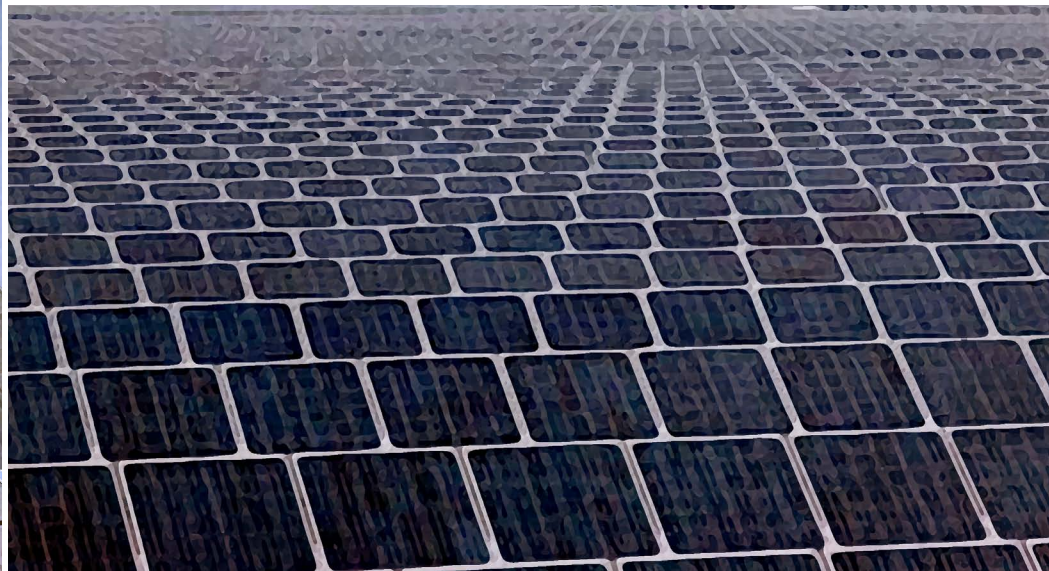


# SunShot Vision Study

February 2012





---

# 8. Solar Industry Financial Issues and Opportunities

## 8.1 INTRODUCTION

---

Although sunshine is free, capturing the sun's rays to generate electricity is a capital-intensive undertaking. Photovoltaic (PV) and concentrating solar power (CSP) technologies have high up-front costs and low operating costs. This means that improving their electricity-production economics is highly dependent on reducing their capital costs (addressed in previous chapters) and reducing the cost of financing those capital costs (addressed in this chapter). Solar technologies also tend to be long-lived assets, which means that long-term financing arrangements are not only appropriate, but are needed to enable investment recovery to be spread out over an extended period, resulting in lower lifetime per-unit electricity costs.

To date, government policies have driven the expansion of solar energy worldwide, and these policies have defined the amounts and types of financing used by solar market participants. In Europe, feed-in tariffs have been the primary stimulus for investment in renewable electricity, enabling a more traditional project finance approach to be used (i.e., usually involving significant amounts of non-recourse debt). In the United States, tax incentives—such as the production tax credit (PTC), investment tax credit (ITC), and accelerated tax depreciation—have been the primary policy tools.

Achieving the SunShot price targets is projected to make solar electricity broadly cost-competitive with electricity from other sources by 2020. This should stimulate private solar investment—and facilitate the use of mainstream financial instruments—by 2020 and beyond. During the transition to becoming fully cost-competitive, solar expansion will still likely be dependent on government incentives.

Under the SunShot scenario, there are two categories of solar financing challenges: financing the solar supply chain and financing solar projects (and associated transmission infrastructure). Financing the expansion of the solar supply chain—such as manufacturing facilities for PV modules and CSP mirrors—and the electrical transmission infrastructure should be relatively straightforward because many of the mechanisms for doing so are already well developed and liquid. Financing SunShot-scale solar project deployment—the widespread construction of distributed and utility-scale solar electricity-generating plants—is a greater challenge, with different considerations in the pre-2020 and post-2020 periods.

After reviewing the finance-related inputs used in the SunShot analysis, this chapter quantifies the amount of supply-chain and project financing required under the SunShot scenario. This is followed by a discussion of current and emerging financial structures and incentives that could help stimulate solar energy growth, especially in the pre-2020 transition period.

## 8.2 REVIEW OF FINANCE-RELATED INPUTS USED IN THE SUNSHOT ANALYSIS

Table 8-1 provides an overview of the financial assumptions used in the SunShot analysis for the deployment of residential, commercial, and utility-scale PV and utility-scale CSP. As discussed in Chapter 3, the Solar Deployment System (SolarDS) model was used to analyze the residential and commercial PV markets, and the Regional Energy Deployment System (ReEDS) model was used for utility-scale PV and CSP, as well as for all other renewable and conventional generation technologies.

As of May 2011, neither SolarDS nor ReEDS is capable of modeling the intricate financial structures involving tax-equity investors, such as the partnership flip structures and leases described in this chapter, that are common in the industry today.<sup>70</sup> Instead, both models approximate the financial aspects of these structures by assuming that long-term debt financing is available for a significant portion of capital costs—i.e., the debt serves as a proxy for tax equity. Moreover, ReEDS assumes financing costs and capital structures that average the financial characteristics of utility-owned projects and projects owned by independent power producers (IPPs), as both ownership types contribute to the expansion of generation capacity. Finally, with the 40-year time horizon of the *SunShot Vision Study*, the SolarDS and ReEDS models use financial assumptions based on long-term historical data, where appropriate and available. The details on specific financing assumptions are provided in the notes below Table 8-1.

# 8

## 8.3 FINANCING REQUIREMENTS FOR THE SOLAR SUPPLY CHAIN

Under the SunShot scenario, annual U.S. PV and CSP installations (including rebuilds) could stabilize at about 25–30 gigawatts (GW)/year (yr) and 3–4 GW/yr, respectively. Building out the U.S. PV and CSP manufacturing capacity to meet this demand would require investing roughly \$25 billion by 2030 and \$44 billion by 2050.<sup>71,72</sup> Although the investments required to finance these manufacturing capacity

<sup>70</sup> As of May 2011, the System Advisor Model (SAM) is able to model these advanced financing structures and can be found at [www.nrel.gov/analysis/sam](http://www.nrel.gov/analysis/sam).

<sup>71</sup> Assumes: 1) Manufacturing capital expenditure (CapEx) costs, in terms of annual production capacity, decline from about \$2/watt (W) in 2010 to about \$0.5/W in 2020; the CapEx requirements for concentrated solar power (CSP) technologies are not well documented, so, conservatively, the CSP CapEx is assumed to be equal to the PV CapEx. 2) Annual U.S. installations (including rebuilds) grow to 25 GW/yr by 2030 and 30 GW/yr by 2050 for PV, and 3 GW/yr by 2030 and 4 GW/yr by 2050 for CSP. 3) Average economic life of manufacturing equipment is 10 years. 4) The manufacturing utilization rate is 80%.

<sup>72</sup> All cumulative values in this chapter are in net present value calculated using a 7% discount rate per the U.S. Office of Management and Budget (OMB) 2003 guidance.

Table 8-1. Solar Financing Assumptions

	SolarDS		ReEDS <sup>a</sup>	
	Residential Rooftop (new/retrofit)	Commercial Rooftop	Utility PV	Utility CSP
Inflation rate <sup>b</sup>	3%	3%	3%	3%
Loan rate (real)	4.5% <sup>c</sup> /6% <sup>d</sup>	4.5% <sup>e</sup>	4% <sup>f</sup>	4% <sup>f</sup>
Loan term (years)	30/15	20	15	15
Debt fraction	80%–100% <sup>g</sup>	60%	60%	60%
Equity rate (real)	N/A	N/A	11.7% <sup>h</sup>	11.7% <sup>h</sup>
Down payment (equity fraction)	0%–20% <sup>g</sup>	40%	40%	40%
Discount rate (real)	N/A <sup>i</sup>	N/A <sup>j</sup>	5.5% <sup>k</sup>	5.5% <sup>k</sup>
Depreciation	N/A	MACRS <sup>l</sup>	MACRS	MACRS
Federal tax	25%–33% <sup>m</sup>	35%	35%	35%
State tax	by state	by state	5%	5%
PV/CSP lifetime (years)	30	30	30	30

<sup>a</sup> The financial assumptions in ReEDS for utility-scale PV and CSP are the same for other renewable and conventional generation technologies. The one exception is loan terms, which vary between 15 and 30 years depending on technology.

<sup>b</sup> Conservative estimate of inflation based on historical U.S. Gross Domestic Product (GDP) deflator data over the last 30 years. Accessed November 2010 at: <http://research.stlouisfed.org/fred2/data/GDPDEF.txt>.

<sup>c</sup> Based on a 20-year historical average of real U.S. 30-year fixed mortgage rates. Accessed January 20, 2010, at: [www.freddiemac.com/pmms/pmms30.htm](http://www.freddiemac.com/pmms/pmms30.htm) (Freddie Mac 2010).

<sup>d</sup> Based on a 3-year historical average of real rates for \$30,000 U.S. home equity loans. Accessed January 20, 2010, at: [www.wsjprimerate.us/home\\_equity\\_loan\\_rates.htm](http://www.wsjprimerate.us/home_equity_loan_rates.htm).

<sup>e</sup> Based on a 12-year historical average of real yields of corporate bonds rated Aa and A by Moody's (SIFMA 2010).

<sup>f</sup> Reflects a nominal cost of debt of approximately 7%, the midpoint between the nominal costs of debt for higher-risk projects owned by investor-owned utilities and those owned by independent power producers (Wimer 2008).

<sup>g</sup> Assumes that 80% of residential customers use a 20% down payment, and 20% of residential customers use a 0% down payment to characterize the alternate ownership structures such as third-party PV ownership (NREL 2009, SEIA/GTM Research 2011a) or property-assessed clean energy (PACE) style financing (NREL 2010).

<sup>h</sup> Reflects a nominal cost of equity of 15%, the midpoint between the nominal costs of equity for investor-owned utilities and independent power producers (EEI 2009, Wimer 2008).

<sup>i</sup> SolarDS uses a simple payback time to adoption relationship for residential customers.

<sup>j</sup> SolarDS uses a payback time to adoption rate for commercial customers that use the internal rate of return of future cash flows.

<sup>k</sup> Reflects a nominal after-tax weighted average cost of capital (WACC) of 8.6%.

<sup>l</sup> MACRS (modified accelerated cost recovery system) is applied to taxable commercial customers.

<sup>m</sup> Assumes that 50% of residential customers are at a 25% federal tax rate, and the other 50% are at a 33% federal tax rate.

expansions are not trivial, on an annual basis they would require investments on the order of \$1–\$3 billion, well below levels seen during the past couple of years (as discussed below). Moreover, the necessary financing instruments and structures are well developed and well understood in the capital markets.

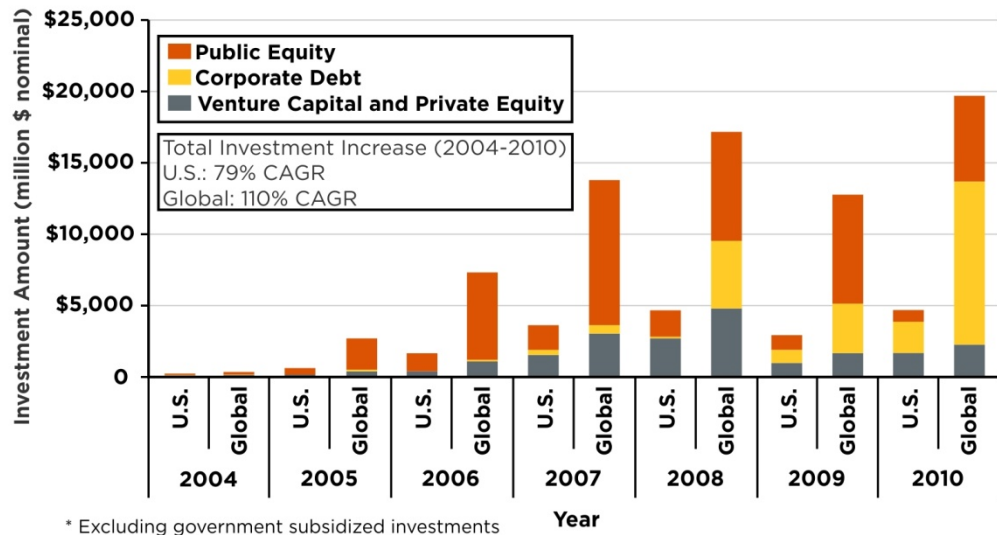
Historically, the solar supply chain has been financed primarily by a mix of venture capital (VC), private equity (PE), public equity, and corporate debt. VC investments



are often the earliest form of private investment in corporations, when both the potential reward and risk are the greatest. In the solar industry, PE is usually the next source of funding, as companies require additional and greater amounts of capital for manufacturing expansions. Finally, companies can issue public equity, selling shares of the company on the open market. In addition to equity financing, corporate debt can be used to fund a company’s operations and expansions.

Figure 8-1 shows the dramatic increase in investment in the U. S. and global solar supply chain, including PV and CSP, over the past 6 years. In 2004, only \$142 million and \$231 million were invested in solar companies in the United States and globally, respectively. In 2010, solar supply chain investment reached more than \$4.7 billion in the United States and nearly \$20 billion globally, corresponding to 6-year compound annual growth rates (CAGRs) of 79% and 110%, respectively. Such rapid expansion indicates the ability of the VC, PE, public equity, and corporate debt capital markets to respond swiftly to signals of the solar industry’s growth potential. In addition to the growth of total supply chain investment, the proportional mix of investment has shifted from riskier to more-secure financial instruments. In the years between 2004 and 2006, for example, corporate debt accounted for between 0% and 6% of total global investment, whereas in 2010 almost 60% of total investment in solar companies came from corporate debt.

Figure 8-1. U.S. and Global Solar Supply Chain Investment



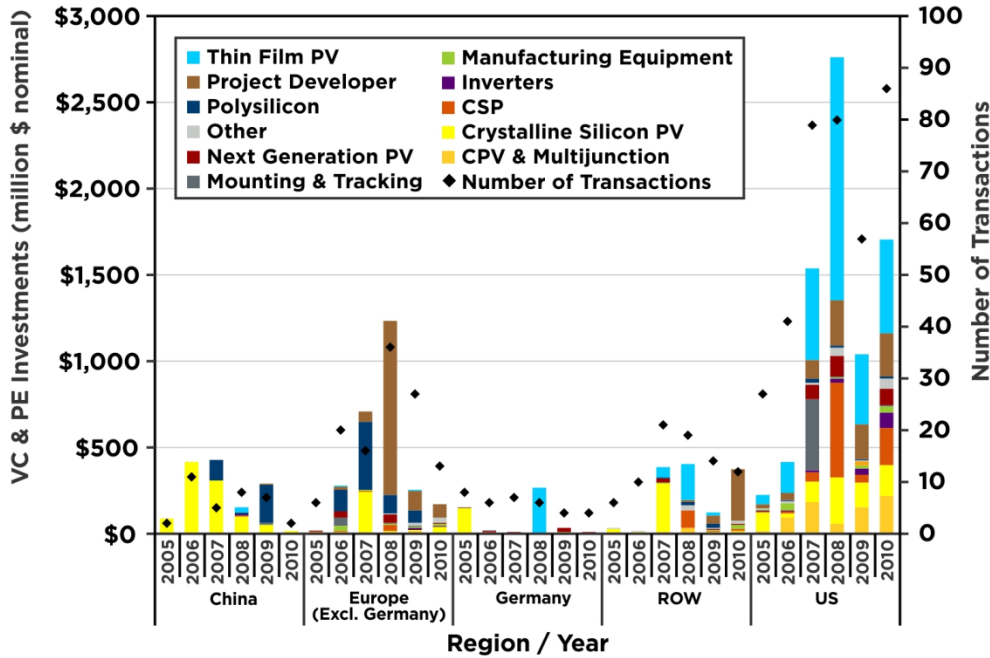
Source: Bloomberg New Energy Finance (2011)

Figure 8-1 excludes government-subsidized investments. Government-supported debt grew from \$579 million in 2009 to \$32.8 billion in 2010, to become greater than any other source of capital. Most of this government-supported debt was issued by the China Development Bank.

Figure 8-2 illustrates VC and PE investment in the solar supply chain, including PV and CSP, showing the technological and regional breakdown of such funding. U.S. companies have consistently received the most VC and PE funding, and a far more diverse set of solar technologies is financed in the United States than in the other active solar markets.



Figure 8-2. VC and PE Investment in the Solar Supply Chain



Source: Bloomberg New Energy Finance (2011)

## 8.4 FINANCING REQUIREMENTS FOR SOLAR PROJECT AND TRANSMISSION DEPLOYMENT



Deploying solar projects—i.e., deploying PV and CSP electricity-generating facilities—and associated transmission infrastructure will cost much more than expanding the solar supply chain under the SunShot scenario. This section explores the potential project and transmission costs.

### 8.4.1 FINANCING SOLAR PROJECTS

Under the SunShot scenario, solar capacity in the United States is projected to meet 14% of total contiguous U.S. electricity demand by 2030 and 27% by 2050. To achieve these penetration levels, annual solar installations are projected to stabilize around 25–30 GW/yr for PV and 3–4 GW/yr for CSP. On an annual basis, this translates into roughly \$40–\$50 billion/yr.<sup>73</sup> On a cumulative basis, the required investments are roughly \$250 billion through 2030 and \$375 billion through 2050. Although these are significant investments, the total capital required to build all types of electric-generating equipment—conventional and renewable—in the SunShot scenario through 2050 is actually only \$2 billion more than in the reference scenario. When other costs are considered—such as fuel, transmission, and operation and maintenance (O&M)—less money is actually spent in the SunShot

<sup>73</sup> Assumes solar technology costs and mix of PV and CSP technologies per SunShot scenario as described in Chapter 3 and Appendix A.

scenario than in the reference scenario (see Chapter 3). However, it is still relevant to consider what effect financing may have in achieving the SunShot scenario.

## 8.4.2 FINANCING TRANSMISSION

In both the SunShot and reference scenarios, the U.S. transmission infrastructure must be reinforced and expanded to accommodate new generation resources. Technical aspects of the transmission requirements are detailed in Chapters 3 and 6.

As discussed in Chapter 3, the projected cost of expanding transmission in both the SunShot and reference scenario from 2010 to 2050 is about \$60 billion dollars (2010\$, net present value). The discounted cost for the SunShot scenario is approximately the same as the reference, even though more transmission capacity is built, because this additional capacity is developed later in the study whereas the reference scenario develops more transmission capacity earlier in the study. Regardless, the entire cost of transmission expansion is equivalent to less than a few years of fuel savings in the SunShot scenario. The \$60 billion transmission investment required in both scenarios is spread out over 40 years, representing about 2% of the total electric-sector costs. While building out the transmission infrastructure at this level will present many challenges (especially related to siting), it is within the historical range of U.S. transmission expenditures by investor-owned utilities, which was \$2–\$9 billion per year between 1995 and 2008 (Pfeifenberger et al. 2009).

# 8

## 8.5 FINANCIAL STRUCTURES AND INCENTIVES

As previously noted, although substantial investments will be required to finance SunShot-scale expansion of the solar manufacturing supply chain, there is sufficient capital to do so, and the necessary financing instruments and structures are well developed and understood in the capital markets. However, financing solar project deployment (e.g., new power plants) under the SunShot scenario will cost much more than financing the supply chain. Especially in the pre-2020 period, new financing options will be required before solar electricity is cost competitive with other electricity sources. In 2020 and beyond, cost-competitive solar energy should stimulate private solar investment and facilitate use of mainstream financial instruments. This section discusses the current financial incentives and financing structures that support U.S. solar and transmission projects, followed by a description of emerging solar project financing structures that may support solar deployment in the coming years.

### 8.5.1 CURRENT FINANCIAL INCENTIVES AND STRUCTURES

Current financial incentives and structures for solar projects are based on the availability of government incentives, particularly the federal ITC. Although the *SunShot Vision Study* assumes that no solar projects receive an ITC after 2016, this incentive—and government incentives at other levels—will be important for stimulating solar deployment during the transition to solar cost competitiveness.<sup>74</sup>

<sup>74</sup> Although the SunShot scenario costs assumptions do not include any ITC after 2016, under the current Internal Revenue Service (IRS) tax code, the 30% ITC will revert to a 10% ITC for commercial and utility systems after 2016.



This subsection begins with a discussion of government incentive-based financing and then describes current solar financing structures, which are based on the availability of government incentives. Lastly, transmission financing considerations are discussed.

### Government Incentives

Financial incentives for U.S. solar projects are provided by the federal government, state and local governments, and some local utilities. Historically, federal incentives have been provided primarily through the U.S. tax code, in the form of an ITC (which applies to residential, commercial, and utility-scale installations) and accelerated 5-year tax depreciation (which applies only to commercial and utility-scale installations). For commercial installations, the present value to an investor of the combination of these two incentives—which can be used only by tax-paying entities—amounts to about 56% of the installed cost of a solar project (Bolinger 2009).<sup>75</sup>

Most solar project developers are not in a financial position to absorb tax incentives themselves (due to lack of sufficient taxable income to offset deductions and credits<sup>76</sup>), and so they have had to rely on a small cadre of third-party “tax equity investors” who invest in tax-advantaged projects to shield the income they receive from their core business activities (e.g., banking). In doing so, these tax-equity investors monetize the tax incentives that otherwise could not be efficiently used by project developers and other common owners of the renewable energy plants.

Federal tax-based incentives may play a significant role in stimulating solar development until 2017, when the ITC is assumed to expire under the SunShot scenario. However, the amount of tax equity available for solar projects is uncertain. Due to the global financial crisis, tax-equity investments in renewable power projects in the United States peaked at \$6.1 billion during 2007, declined to \$3.4 billion during 2008, and plunged to \$1.2 billion during 2009 (US PEF 2010). Assuming that the tax equity market is able to return to its former level of 2007 (\$6.1 billion per year), that utilities enter the tax-equity market in force (UBS 2008), and other new tax-equity investors make significant contributions, the total size of the tax equity market could grow to about \$10 billion per year in a relatively short period. However, solar energy would have to compete with other renewable energy technologies for this tax equity.

Federal benefits can be used in combination with state and local incentives, which come in many forms, including—but not limited to—up-front rebates, performance-based incentives, state tax credits, renewable energy certificate (REC) payments, property tax exemptions, and low-interest loans. Incentives at both the federal and state levels vary by sector and by whether or not the systems are utility scale or distributed. Incentive levels and eligibility also vary by type of technology.

<sup>75</sup> Although the accelerated 5-year tax depreciation has a present value to an investor of about 26%, only 12% of that value is from the accelerated schedule. The remaining 14% would have been realized under a conventional 20-year straight-line schedule.

<sup>76</sup> Offsetting income is particularly difficult for certain developers given the IRS’s “passive income” rules affecting individuals, personal service corporations, and closely held corporations, which state that “passive income” can only offset “passive losses.”



In most cases, solar project developers need to combine several of these federal, state, and local incentives to make projects economically viable. Given the complexity of capturing some of these incentives—particularly in combination—solar financiers have adopted (and in some cases, modified) complex ownership structures previously used to invest in other tax-advantaged sectors in the United States, such as low-income housing, historical buildings, and commercial wind projects. These financing structures—for projects on both the utility and customer sides of the meter—are described below.

### Utility Side of the Meter

Although a number of utility-scale<sup>77</sup> CSP projects were built in California during the 1980s (and are still operating), the proliferation of large solar projects interconnected on the utility side of the meter has been a relatively recent phenomenon. Before 2010, there were only 113 megawatt (MW) direct current (MW<sub>DC</sub>) of utility-scale PV capacity in the United States. In 2010, the United States installed 242 MW<sub>DC</sub> of such projects. There were no CSP plants built from 1992–2006; since then, several facilities less than 10 MW alternating current (MW<sub>AC</sub>) in size have been placed in service as well as a 64-MW<sub>AC</sub> project in Nevada (2007) and a 75-MW<sub>AC</sub> plant in Florida (2010) (SEIA/GTM Research 2011b). In most cases, these projects are owned by IPPs (in conjunction with tax equity investors), who sell the power to utilities under a long-term power purchase agreement (PPA).

Most of these projects are financed using one of the following three structures: a partnership flip, a sale/leaseback, or an inverted lease. Each of these tax-driven structures allocates the benefits of ownership among the project developer and various project investors. Solar projects can have multiple benefits: cash proceeds from the sale of power or lease of equipment to the site host, a federal ITC or cash grant, depreciation benefits, RECs, and state or local grants. Financial structures are chosen and modified to optimize each party's return, exposure to risk, and desired long-term ownership of a solar asset. Each transaction is complex and includes sophisticated structuring among the project developer, equity provider, debt provider, and sometimes even the end-users. Not surprisingly, these one-off arrangements are expensive and time consuming as they involve multiple attorneys, accountants, and other professional advisory services. This complexity results from having project developers go to great lengths to fully monetize incentives that are designed to increase the proliferation of solar projects. Wind projects, which must be structured similarly to monetize the tax credit and depreciation incentives, sacrifice approximately 40% of the value of the PTCs to use the tax capacity provided by tax equity investors (Hudson Clean Energy Partners 2009).

To date, most solar projects interconnected on the utility side of the meter have been financed by IPPs using one of the aforementioned three structures, with power sold to the utility under a long-term PPA. There are, however, some emerging issues with this IPP/PPA model. Under certain conditions, accounting principles may require the utility to essentially carry the project from which it is buying power on its balance

<sup>77</sup> Solar projects on the utility side of the meter are often referred to as utility-scale projects because they tend to be large (multi-megawatts) in size. However, smaller, distributed utility-scale generation—sometimes called wholesale distributed generation (DG)—often falls under the “utility side of the meter” category. In addition, utilities may explore other distributed-level opportunities in the future that are also on the utility side of the meter.

sheet as a long-term liability. This, in effect, means that the utility will be taking on risk that it cannot necessarily control. Similarly, debt-rating agencies increasingly view long-term PPAs as debt-equivalent obligations, meaning that an over-reliance on PPAs may negatively impact a utility's debt rating. Finally, with the price of solar power expected to decline rapidly in the coming years, a regulatory commission might question retroactively why a utility would have agreed to sign a PPA or even directly own a solar project at current solar power prices. As such, the risk of a retroactive disallowance of an investment in solar needs to be carefully explored with the governing regulatory commission and comfort established that the investment is prudent, regardless of the future projections of solar power prices.

Now that utilities are able to access the ITC utility ownership of solar projects interconnected on the utility side of the meter is becoming more common. There are a number of benefits and a number of challenges to utility ownership.

The largest benefit of utility ownership of solar assets is that utilities have “built-in” financing arrangements available to them through their ability to rate-base investments. This means that as long as a utility's regulatory commission supports the investment and allows the utility to participate in the generation ownership arena, the investment (plus a return on the equity invested) would be recovered through a cost-of-service revenue requirement that would be paid by all ratepayers over the life of the investment. This approach could eliminate the need to access capital markets on a project-level basis. In this model, the capital is provided through the utility's balance sheet, using traditional equity and debt instruments. A utility's investment in solar would be valued at the utility's weighted average cost of capital (WACC), which is typically significantly lower than that of an IPP. Further, a utility's rate-recovery period for investments in solar would likely be 25–30 years (i.e., based on the expected life of the asset), which is significantly longer than the 10–20-year recovery period typically seen in the IPP/PPA model. This longer financing horizon for utilities spreads out the annual revenue requirement, making the burden on customers less than through an IPP/PPA structure. An additional benefit of utility ownership is that they do not have to renegotiate contracts coming to an end with third-party generation owners; negotiating new terms, including PPA price has the potential to add costs over the life of an asset. Utilities also have a better knowledge of where the most appropriate places to site solar systems are in order to improve grid reliability and reduce grid congestion during peak hours.

However, there are two key challenges to utility ownership. First, utility regulators might not consider rate-basing of solar projects as prudent and may not approve the full value of the investment. Many utilities will not move forward without preauthorization from their regulators for owning solar assets above their utility's current avoided cost.

Second, regulations constrain how utilities are able to use the ITC. The economics of utility ownership are challenged by a regulatory measure that limits utilities' ability to pass on the full advantage of a solar project's tax benefits to their rate bases. In particular, the IRS currently requires that the benefit of the ITC to ratepayers be amortized over the life of the facility—a process called “normalization.” Normalization defers the up-front tax benefit and dilutes the incentive intended under the federal tax code. Utilities cannot take the ITC without normalizing the tax benefit. Due to this normalization issue, many utilities have not purchased solar

assets. Instead, they have allowed IPP’s to monetize the ITC and pass along the benefit through lower-priced electricity.

**Customer Side of the Meter**

Despite the increasing interest in utility-scale solar power projects (using both PV and CSP technologies), to date most solar-electric systems have been installed “behind the meter,” meaning on the customer, rather than utility, side of the meter. These customer-side systems have been installed in both residential and non-residential applications and have primarily used PV technologies. Variations in tax rules between the residential and non-residential sectors, as well as varying tax status within the non-residential sector (e.g., commercial versus non-profit versus governmental) have given rise to a variety of different financing or ownership structures used in each sector or sub-sector.

Table 8-2 summarizes the principal financing options available, categorized as either self financed or third-party financed. Self-financed projects rely on some mix of equity (i.e., cash) provided and debt assumed by the site host, with the sources of that equity and debt varying considerably among the residential, non-residential taxable, and non-residential tax-exempt sectors. Prior to 2006, almost all behind-the-meter PV projects were self financed.

**Table 8-2. Categorization of Financing Approaches for Behind-the-Meter PV Projects**

		Residential	Non-Residential	
		Taxable	Taxable	Tax-Exempt
Self financed	Equity (Cash)	Cash savings	Balance-sheet finance	Internal funds or reserves
	Debt	Mortgage; home equity loans; property tax loans		Bank loans; muni bonds; CREBs <sup>a</sup>
Third-party financed	Lease	Operating lease	Operating lease	N/A
	Service contract (PPA)	Not as common as lease	More common than lease	Very common

<sup>a</sup> CREBs = clean renewable energy bonds.

Starting in 2006, however, third-party financing began to expand rapidly, particularly in the non-residential sector. This rapid expansion was driven in large part by an increase in the federal ITC from 10% to 30%. A 30% ITC coupled with accelerated tax depreciation was large enough to attract the attention of institutional tax equity investors, who partnered with PV project developers to offer solar leases and service contracts to mostly non-residential site hosts.

Under a solar lease, the tax equity investor, often in partnership with the project developer, owns the project and benefits from lease payments and tax benefits, while the site host makes lease payments and benefits from the power generated. Project operations may be managed by the site host or the tax equity investor, depending on local conditions. Another third-party financing mechanism is the solar service contract, which is often loosely referred to as a third-party PPA. Although the

contract itself is similar to a PPA on the utility side of the meter, on-site generation hosted by a customer entails a contract between the customer and the project owner (the utility is not involved), and it needs to be legally structured as a contract for solar services. Under this arrangement, the tax equity investor—again, often in partnership with the project developer—owns and operates the project, takes the tax benefits, and sells the energy to the site host, while the site host pays for the energy generated and uses it to displace energy that it would otherwise purchase from the utility. In either case, the goal has been to structure the lease or PPA payments such that the site host is paying no more than it would have otherwise paid to the utility, thereby making solar a budget-positive, or at least budget-neutral, proposition for the site host right from inception.

These third-party financing options have proven to be popular with site hosts for three primary reasons: 1) they reduce or eliminate the up-front cost to the host; 2) they enable full and efficient use of the federal tax incentives; and 3) system operations and maintenance are the responsibility of the third-party owner in the case of a solar service contract (and sometimes for solar leases). In the non-residential sector, PPAs have proven to be more popular than solar leases. Furthermore, for tax-exempt entities, traditional operating leases are not an option, and tax-exempt leases are not as favorable as service contracts (Bolinger 2009). Although relatively new in the residential sector, third-party financing options have recently made substantial inroads in this market segment as well, accounting for more than 20% of residential systems, and 30% of total systems, installed under the California Solar Initiative (CSI) incentives in 2010 (CSI 2011).

## Financing Transmission

Transmission regulatory approvals (see Chapter 7) and cost allocation (i.e., who pays for transmission) for transmission expansion are among the most significant barriers to renewable energy development in the United States. Although there are many models for transmission cost allocation, the most common U.S. model to date requires the generator to fund transmission expansion, further explained below. However, a July 2011 federal order could change transmission cost allocation going forward, once implemented.

Under existing Federal Energy Regulatory Commission (FERC) rules for network—as opposed to radial, or one-way—transmission development or expansion, the transmission operator [typically the investor-owned utility (IOU)] can finance the transmission development itself and recover costs from ratepayers or require the generator to finance the cost for network upgrades up front. Utilities are often reluctant to finance transmission to serve renewable projects for fear that such investment would be deemed unreasonable by regulatory authorities if the generation failed to come online, potentially creating stranded costs that must be borne by their shareholders. To avoid such risks, they typically require developers to pay for all or a significant portion of the required network upgrades instead. Alternatively, developers may have to post a security deposit for the time it takes to build the new line. However, developers find it difficult to finance both a generating project and significant network upgrades. This situation has created a large logjam of generator interconnection waiting lists for transmission, known as interconnection queues.



An alternative to generator-funded cost allocation is socialization of transmission costs, i.e., distributing costs for transmission expansion and upgrades to all customers, which has had some success in enabling the financing of transmission for renewables. The reasoning is that expanding the transmission system benefits all customers by increasing competition, enhancing reliability, and providing access to renewable resources, among other benefits (Pfeifenberger et al. 2009). Within the Electric Reliability Council of Texas (ERCOT) Interconnection, these costs have been spread among all customers of all utilities for more than a decade. Transmission connecting Texas' recently created competitive renewable energy zones (CREZs) will be financed the same way.

The California Independent System Operator Corporation (CAISO) has implemented a cost-allocation model for the Tehachapi Transmission Project, which involved policymakers (CAISO and FERC) cooperating with local participants to approve a \$1.8-billion transmission line that will allow about 4,500 MW of wind capacity to reach markets by 2013. This project involved up-front financing by Southern California Edison, using tariff-based cost recovery through transmission rates and pro rata fees paid by generators, with installation of the line preceding installation of the renewable generators that largely justify construction of the line (Pfeifenberger et al. 2009). Costs are spread among all generators interconnecting, but costs that are incurred prior to full subscription by generators are socialized. Similar arrangements can be contemplated for expansion of transmission for solar generating capacity.

## 8

In July 2011, FERC issued Order 1000, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities." The new order has the potential to facilitate transmission expansion as it relates to renewable energy projects in two main ways. First, local and regional transmission planning processes must consider transmission needs driven by state or federal laws or regulations [e.g., renewable portfolio standard (RPS) requirements]. Depending on how this is implemented, it could mean that utilities do not need to be concerned with regulatory stranded costs for renewable energy-specific transmission, because the FERC order could be used to prove the investment was prudent. Second, regional transmission cost allocation methods cannot require "participant funding" of transmission facilities. This could mean that generators may not be required to cover the full cost of transmission facilities. Implementation of this new FERC rule could help finance transmission for renewable energy projects going forward.

### 8.5.2 EMERGING SOLAR PROJECT FINANCING STRUCTURES

In addition to the more prevalent solar project financing structures described above, three emerging project financing structures have not yet been widely used to finance solar projects in practice; these include prepaid service contracts, property-assessed clean energy finance (PACE), and on-bill financing.

#### **Prepaid Service Contract**

A prepaid service contract is similar to a regular service contract (or third-party PPA) between the project owner and an offtaker (i.e., power purchaser) as described above, with one important exception: a significant portion of the power is purchased upfront, before it is delivered. This structure works well with governmental

institutions that can issue low-cost debt and use the proceeds to make an up-front payment. Because the project effectively benefits from both low-cost (and in certain cases tax-exempt) debt financing and the private sector tax benefits generated by the project, the effective cost of power under a prepaid service contract can be significantly lower than under other financing options (Bolinger 2009). Although several large wind projects built since 2007 have used prepaid service contracts, this financing structure has been slower to catch on with solar projects. In particular, it is difficult to justify the use of this rather involved and complex structure for relatively small PV projects—as opposed to larger wind projects. However, as larger PV and CSP projects, or portfolios of projects, have proliferated the prepaid service contract has begun to gain favor among developers and tax-exempt governmental offtakers.

### Property-Assessed Clean Energy Finance Programs

In PACE programs, municipal financing districts lend the proceeds of bonds or other funds to property owners to finance end-user renewable energy and energy-efficiency improvements. The property owners then repay these loans over 15–20 years via annual assessments on their property tax bills. These programs offer the advantage of 100% financing with tax-deductible interest payments, as well as the loan being tied to the property rather than to the homeowner. Since the City of Berkeley, California, first announced the basic structure of its program in October 2007, PACE programs have spread rapidly across the country; 27 states and Washington DC have authorized PACE financing policies thus far (DSIRE 2011). Residential PACE programs hit a significant roadblock in mid-2010, however, when Fannie Mae and Freddie Mac, which underwrite a significant portion of home mortgages, determined that they would not purchase mortgages with PACE loans because PACE loans, like all other property tax assessments, are written as senior liens.<sup>78</sup> These issues are still being resolved, and while it is not yet known whether or how residential programs will move forward, PACE assessments remain a viable option in the commercial space. As of March 2011, there were four commercial PACE programs in operation, which had approved \$9.69 million in funding for 71 projects, many of which were PV. There were also nine commercial programs in formal planning stages, and at least seven in preliminary planning stages (LBNL 2011).

### On-Bill Financing

On-bill financing is a relatively new form of financing that combines a state subsidy, such as an up-front rebate or interest rate buy-down, with a loan from the electric utility. The goal is to reduce or eliminate the up-front cost of the project to the customer by financing all of the costs not covered through rebates with an on-bill adder. The loan payments are made over a period that is long enough—and with a low-enough interest rate—to create cost savings from the first day (Brown 2009b). This mechanism has been used only for energy efficiency and there are not any

<sup>78</sup> On July 6, 2010 the Federal Housing Finance Agency (FHFA), which regulates Fannie Mae, Freddie Mac, and the 12 Federal Home Loan Banks, issued a statement determining that PACE loans “present significant safety and soundness concerns” and called for a halt in PACE programs for these concerns to be addressed. FHFA determined that, “the size and duration of PACE loans exceed typical local tax programs and do not have the traditional community benefits associated with taxing initiatives” (FHFA 2010). Because Fannie Mae and Freddie Mac do not consider PACE loans to conform with traditional taxing initiatives, they are not interested in purchasing mortgages on homes with PACE liens. Certain PACE programs are attempting to solve the problem by setting up programs as second-tier liens.

known applications for solar; however, legislation was introduced (and failed to pass) in Hawaii, directing public utilities to implement on-bill financing for solar technologies (Brown 2009a). Despite the advantages of on-bill loans, this type of financing mechanism faces a number of implementation challenges (Brown 2009b): the need for a sizable amount of initial capital to fund the revolving loan, concern about the potential for defaults, uncertainty about how utilities will be regulated with respect to providing a loan versus a financing product, and the need to update utility billing systems to allow for automated and electronic management of on-bill loans.

## 8.6 REFERENCES

- Bloomberg New Energy Finance. (2011). *Bloomberg New Energy Finance*. [www.newenergymatters.com](http://www.newenergymatters.com). Accessed February 25, 2011.
- Bolinger, M. (2009). *Financing Non-Residential Photovoltaic Projects: Options and Implications*. Report No. LBNL-1410E. Berkeley, CA: Lawrence Berkeley National Laboratory. <http://eetd.lbl.gov/ea/EMS/reports/lbnl-1410e.pdf>. Accessed September 2010.
- Brown, M. (2009a). Conover\*Brown. Personal communication. December 2009.
- Brown, M. (2009b). *On-Bill Financing: Helping Small Business Reduce Emissions and Energy Use While Improving Profitability*. Prepared for the National Small Business Association. Denver, CO: Conover\*Brown.
- California Solar Initiative, CSI. (2011). "California Solar Statistics." <http://www.californiasolarstatistics.ca.gov/>. Accessed February 2011.
- Database of State Incentives for Renewable Energy & Efficiency, DSIRE. (2011). Property Assessed Clean Energy (PACE) map, updated August 2011. [http://www.dsireusa.org/documents/summarymaps/PACE\\_Financing\\_Map.ppt](http://www.dsireusa.org/documents/summarymaps/PACE_Financing_Map.ppt). Accessed August 2011.
- Edison Electric Institute, EEI. (2009). *2008 Financial Review: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry*. Washington, DC: EEI.
- Federal Housing Finance Agency, FHFA. (July 6, 2010). *FHFA Statement on Certain Energy Retrofit Loan Programs*.
- Freddie Mac. (2010). *30-Year Fixed-Rate Mortgages Since 1971*. [www.freddiemac.com/pmms/pmms30.htm](http://www.freddiemac.com/pmms/pmms30.htm). Accessed January 2010.
- Hudson Clean Energy Partners. (2009). *ACORE & American Bar Association Teleconference: What the Stimulus Means for Renewables - Viewpoints of Key Players*. Teaneck, NJ: Hudson Clean Energy Partners.
- Lawrence Berkeley National Laboratory, LBNL Renewable Funding, Clinton Climate Initiative. (2011). *Policy Brief: Property Assessed Clean Energy (PACE) Financing: Update on Commercial Programs*. March 23, 2011.
- National Renewable Energy Laboratory, NREL. (2009). *Solar Leasing for Residential Photovoltaic Systems*, NREL/FS-6A2-43572. <http://www.nrel.gov/docs/fy09osti/43572.pdf>. Accessed January 2012.
- NREL. (2010). *Property-Assessed Clean Energy (PACE) Financing of Renewables and Efficiency*. NREL/BR-6A2-47097. <http://www.nrel.gov/docs/fy10osti/47097.pdf>. Accessed January 2012.

- Office of Management and Budget, OMB. (2003). “Circular No. A-4: Memorandum for Heads of Executive Departments and Establishments.” The White House. Washington, DC. September 17, 2003.  
[http://www.whitehouse.gov/omb/circulars\\_a004\\_a-4/](http://www.whitehouse.gov/omb/circulars_a004_a-4/). Accessed November 2010.
- Pfeifenberger, J.; Fox-Penner, P.; Hou, D. (2009). “Transmission Investment Needs and Cost Allocation: New Challenges and Models.” Presented at the Federal Energy Regulatory Commission, December 1.  
[www.brattle.org/documents/uploadlibrary/upload823.pdf](http://www.brattle.org/documents/uploadlibrary/upload823.pdf). Accessed September 2010.
- Securities Industry and Financial Markets Association, SIFMA. (2010). *Moody’s Corporate Bond Yield Averages*. New York.
- Solar Energy Industries Association, SEIA and Greentech Media, GTM Research. (2011a). U.S. Solar Market Insight, 1<sup>st</sup> Quarter 2011.  
<http://www.greentechmedia.com/research/solarinsight>. Accessed June 2011.
- SEIA/GTM Research. (2011b). *U.S. Market Insight: 2010 Year-in-Review*.
- UBS. (2008). *UBS Investment Research on SunPower Corp*. Zurich: UBS.
- U.S. Partnership for Renewable Energy Finance, US PREF. 2010. *Prospective 2010 – 2012 Tax Equity Market Observations*. <http://uspref.org/wp-content/uploads/2011/07/US-PREF-Tax-Equity-Market-Observations-v2.2.pdf>. Accessed October 2011.
- Wimer, J. (2008). *Recommended Project Finance Structures for the Economic Analysis of Fossil-Based Energy Projects*. Report No. NETL-401/090808. Pittsburgh, PA: National Energy Technology Laboratory



