the reduced cost onto the customers in the form of lower prices.

Question 4: Why is the competition effect going away?

The analysis showed that increased competition had the effect of reducing system prices, but that this effect was diminishing over time. There are at least two possible interpretations of this. The first, more cynical interpretation is that firms are better able to tacitly collude and keep prices uniformly high regardless of the level of competition in the area. It could be that they learn better to coordinate their prices and that few installers are willing to charge below what has become the established market price. This may be enabled by the increasing level of government support available; as government support increases, commensurate reductions in price are slow to occur or are not happening at all.

The second, less cynical interpretation is that as the industry has grown, it has become more competitive and the boundaries of the relevant market have expanded. If consumers are willing to do business with installers outside the local area who have a broader market presence, then prices may be affected by competition at a state or regional level. Therefore, although there may be differences in local measures of competition, system prices may not vary accordingly. Whatever variation there had once been at the county level is going away as the photovoltaic market has matured and local firms must compete against more distant firms. I consider this second interpretation to be more likely.

If the first interpretation is true, then it is bad from a policy perspective. It would suggest that more aggressive decreases in incentive levels are necessary to keep system installers honest. If the second is true, then this is good from a policy perspective. The larger the relevant competitive area, the greater the number of installers competing with one another and the greater the competitive pressure driving prices down.

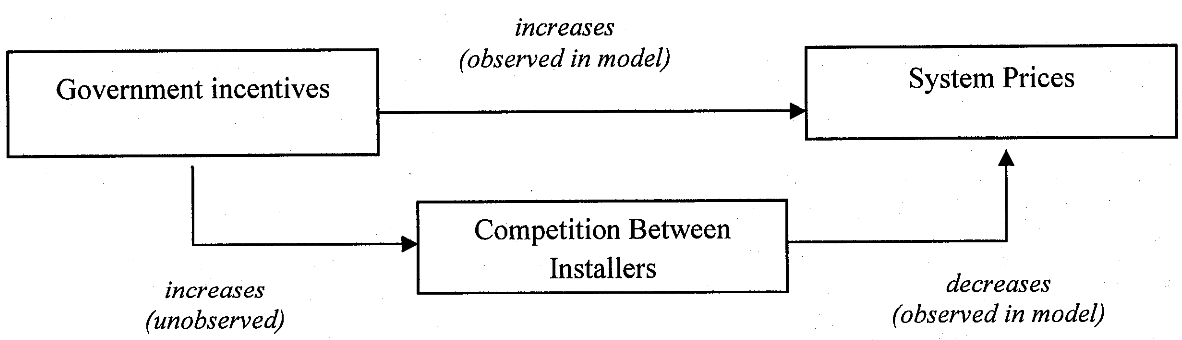
Question 5: Why are incentives being captured?

The coefficients of log_incentive and federal tax credit were positive, suggesting that as government rebates and tax credits increase so does the system price. The direct interpretation of this may be unsettling – that system installers are "capturing" part of the incentive intended by the government for the end customer. This raises a series of question about the government incentives. One question is, why do installers capture part of the government incentive? Another question is, if they are able to capture part of the government incentive, then why don't they capture all of it? Finally, it is worth asking whether this dynamic is good from a policy perspective.

A cynic might argue that the support of the photovoltaic industry is not a good idea because a portion of that incentive is going to the installers, instead of into the pockets of the system-owner / buyer. This is certainly possible because prices aren't easily observed and comparable. This is because of the customized nature of the product. A system owner will have to contact a potential installer and ask that they put in a bid for the work. Residential system owners might only approach one installer about putting in a solar PV system and at best might ask two or three. The owners of larger systems – commercial owners – might have a more sophisticated decision-making process, but they only account for a small percentage of total systems.

The apparent positive effect of incentives on system prices is surprising for a number of reasons. The most naïve argument would be to believe that system installers would pass on any government incentives onto the end customer. However, upon further thought, it would not make sense for installers to leave money on the table, so one should actually expect that at least part of the government incentive be captured. Yet one wrinkle in this more sophisticated story is that higher government incentives should make the market more attractive and more attractive for firms to enter. This would then increase competition which should drive down prices. Thus higher government incentives can be argued to have two countervailing effects on system prices: to increase system prices by allowing firms to simply charge more and to decrease system prices by increasing competition. This relationship is illustrated in Figure 43. Relationship Between Incentives, Competition and System Prices

Figure 43. Relationship Between Incentives, Competition and System Prices



To reconcile this, we must begin with the reasonable assumption that there is some heterogeneity in installer capabilities and thus cost of sales per watt installed (and the corollary that there are different profit margins). If an installer is to survive, it must set its prices equal to or above its cost to install the system. At a given market price, some installers are making zero profit and others are making a range of positive profits. If any installers are making a net loss, then they will soon leave the industry. The positive effect of the incentive on price per watt may reflect the <u>average</u> effect amongst installers, but this may not hold true for all installers. Those installers with the lowest cost of sales may in fact be capturing some of the government incentive. However, the government incentive allows firms with higher cost of sales (i.e. worse firms) to enter the market.

Thus the portion of the government incentive captured by system installers is the cost paid to attract more firms to enter the industry and to reward those firms that have better than average cost of sales. The magnitude of this cost is driven by the variation in installer capabilities relative to the capabilities of the marginal installer (i.e. the worst installer that still gets business). If the distribution of installer cost of sales is tight, then the cost is low. But if the distribution of installer cost of sales is wide, then the cost will be high.

As for the negative effect of competition on prices, this was expected. Competition can only reduce the cost so far because, unless a firm miscalculates or there are temporary extenuating circumstances, an individual firm will not offer a price that is less than its cost. Thus, this effect represents the portion of the firm's profit margin that the firm sacrifices in order to be competitive. The minority of firms that are not able to offer a competitive price and earn a profit will exit the market. This answers the first question and part of the third question that was posed earlier.

The second question was – why don't installers capture all of the government incentive? The answer begins by considering the two general constraints installers face when setting prices. Installers cannot charge too much without changing the economics of purchasing a photovoltaic system for the system owner. The value of the system to the owner is the value of the electricity plus the value of RECs generation plus the rebates and tax credits from the government. This sets an upper bound on what installers can charge.

Competition between installers drives the market price down. There are relatively low barriers to entry into the system installation business. General contractors and electricians have almost all of the technical expertise necessary to install a photovoltaic system. Depending on the requirements set by the state to be eligible for the rebate, all that may be necessary is a regular contractor or electrician's license (this is the requirement in California). Other states may require that the installer be NABCEP (North American Board of Certified Energy Practitioners) certified, but all that is required is a short course that includes some information specific to wiring photovoltaic modules and inverters.

The other constraint is from the upstream part of the photovoltaic value chain. The fact that module prices in the US have remained stable (see Figure 24. Retail Module Price Index, January 2003-July 2009) while incentives have generally increased suggests that some of the surplus is being captured at the module manufacturer or upstream. Industry analysts gleaning information from publicly-owned companies have observed that the profit margins have been smaller the closer the firm is to the end of the value chain (Chase 2009). That is, silicon producers had the largest profit margins, module manufacturers had modest profit margins, and installers had the lowest profit margins. The difference is the relative market power of firms in each part of value chain. During the silicon shortage, module manufacturers were dependent on the limited number of silicon producers. Compared to the number of module manufacturers, there are also many more installers, suggesting that module manufacturers have greater market leverage over installers. Thus, if excess profits were available then silicon producers or module manufacturers would price their products to capture the excess profit. In fact, there is some evidence of this. Despite module production being a global industry, module prices are lower in the United States than in Germany which offers attractive feed-in tariff rates. This capturing of the government incentive by upstream firms may not necessarily be bad as long as the profits are being reinvested in the business.

Armed with a better sense of what the captured incentive is doing, we can begin to consider its policy implications. The ideal policy would encourage more competition between installers. Competition reduces price through two mechanisms. First, in a static sense, competition drives the sales price and profit margins downwards towards the firm's cost to install. And if there are more competitors in the market, then there will be greater pressure to offer a lower price. Competition keeps installers "honest" and profit margins, on average, are kept low. Second, competition creates pressure for installers to leverage their experience and reduce their cost of sales. This creates the potential for future price reductions and that potential will be realized as the strength of the firm's competition increases. The constant entry and exit of installers brings new competitors into the mix, some of which will become strong competitors.

To maintain these two mechanisms, we need three things: high competition to push prices towards installers' costs, opportunities for firms to learn and decrease their cost of sales, and a constant influx of new firms to replace the [generally bad] firms that exit the industry.

Government incentives help to do all three of these. They keep competition high because incentives allow initially weaker firms to enter the industry. By increasing the value of the system to the customer, incentives increase the number of installations and give installers an opportunity to learn. They also generate a constant influx of new firms because firms must believe there is profit to be gained from entering the industry.

What incentives do not do however is force the bad installers to exit the industry. For this reason, very high government incentives are not the answer. Without the risk of going out of business, firms are not pressured to improve their own cost of sales. Bad firms are also allowed to stay in the industry and it is the variance in firms' cost of sales that drives the proportion of the incentive that is captured as pure profit (by stronger firms).

Setting incentive levels would seem to be a balancing act between these two extremes. Countries such as Germany have chosen to provide high incentives, but arguably at the cost of allowing high profits for system installers and other firms upstream in the value chain. Countries like Japan who are currently offering smaller incentives are arguably using their money more efficiently by allowing smaller profits for fewer system installers.

Question 6: What do the regression coefficients say about the cost of sales of system installers?

Although the observed data includes system prices, the regression coefficients can give us some insights into installers' costs. The coefficient for self_install is -0.149 in the final model. Thus systems that were owner-installed were 14.9 percent less expensive than systems that were installed by firms. Using the average price of $11.15 per watt, this equates to $1.66 per watt. This is consistent with the estimates provided in Table 5.

A general sense of the range of the firms' cost of sales can be gleaned by inspecting the coefficient for survivor. The survivor variable is a rough measure of firm's operational capabilities. In short, it is "good" firms that end up as survivors. The rationale is that firms who have stayed in the industry for more than three years should install photovoltaic systems more efficiently and effectively than firms who exited the industry in the first three years (or firms who entered the industry within the past three years and have not yet "revealed" their true colors). According to model 10, systems that were installed by survivor firms cost on average 0.035 *100% less than systems installed by non-survivor firms. If we make the assumption that the operating margins of survivors are equal or greater than the operating margins of non-survivors, then the 3.5% difference, or $0.39 per watt, reflects a difference in cost of sales between survivors and non survivors.

The comparison between non-survivors in their non-rookie year and survivors in their rookie year may offer a more aggressive estimate of the range of cost of sales. Recall from Table 12 that non-survivors in their non-rookie years charged even higher prices than non-survivors in their rookie years. Thus, non-survivors in their non-rookie years probably represent the worst firms in the population. Survivors – whether in their rookie year or not – tend to offer lower prices. The coefficient difference between these two groups is 0.0646. This translates into 0.0646 * 100% * $11.15 = $0.72 per watt[37].

[37] A third way to estimate the spread in cost of sales is by estimating the value of the rebates by system installers. This is possible based on the argument I made earlier that some installers are able to capture this amount or more because there are less capable installers in the industry who need the incentives to stay in business. The coefficient of incentive is 0.20 in model 3 meaning that a one percent increase in the incentive translates into a 0.20 percent

It may also be possible to estimate the size of firms' profit margins by examining the coefficient of Herfindahl index. If we assume that firms will reduce prices down to their cost of sales and not lower, this represents the amount that firms must reduce their selling price to be competitive. The coefficient is 0.15 in model 12 which is equivalent to a price difference of 0.15 * 100% * $11.15 = $1.67 per watt. This is of course an overestimate because we have not considered the interaction term which has a coefficient of -0.022. For every year after 1997 (recall that year 1 = 1998), the price difference is reduced by 0.022 * 100% * $11.15 = $0.245 per watt. Thus in 1998, the average firm's profit margin was as high as $1.67 - $0.245 = $1.42 per watt.

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increase in the system price. A 10% increase to the average incentive per watt is 10% * $2.99 = $0.29. A 2% increase in system price is 2% * $11.15 is $0.22.

Section IV - Conclusion

Analysis of the photovoltaic systems dataset indicates that there are important dynamics within one stage of the value chain that are more complicated than the conventional view of an experience effect uniformly driving costs down. The dynamics discussed were an experience dynamic, a competition dynamic and an industry turnover dynamic. Closer attention to these dynamics is warranted because it helps to focus our attention on more surgical interventions and provides alternatives to a brute force intervention like offering larger and larger incentives.

The overarching idea is not entirely surprising: system prices should decline when there are fewer bad (i.e. high cost of sales) firms in the industry and a greater installation capacity of good firms. Creating a greater installation capacity of good firms can be accomplished by having more "good" installers in the industry or by having larger good installers. New firms entering industry test their abilities against existing firms. If they can reduce the cost of sales over time, then they add to the overall installation capacity of good firms. Large good firms are important because they set the standard in terms of price and quality. They may also have some advantages in reducing cost of sales because knowledge and learning travel more easily within a firm than between firms.

Relating Analysis Results to the Experience Curve

This thesis argues that the experience curve is an unreliable tool for predicting future cost reductions. Plotting historical cost or price data against production up to that point may be a useful way to describe the data, but to take the additional step of extrapolation is risky since it assumes that whatever has driven down costs in the past will continue to do so into the future. In the total absence of any contextual information, experience curve extrapolation is probably not unreasonable over a short time horizon. It may also be useful because its simplicity makes it easy to communicate basic trends and garner support for the technology. However, a better, more intellectually honest alternative is to develop an understanding of the mechanisms underlying the experience curve.

To some extent, industry commentators have already begun looking at the mechanisms behind the experience curve. They point out the past effects of the polysilicon shortage and, more recently, of plummeting demand resulting from the economic crisis of 2008. However, they have tried to have their cake and eat it too, arguing that continued support for the industry is worthwhile because the costs will continue to fall at earlier historical rates and lead to payoffs after only a short period of investment. In fact, if we think of experience curves as a descriptive tool (i.e. without any inference of causal logic), then we see some unsettling trends. The progress ratio of systems in Germany is unimpressive and the progress ratio in the US is even worse. Japan's progress ratio, while lower (better), is not robust and hinges on the inclusion of two early data points. These high (bad) observed progress ratios should raise questions about how and how much learning can continue to occur for module costs and for the intrinsically less-promising non-module costs.

This thesis is an attempt to begin an examination of cost reduction trends in systems installation. It begins by providing some background information about the technology, the industry and the history of government support for photovoltaics. It then explores a dataset comprised of almost 55,000 photovoltaic systems. One aspect that is highlighted is the population of system installers.

With the exploration of the photovoltaic system installations dataset, observations about system installers, and regression analysis, I hope to leave the reader with a more sophisticated view of systems installation. The installation industry is comprised of a modest number of firms, but a small minority install the majority of the photovoltaic systems in the United States. In the results and discussion of the regression analysis, I have argued that they must be given opportunities to learn, competitive pressure to motivate them to learn, and competitive pressure to pass on their lower installation costs to the end customer. Incentives play a role in accelerating this market, though the larger the incentives the greater the profits for average and above average firms.

Although others have found some evidence of good progress ratios for non-module costs (Schaeffer et al 2004), this is not consistent with evidence from the dataset of photovoltaic system installations in the US. Understanding the differences between these two findings might yield insights about how systems installation should be organized as an industry.

One debate worth commenting on is whether the United States should increase its support for photovoltaics, possibly in the form of a feed-in tariff. The feed-in tariff has seemed to work for Germany and by decreasing the rate offered by the tariff, it has a "built-in self destruct mechanism" that is triggered at the point of grid parity. On its face, this would seem difficult to argue against. It jumpstarts industry growth, does not give the industry a free lunch and ends with a renewable energy source competitive with traditional forms of generation. I would argue however that although the German feed-in tariff is a bold and admirable measure for developing the photovoltaics industry and meeting carbon emissions targets, it may be premature given the state of photovoltaic technology.

The assumption the German policy is that firms in the industry will be able to reduce their own costs at the rate set out by the German government and that the industry will be structured such that these cost decreases will be passed onto the end customer. Declining incentives provide the carrot for industry to decrease prices – for improving their internal operations and for reducing their profit margins. However, declining incentives work in driving industry's prices down when there is some slack in the profit margins. It does not ensure that industry will reach those targets.

There are two reasons why this is a justified concern. First, the industry has not yet been strenuously tested. Despite the decreasing feature of the feed-in tariff, the rates have always been high (recall Table 4). It may be the case that declining feed-in tariffs have successfully decreased profit margins but have been less successful in decreasing firms' cost of sales at the same rate. It may also be possible that early high prices included a risk premium that was necessary to entice firms to enter this new line of business. As the photovoltaics industry has become more established, that risk premium may have gone away. However, the risk premium is not a "real" cost necessary for the physical installation of the system.

With the accelerated rate of decrease put into place as part of the 2009 feed-in tariff revision, some firms have become nervous about matching those rates. Some of this nervousness may be warranted because cost reduction in the future will probably be more difficult than cost reduction has been in the past, even allowing for the psychological phenomenon where cost reduction seems difficult *ex ante* but seems trivial *ex post* with the benefit of hindsight. Technological evolution has been described by an S-curve (Sahal 1981, Foster 1986, Schilling and Esmundo forthcoming) which states that even after a period of rapid improvement, a technology will begin to reach inherent limits and progress will slow. The key question is whether the technological progress reaches the asymptote before or after photovoltaics reach grid parity.

A worst case scenario would be if the cost of solar does not decrease at the expected rate and governments discontinue their support for it. While the state of the technology may have improved, momentum for continued research, investment and deployment of solar will be lost. This may mirror the solar industry in the 1980s after US government support declined precipitously. Even if governments continue to support the industry in light of slower technological progress, the policy will be much more costly than would be necessary.

Areas for Future Research

This thesis has touched upon several directions for future research. Methodologically, there are several options for strengthening the arguments made in this document. It is possible to find better measures than those used for my regression analysis. There may be more creative ways of looking at the current data, or it may be possible to work more closely with state agencies to add more fields to the data.

Another possibility would be to distribute a questionnaire asking installers about their practices and business success. With less than 2000 installers in the US, this is not an impossible task.

Several new conceptual questions have also come up. One question is how the Japanese industry has managed to continue installing new capacity without government incentives and without having attained grid parity. The answer may be as simple as a misunderstanding or lack of awareness of the Japanese incentive system for photovoltaics. But it is also possible that Japan has found a way to continue the sales and installation of photovoltaic systems without directly influencing the costs and benefits to the system owner. Valuing solar energy may have become a culturally institutionalized belief, i.e. one that is followed not because it is the result of a rational cost-benefit calculation, but because it is seen as socially appropriate (Tolbert and Zucker 1983). The good thus has a social value in addition to its instrumental value that is worth paying extra for. Examples might include Starbucks Coffee, organic food, mid- to high-end clothing. If this is true, it would suggest an alternative to larger and more sophisticated incentive schemes.

Another research direction is to study the structure of the system installation industry in Germany and Japan. This may help to explain the difference between progress ratios in the three countries. Little is known or discussed about the Japanese and German industries, at least in the US. Japan's construction industry is much more centralized than in the US. Thus if only a handful of these large firms also installed photovoltaic systems, there would be no room for bad firms in the industry. Homes are prefabricated and modular in design which should make retrofit and new home installations easier. In Germany, solar installers also seem to be larger than in the US. The business model that has become prevalent is a franchise model where large firms partner with local contractors. Barriers to entry are reduced for local contractors and large firms can disseminate best practices and pass on their market leverage to large swaths of individual installers. Japan and Germany may offer insights into how to organize the installation industry for cost and price reduction.

A third question would be to look at how profits are distributed throughout the photovoltaics value chain. Profits are collected at each stage of the value chain and profit margins may be higher in some stages than in others. For instance, in the recent past, silicon producers had the highest profit margins on average, module manufacturers had modest profits margins and system installers had the smallest margins. What are the dynamics that lead to a shifting share of profits across the value chain? This is a relevant question because different stages of the value chain compete with one another for a fixed amount of profits. There may be interesting dynamics if one stage is better able than others to reduce its cost of sales / cost of goods sold or if one stage with greater power can "hold up" the rest of the industry.

To illustrate why this is relevant, I will describe how intra-value chain dynamics might play out in a worst case scenario for Germany. Installation is a local industry, but silicon, module and inverter markets are global. If other countries offer high incentives for solar as the German feed in tariff declines, firm in upstream stages of the value chain may be unable or unwilling to match the decreasing feed-in tariff rate because they have the option of selling their goods in other markets. Installations in Germany may fall off while the price of the solar technology remains unchanged. The German government would be forced into a situation in which it has two uncomfortable choices. First, it may consider slowing, stopping or even reversing the decreasing level of the feed-in tariff in order to maintain a steady rate of photovoltaic deployment. Or, it can allow the German market to shrink and force Germany manufacturers to rely on foreign markets for revenue growth.

The fourth and final direction for research is to study the nature of demand for photovoltaic systems. The preferences of the individuals and organizations who have already purchased photovoltaic systems are probably unlike the preferences of those who have not purchased photovoltaic systems. Factors other than those described in Table 1(government incentives, cost of system, value of electricity, value of REC sales) have likely played into these decisions. It may be that purchasers strongly believe in sustainability or in reducing carbon emissions and are willing to install a system almost as a donation. Or for firms, there may be a marketing benefit in portraying themselves as an environmentally-conscious business. Individuals may be motivated by the fashion aspect of solar, that can be used to signal a public identity to others. In Rogers' (1995) terms, these are "innovators" and "early adopters."

However if solar deployment is to increase drastically, then it may require that the "majority" (Rogers 1995) also purchase and install photovoltaic systems. These consumers may be less predisposed to the technology and may follow a highly analytical cost-benefit logic. They may also be less motivated to educate themselves about how photovoltaic systems work and how to evaluate different system options. Depending on the number of innovators and early adopters in the US, the solar industry's estimates of a solar demand curve may underestimate price elasticity since previous estimates were based on more eager consumers. Thus to maintain the same rate of deployment and the industry may have to decrease costs at a higher rate.

Closing Notes

To close, I bring up two issues that I have not been able to fully address but warrant mentioning. First is the role of the experience curve in building a social movement for solar. It is only recently that support for renewable energy has built up momentum and for a long time solar energy was seen as "fringe" technology. It is important that solar energy be regarded as a mainstream option; if it were not, there would not be serious discussion about supporting research, development and deployment.

However, there should be limits to the enthusiasm over solar and it should be based on sound reasoning. My fear is the development of a "solar bubble" where high expectations lead to a self-fulfilling prophecy, but the realities of the technology make it impossible to meet those expectations indefinitely. If the bubble bursts, the industry may be damaged by eradicating support and making people more cynical of bold visions for a renewable energy future.

The second issue has to do with the role of photovoltaic technology in solving the climate change problem. Implicit in my discussion has been the idea that government and industry resources should be used efficiently and that there is an optimal rate of development and deployment. This idea is no longer valid if we are confronted with the most troubling climate change scenarios. In this case, there may simply be an unavoidable cost of accelerating deployment of solar to reduce the level of carbon dioxide in the atmosphere. That cost may be of secondary importance compared to the problems of adapting to a changed climate.

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