9. Solar Industry Financial Issues and Opportunities

Table of Contents

9. Solar Industry Financial Issues and Opportunities 1

9.1 Introduction 1

9.2 Review of Finance-Related Inputs Used in the Solar Vision Analysis 2

9.3 Financing the Solar Supply Chain (Corporate Finance).................. 4

9.4 Financing Solar Deployment (Project Finance) 7

9.4.1 Current Financial Incentives and Structures 7
9.4.2 Emerging Solar Project Financing Structures 11
9.4.3 The Limitations of Relying on Tax Equity to Drive New Project Development.. 12
9.4.4 Financing Transmission for the Solar Vision.................................... 14

9.5 Fundamental Financial Principles Critical to Achieving the Solar Vision 15

9.5.1 Financial Principles Defined 15
9.5.2 Potential Policy Options that Meet the Financial Principles.............. 16

9.6 Summary/Conclusions 19

9.7 References 20

List of Figures

Figure 9-1. U.S. and Global Solar Supply Chain Investment* 5
Figure 9-2. VC & PE Investment in the Solar Supply Chain...................................5
Figure 9-3. Estimate of Tax Equity Required to Finance Solar Vision* 13

List of Tables

Table 9-1. Solar Financing Assumptions..3
Table 9-2. Cumulative Solar PV Manufacturing Investment Required in 10% and 20% Scenarios (2010-2030)...6
Table 9-3. Installed GW and Corresponding Investment Requirements, by 2030...7

Table 9-4. Categorization of Financing Approaches for Behind-the-Meter PV Projects..10

9. Solar Industry Financial Issues and Opportunities

9.1 Introduction

Although sunshine is free, capturing the sun's rays to generate usable heat and/or electric power is a capital-intensive undertaking. Solar facilities have high up-front costs and low operating costs, which means that improvements in their production economics are highly dependent on (1) reducing the capital costs of the solar facilities (addressed in previous chapters), and (2) reducing the cost of financing those capital costs (addressed in this chapter). Solar facilities also tend to be long-lived assets, which means that long-term financing arrangements are not only appropriate, but are also critical to enabling investment recovery to be spread out over an extended period of time, resulting in lower per-unit production costs over the life of each facility.

Encouragement of solar and other renewable sources of power has been dominated by government policies, and those policies have defined the amounts and types of financing used by market participants to develop and construct new facilities. In Europe, as exemplified by Denmark, Germany, and Spain, favorable feed-in tariffs have been the primary stimulus for investment in renewable electricity, enabling a more traditional project finance approach (i.e., involving significant amounts of non-recourse debt) to be used. A different approach has dominated government support in the United States, where tax incentives (e.g., the production tax credit (PTC), the investment tax credit (ITC), and accelerated tax depreciation) have been the primary policy tools employed. Most project developers are not in a financial position to absorb these tax incentives themselves, and so have had to rely upon a small cadre of third-party "tax equity investors" who invest in tax-advantaged projects in order to shield the income they receive from their core business activities (banking, for example). In doing so, these tax equity investors monetize the tax incentives that otherwise could not be efficiently used by project developers and other natural owners of the renewable energy plants.

The aggressive solar electric generating capacity expansion scenarios assumed in this Solar Vision study, along with the potential for solar heating and cooling technologies to meet end-use energy needs, will require large amounts of capital investment. The largest need for capital is for construction of utility-scale solar electric generating plants and distributed solar energy systems themselves, but significant capital also will be needed to finance the expansion of solar power's supply chain (production facilities for photovoltaic (PV) cells, solar thermal receiver tubes, mirrors, etc.), as well as transmission expansion. Solar generating plants are likely to be financed primarily using an array of project finance structures, transmission projects are likely to be financed by electric utilities or other transmission developers, while financing of the industry's supply chain likely will be dominated by conventional corporate balance sheet financing.

The primary goals of this chapter are:

- to inform and benchmark the finance-related assumptions (costs of capital, capital structures, capital recovery periods, etc.) used in the Solar Vision analysis process that evaluates the economics of the Solar Vision scenarios;
- to explore the feasibility of securing financing that is adequate, in terms of amount and cost, to realize the rapid capacity expansion envisioned in the Solar Vision scenarios; and
- to describe a set of key financial or finance-related principles that will be critical for designing policies aimed at realizing the goals of the Solar Vision.

The financing arrangements discussed in this chapter are primarily those that are currently in use for solar electric projects, or that are being considered for use in such projects in the near future. While the Solar Vision study also includes consideration of solar water heating and cooling (SHC) technologies, the market potential for these applications has not been studied as intensively as the application of solar electricity generation. In general these arrangements are transitional, in that they are financial approaches for sustaining the technology, given current and expected government incentive policies, until cost parity is achieved and the technology can attract capital on its own economic merit. Once this occurs, solar financing arrangements will likely become similar to those for conventional technologies.

9.2 Review of Finance-Related Inputs Used in the Solar Vision Analysis

Table 9-1 provides an overview of the financial assumptions used in the Solar Vision analysis for the deployment of residential-, commercial-, and utility-scale PV, as well as utility-scale concentrating solar thermal power (CSP). As discussed in Chapter 3, the Solar Deployment Systems (SolarDS) model was used to analyze the residential and commercial PV markets, and the Regional Energy Deployment System (ReEDS) model was used for utility PV and CSP, as well as for all other renewable and conventional generation technologies.

At this time, 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 later) that are common in the industry today. 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 20-year time horizon of the Solar 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 footnotes below Table 9-1.

Table 9-1. Solar Financing Assumptions

	SolarDS		ReEDS [1]	
	Residential (new / retrofit)	**Commercial**	**Utility PV**	**Utility CSP**
Inflation Rate	3%	3%	3%	3%
Loan Rate (real)	4.5% [2] / 6% [3]	4.5% [4]	4% [5]	4% [5]
Loan Term (years)	30 / 15	20	15	15
Debt Fraction	0% - 80% [6]	60%	60%	60%
Equity Rate (real)	N/A	N/A	11.7% [7]	11.7% [7]
Down Payment (Equity Fraction)	20% - 100% [6]	40%	40%	40%
Discount Rate (real)	N/A [8]	N/A% [9]	5.5% [10]	5.5% [10]
Depreciation	N/A	MACRS [11]	MACRS	MACRS
Federal Tax	25 - 33% [12]	35%	35%	35%
State Tax	by state	by state	5%	5%
PV/CSP Lifetime (years)	30	30	30	30

1. The financial assumptions in ReEDS for utility 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.
2. Based on a 20-year historical average of real U.S. 30-year fixed mortgage rates. Accessed January 20, 2010 at: http://www.freddiemac.com/pmms/pmms30.htm.
3. Based on a three-year historical average of real rates for $30,000 U.S. home equity loans. Accessed January 20, 2010 at: http://www.wsjprimerate.us/home_equity_loan_rates.htm.
4. Based on a 12-year historical average of real yields of corporate bonds rated Aa and A by Moody's. Accessed January 20, 2010 at: http://www.sifma.org/research/pdf/Moodys_Corporate_Bond_Yields.pdf.
5. 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).
6. Assumes that 80% of residential customers use a 20% down payment and 20% of customers use a 100% down payment (equivalent to a cash purchase).
7. 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).
8. SolarDS uses a simple payback time to adoption relationship for residential customers..
9. SolarDS uses a payback time to adoption rate for commercial customers that use the internal rate of return of future cash flows.
10. Reflects a nominal after-tax weighted average cost of capital (WACC) of 8.6%.
11. MACRS is applied to taxable commercial customers.
12. Assumes that 50% of residential customers are at a 25% federal tax rate and the other 50% are at a 33% federal tax rate.

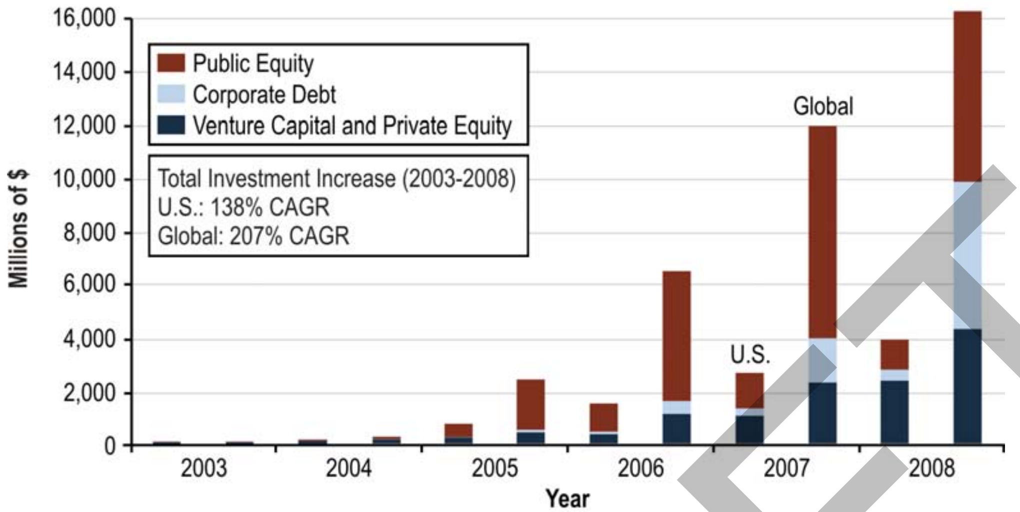
9.3 FINANCING THE SOLAR SUPPLY CHAIN (CORPORATE FINANCE)

The Solar Vision scenarios require that the global manufacturing capacity for PV and CSP grow significantly over the next twenty years. In 2008, there was 7.9 gigawatts (GW) per year of production capacity for PV and less than 1 GW per year of production capacity for CSP (Shah 2010 and Bullard 2009). In the 10% scenario, U.S. installations of PV and CSP are projected to grow to roughly 14 GW per year and 4 GW per year respectively. Assuming that U.S. shares of global PV and CSP demand trend respectively towards 20% and 33% by 2030, global manufacturing capacity would need to increase at a steady pace reaching roughly 85 GW per year for PV and 14 GW per year for CSP by 2030. In the 20% scenario, U.S. installations of PV and CSP are projected to grow to roughly 23 GW per year and 5 GW per year respectively. Again, assuming that U.S. shares of global PV and CSP demand trend respectively towards 20% and 33% by 2030, global manufacturing capacity would need to increase to about 140 GW per year for PV and 20 GW per year for CSP by 2030. While the investments required to finance these manufacturing capacity expansions are considerable, there is a sufficient amount of capital to do so. 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, private equity, public equity, and corporate debt. Venture capital (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, private equity (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 also be used to fund a company’s operations and expansions.

Figure 9-1 shows the dramatic increase in investment in the U.S. and global solar supply chain, including PV, CSP and SHC technologies, over the past five years. In 2003, there was just $52 million and $60 million invested in solar companies in the U.S. and globally, respectively. In 2008, solar supply chain investment reached almost $4 billion in the U.S. and over $16 billion globally, corresponding to five-year compound annual growth rates (CAGRs) of 138% and 207%. Such rapid expansion indicates the ability of the VC, PE, public equity and corporate debt capital markets to swiftly respond 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 2003 and 2006, for example, corporate debt accounted for between 3% and 7% of total global investment, while in 2008, over a third of total investment in solar companies came from corporate debt.

Figure 9-1. U.S. and Global Solar Supply Chain Investment*

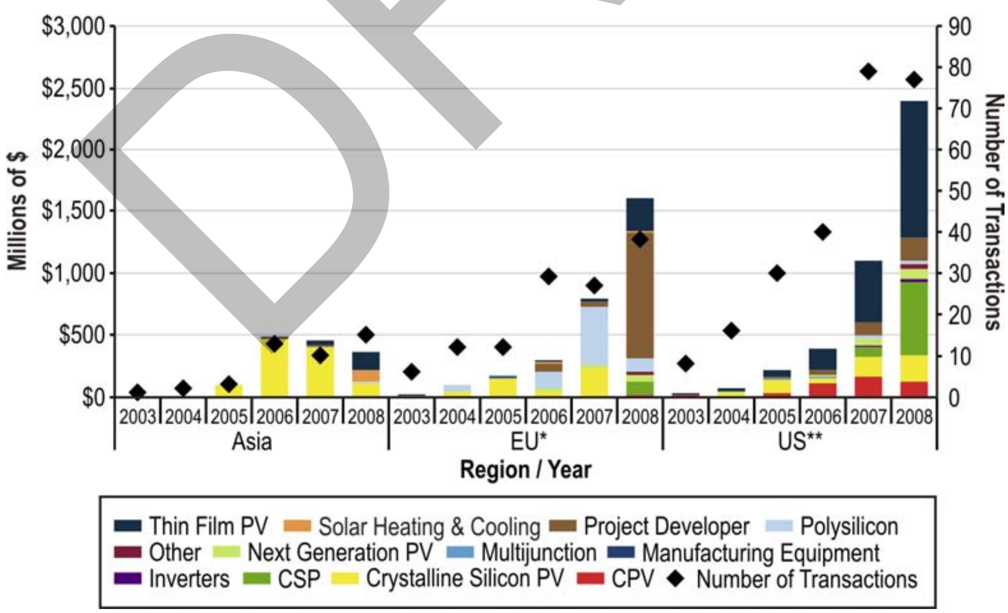


* Excluding government R&D investments

Source: New Energy Finance (2009); Jennings et al. (2008)

Figure 9-2 illustrates VC and PE investment in the solar supply chain, including PV, CSP and SHC technologies, 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 U.S. than in the European Union or Asia.

Figure 9-2. VC & PE Investment in the Solar Supply Chain



Source: New Energy Finance (2009); Jennings et al. (2008)

9

In terms of the capital expenditure (CapEx) requirements for scaling up production, the capital requirements for PV technology are the best understood. Thus here we focus on estimating the capital requirements for expanding the PV supply chain in line with the solar vision scenarios. We do not explicitly estimate the capital requirements for expanding the CSP and SHC supply chains; however, expanding these technologies is less capital intensive on a $/GW capacity basis as they have less technologically sophisticated supply chains compared to PV.

In the case of crystalline silicon PV, the major parts of the supply chain include: polysilicon production, wafering, cell processing, and module production. Accounting for the capital investment requirements across these manufacturing steps yields an estimated total CapEx of $1.5-2.5/W across the supply chain crystalline silicon module manufacturing. A number of thin-film technologies have lower CapEx requirements, on the order of $1/W. Over time, as crystalline silicon manufacturing matures, the emergence of vertically integrated and semi-vertically integrated manufacturing models (integrated ingot, wafer, cell manufacturing all in one factory) are expected to result in significant improvements throughout the supply chain, and subsequent reductions in the CapEx requirements for scaling up PV manufacturing.

Table 9-2 sums up the financing requirements of the PV supply chain in order to reach the Solar Vision deployment levels in the United States and a similar level of growth globally. An incremental investment of $30 billion would be required between 2010 and 2030 to reach a level of production sufficient to supply the U.S. market under the 10% scenario, with $55 billion required for the 20% scenario. Although this level of financing does not appear to be significant compared to U.S. investments in manufacturing generally, it is important to keep in mind that international (i.e., non-US) demand for PV will also be expanding over the vision period, requiring additional investment capital above and beyond that required by the Solar Vision. Assuming that U.S. demand as a percentage of overall global demand increases from 10% in 2010 to 20% in 2030 in the 10% and 20% scenarios, global production would need to expand to 70 GW per year and 115 GW per year by 2030 in the 10 and 20% scenarios, respectively. Under these assumptions, the 10 and 20% scenarios would require estimated global investments in PV manufacturing scale-up of $170 and $300 billion, respectively. Using the CapEx, economic life and utilization rate assumptions in Table 9-2, additional global investments of $55

Table 9-2. Cumulative Solar PV Manufacturing Investment Required in 10% and 20% Scenarios (2010-2030)

	10% Scenario (2009$)	20% Scenario (2009$)
United States	$30 billion	$55 billion
Rest of World	$140 billion	$245 billion
Global	**$170 billion**	**$300 billion**

Assumptions:

1) Manufacturing CapEx costs, in terms of annual production capacity, decline from $2.1/W in 2010 to $1/W in 2030
2) Average economic life of manufacturing equipment is 10 years
3) U.S. demand as percentage of overall global demand increases from 10% in 2010 to 20% in 2030 in both scenarios
4) 80% manufacturing utilization rate

billion and $85 billion would be required for scaling up CSP manufacturing in the 10% and 20% scenarios, respectively.[1]

9.4 FINANCING SOLAR DEPLOYMENT (PROJECT FINANCE)

The Solar Vision scenarios require installed solar capacity in the US to grow to 10% or 20% of total U.S. electric demand by 2030. To meet this vision, a substantial number of new solar projects must be developed and financed each year. Table 9-3 shows the installed GW of solar electric generating capacity and corresponding project financing requirement to achieve the Solar Vision scenarios. The investment requirements are based on the mid-range installed system cost projections presented in the Chapter 3. This does not include new transmission expansion, which will require an additional cumulative investment of $7B for the 10% case and $18B for the 20% case above the reference cases. These estimates are in constant 2009 dollars, but they are not discounted because the intent is to show the total quantity of financing that must be raised, at today's price level.

Table 9-3. Installed GW and Corresponding Investment Requirements, by 2030[2]

Target	GW Solar Electric	Investment (2009 $B)
10%	180	$490
20%	303	$850

In the remainder of this section we explore the feasibility of, and potential options for, raising the required project-specific financing to achieve the 10% and 20% Solar Vision goals. First we discuss the current financial incentives and financing structures that support U.S. solar projects, both on the utility-side and customer-side of the meter. Next, we explore emerging solar project financing structures that may propagate to support solar in the coming years. Then we investigate tax equity investors as the main mechanism to drive new solar project development, and highlight the limitations of relying on these market participants. Finally, we examine the financing requirements for transmission improvements and expansion, to meet the Solar Vision goals.

9.4.1 CURRENT FINANCIAL INCENTIVES AND STRUCTURES

Financial incentives for solar projects in the U.S. are provided by the federal government, as well as by state governments and in some cases local utilities.

[1] CSP supply chain investment estimates also assume that manufacturing capital expenditure costs (in per Watt terms) change in proportion to CSP capacity factors, as higher capacity factors will require larger solar fields and greater amounts of thermal storage.

[2] The GW and financial requirements for the 20% case are not simply double those of the 10% case primarily because the base to which the percentage penetration is applied (US electricity generation) is assumed to grow between 2009 and 2030 in the 10% case, whereas no growth is assumed in the 20% case (i.e., generation is assumed to remain at 2009 levels through 2030). Also, projected capacity factors for solar in the 20% case are higher than in the 10% case.

Federal incentives have historically been provided primarily through the U.S. tax code, in the form of an ITC which applies to both residential and commercial installations, and accelerated 5-year tax depreciation which applies only to commercial installations. Thus for commercial installations, the present value of the combination of these two incentives – which can only be used by tax-paying entities – amounts to roughly 50% of the installed cost of a solar project (Bolinger 2009). These federal benefits can be used in combination with state and local incentives, which come in many forms, including (but not limited to): upfront rebates, performance-based incentives, state tax credits, renewable energy certificates (RECs) 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. Further, incentive levels also vary by type of technology; e.g., solar PV v. SHC.

In most cases, solar projects need to combine several of these federal, state, and local incentives together in order to be 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 U.S. such as low-income housing, historical buildings, and commercial wind projects. These structures are described below. First we discuss structures that can be used to finance solar projects that are interconnected on the utility side of the meter. Then we discuss structures that can be used to finance solar projects that are interconnected on the customer side of the meter.

Utility Side of the Meter

Although a number of utility-scale[3] CSP projects were built in California during the 1980s (and are still operating), for the most part the proliferation of large solar projects interconnected on the utility side of the meter has been a relatively recent phenomenon. For example, several multi-megawatt (MW) PV projects and one 64 MW CSP project were built in the U.S. in 2007, with a few additional utility-scale PV projects completed in 2008 and 2009. In most cases, these projects are owned by independent power producers (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 – cash proceeds from the purchase of power or lease of equipment from the site host, allocation of the ITC or cash grant from the US Department of Treasury 1603 Grant Program, depreciation benefits and RECs -- among the various project investors and the project developer to optimize each parties return and exposure to risk and desired long-term owning the solar assets. 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

[3] Solar projects on the utility side of the meter are often referred to as utility-scale projects because they tend to be large (multi-MW) in size. However, distributed utility-scale generation, sometimes called wholesale distributed generation (DG), also often falls under the 'utility side of the meter' catergorization. In addition, utilities may explore other distributed level opportunities in the future that are also on the utility side of the meter.

consuming as they involve multiple attorneys, accountants professional and other 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.

To date most solar projects interconnected on the utility side of the meter have been financed by IPPs using one of these 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 on its balance 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 power purchase agreements as debt-equivalent obligations, which means that an over-reliance on PPAs may negatively impact a utility's debt rating. Finally, with the cost of solar power expected to decline rapidly in the coming years, the importance of the role of the ITC and accelerated depreciation should not be discounted. In that the cost of a solar installation today is higher than the utility can foresee in the near future, the utility can anticipate lower project costs. Absent the tax incentives, a regulatory commission might question retroactively why a utility would have agreed to sign a PPA or even own directly a solar project knowing the costs are likely to be coming down. As such, the risk of a 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 projects.

Now that utilities are able to access the ITC (a change resulting from October 2008's *Energy Improvement and Extension Act*, H.R. 1424, and discussed in more detail in Section 10.3.1 of this report), utility ownership of solar projects interconnected on the utility side of the meter is becoming more common. There are compelling reasons for utilities to own solar assets. 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.

Alternately, the capital can be 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.

There are also benefits to utility ownership in terms of maximizing the value of the energy output. By owning the asset, utilities can directly offset their wholesale energy procurement obligation with the energy produced by the solar resources.

Because solar is an as-available, real-time resource, it is typically a price-taker, receiving the wholesale hourly market clearing price in deregulated states. This allows it to capture more value for the bulk of its energy, which is typically produced during peak hours.

While extending the ITC to utilities has increased their interest in investing in solar, there are still some potential regulatory roadblocks that could prevent utilities from fully capturing these tax benefits. In particular, regulators may require that the ITC be amortized over the life of the facility (a process called "normalization"), deferring the tax benefit and diluting the incentive intended under the Federal tax code.

Customer Side of the Meter

Although utility-scale solar power projects (using both PV and CSP technology) are becoming more common, to date most solar electric systems have been installed "behind the meter" (i.e., on the customer, rather than utility, side of the meter). These customer-side of the meter systems have been installed in both residential and non-residential applications and have primarily used PV and SHC technology. 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 9-4 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 three sectors (residential, non-residential taxable, and non-residential tax-exempt). Prior to 2006, almost all behind-the-meter PV projects were self-financed.

Table 9-4. Categorization of Financing Approaches for Behind-the-Meter PV Projects

<table>
<tr><th colspan="2" rowspan="2"></th><th>Residential</th><th colspan="2">Non-Residential</th></tr>
<tr><th>Taxable</th><th>Taxable</th><th>Tax-Exempt</th></tr>
<tr><td rowspan="2">Self-Financed</td><td>Equity (Cash)</td><td>cash savings</td><td rowspan="2">balance sheet finance</td><td>internal funds or reserves</td></tr>
<tr><td>Debt</td><td>mortgage;
home equity loans;
property tax loans</td><td>bank loans;
muni bonds;
CREBs</td></tr>
<tr><td rowspan="2">Third-Party-Financed</td><td>Lease</td><td>operating lease</td><td>operating lease</td><td>N/A</td></tr>
<tr><td>Service Contract (PPA)</td><td>not as common as lease</td><td>more common than lease</td><td>very common</td></tr>
</table>

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 (starting in 2006) in the federal investment tax credit 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 operation 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. While the contract itself is similar to PPAs 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 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) in the case of a solar service contract, system operations and maintenance are the responsibility of the 3rd party owner. 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). Third-party financing options have only recently begun to make inroads in the residential sector.

9.4.2 EMERGING SOLAR PROJECT FINANCING STRUCTURES

In addition to the more-prevalent solar project financing structures described above, there are three emerging project financing structures that have not yet been widely used to finance solar projects in practice. These include: pre-paid service contracts, property assessed clean energy tax finance, and on-bill financing.

Pre-Paid Service Contract

A "pre-paid service contract" is similar to a regular service contract (or PPA) between the project owner and a tax-exempt governmental offtaker (i.e., power purchaser) as described above, with one important exception: the governmental offtaker issues tax-exempt debt and uses the proceeds to pre-pay a significant portion of the power to be delivered. Because the project effectively benefits from both low-cost, tax-exempt debt financing and the private sector tax benefits generated by the project, the effective cost of power under a pre-paid service contract can be significantly lower than under other financing options (Bolinger, 2009). Although several large wind projects built since 2007 have used pre-paid service contracts, this financing structure has been slower to catch on with solar projects. To date it has been difficult to justify the use of this rather involved and complex structure for relatively small PV projects (as opposed to larger wind projects). As larger utility-scale PV and CSP projects continue to proliferate, however, the pre-paid service contract may gain favor among developers negotiating with tax-exempt governmental offtakers.

Property-Assessed Clean Energy (PACE) Finance Programs

In PACE programs municipal financing districts lend the proceeds of bonds (or other funds) to residential property owners to finance end-user renewable energy and energy efficiency improvements. The property owners then repay these loans over 15 to 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 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. Programs now exist in a number of California jurisdictions (including Palm Desert, and Sonoma County), as well as in Boulder (Colorado), Annapolis (Maryland), and Babylon (New York), to name just a few. Since all of these programs are relatively new, however, it is too early to judge the success and likely impact of the PACE model.

On-Bill Financing

On-bill financing is a relatively new form of financing that combines a state subsidy (e.g. upfront rebate, interest rate buy-down, etc.) with a loan from the electric utility. The goal is to reduce or eliminate the upfront 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 long enough – and with a low-enough interest rate – to create cost savings from the first day (Brown 2009b). To date, this mechanism has been used only for energy efficiency and there are not any known applications for solar (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 vs. a financing product; and the need to update utility billing systems to allow for automated and electronic management of on-bill loans.

9.4.3 The Limitations of Relying on Tax Equity to Drive New Project Development

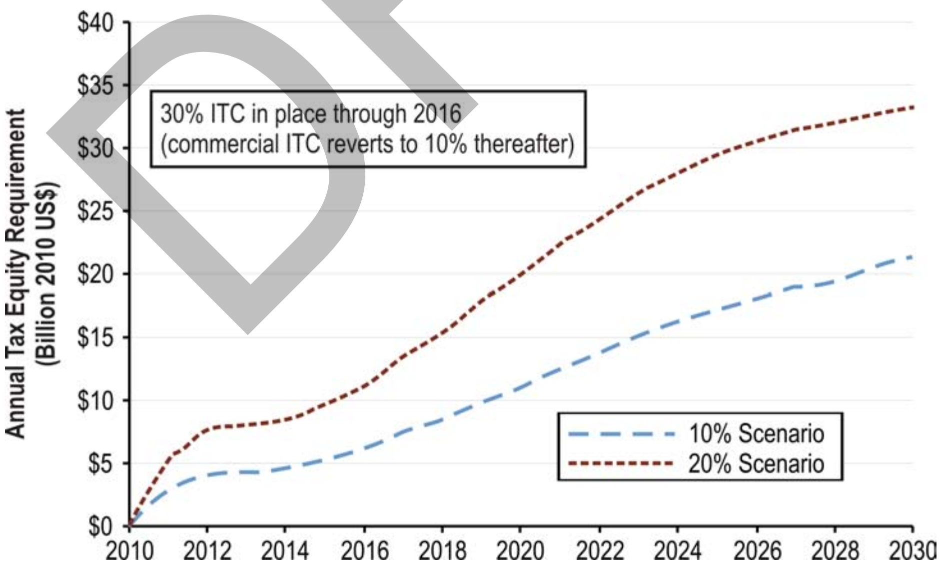
Many of the financing structures described in the previous section rely on an ongoing supply of third-party tax equity. As revealed by the financial turmoil in recent years, it may be difficult to raise the amount of capital required to finance the build-out of the Solar Vision if the market continues to rely so heavily on tax equity. In fact, there were signs that the market may have been bumping up against a tax equity ceiling in 2008, even prior to the onset of the global financial crisis that has decimated so many investors' tax appetites. Roughly $5.5 billion of tax equity was invested in renewable power projects in 2008, up only slightly from $5.4 billion in 2007 (Hudson Clean Energy Partners, 2009). This marginal 2% increase in tax equity investment stands in stark contrast to the robust 63% growth in both wind and solar capacity installed in the US in 2008 relative to 2007, and suggests that the tax equity market has been hard-pressed – even during relatively good times – to raise more than $5.5 billion devoted to renewables.

Of course, in the wake of the global financial crisis that culminated with the outright demise of several prominent tax investors, while leaving most others greatly enfeebled, the tax equity market as a whole is now considerably weaker than it was in early 2008. By several accounts, only a handful of tax equity investors remained active in renewables in 2009, down from nearly twenty at the height of the market in 2008. Though conditions began to improve in the second half of 2009, tax equity investment is not expected to exceed 2008 levels in 2009, despite considerable demand for such investment.

It is possible that new tax equity investors could enter the market to make up some of the shortfall. For example, as a result of the October 2008 stimulus package, investor-owned utilities are now able to access the 30% ITC. UBS (2008) estimates that the top thirty investor-owned utilities in the United States have the combined tax capacity to invest up to $2.2 billion of tax equity in solar in 2010 (assuming that they commit 10% of their tax base to the solar market). Other potential investors include hotel chains and high-tech companies, e.g., recently Google announced that it will begin to invest its own capital in renewable energy projects Fehrenbacher 2009).

Even if the tax equity market does expand significantly from 2009 levels, through an influx of new investors and/or a return of former investors, it will be hard-pressed to finance the growth required under the Solar Vision. Figure 9-3 shows the annual tax equity requirement for both the 10% and 20% solar penetration scenarios. It assumes that 1) 70% of new solar capacity will require tax equity and 2) that among those projects requiring tax equity, tax equity will finance 70% of total installed

Figure 9-3. Estimate of Tax Equity Required to Finance Solar Vision*



*Estimate assumes that 70% of capacity requires tax equity, and that tax equity accounts for 70% of installed costs

9

costs.[4] As shown, the 10% scenario will require roughly $5 billion per year of tax equity investment just for solar by 2014, increasing significantly thereafter. The 20% scenario has an even larger solar requirement, particularly in later years. Obviously, wind and other renewable technologies (e.g., geothermal and biomass) will also be competing for tax equity investment over this same period.

Presuming that the tax equity market is able to return to its former level of 2008 ($5.5 billion/year), that utilities enter the market in force (e.g., $2.2 billion/year per UBS estimate), and that other new investors also make significant contributions (e.g., $2 billion/year from others), the total size of the tax equity market could grow to roughly $10 billion/year in relatively short order. Even under this optimistic scenario, however, $10 billion/year is not enough to finance the market expansion envisioned by just the wind and solar industries, let alone other renewable technologies (e.g., geothermal and biomass). Specifically, of the $5.4 and $5.5 billion of tax equity invested in renewables in 2007 and 2008, respectively, roughly $5.2 and $5.0 billion went to wind power (Hudson Clean Energy Partners, 2009). With the 10% solar scenario requiring another $5 billion per year (Figure 9-3), wind and solar alone could tap out the entire tax equity market in the years ahead, while still leaving some portion of demand unfulfilled.

This elementary analysis suggests that in order to meet the financial requirements of even the 10% Solar Vision scenario, the market will likely need to transition away from such a heavy reliance on tax equity investors. As such, it is worth exploring federal policy options that could significantly broaden the sources of investment capital for renewable power development during its transition to cost parity with conventional sources of generation.

9.4.4 FINANCING TRANSMISSION FOR THE SOLAR VISION

The nation's transmission infrastructure will need to be reinforced and expanded to accommodate the 10% and 20% Solar Vision goals, given that high-quality solar resources often are remote from power consumption centers. Technical aspects of Solar Vision’s transmission requirements are discussed in some detail in Section 7.3.2 of this report.

Analysis for the 10% and 20% solar cases, relative to the reference case, indicates that achieving the Solar Vision goals will require expansion of the national transmission infrastructure through 2030 by about 7,900 GW-miles and 21,100 GW-miles respectively. If one considers that a 500 kilovolt (kV) line can carry about one GW of power, these transmission expansions represent transmission additions equivalent to about 400 to 1,100 circuit-miles of 500 kV line each year through 2030. Typical high-voltage transmission system expansion in the U.S. over the last decade has totaled about 1,000 circuit-miles per year, mostly at voltages lower than 500 kV. Only about 3,000 miles of transmission lines 230 kV or higher have been installed nationally since 2001, with only about 20% of that crossing state lines. The transmission capacity expansion needed to accommodate the Solar Vision goals thus is ambitious relative to past experience in the US.

[4] These assumptions are more conservative than some used by others. Hudson Clean Energy Partners (2009), for example, assumes that 76% of all solar capacity requires tax equity, and that tax equity finances 100% of project costs. We reduce the 100% assumption down to 70% here, in order to account for the potential impact of the 30% cash grant program.

As mentioned in Section 9.4, the cost of this (transmission) expansion, in estimated 2009 $ billions, is about $7B for the 10% case and $18B for the 20% case, on a cumulative basis relative to the respective reference cases. These are large absolute numbers, but this investment is relatively small compared with the generating project investment needed to achieve the Solar Vision scenarios. Transmission investment would be only 1% to 2% of the total investment required to implement the solar projects themselves. Funding these investments through sources including electric utilities, regional transmission companies, merchant transmission developers, and generators seeking interconnection will likely be readily obtainable if regulatory approvals for construction can be obtained.

Regulatory approvals are a larger challenge than financing. Approvals often are difficult to obtain due to lack of consensus among local, regional, and national units of government. Some progress has been realized on this front, such as the Regional Renewable Energy Zone proposals proposed in Texas and various parts of the West, and such as the Tehachapi process in California. The latter involved policy-makers (CAISO and FERC) cooperating with local participants to approve a $1.8B 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) Similar arrangements can be contemplated for expansion of solar generating capacity.

9.5 FUNDAMENTAL FINANCIAL PRINCIPLES CRITICAL TO ACHIEVING THE SOLAR VISION

9.5.1 FINANCIAL PRINCIPLES DEFINED

Achieving the Solar Vision scenario goals will require a re-thinking of existing financial frameworks. To date tax-based federal incentives combined with a broad range of state incentives have provided sustenance for a modest but growing US solar energy industry. As discussed above, tax-based incentives are relatively inefficient and will be inadequate to drive the growth envisioned in the solar vision scenarios. With this in mind, there are several fundamental principles to consider when designing a financial framework for growing a strategic industry such as the solar industry. These principles include the following: employ mechanisms that will aid the transition from public to private financing over time; provide long-term, stable policies; provide investors with stable and adequate returns; allocate project risk efficiently and compensate project risk fairly. Each of these principles will be discussed in more detail below.

The transition from public to private financing: Solar energy assets are long-lived, with useful lifetimes on the order of 30-40 years. These assets require high up-front capital outlays, but little in the way of long-term operating expenses. Investment appetite is based upon returns, the availability of capital, and asset liquidity. Most importantly, expected cost reductions, along with expected increases in the costs of conventional generation (including the possible impacts of carbon taxes), are likely to make solar energy assets economically viable on a stand-alone basis in the not-too distant future. This last point engenders confidence that public financing of the solar energy industry will not be open-ended, and that private markets will gradually take up the financing mantle as the industry grows, unsubsidized investment returns are met, and large-scale industry financing mechanisms mature.

The need to provide long-term, stable policies: Policy instability and a short-term focus can drive financing and installed system costs up, and severely retard growth in the manufacturing base, distribution infrastructure and installation networks that are intrinsic elements of a steadily growing market. Public policy can be structured to incentivize sustainable growth in an industry by providing a stable policy environment with a long-term time horizon. Such a policy framework will help to provide stability through business cycles and other unanticipated events and changes in market conditions.

Provide investors with stable and adequate returns: During the transition from public to private sector driven financing adequate project returns can be met with a myriad of incentives. Based on historical returns across many different industries, project returns initially in the range of 8% to 12% should be sufficient to ensure a broad enough investor base to drive growth in an emerging industry. Currently a mix of Federal, State and local incentives (along with available solar resource and local energy prices) are sufficient to meet these types of hurdle rates in a number of locations throughout the U.S. Additional incentives, like guaranteeing a lower cost of capital and supplemental production-based incentives, could help to ensure stability through difficult economic times. However, it is important to note that as the installed cost of solar assets declines, returns will increase, and return-based incentives should correspondingly decrease. Ultimately, investment returns will rest on stand-alone solar energy economics and be sufficient to drive growth in the industry absent public money.

Allocate project risk efficiently and compensate project risk fairly: Deploying new technologies involves risk, which raises the cost of capital and negatively impacts investment returns. Loan guarantees are a means to partially mitigate these risks, constraining the cost of capital by shifting some of the risk to the loan guarantor. Ideally, some amount of risk should remain with the project owners/investors, but to accept increased risk, a higher return is typically required. Quantifying this “higher” return is difficult in the absence of years of empirical data, but more direct means of risk compensation like insurance instruments could enable risk to reside with the project owners/investors and provide for a fair investment return. These types of insurance instruments are in their nascence, are being offered by a select few global re-insurance firms, and could be supplemented via a public offering.

9.5.2 POTENTIAL POLICY OPTIONS THAT MEET THE FINANCIAL PRINCIPLES

There are a number of concrete policy options that conform to most of the guiding principles discussed above. These include cash incentives, loan guarantees and insurance instruments, feed-in tariffs, and the proposed federal clean energy bank. Most of these have been implemented in various states or countries, with real-world experience to draw upon, while others are more theoretical. The first to be discussed – shifting from tax to cash incentives – is currently being tested at the federal level in the United States, as a result of stimulus legislation implemented in 2009.

Cash Incentives

Compared to tax credits of the same amount, cash incentives allow for simpler, less expensive financing of solar projects and attract a larger pool of potential investors. The American Recovery and Reinvestment Act of 2009 allows, for the first time in the United States, eligible non-residential solar projects to choose between the 30% ITC and a 30% cash grant of equivalent face value (e.g., the grant is purposely not taxed as income at the federal level, in order to mimic the value of the 30% ITC). This choice is intended to reduce the solar industry's reliance on third-party tax equity investors, many of whom dropped out of the solar finance market in late 2008 as their tax base was decimated by the global financial crisis. In this sense, the choice to elect a cash grant rather than the ITC is only a half-step, since tax equity investors may still be required to monetize the value of accelerated tax depreciation, and since the ability to elect the grant is only temporary.

Nevertheless, this policy shift has been largely welcomed by the industry. It is also worth noting that some of the regulations surrounding the cash grant are more favorable to certain financing structures than are the rules that apply to the ITC. For examples, the ITC is subject to passive credit limitations, which restrict the ability of certain investors (primarily individuals or partnerships consisting of individuals) to make efficient use of the ITC. The cash grant, however, is not subject to these passive credit limitations. Similarly, if a community solar project can capitalize 30% of installed costs with a cash grant from the federal government, then presumably fewer investors will be needed to fully finance the project, which may allow the project to more easily qualify for certain exemptions from securities registration allowed by the Securities and Exchange Commission. In these ways, the true value of the 30% cash grant to certain solar projects may well exceed its face value.

For additional information on direct cash incentives, which have been used extensively by states and utilities, see Section 10.2.2 on Financial Incentives.

Loan Guarantees and Insurance Instruments

Policy instruments such as loan guarantees and insurance instruments could mitigate project risks like (1) stranded assets – in which the solar energy generating asset is still fully functional, but the counterparty responsible for electricity or gas payments defaults, and (2) new technology risk – in which the perceived or real risk of employing a new technology demands a higher investment return, effectively raising the cost of capital and lowering the return on a project.

Loan guarantees can overcome stranded asset risk, enabling repurposing of the asset, but any such program must be streamlined and should be governed by predetermined metrics for applicability. Once eligibility metrics are met, projects should be automatically approved for the loan guarantee program. The efficacy of any such program would be dependent on default rates. Loan guarantees could also address new technology risk, but with no data on default rates, program costs could conceivably be high.

For additional information on the DOE Loan Guarantee Program, see Section 10.2.2 on Financial Incentives.

Insurance instruments, however, could insure against new technology failures. Insurance instruments could be provided by the government, or sourced from a private company and paid for by the government. The purpose of the insurance instrument would be to increase the investment return for the project owners to compensate for the technology risk they would retain. Pricing of such instruments is presently in its infancy for the solar energy industry.

Ultimately, when stranded asset and technology risk costs are better profiled with data, the costs of such programs could be built into the rate base. Geography and a fragmented industry, however, could make equitable distribution across the rate base difficult.

Feed-In Tariffs

As further described in the Section 10.2.2, feed-in tariffs (FITs) typically offer guaranteed, long-term, performance-based cash payments to renewable energy project owners for the total electricity produced.

As demonstrated in Europe, FIT policies can (if they are well-designed) meet the investment policy principles defined above: FIT payment levels decline over time in order to facilitate the transition from public to private financing as technology cost decrease; FIT payment levels can be pre-specified over multiple years providing a long-term and stable environment for market growth; FIT payments can be based on actual project costs and set to provide a stable, adequate return to investors; FIT payments can be differentiated by technology, size of project and potentially other factors to fairly account for risk.

As with any policy, FIT policies have distinct advantages and notable challenges. In terms of advantages, FIT policies are performance-based incentives that encourage optimal output from eligible facilities, because project owners are paid only if they generate power. A growing body of European research is beginning to show that FIT policies have fostered RE development at a low cost per kWh (Butler and Neuhoff 2008; Fouquet and Johansson 2008; IEA 2008; Menanteau et al. 2003). Finally, FIT policies have been credited with encouraging a strong flow of investment capital to the German solar market.

One of the challenges to implementing FIT policies in the U.S. is the high total public cost burden, as demonstrated by experience in Germany and Spain. The total payment under Germany's FIT policy (for all renewable technologies) was just under €9 billion in 2008, compared to just under €4 billion in 2004 (BMU 2009). While these payments supported about 72 TWh of renewable generation in Germany, the payment levels are expected to increase as more generation is added, creating an even larger funding burden. If this level of investment is considered to be too high in the U.S., the long-term sustainability of the policy could be called into question.

Another challenge is that there are state-federal jurisdictional issues in the United States. Based on current U.S. law, there are only rare instances when a FIT policy can be automatically offered to project owners/developers, without any subsequent applications or approvals (at the state or federal level) (Hempling et al. 2010). Therefore, while FIT policies can meet the investment policy principles outlined, the cost may be considered too high and the administrative burden may be too great (under existing federal law) to justify implementation.

Federal Clean Energy Bank

A federal clean energy bank, which does not currently exist but has been proposed in legislation, would support the deployment of solar and other clean energy technologies by ensuring the availability of project capital and decreasing financing cost.[5] Given the scale of total project investment required to achieve the 10% and 20% Solar Vision scenarios, the availability of sufficient project capital is critical. In the early years, a federal clean energy bank could ensure that capital is available for projects using new technologies, which may not be the case in a risk-averse lending environment. Even during the global financial crisis, Germany was able to substantially increase annual PV installations from 2008 to 2009, in part, due to its government-owned KfW bank providing the adequate capital. A federal clean energy bank would also be able to lower the cost of debt financing, which may be quite high for new technologies, and thus allow for sufficient investor returns.

9.6 SUMMARY/CONCLUSIONS

The Solar Vision presents an ambitious plan for a rapid and substantial scale-up of solar energy deployment in the United States. Financing such an expansion will require significant new investment, in both the solar manufacturing supply chain and in solar energy projects (e.g., PV, CSP, and SHC projects). Attracting adequate investment to finance the required growth of the solar supply chain is unlikely to be a problem, as the mechanisms through which to do so are generally well-developed and liquid. Similarly, financing the necessary transmission is not expected to be a problem – the larger challenge with respect to transmission will be regulatory approvals. On the other hand, financing the envisioned deployment of solar projects could be more challenging, particularly if the market continues to rely principally on third-party tax equity investors. Based on simple projections, there does not appear to be adequate third-party tax equity to finance the growth of the market in the 10 or 20% solar vision scenarios. As a result, a re-evaluation of the use of federal tax incentives – and the complex financing structures required to monetize these tax incentives – as a means to stimulate solar deployment is warranted.

Several fundamental financial policy principles should be at the forefront of any discussion of how the U.S. might transition away from the current tax-based incentive regime to a more sustainable and scalable approach. Specifically, financial incentives should:

[5] The creation of the Clean Energy Deployment Administration was included in both the American Clean Energy and Security Act of 2009 (H.R. 2454), passed by the House of Representatives, and the American Clean Energy Leadership Act of 2009 (S.1462), passed by the Senate Energy and Natural Resources Committee.

- Anticipate and facilitate the transition from a publicly financed to a privately financed industry;
- Be long term and stable, but not open-ended;
- Be sustainable and scalable - sufficient to entice investment, but not excessive, and sufficient to encourage large scale implementation; and
- Strive to reduce risk and facilitate risk allocation to project owners.

Several examples of policies that merit consideration under these principles include cash (rather than tax) incentives, loan guarantees or new structured insurance instruments, feed-in tariffs, and creation of a federal clean energy bank.

As solar reaches economic parity with other conventional sources of energy, it will progressively require less public support and be able to tap into mainstream financial instruments to finance its growth. Until then, government incentives and subsidies will be required to support the deployment of solar. In the mean time, policymakers can facilitate the ultimate transition to private, mainstream finance by adopting incentives that adhere to the policy principles listed above, and that do not require solar financiers to devise and enter into complex arrangements in order to capture their value.

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