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Author

Bolinger, Mark A

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Third-Party Finance for Commercial Photovoltaic Systems: The Rise of the PPA

Mark Bolinger, Lawrence Berkeley National Laboratory

1. Introduction

Installations of grid-connected photovoltaic (PV) systems in the United States have increased dramatically in recent years, growing from less than 20 MW in 2000 to nearly 500 MW at the end of 2007, a compound average annual growth rate of 59%.¹ Of particular note is the increasing contribution of “non-residential” grid-connected PV systems – defined here as those systems installed on the customer (rather than utility) side of the meter at commercial, institutional, non-profit, or governmental properties² – to the overall growth trend. Although there is some uncertainty in the numbers, non-residential PV capacity grew from less than half of aggregate annual capacity installations in 2000-2002 to nearly two-thirds in 2007.³ This relative growth trend is expected to have continued through 2008.

This article, which is excerpted from a longer report,⁴ focuses specifically on just one subset of the non-residential PV market: systems hosted (and perhaps owned) by commercial, tax-paying entities. Tax-exempt entities (e.g., non-profits or municipalities) face unique issues and have different financing options at their disposal; readers interested in PV financing options for tax-exempt entities can find more information in the Bolinger report.

2. Policy Drivers

The growth of commercial PV, and the evolution of commercial PV finance in the United States, has been very much driven by federal and state policy incentives. In combination, these incentives provide a significant amount of value to commercial PV systems, yet this value is delivered through a variety of sources and mechanisms. At the federal level, policy support for the deployment of commercial PV has been concentrated within the Internal Revenue Code (“the Code”), in the form of an investment tax credit and accelerated tax depreciation (together, referred to as a project’s “tax benefits”).

A. Federal Investment Tax Credit

Section 48 of the Code provides an ITC for certain types of energy projects, including “equipment which uses solar energy to generate electricity.” Though historically (through 2005) equal to 10% of the project’s “tax credit basis” – i.e., the portion of system costs to which the ITC applies (typically 100% of installed costs, but reduced by the amount of any non-taxable cash incentives received) – the ITC was increased to 30% in 2006 and, unless altered by future legislation, will remain in place at the 30% level through 2016. The credit is realized in the year in which the PV project begins commercial operations, but vests linearly over a 5-year period. Thus, if the project owner sells the project before the end of the fifth year since the start of commercial operations, the unvested portion of the credit will be recaptured by the IRS.

B. Accelerated Tax Depreciation

Under Section 168 of the Code, “equipment which uses solar energy to generate electricity” qualifies for 5-year, 200 percent (i.e., double) declining-balance depreciation. Such equipment may also qualify for 50% bonus depreciation if placed in service in 2008-2010 and other requirements are met. In most cases, 100% of a PV project’s “depreciable basis” (i.e., the dollar amount to be depreciated) will qualify for this accelerated schedule. However, the project’s depreciable basis must be reduced by the amount of

any non-taxable cash incentives received (this is not likely to be a common occurrence, since most cash incentives provided to non-residential PV systems will be taxable). Moreover, Section 50 of the Code requires that the depreciable basis also be reduced by one-half the amount of the Section 48 ITC. Thus, a commercial PV project taking the ITC will, in most cases, be able to depreciate 85% (=100% - 0.5 * 30%) of the project's installed cost for tax purposes, using a 5-year MACRS schedule.

In addition to the federal support described above, many states, municipalities, and utilities offer incentives for the deployment of PV. Although the scope and breadth of these incentives vary considerably from state to state and program to program, they fall into five basic categories:⁵

C. Cash Incentives

The most commonly cited state-level programs supporting PV deployment are those that provide cash incentives for system installation. Historically, these programs (often known as “buy-down” or “rebate” programs) have offered primarily up-front, capacity-based incentives (CBIs), which provide a certain dollar amount per installed Watt (W) of PV upon proof of installation. More recently, to encourage better system performance, some of these state PV programs (most notably in California) have begun to transition away from CBIs to what are known as production- or performance-based incentives (PBIs). Unlike CBIs, PBIs do not provide up-front cash on a \$/W basis; rather, they provide ongoing cash payments on a \$/kWh basis over a pre-determined period (e.g., 5 years).

D. State Tax Incentives

Though not as common as cash incentives, a number of states have enacted investment or production tax credits to support customer-sited PV. Many other states exempt purchases of PV systems from sales tax, and/or provide property tax exemptions or reduced assessments.

E. Set-Asides or Multipliers within State Renewable Portfolio Standards

In addition to, or instead of, providing cash and tax incentives for PV installations (or PV-generated power), a number of states encourage the deployment of solar (including PV) as part of a renewable portfolio standard, or RPS. Simply put, an RPS is a requirement that retail electric providers operating within a given political jurisdiction include a minimum amount of qualifying renewable power within their energy mix. As of January 2009, 28 states plus the District of Columbia had an RPS in place, and 17 of these RPS policies specifically encourage the use of solar power (including PV) through the use of set-asides or multipliers for solar power (or distributed generation more broadly).⁶ A federal RPS has also been debated in Congress on several occasions, but so far has never progressed beyond the conference committee.

F. REC Markets

Load-serving entities subject to state RPS policies often demonstrate their compliance using what are known as renewable energy certificates (RECs). A REC is a financial instrument that represents the particular attributes of the underlying form of power generation. A unique commodity, RECs can be bundled and sold along with the underlying power, or else stripped off and sold separately from the commodity electricity. Although the precise value of a REC is typically determined by the market forces of supply and demand, RECs derive their value (whatever it may be) primarily from the underlying RPS policies that use RECs as a form of currency;⁷ as such, RECs are very much an instrument of policy.

G. Net Metering

Net metering is a policy tool that enables utility customers with qualifying forms of onsite generation not only to interconnect with and draw power from the grid when on-site power consumption exceeds on-site power generation, but also to feed power back into the grid when the reverse is true. When the latter occurs, the customer's electricity meter literally spins backwards, thereby crediting the onsite generation at the customer's retail price of electricity. If, on a net basis during a given month, a customer/generator produces more power than it consumes, the amount of "net excess generation" is typically rolled forward and credited to the next month's bill. As of January 2009, 44 states plus the District of Columbia offered some form of net metering.⁸

3. Viable Financing Structures

Site hosts and project sponsors differ in their ability to make full and efficient use of this patchwork of federal and state incentives for PV (e.g., a commercial entity with limited tax liability may not realize much value from a project's tax benefits). Thus, as the value of such incentives has increased over time (e.g., the federal ITC increased from 10% to 30% in 2006), several different financing structures have emerged and evolved as a way to maximize incentive capture while minimizing risk. Some of these structures involve third-party ownership, where a financial institution with a significant income tax burden (such as an investment bank or insurance company) owns most or all of the project in order to reap its tax benefits. Such investors are referred to as "tax equity investors" (or just "tax investors").

A. Balance Sheet Finance

Only a few years ago, a commercial site host wishing to utilize PV power had only one viable option: to purchase a turnkey system from a PV project developer. This basic finance model is still in use today. Project-level debt may be available (e.g., from a bank) to help finance the purchase, but more likely the project is capitalized on the site host's balance sheet, using some internal mix of corporate-level debt and equity. The site host benefits not only from avoided electricity costs and REC revenue (should it choose to sell its RECs), but also from any state CBIs or PBIs, as well as the project's tax benefits (presuming it has sufficient tax appetite to make use of them).

Though relatively straightforward, this traditional finance model suffers from the primary adoption barriers facing PV. Specifically, most commercial site hosts do not consider electricity generation to be a part of their core business, and must ascend a steep learning curve in order to gain sufficient comfort with the idea of self-generating a portion of their electricity needs with PV. They may also be easily put off by the high up-front cost of PV, as well as the technology and performance risk that comes with ownership. Finally, even site hosts that are able to get past these hurdles may still not be in a financial position to make efficient use of the project's tax benefits, which can greatly impinge upon project economics.

B. Leasing

In this third-party-ownership structure, a leasing company owns the PV system and leases it to the site host (the lessee) over a period of years. During this lease term, the site host is responsible for operating and maintaining the system, and is entitled to use the power generated by the system to offset its purchase of power from the utility. In exchange for this use of the system, the lessee makes a series of recurring lease payments to the lessor (these payments must be made irrespective of how well the system performs).

Under a "capital lease," the lessee (site host) receives the project's tax benefits; this is sub-optimal if the lessee cannot efficiently use them (many can not), and is the primary reason why capital leases are not prevalent in the commercial PV market. Under an "operating lease," however, the tax benefits go to the lessor – a leasing company or tax investor that can typically make efficient use of them. Thus, an operating lease overcomes the barrier of PV's high up-front cost and also allocates the project's tax

benefits to the party best able to use them, but otherwise leaves O&M responsibilities and performance risk with the lessee/site host.

C. Power Purchase Agreement (PPA)

Under this third-party ownership structure, the site host neither owns nor leases the PV system, but instead agrees to buy all of the *electricity* generated by the system for a specified term, through what is known as a power purchase agreement (PPA).⁹ The project developer either owns (in partnership with its tax investors) or leases (from its tax investors) the system, and is responsible for operating and maintaining it throughout the entire PPA term. The project developer (and its tax investors) take on the risk that the project does not perform as expected – i.e., the site host only pays for power that is actually generated. As the owners of the project, the project developer and/or its tax investors take all of the project’s tax benefits (and, in effect, pass a monetized portion of them through to the site host in the form of a lower PPA price).

In most cases, the goal of all parties has been to set the PPA price so that the site host initially pays no more for PV power than it would otherwise pay the utility for regular service. Over time, however, the PPA price typically escalates by anywhere from 1% to 5% annually, and therefore may end up being either higher or lower than utility rates over what is typically a 20-year contract term. Most PPAs also include an “early buyout option” that is exercisable at one or more specific points in time (though typically never prior to the end of the project’s sixth year, by which time the majority of the project’s tax benefits have been utilized) and allows the site host to purchase the system for the greater of either a pre-arranged price that will adequately compensate the project’s investors, or the system’s fair market value at the time the option is exercised. In some cases, PPA prices are even structured to “step up” considerably after six years as a means of encouraging an early buyout once all of the tax benefits have been exhausted.

From the site host’s perspective, a PPA feels very much like an operating lease: no up-front costs, ongoing payments that are treated as an operating expense and that are often expected to be less than what it would otherwise pay to the utility, no need to be able to use the project’s tax benefits, and opportunities to purchase the system at its fair market value at one or more points in the future. The primary difference – which reportedly is a major selling point for the PPA¹⁰ – is that, under a PPA, the site host is not required to operate and maintain the system, and likewise faces no performance risk. In short, the PPA model effectively provides the site host what it presumably *really* wants – solar *power* at an affordable price, rather than solar *equipment* that it must operate and maintain.

4. Choosing a Structure

Though few decisions can be boiled down to this level of simplicity, Figure 1 provides a basic decision tree that might help guide commercial site hosts to a suitable financing structure. This tree could potentially be branched in a number of different ways, but the question of tax appetite seems to be the most logical starting point (although given a new federal grant program described in the concluding section of this article, the site host’s tax appetite could become much less relevant going forward). If the site host can efficiently use the project’s tax benefits *and* is willing to accept performance risk, then either balance sheet finance or a capital lease (or a bank loan) may be appropriate, depending upon the extent to which the site host can fund the up-front cost of the system. If the site host has no tax appetite but is creditworthy (ideally with an investment-grade rating), then either an operating lease or a PPA would seem to be most logical, depending primarily upon the host’s willingness to accept performance risk, and to a lesser extent on system size – leases are arguably more-suitable than PPAs for smaller projects.

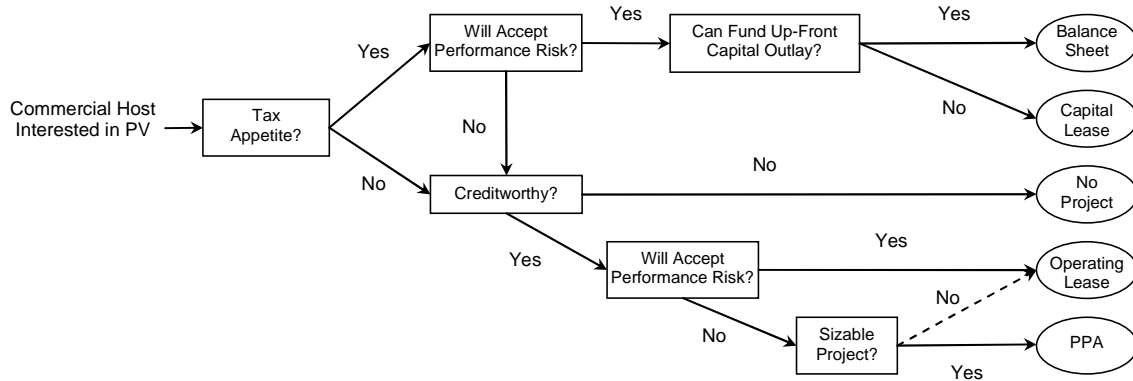


FIGURE 1. CHOOSING AN APPROPRIATE FINANCE STRUCTURE

Because PPAs simplify PV for the site host by eliminating the need for tax credit appetite, while also shifting performance risk and O&M responsibilities to others, they have reportedly been capturing an increasing share of the commercial PV market. By one estimate¹¹, PPAs have grown from just 10% of the non-residential U.S. PV market in 2006 to roughly 50% in 2007, and were projected to reach roughly 90% of the market in 2008, assuming that the federal ITC was extended early in that year (it was not extended until October 2008, by which time some projects had already reportedly been temporarily put on hold pending ITC certainty and resolution of the global financial crisis). Other estimates are more-conservative¹², but still exhibit and predict strong growth for the PPA model. Reflecting their prominence in the market (at least prior to the recent financial crisis), the rest of this article will focus exclusively on PPAs: how the developer finances such projects; what their economics look like, including sensitivities; and the outlook for such projects.

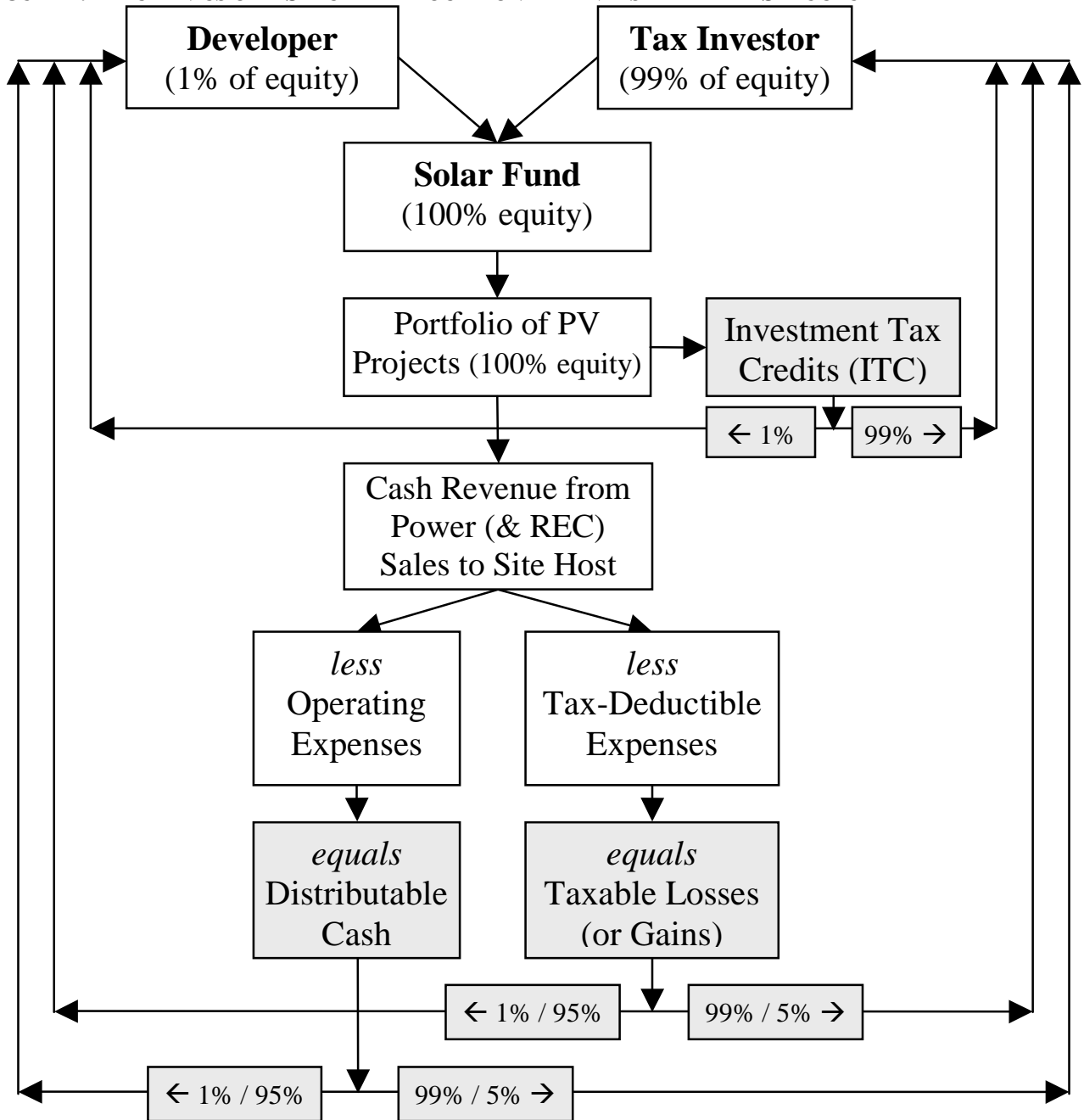
5. Financing the PPA

From the commercial site host's perspective, entering into a PPA simply means signing a contract with the PV project developer and its tax investor – i.e., the site host is not required to make any financing decisions. Rather, the burden of financing the project falls upon the project developer, which can finance a PPA project in one of at least four ways: it can sell the project to a tax investor with an option to buy it back in the future, once the tax benefits are exhausted; it can enter into a “special allocation partnership” with a tax investor to jointly own the project (but allocate the vast majority of the tax benefits to the tax investor); it can lease the project from a tax investor, through a sale/leaseback arrangement; or it can lease the project to a tax investor, through an inverted pass-through lease, with an election to pass the tax benefits through to the tax investor. All four methods have been used in the market, in some cases by a single PPA provider on different occasions. Though each approach has its strengths and weaknesses, this article focuses only on the “special allocation partnership” flip structure.¹³

Special allocation partnership (i.e., “flip”) structures have been used in the U.S. wind power sector for a number of years, and are therefore a familiar financing vehicle to many tax investors. Under this structure, the developer and tax investor each invest as partners in a special purpose entity or fund set up for the sole purpose of owning and operating one or more PV projects (in Figure 2, the “Solar Fund”). A substantial majority of the equity in the project company or fund – as much as 99% for solar deals, though typically less for wind projects – comes from the tax investor, with the remainder – as little as 1% – from the developer. The three benefit streams thrown off by operating projects – distributable cash, taxable gains or losses, and tax credits (represented in Figure 2 by shading) – are allocated primarily (as much as 99%¹⁴) in favor of the tax investor until it reaches an agreed upon internal rate of return (IRR), which is not expected to occur before the project's tax benefits have been exhausted (and, particularly for solar deals, may need to occur considerably later than that). Once the tax investor's target return is reached, the

allocations of distributable cash and taxable gain or loss (any tax credits will have been fully utilized by this point) “flip” heavily in favor of the developer for the remainder of the partnership (in Figure 2, the flip in allocations is denoted by a slash symbol – “/”). After the flip, the developer typically has an option to purchase the tax investor’s remaining interest in the project at its fair market value, as determined at that time. Since the tax investor’s post-flip allocations will be small (as low as 5%), the fair market value of its share of the project is also expected to be low.¹⁵

FIGURE 2. MECHANICS OF A SPECIAL ALLOCATION PARTNERSHIP “FLIP” STRUCTURE



6. Modeling the Economics of a PPA in California

This section analyzes the economics of the PPA model within the context of California's solar market. California is chosen for two reasons. First, California represents by far the largest solar market in the United States, and is also where much of the financial innovation described in this article originated and has become most-firmly entrenched. Second, the California Solar Initiative (CSI) includes a transparent schedule of how incentive levels will change over time as installed capacity goals are met, thereby providing an ideal framework for sensitivity analysis that is, at least somewhat, grounded in reality.

The financial analysis ignores the impact of power bill savings on site host economics, since power bill savings will depend on a variety of factors, including retail rate structure, site host load shape, and net metering policies, and must be modeled over shorter time scales than are appropriate or otherwise necessary for this article. Instead, the analysis focuses on the site host's *cost of procuring those power bill savings*, whatever they may be. In other words, the model calculates the amount of incremental revenue (above and beyond any cash or tax incentives, and consisting of both power bill savings and any additional revenue from the sale of the project's RECs) required for the project to make economic sense. If the power bill savings (plus any REC revenue) are expected to be higher than this modeled revenue requirement, then the project will be economical (presuming the model's assumptions reflect reality over time). Finally, the modeling ignores any end-of-term or early buyout options (i.e., it assumes that, if present, these options are *not* exercised).¹⁶

Table 1 shows the results of this modeling exercise. The first two rows in the "MODELING RESULTS" section show the first-year (\$0.206/kWh) and levelized 20-year (\$0.270/kWh) revenue that is required (above and beyond any cash or tax incentives) to satisfy all modeling constraints. Again, if the project can generate at least this much revenue through some combination of power bill savings and REC sales, then the project will be economical (as modeled). As a benchmark of likely bill savings in California, Wisner et al. (2007) found that the most advantageous energy-only electricity rates for commercial solar in California came to roughly \$0.18/kWh in 2007 (electricity rates may have risen or fallen since then).¹⁷

TABLE 1. MODELING RESULTS FOR A SITE HOST PPA (FINANCED BY A SPECIAL ALLOCATION PARTNERSHIP STRUCTURE) IN CALIFORNIA

MODELING ASSUMPTIONS	
System Size (kW _{DC})	500
Installed Cost (\$/kW _{DC})	\$6,000
Annual Performance (kWh/kW _{DC})	1,350
Performance Degradation (%/year)	0.5%
Annual O&M Cost (\$/kW _{DC} -year)	\$30
Annual O&M Escalation (%/year)	3%
State Incentive Type	5-Year PBI
State Incentive Level (\$/kWh)	0.22 (Step 5)
Debt Leverage (% of installed cost)	0%
Tax Investor IRR Target at Flip Date	7.0%
Target Flip Date (end of year)	18
Period of Analysis (years)	20
Required Revenue Escalator	4%
MODELING RESULTS	
First-Year Required Revenue (\$/kWh)	0.206
Levelized 20-Year Required Revenue (\$/kWh)	0.270
Tax Investor 20-Year After-Tax IRR	7.0%
Developer 20-Year After-Tax IRR	18.8%
Overall Project 20-Year After-Tax IRR	7.6%

Since the revenue requirements under the PPA model may be met through some combination of power sales and REC revenue, they should not be directly equated with PPA prices, which might be somewhat lower to the extent that the owner strips off the RECs and sells them separately. That said, it is perhaps worth noting that the calculated first-year revenue requirement under the PPA model (\$0.206/kWh) is in the ballpark of a recent 3.4 MW PPA project in California involving the Milpitas School District (as site host), Chevron Energy Solutions (as developer), and Bank of America (as tax investor/lessor). This PPA features pricing starting around \$0.20/kWh and escalating at 4.5% per year over a 23-year period.

7. Sensitivity Analysis

Using the assumptions shown in Table 1 as a starting point, this section takes a closer look at individual modeling assumptions to gauge their impact on the economics of solar PPAs in California.

- **Installed Costs:** As installed costs drop from the $\$6/W_{DC}$ base-case assumption to $\$5/W_{DC}$, required revenue falls by $\$0.06/kWh$, making the solar sale significantly easier.
- **PBI Levels:** The base-case assumption is Step 5 of the CSI (i.e., $\$0.22/kWh$), in which all three participating utilities resided as of early February 2009. As 5-year PBI payments decline from Step 5 ($\$0.22/kWh$) to Step 6 ($\$0.15/kWh$), required revenue increases by $\$0.03/kWh$ on a 20-year levelized basis. In the opposite direction, the revenue requirements under Steps 2 and 3 are roughly consistent with PPA prices signed several years ago.
- **Flip Date:** Although the base-case assumption is for the flip in allocations to occur at the end of the project's eighteenth year, earlier flip dates are quite possible – conceivably as early as the end of the sixth year (by which time most of the project's tax benefits have run their course). In practice, however, the need to have revenue requirements approach competitiveness with utility rates (in the absence of high REC pricing) does not typically allow a flip in cash and tax allocations prior to the project entering its late-teen years. Specifically, flip dates of 10 years or earlier significantly increase the amount of revenue required: by $\$0.15/kWh$ for a flip at the end of the tenth year, and by as much as $\$0.40/kWh$ for a flip at the end of the sixth year.
- **Tax Investor Yields:** In the best of times, tax investor target returns have fallen into the 6% range (Table 1 somewhat conservatively assumes 7%). Since the start of the financial crisis, however, yields are reportedly up by roughly 200 basis points.¹⁸ Moving from a 7% to a 9% return pushes levelized revenue requirements up by nearly $\$0.07/kWh$. Another way to think about the recent increase in tax equity yields is to translate them into installed cost terms – i.e., installed costs would need to drop to nearly $\$5/W_{DC}$ (or by almost $\$1.0/W_{DC}$) in order to maintain the same revenue requirements (both first-year and levelized) in the face of tax equity yields rising from 7% to 9%.
- **The Double-Threat of Higher Returns and Lower Incentives:** If the tax investor target IRR remains at 9% over time, then installed costs must drop further (from roughly $\$5/W_{DC}$, per the previous bullet) to roughly $\$4.60/W_{DC}$, $\$4.20/W_{DC}$, and $\$3.90/W_{DC}$ as PBI levels decline in the future to $\$0.15/kWh$, $\$0.09/kWh$, and $\$0.05/kWh$ (Steps 6-8 of the CSI), respectively, in order to maintain the “base-case” revenue requirements (first-year and levelized) shown earlier in Table 1.

8. Conclusion

Financial innovation in the non-residential PV market over the last five years has been more revolutionary than evolutionary in nature. Drawing upon financial structures pioneered in the U.S. wind power industry, and spurred on by a sharp increase in tax benefits at the federal level and a shift towards PBIs at the state-level, third-party ownership has been a primary driver of the strong growth of PV in the non-residential sector over this period.

Looking ahead, it is tempting to conclude that ongoing financial innovation is likely to be more evolutionary than revolutionary in nature. In particular, the eight-year extension of the 30% federal ITC

in October 2008 provides an unprecedented period of stability in which to tweak and refine existing financing structures to better meet the needs of the commercial PV market. It also provides a solid footing on which the industry can invest in the supply chain capacity and infrastructure necessary to meet future demand.

Somewhat paradoxically, however, the future of commercial PV finance is currently more uncertain than it has been in a number of years. For example, declining state-level cash incentives make third-party ownership (and solar in general) a harder sell, absent commensurate reductions in installed project costs. To date, such cost reductions have not kept up with the pace of incentive decline,¹⁹ though industry observers generally expect significant module price reductions in 2009 and 2010, as a result of lower silicon prices and an over-supply of manufacturing capacity relative to likely demand.

Moreover, the fallout from the current financial crisis has caused project delays and cancellations, leading to layoffs among project developers. Many of the large banks and insurance companies that have invested tax equity in commercial PV projects no longer have taxable income to shelter in this way (some of these tax investors, such as Lehman Brothers, no longer even exist), leading to an acute shortage of equity capital. Those few tax investors who are still investing in solar now require higher returns in exchange for use of their tax base. This, in turn, exacerbates the affordability challenge, making solar less competitive with utility rates.

To try and address this problem – i.e., an ITC that has been rendered largely ineffective as a policy tool because of a lack of tax investors able to monetize the credit and pass along its benefits – Congress passed a number of changes to federal renewable energy policy as part of *The American Recovery and Reinvestment Act of 2009*, signed into law on February 17, 2009. These include an extension of first-year “bonus depreciation” (the project owner can write off 50% of the depreciable basis, after reduction for 50% of the ITC, in the project’s first year), as well as a new provision allowing owners of qualifying commercial projects that commence construction in 2009 or 2010 (and that are completed prior to 2017) to choose between the ITC or a cash grant of equivalent value. This provision potentially gives the project owner the ability to bypass the tax equity market altogether (although a tax base will still be needed to efficiently absorb accelerated depreciation losses), and could therefore have a profound impact on commercial PV financing structures.

Finally, as part of the eight-year extension of the 30% ITC that passed in October 2008, utilities gained the ability to directly use the credit (“utility property” was previously excluded from ITC eligibility). To what extent utilities decide to enter the PV market, and in what form (e.g., as passive tax investors, as strategic project developers/owners of distributed “rooftop” projects, or as developers/owners of large “utility-scale” projects that feed power directly into the grid), remains to be seen. What is clear is that many utilities have demonstrated a growing interest in solar, and most utilities are still profitable, with tax liability to potentially shelter through some form of PV ownership. As such, utilities and other “non-traditional” tax investors (e.g., profitable high-tech companies) could step in and drive the next wave of innovation in commercial PV financing.

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Mark Bolinger is a Research Scientist in the Electricity Markets and Policy Group at Lawrence Berkeley National Laboratory (LBNL). Mr. Bolinger’s work at LBNL focuses on the design and evaluation of renewable energy policies; understanding the cost, performance, and value of renewable generation within electricity markets; and renewable project finance. Mark holds a masters degree in Energy and Resources from the University of California at Berkeley, and a bachelors degree in history from Dartmouth College.

ENDNOTES

¹ Larry Sherwood, *U.S. Solar Market Trends 2007*, INTERSTATE RENEWABLE ENERGY COUNCIL, August 2008, available at http://www.irecusa.org/fileadmin/user_upload/NationalOutreachPubs/IREC%20Solar%20Market%20Trends%20August%202008_2.pdf (last visited Feb. 19, 2009).

² A number of “utility-scale” or “central-station” PV projects – i.e., those that sell power directly to a utility, rather than displacing power purchased from a utility – have also been built or announced in the United States. These central-station systems are not the subject of this article.

³ Sherwood, *supra* note 1.

⁴ Mark Bolinger, *Financing Non-Residential Photovoltaic Projects: Options and Implications*, LAWRENCE BERKELEY NATIONAL LABORATORY, 2009.

⁵ Readers interested in learning about specific incentives available in each state can find more information at www.dsireusa.org.

⁶ A set-aside (sometimes also referred to as a “carve-out” or “tier”) is simply a requirement that a certain amount of the renewable power required under an RPS come from a specific resource, such as solar. A multiplier is simply a provision that counts each MWh of solar (or whatever the favored resource) as something more than one MWh for purposes of RPS compliance, thereby enabling the utility to comply with the standard more easily if it uses the favored resource.

⁷ RECs also derive some value from voluntary green power purchases, but to date, the price of RECs sold into so-called “voluntary markets” has paled in comparison to the price levels reached in RPS “compliance markets.”

⁸ Database of State Incentives for Renewable Energy, 2009, available at www.dsireusa.org (last visited Feb. 19, 2009).

⁹ Technically, the PPA is typically structured as a “service contract” within the meaning of Section 7701(e) of the Code (which distinguishes a service contract from a lease). This is primarily an issue for tax-exempt site hosts, which must take care that the agreement is not characterized as a lease, so as not to jeopardize the tax investor’s use of the project’s tax benefits.

¹⁰ Chadbourne & Parke LLP, *A Hot Solar Market*, PROJECT FINANCE NEWSWIRE, June 2008.

¹¹ John Guice, “Solar PPAs: Market Overview,” IREC webinar on *Solar Power Purchase Agreements*, June 12, 2008.

¹² Paul Detering & Matt Lugar, “The Advance of the Solar PPA: When an Organization is Ready for a Power Purchase Agreement,” Greentech Media Webinar presentation, September 19, 2007.

¹³ Readers interested in more information on the other financing approaches are referred to Appendix C of Bolinger, *supra* note 4.

¹⁴ These partnerships are structured to comply with a “safe harbor” for “wind farm” partnerships issued by the IRS through Revenue Procedure 2007-65. Specifically, Revenue Procedure 2007-65 requires that the developer take at least 1% of the project’s tax benefits.

¹⁵ For a more-detailed description of special allocation partnership flip structures, as used in the U.S. wind industry, see John Harper et al., *Wind Project Financing Structures: A Review & Comparative Analysis*, LAWRENCE BERKELEY NATIONAL LABORATORY, 2007.

¹⁶ Specific project-related modeling assumptions are shown in Table 1, and are described in more detail in Bolinger, *supra* note 4.

¹⁷ Ryan Wiser et al., *The Impact of Retail Rate Structures on the Economics of Commercial Photovoltaic Systems in California*, LAWRENCE BERKELEY NATIONAL LABORATORY, 2007.

¹⁸ Chadbourne & Parke LLP, *State of the Tax Equity Market*, PROJECT FINANCE NEWSWIRE, November 2008.

¹⁹ Ryan Wiser et al., *Tracking the Sun: The Installed Cost of Photovoltaics in the U.S. from 1998-2007*, LAWRENCE BERKELEY NATIONAL LABORATORY, 2009.